ELECTRICITY PRICING AND REGULATION

A thesis submitted for the degree of Doctor of Philosophy

by

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July 1999

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Abstract

This work aims to assess the development of competition in the electricity industry of England and Wales, emphasising one of the key elements of the restructured industry, the pool - a centralised day-ahead electricity spot market.

The pool's structure is examined, along with the relationship that the pool has with the market for electricity forward contracts. However, the key to this work is the relationship between the major electricity generators and the industry's regulator. This is introduced through two theoretical models, and undertaken through a series of econometric models using pool prices, forward prices, electricity demand, and the share prices of the major generators: National Power and Powergen.

The work tests the hypotheses put forward by Green (1992) and Helm & Powell (1992) of an inverse relationship between the volume of output that a generator sells forward through contracts and the general level of pool prices. The break-up of the first and second sets of forward contracts - which expired in 1991 and 1993 – and their impact on pool prices are assessed.

By using the market model, this work examines the impact of a series of both regulatory and non-regulatory events on the share returns of National Power and Powergen.

Given the existence of spot and forward markets for electricity, one would expect a relationship between the prices in these markets The relationship is examined for England and Wales by a synthetic data set that approximates the prices at which the contracts were sold. The relationship is then examined using actual and forecast electricity prices for California, this latter analysis forming part of an overview of electricity deregulation in America.

Ultimately, this research hopes to add to the growing amount of material on energy privatisation - a topic that continues to promote interest and controversy in academic and industrial circles.

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ACKNOWLEDGEMENTS.

The assistance and comments provided by my two supervisors, Professor Martin Cave and Dr. Ian Garrett, have proved invaluable in the completion of this work. I would also like to thank Professor Antonios Antoniou for the opportunity to undertake this research, and Professor Len Skerratt for his continued support.

Thanks must go to all of the staff of Brunel University's Economics & Finance Department for their support throughout my research and teaching, with special thanks going to Norma Bowes and Sally Lane. Thanks also to John Hunter and Kyriacos Kyriacou for advice on statistical processes.

Electricity pool price, uplift and demand data supplied by NCG's Energy Settlements and Services Division, with a special thanks to Maurice Smith for his completion of the data set.

Data on Electricity Forward Agreements supplied by Gerrard & National Intercommodities Ltd.. Thanks go to Ian Galea and James Hoare for their time, patience and assistance in this matter. Thanks to Jackie Barry (London Electricity) and Evan Edwards (Eastern Electricity) for supplemental information on the structure of the EFA market.

Thanks must be given to the following individuals for the supply of copies of the Horton IV estimates, their revisions, and subsequent notes on their formation: David Crook (Powergen), Charles Eickhoff (Swalec), Helen Jones (Northern Electric), Richard Penn (D.T.I.), and Geoff Horton (Offer).

All information on the deregulation of the Californian electricity industry was supplied by the California Public Utilities Commission, San Francisco, California.

All information on the share prices of the electricity generators and the FTSE-100 index were retrieved from Datastream. Thanks to Sian Owen and Denise Foreman for assistance in this matter.

Special thanks must go to Dr. Richard Green (University of Cambridge) and Andrew Powell (University of Warwick) for helpful comments on an earlier draft of this work. Thanks also to Steven Thomas (Citizens Power) for a little piece of inspiration and to Tomasso Valletti (Department of Economics, London School of Economics) for assistance on game theory modelling.

Special thanks go to Dr. Paul Tayler (Nuclear Electric; later Department of Computing, Brunel University) and Timothy Tutton (Energy Consultancy Division, Coopers & Lybrand) for comments and advice on the validity of the methodology utilised to create the Horton IV data set.

Thanks to Martin Stanley (Head of Physical Trading), Graham Southall (EMC Trading Manager), Paul Taylor (Physical Trading Manager), Colin Prestwich (Pool Development Analyst) and all of the Pool Trading and Electricity Operations Team at Eastern Power and Energy Trading for helpful comments and answering innumerable questions on the day-to-day operation of the electricity pool.

Thanks to Robert Galer (Manager, UK Gas Trading, Eastern Power & Energy Trading) and Alan Bowditch (Position Manager, UK Gas Trading, Eastern Power & Energy Trading) for their continued support during my re-write stages.

This thesis was written using WordPerfect versions 5.1 and 6.0, and Microsoft Word for Windows. All econometric analyses were performed on Microfit 3.0 and Microsoft Excel 5.0.

For my mother

"She may not look like much but she's got it where it counts, kid. I've made a lot of special modifications myself."

Han Solo, Captain of the *Millennium Falcon*,
***Star Wars* Episode IV: "*A New Hope*" (1977).**

"You want the impossible."

Luke Skywalker, Jedi Knight,
***Star Wars* Episode V: "*The Empire Strikes Back*" (1980).**

"No more training do you require. Already know you that which you need."

Yoda, The Jedi Master,
***Star Wars* Episode VI: "*Return of the Jedi*" (1983).**

CHAPTER I - Introduction.

The privatisation programme undertaken by the Conservative governments of Thatcher and Major has been a source of considerable debate in industry and academia ever since the process was first proposed. The programme was founded on the virtues of private ownership and on extending the role of competition in the economy, as well as limiting the interfering nature of central and local government in economic decision-making. Such arguments as the need for appropriate efficiency incentives and the need for a more *laissez-faire* approach were at the forefront of the demands for the massive process of privatisation and deregulation which the Conservative government began shortly after their election victory in 1979.

The privatisation programme implemented in the UK was on a scale unparalleled at the time, and as such, it represented a very difficult and precarious path for the government to undertake. One could not argue that the programme has been either a true success or a total failure - the learning process that began with the first privatisations is far from complete. As the government continued its privatisation process, it learnt from each of the industries that it has sold to the private sector. In particular, the electricity industry was the beneficiary of the experience learned in privatising the gas industry, which was privatised as an integrated monopoly. As a consequence, British Gas was in almost continued conflict with its regulator throughout much of its life. In contrast to the integrated monopoly of British Gas, the electricity industry was vertically separated and competition introduced into those areas where it was feasible to do so. In the case of this work, the key area of interest is electricity generation.

Each of the newly privatised industries faced its own regulator, charged with the responsibility of ensuring that consumers' interests were championed, as well as maintaining the spread of competition in those areas of the industry where such policies could be implemented. Although there are four main areas in the electricity industry: generation, transmission, distribution and supply, the potential for competition is greatest in generation, and to a lesser extent in supply. It was this sector of the industry that was the most drastically altered as a consequence of privatisation. The transmission grid and regional distribution companies were almost completely unaltered, while the generation sector was broken up into three generating companies, and the regulator actively encouraged new entry in generation. However, the degree of regulatory activity in the industry since privatisation has been indicative of the fact that competition has not developed to the extent anticipated by either the government or the regulator. It is this relationship between the regulator and the electricity generators which is at the heart of this thesis.

Privatisation brought with it the creation of a spot market for electricity - the pool - into which all generators must bid the prices of their generating plant. It was hoped that competition would develop in this market as generators attempted to get their plants called upon to generate. However, the generators created at privatisation possessed market shares which gave them considerable power in this market, and although new entry did occur, it did not occur on the scale needed to erode this market power. Thus regulation took the place of competition on a broader and broader scale.

This increased level of regulatory intervention served to make the relationship between the regulator and the generators more and more adversarial, as the generators began to operate in the pool in ways that maximised their profits, but which did not necessarily benefit consumers. This type of conduct led to investigations by the regulator into the structure of the industry and the conduct of the firms in the generating sector - reviews into generator strategy, pool prices, and the possibility of restructuring the generation sector.

In addition to the spot market for electricity, there is also a forward market, in which financial-type forward contracts are bought and sold. The spot and forward markets inter-react in such a way that the incentives of the generators can be altered, and the potential for spot market competition can be restricted by the role of the contract market.

Although all sections of the industry are regulated, there is a great deal of practical concern that the regulator does not possess full powers required to prevent the generators from making their strength felt in the spot and forward markets. In addition, there is the complication that, although regulation is a surrogate for competition, it can never truly take the place of competition. Typically, regulation serves to create a form of hybrid market, based upon discretionary intervention resulting from those activities that have attracted the regulator's attention.

Fears that the regulator does not possess either sufficient power or sufficient information to perform an adequate job are at the heart of theories of regulation. The best example of this in the regulated electricity industry was the controversial decision taken by the regulator to review the distribution price controls in the light of the defence package offered to shareholders of Northern Electric after it faced a hostile take-over bid by Trafalgar House (discussed below). Furthermore, if the generators are aware of the regulator's limited arsenal, they may choose to operate in such a way that their true intentions and strategies cannot be directly inferred. This implies either that they do not believe that their true actions will be detected, or that the regulator will undertake the actions needed to stop them.

The credibility of regulation is also an important element of this thesis, as it forms the basis for many of the conclusions of the empirical studies. It is important, for regulation to be successful, that the regulator maintains credibility, and that the generators be aware that he will act in a manner that will restrict their potential operations.

It is therefore the objective of this thesis to attempt to ascertain precisely how the electricity generators have responded over time to the continuing threat of regulation, and whether they believe this threat to be a clear and present danger to their operations. This issue will be examined by means of a number of empirical studies, including analyses on pool prices and their components, share prices of the electricity generators, and by examining the potential relationships between the electricity spot and forward market. It is also possible to view this analysis in the light of continuing electricity deregulation in America, where the electricity industry remains one of the last great monopolies, and where the UK experience could be seen as a valuable guide for possible strategies of deregulation.

Chapters II and III introduce the key terms and structures to be used throughout this thesis. These include the history and the structure of the pool, the history of electricity privatisation in the UK and the role of the spot and contract markets for electricity.

Chapter IV introduces the theoretical foundation for the empirical studies of the later chapters by examining two theoretical models of the pool: the Folk Theorem and the supply function model of Green & Newbery (1992). The former is a dynamic model that permits the dynamics of the pool to be examined by using either price or quantity schedules, while the latter is primarily a static model that allows price-quantity schedules to be evaluated. Therefore, while the former examines the repeated dynamics of the pool, the latter examines the true price-quantity bidding nature of the pool.

Having introduced the theoretical basis, Chapter V contains a range of studies based around the hypothesis that regulatory announcements would have a considerable effect on how the generators set pool prices. Such events are assessed using dummy variables to represent these events in a series of regressions, and to use the coefficients on the dummy variables to assess the consequences of these events.

Chapter VI focuses upon the role of the contract market in determining the pool price through an assessment of the impact of the break-up of the two major sets of electricity forward contracts in March 1991 and March 1993. It is therefore anticipated that the validation of these hypotheses will indicate the importance that the contract market has on the pool, and therefore the possible need for regulatory action in the contract market. This work is based upon and develops further the work of Helm & Powell (1992).

Chapter VII assesses how certain events have impacted upon the share returns of the two main generators – National Power and Powergen – through use of the market model. Chapter VIII incorporates a more in-depth examination of the forward contracts that initially governed the electricity industry following privatisation. The relationship of the prices of these contracts and the actual outturn pool prices is assessed in order to examine the actual strength of the contracts. This chapter also includes an examination of the progress of electricity deregulation in California – one of the most notable locations in which the UK experience of electricity deregulation is being used as a guide. Chapter IX concludes.

CHAPTER II: Electricity Privatisation in England and Wales - Contents.

Introduction - Privatisation and Beyond.

This chapter will assess the development of the electricity industry both before and after its privatisation in 1990. Specifically, it will examine the impact of privatisation upon the industry and how the industry has developed - for better or for worse - as deregulation has proceeded.

Electricity was restructured with the objective of increasing competition in those sections of the industry where such a transition was feasible, and maintaining prices and services for consumers in those sections where natural monopoly elements prevented the use of competition. Those parts of the industry where competition was deemed possible were generation - a move made possible by the division of the CEGB's generating capacity into three companies - and domestic supply, through the twelve regional distribution and supply companies. The introduction of supply competition was made possible by the use of a three-stage programme. In the first stage, beginning at privatisation, consumers with an annual electricity demand in excess of 1 MW were allowed to choose their own electricity supplier. As of April 1994, consumers with an annual demand in excess of 100 kW could choose their own supplier, and from April 1998 full domestic supply competition will be phased in over a six-month period.

Despite the vertical separation of the industry at privatisation, generators have undertaken supply and distribution contracts and regional suppliers have acquired generating assets. Therefore, the degree of inter-relationships between sectors represents an important aspect of the continuing deregulation of the industry. This is especially true given the mergers and acquisitions boom that gripped the industry in the summer of 1995 and has continued through a wave of rationalisations and horizontal and vertical integration.

Section I - Privatisation and industrial restructuring.

1.1. The UK Electricity Industry before and after Privatisation.

The UK electricity supply industry was perhaps the most radical of the privatisations carried out by the Conservative government as part of its commitment to private ownership. Privatised in 1990, the electricity industry was the beneficiary of the wisdom acquired from the earlier privatisations, notably of British Telecom (1982) and British Gas (1986). What made the privatisation of the electricity industry stand out from its predecessors was the considerable restructuring which accompanied the now customary share offers.

British Telecom had been privatised with BT itself retaining a highly dominant position within the industry. The then small Mercury was its only competitor, protected by the government's duopoly policy. British Gas, by contrast, had been privatised as a fully integrated monopoly, a move that was seen by many as a mistake. This viewpoint was quickly vindicated as the concerns about abuses of market power increased.

The privatisation of the nationalised Central Electricity Generating Board (CEGB) was first put forward in a 1988 White Paper, "Privatising Electricity", and followed attempts made earlier in the 1980s to introduce competition into the industry. (The systems were different in England and Wales than in Scotland. Only the former is discussed here). The pre-privatisation structure consisted of the CEGB that owned and operated all of the generating capacity in the country as well as the grid, and distributed power in bulk to the twelve Area Electricity Boards for sale to customers. In addition, there were electricity imports from the Scottish electricity companies and Electricite de France via interconnector relay systems linked directly to the national grid.

Unlike both British Telecom and British Gas, the electricity supply industry was to be vertically separated upon privatisation. This separation ultimately happened in the gas industry with the creation of Transco and Centrica from British Gas over the period from 1995 to 1997. Although it has yet to occur fully in telecommunications, BT is required to grant its competitors equal, non-discriminatory access to its network.

The company made responsible for all of the industry's high voltage transmission facilities was the National Grid Company (NGC), which would be co-owned by the twelve Regional Electricity Companies (RECs, the former Area Boards).

The RECs themselves were largely unchanged by privatisation - they remained primarily (low voltage) distribution and supply companies, each of which possessed a local monopoly franchise with distribution charges regulated by an Offer price cap. As with generation, there has been a notable spread of competition in supply following privatisation. Those consumers with an annual electricity demand greater than 1MW were free to choose their own supplier as of privatisation, with the threshold lowered to 100kW in April 1994, and with full competition phased-in from April 1998. In this deregulated market, the RECs also face competition from wholesalers (second-tier suppliers) for consumer business. The RECs now face competition from independent companies, the three main generators, and several large electricity users, as customers have the option of bypassing their local REC completely.

The most challenging early feature of privatisation was to be found in the generating sector, where it was anticipated that competition could truly be made the driving force. The initial plans would have had the CEGB's generating capacity divided between two firms: National Power and Powergen. This plan was seen as doomed to failure, through the production of a system highly conducive to the exploitation of monopoly power and, inevitably, further restructuring in the future.

The structure was intended to be an asymmetric duopoly, with National Power being given control of all of the CEGB's nuclear plant and the majority of the fossil fuel plant (two-thirds of the industry's generating capacity), while the remaining fossil fuel plant would go to Powergen (the remaining third). The rationale behind this structure was to encourage the private sector to invest in nuclear power by grouping it with such a large proportion of the fossil-fired capacity. However, the private sector did not consider nuclear power to be a safe investment, due to increasing concerns about the environmental consequences of nuclear power and the potential level of decommissioning costs. Consequently, the government was forced to re-evaluate this facet of its privatisation programme.

Faced with an opportunity to re-evaluate its plans for the privatisation of the generating sector, the government made little substantive changes to the planned restructuring, with government retaining National Power and Powergen as the two principal generators with their aforementioned shares of the fossil fuel plant. The nuclear capacity became the publicly owned Nuclear Electric, itself ultimately floated as British Energy in 1996. British Energy comprises Nuclear Electric's Advanced Gas-cooled Reactors (AGRs), its Pressurised Water Reactor (PWR), and Scottish Nuclear's AGR facilities. Nuclear Electric's Magnox facilities are still in public ownership as Magnox Electric.

The NGC, with responsibility for distribution and supply to the RECs, was originally co-owned by the 12 RECs, but was floated as a separate company in late 1995, with the RECs relinquishing their ownership shares. In addition to the grid, NGC also owned the pumped storage businesses - the Welsh hydroelectric plants at Dinorwig and Ffestiniog used to meet peaks in demand. The floatation of the grid was planned for the summer of 1995, but the regulator delayed this until the end of the year. Shortly after its floatation, the grid's pumped storage businesses (now known as First Hydro) were purchased by the Mission Energy group, part of the US company Edison International.

Exports continue from Scotland (Scottish Nuclear, Scottish Hydro Electric, and Scottish Power) and France (Electricite de France). Although designed for both export from and import to the English grid, the flow through the interconnectors is typically to, rather than from, England and Wales.

The structure of the Scottish electricity supply industry was largely unchanged after its privatisation. The assets of the former North of Scotland HydroElectric Board (NSHEB) were transferred to Scottish HydroElectric, and those of the former South of Scotland Electricity Board (SSEB) went to Scottish Power. The exception to this agreement was the SSEB's nuclear capacity, which was transferred to Scottish Nuclear Limited. All three companies remain vertically integrated.

Since privatisation in England and Wales, there has also been a substantial increase in the number of small, independent power producers (IPPs), who are commonly linked to the RECs in some manner, be it in the form of joint ownership or equity shares. In the event of joint ownership, the RECs may contract out to the IPPs for up to 15% of their total power needs. The RECs have utilised this limit to varying degrees, with some contracting for over 80% of their total power requirements, others for less than 10%.

The modifications to the generating sector corresponded to modifications to the market for electricity, which became a spot market (actually a day-ahead market), called the pool. The electricity pool is effectively a spot market for bulk power that is owned and operated by NGC, through which the vast majority of all transactions for electricity must flow. (The role of the pool is outlined in depth in subsequent chapters).

There are four specific licences that can be issued to the companies who trade in the pool. These are for generation (held by generators), transmission (held only by the NGC), a second-tier supply licence (held by any company seeking to supply in the second-tier market), and a PES licence (held by the RECs, which covers both distribution and supply).

As with all privatised industries, the industry has a regulator: the Office of Electricity Regulation (Offer), headed by the Director General of Electricity Supply (DGES), Professor Stephen Littlechild, who has held the position since privatisation. The DGES holds regulatory authority over the industry with the President of the Board of Trade and the Monopolies and Mergers Commission (MMC). The three main activities of the DGES are to ensure that licensees are able to finance their licensed activities, that all reasonable demands for electricity are met, and that competition in generation and supply (but not transmission and distribution, as these are monopoly elements) is promoted.

The DGES has an obligation to act in the manner which he perceives the most appropriate, given the interests of consumers, the promotion of efficiency and economy on the part of licence holders, and the promotion of the efficient use of electricity. The DGES possesses a variety of functions, such as the provision of new licences, the monitoring and enforcement of the licence conditions, the investigation of complaints, and the provision of advice to the Secretary of State.

Of potential interest to this analysis are the following conditions. Firstly, Condition 5 of the PES licence contains the REC obligation on economic purchasing, which requires a supplier to purchase electricity at the most effective price having weighed up all alternative sources. The purchasing conditions of the PESs are dependent upon such factors as the duration of the appropriate forward contract, expected movements in pool and contract prices, and the predictability and variability of electricity demand. Secondly, Condition 6 of the PES licence concerns the own-generation limits imposed upon the RECs. It states that the own-generation capacity of the licensee and the appropriate share of declared capacity should not exceed the limit of 15% of the total demand in the PES's area. Amendments may be made to the licences as appropriate, at the discretion of the DGES.

The other major change brought about as a consequence of privatisation was the introduction of the Fossil Fuel Levy (FFL) and the Non-Fossil Fuel Obligation (NFFO). The former of these conditions requires the RECs to contract a certain percentage of their demand from plants powered by non-fossil (including nuclear) fuels. The goal is to ensure a continued diversity of fuel supply. Those generators who have NFFO contracts are paid a premium for the electricity generated. This premium is financed by the FFL, paid by licensed electricity suppliers, and reflected in consumers' bills. The FFL is currently set at 10%, and is to be discontinued at an unspecified future date.

1.2. Industrial reforms made since privatisation.

In addition to the restructuring at privatisation, it was hoped that competition would develop in the generating sector by the availability of public electricity supply (PES) licences. Subject to authorisation, any company can obtain a licence to act as a generator and to build and operate power stations. In the first three years after privatisation, over twenty of these licences were issued, mainly for the newly developed, high efficiency combined cycle gas turbine (CCGT) generating equipment. The IPPs, many of whom are partially owned by the RECs, have constructed plants and have been able to secure contracts for gas supplies, supplying fifteen year contracts with their parent companies.

(The issue of REC ownership of IPP plants will be examined with below).

In the first year after vesting, National Power and Powergen together accounted for 74% of the electricity sold into the pool, with Nuclear Electric and the other generators (mainly the Scottish companies) comprising the remaining 26%. The balance has continually shifted away from the incumbent duopolists towards the nuclear industry and the IPPs. This is due to increased investment in new plant and also legislation from the DGES with regard to plant closures. Consequently, by late 1994, Nuclear Electric was facing the prospect of overtaking Powergen as the second largest generator in the industry. Although Nuclear Electric has little direct influence on prices, its plants play an important role in setting prices. Nuclear Electric's plant is baseload capacity, i.e. it operates twenty-four hours a day, and if its supply is interrupted, then electricity prices will increase sharply in a relatively predictable manner. This facet of the industry was illustrated in early 1995 when Nuclear Electric's Dungeness and Heysham reactors were shut down on maintenance grounds – the resulting price spikes were well reported.

In the longer term, yet more capacity could be added both through more independent generators, who continue to enter at an increasing rate, and through the Scottish and French companies, who have increased the load capacity of the interconnector. Further competition has come in the form of Open Cycle Gas Turbines (OCGT) plants and Combined Heat and Power (CHP) facilities.

The main concern regarding the generation sector is that it is uncompetitively and inefficiently structured as a triopoly. Although Nuclear Electric is one of the largest generators in terms of available capacity, it has no direct influence on how prices in the pool are set. Prices are in fact set by National Power and Powergen over 85% of the time, with the pumped storage businesses (later First Hydro, see above) setting prices the remaining 15% of the time.

Even if the generators behave non-collusively in the spot market, they still possess a high degree of market power that is constrained only by the threat of new entry. If entry deterrence can occur without lowering prices, then there are dead-weight welfare losses from operating at too high a price with too low an output. If entry deterrence should prove unsuccessful, then inefficiency will result from excess entry, investment, and the unnecessary duplication of resources. Such conditions could be exacerbated due to the cost pass-through condition of the RECs' supply licences.

Theoretically, given the highly concentrated industrial structure, the inelastic nature of electricity demand, and the fact that National Power is effectively a resident monopolist (given the MMC's definition of a monopoly), it is unlikely that competition in the spot market will result in marginal cost pricing. The industry's highly concentrated structure, combined with the repeated interaction of the generators within the pool's bidding structure, could result in collusive behaviour and high prices. If this were to occur on a large scale, this could lead to excessive investment in new capacity within the industry.

It is therefore the role of the regulator to prevent such an outcome, and the conclusion as to whether regulation has been successful is a highly debated one. This is increasingly relevant following the revised distribution price review of 1995 and the increasing number of take-over and merger offers for RECs in the period which occurred in and after the summer of 1995.

An important regulatory consideration, especially from the viewpoint of the large incumbent generators, is whether it is socially desirable to allow the RECs to own a share in the IPPs. Given the cost pass-through of the RECs, it has been argued that the RECs may simply purchase electricity from the plants in which they have an equity stake regardless of the cost, then pass these inflated costs on to the consumers. The revenue lost by uncompetitive purchasing will be compensated for by revenue gained from electricity sales, with a minimum of risk for the RECs - representing a serious violation of the efficient purchasing condition of the PES licence. This was such a concern voiced by the larger generators that the DGES was forced to undertake an inquiry into the issue. (Offer, Review of Economic Purchasing, 1992, 1993).

The RECs argued that, given the lack of long term contracts being offered by the incumbent generators, the contracts being offered by the IPPs represented the least cost way of making future electricity purchases. The evidence compiled on CCGT plants is that they have higher total costs than the variable costs of existing coal fired plants and new coal fired plants burning imported coal.

One of the solutions put forward for the problems with the contract market was a tendering system whereby all generators would bid for contracts to supply the RECs, with competition being ensured by all of the bids going through the DGES. Alternatively, some modified form of benchmark pricing could be used, which would permit only a partial cost passthrough. This would be some fraction of the excess cost of any long-term contract relative to the average costs of purchase faced by the other RECs. However, such a proposal would increase the degree of risk faced by the RECs, as they would no longer be fully insulated from unanticipated price increases, requiring them to seek a higher return on their activities.

If the RECs were required to bear a higher proportion of the risks, then it would discourage them from investing in the IPPs. Such an occurrence would limit new entry into the industry, thereby strengthening the power of the incumbents. The review carried out by the DGES into this matter concluded that there were no detrimental effects on prices caused by the practice of allowing RECs to invest in the IPPs. Indeed, the DGES found that, by encouraging new entry into the industry, the RECs were promoting efficiency rather than harming it.

In February 1994, following months of concern regarding price setting within the pool, and repeated threats of an MMC reference for National Power and Powergen, an agreement was reached between the regulator and the generators on conditions for price control and the sale of generating plant. Although this will be covered in a subsequent section, it is important to note that the generators initially did not have a great deal of success complying with the terms of this agreement, experiencing problems with both the price control element and the sale of plant. Ultimately, the main beneficiary of the forced sale of plant was the Eastern Group.

Some of the remaining reforms have already been referred to in passing. However, it is appropriate to re-state some of them. Firstly, following the sale of the government's residual forty percent stake in the electricity companies in March 1995, a series of REC take-overs resulted. These were pre-empted by the bid for Northern Electric made by Trafalgar House in December 1994, but the remaining take-overs occurred after the government's sale, notably in the summer of 1995. Many of the acquiring companies have generation interests or experience (notably the American companies), and it is anticipated that further moves into generation may be made over time.

The forced sale by the RECs of their shares in the National Grid occurred in late 1995, and shortly after the pumped storage businesses (First Hydro) were purchased by Mission Energy. The most notable point of this move was the price paid by Mission - £650 million, well in excess of the prices anticipated by both the City and the NGC itself. This move led many to believe that Mission intended to expand its role in the generation market.

Of course, the main take-over plans that failed are those of National Power and Powergen, and their attempts to take over Southern Electricity and Midlands Electricity respectively. These moves were approved by the MMC, subject to certain conditions concerning the divestiture of generating plant. However, in a move that led to widespread controversy, the Trade and Industry Secretary Ian Lang opposed them and the take-overs were blocked. In addition, there was the move by Southern International (US) to acquire National Power, a move blocked by the government by the retention of its golden share.

1.3. Research into the electricity industry's post-privatisation structure.

Prior to privatisation, a number of commentators examined the consequences for efficiency of a number of different potential structures for the industry. Suggestions ranged from the establishment of nine or ten separate companies, none of whom could grow to supply in excess of 20% of the market, to strategies that simply advocated extensive regulation in all sectors of the newly privatised industry. This section examines the work of several noted authors and their conclusions regarding the structure of the generating sector and the conduct of the generators.

Green & Newbery (1992) attempt to model the electricity spot market by means of the following methodology derived from Klemperer and Meyer's (1991) supply function approach to oligopoly. It is assumed that each firm submits a smooth supply schedule for its generating output, relating output to marginal price, and that a price is also submitted for each time that their generating unit is started. In addition, payments are made for a nonzero LOLP (loss of load probability - the risk of a power shortage - see below for additional information) as demand approaches the available capacity. These simplifying assumptions are designed to limit the market power of the firms, and therefore provide an optimistic assessment of the true condition of the generating sector.

The only equilibrium sought are non co-operative Nash equilibrium in the spot market, analysed as a one-shot game, in which there is assumed to be no learning process. (Theoretically, this is an ideal situation in which the duopolists could maintain a collusive equilibrium in a repeated game). The demand function used is the load duration curve, which gives the number of hours in a day in which demand exceeds a certain level.

Demand is given as a function of price and time, where time is the number of hours in which demand exceeds a certain level. The demand curve for a particular firm in a symmetric duopoly is the total demand minus the supply of its competitor. Because generators supply both price and quantity to the market, neither conventional Bertrand nor Cournot oligopoly methodology may be utilised. This problem was eliminated in general terms by Klemperer and Meyer's (1991) technique of supply function equilibrium in oligopoly. By using this methodology, it is discovered that there is a range of potential equilibrium, lying between the Bertrand (marginal cost pricing) and Cournot solutions. There is only a unique solution in the event that the demand schedule is arbitrarily high.

The use of a shadow price to incorporate supply constraints into the analysis narrows the range of potential equilibrium has been narrowed. The range of equilibrium will no longer include the Bertrand point and some of the more competitive solutions. There is only a unique equilibrium in the event that maximum demand intersects with full capacity to generate the Cournot solution, or if demand is capacity constrained (insufficient capacity to meet demand) at the Cournot point. By subsequent modifications to the analysis, it is shown that if incumbents and potential entrants all have access to the same technology, and the incumbents can credibly commit to a supply schedule, then the incumbents can earn higher long run profits by co-ordinating on a high-output, low-price strategy.

In examining the more realistic case of an asymmetric duopoly, the results indicated that the cost functions for the two firms were not dissimilar at the industry level (this was not true at the firm level) than in the symmetric case. In the asymmetric case the larger firm (National Power) will gain more from a price increase and will therefore choose a steeper supply function, relative to marginal cost, than in the symmetric case. This gives the smaller firm (Powergen) a less elastic residual demand curve and a greater incentive to raise price. The combined effect will make the industry supply curve steeper. In the asymmetric case, Powergen is actually seen to be better off than National Power, due to NP's steeper supply function (relative to marginal cost) which means that it does most of the work in terms of keeping prices high. NP produces a greater output, but the greater surplus it earns over its fuel costs is more than offset by its higher fixed costs. In the asymmetric case, less output will be sold at a higher price, and industry operating costs will be further raised for any level of output since the stations will no longer be operating in merit order. (This technique is discussed further in Chapter IV).

From Green & Newbery's (1992) empirical analysis, in the short run the strategies followed by National Power and Powergen have little effect on entry. During this period they will have considerable market power and can offer supply schedules with price considerably above marginal cost - even in the event of a non-collusive strategy. There are also additional methods of manipulating the market by exploiting constraints in the grid's transmission capacity and by altering different bid components, in addition to being able to support collusive outcomes in the repeated game.

In the medium term, considerable entry would be likely in response to the high level of prices, but the expansion of capacity is not justified on cost benefit grounds. If the incumbents can successfully commit to a competitive strategy after entry, they will deter more entry and earn higher long run profits than by a collusive strategy. However, total dead-weight loss caused by the industry is far greater in the current structure than if the industry had been broken up into five equal-sized firms, which is found to be the optimal structure. However, Green & Newbery (1992) also argue that there is the potential for considerable social welfare loss caused by excessive and unnecessary entry.

Furthermore, the authors suggest that the potential for the exercise of market power was considerably underestimated by the government at the time of privatisation, perhaps misled by the degree of competition in concentrated Bertrand markets. The potential dead-weight losses are high, both on the demand side and the cost side due to deviations from the merit order. The extent of these losses is dependent upon the degree to which the incumbents attempt to raise prices and short run profits in the period before entry. Almost all of these losses are seen to be potentially avoidable, had the industry been divided into five equal-sized firms at vesting. It is also seen that the logistical complications of such a structure would not have been great, and it can therefore be concluded that a major opportunity was lost to introduce greater competition into the generating sector.

Wolfram (1995) undertakes an extensive study into the UK electricity industry in an effort to ascertain the nature of price-cost mark-ups and the extent to which generators exercise their market power. Utilising pool purchase price as the dependent variable, the study incorporates many independent variables and assesses their responsiveness to such events as the ending of the vesting contracts and the announcement and publication of the regulatory reviews. The data set in use consists of half-hourly pool price information from every day in sixth months (January, February, March, April, July and November) from 1992, 1993 and 1994. The following factors were used as independent variables: electricity demand, weather conditions (temperature, wind speed, cloud cover, and the time of day), GDP (to incorporate the effect of industrial production), fuel prices (coal, gas, heavy fuel oil, light fuel oil), and plant additions and closings.

In measuring the extent of the generators' price-cost mark-ups, the generators' marginal costs had to be estimated. These estimates were based around the generators' plants, their output, their fuel sources and the cost of that fuel, and the plant's thermal efficiency levels (the rate at which the plant converts fuel to electricity). The study indicated that the price-cost mark-ups were 20%, although estimates of generators' market power (as provided by the NEIO, Bresnahan (1989)) did not support this conclusion. The estimates of market power derived from the data indicated that the optimal industry structure was in fact a twenty-firm symmetric Cournot oligopoly, far from its current structure. It was hypothesised that the indicated level of market power was a consequence of the inelastic nature of the demand for electricity. Indeed, despite the relatively high level of the price-cost mark-up, further analysis showed that the two large generators exploited far less of their dominant position than was actually possible - an outcome attributed to the threats of entry and tighter regulation, and the existence of the vesting contracts. However, it was shown that it was the possibility of entry and regulation that were exhibiting the highest constraint on the mark-ups. If this conclusion is valid, then the threat of entry constraining prices is of course one of the characteristics of a contestable market, making the generating sector contestable rather than competitive. The possibility of contestability in generation is examined below in conjunction with the role of the contract market. However, it is noted that as the pool price is the main signal given out to potential entrants, pricing to deter entry means that the pool price should be held as low as possible - a goal which the generators may achieve through the use of the contract market.

Newbery (1994) examines the development of electricity supply industries in several industrialised nations, focusing primarily on those that have been privatised and examining those industries from a pricing and regulatory standpoint. For the industry in England & Wales, both the NGC and Offer have determined that marginal cost pricing is infeasible as marginal cost is consistently below average costs. Given that the industry has retained many of its natural monopoly characteristics despite privatisation, this should not be too surprising.

Newbery views the key determinant to consider when examining the possibility of industrial restructuring is the extent to which subsequent reforms may be allowed given what has gone before. It was anticipated that, in England and Wales, given the vertical separation of the industry, the pool was to operate in a manner that induced competitive behaviour by the generators. However, as has been illustrated, such operations raise questions regarding the financing of investment.

In terms of general efficiency, the electricity industry has seen its workforce halved and greater cost controls implemented. Despite increased competition and investment in the generating sector, the RECs have essentially retained their regional (franchise) monopoly structure. The extent to which this will remain so has already been questioned, given the continued deregulation of the RECs ability to obtain customers beyond their franchise area. The future is more questionable with the opening up of the franchise market in 1998 leading to full competition between the RECs.

In terms of operating efficiency, the evidence is mixed. Newbery suggests that the merit order has been compromised by the asymmetrical structure of the industry's generating sector, and that the dead-weight losses could be considerable, given the incumbents' ability to raise the marginal cost-price margin. Privatisation has seen a considerable reduction in staffing levels and limitations in research. There are strong incentives to premature retirement of the older, labour-intensive coal-fired stations, to be replaced by the less labour-intensive CCGT plants.

Although the retention of the transmission monopoly elements in public ownership is a possibility, it is one that would bring its own problems. The only feasible alternative to REC ownership of the grid was generator ownership of the grid, but such a move would have provided an obvious means to collusion through vertical integration. The last alternative, realised in 1995, is that of a wholly independent transmission company, but this could raise questions as to the neutrality of the owners. The final question concerns the distribution network and whether it should be an exclusive monopoly or whether generators should be allowed to construct their own lines. However, such a move would doubtless bring questions regarding inefficiencies resulting from an unnecessary duplication of investment.

The dominant regulatory question since privatisation is whether generators require explicit regulation, or whether the market can be safely left to competition. With National Power and Powergen dominating the setting of pool prices, the pumped storage businesses account for the remaining time that pool prices are set. However, the pumped storage businesses behave reactively based upon the actions of the other generators, and therefore cannot be said to be determining prices in the same way as National Power and Powergen.

It is indeed possible that the regulator may, in the future, prevent the RECs from passing through the costs of these contracts to their customers. Such a move would act as a disincentive to the signing of long-term contracts, and in doing so this would reduce the IPPs security (assuming risk-aversion) and deter entry - clearly indicating that there is a fine balance between these two concerns. The large generators did little to oppose this switch made by the RECs to the IPPs, possibly because increased contract cover would limit their market power, or possibly because they did not wish to limit entry for fear of accusations of limit pricing behaviour or some other anti-competitive practice. The outcome was an increase in the rate of entry leading to contracts that could not be overruled in a privatised electricity market.

One could argue that the lack of true price competition in generation has been responsible for high pool prices, which themselves induce excess entry. However, given that this entry was in the form of baseload power, it has therefore had little effect on the market power of the incumbents who own the majority of non-baseload plant. This has been at least partially rectified by the February 1994 undertaking.

This undertaking also had the distinction of imposing direct regulation on prices for the first time in the pool's history for the years 1994-5 and 1995-6. If the caps had been extended beyond 1995-6, it would have been an admission of failure on the part of the regulator in his efforts to allow competition to rule the submission of prices to the pool. Paradoxically, the price cap also meant that the generators had to collude in order to meet the cap, thus reversing another of the goals of privatisation. However, it is anticipated that with the removal of the caps and the required divestiture of plant from National Power and Powergen, the pool should begin to operate as it was intended to do so from the beginning.

However, even if the generating sector can be sufficiently fragmented to encourage competition, transmission constraints may serve to make effective market areas small and allow market dominance within those areas. Further problems include the extent to which entry is free, or whether it should be controlled to prevent excess entry, as some fear has already occurred. Another long-run issue is whether generation can actually develop as a competitive sector.

Section II - Developments in generation and the future of the sector.

2.1. Competition in Generation: The Importance of REC own-generation.

All RECs face limits on the amount of electricity that may be supplied by own-generation interests, as dictated under their public electricity supply (PES) licences. In addition, they must not own or have an interest in plant beyond a specified limit of 25% of their required capacity. The total limits faced by the RECs sum to 8.2GW, with present total interests being approximately 4GW, including capacity currently under construction. Different RECs have used their limits to different degrees: some RECs are very active in own-generation interests while others have little or no apparent interest in even using their own-generation limits. The pivotal aspect of the own-generation limits is the desire to increase competition into the generation sector. At present, RECs have an interest in generation plant which produces approximately 8% of total output, with their share of total capacity being around 5%. It is anticipated that these figures will increase correspondingly as capacity under construction comes on line.

In order to deter an MMC reference, in February 1994 both National Power and Powergen agreed to undertakings on prices and to the sale or disposal of some of their generating plant: 4000MW and 2000MW of plant respectively. Following this agreement, a number of RECs contacted Offer requesting the possibility of increasing their own-generation limits, their objective being to purchase plant from either National Power or Powergen. It was anticipated that this would be operated as part of a consortium of interests, but eventually it was Eastern Electricity that was successful in purchasing this plant. This move raises a number of concerns for the regulator and the industry. Firstly, the regulator has made it clear that a competitive market in generation remains a top priority for the industry, and this move goes some way to improving the current situation. Secondly, the rationale behind this undertaking was to encourage new entrants into the industry, not encourage the expansion of existing participants. Finally, as the nuclear sector continues to increase its generating output, the spread of competition in generation may become increasingly important, and the need for the sale of these plants may gain an added impetus.

The key question mark hanging over the decision to expand the RECs' own-generation limits is the extension of the competitive market in 1998. The RECs will still retain a great deal of market power over their (ex-) franchise customers who may be hesitant or have no great desire to change their supplier after the onset of full competition. Indeed, even the regulator has admitted that the spread of competition will take some time in the post-1998 environment. The argument essentially reverts back to that of whether allowing a REC to purchase electricity from a plant in which it has a share or a controlling interest represents a potential violation of the PES licence.

Under ideal circumstances, RECs could undertake the purchase of plant and not exploit their franchise while simultaneously contributing to competition. In order to achieve this scenario, it is possible that modifications to the current regulatory system regarding efficient purchasing could be introduced which would prohibit excessive contracting from such plants. However, perhaps an alternative rationale should be considered. It is illogical to expect that RECs have undertaken their operations into the generation sector solely to increase competition. On many occasions, the RECs have voiced their dissatisfaction with the generators and their bargaining power. In addition, as part of their PES licences, RECs must ensure stability and security of supply. Therefore, it may be the case that the desire to increase competition into the generation sector is a secondary concern for the RECs when considering their own-generation interests. Indeed, encouraging competition in generation may have no bearing on RECs' strategies: their primary motivation is in fact securing long-term reliable supplies in order to meet the demands of their customer base.

The major generators did not favour modifications to the own-generation limits in order to permit vertical integration. They perceived it as a threat to consumers under the captive franchise and a potential distortion to the spread of competition. However, any such modifications would increase the RECs' independence from the generators, and therefore the generators can hardly be considered impartial in this argument. The RECs themselves were anxious to obtain the relaxation or even abolition of the own-generation limits, citing the abolition of the direct sales limits as their motivation. The direct sales limits by National Power and Powergen were abolished as a means of facilitating competition, and thereby damaging REC market shares. The alteration of the own-generation limits is therefore seen by the RECs as a means reconciling the imbalance which the RECs perceive as resulting from the legislation, while allowing them to experience the benefits of linking supply and generation.

Despite support for this move, consumer groups echoed the concerns of the regulator: whether there would be sufficient restraint on the RECs to purchase in accordance with the PES licences, both now and after 1998 were the own-generation limits to be expanded. The RECs have maintained that the existing regulation will be adequate to restrain any and all attempts to violate the PES licence and exploit consumers. In order to consider the validity of this claim, certain factors need to be considered.

Firstly, as competition has become more widespread since privatisation, the RECs should be allowed the opportunity to expand their opportunities in the dynamic marketplace, just as the generators were following the abolition of the direct sales limits. Secondly, in order to protect consumers' interests, perhaps only marginal or conditional relaxation of the limits could be made, or any modifications to the limits could be accompanied by modifications and strengthening of existing regulation. Thirdly, rather than undertake an across-the-board relaxation of the generation limits, as the RECs approach their current limits they could petition the regulator for relaxation, with all requests being treated on a case-by-case basis. Finally, the limits could remain in force until 1998, and then be modified as the competitive market develops.

At the present time, it appears that the own-generation limits will remain firmly in place, reflecting the regulator's concerns about the inadequacy of the economic purchasing condition and the supply price control were the limits to be relaxed. The only exception to this rule would seem to be Eastern, a company anxious to make its mark in the generating sector through the purchasing of the aforementioned divested plant from National Power and Powergen. In this instance, Eastern has been allowed to purchase such high quantities of generating facilities in the interests of price competition - particularly in the non-baseload sector.

A further alternative method of protecting consumers has been put forward in the form of a tendering process for contracts. It is claimed that the tendering process would act as a surrogate for competition, especially if transparent and guaranteed by regulatory oversight, and linked to special conditions regarding RECs' own plant. Unfortunately, the tendering process has already been put forward by Nuclear Electric and largely dismissed as inappropriate. The final alternative is that of loosening the limits while imposing restrictions which prohibit the RECs from signing contracts for the franchise markets from their own plant. If imposed, these restrictions would doubtless have to re-evaluated in the light of the success (or lack thereof) of the events of 1998. At the present time, these appear to be the only circumstances under which a relaxation of the limits will be considered.

The nature of this argument is an important indication of the nature of the regulatory process in the electricity industry. The regulator's mandate requires the encouragement of competition in all aspects of the industry, while protecting the best interests of consumers. However, in this situation, the two goals appear to be in direct conflict with no apparent means of reconciliation. The only means of doing so is to allow competition but temper it with more regulation in order to protect consumers. However, this again violates the regulator's own personal belief in allowing the competitive process to run the industry while allowing regulation to take a backseat in order to 'guide' the industry. A suitable compromise would be to encourage new entrants into the industry to purchase plant from National Power and Powergen while retaining the own-generation limits. This would run parallel with an undertaking that the own-generation limits would be re-evaluated in the light of the 1998 programme and the RECs ability to undertake second-tier supply from domestic consumers.

Before concluding, consideration should be made of the links between the Scottish electricity industry and that in England and Wales. RECs have the right to seek out second-tier contracts in Scotland, but few have attempted to do so, and those who have met with limited success. This may be because of the vertically integrated nature of the Scottish industry, which may serve to limit an entrant's profit margins on the supply activity. Alternatively, it may be because the vertically integrated structure in Scotland may make the incumbent companies more willing to defend their market share by offering more competitive terms. Indeed, it should be noted that prices in the Scottish electricity market are lower than in England and Wales.

The difference between the structures of the two markets makes it difficult to draw any accurate parallels. However, if the Scottish companies offer more competitive second-tier terms because they are anxious to protect their profit margins in generation, then it is theoretically possible that the same may apply to RECs if their generating capacity were increased. If this were the case, then an expansion of the RECs' generating capacity may lead to an increased competitive impetus in the second-tier market as a consequence of vertical integration.

A further point may be drawn from the Scottish industry. Given the vertically integrated nature of the industry, the companies as electricity suppliers are contracted primarily from their own generating plants. As in England and Wales this is subject to an economic purchasing condition which prohibits exploitation of a captive franchise. However, the vertically integrated nature means that an additional provision has been built into the Scottish PES licences which imposes a direct limit on the prices that suppliers may charge themselves for electricity under contract from their own plants. In theory, the same principle could be applied to the RECs if they were allowed an expansion in their own generation limits.

2.2. Competition in Supply: The Consequence for Generation.

As previously examined, as part of the electricity privatisation programme established in England and Wales, competition was to be encouraged not only in generation but also in supply. To that end, customers would be allowed to choose their own electricity supplier from the RECs (and indeed the generators) in a phased programme of introduction. This began at the time of privatisation with those customers whose demand was greater than 1MW per year being allowed to choose their own supplier, a scheme extended to those customers with a demand greater than 100kW in 1994, and will be extended to open competition in 1998. The importance of this experiment for the generation sector is that - as will be explained - the two are linked by the effects of the regulator's decision in 1994 regarding an MMC reference for National Power and Powergen.

Since the opening of the supply market, approximately 50% of the 1MW customers have chosen to participate by choosing a different second-tier supplier (i.e. one other than their local REC). Of these customers, 30% buy electricity at pool related prices in a move that effectively increases their risk exposure to pool price fluctuations. In the greater-than-100kW market, over 20% of the customers have chosen a different second-tier supplier, 7% of which have chosen to purchase at pool-related prices. Offer has maintained that all customers have experienced the benefits of greater competition have been felt by all customers, not just those that have elected to change suppliers. However, the figures may also indicate the fact that there is a limited interest in seeking to change suppliers. This may be reflected in figures for the post-1998 competitive market, especially if the spread of competition is unaccompanied by efforts to increase consumer awareness in the opportunity. However, with the initial immediate introduction having been replaced with a six-month phasing-in period beginning April 1998, it is difficult to determine precisely how successful the programme will be. In order to ascertain the potential for competition, it is necessary to look at the average consumer's bill.

In the 100kW market, approximately 2% of the average bill is made up of the supply business margin, while 65% of the bill is the cost of purchasing electricity from the generators. Therefore, the key area for competitive pressure is the electricity purchase costs, in which inefficient purchasing of electricity will not be tolerated as customers will seek to change suppliers. Because the reduction of generation costs is a key aspect of the programme, competition in generation is pivotal to the continuing success of competition in supply. In the less than 100kW market, the supply margin generation component represents approximately 60% of the average consumer's bill. The spread of competition in supply therefore relies on a 'domino effect' in competition: initial competition in the industry was intra-fuel; then competition in generation was established and encouraged; then competition in supply. In terms of examining the success of each of these schemes, perhaps we should consider their most notable characteristics. Intra-fuel competition was dominated by, and is synonymous with, the 'dash for gas'. Competition in generation is still associated with baseload entry and repeated threats of an MMC reference for the big generators. Finally, it is probably too early to comment on the nature of competition in supply.

While it is clear that domestic consumers will become the focus of the spread of competition after 1998, perhaps a more important question is how many consumers will actually want to change suppliers. For the suppliers themselves, the issue is the extent to which it is worthwhile actually pursuing consumers, as there will doubtless be some consumers for whom changing suppliers is undesirable. If suppliers can isolate these consumers, then they will leave them within their franchise sector, with the most profitable consumers becoming the object of attention. It is the customers within the franchise who will still rely on regulation to protect their interests, and hope that the potential benefits if competition in supply still reach them. In contemplating whether to change supplier, consumers will have to weigh up the following considerations: relative prices, terms of supply, costs of metering, settlement costs, availability and accuracy of information, and the search costs of finding a suitable alternative supplier. For example, the present customers in the 100kW market have a variety of available schemes to assist them in seeking and establishing contracts with their chosen supplier - a suitable system would have to be in place and operation by 1998 if their is to be any opportunity for success.

At present, for those larger consumers seeking to change supplier, the cost of an appropriate electricity meter with the network interface is between £150 and £200, plus an average annual charge for settlement and the communication links. For the year 1995/6, the pool is proposing an annual charge per metering system of £299. Considering the cost of the average domestic consumer's bill is between £300 and £400 per year, this current scheme is clearly inappropriate for the domestic market, and will require considerable modification if it is to prove successful. Under the current situation, those consumers seeking to choose a second-tier supplier would have to install half-hourly metering systems and the associated communication links, while customers remaining on first-tier supply (i.e. their current local REC) would be metered as present. Therefore, in order to encourage second-tier supply, Offer has proposed two possible schemes: a metering solution and a load profiling solution.

Under the metering solution, it would first be necessary to cut the production costs of the meters by simplifying their technical requirements, while the benefits of scale economies would be felt through the increased production runs. It is anticipated that larger production runs would cut the costs of the meters to £40 to £50, still double the cost of the average ordinary domestic meter. Alternatively, it may be possible to modify the existing domestic meters to allow them meet the required specifications - this would be at a cost of £15 per meter. A further alternative would be the development of modular meters with the capability of half-hourly metering at a cost of £40 to £60. Similar options exist for the meter communication systems and meter reading, but the question which dominates this debate is whether the current state of technology is both efficient enough and inexpensive enough to actually encourage the average domestic consumer contemplate joining in the 1998 competitive process. Based on these figures, there must be considerable doubts as to the success of the plan.

The load profiling solution would rely upon a series of load profiles covering each consumer group, which would probably vary slightly across REC areas, but which would be uniform for all first-tier and second-tier suppliers. All supplies of electricity and the settlement thereof would be based on these profiles. Under the scheme, customers would be able to choose between first-tier and second-tier supply on the basis of their existing meter plus a load profile. Customers would also retain the option of installing a new metering and communications system based upon half-hourly metering or other agreed frequency. The key points of contention in this situation are the nature of the profiles and the exact frequency of the meter readings. If a series of global profiles were adopted, then profiles would be assigned to all consumers without half-hourly metering. By contrast, difference profiling assigns profiles only to second-tier customers without half-hourly meters, and calculates first-tier consumption based on a similar differencing mechanism as under the present situation. The two approaches have their differences in the consequences for suppliers and customers, as well as data analysis and pricing concerns. The frequency of the meter readings is important for the degree of estimation associated with the billing of consumers, and will therefore have important consequences for both suppliers and consumers.

In any competitive situation, there is scope for winners and losers. In the case of the post-1998 environment, a commercial study by MarketLine International (Utility Week 06/12/96) determined that those RECs most at risk from competition were those with a high percentage of sales to domestic consumers. The companies fitting this profile were Seeboard, SWEB and Eastern as they all have domestic electricity sales representing in excess of forty percent of total sales with high levels of demand per consumer. As such, these consumers are deemed to represent a profitable market for alternative suppliers.

This may seem to have little to do with the nature of competition in generation, apart from the obvious requirement that generators will have to supply RECs on more competitive terms than at present if full competition is to be a success. However, the spread of competition in supply is heavily linked to requests that the some of the RECs have made to the regulator regarding their own-generation limits, which has also precipitated the efforts of RECs to purchase plant from the generators.

Section III - Conclusions.

The electricity supply industry in England and Wales has been subject to one of the most revolutionary privatisations observed in the UK, and its format has been used as the model for the privatisation of the electricity industries in other countries. However, more than five years after privatisation, the future of the industry remains unclear. The only thing that can be stated categorically about the UK electricity industry is that it has yet to emerge from its transitional post-privatisation status.

The current status of the generation market may be assessed either by generator output or plant capacity, and may therefore be utilised to examine the principal changes in the industry since privatisation. The main changes are the decline of National Power and Powergen's combined market share of output from 73% to 57%, Nuclear Electric's expansion of market share of output from 17% to 22% and the establishment of the IPPs and their capture of 10% of the market by output. In addition, there is the closure or mothballing of 12GW of old (mainly coal-fired plant) and a 25% reduction in the share of output produced by coal. Furthermore, the intention of constructing 10.3GW of new generating capacity, 8.8GW of it in the form of CCGT plant.

Electricity generation in England and Wales can be classified as either baseload, peak, or mid-merit. Baseload plant operates for 24 hours a day, as the costs of not generating are small and therefore activating and deactivating the plant can be uneconomic. As stated, baseload plant is typically nuclear capacity and the newer, thermally-efficient CCGT plant, which has served to push the older coal-fired plant further up the merit order into the mid-merit range. Mid-merit plant and peak plant combine to make up non-baseload plant. Peak generation operates for short periods of time as required, and plant that falls between baseload and peak is classified as being mid-merit.

The newer CCGT plants possess the capability to operate at either baseload or mid-merit, with the latter operations becoming increasingly commercially attractive due to the widening differential between baseload and mid-merit prices. However, the gas supply contracts that provide CCGT plants with their fuel make baseload operations more practical. It is therefore hoped that these events should facilitate the development of the price competition that is seen as being pivotal to the future of the industry.

However, the merger and take-over boom that gripped the industry from late 1994 onwards has the capacity to reform the industry fundamentally in terms of price competition, structure, conduct and regulation. (HMSO.a and HMSO.b, 1996). What has been observed as a consequence of the mergers boom is the establishment of companies with cross-utility interests (e.g. United Utilities), vertically integrated companies (e.g. Scottish Power/Manweb), and (most notably) transatlantic companies. The role of American companies in the development of the UK industry should not be downplayed (especially after the failed take-over bid for National Power by the Atlanta-based Southern International), as the UK industry is still seen as a blueprint for US electricity deregulation.

The main issues in the industry to be determined or at least partially resolved by the end of the century include the following. The continued development of new capacity into the industry will include the commissioning in 1996 of 3.5GW of capacity, incorporating 1.1GW of CCGT technology owned by IPPs, and 2.2GW of CCGT technology owned by National Power and Powergen. The sale of the 6GW of plant by National Power (4GW) and Powergen (2GW) to Eastern Electricity under the terms of the 1994 undertaking, and the consequences of that sale for the future of the industry. The sale of First Hydro's pumped storage businesses to the Edison International (US) subsidiary Mission Energy at a price higher than the NGC's own estimates implies a long-term commitment to the industry. Finally, the future of the nuclear sector must also be determined.

Perhaps most importantly, the intentions of the new owners of the RECs are to be ascertained. Many have sought to expand their role in generation, while any strategies must of course incorporate the total deregulation of the industry to incorporate all consumers in March 1998. This is a further area whose effects are difficult to predict. Deregulation to date has witnessed over seventy percent of consumers with an annual electricity demand greater than 1MW shopping around for their power, while almost fifty percent of consumers with an annual demand of greater than 100kW have done likewise. Other major factors such as the ending of the Fossil Fuel Levy and the expiration of the five-year coal contracts in 1998 must also be considered. There are also of course, further possibilities for new entry, and the interactions between the electricity industry and its various fuel suppliers, in addition to the environmental issues associated with these fuels. Further, there are political concerns to be considered in the form of the Labour Party's windfall tax on utilities, and the changes to the tax treatment of long-life assets announced in the Conservative's November 1996 budget. How these changes will influence the industry is uncertain, although their will be greater risk attached to investment projects regardless of which party is in government.

<u>CHAPTER III: The Electricity Pool and the Role of the Forward Contracts Market - Contents.</u>

Section I - The electricity pool and the contract market.

1.1. The electricity pool.

The restructuring of the generating sector discussed above was matched by a similar restructuring of the actual market for electricity, which became a spot market called the pool. The electricity pool is owned and operated by NGC for bulk power trades, through which the vast majority of all transactions for electricity flow. There is a very small minority of transactions that occur outside of the pool, generally involving large users purchasing directly from generators. The current operating structure of the pool is as follows.

The pool operates a day in advance, with generators having to submit bids - offer prices - for the following day, specifying the availability and price of power for each of its generating sets which are subject to 'central despatch'. Prices must be submitted no later than 10.00 a.m. on the preceding day, and are set for periods of half-hour duration, of which there are forty-eight in a day.

These offers from the generators, which effectively constitute the industry supply curve, are combined with a forecast of demand made by the NGC. These data are used to establish a plant schedule, termed a merit order, by means of a computer algorithm called GOAL. Within the merit order, plant is ranked in ascending order of price in order to generate the current market clearing price, known as the system marginal price (SMP). The SMP fluctuates considerably during the day to reflect both the cycle of demand and the differences in bid prices, which themselves reflect the differences in the operating costs of the various generating stations.

Given that the SMP is calculated in advance, using anticipated supply and forecasted demand, there is an inherent degree of uncertainty attached to the pool's operations, which is reflected in the loss of load probability (LOLP), which calculates the risk of power failures. The estimated value to the consumer of a power loss is termed the value of lost load (VOLL) which was set at the time of privatisation at £2/kwh and represents an indexed component, rather than being determined by market forces (Review of Economic Purchasing, Offer 1993).

The LOLP, VOLL and SMP are combined to form the capacity payment, which is designed to influence the incentive to invest (see below). If (declared) capacity is large relative to demand then the LOLP will be low. However, if the reverse is true, then capacity may be put under pressure and the LOLP could significantly increase prices. This mechanism has a tendency to produce stability in the market (Bunn & Larsen, 1994).

The interaction of capacity payments with the SMP is illustrated in the pool purchase price (PPP), which is received by all generators whose plant is called upon to generate. The PPP is given as:

PPP = SMP + LOLP(VOLL - SMP)

The second term on the right hand side of the above equation is termed the capacity payment. A similar payment, which is dependent on bids, is made to those generators who declare availability but who are not called upon to generate.

The pool selling price (PSP) is paid by the RECs, and those customers who are able to purchase direct from the pool is given as:

PSP = PPP + 'Uplift'

The uplift component is dependent upon the levels of payments for reserve capacity, unscheduled availability, ancillary services, and the costs of transmission constraints. The importance of each of these components is detailed as follows.

Firstly, reserve plant is held by the NGC in case of unforeseen circumstances. These plants are paid the PPP minus the incremental price of the generating unit.

Secondly, transmission constraints result in the payment of additional sums into the pool as the actual operating schedule may differ from the unconstrained schedule submitted previously. Generating units which do not operate according to the unconstrained schedule receive additional revenue as a consequence of being constrained-on or constrained-off the schedule. A plant that is constrained-on is one that is dispatched even though it is not scheduled to do so is paid its offer price. A plant which is constrained-off is one which is not dispatched even though it is scheduled to do so, and is paid PPP minus its offer price.

Thirdly, generators also receive payments for ancillary services, which are services used to maintain the appropriate standard of quality within the system in terms of voltage, frequency, and constancy of supply. Ancillary payments are made for the following purposes. Firstly, black-start capability, namely those stations with the capacity to start up rapidly in the event of an emergency. Secondly, reactive power, which is used to stabilise voltage levels. Thirdly, frequency response, which is based upon the ability of generating units to alter output based upon changes in total system frequency, itself dependent upon changes in demand, and fourthly miscellaneous payments that are made for a variety of other services.

The inherent price instability present in the pool may be limited by the two possible methods that will be examined in detail: contracts for differences (CFD) and electricity forward agreements (EFA). The structure of each of these markets will be examined fully, but it is now appropriate to examine the role of forward contracts in general.

1.2. Electricity contracts: The use of financial instruments within the electricity industry.

Contracts for differences (CFDs) function on the basis that two parties enter into an agreement over the forward price of a commodity. To consider a general example, suppose that we have a consumer who knows that he will require 1000 units of a commodity at some point in the future. The use of a CFD allows this consumer to reach an arrangement with a supplier, whereby both parties agree on the future purchase price of this commodity. For example, the two parties could agree upon a CFD for 1000 units at £100 per unit, with the mutually agreed price known as the strike price, payable on delivery at the appropriate future date.

If the market price of the commodity on the future date is more than the strike price, the supplier pays the difference to the consumer on the 1000 units (in addition to the normal cash flows that occur in the sale of the commodity). By contrast, if the market price is less than the strike price, the consumer pays the difference to the supplier. In this simple case, there is no upfront cash payment when the contract is agreed - the only cash flow on the contract is the difference once the actual price is known. This type of arrangement is known as a two-way CFD.

The use of CFDs therefore allows hedging, given that the supplier actually wants to sell the physical commodity, and that the buyer actually wishes to purchase it. If the buyer of a CFD has no intention of actually purchasing the commodity, then the contract will increase risk as opposed to reducing it, as the buyer is now vulnerable to fluctuations in the commodity price. CFDs have been used as successful tools in many markets, due to the following advantages.

Firstly, CFDs allow the trader to manage price risk independently of the delivery of the physical commodity. Therefore, a CFD could be agreed with a counterparty for which delivery would be impractical. Secondly, the buyer and seller in a forward agreement are both aware of one another's identity, which could lead to problems or an unwillingness to trade. By contrast, markets for CFDs generally utilise brokers, thus ensuring anonymity for those involved in trades and avoiding any embarrassing confrontations or refusals to trade. Thirdly, CFDs often provide a focus for liquidity, with fine prices and low transactions costs. This is partly due to the traders, who have precise requirements for the type and grade of a commodity for physical delivery, being willing to trade a standard benchmark CFD. By using benchmark instruments, there is a focus upon liquidity and a lowering of transaction costs. This enhances the attractiveness of the market to other traders, and further aids liquidity.

In addition to the use of two-way CFDs, there are also one-way CFDs, of which there are two types - 'caps' and 'floors'. In 'cap' arrangements, the buyer pays an upfront premium to the seller, and in return receives a compensatory payment if the market price exceeds the strike price. No payment is received if the market price exceeds the strike price. Buying caps protects the consumer against high prices without foregoing the benefits resulting from potential low prices, as well as giving the seller guaranteed revenue.

A similar arrangement is that of a 'floor', suitable for purchase by a producer. Here, in exchange for the upfront premium, the buyer of the floor receives a compensatory payment if the market price is below the strike price, and the consumer receives the security of a set price.

1.3. Electricity forward agreements: An Overview.

To allow the hedging of forward electricity prices, two types of CFD are available for electricity. Firstly, the long term vesting contracts that were negotiated by the generators and the regional electricity companies (RECs). Over the three year period after vesting, these contracts - many of which were cap agreements - covered an average estimated 80% of annual electricity sales were of between one and three years duration. Secondly, the EFA market has been developed to allow participants to tailor their cover using two-way CFDs. In this market, Gerrard & National Intercommodities (GNI) Ltd. acts as a broker, initiating transactions by matching potential buyers and sellers. Although initially the sole broker in the market, GNI was joined by Tradition Financial Services and Euro Brokers in 1995.

The EFA market was effectively established to provide an additional means by which the electricity industry could hedge its exposure to pool price risk. The EFA market represents the natural market for not just RECs and generators, but for anyone else involved in the electricity market, or other energy traders who wish to take on exposure to electricity. Anyone may join the EFA market, but trade is clearly dependent on finding a suitable counterparty. All trade in the EFA market is screen-based, but smaller transactions may be carried out by telephone.

Despite the lack of standardisation of CFDs - in principle, any structure could be traded - liquidity in the EFA market has tended to focus on particular types of trade. Consequently, standard documentation emerges, and trading interest centres on benchmark instruments which are of general interest to the market participants.

The framework which has been constructed for trade should be flexible enough to permit a full variety of structures for trading and hedging purposes, whilst retaining simplicity. Each day is divided into six four-hour periods, numbered 1-6. These are given as: Period 1: 23.00 - 3.00; Period 2: 3.00 - 7.00; Period 3: 7.00 - 11.00; Period 4: 11.00 - 15.00; Period 5: 15.00 - 19.00; and Period 6: 19.00 - 23.00.

Trades cover one of these contract periods for either both days of a weekend, WE1-6, or all five weekdays of a week, WD1-6. These contract periods can be traded for a single week, a strip of weeks (e.g. for a month or a quarter), or a fifty-two week strip to cover a whole year. It was found by consultation with the potential market participants that the four-hour period was the most conducive to investment in the market, and was therefore chosen to encourage liquidity.

Although most interest in the market is in the pool purchase price (PPP), it is also possible to trade the pool selling price (PSP), the system marginal price (SMP), or the spreads between them. It should be apparent that the PSP - SMP spread represents the level of capacity payments, and the PSP - PPP spread indicates uplift levels.

Once the transactions have occurred, all contracts contain the following standard information: the name of the buyer/seller, the actual variable being traded, the time period involved, the contract week(s), the number of MW being traded, and the agreed strike price.

Although there are any number of possible trades, the standard trades are bilateral trades, REC-REC trades, and REC-financial institution trades, all of which are governed by the standard EFA terms and conditions. The most common types of contracts traded are baseload power and the "A4" load shape, i.e. Baseload+WD3+WD4+WD5.

Trades are conducted based upon each company's requirements, although there are standard trading rounds in April, July and October of each year. There are no set price forecasts (as with the Horton IV estimates), but all trades are based upon the market's perceptions of the appropriate price.

The nature of the electricity market makes it likely to attract both hedgers and traders. When discussing price volatility, it is important to remember that this volatility is not based on the difference in pool prices in different periods, but rather the difference between the EFA price and the pool prices during the period of consumption covered by the contract itself.

Since EFA prices ultimately fix on the average pool price for the appropriate period, one expects some form of relationship between pool prices and forward prices to exist. Obviously, different market participants will have different expectations of pool prices, and there will invariably be exogenous shocks to the system. Unless the pool price is hedged, both the RECs and the generators are exposed to price risk. However, at low pool prices, this risk is somewhat asymmetric: if the expected pool price is £15, then the lowest it can fall is to zero, but there is nothing to prevent prices from rising exponentially. Consequently, there may be more incentives for buyers to hedge than for sellers, a fact that may tend to increase EFA prices.

The EFA market also integrates the existing CFDs held by pool members, as one would expect the willingness of parties to trade in EFAs to be determined by their existing contract cover. As all generators receive PPP regardless of what price their electricity is offered at, and depending on their level of contract cover, generators may become indifferent to the pool price. As a result a generator's main concern - if it has covered a sufficiently high proportion of its output - is to offer this output to the pool at prices low enough to ensure that it reaches its projected power generation. If this hypothesis is valid, then pool prices will have been significantly lower than expected (as was observed in the post-privatisation period and is outlined further below), while the CFDs between generators and RECs have allowed the generators to guarantee their revenue. However, this factor does not preclude increases in pool prices as circumstances change.

The use of spread trades involves buying one instrument at the same time as selling another, related instrument. By doing this, the trader takes on exposure to the difference between two prices, while remaining indifferent to the overall level of prices.

The most common form of spreads are those involving the uplift and capacity payments, but other forms of spread may also be of interest. For example, the spread between corresponding weekend and weekday prices, the spread between different contract periods, or the spread between different weeks, Such spreads must be undertaken by trading the two appropriate EFA contracts as separate entities.

The significance of spread trading arises when the difference between two periods is less volatile than the prices observed in these periods. Spread trading has become an important feature of many markets, and there are several reasons to expect it to play a similar role in the EFA market.

Firstly, many companies are expected to be exposed to spread risk as part of their everyday pool operations. For example, a pumped storage business (PSB) is exposed to the spread between cheap night-time electricity and expensive peak period electricity, or an amount equal to their expected turnover of power. Therefore, a company such as a PSB which expects to buy electricity during WD2, then sell it during WD3, WD4, and WD5, is exposed to the WD2/3, WD2/4, and the WD2/5 spreads.

Secondly, spread trading is important given the large number of different contracts that can be traded. A trader may bid to buy week 40 WD3 at £22.00 as a means of hedging exposure. There may be no response to this bid, but the trader notices that week 40 WD4 is offered at £20.00. By buying WD4 rather than WD3 to cover his exposure, the trader is taking on a spread position - not by actually executing a spread trade, but by buying one contract instead of another - this is a 'soft' spread. Effectively, the trader is now short WD3 and long WD4 at a spread of £2.00.

In executing a spread, a trader can not only make a profit, but can also reduce his risk. For example, if finding no interest in his WD3 bid, the trader had simply left his bid in and not looked for spread opportunities, he could have been unhedged for some considerable period and exposed to fluctuations in WD3 prices. By trading WD4 instead, the outright WD3 exposure has been converted to a less risky spread exposure. The attraction of a spread trade against that of an outright trade is that, not only does it reduce risk, but the trader might have a view on the WD3/4 spread even if he has no view on the overall direction of prices. In addition, spread trading also benefits the market as a whole by increasing liquidity.

The nature of the EFA market is more conducive to short run than to long run trading, as most long-run contracts are met by CFDs rather than EFAs. This may have accounted for the increased popularity of the EFA market as can be observed by an examination of the RECs' contract portfolios which clearly indicates an increase in the usage of short run contracts (MMC 1996a, 1996b). This is in addition to RECs being increasingly willing to purchase unhedged from the pool, doubtless due to increased uncertainty regarding future pool prices. In the period since the EFA market became operational, EFAs have captured only 3% of the contract market. However, the trading volume had increased from 0.1TWh in 1992/3 to 8TWh in 1995/6, clearly indicating their growing importance.

Newbery (1995) criticises the EFA market for not utilising its full potential, arguing that the flaws in the EFA market are its low liquidity (relative to a conventional futures market) and its difficulty in the pricing and liquidation of specific EFA contracts. It is also argued that the advancement of the EFA market would be best served by the increased trading of baseload strips, as these represent a homogenous commodity which faces a level of demand conducive to the creation of an appropriate level of liquidity. In addition, the trading of such strips is also seen as permitting RECs to re-trade depending upon unexpected fluctuations in their consumer demand, as well as permitting arbitrage between the contract market and the pool.

1.4. Contracts for differences: An Overview.

On a fundamental level, financial markets theory indicates that the spot price in a market for a commodity is determined by the forward market price for that commodity. In the case of the electricity industry, this means that the markets for electricity forward agreements (EFAs) and contracts for differences (CFDs) should lead the pool in terms of pricing. This is conditional upon the assumption of rationality and the available information set when the contract is agreed. In financial markets theory, if the futures/forward price is above the spot price, it is assumed that the futures price will fall over time (contango), while if, by contrast, the futures price is below the spot price then the futures price will rise over time (backwardation).

However, given that information on the spot price is readily available, whereas that on the strike prices of contracts for differences is not, some proxy is required for the strike price as a whole. There have been several official price estimates carried out by Offer, as well as those developed by the RECs, the generators, and independent institutions. The initial vesting contracts signed at the time of privatisation were based on the Horton IV price estimates generated by Offer. However, these estimates were well below the actual prices for the pool's first level of operation, which doubtless proved to be a contributing factor in the RECs decision to terminate some of the vesting contracts in March 1991. It can therefore be surmised that, even if the Horton estimates were used on only a partial level to determine the strike prices of contracts, then the forward price was not an accurate predictor of the spot price. However, such an inequality could be due to several factors exogenous to the models of price determination (see below).

Before continuing, it is important to note how the RECs contracting strategies have changed since privatisation. Initially, the bulk of electricity traded in the pool was done so under contract - approximately 95%. However, with the introduction of more independent power producers (IPPs) into the generating sector, and increased uncertainty regarding pool prices, contracted output fell, and has continued to do so. The duration of these contracts has also become an important issue, with contracts ranging from 15 years to less than a year in length. The longest contracts have typically been offered by the IPPs, in whom the RECs tend to have some kind of equity share. As a rule of thumb, general classifications of contract length are: 15 years, 10 years, 2-6 years, 1 year, and less than a year.

Most contracts and contract offers differ in form, but some are relatively easy to compare, while others necessitate restrictive assumptions before any comparisons. The contracts are highly complex and contain several different prices and terms. In general, these concern the effects of different forms of indexation of the prices in the contract (both in terms of the rate of inflation and the relevant fuel price) and restrictions on when the contract can be exercised. It is also possible to include cost pass through of transmission charges, or the sharing of benefits if pool prices are high, as well as restrictions on calling to a particular plant's availability.

Contract comparisons and availability can be based on load factors, i.e. the percentage of hours in the year covered by the contract. Baseload contracts feature prices based on an average of all contract hours during a year (8760 hours, or 17560 half hour periods), while the call on lower load factors is concentrated towards peak periods. This makes lower load contracts more valuable, and they therefore command a higher price in the market. The extent to which this is the case depends upon how much higher pool prices are at peak than at baseload periods of low demand.

There are essentially three types of contracts: baseload RPI indexed contracts, as offered by Nuclear Electric; coal-fired sculpted load contracts, as offered by National Power and Powergen; and variable load contracts with indexed prices, as offered by the IPPs.

The contracts offered by National Power and Powergen offered in late-1992 were based on October 1992 prices, offering a price of 3.20p/kwh, declining to 3.1p/kwh in 1997/8 - making an average of 3.17p/kwh. The present value of these contracts would be higher after adjustments, because a higher quantity is sold in the early years at higher prices. The contracts also take into account the expected costs of the installation and operation of future capacity. If an 8% discount rate is assumed, along with an even decline in volume by 18%, the contract price becomes a discounted weighted average of 3.19p.

Nuclear Electric's contract auction had a reserve price of 2.75p covering the same period as the National Power/Powergen contracts plus 1992/3. The price during the subsequent five years of the contract was dependent upon the price applied during the contract's first year. These prices were typically lower than 2.75p, with Nuclear Electric's auction price for a one year contract being 2.63p, producing a price of 2.78p for the next five years. Given the concerns raised by the RECs that the appropriate price was 2.45p, the subsequent price was 2.825p. The Nuclear Electric contracts were expressed in 1991 money terms and need to be raised to 1992 prices to make a comparison. Adding 3.6% inflation produces between 2.88p and 2.93p depending on the initial price assumption.

The load factor for the National Power/Powergen offer is approximately 52-54%, making the difference between the nuclear contracts and the coal-fired contracts as a result of the peak premium equal to the difference between the peak premium divided by 8760 and the same premium divided by 53% of 8760. If the contracts were to be equalised solely on this basis, the capacity premium of new investment would have to be in the order of £31/kw. If one were anticipating a high price of capacity (high cost of new plant), the coal-fired offer would be preferred, while a low price of capacity would lead to a preference for the nuclear contracts.

Similar analyses may be undertaken to compare baseload contracts and variable load contracts with indexed prices, and indexed near baseload contracts with sculpted load contracts. Comparisons involving the first pairing are difficult due to the considerable differences in contract lengths, but a proxy for the nuclear price is 2.9p for an RPI indexed contract. Based on current fuel prices, IPP contracts are in the range 2.3-2.7p. Taking into account a rise in fuel prices, this becomes 2.6-3.0p, where typical, gas fired contracts are indexed up to 20% against coal or electricity prices.

The second pairing shows that IPPs allow a lower load factor, making comparison with the National Power/Powergen contracts easier. In one instance, using a 65% contract load factor results in a gas fired price of around 2.85p. Differences in both load factor and indexation must be considered along with prices. Under gas fired contracts, prices range from 2.6-3.0p based on a load factor of 90%.

Some contract prices are in the public domain, for example. Nuclear Electric's basic 1992 contract price is 2.75p/kwh, which adjusted to the period 1993/8 becomes 2.78p. The coal fired offer made for the same period is 3.26p, adjusting to 3.19p. The IPP contracts are offered in the range 2.6p-3.0p, which can be adjusted to 2.5p-2.9p.

In theory, the estimated pool price should equal the contract price. However, there are several reasons why it may not, the most important being possible inaccuracies in the assumptions used to develop the contract strike price. Assumptions concerning the level of electricity demand would have been made by the generators in constructing their original contract offers, for example Offer assumes that peak electricity demand rises by 1% per year. Any major regulatory changes, such as the February 1994 price cap would also be considered, as would the forced sale or retirement of plant. Furthermore, the continuing decline of contracted output over time would also be a factor to consider.

Given the potential in the contracts market and the EFA market, there are two fundamental reasons for the equality, or lack thereof, between the contracts' strike price and the pool price. If the estimated strike price does not equal the actual pool price - specifically if it is below it - then this could be due to generators attempting to keep prices low as a means of increasing their profits from the contracts. This is a highly probable outcome based upon the possibility of strategic forward market trading. However, it may also be due to the fact that the market is imperfect. Alternatively, if the contract price does equal the pool price, then this could be based on a pre-meditated attempt to keep the pool price at some desired level, again indicating the use of strategic behaviour. The fact that there are two possible reasons for pool prices below the strike price, determining which is responsible could prove difficult.

1.5. Forward Markets with an Imperfectly Competitive Spot Market.

As in the electricity pool, there has been general concern that futures trading could be compromised when the underlying market is imperfectly competitive. The reason is that small traders would be hesitant to enter into a contract if they were aware that non-market forces could manipulate the contract. However, this is not always the general case, as the oil market demonstrates.

Lucas & Taylor (1993) utilise a game theoretic approach to analyse the current imperfectly competitive structure within the pool. They conclude that there is no reason to expect competitive behaviour from the generators in the pool and foresee several complicating aspects that will prevent competitive bidding. Firstly, that in the presence of an asymmetric game, a situations which exists in the pool, smaller generators will bid nearer to marginal cost in games without contracts. Secondly, mixed strategies by generators are possible, so there is no reason to expect the empirical evidence to converge to a single constant behavioural form. Thirdly, contracts exert a calming effect on the pool as generators bid against one another to obtain favourable combinations of bid generation and contract cover - this is the main factor reducing pool prices.

The conclusions that they derive from an empirical standpoint are as follows. Firstly, the pool cannot be expected to produce prices that provide transparency to customers or appropriate signals to investors. Secondly, contracts are crucial determinants of pool prices, so the regulator should pay more attention to them and information on them should be made publicly available. Thirdly, the UK experience in its present form should not be taken as a model for deregulation in other countries. The empirical consequences of these conclusions will be returned to below, as will the model itself.

It can therefore be claimed that imperfect competition and futures trading are incompatible, because market power limits the degree of futures trading. At the same time, there may be other circumstances in which this is not true. Anderson (1991) investigated this in depth.

Under imperfect competition, the participation of small traders may be discouraged, which in the case of the pool would manifest itself in the larger generators trying to restrict the market share of the IPPs. In addition, powerful firms may wish to discourage futures trading, and may also have the ability to suppress it. Again, this may be true, given the RECs accusations regarding the incumbent generators' attitudes towards negotiations for contracts for differences.

Efforts to manipulate the futures market (corners or squeezes) are seen as different to exercising market power in the cash market, which in this case represents the manipulation of the pool price. It is often the case that those accused of manipulating the futures market are powerful hedgers who are in a position to influence prices in the cash market at least in the short run.

In focusing on the behaviour of prices in these markets, the question is whether the actions of powerful producers generate greater biases in the futures price than in the case for competitively produced goods. Particularly, do powerful firms have a desire to alter the bias to their advantage?

Participants in a futures market are either hedgers or speculators. Related to these types of traders are the two functions of futures markets: risk shifting or price discovery. Agents who face unwanted cash market risk seek to transfer that risk by trading forward through futures contracts. Any imbalance between short or long hedging (having insufficient amounts or having an excess) is met by speculators. However, in order to be willing to absorb this risk, speculators must expect a price change that will be beneficial to their position. However, the problem in utilising conventional theory in the pool is that there are no speculators - the only participants are hedgers. However, as the volume of trade within the EFA markets continues, there is no reason to believe that this will continue to be the case.

This general view is founded on the assumption that there is no market power to exploit, and therefore requires some modifications to function in the presence of market power, where the participants may have more complex motives for their actions. By definition, a futures contract is an unconditional commitment to buy or sell a good at some point in the future. If agents do not hold their contracts to maturity, they must engage in a closing out transaction that offsets their position. In theory, there is no reason to prevent this from occurring within the EFA market as offsetting transactions may not be uncommon. Indeed, this may be one of the principal advantages of the EFA market, namely that it may eventually adopt many of the characteristics of a true financial futures market which will only contribute to its efficiency.

If an agent's profits depend upon the cash price and some choice of action, then his actions in the event that he possesses market power will clearly influence the cash price. The existence of strategic futures trading results if the price in the future when the contract matures depends upon the price which the agent can influence. The futures position can therefore change the behaviour that the agent finds most profitable. In general, the larger the futures position, or the closer the relationship between the cash and the futures prices, the more the action will be influenced by the futures position. Strategic trading occurs because the futures position can be selected at an earlier point in time. As will be seen as the analysis continues, it can be argued that this is exactly what has occurred within the pool with the large incumbent generators keeping prices low when the RECs were heavily contracted. Such a move would considerably increase the difference payments made by the RECs to the generators.

A starting point for the analysis is to assume a situation in which futures trading is being undertaken by imperfectly competitive firms and that there are no strategic motives for trading - as defined above. If a monopolist has sold futures, then its profits will clearly depend on the situation in the cash market and the futures market. If the monopolist has previously sold futures, then any actions that decrease the price in the spot market will increase its profits from the futures market - as is the case in the pool.

From the viewpoint of welfare analysis, whether futures trading in an imperfectly competitive market is beneficial relies upon an understanding of the determinants of the monopolist's futures position.

Anderson (1991) develops a sequence of propositions, as well as utilising those of others, to examine the nature of interrelationships between the two markets.

Firstly, if futures traders are competitive, risk averse speculators which operate in a domain of public information with a risk-neutral monopolist, then there is a unique rational expectations equilibrium. This will be a situation in which the futures price is unbiased and all agents retain zero futures positions. The reasoning behind this conclusion is that a risk-neutral monopolist will only hold futures if a profit is anticipated. Given perfect information, the only occasion on which the futures market will clear is if the futures price is an unbiased predictor of the spot price. Were this to be the case, there would be no risk and therefore no motive for retaining futures positions. In other words, RECs would not buy CFDs if they had perfect foresight.

Secondly, a risk averse monopolist will hold long (having assets in the contract for sale) or short (net indebtedness of the assets) futures in equilibrium. The actual position will depend upon the nature of the market and the existence of technological uncertainty. Hedging depends upon the agent's correlation of output and demand. In the presence of non-stochastic costs or uncorrelated demand uncertainty and costs, the monopolist will not sell futures. Given that all competitive agents are pure speculators, the equilibrium price must be biased downwards to encourage speculators to bear risk (the futures price must be expected to rise). This illustrates the importance of the dominant firm's attitude to risk.

If the competitive agents are also hedgers, then the outcome is based upon the balance of hedging interests, as in a competitive market. For example, if the competitive agents are consumers who operate long futures positions, then the balance of hedging would generate a positive bias to the futures price.

This would therefore induce the monopolist to reduce his short positions. It is therefore theoretically possible that this incentive could be strong enough to induce the monopolist to go long in the futures' market. This could potentially exacerbate the misallocation of resources in the spot market.

Extending these propositions, Anderson proceeds to expand the model to an oligopolistic structure. Eldor & Zilcha (1986) conclude that spot-futures interaction is most likely when there is a static oligopoly in which futures and spot decisions are made simultaneously. The model generated is a variation on the Cournot model, adapted for demand uncertainty and futures trading. Here, an N-firm oligopoly with homogenous products and identical cost functions is used, with price and output decisions in both markets being made simultaneously. After one time period, the uncertainty is removed and spot and forward positions are resolved. The similarities between this structure and the pool are apparent, but the difference is that the spot and futures positions are not resolved simultaneously. The model relies on the assumption of risk-aversion of non-competitiveness - this allows for a Nash equilibrium in the spot market.

The proposition derived from this model is that an imperfectly competitive firm will, if futures are unbiased, only seek to hedge, thereby causing the producer to sell his entire output forward. If the futures price were biased, then the speculative motive leads to overhedging. Clearly, if the generators anticipated high prices in the future, they would seek to sell output forward at that price in order to ensure a healthy revenue stream. Conversely, when the futures price is biased downwards, the speculative motive leads to underhedging.

A second proposition derived from the model is that if the futures price is unbiased, the producer is able to eliminate all risk by selling his output forward. Given risk aversion, firms would be willing to increase output above normal levels in order to eliminate risk.

Despite their validity, these propositions do not indicate that the existence of a futures market integrated into an oligopolistic market structure generates an improvement in the allocation of resources. The reason for this is an absence of the determinants of the futures price. It is logical to expect that in the presence of rational expectations the futures price will be unbiased, given public information and at least one risk-neutral speculator trading futures. However, because if risk-averse oligopolists dominate the market, it is likely that output will increase and price will fall because of futures trading.

A further extension can alter the analysis such that the demand curve faced by the industry becomes the demand curve net of sales by spot market price-taking producers. This extends the analysis to a competitive fringe, but only on the assumption that the fringe does not trade futures. This is the approach adopted by Newbery (1984), who permits feedback between futures trading and competitive supply. In this model, a perishable good is produced by a single powerful producer and a large number of small, identical price-taking firms. Output is uncertain and is conditional upon a single random variable that affects all firms.

The futures market exists and meets at the same time that agents make their production decisions, for which there is no risk. The similarities between this structure and the electricity industry should be apparent, with electricity as a non-storable good, the incumbent generators as the single producer, and the IPPs as the competitive fringe. The participants in the futures market are the dominant producer (risk-neutral with no hedging motive), the competitive fringe (risk averse with a clear hedging motive) and a number of price taking, risk-averse speculators.

If the competitive fringe and the competitive speculators trade futures but the dominant firm does not, and if all agents accept the given cash price distribution, the fringe will sell futures. Here, the expected supply by the fringe is greater than would have been the case in the absence of futures. This is due to the risk-aversion of the participants.

The framework is altered to allow for the structure of Cournot duopolists who can choose their futures decisions prior to their output decisions. This imparts an advantage equivalent to that of a Stackelberg leader, which represents an incentive to trade futures for both firms. Allaz (1987, 1989) made these modifications to the model to derive the following conclusion. If quantity-setting oligopolists can trade futures prior to selecting their output levels, then with perfect foresight, a Nash equilibrium will occur where each oligopolist will sell futures. This will result in a greater output and lower cash price than would have occurred in the Nash equilibrium in the absence of futures - thus indicating a clear improvement in resources.

If the futures choice is made when either demand or cost in the cash market are uncertain, then decisions may be altered for risk-averse powerful producers. This has been examined for a linear demand curve with an uncertain intercept, constant marginal costs across all firms, expected utility maximisation and an unbiased futures price. In this scenario, the optimal futures position of the producers has two additional components that result in the hedging motive reinforcing the speculative motive. Consequently, the risk averse oligopolist increases futures sales above the level required for solely strategic purposes, thereby increasing the aggregate cash market output accordingly.

These cases are only applicable to situations where oligopolists meet to trade futures on one occasion prior to the cash market decision. This is clearly a limiting case, as participants would meet several times prior to cash market resolution, thus allowing traders to revise their positions. Although this cannot be said to be true with certainty for the CFD market, it is highly likely to be true for the EFA market. This permutation was analysed by Allaz & Villa (1986), who allowed for successive meetings in the futures market and revision of futures positions.

This generates the final proposition under examination, namely that under perfect foresight, as the number of meetings in the futures market grows infinitely, and the accumulated futures position immediately prior to cash resolution grows, marginal cost pricing will occur. This indicates that futures trading will generate a competitive outcome, even for Cournot duopolists. It can be argued that this is the situation which existed initially post-vesting, with a near total contract coverage of output accompanied by (an approximation of) marginal cost pricing.

Despite the difference in forward and futures markets, there is a sufficiently strong theoretical foundation to transfer these propositions across to the electricity industry, as did Powell (1991). Not all of these propositions are relevant, nor can they all be applied to the UK electricity industry. Specifically the absence of speculation in the pool, the fact that all monopolists (generators) have sold more futures than they have bought, generating costs are not identical, the competitive fringe does trade futures, and firms trade futures on several occasions prior to the pool meeting. However, they clearly indicate the importance of the interrelationships between the spot and forward markets for commodities in general and the electricity industry in particular. In addition, it is also clear that firms with market power could be able to alter their decisions in such a way as to manipulate the spot market to their advantage.

Despite the key problem in applying these propositions to the electricity industry, namely the absence of speculators, they have formed the basis for the key works in this field, including Green (1992), Green & Newbery (1992), Helm & Powell (1992) and Gray & Helm & Powell (1996).

1.6. Evaluation of the Contract Market.

Despite the lack of empirical research into the market for contracts for electricity, there are several key studies. Helm & Powell (1992) and Gray & Helm & Powell (1996) draw heavily on generator behaviour in the contract market as a means of explaining the behaviour of generators. There were two types of CFDs detailed above: one-way CFDs and two-way CFDs. The nature of a two-way CFD serves to isolate generator revenue from pool prices, as the generators receive a fixed price for their power. As explained, RECs benefit from having hedged their risks to achieve a fixed price in their franchise markets. Generators also receive premiums and gain added security, allowing them to hedge their investment costs.

REC contract portfolios were described above, with the initial vesting contracts being signed as a means of providing security to the UK coal industry. With the vast majority of electricity purchases covered by CFDs, it is almost impossible to ascertain either generator revenue or generator incentives from pool prices.

Utilising the work of Anderson (1991) and others, Powell (1993) successfully developed and adapted traditional financial markets theory for the electricity industry. He concludes that, in the absence of collusion, forward or forward-type contracts serve to increase the degree of competition within the market. This is because contracts represent an additional step towards price competition, thus pushing the market closer to a perfectly competitive structure.

By contrast, it may also be concluded that contracts may also make collusive behaviour more likely, given that the structure of the industry is already highly conducive to collusion. However, CFDs may also be sold in such a manner that removes all incentives to depart from an agreed price. This could occur if the generators select a desired price level and utilise contracts to adapt their own incentives to maintain this price. This possibility increases the likelihood of strategic behaviour by generators within the marketplace.

In the first year after vesting, with over 95% of total generator output covered by CFDs, generator revenue had effectively been made independent of the pool price. This allowed generators to manipulate the pool price to any desired level within the bounds of the regulatory framework. Given the potential for considerable new entry in the post-vesting environment, the incumbent generators had a vested interest in keeping prices low. As will be seen, pool prices after vesting were below official estimates, and given that the pool price is the most important piece of information available for potential entrants, manipulation to deter entry is possible. Clearly, one would expect high prices to encourage entry, not low prices. As a consequence, one would anticipate that pool prices would remain high after entry and not decline, in order to sustain profits for entrants.

The importance of accurate information in capacity investment is illustrated in Bunn & Larsen (1994). Given the lead time of at least three years to commission new generating plants, the uncertainty in plant retirements and the non-linearity of using the LOLP to signal capacity needs, the pool is likely to produce cycles of under- and over-capacity. Ideally, in the short run, new investors will wish to bring in new capacity if they expect it to operate at a level below SMP. This in turn depends on the variabilities in expected fuel prices and hence on generation costs. In its simplest form, basing investments solely on capacity payments would mean discounting the capital cost per kWh of new plant at the desired rate of return and comparing this with the expected stream of capacity payments from the pool. However, such a move could be inappropriate due to other potentially critical factors, such as those outlined below.

The extent to which serious capacity cycles will occur depends upon the uncertainty in demand, the foresight of planners (how far ahead LOLP is forecast), the degree of knowledge about the competition and competitive behaviour in the industry. In the simplest "market signal" case of generating companies' responding to the recent annual average value of LOLP, Bunn & Larsen (1994) showed that severe cycles of the reserve margin resulted. However, if the regulator were able to encourage and information exchange with respect to planned construction and retirement over a three year period, and better demand forecasts, then the capacity payments approach appears to be capable of maintaining the reserve margin at a desired level (24% is the industry target).

However, in practice, investment in capacity can occur for various financial and strategic reasons based on corporate decision making. In order for the regulator to be able to influence the reserve margin by influencing the VOLL, it is essential that reliable information on the demand-supply balance be made public at least three years in advance, and that the regulator should have some ability to smooth out plant retirement. Achieving this will require a more formal assessment procedure, by the regulator or an independent body, to approve new construction and retirement plans. Under these circumstances the system can work and be well regulated. Without them, severe cycles of over and under capacity could result from using only market signals. However, the resultant fluctuations in a utility's prices would be politically unacceptable and would doubtless result in regulatory intervention.

Such controls on plant would represent a considerable shift in regulatory policy. However, the current market is too prone to uncertainty and dynamic instability due to political and economic reasons, e.g. the 'dash for gas', the closure of the coal mines, and REC contracting strategies. In order to limit this uncertainty, REC-IPP arrangements are an obvious outcome. Less uncertainty, and therefore less business risk, in the market brought about by tighter regulation would help to encourage the system to work. *Much of this uncertainty is due to the strategic power of the* large generators and the limitations of the market system to promote an efficient allocation of resources and prices.

The system of capacity payments has been the subject of much consideration by the DGES, especially given his findings in the 1991 price review (Offer, 1991) that the duopolists (notably Powergen) were altering their available plant schedule in order to profit from the capacity payments scheme. The review led to an alteration in the generators' licences, whereby old plant could not be tactically mothballed, and any retired plant had to be offered for sale to an independent power producer. This policy was backed up by the 1994 agreement (made as part of a deal to deter a referral to the MMC) whereby National Power and Powergen agreed to dispose of 15% of their capacity before the end of 1996. The regulator's dissatisfaction with the lack of haste of the generators in selling plant led him to consider relaxing the REC's own generation limits, as several of the RECs expressed an interest in purchasing plant from the larger generators. This move to be backed up by a modification to the RECs contracting arrangements prevented excessive contracting from a station in which they had a controlling equity share.

Basing investment solely on current market price signals will generate extreme swings in capacity, with an anticipated reserve margin almost double the desired level by the end of the century, and a subsequent sharp decline to half the desired level by the early 21st century. Concerns have been voiced recently regarding the sharp rise in pool prices in January 1995 following the shutdown of Nuclear Electric's Dungeness and Heysham reactors as a result of routine safety inspections. This sent pool prices to record levels, shattering the imposed price cap of 2.4p/kWh. The corresponding rise in capacity payments led to questions regarding the level of current generating capacity, although some commentators believe that the pool pricing system operated just as it should have done.

Improvements in information exchange between generators should smooth out the capacity levels in the early 21st century, as should improvement in foresight, the shortening of construction times, and the smoothing of the generators' retirement profile. However, all of the scenarios postulated by Bunn & Larsen (1994) exhibit a sharp increase in the reserve margin at the end of the century.

In considering the potential future developments in capacity in the industry, accurate information is vital. Powell (1991) concludes that a large proportion of forward contracts will encourage generators to operate a high output/low price strategy. Thus, the contracts will result in exploitation of the dominant monopoly position as a means of deterring entry. However, with the dissolution of the first tranche of vesting contracts in March 1991, the incentives of the generators would have been altered. As a consequence, any efforts made by the RECs to purchase additional contracts would effectively represent the purchase of a means of controlling the generators' exploitation of their position within the industry.

From an empirical viewpoint, it would clearly not be in the generators' best interests to issue an excessive number of these contracts. This may be done by limiting the actual number of contracts made available and/or making those contracts that are offered unattractive to the RECs who wish to purchase them. A possible empirical foundation for this viewpoint may be found in Offer's Review of Economic Purchasing (1993).

In the review, it is stated that many of the RECs who attempt to undertake contract negotiations with the incumbent generators do so with little or no bargaining power. The RECs also complain of an unwillingness to negotiate on the part of the National Power and Powergen, an attitude that they use to attribute the attractiveness of the longer-term contracts offered by the IPPs. In their defence, the generators complain that the RECs make little or no effort to seek contracts from them.

The nature of the purchase of contracts by the RECs is highly conducive to a Prisoner's Dilemma structure. A single REC will want the other regional suppliers to purchase the contracts as a means of controlling the generators. If taken to its logical conclusion, this will generate a free-rider problem with very few of the RECs actually purchasing contracts.

Despite the transparency of the pool, the contract market remains almost untouched by regulatory intervention. The confidentiality between REC and generator allows for near-perfect price discrimination by the generator through the contract market. Coincidentally, the same may be said of REC contracts to larger customers in the greater than 100kw market. An additional complication concerns the amount of information contained in the pool price, with the importance of accurate information to the efficient development of the industry having already been illustrated.

However, as will be shown, when the general level of pool prices increased in March 1991 with the dissolution of the first set of vesting contracts, there were no fundamental changes to the underlying structure of the industry. This was also the case in March 1993 following the break-up of the second set of contracts for differences. Therefore, one must consider what form of signal this would give to potential entrants to the generation sector. Given the high capital expenditure required for new capacity, one must consider firms to be risk-averse, with such price fluctuations representing a cause for concern.

Despite the fact that the market for CFDs is both confidential and characterised by non-standardised contracts, the latter is not true of the EFA market. The conclusions to be drawn from this outcome are unclear, but it may indicate that it may be conducive to greater efficiency within the EFA market. The lack of transparency and standardisation in the contract market will clearly have an adverse effect on the efficiency of the pool. This could well damage the industry's operating signals, deter entry, and harm the prospects for long-term efficiency.

1.7. Contracts and the Pool.

Following on from his previous research, Green (1992) utilises the methodology established in Green & Newbery (1992) to examine behaviour in the contract market for duopolistic generators. As has been shown, when contracts cover the majority of a generator's output, the incentive to raise prices is lower, a supposition backed up by the low prices observed in the initial period of the pool's operation.

When a generator sells electricity forward under a contract, it is effectively 'reserving' part of the spot market for its own supplies, since it could sell that amount of electricity at the going spot market price, but instead earns profits based upon the contract price. The 'residual', uncovered market will be smaller, and since the generator's optimal mark-up rises with their uncovered sales, the pool price will be lower. This reduces the generator's profits from the uncovered spot market.

With rational expectations, the price that the generator can obtain for its contracts will also be lower, but the extra sales that can be reserved by the contract will not often outweigh this effect. This means that for some parameter values, a generator would wish to sell contracts even if its rivals were not involved in the contract market.

Because the rival will generally follow the same stance, both generators would sell electricity under contract, giving a lower pool price and a somewhat higher output than in the absence of the contract market. However, for some parameter values, the generators would not wish to be the first to enter the contract market, because the act of reserving sales in the contract market will drive the price down in the residual pool to the extent that the generators profits would fall.

If a generator expects its rival to base its contracting strategy on the price for which contracts can be sold, the analysis becomes more complex. If the generator increases its own sales in the contract market, its rival will typically sell fewer contracts as the price falls. This means that the residual pool does not shrink by the full amount of the generators extra sales, and so the price will not fall by as much, making additional contract sales more profitable than if the rival was not expected to respond. In the limit, the generator might expect its rival to aim to keep the contract price, and hence the total contract sales, constant, expanding or contracting its own sales to offset any change in the other firms. Under these conditions, the generator would want to reserve as large a part of the market as it could, since its rival would be expected to reserve the remainder, and so both generators would end up fully contracted, and selling at marginal cost in the spot market.

It therefore follows that the regulator should do as much as possible to encourage competition in the contract market and to encourage generators to sell electricity through both contracts and the pool. Although it is possible that the generators could refuse to participate in the contract market and earn large profits in the spot market, it is unlikely that they would choose the highest prices that they are capable of achieving. If they did, they would effectively be inviting new entry and/or regulatory intervention. The generators may wish to operate in a manner analogous to limit pricing, which the contract market may help them to achieve if they behave competitively in the pool, given that they have sold sufficient electricity under contract.

This becomes important when considering the effects of entry. In the short run, the residual demand curve facing the two generators is fixed. It could be hard for the generators to commit to entry deterrence, given that the price schedules are changing every day. Facing a fixed demand curve in the medium term, they might be tempted to deviate from a limit pricing strategy to obtain higher short-run profits. If potential entrants were aware of this, they could enter until they had shifted the residual demand curve so far to the left that the generators could not obtain a price above the entrants' costs.

However, few potential entrants have been willing to enter without the security of long term contracts to hedge pool revenues. This means that the residual demand curve in the contract market could be very elastic at the level of the entrants' average costs. The generators would be unable to obtain a higher price in the contract market, and if they did not sell many contracts, thus signalling a high pool price. Consequently, the RECs could buy additional contract cover from entrants, who would be financially secure, and force the pool price down. Since the limit price for entry is above the marginal running costs of almost all the generators' present capacity, they would want to sell as much as possible at that price.

This would imply that the generators would do best to sell a large number of contracts, ensuring that price in the pool would equal that price that would exist if no entry occurred. Any attempts made by the generators to raise the price by selling fewer contracts would simply result in a lower market share at the limit price. Entry would force the price below this level and would be unprofitable until new capacity was required. This could well be an optimal outcome, giving prices at long run marginal cost, without incurring the costs of unnecessary entry.

A pivotal study into the effects that the contract market can have upon the pool is that of Helm & Powell (1992). By an analysis of pool prices from vesting until August 1991, it is shown that there was a large increase in prices without any apparent underlying structural foundation. The increase occurred on or around the 22 March 1991, which coincides with the dissolution of the first set of vesting contracts. Prior to this event, there had also been a close relationship between pool purchase prices (PPP) and electricity demand, which was severely disrupted after this event.

Helm & Powell conclude that there was a structural break that distorted the relationship, which they determine to be a long-run relationship. In order to test the validity of this hypothesis, long-run stability of that relationship was tested for. Having verified that both PPP and demand exhibit stationarity, the variables are examined to confirm the existence of a relationship. The initial test is indicative of some uncertainty, but a subsequent test utilises a dummy variable that takes a value of zero until 22 March 1991 and a value of one thereafter. In the case of this latter test, there is very strong evidence of cointegration. It is therefore concluded that there is a relationship between these two variables which was altered in late March 1991.

A subsequent approach utilises a dynamic model of PPP and demand with an error correction format. This model should, and does, illustrate the same conclusions as the initial test by utilising a lagged format for both variables and the dummy variable. An important point that was noted was the statistical significance of the dummy variable, indicating the change to the long-run relationship. The final approach used was that of general to specific modelling to develop a model which would essentially have an error correction format. The dummy variable retained its statistical significance in this model, and the error correction format was validated as accurate, despite some statistical problems.

In order to ascertain the reasons behind these conclusions, bid data obtained from the NGC was studied as a means of estimating electricity supply curves for several time periods before and after April 1991. The conclusions derived from these supply schedules appeared to indicate that the curves had been shifted upwards and to the left. The only possible reason (barring increases in LOLP, which were ruled out) is that the bids that comprise the supply function had been increased beyond competitive levels.

The essential conclusion derived from this analysis is that the contract market can play a pivotal role in determining behaviour in the pool. This conclusion is important because of the lack of regulation for the contract which, in theory, could allow for perfect price discrimination. This analysis was extended to incorporate several of the events included in this study (with similar conclusions) in Gray & Helm & Powell (1996).

The importance of the work of Green & Newbery cannot be overlooked, as they are regarded as the key authors in this field. However, some questions have been raised from their work. Firstly, their pivotal article in J.P.E. (1992) has its conclusions derived from methodologies focusing upon the existence of a symmetric duopoly. This industry (at that time) was definitely an asymmetric duopoly, a factor that limits the accuracy of the conclusions. This factor was noted in their conclusions. A further assumption, the implications of which are noted, is the use of 'typical' days in assessments - this clearly ignores the extremes that may influence prices.

A second point linked to the work of both Green & Newbery and Helm & Powell (1992) is that nuclear power is ignored in their conclusions. The justification made is that because nuclear power is baseload power, Nuclear Electric has no role in setting prices. However, the shutdown of two key nuclear plants in January 1995 (Dungeness and Heysham) sent pool prices to record levels. This must indicate that nuclear power does have a role in setting prices. This point has been noted on more than one occasion by Offer, who also indicated the importance of Nuclear Electric in the contract market.

Perhaps the most interesting component lacking from these studies is the lack of any real empirical evaluation of the contract market. Although this is due primarily to a lack of relevant data, it may be possible to establish proxies for certain key variables and, having increased their accuracy, utilise them as key data sets.

1.8. Potential methods for increasing pool competition and the role of the regulator.

It is almost generally accepted that, in most industries, entry implies competition. However, in the case of the generating sector, this is far from the case. It is Offer's responsibility to judge requests for generating licenses by those firms that see themselves as being able to effectively provide a service to the public in a manner governed by Offer's mandate to encourage competition and protect consumer interests. However, with in excess of 20 licenses to generate having been granted since privatisation, one must consider how successful this policy has been, and perhaps more importantly, has Offer granted too many or too few licenses and if so what have the consequences of that action be ?

It is a well-known fact that in the period since privatisation, National Power and Powergen have dominated the industry, with Nuclear Electric becoming an increasingly larger player in the market over the last few years. In that time, National Power and Powergen have seen their market shares eroded, both through the rise of Nuclear Electric, but also through the increasing number of small generators (IPPs) which have entered the industry. In that time, there has been little in terms of a downward influence on prices, and indeed, many of the larger electricity consumers have alleged that the opposite has been occurring. Therefore, we must consider the possibility that none of the new entrants have either the plant facilities or the resources to enter the uncompetitive core of the generating sector. If this were the case, then if the number of new entrants continues to increase, then it may well serve to damage all of those firms in the competitive fringe. In order to enter the core, a company would need sufficient mid-merit plant to have an influence on setting prices. Although it is true that as more plant enters at baseload, some of the current baseload plant will be pushed into mid-merit, it is uncertain as to the ultimate effects of these actions, or the length of time such a shift could take.

It is apparent that the market share of the generators must also be compared with the shares that the generators possess of baseload and non-baseload plants - an important issue in the MMC reports into the aborted National Power and Powergen take-over bids (HMSO.a and HMSO.b, April 1996). As discussed above, this is because plant that operates at baseload does not set price, while non-baseload plant has a far greater role in setting prices. Therefore, if a generator has a high proportion of non-baseload plant, then that firm will have the ability to influence price to an extent that its competitors may not have. The estimates developed by the MMC showed that for the year 1995/6 National Power possessed 57% of the non-baseload market, Powergen possessed 41%, and the pumped storage businesses possessed 2%. As such, no other firm had any ability to influence prices. It was also estimated that if the plant divestiture plans went ahead as scheduled, then the company (companies) which acquired that plant would have an approximate 20% share of the non-baseload market, thus increasing competition in the generating sector.

While the policy of encouraging entry cannot be denied, one must consider the broader picture. The increased number of entrants has certainly led to a more rapid acceptance and usage of combined cycle gas turbine (CCGT) technology, aided by a change in the European Community directives permitting the wider use of gas for power generation. Indeed, prior to privatisation, gas was considered to be one of the most uneconomic fuel sources available, with only coal and nuclear plants being considered for any new investment in generating capacity. The decline in construction of new coal plants has been well documented in the aftermath of the Conservative government's pit closure scheme. Further, the decision to privatise the nuclear industry was accompanied with concerns that there would be no new nuclear plants constructed or developed after privatisation, unless of course they were nuclear fusion reactors, an area which is largely still in the experimental stages.

The spread of new entry in generation was largely the cause of the 'dash for gas', and its associated effects on the gas industry. This was accompanied by a considerable plan of workforce cuts and restructuring carried out by all of the newly-privatised companies, and a focus on improving customer service standards. These were not only in order to comply with Offer's demands, but also to attract business in the market for those customers with an electricity demand greater than 1MW. At the same time, there was a conscious effort made to diversify away from regulated areas into non-regulated areas. In the case of the RECs, this coincided with the majority of their number expanding into generation. Throughout this time, the relationship between the regulator and the larger generators became increasingly hostile and adversarial, with the threat of MMC referral being made on several occasions.

This came to a head in the 1993 price review, and the subsequent agreement made in February 1994. As a consequence of these investigations, National Power, Powergen and Offer established an undertaking which resulted in them agreeing to dispose of plant and subjecting themselves to a price cap. Since then, the regulator has been concerned that the generators have not made sufficient effort to sell some of their capacity, and has reconsidered the possibility of an MMC referral, as well as allowing the RECs to buy plant from the generators as a means of increasing their own generation limits.

In examining the potential for the regulator to increase competition in generation, it has a number of limited options. The importance of the price undertaking and the corresponding sale of plant agreement is shown in Green (1996a). This examines the three main regulatory possibilities available in order to increase competition in electricity generation: partial divestiture (the policy in use), breaking up of the dominant firms, and encouraging entry.

Given the pool's "merit order" system, the optimal profit maximising strategy for any firm is to bid its generating units at marginal cost. High bids will reduce the amount of time for which the generator is called upon to submit to the pool, and as there is such a high number of plants in the generation network, any effect on prices will be negligible. At least, this is how the pool should function in theory.

However, given the market dominance of the two duopolists, this solution becomes invalid. Given the magnitude of the holdings of either of these companies, if one of the companies increased the bid prices of their plants, then these stations would still be called upon less. Nevertheless, these stations would still be called upon to generate, but by virtue of the monopoly position, the system marginal price will increase and those stations that remain on the merit order will earn more. In this scenario, bidding above marginal cost will raise profits.

The pool price undertaking of 1994 was set as a means of controlling this problem after concerns were voiced by the regulator, consumer groups, and large energy users. In addition, the generators were required to sell a certain amount of their generating plant (4 GW by National Power, 2 GW by Powergen). The key aspect of this sale was that the plant was mid-merit, thereby introducing true competition into generation, rather than the continued addition of baseload sets. In order to assess the validity of this approach, the following model is used.

In this model, there are ***n*** generators which compete through the submission of linear supply functions of the form: $(q_i(p): R^+ \geq R^+, i = 1...n)$. These functions state the amount that each firms is willing to produce at any given price, where the supply functions are non-decreasing in order of price (just as the merit order ranks plants in order of increasing bids).

Electricity demand is given by: $D(p,t)$, where $dD/dp < 0, d^2D/dp^2 = 0$. Demand is variable both over time and also as a consequence of random shocks. However, in this analysis, it is impossible to distinguish between the two causes of demand variation. With the price determined by a market clearing condition where supply must equal demand at all points in time:

$$D\left(p^*(t),t\right) = \sum_i q_i\left(p^*(t)\right) \quad \textbf{(0.a)}$$

The equilibrium is established through the set of supply functions, one submitted by each generator, where each firm is maximising its profits given the supply functions of the other firms at each point in time. Profits may be presented as a function of price, assuming that the residual demand is produced (total demand less the other firms' supply at that price) in order to clear the market:

$$\pi_i(p,t) = p\left(D(p,t) - \Sigma q_j(p)\right) - C_i\left(D(p,t) - \Sigma q_j(p)\right) \quad \textbf{(0.b)}$$

Differentiating with respect to price:

$$\frac{d\pi_i(t)}{dp} = D(p,t) - \sum_{j\neq i} q_j(p) + \left[p - C_{i'}\left(D(p,t) - \sum_{j\neq i} q_j(p)\right)\right]\left(\frac{dD(p,t)}{dp} - \sum_{j\neq i}\frac{dq_j}{dp}\right)$$

(0.c)

Equating the derivative with zero yields the profit maximising price at a particular time, and also the corresponding profit maximising output (the residual demand). If it is assumed that $d^2D/dpdt = 0$, then this price cannot be optimal. The given (price, quantity) pair will then yield a point on the profit maximising supply function. Manipulating the first order condition:

$$q_i(p) = \left[p - C_{i'}\left(q_i(p)\right)\right]\left[-\frac{dD}{dp} + \sum_{j\neq i}\frac{dq_j}{DP}\right] \quad \textbf{(0.d)}$$

It is optimal to utilise the equation in a linear format in order to establish demand and marginal cost, where it is assumed that dD/dp is a constant. Each firm has a quadratic cost function, from which marginal costs increase linearly and are normalised at zero output:

$$C_i(q_i) = \frac{1}{2} c_i q^2_i \qquad C_i'(q_i) = c_i q_i \tag{0.e}$$

As there are many solutions to (0.e), it is easier to concentrate on the unique linear solution, in which each firms' supply function is $q_i(p) = \beta_i p$, therefore $dq_j/dp = \beta_j$. Inserting these supply functions into (0.e) and dividing both sides by p yields:

$$\beta_i = (1 - c_i \beta_i)\left(-\frac{dD}{dp} + \sum_{j \neq i} \beta_j\right) \qquad i = 1, \ldots, n \tag{0.f}$$

Each firm acting in a strategic manner will possess one of these functions, thereby permitting the use of simultaneous equations to solve for the model and to yield the slopes of the supply functions. If this function is chosen by all but one of the firms, the remaining firm's best option is to follow suit, making it an equilibrium.

Rather than being absolute, the model establishes relative results that were designed to fit the industry. As a result, the outcomes of the model in fact represent indexes of policy effectiveness. Average price and output are therefore measured relative to those values which would occur if the generators were bidding at marginal cost, where welfare is given as the sum of consumer welfare and profit, and is maximised when generators bid at marginal cost. Deadweight losses are measured relative to the maximum, with losses resulting from the base case normalised to equal unity.

National Power is given a cost parameter of one-and-two-thirds (£/GW of output), and Powergen a parameter of two-and-a-half, thus ensuring consistency with the fact that Powergen is two-thirds the size of National Power. The duopolists can generate a joint total output of 10 GW at a marginal cost of £10/MWh (6 GW from National Power, 4 GW from Powergen), while an output of 30 GW would have a marginal cost of £30/MWh, a range in which most mid-merit prices lie. With baseload power from Nuclear Electric, the IPPs and imported electricity adding a further 15 GW, this power is treated as a constant to be subtracted from demand as by definition these stations run continuously.

Demand varies over time, operating in the interval from zero to one. The function's intercept is a cubic function of time, to yield a reasonable approximation of the industry's load curve, i.e.

$$D(p,t) = 30 + 120\,(0.5 - t)^3 - 0.5p \tag{0.g}$$

Bidding at marginal cost, the generators' output will vary between 10 GW and 30 GW, implying a total industry output of between 25 GW and 45 GW at prices between £10/MWh and £30/MWh. The slope of the demand curve (-0.5 GW per £/MWh) gives an average elasticity of about -0.25.

With this framework established, the three outlined methods of increasing competition are examined.

In examining forced partial plant divestiture, the model operates such that if a firm is required to sell off ten percent of its capacity, its marginal cost parameter will change from unity to $c_i/0.9$, while the new company will have a cost parameter of $\hat{c}_i = c_i/0.1$. If this new company bids at marginal cost, its output will be equal to $p/\hat{c}_i$ – a formulation that is linear in p, and is compatible with the duopolists choosing linear supply functions. This output is subtracted from the residual demand to be met by the duopolists, so that they now face a demand curve with a slope of $(dD/dp - 1/\hat{c}_i)$.

Working from this formulation, it is shown that selling off an increasing proportion of the duopolists' plant will lead to increased competition in generation. Specifically, if National Power gave up one-sixth of its capacity, and Powergen one-eighth, then a significant decline in prices would result, corresponding to an increase in output and a reduction in deadweight losses of about 40%. As subsequent divestitures are undertaken, the deadweight losses are reduced, but only a certain degree of divestitures can be voluntary. It is also shown that, unlike the prices and output levels, the extent of the deadweight losses are insensitive to the elasticity of demand.

There is no guarantee that the newly created companies will bid at marginal cost, as strategic bidding could be undertaken to increase profits. It is assumed that the divested capacity of each generator is put into a new, separate company, and that these four companies then adopt the equilibrium in linear supply functions. There is no logic in forcing the incumbents to divest more than half of their capacity, as the new firms would then have a greater market share than the initial incumbents.

Prices are higher than if the new capacity bids at marginal cost, and output is lower. Deadweight losses are slightly lower until about 40% of the duopoly's capacity has been divested, a fact due to a reduction in the industry's costs. A firm that is bidding strategically will have a marginal cost below the market price, while a non-strategic firm will bid at marginal cost. Its marginal cost will therefore exceed that of the strategic firms and switching output from strategic to non-strategic bidders could reduce the industry's total costs. This is exactly what happens to the firms that had been bidding at marginal cost switch to strategic bids - their output will fall and that of the duopolists will rise. The firms' marginal costs will not be equal (unless the firms are symmetric), but the reduction in costs more than outweighs the reduction in consumer surplus from a higher price.

The second alternative is to break up the duopolists completely. Three ways of doing this are suggested: National Power could be split into two equal halves; both firms could be split in half; or National Power could be split into three while Powergen was split into two. This would produce five firms of approximately equal size, each owning three or four large power stations. The industry could in fact be broken up into a number of smaller firms, but the resultant firms would jeopardise their company-level economies of scale.

It is estimated that this would reduce any deadweight losses to zero. However, these estimates do not consider the costs of such a reorganisation, which could be considerable, especially given that any reorganisation could only come about as a result of a (generally protracted) MMC inquiry.

The final option is the encouragement of entry, which would have to be in the form of CCGT plant, as it is the continually chosen viable option for new generating capacity. However, as this is predominantly baseload plant, it would have virtually no influence on mid-merit competition or prices. Such entry is modelled by an autonomous leftwards shift of the incumbents' demand curve for electricity by an amount comparable to the new entry. Their supply functions will remain unaffected, and therefore the equilibrium price will fall and output will rise. This will cause a decline in the deadweight losses, but the costs of constructing the CCGT plant must also be considered.

If the new stations replace older stations with higher avoidable costs, or there is a need for new capacity to meet demand growth, then CCGT construction carries no penalty. If there is no need for new capacity, and the new stations have higher avoidable costs than those they replace, then their additional costs must be added to the deadweight losses before the net effects of the policy are evaluated.

It is assumed that the entrants have an average cost of £20/MWh that, until entry, is avoidable. The duopolists' marginal costs vary between £10/MWh and £30/MWh, their average costs are £20/MWh, and their fixed costs are sunk. Based upon these assumptions, it is shown that no entry can be justified by relative costs - the avoidable costs of existing plant which would be saved over the course of a year will exactly equal the cost of new capacity.

The construction of power stations by the IPPs has been based upon a number of determinants, including the current and future prices of electricity, the regulatory environment, government policy and corporate strategy – in addition to considering the amount of output sold under contract. Indeed, the majority of entrants have been backed by long-term contracts. Newbery (1995) suggests that an entrant could sell a long-term contract and enter without risk whenever spot prices rose too far above the entrant's costs. The presence of a contestable contract market (since it costs very little to bring a project to the stage where contracts are signed) therefore restrains the average spot price. In practice, long-term predictions of demand relative to capacity are likely to have more impact on long-term contracts than short-term movements in spot prices, although the frequent exercise of market power might increase the "insurance premium" that buyers were willing to pay for an alternative supply.

Given the importance of long-term considerations, it is unlikely that entry will continue until the average spot price is driven down to the level of entrants' costs. As entry occurs and the duopolists demand curve shifts inwards, the average price falls and total output rises. At first, welfare gains from lower prices outweigh the excess costs of the new stations and entry raises welfare. As more of the duopolists' output is displaced, however, their marginal cost falls, raising the cost penalty incurred by the entrants. This cost penalty soon outweighs the benefits to consumers and so entry reduces welfare. When additional capacity is needed, it would be preferable if the duopolists did not build it, but there is no case for promoting competition without need.

In considering the nature of the regulator and the regulatory process in general, one must look in detail at the nature of the regulator and how their decision-making process operates. Firstly, one must remember that it was the government's objectives that were at the heart of the privatisation programme. In the case of the gas industry, the industry was privatised with the goal of increasing revenue, whereas the electricity industry relied upon the more altruistic goal of increasing competition into the industry by the experimental process of inter-generator competition. The regulator, despite its close links with the MMC and the President of the Board of Trade, is largely in control of the industry, with no firm having any great desire to go beyond the regulator.

Integrating the responsibilities of encouraging entry and ensuring customer protection is at the heart of the regulator's mandate. To do this, any and all monopoly components must be identified and their possibility for competition examined. In the electricity industry, it is the (natural monopoly) transmission system, which is the responsibility of the now-privatised National Grid Company. All other components are seen to be competitive, as witnessed by the spread of competition from those customers whose demand is greater than 1MW per year, to those customers whose demand is greater than 100kW per year in 1994, to the eventual opening up of competition in 1998. Given the concerns regarding monopoly power, one must consider why the regulator has not made stronger efforts to prevent the dominance of National Power and Powergen. It could be argued that the continued threat of an MMC reference is the regulator's deterrent against National Power and Powergen abusing their dominant position. However, given the number of times that this threat has been made, one must consider whether a continued reliance on this policy is misguided (see below).

Under ideal conditions, the regulator would be both independent and unaccountable to any body or institution, be it governmental, industrial or academic. This would guarantee impartiality and the removal of the possibility of any external influences affecting the regulator. These two characteristics are highly unlikely to occur, principally because of the nature of the regulator-government relationship. The regulator shares power with the MMC and the Secretary of State for Trade and Industry, and therefore it cannot be seen to be independent from them. In addition, the degree of independence between the government and the regulator has become an important issue. This is largely due the coincident timing of the decision to re-evaluate the 1994 distribution price review being made on the day after the sale of the government's residual electricity holdings.

One of the regulator's rights should be that of total access to any and all information which it may desire from the firms which it regulates, and it must also possess the right to do as it wishes with that information. However, the firms in question tend to classify certain information as 'commercially sensitive' and maintain that it cannot be released into the public domain without representing a possible violation of their duty to their shareholders. This is often at the core of the lack of co-operation between the regulator and the regulated firms, as it prevents the regulator from doing their job properly and distorts information for any potential entrants.

Entry was seen as a vital part of the privatisation and restructuring process in the electricity industry, but as the dominance of National Power and Powergen has barely been affected in the period since privatisation, one must consider the wisdom of that decision. According to the privatisation 'plan', entry in the form of new capacity will be encouraged based on the level of capacity payments generated in the pool and thus the actual need for new plants. However, one cannot base entry on these decisions alone, and therefore we must examine other factors such as profitability. The electricity industry cannot plausibly be seen as a target for hit-and-run entry, and therefore we must conclude that those firms that have entered the industry have done so based on a long-term plan.

It would be an intriguing experiment if one could ascertain the motives behind new plant construction and determine how many plants were constructed based upon anticipated levels of capacity payments and how many (if any) were constructed because of regulatory encouragement and the 'dash for gas'. Most (all) new entry into the generating sector has been low- or mid-merit baseload plants. However, the most profitable plants are the non-baseload sites owned and operated by National Power and Powergen (and later Eastern), as well as the reserve and reactive Pumped Storage Businesses.

Almost all entry has been in the form of plants constructed with the financial support and/or guaranteed contracts from the RECs, as few firms have been willing to bear the risk of entering without the security of backing from some source. Since over 20 licenses have been granted, there is a conscious desire to prove that competition is possible, that it exists, and that it actually works.

There are some interesting parallels between the current situation in the electricity generating sector and the gas supply industry in its' post-privatisation, post-entry scenario. In the gas industry, over 30 firms were encouraged to enter the gas supply industry by a combination of government and regulatory incentives, and a variety of favourable terms of gas prices. However, as a consequence of declining gas prices and alleged over-contracting of gas purchases through high priced take-or-pay contracts, there are concerns that a 'bubble' has developed in the gas market, which will eventually burst and wipe out many of the smaller firms which the regulator itself encouraged to enter. If this eventuality occurs, then it will severely damage long-run competition in the industry as well as harming the structure of the industry itself.

The equally problematic situation in the electricity industry is that which has arisen because of the high number of entrants. The electricity pool operates on a system which requires that there be a reserve margin of 21% of capacity at all times in case of station outages, malfunctions, power surges, or other unforeseen eventualities. This helps to determine capacity payment levels and therefore new entry as mentioned above. There has been considerable concern voiced by the NGC that, because of the high level of new entry encouraged by the 'dash for gas', the capacity margin will rise to almost 50% before the end of the century if efforts are not made to stabilise it. In the short-term, this eventuality would probably lead to some short-term changes in plant deferment and retirement. In the long run however, this could precipitate considerable cycles of instability in plant capacity, which could lead to problems in guaranteeing adequate capacity in the future. This is especially probable if no efforts are made to stabilise the system through information exchange between generators as to their future investment plans.

In conclusion therefore, we must consider the possibility that the regulatory stance that has been either adopted by the regulator or forced upon it by the government has had potentially detrimental long-run effects upon the industry. In addition, it is apparent that entry does definitely not equal competition, and perhaps the regulator should focus his efforts upon what would generate competition in the electricity industry's generating sector.

Section II - Proposed empirical modelling and the methodologies to be used.

2.1. Pool Price Analyses Performed using Multivariate Regression Analyses (Chapter V).

It is not an unreasonable hypothesis to expect that certain events relating to the electricity industry would influence the general level of pool prices. Specifically, one would anticipate that regulatory announcements would have a considerable effect on how the generators set pool prices, given the terms of their licences. Such events as the announcements of the intention to undertake pool price reviews, the publishing of those reviews, the February 1994 price undertaking, and others could be examined to assess how (if at all) they have influenced prices. In addition, given the statements above concerning the contract market, one could hypothesise that the break-up of the forward contracts in March of 1991 and 1993 would increase pool prices. Finally, one could hypothesise that the occasions on which the generators have been threatened with an MMC reference to influence prices.

It may therefore be possible to utilise dummy variables to represent these events in a series of regressions, and to use the coefficients on the dummy variables to assess the consequences of these events.

The dependent variable in these regressions is to be pool purchase prices (PPP), or some variant thereof. It can also be shown that similar analyses can be performed using uplift levels, partially on their own merit, and partially as an alternative to the (unavailable) generator bid prices. Each of these data sets has been obtained in a half-hourly format for the period October 1990 to November 1995. The independent variable(s) include electricity demand, uplift, pool prices and/or lagged dependent variables (naturally, depending upon the equations under examination). It may therefore be possible to establish a sequence of regressions, such as: univariate price analyses, univariate uplift analyses, uplift-price, and uplift-demand. (Price-demand analyses are retained exclusively for the second empirical chapter).

Conventional regression analysis will allow each of these regression sequences to be modelled over an appropriate time period, with the dummy variables representing the relevant events.

In terms of the possible hypotheses, the pool price reviews remain the most obvious choice but the threats of an MMC reference make an intriguing option. The dissolution of the two sets of vesting contracts will also be examined as a prelude to the second main analysis. The analysis of pool price reviews and their outcomes is a relatively straightforward matter, with an examination of the variables' changing structure over time.

As a general rule, it is assumed that the dummies will only have a short run effect, based upon the assumption of regulation being a repeated game between the generators and the regulator. This short run factor is reflected in the length of the analysis period. The only problem that this may introduce the interaction of two distinct dummies. However, the events selected are deemed to be sufficiently far apart to prevent this from occurring, and feedback between the events is not anticipated.

2.2. Pool Prices and Electricity Demand Analysed by Multivariate Regression Analysis (Chapter VI).

The pool-based data sets have been obtained in a half-hourly frequency for the period October 1990 to November 1995. The relationship may take the form of an examination over the entire period or some section thereof. The variables in question are pool purchase price and gross electricity demand.

The objective of this analysis is to test for the presence of two anticipated disruptions to the relationship. These are anticipated in March 1991 and March 1993 and may be tested for using structural break and dummy variable analysis. These dates correspond to the dissolution of the first and second sets of contracts for differences between the RECs and the generators. It is therefore anticipated that the validation of these hypotheses will indicate the importance that the contract market has on the pool, and therefore the possible need for regulatory action in the contract market. This work is based upon and develops further the work of Helm & Powell (1992).

The same considerations that apply to Part I are also relevant here in terms of establishing the format and structure of the model.

2.3. Generator Share Prices and the Influence of Regulatory Announcements (Chapter VII).

This section will attempt to assess how the events which are chosen as a means of assessing the linkages between electricity prices and regulation are compatible with the results yielded when an assessment of the links between regulation and share prices are made. The data set is shorter for these analyses, existing from March 1991 to November 1995 due to the floatation date of the generators.

The share prices under assessment will be those of National Power and Powergen, and will be analysed by means of the standard market model with dummy variables inserted to represent the relevant events. As this analysis will essentially be identical to that of the first section, the same potential advantages and difficulties again apply.

2.4. Analysis of the Electricity Spot and Forward Markets (Chapter VIII).

The Horton IV estimates are seen as the nearest commercially available approximation to the strike prices for the contracts for differences established at vesting, but any extension of them will require the incorporation of any events which may have affected the assumptions underlying them. This will require an identification of the key events in the electricity industry, and their possible effects on the Horton IV. It is possible to obtain an idea of certain contract terms by examining Offer publications and applying the same reasoning to the contract market in order to construct a synthetic load profile utilising the estimates and all published information on pool prices. The Horton IV estimates are themselves readily available from the Department of Trade and Industry.

In undertaking any examination of the market for contracts for differences and REC contract portfolios, one must consider the actual load factor of the contracts. The load factor (or load shape) is the ratio of kWh consumed by customers to the peak consumption, multiplied by the number of hours under examination.

Although baseload contracts were made available to the RECs (i.e. contracts with a 100% load factor), these are not as valuable as contracts with a lower load factor, and are consequently worth less in the contract market. Electricity consumption in England and Wales is around the 64% load factor mark, while that in the franchise market is nearer to 52-54% because of sharper peaks in demand. As defined above, the load factor of a contract is the ratio of kWh covered by the contract to its peak cover multiplied by the number of hours in the year (8760).

It can therefore be concluded that, if it is assumed that the Horton IV estimates were derived on assumptions regarding the expected level of demand and capacity, then it should be possible to construct an approximation of a sculpted contract schedule. In assessing the relationships that can be assessed using this data set, one would anticipate a relationship to exist between pool prices and estimates of contract prices.

The full details of the process utilised to generate the data set based on the Horton IV estimates is contained in the relevant chapter. However, the data set will terminate with March 1994, one year after the vesting contracts expired. This is because the estimates will be highly inaccurate in the year 1993-4, and expansion beyond this date is inappropriate.

The situation in the UK is also to be contrasted with an overview of the Californian electricity industry and that industry's forward market. This is being undertaken by means of a similar series of empirical models using actual and forecast electricity prices to develop the spot-forward models beyond those of the commercially sensitive UK situation which precludes the release of contract data.

Section III - Conclusions.

The inter-relationships between the pool and the contract market lie at the heart of the post-privatisation structure of the electricity industry. The work of Green, Newbery, Helm and Powell has shown the importance of the ties between the industry, and although the degree of contract cover faced by the generators has declined, it may be concluded that the contract market remains a pivotal element of generating strategy.

As discussed in the previous chapter, the generators possess a high degree of market power in setting pool prices. However, based upon the RECs' comments in the Review of Economic Purchasing (1992), it may be concluded that they also possess considerable market power in the contract market. Although the RECs have diversified their contract portfolios away from National Power and Powergen, these generators remain a key element of any REC's contracting strategy. While the RECs have moved away from the major generators and towards the Independent Power Producers, the IPPs fail to damage the main generators role in the contract market, although it has been discussed that the IPPs have made the generating sector more contestable, if not more competitive.

The major concern regarding the contract market is that the confidentiality of contract strike prices allows for possible perfect price discrimination by the generators. The ideal situation for the generators' contract buyers (RECs and large consumers alike) would be disclosure of contract details and prices in particular. However, the highly diversified nature of contracts makes this outcome of limited usefulness. The contract market would benefit from a degree of homogeneity of contracts - a characteristic that is possessed by the EFA market. Transparent prices and contract homogeneity would allow companies to more easily compare contract terms and ensure that efficient contracting was being undertaken.

The extent of the importance of the contract market will be clearly demonstrated in 1998 when the final set of coal contracts expires. There is not, at present, a commercial system capable of replacing the government-enforced contract market that has existed since vesting, and as such there is concern in the industry as to the potential for future developments. Furthermore, the contracts will expire just as full domestic competition is set to become a reality, allowing the demand for and supply of electricity to become more responsive to each other. Given that the pool has, to date, operated on demand forecasts, the inter-reactions of the demand and supply sides of the industry will take deregulation to its next stage, rather than the pseudo-market that currently exists.

CHAPTER IV: Theoretical Perspectives on the Electricity Generating Sector - Contents.

SECTION I – Introduction.

While it should be apparent that the threat of regulation should influence the behaviour of the firms that face this regulation, the fact that this preposition forms the key to the majority of the empirical work in this thesis requires an examination of its theoretical basis. To that end, this chapter will contain an evaluation of two models of the pool: the Folk Theorem and Klemperer & Meyer's supply function analysis as applied to the UK electricity generating sector by Green & Newbery (1992).

The Folk Theorem (Friedman, 1971) is based around the existence of an infinitely repeated ***n***-person game within which the combinations of players actions that have been chosen are observable producing the possibility an infinite co-operation or punishment strategy. This is most commonly based around a dynamic approach to the simple static Prisoner's Dilemma game. The Prisoner's Dilemma game is based around the principle of co-operation between the players and the pursuit of certain payoffs. For a full and concise explanation, see Clarke (1990).

However, as will be discussed, the Folk Theorem can be adapted to allow for price or quantity bidding within a model of the electricity pool – dependent upon several assumptions discussed below. The key to this analysis is an assessment of the probability of the game ending – in this case through regulation. This is vital given the econometric analysis that follows in the later chapters. A breakdown and simplification of the structure of pool prices and the way in which regulation can influence certain key components of prices develops the study of the Folk Theorem further.

What the Folk Theorem is unable to do is assess the actual price-quantity bidding structure of the pool. This is undertaken through an examination of the supply function approach to oligopoly as developed by Klemperer & Meyer (1989) and applied to the electricity industry by Green & Newbery (1992). This approach has already been introduced (See Chapter II, Section 1.3) and is structured as a one-shot game with no learning process. As such, it does not have the inherent dynamics of the Folk Theorem.

In undertaking these studies, it is hoped that this chapter will provide a key theoretical insight to the econometric studies that follow in later chapters.

SECTION II – Pool Bidding and the Folk Theorem.

1.1. The Folk Theorem.

As discussed in Section I, this study is designed to provide a theoretical basis for the empirical studies that are to follow. With this objective in mind, let us make a few general simplifications. The structure of the electricity pool may be simplified to a sealed and simultaneous bid auction, where both price and quantity levels are contained in the bid. Generators then receive payoffs based upon the interactions of their bids and those of the other players. Because a generators bids contains both price (the price at which their facilities will generate) **and** quantity (the amount of electricity that can be generated), they cannot be fully modelled by standard price (Bertrand) or quantity (Cournot) models. However, the value of the Folk Theorem – despite this limitation – will be evaluated, with the supply function approach to oligopoly discussed in Section III.

The electricity pool can be seen as a repeated dynamic oligopoly game comprised of a sequence of individual discrete time periods. As such, the conduct of the firms in each individual period serves to develop a rivalry according to the rules of some static game, with the resulting supergame composed of repeated plays of the single period games.

Let us establish some definitions. A subgame is a node that is a singleton in every player's information partition, that node's successors, and the payoffs at associated end nodes. A strategy combination is a subgame perfect Nash equilibrium if it is a Nash equilibrium for the entire game **and** its relevant action rules are a Nash equilibrium for every subgame. A strategy combination is a perfect outcome if it remains an equilibrium on all possible paths that branch off into different subgames (Gibbons, 1992).

In modelling the Prisoner's Dilemma (see above) as a repeated game, the issue is whether sustained collusion is feasible. As such, the stability of collusion within a dynamic environment is dependent upon whether or not the present value of lost future profits from colluding exceeds the present value of short-term gains from cheating. Therefore, the discount factor employed by the players is of critical importance. This variable may be defined as follows.

The discount rate, r, is the extra fraction of a payoff unit needed to compensate the player for delaying receipt by one period, and is analogous to the interest rate. The discount factor, δ, is the value in present payoff units of one payoff unit to be received from one period to the present. The discount factor is analogous to the discount rate, and given that the simple form of δ is defined as $1/(1 + r)$, models using either the discount rate or discount factor may be used depending upon notational convenience. The discount factor will be used in this model.

Discounting has two important sources: time preference (ρ) and a probability that the game might end (θ). It is usually assumed that these two variables are constant. If they both take the value of zero, a player is indifferent between whether payments are scheduled now or are scheduled ten years from now. Otherwise a player is indifferent between $x/(1 + \rho)$ and x guaranteed to be paid a period later.

With probability $(1 - \theta)$ the game continues and the payment guaranteed to made in a period's time is made, so the player is *indifferent between* $(1 - \theta)\, x/(1 + \rho)$ *and the promise of* x guaranteed to be paid a period later, contingent upon the game continuing.

The discount factor is therefore: $\delta = 1/(1 + r) = (1 - \theta)/(1 + \rho)$.

This generates the potential for the game to incorporate the impact of regulation. In this case, θ can represent the probability of the game ending **through regulatory intervention**. As stated, in simple forms of the game, θ is a constant, although a more complex form of the game would have θ given as a function of the historical payoffs to date. For simplicity, θ is treated as a constant.

In this environment it is possible to find a simple equilibrium for the infinitely repeated Prisoner's Dilemma in which both players co-operate through adoption of the "grim" strategy, defined as follows.

With the grim strategy, a player starts chooses to co-operate, and will continue to co-operate thereafter until the other player cheats, in which case cheat thereafter. If this is modelled as a simple 2 x 2 matrix, then if player 1 uses the grim strategy, then the grim strategy is weakly the best response of player 2. If player 2 co-operates then he will continue to receive the high (***co-operate, co-operate***) payoff forever. If player 1 cheats, he will receive the high (***cheat, co-operate***) payoff once, but then the lower (***cheat, cheat***) payoff thereafter (Gibbons, 1992)

Although eternal co-operation is a perfect outcome in the infinite game, so is practically anything else – including eternal cheating. It is this multiplicity of equilibria that may be summarised by the Folk Theorem.

In an infinitely repeated game with finite action sets, any combination of actions observed in a *finite number of repetitions is the unique outcome of some subgame perfect equilibrium,* provided that the following conditions are met. Firstly, that the rate of time preference is zero, or at least positive and sufficiently small. Secondly, **the probability that the game ends is zero, or at least**

positive and sufficiently small, i.e. the probability of the regulator intervening is minimal. Thirdly, that the set of payoff combinations that strictly Pareto-dominate the minimax payoff combinations in the mixed extension of the one-shot game is ***n***-dimensional (the Dimensionality condition) (Gibbons, 1992).

The Folk Theorem helps answer whether discounting serves to limit the impact of a possible last period. In the presence of discounting, the present gains from cheating are weighted more heavily and the future gains from co-operation are weighted more lightly. If the discount rate is very high, the game is almost one-shot – any model that has a high number of repetitions relies upon the discount rate not being too high.

Allowing a little discounting is nonetheless important to show that there is no discontinuity at the discount rate of zero. If we come across an undiscounted infinitely repeated game with many equilibria, the folk theorem tells us that adding a small discount rate will not reduce the number of equilibria. This contrasts with the effect of changing the model by making the number of repetitions large but finite. This often eliminates all but one outcome: the chainstore paradox, i.e. solving a finite incumbent-potential entrant model by backwards induction, the potential entrant will always join and the incumbent will always collude.

A discount rate of zero supports many perfect equilibria, but if the rate is large enough, the only equilibrium outcome is eternal cheating.

Time preference is straightforward, but what is surprising is that assuming that the game ends with probability θ does not make a drastic difference.

It is possible to allow θ to vary over time, so long as it does not become too large. If $\theta > 0$, the game ends with probability one, or rather the expected number of repetitions is finite, it still behaves like a discounted infinite game, because the expected number of repetitions is always large – no matter how many have already occurred. The game still has no last period, and it is true that imposing one, no matter how far beyond the expected number of repetitions, would radically change the results.

Allowing the game to end at some uncertain date prior to T is not the same as establishing that the game has a constant probability of ending. In the former, the game is like a finite game, because as time passes the maximum amount of time remaining will shrink to zero. In the latter, even though the game will probably end by T, if it lasts until T the game looks exactly the same as at time zero.

In this situation, the Folk Theorem can be used to model the pool but only if one simplifies the structure to focus upon either price or quantity bids, i.e. players face a ***high price, low price*** or ***high output, low output*** strategy set and corresponding payoffs. In this environment, the (***high price, high price***) or ***(low output, low output)*** combinations would equate to the (***collude, collude***) options discussed above. Furthermore, the impact of regulation can be incorporated through the component θ, the probability of the game ending. Given this, the collusive equilibrium of the grim strategy will hold if the discount factor is sufficiently low: i.e. if the probability of regulatory intervention increases sharply, then the collusive equilibrium will not hold. This will be incorporated into the discount factor and hence impact upon the bidding strategies of the players.

Having introduced the terminology, the stage game may be presented using the following notation:

S_i :	strategy set, player i
$S = (S_1, S_2, \ldots\ldots, S_n)$:	strategy set for the game
$\pi_i(S)$:	payoff, player i
$\Pi = (\pi_1, \pi_2, \ldots\ldots, \pi_n)$:	payoff vector for the game
$G = (S, \Pi)$:	single period or stage game

If S_i is the range of outputs open to firm i and $\pi_i(S)$ is the profit gained by firm i, the stage game is a Cournot quantity setting oligopoly. If S_i is the range of prices open to firm i and $\pi_i(S)$ is the profit gained by firm i, the stage game is a Bertrand price setting oligopoly with product differentiation. In both cases, each firm has a constant marginal cost, no fixed costs, and quantities (prices) are chosen simultaneously.

In order to evaluate the resulting infinite supergame, suppose a game is repeated T times and that player i seeks to maximise the present discounted sum of the stage game payoffs:

$$\sum \delta^t \pi_i (S_t) \tag{0.a}$$

where Σ is from $t=1$ to $t=T$; S_t is the vector of strategies of the n players in period t; and $\alpha < 1$ is the factor used to discount future income. In this sense, $\delta = 1/(1 + r) = (1 - \theta)/(1 + \rho)$ as defined above.

The T-period supergame is then described by the vector $G^T = (S, \Pi, \delta, T)$.

In this T-period game, a pure strategy for player i is a T-element vector σ_i. The first period of σ_i, $\sigma_i(1)$ is an element of S_i and gives player i's move in the first period. The second element of σ_i, $\sigma_i(2)$ is a function mapping S to S_i. $\sigma_i(2)$ gives player i's move in the second period as a function of the moves of all players in the first period.

The third element of σ_i, $\sigma_i(3)$ is a function mapping S^2 (a Cartesian product of S and itself) to S_i. Here, $\sigma_i(3)$ gives player i's move in the third period as a function of the moves of all players in the first two periods.

In like manner, $\sigma_i(t)$ gives player i's move in the period t as a function of all of the previous moves of all of the players.

It may be stated that:

$$a(\tau) = (a_{1\tau}, a_{2\tau}, \ldots\ldots\ldots a_{n\tau}) \tag{0.b}$$

For the vector of actions taken in period τ. The history of the game to time t is then:

$$H_t = [a(1), a(2), \ldots\ldots a(t-1)] \tag{0.c}$$

H_t shows the actions of all players in all periods. It is a vector of $n(t-1)$ elements, a point in S^{t-1}, the (t-1) fold Cartesian product of S with itself. S^{t-1} is the set of all possible histories of the game prior to period t.

With this notation, the elements of player i's strategy σ_i are

$$\sigma_i(1) \in S_i \tag{0.d(i)}$$

$$\sigma_i(t): S^{t-1} \rightarrow S_i \qquad t = 2, 3, \ldots.., T \tag{0.d(ii)}$$

The action taken by player i in period t is the realised value of $\sigma_i(t)\ (S^{t-1}) = a_{it}$. Thus player i's action in period t depends on the choices of all players in all previous periods.

$\sigma = (\sigma_1, \sigma_2, \ldots\ldots\ldots, \sigma_n)$ is a strategy vector for the t-period game. A non co-operative equilibrium for the supergame is defined in the usual way. σ is a non co-operative equilibrium for $G^T = (S, \Pi, \delta, T)$ if, for all i, element i of σ maximises player i's payoff, taking all other elements of σ as given.

Consider an infinitely repeated supergame: $T = \infty$. Let σ_{Cournot} be the strategy vector if all players play their stage game Cournot output period by period. For σ_{Cournot} the supergame is simply a repetition of the stage game period after period.

Playing the Cournot strategy from the stage game in every period is a non co-operative equilibrium for the supergame. If all other players play their Cournot strategy in every period, the best a single player can do is play his Cournot strategy in each period. The question is whether there are equilibrium strategies for the supergame that yield a higher payoff than simply repeating the stage game equilibrium strategy.

In order to assess the role of a trigger strategy, consider any stage game strategy s_{collude} that yields each player at least as great a single period as the Cournot strategy. If all firms have the same constant marginal and average cost, the joint profit maximising strategy is one example of such a strategy. Following Friedman (1971), define a trigger strategy for the supergame as follows:

1. Each player begins by playing his or her part of s_{collude} and continues to do so as long as all other players continue to do the same.
2. Revert to s_{Cournot} in the period following any defection from s_{collude} and continue to play s_{Cournot} thereafter.

Formally the trigger strategy is defined as:

$$\sigma_i(1) = S_{i,collude} \tag{0.e(i)}$$

$$\sigma_i(t) = \{s_{i,\text{collude}} \text{ if } \sigma_j(\chi) = s_{j,\text{collude}},\ j \neq i;\ \chi = 1, \ldots, t-1;\ t = 2, 3, \ldots : s_{\text{Cournot}} \text{ otherwise}\} \tag{0.e(ii)}$$

Whether or not a player prefers to produce his or her part of s_{Cournot} depends upon a comparison of the payoff from defecting and the payoff from adhering to the cartel strategy. If defection has not yet taken place, payoff streams following defection or adherence in period *t* are the same as payoff streams following defection or adherence in period 1. It follows that the initial period need only be considered.

Beginning from period 1, let $\pi_{i,collude}$ be player *i*'s per period profit if all firms adhere to the collusive strategy, $\pi_{i,defect}$ be firm *i*'s best response one period profit if it defects from the trigger strategy and $\pi_{i,Cournot}$ be firm *i*'s per-period profit after rivals revert to the Cournot strategy. Assume that:

$$\pi_{i,defect} > \pi_{i,collude} > \pi_{i,Cournot} \tag{0.f}$$

The first inequality means that it is tempting to defect from the collusive strategy. The second inequality means that reversion to the Cournot strategy is costly compared to with adhering to the collusive strategy. Such inequalities hold, for example, if the stage game is Cournot *n*-firm quantity setting oligopoly with a linear demand curve and marginal cost constant and identical across firms and the collusive strategy is to have each firm produce a fraction 1/*n* of the joint-profit-maximising output.

Firm *i*'s payoff if it adheres to the collusive agreement is:

$$\mathbf{PDV}_{i,\mathbf{collude}} = \delta\pi_{i,collude} + \delta^2\pi_{i,collude} + \ldots\ldots$$

$$\mathbf{PDV}_{i,\mathbf{collude}} = \pi_{i,collude}\,\Sigma\delta^{t}$$

$$\mathbf{PDV}_{i,\mathbf{collude}} = (\delta/1 - \delta)\,\pi_{i,collude} \tag{0.g}$$

Firm i's payoff if it cheats for one period and triggers retaliation thereafter is:

$$\mathbf{PDV}_{i,\mathbf{defect}} = \delta\pi_{i,defect} + \delta^2\pi_{i,Cournot} + \delta^3\pi_{i,Cournot} + \ldots\ldots$$

$$\mathbf{PDV}_{i,\mathbf{defect}} = \delta\pi_{i,defect} + (\delta^2/1 - \delta)\,\pi_{i,Cournot} \tag{0.h}$$

For the trigger strategy to be a non co-operative equilibrium, the payoff from adhering to the trigger strategy must exceed the payoff from defection.

Using **(0.g)** and **(0.h)**, $\mathbf{PDV}_{i,\mathrm{collude}} \geq \mathbf{PDV}_{i,\mathrm{defect}}$ if:

$$\delta \geq (\pi_{i,defect} - \pi_{i,collude}) / (\pi_{i,defect} - \pi_{i,Cournot})$$

(0.i)

This condition **(0.i)** is always satisfied if the discount rate is sufficiently small and hence the discount rate remains close to unity. Thus the trigger strategy is a non co-operative equilibrium if firms' discount rates are sufficiently small.

If **(0.g)**, **(0.h)**, **(0.i)** are satisfied, the trigger strategy is a subgame perfect non co-operative equilibrium. Suppose first that all firms have produced the collusive output from period 1 through period $t - 1$. Then from period t onward, firm i faces the alternative income streams generated by the defection and collusion strategies. If the trigger condition is satisfied, firm i prefers to follow the trigger strategy from period t onward.

In contrast, suppose that some firm defected from the trigger strategy in a period before t. Then when firm i arrives at period t, it finds all other firms playing their stage game Cournot strategies. The Cournot strategy is a best response if all other firms play their Cournot strategies, so the best it can do is play its own stage game Cournot strategy. This is what the trigger strategy calls for, and as such, it defines a perfect equilibrium from any period onward – no matter what the history of the game. This is the defining characteristic of subgame perfection.

The result is that the trigger strategy, **(0.e)**, sustains output paths that allow each player to earn more than the Cournot payoff. This is an example of the **Folk Theorem (Friedman, 1971)**, which holds that non co-operative behaviour can sustain any strategy producing individual payoffs that exceed Cournot payoffs **if the interest rate is small enough, i.e. if the discount factor defined above remains close enough to unity.**

The model may also be adapted slightly to incorporate the issues of structure, conduct and the stability of collusion in the presence of a trigger strategy.

For simplicity, consider the case in which firms are symmetric, so that concentration is inversely related to the number of firms present. Examine an n-firm oligopoly with linear inverse demand curve, i.e. $p = a - bQ$ in which all firms enjoy the same constant marginal cost, c, per unit.

If n firms settle on a collusive output q per firm, then:

$$\pi_{i,collude} = b(S - nq)q$$

(0.j(i))

$$\pi_{i,defect} = b[(S - (n-1)q / 2]^2$$

(0.j(ii))

We know that for this model, Cournot profit per firm is:

$$\pi_{i,Cournot} = (S / n + 1)^2$$

(0.j(iii))

Utilising **(0.j(i))** and **(0.j(ii))**, this may be re-arranged to yield:

$$(\pi_{i,defect} - \pi_{i,collude}) / b = [(S - (n-1)q / 2]^2 / 4$$

(0.k)

Equations **(0.j(ii))** and **(0.j(iii))** yield:

$$(\pi_{i,defect} - \pi_{i,collude}) / b = [(n-1)\,[S - (n+1)q].[\,n+3)\,S - (n^2 - 1)q]] / 4(n+1)^2$$

(0.l)

If:

$$\delta = (\pi_{i,defect} - \pi_{i,collude}) / (\pi_{i,defect} - \pi_{i,Cournot})$$

(0.i(i))

and substituting **(0.k)** and **(0.l)**:

$$q = [(n+1)^2 - \delta\,(n-1)(n+3)\,] / [(n+1)^2 - \delta\,(n-1)^2\,] / [\,S / (n+1)\,]$$

(0.m)

which is valid so long as $q \geq S/2n$. This is the case if:

$$\delta \leq (n+1)^2 / (n+1)^2 + 4n$$

(0.n)

These conditions can be given three interpretations: if the interest rate is too high, if the discount factor is too much below unity, if the rate of time preference for profit is too great, then a cartel is unable to sustain joint profit maximisation with a trigger price strategy.

On the other hand, if the above condition is not met, then use of a trigger price strategy allows an n-firm cartel to maximise joint profits. If the above inequality is satisfied, then $q = S/2n$ and the cartel is able to maximise joint profits. Therefore, as market concentration rises (as n falls), the range of interest rates over which tacit collusion is a subgame perfect equilibrium strategy for joint profit maximisation increases.

However, as the pool requires price-quantity bids to effectively model generation, it is uncertain whether the folk theorem can successfully be applied to an extent beyond the price or quantity bidding. Instead, the supply function approach to equilibria developed by Klemperer and Meyer (1989) and applied to electricity generation by Green & Newbery (1992). These elements will be discussed in depth in Section II.

Section 1.2. Assessing the impact of regulation on components of pool prices.

Before moving on to examine the work of Green & Newbery (1992), let us consider further the feasibility of actually applying the Folk Theorem to the pool. Given that the most important factor in the pool on a day-to-day basis is the level of system marginal price (SMP), a price-setting game will be considered.

Given that the impact of regulation lies at the core of this work, the role of the regulator (through the factor θ) in determining (either directly or indirectly) generators' bids. To do this, it is necessary to develop assumptions about the bid structure.

To assess the impact of regulation on the generators' bids, consider the following structure of the generators' bids. First, let us assume that bids are bounded on the lower level by the competitive bid price and on the upper level by the monopoly bid price. Second, let us assume that the bid price for electricity can be broken up into specific components that can vary in each half-hour period. Third, let us assume that regulation - either in the form of a credible regulatory threat or a specific course of action has the potential to influence certain components of the electricity bid price, and hence the payoffs of the game. Fourth, that the players can witness the outcomes of all of the preceding plays of the game, $t = 1......t-1$, before choosing their strategies in period t. The first assumption can be stated as follows:

$$P_c \leq P_b \leq P_m \tag{0.o}$$

where: P_c = competitive (**"cheating"**) bid price

P_b = electricity bid price

P_m = monopoly (**"collusive"**) bid price

This assumption is made purely as a simplification. The price of electricity in any half-hour is potentially bounded on the lower level by the marginal price of the last genset. As baseload stations are often bid in at zero to ensure their presence in the merit order - conceivably the lowest price for electricity is zero. Similarly the highest price for electricity in any half-hour is the marginal cost of the most expensive genset. The peak electricity price to date is £836MWh; thus representing a price distribution that is both skewed and truncated.

However, let us return to the second assumption. On a day-to-day basis in the pool, there is a price below which electricity cannot fall assuming that a zero price for electricity does not result (this has never occurred in the history of the pool). Such factors as fuel costs, thermal efficiency levels, minimum safe generation (MSG) levels, and other technical and engineering constraints determine this minimum price for electricity. These factors are broadly fixed in the short to medium term and could therefore be seen as a constant term in prices. These factors will vary dependent upon which plant actually sets price in a given half-hour, but for simplicity it is assumed that a general "minimum" level can be reached.

In addition, there are other factors that will represent non-constant determinants of the bid price. These factors can be given as: intra-day and inter-day price fluctuations; seasonal price variations; climatic determinants; industrial growth; GDP levels; and the level of the price-cost mark-up. The price cost mark-up can be indicative of the level of market power possessed by the firms in the industry, and thus directly determined by the strength and extent of regulation in the industry. Within this component, there lies the variation caused by the specific generating stations and individual generating units that are called upon to generate by NGC.

There is also an additional element to electricity prices: the potential for anomalous, extremely high but extremely brief (at most two half-hour periods) price spikes. These spikes have occurred on only a handful of instances in the post-privatisation environment, but their existence is a distinct possibility.

Therefore, the bid price of electricity can be broken down into three components: a "permanent" component, a "drift" component and a "jump" component, which will be present in each generator's bid. In order to retain the simplistic nature of this model, there will still be only two symmetric generators, ***i*** and ***j***. These components may be given as follows.

- The permanent component (A_{it}) which will be composed of engineering (E_{it}) and technical (K_{it}) factors.

- The drift component (D_{it}) which will be composed of seasonal and temporal factors (S_{it}), climatic variations (W_{it}), GDP levels and industrial growth (I_{it}), the price-cost mark-up (C_{it}).

- The generating order (or stack) component (G_{it}).

- The jump component which will be the result of random variations and scheduling anomalies (R_{it}).

Each of the components will exist in each of the time periods, $t = T$, and for each generator i,j.

- Permanent component: $(A_{it}) = (E_{it}) + (K_{it})$
- Drift component: $(D_{it}) = (S_{it}) + (W_{it}) + (I_{it})$
- Price-cost mark-up component: (C_{it})
- Stack component: (G_{it})
- Jump component: (R_{it})

Therefore, the bid price in any half-hour will be given as:

$$P_t \leq P_b = A_{it} + D_{it} + C_{it} + G_{it} + R_{it} \leq P_m \tag{0.p}$$

Let us now consider the actual pricing structure. This will be variable both on an intra-day and an inter-day basis, although certain patterns will emerge. For example, in low demand periods the permanent component will dominate, but in high demand periods, the drift component will dominate. The jump component will - to all intents and purposes - be minimal. The market power component is the key issue, as it will be directly influenced by the probability of the game ending (θ).

The bid price of electricity can therefore be stated as:

$$P_t \leq P_b = \alpha_1 A_{it} + \alpha_2 D_{it} + \alpha_3 C_{it} + \alpha_4 G_{it} + \alpha_5 R_{it} \leq P_m \tag{0.q}$$

where $(C_{it}) = f(\theta)$.

It can therefore be seen that if the existence or possibility of tighter regulation is apparent, there would be a higher probability of the game ending (θ) if the threat is credible. This would have a strong (inverse) influence on (C_{it}).

If the price-cost mark-up is the sole facet of market power, a competitive and efficient (from a scheduling perspective) bid would when (C_{it}) equals zero and there is no jump component:

$$P_b = \alpha_1 A_{it} + \alpha_2 D_{it} + \alpha_3 C_{it} + \alpha_4 G_{it}$$

(0.r)

where (C_{it}) = 0. Likewise, a monopoly price bid (which possessed the jump component) would occur when (C_{it}) was maximised, i.e.:

$$P_b = \alpha_1 A_{it} + \alpha_2 D_{it} + \alpha_{3\,max}\, C_{it} + + \alpha_4 G_{it} + \alpha_5 R_{it}$$

(0.s)

Therefore, the payoff space in the game is a function of the value of (C_{it}) - the extent to which the generators attempt to exploit their market power - itself a function of θ.

This therefore returns us to the issue of θ. Given that this represents the probability of the game ending through regulatory action, in a practical context this would be though breaking up the two main generators. While the history of the pool indicates that this has always been an option, the regulator has been unwilling to undertake such a course of action.

At the same time, regulation must always seem credible so as to prevent the generators from simply behaving as they please. Therefore, θ must possess a value between zero and unity but must also possess a value that allows the grim strategy to hold.

In practice, the decision whether or not to bring the game to end through regulatory intervention will depend upon the current and past bidding behaviour of the generators. This means that θ is not a constant factor and that it is dependent upon the current payoffs and the history of payoffs to date. Therefore the game is circular throughout the playoff history and it is in the players' interests to behave in such a manner that the game continues. Consider the following broad rules:

- If $P_b \geq P_m$, θ -$\geq$ 1
- If $P_b \geq P_c$, $\theta \geq 0$

This therefore implies threshold values to θ, with the lower threshold given as θ_l and the upper threshold given as θ_u. Therefore:

- If $\theta < \theta_l$, regulation is not credible.
- If $\theta > \theta_u$, the game is likely, but not certain, to end.

Therefore:

$$0 < \theta_l < \theta_u < 1 \tag{0.t}$$

represent the upper and lower bandwidths represent the tolerances within which the game.

In the light of this approach, consider the following conclusions that can be derived from these assumptions. First, the bid price of electricity is composed of a series of components, one of which is the extent of market power held by the generators and is represented by the price cost mark-up, (C_{it}). Second, the price cost mark-up (C_{it}), is influenced by the probability of the game ending, θ, which is itself a function of C_{it} and the payoff history to date. This provides the game with its circular element as it is played on a day-to-day basis. Third, the value of θ will - through C_{it} - influence the bid price, P_b, and therefore the equilibrium that results in payoff space. Fourth, ***ceteris paribus***, if C_{it} tends to zero, P_b will tend to the competitive price, P_c , and if C_{it} is maximised, P_b will tend to the monopoly price, P_m. Fifth, in order for the game to continue on a daily basis, θ will remain within upper and lower bandwidths where regulatory action remains credible and there is a distinct non-zero probability of the game ending. In this environment, the grim strategy will hold.

1.3. Price uncertainty.

In light of this analysis, one can conclude that as pool prices contain a permanent component, they should be predictable within certain degrees of confidence. However, this is dependent upon the time frames in question and the actual periods for which one is forecasting prices. While this should be a simple question of market efficiency and the construction of a forward curve for prices, there are two key complicating factors stack and drift components of prices outlined above.

The stack component combined with the drift and (to a lesser extent) the jump component produce the uncertainty associated with electricity prices. The generating stack represents the order in which plants are scheduled and given the almost infinite number of permutations of generating units and generating plants, there is an inherently high degree of uncertainty associated with pool prices. In the light of this, one must also consider the integrated effects of the stack component with the drift component – which will compound the uncertainty described above. In theory, there is a floor below which pool prices cannot fall, as defined by the permanent component of prices. However, on any day at random, the nature of the permanent component is such that it may be outweighed by the other components of price on any given day. This will reduce prices to a composite of a range of variables that are determined by random and unpredictable inter-day and intra-day changes such as the weather. The other major practical flaw with the permanent component of prices is that it is inconsistent with generators bidding their plant in at a zero price.

There is another factor that is of note from this analysis before one begins the empirical analysis, and that concerns the distribution of prices. This model is capable of producing extreme positive prices, but not negative prices. Furthermore, the consistent impact of certain factors will in practice produce a clustering of prices. This may sound inconsistent with the above statement concerning the randomness of prices, but it is simply a question of the time frame in question.

If one chose a given day at random, then the uncertainty associated with the variable components of pool prices could result in pool prices that were random and unpredictable. This is because while one would be able to estimate that pool prices would exist within certain tolerances, specific within-day and within-week uncertainty would make any forward curve little more than a seasonally dictated estimate. However, if one were observing a given series of prices in a specific time period, e.g. a week in winter, then similar factors over the chosen time period would induce a consistency in prices within that time frame.

Consider the £378/MWh price spike of 11th February 1998 from the perspective of a forecaster in late 1997. One could quote an estimate of *Q1 1998* prices based upon a forward curve (approximately £25/MWh) , but it would be difficult to quote a price for a specific day in February. As such, while prices within a specific period will gravitate to an average, prices for specific days can be little more than random. If one were to extend this rationale to a long-term data set for prices, then the distribution of prices would be skewed towards the most common price within that distribution, but prices within that distribution could be viewed as a collection of random variables. Empirically, given that the price for electricity in a given half-hour has ranged from less than less than £10/MWh to almost £1000/MWh with an average of around £22/MWh, it is unlikely that any distribution of prices viewed over a long time period would be normally distributed. Volatility in energy prices is not restricted to electricity, as the example of the gas market illustrates.

The peak and trough gas prices since privatisation have been £4.97 per therm (16/12/97) and **minus** £14.65 per therm (15/03/97), despite being traded within reasonable margins based upon seasonality and the forward curve. For example, up to September 1997, a year strip of 1997/8 traded at approximately 18 pence per therm (as quoted by the BSGM Heren index). Within this, seasonality factors increased the winter period to approximately 21 pence per therm and reduced the summer period to around 14 pence per therm. However, the 16th December 1997 spike resulted in losses of millions of pounds and at least one company going bankrupt. This spike was due to a combination of random events (predominantly those on Transco's flexibility mechanism) but did not coincide with the coldest day of the year or with any major system or terminal problems. In this environment, it can be seen that day-to-day energy prices (both gas and electricity) do have a highly random and unpredictable element based upon specific daily events and the responses to those events.

SECTION II. The Contribution of Green & Newbery.

2.1. The Supply Function Approach to Electricity Generation.

The established work of Green & Newbery (1991), Green (1992), and Newbery (1992) relies heavily on that of Klemperer & Meyer, which established the existence of supply function equilibrium in oligopoly. Commencing from a position of unknown demand, an initial assumption of duopolistic generators is made, each of which submits their own supply functions independently and without knowledge of the function of the other. As demand becomes known, the spot price equates supply with demand, and in the event that there is no equilibrium, the firms receive nothing. The model contains provisions to incorporate reasonable variations in demand. Based upon these assumptions, the model is constructed as follows.

Utilising the load demand curve to represent electricity demand (i.e. those occasions where demand exceeds a given level), this schedule is seen as predictable and given by $D(p,t)$ where t is "time" (the number of hours in which demand exceeds D) and p is the spot price. (In order to ensure consistency with Klemperer & Meyer, it is in fact defined as the spot price minus the marginal cost of supplying an infinitesimal amount, thereby shifting the origin with the consequence that the marginal cost schedule intersects the origin).

It is assumed that, for all (p,t):

$$-\infty < D_p < 0, \quad D_{pp} \leq 0, \quad D_{pt} = 0$$

The net demand faced by firm i at time t, while the other firm j has a supply schedule of $S^j(p)$ is $Q(p,t) - S^j(p)$. The effective generation cost of producing q are $C(q)$ where the marginal cost of generation is $C'(q)$.

Both firms submit their supply functions simultaneously to the despatcher, who then determines the equilibrium price output combination to equate demand to supply at each moment and to set the lowest price, $p(t)$ where:

$$D(p,(t),t) = S^i(p(t)) + S^j(p(t)), \text{ where } j \neq i$$

if such a price exists.

Provided that the profit maximising price-output combinations can be represented by the supply function $q_i = S^i(p)$ and with assumptions on costs and demand, at any t, the choice of q_i implies a particular value of p, which yields a profit maximising solution solved with respect to p. This solution is given by:

$$\pi_i = pq_i - C(q_i)$$

to yield:

$$\pi_i(p) = p.[D(p,t) - q_j(p)] - C[D(p,t) - q_j(p)] \quad \textbf{(1.a)}$$

where $i \neq j$. This results in the first-order condition:

$$\frac{dq_j}{dp} = \frac{q_i}{p - C'(q)} + D_p, \quad i \neq j \quad \textbf{(1.b)}$$

This produces a symmetric situation where $q_i = q_j = q$, where:

$$\frac{dq_j}{dp} = \frac{q}{p - C'(q)} + D_{p'}, \quad i \neq j \quad \textbf{(1.c)}$$

The second derivative of firm i's profit becomes:

$$\frac{d^2\pi_i}{dp^2} = 2(D_p - \frac{dq_j}{dp}) - C_{i'}(D_p - \frac{dq_j}{dp})^2 + (p - C_{i'})(D_{pp} - \frac{d^2 q_j}{dp^2})$$

Provided that both q_i and q_j satisfy (1.b), this becomes:

$$(D_p - \frac{dq_j}{dp})(1 + - C_{i'}\frac{dq_j}{dp}) - C_{i'}(D_p - \frac{dq_j}{dp})^2 - \frac{dq_j}{dp} \quad \textbf{(1.d)}$$

As this is negative, this confirms the local optimality of supply schedules, thus satisfying (1.b) and therefore the symmetric case (1.c). This will yield a Nash equilibrium in supply functions.

The behaviour of the differential equation that characterises the symmetric supply function equilibrium prompts further analysis. Considering points (q,p) such that:

$$C'(q) < p < C'(q) - \frac{q}{D_p} \tag{1.e}$$

then at such points:

$$0 < dq/dp < \infty$$

and the trajectory of the differential equation through this point has a well-defined positive directional slope. It can be seen that all such trajectories pass through the origin, where they all possess the same slope. It is then necessary to consider the stationaries whose equations define the upper and lower limits in (1.e).

If the equation $p = C'(q)$ is considered, then this clearly represents the inverse supply schedule of a competitive firm, and along this schedule:

$$dq/dp = \infty \quad , \quad dp/dq = 0$$

Any trajectory that intersects the lower stationary reaches it with a horizontal slope, and upon crossing the stationary it will have a negative slope. If the trajectory reaches the upper stationary, its slope will be:

$$dq/dp = 0 \quad , \quad dp/dq = \infty$$

where it will cross the stationary vertically and bend back. These conclusions are simplified somewhat by the recognition that the upper stationary is the Cournot schedule, and the lower stationary the Bertrand schedule. Therefore, the options for equilibrium range between the perfectly competitive and the monopolistic. The profit maximising choice of p satisfies the condition:

$$q_i + [p - C'(q_i)]\, D_p = 0$$

or:

$$p = C'(q) - \frac{q}{D_p} \tag{1.f}$$

In order to progress further, suppose marginal costs are constant, i.e. ***C'(q)*** $= 0$, and that demand at time ***t*** is ***Q(p,t)*** $=$ ***a(t) - bp***, and therefore $\boldsymbol{D_p = -b}$. If this is true, (1.c) becomes:

$$dq/dp = (q/p) - b$$

which can be solved to yield:

$$q = Ap - bp \ln p \tag{1.g}$$

for some constant of integration ***A***, which will depend upon boundary conditions (e.g. where supply meets the Cournot schedule). It can also be shown that in the presence of capacity constraints (as measured through a shadow price, where each firm cannot supply beyond an upper limit, ***k***), the range of potential equilibrium will be narrowed, as shown below.

If neither firm can supply beyond $\boldsymbol{q = k}$. At $\boldsymbol{q_j = k}$, the optimal response of firm ***i*** is the Cournot solution:

$$q_i = -D_p(p - C' - \mu)\ ,\ \mu \_ 0\ ,\ q_i \_ k\ ,\ \mu(k - q_i) = 0$$

where the *mu* is the shadow price of the capacity constraint. It is then shown (through graphical analysis) that the overall effect of capacity constraints is to narrow the range of potential equilibrium. The extreme case of this is a unique equilibrium point at the intersection of maximum demand with Cournot supply at full capacity.

In the event that demand is also capacity constrained at the Cournot price, then these factors will also imply uniqueness. Indeed, if the supply schedules bid did not vary daily, and if there were some chance that demand was capacity constrained on the day of highest demand, then the unique equilibrium of the intersection of the capacity constraint and the Cournot schedule would hold at all points in time. The analysis may be successfully modified to fit the case of the UK electricity supply industry, namely that of asymmetric firms.

In this case, the differential equations **(1.b)**, exist for the two companies and give first order conditions for the local profit maximising supply schedules with an asymmetric duopoly, for which the second order conditions are also satisfied. Let the capacities of the two different firms be k_1, k_2, $k_2 < k_1$. Let p^* be the price at which the smaller firm is on its Cournot schedule with full capacity, then it follows that:

$$p^* = C'(k_2) - \frac{k_2}{D_p(p^*,0)}$$

The Cournot schedule of the larger firm, $q_1(p^*)$ is given by:

$$p^* = C'(q_1) - \frac{q_1}{D_p(p^*,0)}$$

which, if combined with the full capacity output of the smaller firm, is less than maximum demand at this price, namely:

$$q_1(p^*) + k_2 < D(p^*,0)$$

then in one equilibrium pair of supply strategies, the smaller firm will reach full capacity at that point where its supply function intersects the Cournot equilibrium vertically (at p), while the larger firm reaches its Cournot equilibrium at the same price. They are also the highest defined such pair, making the equilibrium price strategies are uniquely defined.

In the event that maximum demand at this price is less than twice the capacity of the smaller firm, i.e. $D(p^*,0) < 2k_2$, neither firm will reach its capacity constraint, resulting in a range of potential equilibrium.

It is possible to solve this system for the most profitable pair of supply functions in the short run, or in the longer run, it is possible to take account of the threat of entry, as in Newbery (1991). Further, Green & Newbery (1991) calibrate cost functions for each of the duopolists and solved for the symmetric and asymmetric duopolies. It is shown that the differences between the two types at industry level are small. In the asymmetric case, the larger firm (National Power) gains more from an increase in price and, as a consequence, choose a steeper supply function - relative to marginal cost - than in the symmetric case. This gives the smaller firm (Powergen) a less elastic residual demand and a greater incentive to increase its own prices. The effects of these events combine to make the industry supply schedule steeper.

It is also discovered that Powergen does better than its larger rival, by virtue of its submission of a steeper supply function relative to marginal cost than that of Powergen, as it has the greater influence in keeping prices high. Although National Power has the larger output, its greater surplus is offset by its higher fixed costs. In the asymmetric case, lower output is sold at a higher price, with industry operating costs are raised for any level of output since the stations will not operate in the merit order.

In order to apply these theoretical constructions into a functioning model, electricity demand and generating cost information were gathered, and a series of simplifying assumptions made to facilitate analysis. Firstly, demand is measured over "typical" winter and summer days, thereby removing peaks and troughs. Secondly, the cost functions are based on "adjusted" output, not actual output as a means of adjusting for the observed fact that not all plant in service at all times. Prices are adjusted from marginal cost pricing to profit maximising higher-price combinations, and outcomes simulated.

Due to the nature of the assumptions made, the prices estimated do not vary as much as actual pool prices, in addition to start-up costs being omitted. The incentives for generators to raise price increases as the percentage of their plant in operation increases, and due to the fact that demand peaks are omitted/smoothed. There is the possibility of the exclusion of those occasions in which the exercise of market power has the greatest (negative) impact. However, the authors maintain the belief that the averaging process has not understated the potential for monopoly exploitation.

The results of these empirical studies are as follows. In the event that generators can disregard the possibility of new entrants and regulatory action, then the potential exists for large deadweight welfare losses and correspondingly high profits. By favouring structural reform over direct pricing controls, it is shown that an appropriate response is to establish five equal sized firms, although it is unclear whether or not entry can provide the appropriate dynamics, i.e. limiting incentives to collusion. The relationships between entry and industry structure are examined more fully in Newbery (1991), by examining consumer welfare, industry profits, and the competitive structure in the industry.

As capacity is divided between more firms, profits will initially rise, until the industry becomes more competitive, resulting in competitive supply functions. In the extreme, one of two situations will occur. Prices will fall until entry is no longer attractive, and therefore further competition will lower total profits, or an equilibrium will be achieved with prices reaching a level where the industry is at an optimal structure where the maximum demand reaches the capacity constraint at a certain number of firms. However, a more competitive supply industry is more damaging to consumers if there is entry, as they pay more at the peak when demand is high than they save from paying an off-peak price when demand is low. In the absence of changes to the average price, they are unambiguously worse off, despite gaining the benefits associated with the stability of price synonymous with a more concentrated industrial structure. The existing producers would prefer a more concentrated structure comparable to that that exists at present, because although consumer welfare would be higher, industry profits would be lower. Therefore, entry is seen as deleterious to the incumbent generators.

2.2. The role of the contract market - a summary.

Green & Newbery (1992), Bolle (1992) and von der Fehr & Harbord (1992) all indicated the possibility that the duopolistic generators possessed the ability to raise prices in the pool well above marginal cost, although this was not the situation observed in the pool in the period after privatisation. It is therefore theorised that this was the consequence of the high degree of contract cover. This is because if the pool price out-turned above the price stated in the contracts (the strike price), then the generators would have to repay the difference to the RECs. By contrast, if the pool price were below the strike price, the reverse would be true. As a consequence, generators would have very little incentive to raise prices as long as their output was covered by contract.

The theoretical reasoning for this behaviour is established in Green (1992). This work, based upon spot-forward market interactions, showed that when the majority of the output of the two dominant generators is covered by forward contracts, then they have a lower incentive to raise prices. The authors note that this is consistent with the low (or rather the lower than anticipated) prices in the pool in the first two years after privatisation. By the same logic, it is concluded that as the degree of contract cover begins to fall then the incentive for lower prices will decline and the generators may increase their bid prices submitted to the pool. This was observed in March 1991 and March 1993 when the vesting contracts expired and the generators sold more output to the pool at higher prices.

The key empirical work related to the existence of contracts for differences is Helm & Powell (1992), and Gray & Helm & Powell (1995) supported by the theoretical conclusions of Anderson (1990), Klemperer & Meyer (1991), and Powell (1993). Anderson's contribution concerns the interactions of the spot and forward markets when the spot market is imperfectly competitive; Klemperer & Meyer establish supply function equilibrium in oligopolistic industries; and Powell integrates the two approaches and adapts them to the post-privatisation electricity industry. Helm & Powell's empirical study utilised a cointegrating regression between pool purchase prices and the level of electricity demand, inserting a dummy variable which changed value on the day of the actual break-up of the contracts (22nd March 1991). It was determined a positive significant disruption to prices occurred, implying that the event itself led to an increase in the level of pool prices.

SECTION III. Conclusions.

The objective of this chapter has been to introduce the theoretical foundation for the empirical studies that are presented in the following chapters. The Folk Theorem as presented gives a convincing explanation as to why generators should fear the threat of regulation and how – if they believe the threat to be credible – they will modify their prices accordingly. This aspect of the analysis was developed further in Section 1.2 by an examining of the different components of prices, and showing that the probability of the game ending will influence generators' bid prices through a reduction in their price-cost mark-up. The analysis also indicated two points to be noted for the econometrics. Firstly, in presenting the different components of pool prices, it was shown that there was considerable inter-day and intra-day uncertainty in prices that implied that forecasting could prove difficult. This is an obvious conclusion considering that the commodity in question is electricity, however it was noted that the variable components of prices could – in any given half-hour – outweigh the permanent component of prices resulting in prices being reduced to a combination of volatile and potentially random variables. Secondly, the price distribution would be unlikely to be normally distributed due to the clustering of prices caused by common factors occurring over time and the probability for anomalous prices.

Furthermore, while the Folk Theorem successfully captures the dynamic, repeated nature of the pool, it does not capture the price-quantity bidding strategy. This is successfully addressed by Green & Newbery's (1992) application of Klemperer & Meyer's (1989) supply function oligopoly model. However, as it is based around a one-shot game with no learning process, this model does not capture the dynamics of the pool as well as the Folk Theorem. Ultimately, the role of this chapter is as an introduction to the empirical analysis contained in the following chapters. It is to these analyses that attention is now turned.

CHAPTER V: Regulation and Generation in the UK Electricity Supply Industry - Contents.

SECTION I – The Organisation of the Chapter.

In order to determine how the behaviour of generators is determined within the context of the relationship with the regulator, a series of important events within the industry have been collected and will be analysed. These events generally take the form of regulatory announcements, although there are certain important exceptions. The key regulatory announcements are those concerning the commencement and the publishing of pool price reviews, threats of MMC references for the two main generators (National Power and Powergen) and agreements reached between the regulator and the generators.

It is hypothesised that the generators will lower their bid prices following the announcement of a price review. Because it is National Power and Powergen that set prices most of the time within the pool, and it is generally their conduct which is the most cause for regulatory concern, one would anticipate that prices would fall after a price review was announced. Although the review would doubtless be based upon the generators' behaviour prior to the actual announcement, it is logical to conclude that the generators would not wish to prejudice the regulatory outcome by setting high prices. Therefore, either as a show of good faith or out of concern for their future, the generators should submit lower prices to the pool. The conclusions of the reviews are generally associated with a tightening of the regulatory structure, be it in the form of direct price controls, or an agreement between the generators and the regulator. This should also lead to a decline in prices detectable by a negative dummy.

The same rationale exists in the face of a possible reference to the MMC, which has been threatened as a consequence of pool price reviews. If carried out, and if the outcome had a deleterious effect upon the generators, it could lead to restrictive price caps, enforced plant sales, or break up the offending companies to generate a competitive structure. The goal of this analysis will be to ascertain whether there was any response from the generators as a consequence of these announcements. These hypotheses will be tested by a variety of econometric techniques which it is anticipated will permit the detection of the events outlined. (For the theoretical basis for these hypotheses, see Chapter IV).

First, section II will contain analyses determining the existence of structural breaks in electricity prices over the period October 1990 to November 1995. These will be compared with a list of important events within the pool in order to determine whether the breaks coincide with the events themselves. Secondly, in order to determine whether these events are responsible for the structural breaks, a sequence of dummy variable regressions will be performed in order to ascertain whether the dummies represent any of the events which it is anticipated will influence pool prices.

Section III will comprises a further analysis of generator behaviour by determining the importance (or lack thereof) of the threat of an MMC reference for National Power and Powergen by means of an analysis of uplift levels. In the absence of appropriate figures on system marginal price for electricity, the level of uplift represents the second best means of determining how generators have altered their bids into the electricity pool. Section IV contains additional investigations into the relationships between uplift and electricity demand and uplift and pool prices. Section V concludes. All of the results of these analyses are contained in the appendices.

SECTION II - Regulation and Pool Prices.

2.1. Data selection and initial methodology.

In order to begin the analysis into the influence of regulation on prices, the following equation must be estimated:

1. Pool price analysis

$$\Delta PPP_t = \alpha + \beta_0 \tau + \beta_1 PPP_{t-1} + \beta_2 \Delta PPP_{t-1} + \beta_3 \Delta PPP_{t-2} \cdot + \ldots + u_t \qquad (1.1)$$

This is an autoregressive process with all variables in this and all subsequent equations in natural logs, with PPP representing the pool purchase price for electricity (£/MWh), and tau a time trend. (See below for further details). This equation and subsequent forms are based in part upon those of Helm & Powell (1992. PPP is shown to be an autoregressive process of order nine (see below) and this equation is constructed with this fact in mind.

A series of equations using a two-month time frame were integrated with blocks using a four-month time frame in an attempt to detect the existence of structural break within the four month period. The format was chosen as appropriate to test for stationarity, as well as being appropriate given the dynamic nature of the pool and the nature of trends in electricity pool prices. This shows that pool prices tend to follow a standard process and trend from day to day and week to week.

The data set comprises 1887 observations, showing daily average pool prices and electricity demand levels, averaged from 48 half-hourly observations per day[1] over the period 1st October 1990 to 30th November 1995. This data has been obtained from the National Grid Company's Energy Settlements and Services Division, an institution that supplies information on the electricity pool for commercial use. The data exists in half-hourly observations as this is the format upon which the electricity pool functions in the UK electricity supply industry.

The pool purchase price is measured in £/MWh (pounds per megawatt hour) and is the standard means of displaying price. The pool purchase price (PPP) is the price paid to generators for energy produced and is determined by the system marginal price (SMP), the loss of load probability (LOLP) and the value of lost load (VOLL). These variables combine to form the pool price as detailed previously.

The first requirement for these analyses is that the variables in use must be tested for stationarity and

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[1] Changes to and from British Summer Time in March and October alter the number of half-hourly observations to 46 and 50 respectively on the date of the changes.

the potential existence of trends in the data. To that end, the three variables in question (PPP, uplift and demand) were all tested utilising the standard Dickey-Fuller (DF) and Augmented Dickey-Fuller (ADF) tests for the presence of unit roots with and without the existence of a trend. It was seen that all three variables successfully passed these tests both with and without the trend present.

However, although the three variables passed the DF and ADF tests, the other means of assessing the presence of stationarity were not passed. Primarily, the autocorrelation function (ACF) of each variable indicated non-stationarity, as did the Box-Pierce statistics. The mixed results for stationarity are surprising: as it implies that no permanent component is present in prices – despite the analysis presented in Chapter IV. However, it is possible that – as outlined in Chapter IV, that the combination of the different components of pool prices have generated a data series that can be viewed as random over time – despite the inherent seasonality of prices.

Further analyses were required to assess the data for the presence of trends using the DF and ADF F-tests (for full details of results, see appendix). In the case of pool prices and demand, the data indicated the existence of a deterministic trend. However, further analysis showed the trend coefficient to be statistically insignificant, thus removing any complications. However, although the uplift data indicated the same results, the trend parameter was significant in this case, indicating the existence of a deterministic trend in the data. This trend was removed by creating a "de-trended" uplift variable in accordance with the Box-Jenkins methodology established by Schiller (American Economic Review, 1981) and later developed by Bulkley & Tonks (Economic Journal, 1990). Specifically, the trend is removed through regressing uplift on the trend parameter and subtracting the trend from both sides of the regression as follows:

$$U_t = \beta\tau + Ud_t$$

Where Ud_t is the de-trended uplift variable that may be obtained by rearranging the equation above:

$$Ud_t = U_t - \beta\tau$$

It is this de-trended uplift variable that is used in **all** subsequent regressions.

The relatively short-run time frame chosen for this analysis was both to facilitate the econometric regressions as well as being grounded in an important underlying assumption, namely that not **all** changes in prices would be permanent. This assumption is derived from the fact that while some events will generate permanent changes in prices: pool price reviews, price caps, contract break-ups -

others will simply result in transitory shocks: price spikes, threats of regulatory action, announcements of intentions to carry out regulatory reviews.

Some clarification is required for these statements. While it is logical to argue that the conclusions and recommendations of price reviews be incorporated by the generators into their decisions on bidding plant - with the same being true of price caps and the break-up of contracts for differences - such events as the threat of a review may not. This is because while generators may adjust their prices in response to the threat of a review or an MMC reference, they are still making estimates as to the regulator's final decision. When this decision is reached, the transitory change will then become permanent. This effectively results in two changes: an initial transitory change followed by a permanent change that may support or offset the transitory change. This is essentially based upon the asymmetry of information between the regulator and the generator - a process that works in both directions. One of the objectives of this analysis will be to ascertain whether these changes are instantaneous "step" changes, or whether they occur gradually over time.

One can also argue that if the regulatory system is a repeated game with adversarial overtones, then - for example - any attempts by generators to manipulate prices would be countered by the regulator as soon as possible, given the regulator's information. For example, the price spikes that began in September 1991 led to the announcement of the first pool price review in early October, less than a month afterwards. The magnitude of these spikes was a source of considerable concern, with pool prices doubling on several occasions. Such prolonged price increases would logically lead to regulatory action given the regulator's desire to prevent manipulation of the marketplace by the generators to the detriment of consumer welfare.

Similarly, if the regulator introduced (or stated the intention to introduce) new price controls in the context of a review or demanded an explanation of pricing behaviour from the generators, then there would doubtless be an immediate response to comply with the announcement. However, this would inevitably be followed by attempts by the generators to limit their exposure to the price controls by whatever means are possible within the confines of their licences. This continued action is logical given the assumed inherently adversarial relationship between the regulator and the regulated firms.

An important point to note is that if generator revenues were largely determined by contracts, then any price decline following regulatory action could be viewed as a largely token gesture, as the generators revenues would be partially secure.

2.2. Selection of announcements.

With the above considerations in mind, some of the most important events in the development of the pool have been chosen, predominantly relating to regulation. If these events are as important as has been theorised, then we would anticipate them to generate a structural break within the stream of pool prices, as given by the Chow test and/or the significance of the appropriate dummy variable. These dates have been derived from the Financial Times Index, Offer's official published chronology and its list of library publications (the list of publications and the chronology are updated every three months and are therefore highly reliable). Of course, there is the concern that the companies in the industry are made aware of announcements (notably the most important events) before they are released to the media. However, it is hoped that the three-day dummy event window should capture limit such possibilities. The dates are given with the event that is occurring, and the corresponding observation number of this event in the data sequence under examination. This information is shown in Table 1.

In theory, the importance of the event will be reflected in the value of the coefficient of the dummy parameter and its corresponding significance (or lack thereof). It is believed that these events are of sufficient importance to influence the operations of the electricity pool, as well as the electricity industry as a whole. The majority of these events concern the electricity generators, although some concern the RECs. It is the latter of these events - which occur in 1995, for which it is difficult to predict the effects upon the generators.

Based upon the discussion made in the introduction concerning the effects of these announcements, it is logical to conclude that as one would anticipate a decline in prices, the dummy should possess a negative coefficient for events concerning either pricing controls or market structure and competition (price reviews, MMC threats). One would also expect a positive influence on prices (as shown by a positive dummy variable) for the analyses containing the break-up of the contracts for differences.

The anticipated coefficients of the dummy variables for the non-REC events of 1995 require some justification. The negative coefficient assigned to the dummy to the decision to revise the distribution price controls should be self-explanatory. Of the remaining mergers and take-overs decisions, these have been assigned a negative coefficient as they involve either generators or, in the case of North West Water, another privatised industry.

It is anticipated that the possibility of increased regulatory uncertainty concerning the reactions to these moves would make generators more cautious in their pool submissions as they represent vertical integration - with the obvious exception of North West Water. This move led to increased speculation about so-called "super-utilities", i.e. those with assets across different privatised utilities. This itself led to speculation concerning the need for a suitable utilities commission - a body with the ability to police and regulate cross-industry operations and/or all of the privatised utilities.

A further disruption is anticipated in the form of a structural break in early 1995 due to the closing for safety reasons of Nuclear Electric's Dungeness and Heysham reactors. This resulted in more expensive plants being called upon to generate - effectively shifting the industry's marginal cost schedule upwards. The unanticipated closure of these baseload facilities sent pool prices soaring, and it is expected that a structural break in pool prices should occur within the relevant period.

2.3. Structural break results and the need for dummy variables.

Undertaking structural break analysis using the Chow test, the need to ensure that spurious results were not generated was apparent – especially in light of the inherent volatility of pool prices. As such, the tests were performed using a 1% significance level. The results of the analysis are presented in Table 2, which also includes structural break analysis on uplift and electricity demand. However, these results for price may be summarised as follows.

There have been eleven structural breaks in electricity prices that are significant at the 1% level. These occurred in the following periods:

1. June - September 1991
2. August – November 1991
3. April – July 1992
4. October 1992 – January 1993
5. February – May 1993
6. August – November 1993
7. June – September 1994
8. October 1994 – January 1995
9. February – May 1995
10. April – July 1995
11. June – September 1995

Based upon the list of important regulatory announcements/external shocks detailed above, the following conclusions may be derived. The structural break in the period June - September 1991 coincides with the beginning of the price spikes in September 1991. This event occurs within the timeframe of the August - November 1991 break – as does the announcement by the regulator to conduct the first pool price review. The structural break that occurs in April - July 1992 follows on from the announcement by the regulator of his possible intention to undertake an MMC reference. The structural break in October 1992 – January 1993 coincides with the announcement and publication of the second pool price review in October 1992.

The break of February - May 1993 coincides with the dissolution of the second set of vesting contracts in early April 1992. The structural break of August – November 1993 coincides with the 18th October announcement by the Major Energy Users' Council to Offer urging an MMC reference. This was followed on the 26th October by an announcement by the regulator that he intended to launch an investigation into power companies' profits.

The two structural breaks of 1994 occur in a period of relative volatility of pool prices. This volatility can largely be attributed to the generators' difficulty adjusting to the February 1994 price cap and a series of price spikes. As anticipated, there is a structural break in early 1995 that can be attributed to the plant outages outlined above, with a potential secondary cause being February's threat of an MMC reference. The break of April - May 1995 coincides with the sale of the Golden Share and, more importantly, the revision of the distribution price controls. The break of June - July 1995 coincides with the increased merger activity of that period.

Therefore, on a superficial level, all of the structural breaks could have their foundations in either regulatory actions or perceived important exogenous shocks to the pool. Based upon an analysis of monthly percentage changes in monthly averages of PPP and uplift, all of these breaks appear to coincide with sharp percentage changes in prices or uplift, be they either positive or negative based upon the nature of the event.

In order to eliminate the possibility that these breaks have occurred as a consequence of changes in demand, similar analyses were performed on demand (also an order nine process). There were a total of seven structural breaks in demand, as derived through the same Chow test and a similar equation for demand as for price. Of the seven demand breaks only three of them coincided with breaks in prices. However, it is theorised that although the phenomena may coincide, because the demand returns to its (approximately) similar behaviour after the shock, in most cases the level of prices does not - a theory supported by an analysis of the monthly changes in price and demand. Examples of this phenomenon appear to be the behaviour of pool prices following the announcement of a review. Specifically a sharp decline following the actual announcement of the review, followed by a steady progressive rise over the period of the review, followed by another sharp decline after the review has been published. A similar phenomenon occurs with the dissolution of CFDs between the RECs and the generators. On both occasions, the ending of the contracts has been met by an increase in pool prices over and above that implied by the level of demand, in the short run at least.

Clearly, this cannot be established as a causal linkage purely on the basis of a coincidence, although it does seem unlikely that, for example, such factors as system outages would come into play immediately after the break-up of contracts. This therefore implies some degree of linkage between regulatory action, contract dissolution and pool prices.

Furthermore, the structural breaks in demand tend to be those based upon cyclical factors - the fact that demand is primarily determined by time trends makes it susceptible to structural breaks in shoulder months. Therefore, there is not expected to be a causal link between the breaks in prices and those in demand, despite the (inelastic) relationship that exists between them.

This supposition is supported by an analysis of the monthly changes in prices and demand. In general, it would be highly unlikely that price spikes of the size exhibited within the pool are caused by fluctuations in demand. This would only be the case if that increase in demand was totally unforeseen and led to such a sharp increase in the loss of load probability that the generating network could not withstand the increase without calling on more expensive plants to generate.

Table 1.

Possible causes of structural breaks in prices.

Date	Event	Obs.	No.	Anticipated Sign
22/03/91	Break-up of first set of CFDs.	173	1	Positive
09/09/91	Price spikes begin.	344	2	Positive
03/10/91	First pool price review begins w/ MMC threat.	368	3	Negative
20/12/91	First pool price review published.	446	4	Negative
27/06/92	Generators threatened with MMC reference.	636	5	Negative
08/10/92	Second pool price review launched.	739	6	Negative
18/12/92	Second pool price review published.	810	7	Negative
31/03/93	Break-up of second set of CFDs.	913	8	Positive
24/05/93	Generators threatened with MMC reference.	966	9	Negative
30/07/93	MMC reference and/or plant sales threatened.	1034	10	Negative
15/12/93	MMC reference unless price agreement made.	1172	11	Negative
11/02/94	NP and PG establish price agreement.	1230	12	Negative
19/12/94	Trafalgar House bids for Northern Electric.	1541	13	Unknown
11/02/95	MMC reference threatened over plant sales	1595	14	Negative
06/03/95	Sale of Government's "Golden Share".	1618	15	Unknown
07/03/95	Distribution price controls to be revised.	1619	16	Negative
13/07/95	Southern Electric bids for S.W. Electricity.	1747	17	Unknown
25/07/95	Scottish Power bids for Manweb.	1759	18	Negative
31/07/95	Hanson bids for Eastern.	1765	19	Unknown
10/09/95	North West Water bids for Norweb.	1806	20	Negative
21/09/95	Powergen bids for Midlands Electricity.	1817	21	Negative
02/10/95	National Power bids for Southern Electric.	1828	22	Negative
24/11/95	NP and PG bids referred to MMC.	1881	23	Negative

"Anticipated Sign" refers to the anticipated value of the dummy coefficient on the variable representing that event. To facilitate future reference, these events will hereafter be referred to as events 1 to 23 respectively.

Table 2: Structural break analysis of pool price, electricity demand and uplift.

Obs.	Time Frame		Chow statistic			Chow Statistic
	From	To	PPP	Demand	Uplift	Critical Value (1%)
1 – 123	01-Oct-90	31-Jan-91	0.41739	2.74767	2.05606	3.17
62 – 182	01-Dec-90	31-Mar-91	1.36612	3.50358	1.04175	3.17
124 – 243	01-Feb-91	31-May-91	1.28224	1.34506	1.68380	3.17
183 – 304	01-Apr-91	31-Jul-91	1.01825	1.04217	2.45142	3.17
244 – 365	01-Jun-91	30-Sep-91	5.81065	4.24156	3.24561	3.17
305 – 426	01-Aug-91	30-Nov-91	5.20013	0.69869	3.48942	3.17
366 – 488	01-Oct-91	31-Jan-92	2.26756	4.42904	0.86615	3.17
427 – 548	01-Dec-91	31-Mar-92	1.59783	3.67738	1.10643	3.17
489 – 609	01-Feb-92	31-May-92	1.09297	2.89974	1.58310	3.17
549 – 670	01-Apr-92	31-Jul-92	4.28165	4.81872	3.30461	3.17
610 – 731	01-Jun-92	30-Sep-92	1.43139	3.87259	3.16101	3.17
671 – 792	01-Aug-92	30-Nov-92	2.09171	0.21651	1.90389	3.17
732 – 854	01-Oct-92	31-Jan-93	5.20747	2.42302	1.45017	3.17
793 – 913	01-Dec-92	31-Mar-93	1.08018	1.77696	4.12835	3.17
855 – 974	01-Feb-93	31-May-93	3.91209	0.64109	2.60024	3.17
914 – 1035	01-Apr-93	31-Jul-93	2.05169	1.15377	1.49719	3.17
975 – 1096	01-Jun-93	30-Sep-93	0.34173	2.54948	2.78826	3.17
1036 – 1157	01-Aug-93	30-Nov-93	3.62407	0.15721	1.86737	3.17
1097 – 1219	01-Oct-93	31-Jan-94	2.88588	3.15745	1.71057	3.17
1158 – 1278	01-Dec-93	31-Mar-94	0.99155	1.32914	1.25208	3.17
1220 – 1339	01-Feb-94	31-May-94	2.45407	0.68016	2.02180	3.17
1279 – 1400	01-Jun-94	30-Sep-94	4.92324	9.19657	3.17628	3.17
1340 – 1461	01-Aug-94	30-Nov-94	0.56756	3.02925	0.72192	3.17
1401 – 1522	01-Oct-94	31-Jan-95	3.41975	0.40550	3.16476	3.17
1462 – 1584	01-Dec-94	31-Mar-95	0.19630	2.64888	0.82689	3.17
1523 – 1643	01-Feb-95	31-May-95	3.32985	2.10668	2.49039	3.17
1585 – 1704	01-Apr-95	31-Jul-95	3.66122	2.39839	2.26274	3.17
1644 – 1765	01-Jun-95	30-Sep-95	3.75339	1.13297	3.31764	3.17
1705 – 1826	01-Aug-95	30-Nov-95	1.09712	2.33279	0.96733	3.17
1766 – 1887	01-Oct-95	30-Nov-95	N/A	N/A	N/A	3.17

We now turn our attention to the use of dummy variables in order to ascertain whether the hypothesised causes of the structural breaks did in fact have their anticipated effects.

2.4. Dummy regressions and their validity.

In order to develop this analysis further, the univariate price equation was re-structured to the following format:

$$PPP_t = \alpha + \beta_1 PPP_{t-1} + \beta_2 DUMMY_t \tag{1.2}$$

In order to determine the optimal lag length, this equation was performed for each dummy variable with up to ten lags of the dependent variable.

In order to determine the optimal nature of the price and uplift series, the Akaike information criterion (AIC), the Schwarz information criterion (SIC) and the partial autocorrelation function (PACF) were used. The optimal structure for the pool purchase price variable is one possessing nine lags. This result is mirrored in both the Schwarz criterion and in the PACF, and also in the log version of the price variable. This result was identical for the uplift data series.

Retaining the variable structure, the dummy variable analysis was undertaken. The results are presented in full in Table 3, which shows the AIC and SIC values, the PACF t-ratio and the dummy variable's t-statistic. The results are summarised below.

The majority of the dummy results continue to support a lag structure of nine iterations, with the optimal AIC and SIC values occurring at the eighth or ninth lag. The majority (two-thirds) of the dummy variables is insignificant in their anticipated sign. The dummies that are significant are as follows (with their event, anticipated sign and the level of significance required for the t-distribution):

- Dummy 1: Break-up of first set of CFDs; Positive; 10%
- Dummy 4: First pool price review published; Negative; 1%
- Dummy 7: Second pool price review published; Negative; 1%
- Dummy 8: Break-up of second set of CFDs; Positive; 1%
- Dummy 14: MMC reference threatened over plant sales; Negative; 10%.

Clearly, with the exception of the events pertaining to CFDs, all of the events are regulatory events. Those events concerning the financial markets produce results from which it is difficult to draw any certain conclusions, and these events will be disregarded until later chapters.

There may be lags in the dummy attaining significance, or the dummy may indeed attain significance prior to the public release of the information. This could be due to price inflexibility or speed or delays in assimilating the information and consequences of a certain event.

A further complication, first presented in Glazer & MacMillan (1992), is that it is possible that the threat of regulatory action can actually lead to higher prices, based around the operation of an end game. If a regulated company is certain that a regulatory announcement will lead to tighter regulation, then that announcement may actually have the effect of increasing prices. This is because the regulated firm is convinced that the probability of tighter regulation is so high that they decide to charge high prices while they can. Here, the probability of tighter regulation is seen as an increasing function of the price-cost margin.

Alternatively, if the probability of tighter regulation is low, then prices will fall. This analysis is extended by Kent (1993) to the case of a duopoly supply function equilibrium, in an effort to assess whether the ambiguity is still present in this case, which it is. Gray & Helm & Powell (1995) present an analysis of a collusive super-game in the presence of stochastic regulation, the conclusion of which is to remove the ambiguity and re-establish the conclusion that prices will fall as a consequence of a higher probability of regulation.

The main complication with the ambiguous result of Glazer & MacMillan is that the regulated firm would not only have to be convinced that regulation would be tightened, but they would also have to be aware of the type of regulation which would be introduced. Increasing prices in the face of a regulatory threat, when the ultimate conclusion of that threat is unknown would be quite risky - the regulator could take the regulated firm's actions as defiance of its authority, and proceed to punish them to an extent beyond the firm's own perceptions.

There have been some unusual results obtained through the use of dummy variables in these regressions, most notably centring around the possibility of MMC references and the announcement of pool price reviews, with the latter often implying the possibility of the former.

In order to determine the reasoning behind these outcomes, the analysis will examine the uplift component of pool prices. Because both uplift and system marginal price (SMP) are indicative of the cost of generating plant, it is assumed that they both show the same fluctuations in values. (SMP is the cost of plant requested to generate, uplift effectively representing the cost of plant called in to maintain balance). In the absence of data on SMP, uplift should function as an adequate replacement.

Table 3. Determining the optimal lag length.

Section 3.1. Dummy regressions for the univariate price analyses.

PPP: D1	+ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-5.48757	**-5.54323**	-5.53705	-5.50446	-5.48076	-5.49472	-5.48237	-5.50990	-5.48175	-5.44960
SSC:	Minimise	-5.40844	**-5.43706**	-5.40349	-5.34316	-5.29136	-5.27687	-5.23567	-5.23398	-5.17622	-5.11405
PACF	T-Ratio	6.44180	-2.97230	**-1.58630**	-0.04425	0.94777	2.13350	1.43250	-2.42420	-0.82736	0.61350
Dummy	T-Ratio	0.99807	1.37680	**1.63400**	1.60710	1.41510	1.14770	1.00460	1.17210	-0.82736	1.12590

PPP: D2	+ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.58738	-3.67652	-3.64535	-3.61636	-3.59007	-3.71786	-3.88241	**-3.97233**	-3.93662	-3.93968
SSC:	Minimise	-3.50824	-3.57034	-3.51179	-3.45507	-3.40068	-3.50000	-3.63572	**-3.69642**	-3.63109	-3.60413
PACF	T-Ratio	5.81550	-3.52640	**-0.29606**	-0.58858	0.80569	4.03890	4.50060	-3.48040	-0.02746	-1.89200
Dummy	T-Ratio	0.65109	1.09820	**1.13110**	1.23010	0.99536	0.06150	-0.79003	-0.17176	-0.16356	0.12474

PPP:D3	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.32719	-3.46430	-3.43328	-3.40687	-3.41247	-3.49186	-3.60615	-3.76239	-3.72686	**-3.78440**
SSC:	Minimise	-3.24806	-3.35812	-3.29972	-3.24558	-3.22307	-3.27400	-3.35946	**-3.48648**	-3.42132	-3.44886
PACF	T-Ratio	7.70880	-4.22100	**-0.31241**	0.77045	1.92800	3.33870	3.84050	-4.38060	0.12839	-2.96050
Dummy	T-Ratio	-1.02340	-1.09750	-1.08300	-1.12170	-1.06810	-1.01960	**-1.44430**	-1.12510	-1.12240	-1.12070

PPP:D4	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-4.16251	-4.33156	-4.32112	-4.33708	-4.44847	-4.43744	-4.42581	**-4.53784**	-4.50488	-4.48816
SSC:	Minimise	-4.08338	-4.22539	-4.18756	-4.17578	-4.25907	-4.21958	-4.17912	**-4.26192**	-4.19935	-4.15261
PACF	T-Ratio	7.40750	-4.64120	**-1.44970**	2.17450	3.82380	1.46370	1.15630	-3.79720	0.49896	-1.32960
Dummy	T-Ratio	-3.15610	-4.52290	**-4.77310**	-3.98200	-4.08450	-4.06550	-4.17030	-3.71810	-3.71900	-3.65640

PPP:D5	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-6.13133	-6.10008	-6.06932	-6.04700	-6.01855	-6.10839	-6.23702	**-6.37429**	-6.36025	-6.34182
SSC:	Minimise	-6.05220	-5.99390	-5.93576	-5.88570	-5.82916	-5.89054	-5.99032	**-6.09837**	-6.05472	-6.00628
PACF	T-Ratio	7.91380	**0.14441**	0.35711	0.99129	0.66859	3.49890	4.03580	-4.13690	-1.40420	1.27230
Dummy	T-Ratio	**1.20930**	1.16260	1.07850	0.87705	0.72248	0.02928	-0.62951	0.15944	0.46987	0.17500

PPP:D6	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-5.65481	-5.75968	-5.77658	-5.77806	-5.75253	-5.79445	-5.94664	**-5.96516**	-5.93100	-5.90044
SSC:	Minimise	-5.57567	-5.65351	-5.64302	-5.61677	-5.56314	-5.57659	**-5.69994**	-5.68924	-5.62546	-5.56490
PACF	T-Ratio	5.10300	-3.76470	-2.19510	-1.81510	**0.85096**	2.70490	4.34420	-2.23840	-0.36970	-0.72472
Dummy	T-Ratio	2.80800	3.92340	4.53420	**4.92000**	4.14510	3.17070	2.27620	2.60770	2.61890	2.67710

PPP:D7	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-6.23616	-6.31159	-6.29314	-6.26146	-6.27311	-6.31870	**-6.38994**	-6.37710	-6.34324	-6.31984
SSC:	Minimise	-6.15702	**-6.20542**	-6.15958	-6.10016	-6.08372	-6.10084	-6.14324	-6.10118	-6.03771	-5.98430
PACF	T-Ratio	5.24260	-3.30890	**-1.14810**	-0.29177	2.07860	2.77270	3.20130	-1.43020	-0.41232	-1.07820
Dummy	T-Ratio	-4.04410	-5.13270	**-5.15670**	-4.75170	-3.50640	-2.46230	-1.65520	-1.90740	-1.94290	-2.11060

Table 3. Continued

PPP:D8	+ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-6.04641	**-6.05436**	-6.04668	-6.01553	-5.98370	-5.95999	-5.92602	-5.89106	-5.85743	-5.92636
SSC:	Minimise	**-5.96728**	-5.94819	-5.91312	-5.85423	-5.79431	-5.74214	-5.67932	-5.61514	-5.55190	-5.59081
PACF	T-Ratio	2.92250	1.97610	**1.53910**	0.37599	0.35911	-0.97110	0.20343	-0.09665	0.43223	-3.14400
Dummy	T-Ratio	**5.29320**	4.05000	3.50470	3.36740	3.28400	3.35690	3.29770	3.27930	3.22600	3.68670

PPP:D9	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-5.65255**	-5.63468	-5.60416	-5.58335	-5.57049	-5.54098	-5.62838	-5.59576	-5.56037	-5.52757
SSC:	Minimise	**-5.57341**	-5.52850	-5.47060	-5.42205	-5.38110	-5.32312	-5.38169	-5.31984	-5.25484	-5.19202
PACF	T-Ratio	2.00100	**-1.15370**	-0.38352	-1.06330	-1.38940	0.63312	3.45250	0.47061	-0.17421	-0.56323
Dummy	T-Ratio	-0.04427	-0.05863	-0.05670	-0.03482	-0.01041	-0.02851	-0.12303	-0.13929	-0.12372	**-0.07732**

PPP:D10	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-5.28540	-5.30471	-5.34185	-5.34751	-5.35043	-5.36227	**-5.50682**	-5.48626	-5.48107	-5.44502
SSC:	Minimise	-5.20627	-5.19853	-5.20829	-5.18621	-5.16104	-5.14441	**-5.26012**	-5.21034	-5.17554	-5.10947
PACF	T-Ratio	2.33100	-2.24880	-2.62230	-1.92530	**-1.85960**	2.08440	4.24620	1.15240	-1.67030	0.17431
Dummy	T-Ratio	-0.72264	-0.90546	-1.12210	-1.33340	**-1.56120**	-1.25260	-0.81367	-0.72359	-0.80882	-0.79213

PPP:D11	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-4.72072**	-4.70058	-4.67453	-4.64503	-4.62875	-4.63045	-4.60984	-4.57610	-4.58533	-4.54920
SSC:	Minimise	**-4.64159**	-4.59440	-4.54097	-4.48374	-4.43936	-4.41259	-4.36314	-4.30018	-4.27980	-4.21365
PACF	T-Ratio	11.48660	**1.05270**	0.76021	0.54542	1.26700	1.83320	1.13070	-0.34664	-2.03400	-0.15271
Dummy	T-Ratio	**-1.10220**	-0.96601	-0.88402	-0.80070	-0.59605	-0.35219	-0.20839	-0.24855	-0.47743	-0.49082

PPP:D12	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.95068	-3.92165	-3.90417	-3.87155	-3.84913	-3.90130	-3.87087	-3.95983	**-3.96091**	**-3.92914**
SSC:	Minimise	**-3.87154**	-3.81548	-3.77061	-3.71025	-3.65974	-3.68344	-3.62417	-3.68392	-3.65537	-3.59360
PACF	T-Ratio	16.56150	**0.49333**	1.18220	-0.01510	1.00720	2.88940	-0.61024	-3.46610	-1.83680	-0.64301
Dummy	T-Ratio	-0.82941	-0.75566	-0.60630	-0.60013	-0.45980	-0.13988	-0.20806	-0.76639	-1.05940	**-1.15670**

PPP:D13	Unknown	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-1.75497	-1.78057	-1.78424	-1.75163	-1.74984	-1.97405	-1.96495	**-2.25521**	-2.22045	-2.18488
SSC:	Minimise	-1.67584	-1.67440	-1.65068	-1.59033	-1.56044	-1.75620	-1.71826	**-1.97929**	-1.91492	-1.84934
PACF	T-Ratio	9.77670	-2.38770	**1.86870**	-0.00422	1.73200	5.23220	1.53580	-5.91490	-0.29246	-0.27113
Dummy	T-Ratio	-0.61262	-0.62966	-0.63566	-0.63228	-0.71394	-1.04950	**-1.18260**	-0.85814	-0.84518	-0.83199

PPP:D14	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-1.85653	-1.87246	-1.87158	-1.83896	-1.84094	-2.04131	-2.03524	**-2.29046**	-2.28404	-2.26030
SSC:	Minimise	-1.77740	-1.76628	-1.73802	-1.67767	-1.65155	-1.82345	-1.78854	**-2.01455**	-1.97851	-1.92476
PACF	T-Ratio	8.73850	-2.17060	**1.74390**	0.00114	1.83470	4.95360	1.62940	-5.53620	-1.63570	-1.06450
Dummy	T-Ratio	-2.79680	**-3.35850**	-2.58990	-2.42840	-1.78560	-0.44216	0.07122	-1.75250	-2.27790	-2.51260

Table 3. Continued.

PPP:D15	Unknown	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-1.85645	-1.82955	-1.82805	-1.80558	-1.79612	-1.94991	-2.14465	**-2.18563**	-2.16154	-2.12994
SSC:	Minimise	-1.77731	-1.72338	-1.69449	-1.64429	-1.60673	-1.73205	-1.89795	**-1.90971**	-1.85601	-1.79439
PACF	T-Ratio	7.78720	**-0.66984**	1.72580	0.98468	1.50290	4.38050	4.86440	-2.68130	-1.02590	-0.65351
Dummy	T-Ratio	-0.64794	-0.73328	-0.46019	-0.29606	-0.04953	0.71161	**1.72750**	1.04310	0.79343	0.64264

PPP:D16	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-1.85683	-1.82978	-1.82830	-1.80579	-1.79209	-1.94823	-2.13868	**-2.18210**	-2.15896	-2.12781
SSC:	Minimise	-1.77770	-1.72361	-1.69474	-1.64449	-1.60270	-1.73037	-1.89198	**-1.90618**	-1.85342	-1.79227
PACF	T-Ratio	7.78150	**-0.65308**	1.72640	0.98243	1.49790	4.36290	4.81230	-2.72560	-1.06660	-0.68494
Dummy	T-Ratio	-0.67695	-0.74843	-0.48604	-0.32780	-0.08477	0.61906	**1.55540**	0.87385	0.62843	0.47274

PPP:D17	Unknown	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.39950	-3.39646	-3.39837	-3.36575	-3.33355	-3.58731	-3.58030	-3.78511	**-3.83173**	-3.80991
SSC:	Minimise	-3.32036	-3.29029	-3.26481	-3.20445	-3.14416	-3.36945	-3.33361	-3.50919	**-3.52620**	-3.47437
PACF	T-Ratio	6.83830	**-1.67410**	1.82120	-0.00916	-0.30846	5.56600	1.59980	-4.96670	-2.77940	-1.14370
Dummy	T-Ratio	-1.39470	**-1.61710**	-1.34080	-1.32530	-1.35250	-0.51244	-0.33991	-0.83793	-1.28540	-1.51520

PPP:D18	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.38268	-3.37513	-3.38157	-3.34905	-3.31602	-3.58597	-3.58296	-3.77760	**-3.81383**	-3.78550
SSC:	Minimise	-3.30355	-3.26896	-3.24801	-3.18775	-3.12662	-3.36811	-3.33627	-3.50168	**-3.50829**	-3.44996
PACF	T-Ratio	7.26670	**-1.53340**	1.94130	0.08723	-0.13566	5.74500	1.71330	-4.84750	-2.59170	-0.84784
Dummy	T-Ratio	-0.52862	**-0.71548**	-0.41077	-0.39018	-0.40429	0.37119	0.59838	0.11705	-0.16121	-0.30107

PPP:D19	Unknown	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.29568	-3.28749	-3.29597	-3.26338	-3.23036	-3.49864	-3.56262	-3.76216	**-3.80659**	-3.79201
SSC:	Minimise	-3.21655	-3.18132	-3.16241	-3.10208	-3.04097	-3.28078	-3.31593	-3.48624	**-3.50105**	-3.45646
PACF	T-Ratio	7.09680	**-1.51230**	1.99290	0.05921	-0.13506	5.72660	3.08490	-4.90470	-2.74080	-1.40170
Dummy	T-Ratio	0.14126	0.06086	0.17414	0.17710	0.16831	0.71166	**1.20060**	0.41992	0.03124	-0.10857

PPP:D20	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.40115	-3.40065	-3.40152	-3.36946	-3.33660	-3.52939	-3.58192	-3.80146	**-3.86116**	-3.83603
SSC:	Minimise	-3.32202	-3.29448	-3.26796	-3.20816	-3.14721	-3.31153	-3.33522	-3.52554	**-3.55563**	-3.50048
PACF	T-Ratio	6.92280	**-1.74710**	1.79340	-0.22682	0.18341	4.86330	2.89040	-5.13650	-3.00240	-1.00380
Dummy	T-Ratio	**0.19542**	0.10694	0.10042	0.09694	0.09555	0.11379	0.01644	0.05073	0.08676	0.10192

PPP:D21	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-2.82739	-2.84148	-2.86557	-2.83537	-2.80476	-3.12065	-3.29659	-3.59165	**-3.61794**	-3.59143
SSC:	Minimise	-2.74826	-2.73531	-2.73201	-2.67407	-2.61536	-2.90279	-3.04989	**-3.31573**	**-3.31241**	-3.25589
PACF	T-Ratio	6.91670	-2.12700	2.35440	**-0.48007**	0.49312	6.23990	4.46110	-5.96610	-2.39920	-0.94021
Dummy	T-Ratio	0.87393	0.99479	0.85880	0.87471	0.85910	0.87867	**1.14440**	0.76243	0.67834	0.64091

Table 3. Continued.

PPP:D22	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-2.61488	-2.63602	-2.67079	-2.63824	-2.61795	-2.95094	-3.14202	**-3.47704**	-3.47160	-3.43585
SSC:	Minimise	-2.53575	-2.52984	-2.53723	-2.47694	-2.42856	-2.73308	-2.89532	**-3.20112**	-3.16607	-3.10030
PACF	T-Ratio	7.67940	-2.28980	2.57580	**-0.08611**	1.10520	6.41930	4.82420	-6.38370	-1.66300	-0.24444
Dummy	T-Ratio	**1.14710**	1.27370	1.09880	1.09620	1.04130	0.98359	1.18240	1.04320	1.04310	1.03950

PPP:D23	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-2.48103	-2.50317	-2.51645	-2.48937	-2.48863	-2.95561	-3.28272	**-3.48166**	-3.45696	-3.42075
SSC:	Minimise	-2.40190	-2.39700	-2.38289	-2.32807	-2.29924	-2.73775	-3.03602	**-3.20574**	-3.15143	-3.08520
PACF	T-Ratio	8.80160	-2.31190	2.11020	**-0.72624**	1.76140	7.77490	6.32990	-4.90880	-0.95590	0.13199
Dummy	T-Ratio	1.80480	**2.10480**	1.76700	1.86980	1.13890	-0.15704	-1.67240	-0.12161	0.08448	0.06499

Section 3.2. Summary Table

Regression	Indicated Lag Length	Dummy T-Statistic	Level of significance
1	**Order 2**	**1.63400**	**10%**
2	Order 8	-0.17176	N/A
3	Order 9	-1.12510	N/A
4	**Order 8**	**-3.71810**	**1%**
5	Order 8	0.15944	N/A
6	**Order 8**	**2.60770**	**1%**
7	**Order 2**	**-5.15670**	**1%**
8	**Order 1**	**5.29320**	**1%**
9	Order 1	-0.04427	N/A
10	Order 7	-0.81367	N/A
11	Order 1	-1.10220	N/A
12	Order 1	-0.82941	N/A
13	Order 8	-0.85814	N/A
14	**Order 8**	**-1.75250**	**10%**
15	Order 8	1.04310	N/A
16	Order 8	0.87385	N/A
17	Order 9	-1.28540	N/A
18	Order 9	-0.16121	N/A
19	Order 9	0.03124	N/A
20	Order 9	0.08676	N/A
21	Order 9	0.67834	N/A
22	Order 8	1.04320	N/A
23	Order 8	-0.12161	N/A

Section 3.3. Determining the optimal lag length for the data series.

Section 3.3.1. Pool Purchase Price

	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	3.03040	3.02141	3.00250	2.98330	2.94060	2.75367	2.69686	2.55036	**2.54665**	2.54869
SSC:	3.03628	3.03024	3.01425	2.99805	2.95831	2.77436	2.72051	2.57699	**2.57627**	2.58130
PACF (t)	54.79010	-4.58720	6.32290	6.35710	9.25570	19.74480	10.65940	-17.30660	-3.30860	**0.02375**

Section 3.3.2. Uplift

	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-0.71377	-0.73948	-0.76143	-0.77182	-0.84527	-0.97154	-0.98443	-1.02606	**-1.0294**	-1.02901
SSC:	-0.70788	-0.73065	-0.74964	-0.75708	-0.82756	-0.95087	-0.96078	-0.99943	**-0.99978**	-0.99640
PACF (t)	53.62900	-7.26980	6.76220	4.62770	12.13600	16.01610	5.23510	-9.06390	-3.13130	**-1.61570**

Section 3.3.3. Demand

	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC	-4.73349	-4.78793	-4.88386	-4.88172	-5.00459	-5.49782	-5.66546	-6.04060	**-6.04880**	-6.04708
SSC	-2.36136	-2.35718	-2.38187	-2.38838	-2.44617	-2.60332	-2.66548	-2.72402	**-2.73009**	-2.72558
PACF (t)	54.72850	-10.46210	13.91340	0.27318	15.80460	34.57190	18.57510	-29.20110	-4.40540	**0.86220**

Therefore, all three series show indications of being a lag **nine** process.

SECTION III - Uplift Analyses.

3.1. The importance of uplift

Uplift is the component of prices which separates pool purchase price (used for all analyses to date) and pool selling price, representing the cost of reserve and reactive power utilised to stabilise the pool. Uplift has been a cause for some concern from the regulator, and was itself the subject of a review in 1992 (Report on Constrained-On Plant, Offer, October 1992). In addition, efforts were made to control uplift levels through the introduction in 1994 of the Uplift Management Incentive Scheme (UMIS).

The UMIS was introduced as a result of the dichotomy inherent in NGC undertaking investment in the transmission network. The cost of any such investment would be met by the NGC, while the improvement in planning standards would lead to a reduction in uplift payments which would benefit electricity suppliers and their customers. In order to limit this problem, it became necessary to give the NGC an incentive to ensure an efficient system of transmission. This incentive was created in the form of UMIS.

The scheme oversees the levels of those components of uplift over which NGC can exert some influence, i.e. operational outturn (the cost of transmission constraints) and ancillary services (reserve and reactive power). The NGC and those suppliers buying power from the pool established a target range for these components, which they termed incentivised uplift. In the event that incentivised uplift was less than £570 million during the year (which coincidentally was almost exactly the 1993-4 outturn), the suppliers would repay NGC 30% of the saving, up to a level of £25 million. Similarly, if incentivised uplift exceeded £587 million, the NGC would have to repay the suppliers 20% of the excess, up to a total of £15 million.

UMIS presented the NGC with a further incentive to limit the cost of operating the transmission network. For example, a considerable part of the cost of constraints is caused by the maintenance requirements of power relays and transmission circuits. To limit this cost, NGC increased the amount of overtime worked in the form of system upkeep in order to reduce the length of any outages and their corresponding constraints. NGC also managed to install equipment in order to fortify the network at those places where constrained running could be avoided. Indeed, over the year 1994-5 the system operated such that NGC received the maximum £25 million allowed under the system. This fact was primarily due to the low payments in February and March that came about as a consequence of Offer's 27th January 1995 announcement, as referred to above.

UMIS was extended into the first six months of the year 1995-6 before being phased out and replaced by the Transmission Services Scheme (TSS), which is designed to be more precise in its operations. At the present time, the operational outturn component of uplift contains all the costs of differences between the actual generation levels and the unconstrained day-ahead schedule. Some of the discrepancies are due to transmission constraints, some result from errors in the NGC demand forecast, and some are caused by supply alterations when generators are unable to operate in the manner they predicted when the schedule was constructed.

Under TSS, a revised unconstrained schedule is calculated utilising the actual level of demand observed on the day. Any differences between this revised schedule and the outturn generation should be as a consequence of transmission constraints, making the cost of these constraints equal to the difference between the ex-post unconstrained schedule and the out-turn generation cost. With the exact identification of these costs, NGC will now have a greater incentive to reduce them, with a resultant decline in the risk of being held accountable for those costs that they cannot effectively control.

The scheme also includes an incentive scheme whereby NGC may reduce its transmission losses as the NGC must pay 20% of the cost of any losses beyond a set reference level at a price of £25/MWh, with a set total exposure of £2 million. As with UMIS, the scheme is symmetric, with NGC facing the prospect of receiving up to £2 million by reducing losses below the reference level, currently set to approximately 2% of demand.

Uplift is indirectly determined via the loss of load probability: as demand increases (or supply falls) the loss of load probability will increase and the bid price of the marginal plant called upon to generate will increase. This will lead to an increase in SMP and the price of plant held in reserve to support the pool. Therefore, as the system marginal price increases, so will uplift through increased unscheduled availability payments.

One assumption required for the subsequent analysis is that the loss of load probability is stable. This is not as heroic an assumption as it sounds, as the loss of load probability is a function of demand, which is a seasonal variable and therefore predictable. Therefore, if we assume stability in the loss of load probability, this rules out the possibility that uplift will fluctuate due to system outages or unanticipated increases in demand. This leaves the possibility that the value of uplift is changing due to the generators altering their bidding strategy consciously. The loss of load probability has typically remained stable in the time since privatisation, fluctuating mainly on the basis of system outages, leading to increased payments for the unscheduled availability component of uplift.

On the whole, uplift follows a similar trend to the pool purchase price, but there are certain notable exceptions. For example, there is not such a marked decrease in uplift (in percentage terms) which follows the decrease in prices as a consequence of the February 1994 undertaking by National Power and Powergen. However, there are some unusual changes as a consequence of other factors. For instance, on the 9th March 1993, OFFER informed National Power and Powergen of the conclusions of the report made by the Independent Assessors concerning the possibility of NP and PG closing some of their generating facilities. On the day after this announcement, uplift payments began an upward shift of some magnitude, increasing 300% in four days. However, on the day of the dissolution of the second set of contracts for differences (31/03/93), uplift reached its highest levels for over six and a half months. In addition, it began an upward shift resulting in a sixty-five percent increase in uplift, a level at which they remained for approximately two months until an explanation was demanded by OFFER, at which time they began to fall.

This fact lends credibility to the belief that the generators have the ability to manipulate uplift by their bidding strategy, as well as supporting the use of short-term analysis throughout this study. It is therefore theoretically possible that analysis of uplift may be used in the same manner as those for pool prices and demand, and that the same influences are felt through the increased bid prices and subsequent SMP.

However, it may be appropriate to focus upon a further sequence of regulatory announcements for analysis, namely the occasions on which National Power and Powergen have been threatened with a reference to the MMC. If, as has been theorised in several articles, the nature of the relationship between regulator and regulated firms is analogous to a repeated game, then it may be possible to liken the possibility of an MMC reference to threats within a game. If this is the case, then the first time that a threat is made, it may be perceived as credible and will serve to bring the companies back into line with the objectives of the regulator. However, if the threat is repeated on several occasions without action, then the regulator may lose credibility in the use of this threat.

National Power and Powergen set system marginal price and pool purchase price approximately 85% of the time, with the remainder being accounted for by the NGC's pumped storage businesses (PSB, later First Hydro). It is logical to expect that if National Power and Powergen are afraid of an MMC reference, then system marginal price and therefore uplift will fall. For example, on the first occasion that the DGES threatened an MMC reference, National Power and Powergen may have altered their bidding strategies in such a manner that reflected perceived competitive pricing. Having carried out the regulator's wishes, this threat then subsided. However, if the threat was repeatedly used without being carried out, then the firms may have done little, if anything to alter their bidding strategies.

Alternatively, if the firms do not alter their bidding strategies based upon the threat of an MMC reference, then it may lead to more concerted attempts by the regulator to obtain their compliance.

Section 3.2. Dummy variable analysis using uplift.

Carrying out this analysis is identical to that performed on pool prices, but with a preliminary focus on MMC references. In order to assess this hypothesis, the following equation was used:

$$Ud_t = \alpha + \rho_1 Ud_{t-1} + \rho_2 DUMMY_t \qquad \textbf{(1.3)}$$

Where Ud_t represents uplift as defined above (£/MWh). In order to determine the optimal lag length, this equation was performed for each dummy variable with up to ten lags.

In order to determine the optimal nature of the uplift series, the Akaike information criterion (AIC), the Schwarz information criterion (SIC) and the partial autocorrelation function (PACF) were used. The optimal structure for uplift variable is one possessing nine lags. This result is mirrored in both the Schwarz criterion and in the PACF, and also in the log version of the price variable.

In each case, the announcement of an MMC reference should produce a negative significant dummy variable. The events corresponding to MMC references are 3, 5, 9, 10, 11, 14 and 23. The results of this analysis are shown in Table 4 and are summarised as follows:

- **Dummy 3: First pool price review begins w/MMC threat; Negative 1%**
- Dummy 4: First pool price review published: Negative 1%
- Dummy 7: Second pool price review published; Negative 1%
- Dummy 8: Break-up of second set of CFDs; Positive 1%
- **Dummy 9: Generators threatened with MMC reference; Positive 1%**
- **Dummy 10: MMC reference and/or plant sales threatened; Negative 1%**
- **Dummy 11: MMC reference unless price agreement made; Negative 1%**
- Dummy 12: NP and PG establish price agreement; Positive 1%
- **Dummy 14: MMC reference threatened over plant sales; Negative, 1%**

There are other, financial market events (FME) that also generate significant dummies (see table).

Although this analysis is by no means conclusive, it does raise some important queries. If the nature of the pool can be likened to a repeated game between generators, the possibility of an MMC reference can be likened to a credible threat - as the threat was made and not carried out, it lost credibility.

Once again, the diagnostic performance was mixed (see appendix). However, in order to further develop the results of the pool price analysis, the remaining events were examined by dummy variables with the uplift data set. The equation structure was the same univariate format as utilised for the analyses of the MMC threats, with the actual results displayed in Table 4.

Of the results presented in Table 4, the majority are consistent with the relevant hypotheses. The most surprising of these are the events that were previously considered to have little or no influence on prices. It is clear that of those financial market events, for which a negative coefficient was anticipated, the results appear to be consistent with this hypothesis. This is unusual, as it was assumed up to this point that certain events would not affect the electricity pool. However, it is possible that these events can and do influence uplift but not prices.

To conclude this analysis, the structural break analyses of Section II were repeated for uplift (using an equation similar to **2.1.** – uplift is also an order nine process, see above), with the conclusions presented in Table 2, and summarised as follows. There have been six structural breaks in uplift levels, which occurred in the following time periods:

1. June – September 1991
2. August – November 1991
3. April – July 1992
4. December 1992 – March 1993
5. June – September 1994
6. June – September 1995

Of these breaks, all but one coincide with a structural break in price, namely that of December 1992 – March 1993, with this period itself incorporating the publication of the second pool price review.

Although the diagnostics for these analyses (see appendix) implied some difficulties, the results of this analysis do support those of the PPP analysis as a means of examining the behaviour of the participants of the industry.

Table 4. Determining the optimal lag length for uplift regressions.

Section 4.1. Dummy variable regressions

UPL:D1	+ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-2.84704**	-2.83043	-2.84200	-2.81587	-2.81396	-2.84251	-2.82126	-2.78956	-2.77224	-2.73596
SSC:	Minimise	**-2.76791**	-2.72426	-2.70844	-2.65457	-2.62456	-2.62465	-2.57456	-2.51364	-2.46671	-2.40041
PACF	T-Ratio	5.82340	**-1.20610**	-2.06930	0.78503	1.72900	2.44630	1.10410	-0.55317	-1.29220	-0.10170
Dummy	T-Ratio	0.71610	0.87179	**1.20330**	1.04640	0.74336	0.29168	0.08569	0.16075	0.21289	0.22241

UPL:D2	+ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-1.80961	-1.88854	-1.86964	-1.84826	-1.86708	-2.02190	-2.12980	**-2.25198**	-2.22965	-2.21161
SSC:	Minimise	-1.73048	-1.78237	-1.73608	-1.68696	-1.67768	-1.80404	-1.88310	**-1.97606**	-1.92412	-1.87606
PACF	T-Ratio	6.86340	-3.36240	1.12770	-1.03630	2.24040	4.39370	3.86060	-3.90980	**-0.82407**	-1.28380
Dummy	T-Ratio	1.06850	**1.65410**	1.35130	1.55750	0.97819	0.02011	-0.74314	-0.10558	0.02906	0.20250

UPL:D3	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-1.60072	-1.75091	-1.71887	-1.71480	-1.70147	-1.80646	-1.93830	**-2.00577**	-1.97312	-1.98251
SSC:	Minimise	-1.52158	-1.64474	-1.58531	-1.55350	-1.51208	-1.58860	-1.69160	**-1.72985**	-1.66758	-1.64696
PACF	T-Ratio	6.14840	-4.39630	-0.03580	-1.65890	1.37340	3.72110	4.07930	-3.13450	**-0.52502**	-2.04190
Dummy	T-Ratio	-2.47060	-3.09000	-3.06560	**-3.20780**	-2.88910	-2.68780	-3.10280	-2.68850	-2.64560	-2.81320

UPL:D4	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-2.11891	-2.11655	-2.08577	-2.05338	-2.10650	-2.15715	-2.13657	-2.21315	**-2.22452**	-2.19217
SSC:	Minimise	**-2.03978**	-2.01038	-1.95221	-1.89208	-1.91711	-1.93929	-1.88988	-1.93723	-1.91899	-1.85662
PACF	T-Ratio	7.34980	**-1.69380**	-0.34957	0.14766	2.91130	2.86270	1.13220	-3.27830	-2.08320	-0.59929
Dummy	T-Ratio	-2.71320	**-3.04470**	-3.03190	-2.94410	-2.76270	-2.48530	-2.48120	-2.31130	-2.37240	-2.40560

UPL:D5	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.22707	-3.29161	-3.26596	-3.25242	-3.26726	-3.27794	-3.25527	**-3.30132**	-3.28043	-3.27336
SSC:	Minimise	-3.14794	**-3.18544**	-3.13240	-3.09112	-3.07786	-3.06008	-3.00858	-3.02540	-2.97490	-2.93781
PACF	T-Ratio	10.91070	3.12720	**0.78535**	1.35320	2.15100	2.05610	1.04340	-2.77260	-1.15930	-1.62710
Dummy	T-Ratio	0.08522	-0.35289	-0.45979	-0.63369	-0.87242	-1.12440	**-1.26510**	-0.80770	-0.60699	-0.33985

UPL:D6	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-3.10626	-3.07488	-3.04355	-3.01231	-2.98357	-3.02395	-3.15084	**-3.17221**	-3.15996	-3.12357
SSC:	Minimise	-3.14794	**-3.18544**	-3.13240	-3.09112	-3.07786	-3.06008	-3.00858	-3.02540	-2.97490	-2.93781
PACF	T-Ratio	5.58270	**-0.10517**	0.26366	0.36382	0.64752	2.67610	4.01310	-2.29810	-1.46220	-0.01391
Dummy	T-Ratio	**-1.19050**	-1.18690	-1.14340	-1.08380	-1.00650	-0.70025	-0.50001	-0.50519	-0.53561	-0.53278

UPL:D7	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.24223**	-3.21141	-3.18585	-3.15348	-3.15903	-3.13051	-3.17026	-3.13524	-3.16960	-3.16571
SSC:	Minimise	**-3.16309**	-3.10524	-3.05229	-2.99219	-2.96964	-2.91265	-2.92357	-2.85932	-2.86407	-2.83016
PACF	T-Ratio	2.21180	**0.25098**	-0.79141	-0.15081	1.92660	0.70024	2.66140	0.06214	2.55720	-1.71530
Dummy	T-Ratio	**-3.78250**	-3.33180	-3.39800	-3.14690	-2.15090	-1.74370	-0.84458	-0.77344	0.06911	-0.50057

UPL:D8	+ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.78658**	-3.76073	-3.73239	-3.70364	-3.68948	-3.65568	-3.62205	-3.59200	-3.56788	-3.53876
SSC:	Minimise	**-3.70745**	-3.65456	-3.59883	-3.54234	-3.50009	-3.43782	-3.37535	-3.31608	-3.26235	-3.20321
PACF	T-Ratio	9.95300	**0.74213**	0.59546	0.60866	1.34350	0.00591	0.27266	0.67419	1.02470	-0.80781
Dummy	T-Ratio	**2.32230**	1.95550	1.67560	1.48080	1.15290	1.12780	1.06780	0.94817	0.77236	0.88166

Table 4: (Continued).

UPL:D9	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.82516**	-3.81314	-3.78210	-3.75707	-3.72504	-3.69268	-3.66986	-3.64183	-3.61641	-3.58367
SSC:	Minimise	**-3.74603**	-3.70696	-3.64854	-3.59577	-3.53565	-3.47482	-3.42316	-3.36591	-3.31088	-3.24812
PACF	T-Ratio	8.62050	**-1.38180**	0.30764	-0.85189	0.33035	0.36546	1.03800	-0.79836	0.96649	0.56889
Dummy	T-Ratio	2.35330	**2.57970**	2.42660	2.54860	2.40230	2.29900	2.10720	2.16990	2.02030	1.94030

UPL:D10	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.50324**	-3.50065	-3.49525	-3.46290	-3.43176	-3.43068	-3.39626	-3.36120	-3.32711	-3.29238
SSC:	Minimise	**-3.42410**	-3.39448	-3.36169	-3.30160	-3.24236	-3.21282	-3.14956	-3.08528	-3.02157	-2.95683
PACF	T-Ratio	10.41570	**1.68630**	1.61130	0.15555	-0.44020	1.75870	0.02591	0.01123	-0.38206	0.38608
Dummy	T-Ratio	**-2.69960**	-2.25670	-2.01570	-1.98270	-2.00570	-1.92890	-1.91490	-1.89820	-1.91770	-1.86210

UPL:D11	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.27625**	-3.26248	-3.23841	-3.25310	-3.22014	-3.22378	-3.23160	-3.20633	-3.18190	-3.15578
SSC:	Minimise	**-3.19712**	-3.15631	-3.10485	-3.09180	-3.03075	-3.00592	-2.98490	-2.93041	-2.87637	-2.82023
PACF	T-Ratio	4.36200	**-1.31740**	-0.87813	-2.14480	0.15304	1.88390	1.99210	-0.94692	-1.01080	0.95847
Dummy	T-Ratio	-3.29450	-3.55020	-3.65100	**-4.17970**	-3.85920	-3.17400	-2.88410	-2.95840	-3.03090	-2.86780

UPL:D12	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.35300**	-3.32186	-3.29021	-3.26382	-3.23694	-3.22016	-3.25750	-3.22293	-3.19949	-3.18518
SSC:	Minimise	**-3.27386**	-3.21569	-3.15665	-3.10252	-3.04755	-3.00230	-3.01081	-2.94701	-2.89395	-2.84964
PACF	T-Ratio	4.95810	**-0.18487**	0.20118	-0.77038	0.77246	1.26280	2.61640	0.20972	-1.05450	1.41030
Dummy	T-Ratio	**2.81690**	2.76690	2.62750	2.72140	2.47650	2.29670	2.12670	2.11050	2.11430	2.06410

UPL:D13	FME	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-0.80248	-0.91471	-0.90412	-0.89202	-0.90466	-1.20118	-1.29900	**-1.57365**	-1.54047	-1.53769
SSC:	Minimise	-0.72335	-0.80854	-0.77056	-0.73072	-0.71526	-0.98332	-1.05231	**-1.29773**	-1.23493	-1.20215
PACF	T-Ratio	6.97630	-3.87220	**1.44320**	-1.40330	2.09980	6.03340	3.60660	-5.74760	-0.47792	-1.74440
Dummy	T-Ratio	-1.03740	-1.33660	-1.20980	-1.30840	-1.22890	-1.31350	**-1.55600**	-1.35190	-1.34920	-1.36860

UPL:D14	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-0.63767	-0.73961	-0.71670	-0.70699	-0.69006	-0.97319	-0.99271	**-1.23876**	-1.22025	-1.21571
SSC:	Minimise	-0.55854	-0.63343	-0.58314	-0.54569	-0.50066	-0.75533	-0.74601	**-0.96284**	-0.91472	-0.88017
PACF	T-Ratio	6.19830	-3.72120	**0.93931**	-1.48360	1.24180	5.88910	2.25800	-5.43500	-1.24960	-1.69720
Dummy	T-Ratio	-3.12710	**-4.36080**	-3.52320	-3.84260	-3.05960	-1.29280	-0.59427	-2.34590	-2.64250	-3.07190

UPL:D15	FME	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-0.77304	-0.79043	-0.81610	-0.79028	-0.81401	-1.05627	-1.13113	**-1.21348**	-1.20072	-1.17194
SSC:	Minimise	-0.69391	-0.68426	-0.68254	-0.62899	-0.62462	-0.83841	-0.88443	**-0.93756**	-0.89519	-0.83639
PACF	T-Ratio	7.35250	-2.21500	2.37910	**-0.80502**	2.34670	5.43750	3.25950	-3.36690	-1.44560	-0.82498
Dummy	T-Ratio	-0.91594	**-1.12630**	-0.81726	-0.90399	-0.62370	-0.03282	0.38717	-0.12673	-0.41740	-0.62862

UPL:D16	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-0.77489	-0.79305	-0.81846	-0.79308	-0.81613	-1.05684	-1.12959	**-1.21508**	-1.20299	-1.17424
SSC:	Minimise	-0.69575	-0.68687	-0.68490	-0.63178	-0.62673	-0.83898	-0.88289	**-0.93916**	-0.89746	-0.83870
PACF	T-Ratio	7.32010	-2.22240	2.38290	**-0.83086**	2.33230	5.42010	3.22600	-3.41440	-1.46700	-0.82631
Dummy	T-Ratio	-1.01090	**-1.21750**	-0.94637	-1.04180	-0.76737	-0.23272	0.08735	-0.40243	-0.61625	-0.77533

Table 4: (Continued).

UPL:D17	FME	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.06571**	-3.03618	-3.00555	-2.97372	-2.94062	-2.99866	-2.99100	-2.95874	-2.94817	-2.96985
SSC:	Minimise	**-2.98658**	-2.93001	-2.87199	-2.81243	-2.75122	-2.78080	-2.74431	-2.68282	-2.64264	-2.63430
PACF	T-Ratio	6.10810	**-0.43922**	-0.36971	0.27643	0.08471	2.99090	-1.58050	0.50323	-1.51360	-2.30680
Dummy	T-Ratio	-2.18300	-2.21480	-2.23530	-2.15160	-2.09710	-1.57960	-1.82730	-1.70620	-1.94630	**-2.44650**

UPL:D18	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.02734**	-2.99637	-2.96503	-2.93392	-2.90134	-2.97229	-2.95630	-2.92752	-2.90870	-2.91142
SSC:	Minimise	**-2.94754**	-2.89020	-2.83147	-2.77262	-2.71195	-2.75443	-2.70961	-2.65160	-2.60316	-2.57588
PACF	T-Ratio	6.53250	**-0.34113**	-0.26521	0.37597	0.24407	3.20500	-1.30750	0.75696	-1.23860	-1.88440
Dummy	T-Ratio	-0.91182	-0.96283	**-0.99334**	-0.85996	-0.78018	-0.10974	-0.29194	-0.15463	-0.39901	-0.77194

UPL:D19	FME	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-2.96859**	-2.93857	-2.91005	-2.88045	-2.84831	-2.92676	-2.89370	-2.85888	-2.82884	-2.82983
SSC:	Minimise	**-2.88946**	-2.83239	-2.77649	-2.71915	-2.65891	-2.70890	-2.64700	-2.58296	-2.52331	-2.49429
PACF	T-Ratio	7.56070	**-0.37938**	-0.58277	0.53631	0.31814	3.32360	-0.35506	-0.14546	-0.71633	-1.84130
Dummy	T-Ratio	-0.29089	-0.32229	-0.36352	-0.31203	-0.27573	0.12592	0.05994	0.02802	-0.12438	**-0.51023**

UPL:D20	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	**-3.05894**	-3.02859	-2.99804	-2.96853	-2.96216	-2.97474	-2.94124	-2.90709	-2.87318	-2.84985
SSC:	Minimise	**-2.97981**	-2.92241	-2.86448	-2.80723	-2.77276	-2.75688	-2.69455	-2.63117	-2.56765	-2.51430
PACF	T-Ratio	7.27950	**0.33377**	0.38112	0.54304	1.59900	2.10120	-0.29348	-0.28476	-0.40305	-1.08220
Dummy	T-Ratio	**-1.84620**	-1.75340	-1.65840	-1.57710	-1.46640	-1.45410	-1.45830	-1.45580	-1.45510	-1.48040

UPL:D21	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-2.48478	-2.45931	-2.44343	-2.41146	-2.41205	**-2.52188**	-2.52148	-2.49954	-2.46406	-2.46951
SSC:	Minimise	**-2.40565**	-2.35314	-2.30987	-2.25016	-2.22265	-2.30402	-2.27478	-2.22362	-2.15852	-2.13397
PACF	T-Ratio	7.80260	**-0.76577**	1.25090	-0.24942	1.79760	3.79010	1.78420	-1.09600	-0.14564	-1.95040
Dummy	T-Ratio	-0.87167	**-0.98420**	-0.78763	-0.80939	-0.45458	0.15895	0.41534	0.21300	0.19815	0.07246

UPL:D22	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-2.07203	-2.08117	-2.07229	-2.04690	-2.08733	-2.25791	**-2.27285**	-2.25946	-2.22413	-2.22344
SSC:	Minimise	-1.99290	-1.97499	-1.93873	-1.88560	-1.89794	**-2.04005**	-2.02615	-1.98354	-1.91860	-1.88790
PACF	T-Ratio	8.43620	-2.00590	**1.50040**	0.82985	2.68030	4.59230	2.15740	-1.41220	-0.18516	-1.79860
Dummy	T-Ratio	0.64738	0.50475	0.53196	0.56778	0.74282	1.17420	**1.40870**	1.27150	1.23010	0.99240

UPL:D23	-ve	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	Minimise	-1.87420	-1.88979	-1.85969	-1.83358	-1.85940	-2.10052	**-2.18773**	-2.17996	-2.14684	-2.13877
SSC:	Minimise	-1.79507	-1.78362	-1.72613	-1.67228	-1.67001	-1.88267	**-1.94103**	-1.90404	-1.84131	-1.80322
PACF	T-Ratio	8.41320	-2.16300	**0.43343**	0.78752	2.39070	5.42480	3.44940	-1.58670	-0.48264	-1.59930
Dummy	T-Ratio	1.63040	**1.82740**	1.73530	1.54130	0.64733	0.12204	-0.12348	0.08122	0.13579	0.19007

For the determination of the optimal uplift lag (series nine) please see table 3 above.

Section 4.2. Summary Table

Regression	Indicated Lag Length	Dummy T-Statistic	Level of significance
1	Order 1	0.71610	N/A
2	Order 8	-0.10558	N/A
3	**Order 8**	**-2.68850**	**1%**
4	**Order 1**	**-2.71320**	**1%**
5	Order 2	-0.35289	N/A
6	Order 2	-1.18690	N/A
7	**Order 1**	**-3.78250**	**1%**
8	**Order 1**	**2.32230**	**1%**
9	**Order 1**	**2.35330**	**1%**
10	**Order 1**	**-2.69960**	**1%**
11	**Order 1**	**-3.29450**	**1%**
12	**Order 1**	**2.81690**	**1%**
13	**Order 8**	**-1.35190**	**N/A**
14	**Order 8**	**-2.34590**	**1%**
15	Order 8	-0.12673	N/A
16	Order 8	-0.40243	N/A
17	**Order 1**	**-2.18300**	**5%**
18	Order 1	-0.91182	N/A
19	Order 1	-0.29089	N/A
20	**Order 1**	**-1.84620**	**10%**
21	Order 1	-0.87167	N/A
22	Order 7	1.40870	N/A
23	Order 7	-0.12348	N/A

SECTION IV - Broader Empirical Analyses.

4.1. The need for broader analyses of uplift, pool prices and electricity demand.

It is hypothesised that there should be a positive relationship between pool prices and uplift levels as follows. Because pool prices are derived from the bid prices of plants submitted to the NGC for central despatch, then as pool prices increase, then the prices of plant held in reserve should also increase. This is because generators will attempt to get their least expensive plant into the merit order, and if the prices of this least expensive plant increase, then it follows that the price of their reserve plant must be higher also.

A similar logic follows for the relationship between electricity demand and uplift levels. In the event of periods of high demand, then generators will be called upon to submit more plants to the merit order. These plants will generally represent generating units which would have previously been held in reserve, with these reserve plants being displaced by even more expensive plants to be held in reserve. Therefore, as demand increases, it is logical to anticipate that uplift will increase also via higher unscheduled availability payments, the other components of uplift assumed constant.

An important supposition to be made here is that supply itself must be constant, or rather that baseload supply is to be held constant. Baseload power is comprised of (typically) nuclear capacity which operates twenty-four hours a day and which is required for the smooth running of the pool. If baseload plants are not submitted to the merit order, then more expensive plants will be called upon to operate and therefore both prices and uplift will increase. This will occur in a fairly predictable manner, with the best example being the behaviour of pool prices in early 1995 when simultaneous malfunctions at the Dungeness and Heysham reactors put these important nuclear stations out of operation. This was followed by an immediate and substantial increase in both pool prices and uplift, with the increases primarily brought about through increased loss of load probability leading to increased unscheduled availability payments.

Determining the relationship between electricity demand and pool price is more difficult. The demand for electricity is typically seen as being inelastic, with the short-run price elasticity of demand possessing an approximate value of 0.15 (Taylor, 1975, Branch, 1993, Wolfram, 1995). In addition, the elasticity of demand for electricity typically changes depending upon the time of the year - demand becomes more sensitive to price in winter when demand is at its highest (Taylor, 1975, Branch, 1993, Wolfram, 1995). However, in order to assess the responsiveness of electricity demand to changes in prices, this assumes that consumers actually have the capability to observe prices, and to alter their power usage in response to these prices. This is typically not the case, as only large electricity users have these characteristics, and while it could be possible to undertake price-demand analyses for small and large electricity users, the data set in use does not permit such an analysis.

In order to perform analyses of these relationships, we must ensure that the variables in question are not non-stationary time series, which is determined by means of the Dickey-Fuller and Augmented Dickey-Fuller tests. The format of regression used to verify the existence of stationarity in the relevant variables here (namely pool purchase price, electricity demand and uplift) is:

1. **Pool price analysis**

$$\Delta PPP_t = \alpha + \beta_0 \tau + \beta_1 PPP_{t-1} + \beta_2 \Delta PPP_{t-1} + \beta_3 \Delta PPP_{t-2} + \ldots + u_t \quad \textbf{(1.4)}$$

2. **Electricity demand analysis**

$$\Delta ED_t = \alpha + \theta_0 \tau + \theta_1 ED_{t-1} + \theta_2 \Delta ED_{t-1} + \theta_3 \Delta ED_{t-2} + \ldots + u_t \quad \textbf{(1.5)}$$

3. **Uplift analysis**

$$\Delta Ud_t = \alpha + \rho_0 \tau + \rho_1 Ud_{t-1} + \rho_2 \Delta Ud_{t-1} + \rho_3 \Delta Ud_{t-2} + \ldots u_t \quad \textbf{(1.6)}$$

where all variables are in natural logs, with PPP the pool purchase price for electricity (£/MWh), UP representing uplift (£/MWh) and ED representing electricity demand (MW) and the equations are structured (with regard to their lags) as discussed in Sections 2.1 and 2.2.

The derivation of pool purchase price and uplift has already been detailed. Electricity demand represents gross demand, defined as: "The total gross demand calculated to have been taken by all **consumers** in a settlement period. The metered readings are scaled up to allow for transmission losses to give the gross figure." (Energy Settlements and Information Services Catalogue of Data Items, Issue No. 4, 1st October 1993). This is not **total** demand, which is the demand to be met by generating units based upon the demand forecasts derived by the GOAL computer algorithm.

If the relationships are indeed as outlined previously, then there should be a positive relationship between pool price and uplift. Having already determined that the respective pairs of variables are stationary (see Section 2.1 for this result), a linear combination of them must be formed as follows:

$$Ud_t = \alpha + \lambda PPP_t \quad \textbf{(1.7)}$$
$$Ud_t = \eta + \xi ED_t \quad \textbf{(1.8)}$$

Of course any combination of stationary variables is, by definition, stationary.

(It should be apparent that setting these equations equal to each other results in a price-demand relationship, which is analysed in the next chapter.).

In the case of pool prices, the data is stationary as given by the aforementioned tests, but the sequence does exhibit serial correlation as well as evidence of ARCH process. In the case of demand, stationarity is again attained but this time without serial correlation, although there is again the existence of ARCH. In the case of uplift, stationarity was also achieved, but there was evidence of both serial correlation and an ARCH process. The regression of prices on uplift attained stationarity, as did the regression of demand on uplift, but both failed the diagnostics for serial correlation and ARCH. Therefore, the analyses on uplift and pool prices and uplift and demand may be undertaken, but with some reservations based on the diagnostic performance.

Given that an increase in pool prices, with supply held constant, should lead to an increase in uplift levels for the reasons outlined above. Therefore, we should expect the slope coefficient in equation (1.7) to be greater than zero. Similarly, as demand increases, uplift should also increase: therefore, we should expect the slope parameter in equation (1.8) to have a coefficient greater than zero. These conclusions are relatively easy to establish, but what is a greater issue is the extent to which changes in uplift and demand and changes and uplift and prices are brought about. These questions may be answered by the following equations:

$$\Delta Ud_t = \alpha_0 + \beta_0 \Delta PPP_t \qquad \textbf{(1.7a)}$$

$$\Delta Ud_t = \alpha_1 + \beta_1 \Delta ED_t \qquad \textbf{(1.8a)}$$

The first analysis consists of an examination of the value of the slope parameter of equation (1.7). This coefficient on this parameter should be greater than zero, and indeed it is, as well as being statistically significant. The Wald test was used to test the restriction that this parameter was equal to unity – a hypothesis that was rejected. This is expected, as the uplift parameter should not have such a proportional relationship, based upon the following reasoning. Based upon the data estimated in the MMC reports undertaken into the National Power-Southern and Powergen-Midlands mergers (HMSO, 1996 a. and b.) the following data can be noted. Utilising the data for new entrant costs of generating stations (CCGT generating facilities), a station with a 55% load factor (that which most approximates the UK electricity industry), the prices it submits should be £27.60MWh based upon a central cost estimate. This may be compared with the prices for a plant that bids on a much lower load factor, estimated at £45.80MWh for a 25% load factor and £91.90MWh for a 10% load factor. (All prices are stated in October 1995 prices). Given that those stations that influence uplift through high payments for unscheduled availability will have low load factors, it is unexpected that there should be an equi-proportional relationship between uplift and price. Given that the price for a plant with the 25% load factor is 1.66 times that for the standard 55% load factor. However, as this is a price-to-price relationship, not the price-uplift relationship here, it is possible that there are dynamics at work in the GOAL computer algorithm that can explain this result.

Turning the analysis to the equation which estimates the relationship between electricity demand and uplift (1.8), based upon the difficulty in measuring the price-demand relationship for electricity, it is perhaps to be expected that there should be difficulty in estimating the uplift-demand relationship. The equation (1.8) estimates this relationship, where the slope parameter is statistically insignificant and insignificant from zero, as defined by the Wald test. This implies a minimally responsive relationship or potentially non-existent relationship between uplift and demand. Given the lack of responsiveness of demand to price, this is not entirely unexpected.

Further equations, (1.7a) and (1.8a), attempted to assess the relationship between changes in uplift and changes in price, and changes in uplift and changes in electricity demand. It is hoped that these equations should provide a clearer explanation of the relationships, as well as solving some of the diagnostic problems that existed in the examination of equations (1.7) and (1.8).

The equation (1.7a) that shows the relationship between changes in price and changes in uplift indicates that there is an equi-proportional relationship between the two variables. Further manipulation of the equation (through the addition of lagged variables and the subsequent reduction of the equation's format) indicated that a form that passed the test for functional form was an equation that possesses seven uplift lags and one price lag. However, this form possessed severe serial correlation, which was partially removed through the addition of the parameter RES_t which is the residuals of the regression (1.7) between uplift and price - effectively an error correction term. The optimal structure using the Akaike Information Criterion was an equation possessing seven dependent variable lags and seven price lags in addition to the RES_t variable. The Schwarz Information Criterion suggests an almost identical result: six uplift lags instead of seven. While there is a strong case for prices and uplift to be AR(7) series, the addition of the price component indicates the determining nature of prices on uplift levels.

The analyses of equation (1.8a) which indicates the relationship between changes in uplift and changes in demand showed that the slope parameter had a coefficient value which was shown to be statistically insignificant from unity. This relationship is again difficult to interpret as it would depend upon the plants present in the merit order, although it is reassuring that a positive relationship does indeed exist between the two variables, unlike the case with equation (1.8).

This equation format also marginally failed the test for the correct functional form, although the diagnostics did indicate the existence of serial correlation and heteroscedasticity. Efforts to create a more accurate equation in terms of the diagnostic for functional form and other diagnostics, resulted in the equation being reduced back to an format near to its standard form. The revisions to this were the addition of an extra demand lag and an error correction variable given as the residuals from equation (1.7). This was due to the consistently poor diagnostic performance and the insignificance of the coefficients of the added parameters. The Akaike Information Criterion indicated a regression containing the error correction term, eight lags of the dependent variable and seven demand lags. By contrast, the Schwarz Information Criterion indicated an optimal regression structure of seven lags of the dependent variable and no demand lags. The key point to notice from this analysis is the lack of significance of the demand lags in determining the optimal regression structure, implying that demand does not have any strong statistical significance in determining uplift, despite the strong practical case for demand to have some influence on uplift.

These results are summarised in the appendix.

Section 4.2. Concluding comments on the dummy equations.

There is clear evidence generated in these regressions that regulation has indeed influenced the prices witnessed in the pool. The tendency for regulatory announcements to reduce pool prices is hence a reasonable and valid hypothesis. In addition, having determined that uplift is indeed a valid proxy for system marginal price (SMP), there is evidence that regulation has influenced the bid prices of generators also. While it is undeniable that a true analysis of SMP data would be a valuable addition to this research, the fact that the uplift regressions produce several significant dummies is of key importance. This is of note as the vast majority of significant dummies pertain to regulatory events in general and threats of MMC references in particular.

The fact that the threat of an MMC reference does not consistently generate significant dummies is a point of note. Using the repeated game analogy established and developed in earlier sections, the possibility of an MMC reference is essentially a threat in a repeated game. Game theory establishes that if threats are made repeatedly and not acted upon then they may lose credibility – there is no reason why an MMC reference should be viewed as being any different.

Given the consistent lack of significant MMC dummies in the pool price regressions following the first threatened reference, there is a case for advocating that from that point on actual policy and licence changes (through pool price reviews) would have impacted upon pool prices, but threats of action may not. Furthermore, the fact that uplift declined in response to subsequent threats when PPP did not may imply that bid prices declined while PPP levels (those prices which determined CFD payouts) held constant to ensure continued optimal revenue streams from CFDs.

As has been established, uplift levels may be used as a general replacement for the level at which prices are bid into the pool. The univariate uplift equations detected five out of the six occasions on which Offer threatened an MMC reference on the grounds of conduct. (The other was on the grounds of structure pertaining to vertical integration). It is possible that the system marginal price did respond to the threat of an MMC reference, but pool purchase price was not affected to as great and extent. That is, except for the first occasion when the threat was quite credible and it was too risky not to cut prices substantially. If this is the case, then the announcement of a possible MMC reference does little to benefit consumers, who see their prices as largely unaffected. It is the pool price reviews and related agreements that benefit consumers. With this in mind, the generators may modify their bid prices sufficiently enough to show good faith with the regulator, but they do not cut them in such a manner that they lose revenue from their operations.

Based upon these considerations, it may be possible to develop this possibility utilising an interactive dummy variable to represent uplift levels at the time of threatened MMC references. This requires establishing a standard binary dummy variable and then linking it with uplift through multiplication. As a consequence, uplift will now take the value of either zero or itself on the day on which an MMC reference was threatened. These variables were used for the six conduct-related MMC references and performed using equations **(1.2)**, **(1.3)**, **(1.7a)**, and **(1.8a)** in their original and extended form with up to ten lags of each independent regressor. However, there was little response and in no case was there a significant dummy in any optimal regression. Despite this, there was a proliferation of negative dummy coefficients in the regressions. The results are presented in full in the appendix.

A final means of assessing these conclusions is an examination of uplift and pool price levels after a threatened MMC reference. In the case of the first threatened reference, both prices and uplift decline sharply after the announcement, while the second announcement results in a brief decline in prices which is soon reversed, but a more continued decline in uplift. The third event sees a minimal response from prices, with a brief but sharp decline in uplift. The fourth, fifth and sixth events both appear to have no discernible effect in prices, but they both lead to considerable, continued declines in uplift. The seventh event cannot be assessed due to the lack of data after the event itself.

Although this evidence does not claim to be conclusive, it does again raise questions about the generator responses to an MMC threat in terms of their bidding into the pool and how it affects pool prices.

SECTION V - Conclusions.

This analysis has yielded some important insights into the behaviour of electricity prices since the industry was privatised in 1990. It appears that over the period under examination, there were a sequence of structural breaks in electricity prices. It is hypothesised that the breaks in prices were the consequence of regulatory announcements made in the industry. Clearly, the appearance of significant step-dummies on or around the dates in question does lend support to this hypothesis. Of the breaks in prices that have been identified, all but one occurs at the same time as an important regulatory announcement, or external system influence. The use of dummy variables within this analysis has also proven to be most successful and in the analysis of regulatory announcements, and it is therefore possible that other regulatory announcements and important exogenous shocks may be modelled in this way.

The further extension of the analysis into uplift levels saw how generators may behave in response to the threat of an MMC reference. Although the use of uplift is by no means a perfect replacement for system marginal price, it does help to raise the issue and assist in its development. Following the extension of the uplift analysis to all of the events, further analyses allowed the examination of the inter-relationships between important variables within the pool. These analyses were designed to support the univariate analyses and their conclusions, and although for the most part they did, some the results defied the univariate analyses.

The next section again returned to focus upon the repeated threat of an MMC reference, this time by using an interactive dummy variable. The analysis was based upon the supposition that the generators may alter their uplift levels in response to an MMC reference (again utilised as a replacement for system marginal price) as a means of showing support for the regulator, but not pool prices (as a means of avoiding lost revenue). It appears as though uplift does indeed respond to MMC references, although not always to a statistically significant extent. Despite potentially mixed results, the conclusions were sufficient to at least lend credibility to this hypothesis.

One of the main problems is the diagnostic test performance of the variables in the regressions, a factor that diminishes the usefulness of the results. However, the volatility associated with of pool prices means that they do not conform to the ideal statistical conditions required of data sets.

The analysis that has been performed here should therefore be viewed as a precursor to further investigations into the pool and its operations. It is clear that the announcements made by the regulator do have an important influence on the way that the generators behave and thus how they bid their stations into the pool. On a theoretical level, as detailed above, it may be logical to conclude that the pool be likened to a repeated game, and that threats and behaviour may be credible or not, as the case may be. This is apparent in the case of the analysis of MMC references, the dummy coefficient of which had less significance as the threat was made and not carried out. Clearly there is no proof to substantiate the results of this analysis, but there is some rationale for the linkages between regulatory announcements and the modifications to a bidding strategy. There is an equally strong rationale for the threat of an MMC reference, if not carried out, to become a weapon of limited, if any strength.

The evidence has also indicated that events that take place in the financial markets do not seem to influence pool prices and uplift levels, unless they bring with them the possibility of tighter regulation. This conclusion will be analysed in a forthcoming chapter through the examination of the share prices of the two main generators, National Power and Powergen.

It may therefore be concluded that this analysis has been established using both the theoretical observations on industry structure written to date, as well as being grounded on a solid empirical foundation. It would be highly improbable for a group of coincidences to explain the results presented here, despite the *ceteris paribus* assumption that has been implicit throughout. As a result, it may be stated that the contribution of this study is that is shows how electricity generators respond to the existence of regulation (actual or potential) and how it influences their objectives when the submit their offer prices to the pool.

CHAPTER VI: The Electricity Pool and Forward Contracts within the Electricity Supply Industry - Contents.

Section I - Objectives.

1.1. The role of the pool and the contract market.

Perhaps the most important aspect of the privatisation programme was the creation of the pool - a spot market for all bulk power transactions. With the exception of a small minority, all transactions must flow through the pool, which operates on a half-hourly basis by constructing a merit order of generating plants, functioning in the same manner as an auction system. However, despite aspirations that pool prices would remain at a stable, competitive level, these hopes were dashed by the realisation of the inherent price volatility, and by the generators and RECs signing contracts for differences (either forward or option contracts) which allowed them to hedge price fluctuations. Initially, companies had no choice in signing these contracts, as they were essentially forced upon them by the government to establish security to the nuclear and coal industries, with the actual contract strike prices being determined by the Horton IV pool price estimates. (For further details, see Chapter VIII).

One of the fundamental aspects of financial markets theory is the possibility of a relationship between spot and forward prices. In the period following privatisation, there was considerable analysis of this linkage by Helm & Powell (1992), Green & Newbery (1992), and Powell (1993). It has been theorised that the break-up of the contracts for differences was responsible for price increases this break-up, and it was this linkage which was examined by Helm & Powell, whose work it is hoped will be developed further by this analysis.

1.2. The structure of the chapter.

First, we will detail the actual nature of the contracts market, as well as the research that has already been carried out into the area of the pool and contract relationships. This will focus primarily on the work of Green & Newbery, and will integrate an analysis of Helm & Powell's 1992 study and its outcomes with elements of the preceding chapter. Secondly, we will detail the methodologies to be employed in the testing of the hypotheses concerning the break-up of the two sets of contracts. Thirdly, the results of these analyses and their implications will be presented, discussed, and developed further.

Section II - Spot and Forward Prices in the Electricity Industry.

2.1. The role of contracts for differences in the electricity industry.

As detailed previously, the rationale behind the use of contracts for differences (CFDs) is that two parties enter into an agreement over the forward price of a commodity based upon the belief that the commodity's spot market price will fluctuate. The use of contracts for differences therefore allows the interested parties to hedge their risks of price changes. To consider a general example, suppose that we have a consumer who knows that he will require 1000 units of a commodity at some point in the future. The use of a CFD allows this consumer to reach an arrangement with a supplier, whereby both parties agree on the future purchase price of this commodity. For example, the two parties could agree upon a CFD for 1000 units at a mutually agreed price (strike price) of £100 per unit, payable on delivery at some future date.

If the market price of the commodity on the future date is more than the strike price, the supplier pays the difference to the consumer on the 1000 units (in addition to the actual cash flows for the commodity itself). By contrast, if the market price is less than the strike price, the consumer pays the difference to the supplier. In this simple case, there is no upfront cash payment when the contract is agreed - the only cash flow on the contract is the difference once the actual price is known. This type of arrangement is known as a two-way CFD. For example, a generator and a REC could agree a strike price for electricity for a certain time period/group of periods, and operate in the described way depending upon whether the strike price was greater or less than the pool price. Alternatively, the generators and RECs could establish contracts to buy and sell electricity in advance at whatever the pool price happened to be at the time the contract was called. This arrangement would effectively be a simple forward contract.

Two types of CFDs are available to hedge forward electricity prices. Firstly, the long term vesting contracts negotiated by the generators and the regional electricity companies (RECs). These covered a considerable proportion of annual electricity sales and operated for one to three years following privatisation. Secondly, the electricity forward agreement (EFA) market has been developed to allow participants to tailor their cover using two-way CFDs using what are generally perceived as being short-term agreements. In this market, Gerrard & National Intercommodities (GNI) Ltd. successfully bid for and obtained the franchise to operate the EFA market, and remained the only broker until 1995-6. At this time Tradition Financial Services and Euro Brokers joined them. However, the EFA market will not be analysed at this stage (see Chapter VIII) - it is the market for contracts for differences that will be examined here.

On a fundamental level, financial markets theory indicates that the spot price in a market for a storable commodity is determined by the forward market price for that commodity. To be precise, the forward price for the delivery of a commodity at time period $t+1$ will equal the expected spot price at time t provided that there is no uncertainty. In the case of the electricity industry, this means that the markets for electricity forward agreements (EFAs) and contracts for differences should lead the pool in terms of pricing. However, given that electricity is a non-storable commodity and there is considerable uncertainty, it is unclear precisely how valid this hypothesis is. (See Chapter VIII).

Indeed, given that information on the spot price is readily available, whereas that on the strike prices of contracts for differences is not due to commercial sensitivity, a proxy is required for the strike price. Each of the interested parties in the electricity industry have their own estimates of prices, with the initial vesting contracts signed at the time of privatisation based on the Horton IV estimates. However, these estimates were well below the actual prices for the pool's first level of operation, which doubtless proved to be a contributing factor in the RECs decision to terminate some of the vesting contracts on 22nd March 1991. This was followed on the 31st March 1993 by the ending of the vesting contracts and their replacement with commercially negotiated contracts (see the preceding chapters).

Before continuing, it is important to note how the RECs contracting strategies have changed since privatisation. Initially, the bulk of electricity traded in the pool was done so under contract - approximately 95%. As the degree of cover through vesting contracts decreased, this began to fall, even though some of the output was being replaced by commercially negotiated contracts. However, with the introduction of more independent power producers (IPPs) into the generating sector, increased uncertainty regarding pool prices, and the RECs concern regarding the large generators' market power and negotiating stance in the contract market, contracted output continued to fall, to approximately 65% for in 1995/1996. Contract duration has also become an important issue as RECs attempt to combine flexibility and security of supply by holding a basket of contracts of different lengths. As a rule of thumb, the general classifications of contract duration are 15 years, 10 years, 2-6 years, 1 year, and less than a year.

2.1.1. Vertical integration and the contract market.

The issue of contract cover must be viewed from a different perspective when considering vertical integration, where a REC could fully contract its output with its affiliated generator. In the absence of vertical integration, such a move would be highly illogical for a risk averse REC, as it would be risking the possibility of exploitation by the generator. Indeed, even in the presence of vertical integration, such a move could be inadvisable on the grounds of fuel diversity representing an important part of a REC's contracting strategies (especially given the role of the Non-Fossil Fuel

Obligation). The issue of vertical integration became paramount in the electricity supply industry when some of the RECs sought modifications to their conditions on own-generation capacity, although such concerns were minimal compared to those voiced when generators attempted to take over RECs in 1995-6.

With the approval of the Scottish Power bid for Manweb, it was perceived that vertical integration in the industry was permissible, and in doing so would reverse the process of de-integration established at privatisation. This attitude was strengthened further when National Power and Powergen launched their bids for Southern and Midlands respectively. These bids were deemed inappropriate by the regulator but were approved by the MMC. However, the President of the Board of Trade later blocked them on the grounds that vertical integration was not suitable in the industry at that time. Such a statement led to concerns of ambiguity in the government's policy on vertical integration, especially following Eastern's acquisition of Powergen's divested plant, thus giving Eastern the potential to become a powerful vertically integrated pool trader.

The purchase of Manweb by Scottish Power brought with it changes to both companies PES licences with the purpose of preventing any operations detrimental to consumer interests. While it was admitted that the possibility of further vertical integration could result in operations that could harm consumers, these concerns were waived by the MMC as insufficient to block the mergers. The effects of vertical integration on the contract market are such that if the newly-integrated RECs contracted with their generating divisions, the residual (post-vertical integration) contract market would be thinner (i.e. would have fewer participants). In addition, it would be irrational for a generator to charge high prices to its REC division, making the key concern one governed by the economic purchasing condition of a REC's PES licence, and the degree of cost-passthrough allowed to consumers.

2.2. The actual contract types available.

Contracts and contract offers differ in form, and while some are relatively easy to compare, others require restrictive assumptions prior to any such comparison. The range of contracts is highly complex and contains several different prices and terms. In general, these concern the different forms of price indexation (e.g. inflation and fuel prices) and restrictions on when the contract can be called. It is also possible to include cost passthrough of transmission charges, or the sharing of benefits if pool prices are high, as well as restrictions on calling to a particular plant's availability.

Contract comparisons and availability can be based on load factors, i.e. the percentage of total hours in a year that the contract covers. Baseload contracts feature prices based on an average of all contract hours during a year (8760 hours, or 17560 half hour periods), while the call on lower load factors is concentrated towards peak periods. This makes lower load contracts more valuable, commanding a correspondingly higher price in the market. There are essentially three types of contracts: baseload RPI indexed contracts, as offered by Nuclear Electric; coal-fired sculpted load contracts (i.e. those contracts where capacity changes dependent upon demand) as offered by National Power and Powergen; and variable load contracts with indexed prices, as offered by the IPPs. (For further information on these types of contract, see Chapter VIII).

In theory and in the presence of efficient markets, the estimated contract price should equal the subsequent pool price. However, there are several reasons why it may not, the most important being inaccuracies in the strike price estimates. This problem would have had to have been solved at the earliest possible stage. Assumptions regarding demand are made by the generators in constructing their original contract offers, typically assuming that peak electricity demand will rise at 1% per year, while the dynamic regulatory climate must also be considered.

Given the potential of the contracts market and the EFA market, from a market power standpoint there are two possible fundamental reasons regarding the equality, or lack thereof, between the contracts' strike price and the pool price. If the estimated strike price is less than the out-turn pool price, then this could be due to generators attempting to keep prices low as a means of increasing their profits from the contracts. This is a highly probable outcome, given past research based upon the possibility of strategic trading in forward markets where the underlying spot market is imperfectly competitive. However, it may also be due to the fact that the market is inefficient due to the inherent demand and supply uncertainty. Alternatively, if the contract price does equal the pool price, then this could be based on a pre-meditated attempt to keep the pool price at some desired level. This ambiguity serves to damage any reliance on the efficiency hypothesis, as these two potential outcomes could be used to develop opposite inferences.

2.3. Research into the contract market

Despite the lack of considerable in-depth empirical research into the market for contracts for electricity, there are several key studies. Helm & Powell (1992) draws heavily on generator behaviour in the contract market as a means of explaining the conduct of the generators. There were two types of CFDs: one-way and two-way CFDs. (A one-way CFD with a low strike price becomes irrelevant as it will not be called). The nature of a two-way CFD serves to isolate generator revenue from pool prices, as the generators receive a pre-set price for their power. As explained, RECs benefit from hedging their risks to achieve a fixed price in their franchise markets while generators also receive premiums and gain added security, allowing them to hedge their investment costs.

REC contract portfolios as described above, were initially comprised of the vesting contracts. With the vast majority of electricity purchases covered by CFDs, it is almost impossible to ascertain generator revenue or the nature of generator incentives from an examination of pool prices.

Utilising the work of Anderson (1991) and others, Powell (1993) successfully developed and adapted traditional financial market theory for the electricity industry. He concluded that, in the absence of collusion, the existence of forward or forward-type contracts increases the degree of competition within the pool. This is because the contracts represent an additional dimension of price competition, thereby pushing the market closer to a perfectly competitive structure.

By contrast, it may also be concluded that contracts may also make collusive behaviour more likely, given that the structure of the industry is highly conducive to generator collusion. This is because the pool may, in game theoretic terms, be likened to a repeated game between imperfectly competitive dominant firms. However, CFDs may also be sold in such a manner that removes all incentives to depart from an agreed price with the generators selecting a desired price and utilising contracts to adapt their own incentives to maintain this level. This possibility increases the likelihood of strategic behaviour by generators within the marketplace.

In the first year after vesting, with over 95% of total generator output covered by CFDs, generator revenue had effectively been made independent of the pool price. This allowed generators to manipulate the pool price to any desired level within the bounds of the regulatory framework. Given the potential for considerable new entry in the post-vesting environment, the incumbent generators had a vested interest in keeping prices low, effectively operating a limit price strategy. As will be seen, pool prices after vesting were well below official estimates, and given that the pool price is the most important piece of information available for potential entrants, price manipulation to deter entry could be seen as both possible and beneficial. Clearly, it would be logical to expect high – not low - prices to encourage entry. As a consequence, one would anticipate that pool prices would remain high after entry and not decline, in order to sustain profits for new entrants. (This is standard oligopoly theory).

Following on from his previous research, Green (1992) utilises the methodology established in Green & Newbery (1992) to examine behaviour in the contract market for duopolistic generators using Klemperer & Meyer's (1989) supply function approach to oligopoly. As has been shown, when contracts cover the majority of a generator's output, there is an incentive to lower prices.

When a generator sells electricity forward under a contract, it is effectively 'reserving' part of the spot market for its own supplies, since it could sell that amount of electricity spot, but earn profits based upon the contract price. The 'residual', uncovered market will be smaller, and since the generator's optimal mark-up rises with their uncovered sales, the pool price will be lower. This reduces the generator's profits from the uncovered spot market. This is described as follows.

If generators increase the degree of competition in the contract market regardless of their strategy in the pool (apart from the condition of a short-run equilibrium), this implies that the generators would not be able to raise the contract price by threatening restrictive pool practices. In undertaking to sell contracts, the generators move the residual demand curve in the pool inwards, and in doing so the equilibrium price and volume in the pool declines as the volume of output covered by contracts increases. Therefore, the pool has both increased its profits from the contract market while reducing them in the residual market. If the generator believes that its counterpart in the industry will attempt to "reserve" a high proportion of the market through contracts, then it must do likewise, despite the consequences of eroding the residual pool in which market power could have been exercised.

With rational expectations, the price that the generator can obtain for its contracts will also be lower, but the extra sales that can be reserved by the contract will not often outweigh this effect. This means that for some parameter values, a generator would wish to sell contracts even if its rivals were not involved in the contract market.

Because the rival will generally follow the same stance, both generators would sell electricity under contract, giving a lower pool price and a somewhat higher output than in the absence of contracts. However, for some parameter values, a generator would not wish to be the first to enter the contract market, because the act of reserving sales in the contract market will drive the price down in the residual pool to the extent that the profits would fall.

If a generator expects its rival to base its contracting strategy on the price for which contracts can be sold, the analysis becomes more complex. If the generator increases its own sales in the contract market, its rival will typically sell fewer contracts as the price falls. This means that the residual pool does not shrink by the full amount of the generators extra sales, and so the price will not fall by as much, making additional contract sales more profitable than if the rival was not expected to respond.

It is shown that in the limit, the generator might expect its rival to aim to keep the contract price - and hence the total contract sales - constant, and expand or contract its own sales to offset any change in those of its rival. Under these conditions, the generator would want to reserve as large a part of the market as it could, since its rival would be expected to reserve the remainder, and so both generators would end up fully contracted, and selling at marginal cost in the spot market.

It was therefore concluded that the regulator should do as much as possible to encourage competition in the contract market and to encourage generators to sell electricity through both contracts and the pool. Although it is possible that the generators could refuse to participate in the contract market and earn large profits in the spot market, it is unlikely that they would choose the highest prices that they are capable of achieving. If they did, they would effectively be inviting both new entry and regulatory intervention. The generators may wish to operate in a manner analogous to limit pricing, an objective that the contract market may help them to achieve if they behave competitively in the pool and if they have sold sufficient electricity forward.

Such a possibility becomes important when considering the effects of entry. In the short run, because the residual demand curve facing the two generators is fixed, it could be hard for the generators to commit to entry deterrence, given the inherently dynamic price schedules. Facing a fixed demand curve in the medium term, they might be tempted to deviate from a limit pricing strategy to obtain higher short-run profits. If potential entrants were aware of this, they could enter until they had shifted the residual demand curve so far to the left that the generators were unable to obtain a price above the entrants' costs.

However, few potential entrants have been willing to enter the generating sector without the security of long-term contracts and hence guaranteed pool revenues. This means that the residual demand curve in the contract market could be very elastic at the level of the entrants' average costs. The generators would be unable to obtain a higher price in the contract market, and if they did not sell many contracts (signalling a high pool price), then the RECs could buy additional contract cover from entrants, who could then come in with financial security, and force the pool price down. Since the limit price for entry is above the marginal running costs of almost all the generators' present capacity, they would want to sell as much as possible at that price.

This would imply that they would do best to sell a large number of contracts, ensuring that pool price would equal the price which would exist in the absence of entry. Any attempts made by the generators to raise the price by selling fewer contracts would simply result in a lower market share at the limit price. Entry would force the price below this level and would be unprofitable until new capacity was required. This could well be an optimal outcome, giving prices at long run marginal cost, without incurring the costs of unnecessary entry.

Lucas & Taylor (1993) successfully adapt their game theoretic analysis of generator bidding strategies to include the role of contracts in determining prices. In order to achieve these results, it is necessary to assume that there are two symmetric generators and that their bid (SMP) prices range between marginal cost and twice marginal cost. Within this environment, it is shown that generators' bidding strategy is determined by the degree of contract cover.

Beginning with an elementary case both generators have contracts covering their output from 7000 MW of capacity at a contract price of £31/MWh, and there is a load (maximum demand) of 14000 MW. It is also assumed that each generator has ten 1000 MW capacity plants, the output of which is submitted for central despatch. In this situation, a Nash equilibrium is seen to result with both generators bidding at marginal cost, with the corresponding system marginal price being equal to the marginal cost of generation, i.e. the marginal cost of the most expensive plant needed to meet demand. This is shown to be in sharp contrast to the result observed when contract cover is non-existent, as in the case of the existence of contracts there is now no incentive for generators to submit high bid prices to maintain profits.

If the contract cover is reduced to 3000 MW, then generators lose their incentive to bid at marginal cost, although the contract cover still exerts an influence by limiting the generators' bid strategies. Further game simulations indicate that if one were to expect the generators to bid at marginal cost when demand exceeds the capacity of either individual generator, then the following criteria must be met. The amount of contract cover in the market must be greater than or equal to the difference between the total demand for electricity and the amount of power that can be supplied by one generator operating at full capacity. For example, with a 14000 MW load, the generators must face then at least 4000 MW of contract cover.

This approach may be extended further to the case where generators have asymmetric contract cover. If we remain with the assumption of two generators, A and B, then if A had 7000 MW of its output covered by contract and generator B did not have any of its output covered by contract and retaining a 14000 MW load, the following conclusion will occur. It is observed that Nash equilibrium are found for strategies [1,2] to [1.4,2], i.e. generator A bids from marginal cost to 1.4 times marginal cost, while generator B bids at twice marginal cost. This shows that generator A, with its high contract cover, bids low while generator B, which does not face any contract cover, bids the maximum allowable twice marginal cost. This results in a correspondingly different level of prices.

Finally, the authors extend their analysis to the case of an asymmetric game in plant distribution in order to more accurately present the system in the UK electricity supply industry at privatisation. It is assumed that generator A has twelve 1000 MW plants, all of which have their output covered under contract, while generator B has eight 1000 MW plants, only one of which has its output covered by contract. Again, the price of contracts is set at £31/MWh. In this scenario, the result is a Nash equilibrium of [1,2], corresponding to generator A bidding at marginal cost and generator B bidding at the (maximum allowable) twice marginal cost. This clearly indicates the role that the contract market can have upon the bid prices set by generators for their plants.

Despite the summary of the supply function approach detailed in Chapter IV, it is appropriate to examine this approach further, as well as the other theories put forward to explain the interactions of the pool and the electricity contract market.

2.4. Alternative approaches to the contract market.

The importance of the contract market in determining the spot price set in the pool by the generators is considerable (Helm & Powell, 1992). The models utilised to study the spot market competition are either the supply function model as shown above (Bolle, 1992 and Green & Newbery, 1992 applying Klemperer & Meyer, 1989) or the auction model (von der Fehr & Harbord, 1992). In modelling the pool as an auction, the highest quantity is bought from the bidder with the lowest price. If stochastic demand exceeds available capacity, the residual is purchased from that bidder with the highest price, with both generators being paid that price. It is shown that in equilibrium (potentially a mixed strategy equilibrium) price will exceed marginal cost unless demand is low, and that if a sufficient number of contracts are sold, the price-marginal cost mark-up will be lower.

Each model has its own advantages and disadvantages, but the supply function model is more successful in its study of the role of multi-firm competition, while suffering from the drawback of multiple equilibrium. This drawback makes it difficult to assess the exact nature of the interaction between the spot market and the contract market. Further, the supply function equilibrium is independent of the shape of the demand distribution - only the support of the distribution matters. This implies that the equilibrium is identical regardless of the skewness of the distribution. Such an implication is too strong when capacity costs are positive, and as a consequence, it may therefore be unreasonable to expect generators to maintain spare capacity in the event of highly improbable demand booms. The majority of research has focused on the supply function model, and so that model will continue to be examined here. In addition, a variant on the supply function model will also be examined. Kwok (1996) establishes a new approach to the supply function model by trying to minimise its problems.

The problems associated with the supply function model may be effectively eliminated by assuming a small positive capacity cost and ensuring that the generators choose their capacity prior to the beginning of the spot market's operation. The generators' decisions are known to one another prior to the submission of their supply functions. The fixed cost can be justified by the cost of keeping capacity available (spinning reserve), and it is also logical to assume common knowledge of capacity decisions, as announcements can be made which convey this information to competitors.

As a consequence of this capacity decision, there is only two asymmetric equilibrium which are mirror images of one another. The firm that chooses a lower capacity level reaches its capacity limit before peak demand, and neither firm holds excess capacity. The size of the market now provides feedback effects on the equilibrium, and in a move similar to the Cournot equilibrium, the incumbents reduce their supply when the market shrinks.

For reasons of expediency and simplicity, a single spot trading opportunity is assumed which eliminates the potential for strategic behaviour in the spot market, the possibility of adjustment costs in changing the level of output between successive trading periods, and the risk of regulatory intervention. It may therefore be possible to find some excess capacity equilibrium if the spot market trading frequency increases.

As with the supply function approach, the contracts are restricted to being baseload contracts, with the additional assumption of certain demand and supply thus eliminating the strategic motives for selling forward. Despite the differences in the assumptions, the same conclusions are reached as in aforementioned studies, namely that selling more output forward can result in lower spot prices. In addition, by utilising Cournot competition in the forward market, it can be seen that strategic behaviour becomes an important motive in selling forward contracts.

Green (1992) formulated the forward market competition with spot market competition in the form of supply function competition. The analysis also shows that the incumbent firms will not sell any contracts in equilibrium when the forward market is a Cournot market. Green has chosen a linear equilibrium function that is therefore independent of the maximum level of demand. As a consequence, the amount of output sold forward does not influence the behaviour of the firms in the uncovered market, and therefore Stackleberg leadership cannot be achieved by selling forward.

Kwok shows that the firms will reduce their uncovered output when the size of the uncovered market declines, as well as showing that the firm that has sold more contracts will produce less in the uncovered market. Such a firm will also choose the capacity competition equilibrium in which it does not compete in the uncovered market during periods of peak demand. Such a commitment is not present in those Cournot spot market models and constant marginal costs due to there being a unique

Cournot spot market equilibrium. It is also possible to expand the analysis to incorporate entry threats, in which case, the incumbent firms pre-empt entry by selling more contracts in order to maintain the contract price below the entry level. In addition, the entry threat weakens the links between the hedging position and the equilibrium capacity level, as there is a range of such equilibrium of hedging positions for the large and the small firm. The lower the entry price levels, the larger this range of potential equilibrium.

Newbery (1993) analyses a similar situation under different assumptions. If incumbents commit to a post-entry equilibrium rather than offering long-term contracts, they can successfully maximise profits by choosing that supply function equilibrium which results in a time-averaged price below the entry price. Also, if incumbents sell long-term contracts and can co-ordinate their actions to reach the most profitable equilibrium in the uncovered market, then they always sell sufficient output to pre-empt entry.

At this price, the equilibrium aggregate supply for the uncovered market in the model by Kwok is always lower than Newbery's, in addition to prices being more volatile. Given that prices and consumer welfare are both convex functions of demand, the equilibrium generated result in higher profits but lower consumer surplus than Newbery's model. The comparisons between these two approaches may be given as follows.

Two further models that use limit pricing are developed by Newbery. In the first model, he assumes that incumbents do not sell any contracts and can commit to a post-entry supply schedule. By co-ordinating actions to reach the supply function equilibrium under which the time averaged spot price is just below the entry level, the incumbents pre-empt all potential entry. In the second model, he assumes that the incumbents choose the symmetric supply function equilibrium for the uncovered market that maximises the uncovered profit. The incumbents then pre-empt entry by selling enough contracts to drive the time averaged spot price just below the entry level.

Kwok shows that, when the entry price is binding, the supply function model produces the highest industry profit and the lowest consumer surplus. This is best explained by the fact that the uncovered market equilibrium that results is the least competitive and, given the fact that the time-averaged price are identical across the models developed, the price spread across different periods of time is the largest. Given that profit is a convex function of demand, the higher profits over peak periods more than compensate for the lower profits over the lower demand periods. Indeed, when the entry price is low enough, there is an equilibrium in which the duopolistic generators A and B earn the same profit. This implies that there is an equilibrium in which both firms earn more than they do in Newbery's models. Therefore, if the duopolists can choose between these games, they may prefer contract competition.

Newbery also shows that capacity constraints can lead to a unique supply function equilibrium, and by manipulating these results to endogenise the capacity decision, the set of supply function equilibrium can be reduced to two asymmetric equilibrium which are mirror images of one another. This permits a study of the strategic interaction between spot and forward competition without the imposition of exogenous assumptions on the strategic effects of selling forward on spot market bidding. In equilibrium, it is shown that the smaller firm sells a larger proportion of its output forward, and in doing so not only induces its rival to reduce output as the size of the uncovered market shrinks, but it also facilitates collusion on the capacity decision.

Extending the analysis to the threat of entry, it is seen that the threat will increase the range of equilibrium hedging positions. The duopolists are seen to find it highly profitable to deter entry by selling forward rather than by limit pricing. The implication of this is that prices are more variable when firms sell contracts to pre-empt entry.

To conclude, it should be noted that there are general criticisms based around the entire usage of supply function equilibrium and its application to the electricity-generating sector. Firstly, Gray & Helm & Powell (1995) note that the supply function is assumed to be fixed throughout the day - an assumption which is partially correct as prices cannot be changed, although plant availability can. However, it has already been detailed above that changes in plant availability can influence prices, and therefore must influence the supply function. Secondly, the assumption of a single price does not fully encapsulate pool price and bid price dynamics. Finally, von der Fehr & Harbord (1993) maintain that the supply function view of equilibrium is inconsistent with the generators bidding discrete plant into the pool, and their conclusions are such that there may be no pure strategy equilibrium.

It is therefore apparent that, despite the different approaches utilised, the contract market can play an important role in determining the incentives of generators bidding into the pool. Although the variants of these models that incorporate entry threats and excess capacity are valid, it is important to note the essential similarities between the types of models. It is inappropriate to say which is the correct approach to the contract market, as each of the models has their respective merits and flaws, although the supply function model is most commonly used.

2.5. The electricity spot price.

The half-hourly spot price for electricity depends, in its simplest form, upon electricity demand, generation availability and costs, distribution network availability and losses. Electricity demand is seen as a stable variable determined by daily and seasonal factors, and may therefore be viewed as a constant. Generation availability and costs are seen as a far more important determinant of price than electricity demand, as sharp fluctuations in prices are generally caused by supply shocks, such as important plant malfunctioning rather than demand variations. Losses and availability on the transmission and distribution network are theoretically a stable function of the level of energy flowing through the system. (This is the theoretical approach to the determinants of the electricity spot price. For an examination of the determinants of the **pool price**, see the preceding chapter.)

In more specific terms, the price of electricity is a function of several variables that are not independent of one another. Firstly, fuel costs and maintenance costs, which may be classified as operating costs, representing one of the largest components of prices that is dependent upon the number of plants in operation and the amount of electricity generated. Secondly, another large component of prices are network losses, which depend both upon the amount of electricity generated, as they are an approximate quadratic function of the level of power flowing along transmission lines, as determined by physical laws.

Thirdly, network quality of supply may be classified more accurately as network quality of supply and generation quality of supply. The former refers to the network's capacity to transmit energy, and the latter the proximity of actual generation to a critical level of generation. In the case of the pool, the latter refers to the loss of load probability, while the former is linked with the possibility of overloading a transmission line. Finally, there is revenue reconciliation, which is reliant upon the belief that the utility (NGC) must remain financially neutral within the boundaries of the regulatory process.

2.6. Transactions available to pool participants.

There are generally seen as being three types of transactions which may occur within the electricity marketplace: price-only transactions, price-quantity transactions and transactions based upon long term contracts.

Price-only transactions allow the customer to purchase as much as desired at a specified price, essentially representing the system under which the pool operates (within the availability of power). Price-quantity transactions permit the customer to purchase a specified quantity at a specified price - a situation essentially similar to the long-term contracts but perhaps centred on a shorter-run perspective. As a consequence, these types of transactions may be likened to the electricity forward agreements. Long-term contracts are effectively fixed-price, fixed-quantity transactions between parties and possess the characteristics of the vesting contracts and their commercially negotiated replacements. These tools must be balanced based upon the (conflicting) objectives of achieving the greatest benefits for the utility and customers.

In undertaking these transactions, the costs faced involve the computation of prices and bills, the costs of communicating actual and anticipated prices to customers and the construction and installation of the hardware required for that task. Consumers also face the costs of purchasing the hardware themselves.

The benefits relate to the criteria of efficiency and equity, and efforts should be made to minimise cross-subsidies to customers. On a similar note, consumers should be allowed freedom of choice and the right to determine their own behaviour patterns, and should be able to understand the nature and content of the transactions they have chosen. Both the consumer and the utility should experience benefits of control, operation and planning, with the utility's function being clear and the consumer's reaction being efficient.

The role of forecasts in this system is pivotal, as the utility should be able to forecast future variations in consumer demand, while the customer should have a forecast of how prices will behave in the future. Clearly, the requirements of these forecasts and the extent to which they will prove useful depend upon the consumer. In the case of the UK electricity supply industry, consumers have been grouped into the following bands: those with annual demand greater than 1MW, those with annual demand greater than 100kW, and the residual franchise customers, i.e. those with an annual demand of less than 100kW.

Similarly within this system, consumers must choose transactions based upon the limitations of the system and the technology at their disposal. In the case of price-only transactions, the utility quotes a fixed price for energy where that quote is valid for some specified period of time. As a consequence, the customer can buy any amount of electricity at this price. A price-only transaction would require determining the frequency with which prices are actually updated.

Conceivably, the system could be one of continuous updates such as the existing pool system, but it is more probable that the pool is a system of daily updates, with the half-hourly prices published one day in advance. Indeed, it is more likely that the pool in fact represents a form of hybrid system, as the pool prices that are published represent expected and not actual pool prices. Actual pool prices will be made available during the day to those consumers with the capacity to receive them.

The system price could also be determined by setting the price for some specific billing period, with that price valid for the subsequent bill. Alternatively, the system could be modified to encompass a billing period based upon a time-of-use resulting in different rates being charged based upon the time of day. A longer term approach shows the need to specify the length of the update cycle, i.e. the period for which the prices are actually valid, as well as the specific number of prices quoted. Consider the following example (Schweppe et al, 1988, pg. 59):

$$\rho_k(t \mid \tau) : \textit{Price for kth customer at hour t defined at hour } \tau$$

In the case of the pool, there are 48 half-hourly updates, although the prices fluctuate despite the fact that they have been specified in advance. This may be clarified by means of the following example. The price for the half-hour period 0330 to 0400 is specified at 10:00 a.m. the preceding day based upon all available information at 10:00 a.m. which is collected by the NGC and processed by the GOAL algorithm. In this case, t will equal 0330 hours and the *tau* coefficient will represent 10:00 a.m..

By means of mathematical manipulation, it can be shown that (Schweppe et al, 1988, pg. 59):

$$\rho_k(t \mid \tau) = E[\rho_k(t) \mid \tau] + \textit{Covariance Term}$$

Where the first term of this statement is the conditional expectation of the spot price based upon the available information set. The expectation of the spot price is subject to some uncertainty, as measured by the covariance term. It can be shown that this component of prices is dependent upon possible variations in prices and demand against those anticipated when calculating the prices in advance. As the covariance term essentially embodies uncertainty, it increases in magnitude the further into the future that forecasts are made.

The importance of price-quantity transactions may be limited within the electricity marketplace. This is because as a market such as the pool contains thousands of consumers, each of whom has a unique usage pattern of electricity, the use of price control is more important than quantity control as a means of reducing the transactions costs and increasing benefits.

However, there is still an important role for price-quantity transactions, as they can limit transactions costs. It is more likely that the price-only and price-quantity transactions will be combined to generate a means by which the utility may modify demand on a more frequent basis. This may allow the consumer to respond to system outages provided that the regulator itself has a fast and predictable consumer response. This therefore allows price-quantity transactions to represent a means by which the consumer pledges (contracts) to a level of electricity demand that the utility has the ability to control, e.g. through supply interruptions.

These types of contract imply that the greater control is in the hands of the generator, rather than the consumer. Indeed, specific contracts may give the utility control over specific appliances belonging to the consumer, such as air conditioning and water heating which may be activated or deactivated based upon power usage within the system as a whole. This method implies that the utility must have information on the power usage of the consumer and the value of energy to the consumer at different times of day. However, it is likely that most contracts of this form will contain an escape clause whereby the consumer can override the terms of the contract at the expense of some financial penalty, i.e. failure to interrupt (FTI) charges.

Contracts (long-term and short-term) represent fixed-price, fixed-quantity transactions for specific future time intervals. Power will be supplied at the price specified in the contract for those time periods required by the contract. Given the uncertainties associated with the electricity price, it is most likely that contracts are established as a means of limiting risk exposure through hedging pool price fluctuations.

There are essentially two types of long-term contracts - futures contracts and options contracts. In the case of futures contracts, the utility does not necessarily have to be involved in the marketplace - it may simply allow a broker to conduct the transactions. Such a move would limit the utility's problems and remove the possibility of accusations that the utility was using its position to profit from the market. Electricity buyers (either final consumers or RECs) must choose the types of transactions they require and generators must choose the types of transactions they offer based upon the costs and benefits they experience as a consequence of their choices.

In the case of options contracts, the buyer purchases the right to buy at a specific time up to a fixed amount of energy at a specific price. When that time arrives, the consumer either exercises that option if the spot price is greater than the strike price (the price specified in the contract), otherwise the consumer lets the option lapse and purchases the energy directly from the spot market. In the latter situation, even if the consumer refuses the option to buy the power, the generator has still received revenue from the initial option payment.

In the case of price-only transactions, a consumer would desire this type of transaction possibly based upon the following criteria. Price-only transactions require a minimum of commercial negotiation and allow the consumer to purchase as much or as little as required. If consumers feel that they possess minimal bargaining power then this may dissuade them from establishing a contract, and relying on price-only transactions. The choice of price-only transactions does permit greater flexibility but does increase the uncertainty faced by the consumer, as they now face price fluctuations and the risk of system outages.

Generators may offer price-only transactions as a means of encouraging flexibility in the generating sector. Alternatively, the generator may lack the technical support or capacity to offer contracts, or they may merely seek to profit from the price fluctuations. In terms of price-quantity transactions and long-term contracts, the consumers gain the benefits of security of supply and price stability. It also represents a means by which the consumer may hedge against price fluctuations, as well as benefiting the consumer's consumption/production processes. In the case of the generators, these contracts represent a means by which the generator can supply power "to order", while the secured payment from option contracts reduces the generator's uncertainty and may allow for investment decisions.

The main problem with this system is that it relies upon the assumption of perfect competition within the marketplace. However, the asymmetric situation witnessed in the UK electricity supply industry has meant that the RECs may fear over-contracting their output. From a theoretical standpoint, in the case of a perfectly competitive system, increased risk of price fluctuations could well lead to increased hedging due to risk-aversion based around a desire to minimise exposure to price volatility. With RECs seeking to maintain exposure, this could place the generators in a position of dominance - not only do they have the potential to influence prices but they could also utilise the need for contracts to their advantage by establishing a monopoly position as the only sellers of contracts.

This could mean that the forward market system in this country exhibits a fundamental bias in favour of the generators, a statement that completely discounts the fact that the contract market was essentially established to provide security for the domestic industry. It is indeed likely that such a statement is true, as the RECs have made their concerns regarding the contract market apparent to the regulator, and have sought to diversify away from National Power and Powergen. It is also true to state that because of their individual size in the contract market, that the RECs do not have the same power as the larger generators, unless they were permitted to bargain collectively for contract terms. However, it is uncertain whether the generators would permit the regulator to tolerate such a monopsony situation in the market.

Throughout this review of the literature on the contract market, the role of the contract market has become increasingly apparent. It is now appropriate to turn to the main empirical study that forms the basis of this chapter.

Section III - Assessing the Validity of the Price-Demand Relationship.

3.1. The contribution of Helm & Powell

One of the most important studies into the effects that the contract market can have upon the pool is that of Helm & Powell (1992). By an analysis of pool prices from vesting until August 1991, it is shown that there was a large increase in prices without any apparent underlying structural foundation. The increase occurred on or around the 22 March 1991, coinciding with the dissolution of the first set of vesting contracts. Prior to this event, there had also been a close relationship between pool purchase prices (PPP) and electricity demand, which was severely disrupted after this event.

Helm & Powell conclude that there was a structural break that distorted the price-demand relationship, which is determined to be a long-run relationship. Having determined that both PPP and demand exhibit stationarity, the authors proceed to examine whether or not there is a stable long-run relationship between the two variables. The initial test is indicative of some uncertainty, but a subsequent test that utilises a dummy variable possessing a value of zero until 22 March 1991 and a value of unity thereafter is more successful. In this latter test, there is very strong evidence of such a long-run relationship, and it is therefore concluded that there was a relationship between these two variables that was altered in late March 1991.

A subsequent approach utilises a dynamic model of PPP and demand with an error correction format. This model should, and does, illustrate the same conclusions as the initial test by utilising a lagged format for both variables and the dummy variable. An important point that was noted was the statistical significance of the dummy variable, indicating the change to the long-run relationship. The final approach used was that of general to specific modelling to develop a model with an error correction format. The dummy variable retained its statistical significance in this model, and the error correction format was validated as accurate, despite some statistical problems.

In order to ascertain the reasons behind these conclusions, bid data obtained from the NGC was studied as a means of estimating electricity supply curves for several time periods before and after April 1991. The conclusions derived from the supply schedules indicated that the curves had been shifted upwards and to the left. The only plausible reason for this is that the bids that comprise the supply function had been increased up to or beyond competitive levels.

Gray, Helm & Powell (1995) builds on the work of Helm & Powell (1992) by extending the data set to encompass the second set of contracts for differences, as well as several other regulatory announcements, some of which are the same as those used in this study. (The econometric methodology is the same as for Helm & Powell, 1992). In addition, the authors try to isolate how these announcements affect the relationship between pool prices and demand by analysing how they change the pool price at different times of the day. Specifically, the basis of comparison is the weekly averages of the six EFA periods. The authors conclude that not only has the contract market exerted a significant influence on pool prices, but also that regulation has had a smaller than anticipated effect on prices. In addition, they conclude that the event that has had the single greatest influence on pool prices, prior to the 1994 price cap agreement, is the first pool price review - a result consistent with those in the preceding chapter.

3.2. Replicating the work of Helm & Powell

In analysing the possibility of a long-run change in the relationship between pool prices and demand, both variables in question should be stationary, as tested for by the Dickey-Fuller and the Augmented Dickey-Fuller tests. This requires the analysis of equations of the form detailed for both pool prices (2.1) and demand (2.2). For details of all subsequent equations, see Table 1.(NB. All variables are in the equations are in natural logs):

Equations (2.1) and (2.2) show the standard univariate analysis utilised in the preceding chapter for the testing of stationarity. (The *tau* coefficient represents a time trend.) In the case of pool prices, the data is stationary according to both tests, but the sequence does exhibit serial correlation as well as mild indications of an ARCH process. In the case of demand, stationarity is again attained, and although there is no indication of serial correlation, there is again the existence of ARCH, which is more pronounced than in the pool price regression.

In order to ascertain the nature of the price-demand relationship, one must regress prices on demand and analyse the residuals generated in order to see whether they are stationary. This requires the analysis of an equation possessing the static form (2.3). Stationarity is indeed present, but there is strong evidence of serial correlation and an ARCH process present in the residuals. Next a dummy variable was inserted in order to determine the impact of the break-up of the first set of vesting contracts. This dummy possessed the value of zero from the start of the observation set until 22nd March 1991, and the value of unity thereafter. This generates equation (2.4), the results of which indicate the existence of a highly significant dummy. Although the subsequent results exhibit stationarity, the existence of serial correlation and an ARCH process is again evident.

A possible complicating factor in this analysis is that there is the risk of ambiguity in assessing whether the equation under examination in both the 1992 and 1995 papers (and therefore in this work) is a demand function or a supply function - a typical question of identification. Given the technicalities associated with electricity generation, the supply curve is typically fixed, while it is demand that exhibits more short-term volatility. In the long run, the reverse is true. It is possible that over a longer-term time series that this point should be examined further, and indeed one possible way of rectifying this ambiguity is through the use of an instrumental variable. The most logical choice would be to incorporate weather conditions (through temperature) into the analysis, as temperature is correlated with demand (Wolfram, 1995) but not supply. However, temperature may indeed influence supply, as generating plant maintenance is typically seasonal and occurs in the summer. [2]

3.3. Incorporating the second set of contracts.

The analysis was then performed with a second dummy variable inserted into the regression instead of the first. This dummy – representing the break up of the second set of contracts – has the value of zero from the beginning of the data set until 31st March 1993, and the value of unity thereafter. This generates a regression of the form (2.5). In examining the results from estimating this equation, it is seen that the dummy does attain significance, although the diagnostic results are again potentially problematic. Equation (2.6) containing both dummy variables was then estimated, with the first dummy attaining significance, but the second dummy does not. Stationarity was also generated within the data set, but serial correlation and ARCH are also present. The results are presented in depth in Table 2.

As a footnote to this section of the analysis, structural break analysis was also attempted using the Chow test. However, despite the occurrence of structural breaks, the extremely poor diagnostic performance of these results limits their reliability.

Next, following the methodology of Helm & Powell's paper, a dynamic model of pool prices and demand was performed, the basic model in equation (2.7). This model was tested, as was a model with five lags of the pool price variable, five lags of the demand variable and two lags of each dummy variable. The model was re-estimated along the lines presented in Table 3, with an increasing number of variations for each lag of each variable. This approach resulted in 450 permutations of the same model with the basic format of equation (2.7). These models were evaluated using the Schwarz information criterion and the Akaike information criterion in order to derive the optimal model structure. The results are summarised in Table 3.

The optimal models are the same for each of the respective information criteria: **A30**, i.e. five price lags, five demand lags and each dummy. However, neither dummy is significant, in contrast with the long-run relationship implied above. Throughout the model evaluation process, the increased

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[2] This is one of the suggestions put forward by Andrew Powell

number of lags had a predominantly detrimental performance on the diagnostic results, with the simpler models tending to have better diagnostic performances.

Finally, again in keeping with the work of Helm & Powell, a general-to-specific approach was utilised to develop a more simplified version of the relationship using equations (2.8), (2.9) and (2.10). In the case of the individual dummies, the first (2.8) attained significance, while the second (2.9) did not. Stationarity was also attained, although an ARCH process appeared to be in effect. These results were repeated in (2.10) with both dummies present. The results are presented further in Table 2.

Variable deletion tests were performed on the regressions in order to determine the importance of the dummies. In the static regressions - as with the work of Helm & Powell - the results indicated that the first dummy could not be eliminated when it was the only one present, while the second dummy could be deleted when it was not alone in the equation. There is a theoretical rationale for this outcome: the inter-relationships between the dummies could imply that the effects of the second dummy are overshadowed by the effects of the first.

Alternatively, the second set of vesting contracts may have been smaller in magnitude and could have had a smaller effect. However, because the contracts that were terminated after the first year were franchise market contracts and covered a smaller proportion of capacity than the second set, this cannot be the case. Alternatively, it could be argued that only the first break-up generated a response from the generators, although this is inconsistent with the results obtained from the dynamic analyses that clearly indicate the significance of the two dummies. In the dynamic equations, the variable deletion test on equation (2.10) showed that both dummies could not be deleted in the long-run, potentially implying that the long-term effects of the contract break-up have been negated by subsequent price declines.

The underlying cause of the first break has already been examined in Helm & Powell's paper, and therefore there is little reason to repeat their findings. However, an analysis of the second break is necessary, and may be performed - in the absence of data on the loss of load probability (LOLP) - by using uplift levels.

LOLP is typically stable in the absence of any severe system outages and generally fluctuates only marginally (see the previous chapter for further information on uplift and the loss of load probability). Therefore, if the generators increase their bids to the pool, system marginal price (SMP, the cost of plant actually called upon to generate) will increase and therefore so will uplift (the cost of plant held in reserve). In fact, it is the bids of National Power and Powergen with which we are concerned, as they are responsible for setting price in the pool approximately 85% of the time (the NGC's pumped storage businesses set price the remaining 15% of the time).

At the time of the dissolution of the vesting contracts uplift increased by approximately sixty-five percent, and maintained this level for almost two months. Although it is possible that this was due to an increase in the loss of load probability, it is an extreme coincidence to assume that LOLP should increase at the same time as the vesting contracts expired. A further piece of evidence that supports the belief that the increase was due to the vesting contracts is an announcement from Offer: in response to the increase in pool prices and uplift levels since late March, the regulator demanded an explanation from the generators on the 24th May 1993. This led to an immediate and marked decrease in uplift levels and a corresponding decrease in prices. Rationally, if these increases were the consequence of LOLP, then they would not have declined so sharply in the face of a regulatory announcement. Although this evidence is by no means conclusive, it raises considerable questions as to the motivations of the generators.

3.4. Incorporating regulatory announcements into the Helm & Powell approach.

To further expand the use of the methodology of Helm & Powell and, as a means of integrating the structure of analysis from the first empirical chapter, we will now use the pool purchase price-demand regression to examine the events established previously. In order to retain the structure utilised within the first empirical chapter, the short-run time frame adopted there will be used here also. This analysis will require the use of the same regression as for the dissolution of contracts for differences, but with each individual dummy variable being inserted into the equation as each of the events are analysed.

$$\delta\, PPP_t = \alpha + \lambda_0 ED_t + \lambda_1 ED_{t-1} + \lambda_2 PPP_{t-1} + \lambda_3 DUMMY_{t-1} + u_t \qquad \textbf{(2.11)}$$

Table 1. Equations utilised to examine the pool price-demand relationship.

$$\Delta PPP_t = \alpha + \beta_0\tau + \beta_1 PPP_{t-1} + \beta_2 \Delta PPP_{t-1} + \beta_3 \Delta PPP_{t-2} \qquad \textbf{(2.1)}$$

$$\Delta ED_t = \alpha + \gamma_0\tau + \gamma_1 ED_{t-1} + \gamma_2 \Delta ED_{t-1} + \gamma_3 \Delta ED_{t-2} \qquad \textbf{(2.2)}$$

$$PPP_t = \alpha + \lambda ED_t \qquad \textbf{(2.3)}$$

$$PPP_t = \alpha + \lambda_0 ED_t + \lambda_1 DUMMYA_t \qquad \textbf{(2.4)}$$

$$PPP_t = \alpha + \lambda_0 ED_t + \lambda_1 DUMMYB_t \qquad \textbf{(2.5)}$$

$$PPP_t = \alpha + \lambda_0 ED_t + \lambda_1 DUMMYA_t + \lambda_2 DUMMYB_t \qquad \textbf{(2.6)}$$

$$\Delta PPP_t = \alpha + \lambda_0\tau + \lambda_1 ED_t + \lambda_2 ED_{t-1} + \lambda_3 PPP_{t-1} \qquad \textbf{(2.7)}$$

$$\Delta PPP_t = \alpha + \lambda_0\tau + \lambda_1 ED_t + \lambda_2 ED_{t-1} + \lambda_3 PPP_{t-1} + \lambda_4 DUMMYA_{t-1} \qquad \textbf{(2.8)}$$

$$\Delta PPP_t = \alpha + \lambda_0\tau + \lambda_1 ED_t + \lambda_2 ED_{t-1} + \lambda_3 PPP_{t-1} + \lambda_4 DUMMYB_{t-1} \qquad \textbf{(2.9)}$$

$$\Delta PPP_t = \alpha + \lambda_0\tau + \lambda_1 ED_t + \lambda_2 ED_{t-1} + \lambda_3 PPP_{t-1} + \lambda_4 DUMMYA_{t-1} + \lambda_5 DUMMYB_{t-1} \qquad \textbf{(2.10)}$$

Table 2. Dummy Variable Analysis from Price-Demand Regressions.

2.1. Static Pool Price-Demand Analyses.

Equation	Regressor	Dummy Sign Anticipated/Actual	Significant	Coefficient	Deletable
2.4	DUMMYA	Positive/Positive	Yes	0.22741	No
2.5	DUMMYB	Positive/Positive	Yes	0.04394	No
2.6	DUMMYA	Positive/Positive	Yes	0.22607	No
	DUMMYB	Positive/Positive	No	0.00232	Yes

2.2. Dynamic Pool Price-Demand Analyses.

Equation	Regressor	Dummy Sign Anticipated/Actual	Significant	Coefficient	Deletable
2.8	DUMMYA*	Positive/Positive	Yes	0.035358	No
2.9	DUMMYB*	Positive/Positive	No	0.014314	Yes
2.10	DUMMYA*	Positive/Positive	Yes	0.044632	No
	DUMMYB*	Positive/Positive	Yes	0.027555	No

* Indicates that dummies are lagged by one time period to retain Helm & Powell approach.

For the format of the equations listed, see Table 1.

For all of the regressions listed here, note the following information:

1. The dummy variable values were as follows:

Sample 1 - 173, DUMMYA = 0 Sample 174 - 1887, DUMMYA = 1

Sample 1 - 913, DUMMYB = 0 Sample 914 - 1887, DUMMYB = 1

For equations (2.4), (2.5), (2.6):

1887 observations were used for estimation from 1 to 1887.

For equations (2.8), (2.9), (2.10):

1886 observations were used for estimation from 2 to 1887.

Table 3. Akaike and Schwarz Information Criteria Test Results.

Section 3.1.1. Akaike Information Critera Test Results – Part I

	A	B	C	D	E	F	G
1	-3.70453	-3.70242	-3.70039	-3.70300	-3.70090	-3.69887	-3.70145
2	-3.98944	-3.98896	-3.98879	-3.98952	-3.98905	-3.98888	-3.98957
3	-3.99023	-3.98975	-3.98954	-3.99032	-3.98984	-3.98962	-3.99032
4	-3.99051	-3.99003	-3.98981	-3.99059	-3.99006	-3.98981	-3.99059
5	-3.99066	-3.99017	-3.98996	-3.99073	-3.99021	-3.99068	-3.99374
6	-3.99249	-3.99200	-3.99185	-3.99256	-3.99207	-3.99192	-3.99256
7	-3.70366	-3.70156	-3.69950	-3.70214	-3.70004	-3.69797	-3.70056
8	-3.98851	-3.98803	-3.98783	-3.98860	-3.98812	-3.98791	-3.98860
9	-3.98879	-3.98831	-3.98810	-3.98888	-3.98840	-3.98819	-3.98888
10	-3.98911	-3.98863	-3.98842	-3.98919	-3.98871	-3.98850	-3.98920
11	-3.98925	-3.98877	-3.98856	-3.98933	-3.98885	-3.98864	-3.98934
12	-3.99111	-3.99062	-3.99047	-3.99118	-3.99069	-3.99054	-3.99118
13	-3.73176	-3.72963	-3.72756	-3.73024	-3.72811	-3.72603	-3.72841
14	-4.01877	-4.01827	-4.01807	-4.01887	-4.01838	-4.01817	-4.01862
15	-4.01880	-4.01831	-4.01811	-4.01891	-4.01841	-4.01821	-4.01891
16	-4.02681	-4.02632	-4.02615	-4.02697	-4.02648	-4.02631	-4.02697
17	-4.02721	-4.02673	-4.02655	-4.02736	-4.02688	-4.02671	-4.02737
18	-4.02982	-4.02933	-4.02924	-4.02995	-4.02946	-4.02937	-4.02996
19	-3.74108	-3.73895	-3.73685	-3.73988	-3.73742	-3.73533	-3.73796
20	-4.02880	-4.02831	-4.02809	-4.02926	-4.02842	-4.02820	-4.02891
21	-4.02881	-4.02833	-4.02811	-4.02892	-4.02843	-4.02821	-4.02893
22	-4.03975	-4.03926	-4.03907	-4.03992	-4.03943	-4.03925	-4.03993
23	-4.04311	-4.04259	-4.04242	-4.04329	-4.04278	-4.04260	-4.04332
24	-4.04706	-4.04654	-4.04647	-4.04722	-4.04670	-4.04663	-4.04724
25	-3.76911	-3.76697	-3.76488	-3.76756	-3.76542	-3.76333	-3.76595
26	-4.05899	-4.05850	-4.05830	-4.05908	-4.05859	-4.05839	-4.05909
27	-4.05899	-4.05850	-4.05830	-4.05908	-4.05859	-4.05839	-4.05909
28	-4.06882	-4.06833	-4.06817	-4.06893	-4.06845	-4.06829	-4.06897
29	-4.07598	-4.07545	-4.07530	-4.07613	-4.07561	-4.07545	-4.07617
30	-4.07821	-4.07769	-4.07745	-4.07838	-4.07786	-4.07762	-4.07842

For information on codes, see Section 3.3.

Section 3.1.2. Akaike Information Critera Test Results – Part II

	H	I	J	K	L	M	N	O
1	-3.69934	-3.69727	-3.70608	-3.70612	-3.70609	-3.69589	-3.69587	-3.69585
2	-3.98909	-3.98888	-3.98941	-3.98930	-3.98929	-3.98653	-3.98651	-3.98648
3	-3.98984	-3.98963	-3.99021	-3.99009	-3.99005	-3.98712	-3.98997	-3.98706
4	-3.99011	-3.98989	-3.99049	-3.99037	-3.99033	-3.98733	-3.98732	-3.98728
5	-3.99622	-3.99004	-3.99064	-3.99052	-3.99047	-3.98745	-3.98743	-3.98739
6	-3.99207	-3.99192	-3.99247	-3.99236	-3.99232	-3.98931	-3.98930	-3.98926
7	-3.69845	-3.69638	-3.70522	-3.70526	-3.70520	-3.69508	-3.69507	-3.69503
8	-3.98812	-3.98792	-3.98849	-3.98838	-3.98833	-3.98565	-3.98564	-3.98560
9	-3.98840	-3.98820	-3.98877	-3.98866	-3.98861	-3.98580	-3.98578	-3.98574
10	-3.98871	-3.98850	-3.98909	-3.98898	-3.98894	-3.98606	-3.98604	-3.98601
11	-3.98885	-3.98864	-3.99111	-3.99109	-3.99098	-3.99093	-3.98806	-3.98804
12	-3.99069	-3.99054	-3.99109	-3.99099	-3.99094	-3.98805	-3.98803	-3.98799
13	-3.72620	-3.72346	-3.73334	-3.73338	-3.73332	-3.72348	-3.72347	-3.72344
14	-4.01805	-4.01713	-4.01875	-4.01864	-4.01860	-4.01629	-4.01627	-4.01624
15	-4.01842	-4.01822	-4.01879	-4.01868	-4.01864	-4.01640	-4.01639	-4.01635
16	-4.02648	-4.02631	-4.02679	-4.02668	-4.02665	-4.02497	-4.02496	-4.02492
17	-4.02689	-4.02671	-4.02719	-4.02707	-4.02704	-4.02525	-4.02523	-4.02520
18	-4.02947	-4.02938	-4.02980	-4.02968	-4.02966	-4.02786	-4.02785	-4.02781
19	-3.73582	-3.73372	-3.74266	-3.74271	-3.74265	-3.73286	-3.73285	-3.73282
20	-4.02842	-4.02821	-4.02879	-4.02868	-4.02864	-4.02641	-4.02639	-4.02636
21	-4.02844	-4.02822	-4.02881	-4.02869	-4.02865	-4.02648	-4.02646	-4.02643
22	-4.03944	-4.03926	-4.03973	-4.03961	-4.03958	-4.03806	-4.03805	-4.03802
23	-4.04280	-4.04262	-4.04309	-4.04299	-4.04295	-4.04172	-4.04172	-4.04169
24	-4.04671	-4.04665	-4.04705	-4.04695	-4.04691	-4.04566	-4.04565	-4.04562
25	-3.76381	-3.76171	-3.77071	-3.77077	-3.77071	-3.76119	-3.76118	-3.76116
26	-4.05860	-4.05840	-4.05898	-4.05889	-4.05885	-4.05697	-4.05695	-4.05693
27	-4.05860	-4.05840	-4.05898	-4.05889	-4.05885	-4.05699	-4.05698	-4.05695
28	-4.06849	-4.06833	-4.06880	-4.06871	-4.06868	-4.06739	-4.06738	-4.06735
29	-4.07564	-4.07549	-4.07596	-4.07588	-4.07584	-4.07495	-4.07494	-4.07491
30	-4.07790	-4.07766	-4.07819	-4.07812	-4.07807	-4.07731	-4.07730	-4.07728

Objective: Minimise Akaike Information Criteria

Optimal Regression: A30

For information on codes, see Section 3.3.

Section 3.2.1.Schwarz Information Critera Test Results – Part I

	A	B	C	D	E	F	G
1	-3.67741	-3.67235	-3.66737	-3.67294	-3.66789	-3.66290	-3.66846
2	-3.98650	-3.98602	-3.98585	-3.98658	-3.98611	-3.98593	-3.98663
3	-3.98729	-3.98681	-3.98660	-3.98738	-3.98689	-3.98668	-3.98738
4	-3.98757	-3.98708	-3.98687	-3.98765	-3.98712	-3.98687	-3.98765
5	-3.98772	-3.98723	-3.98702	-3.98779	-3.98727	-3.98774	-3.99080
6	-3.98955	-3.98906	-3.98891	-3.98962	-3.98913	-3.98898	-3.98962
7	-3.67383	-3.66878	-3.66377	-3.66938	-3.66432	-3.65931	-3.66486
8	-3.98263	-3.98215	-3.98194	-3.98271	-3.98223	-3.98203	-3.98272
9	-3.98291	-3.98243	-3.98222	-3.98300	-3.98252	-3.98230	-3.98300
10	-3.98323	-3.98275	-3.98253	-3.98331	-3.98283	-3.98261	-3.98331
11	-3.98337	-3.98289	-3.98267	-3.98345	-3.98297	-3.98275	-3.98345
12	-3.98523	-3.98474	-3.98458	-3.98530	-3.98480	-3.98465	-3.98530
13	-3.69903	-3.69393	-3.68889	-3.69456	-3.68946	-3.68440	-3.68977
14	-4.00994	-4.00944	-4.00924	-4.01004	-4.00955	-4.00934	-4.00979
15	-4.00997	-4.00948	-4.00927	-4.01008	-4.00958	-4.00937	-4.01008
16	-4.01798	-4.01749	-4.01731	-4.01814	-4.01765	-4.01747	-4.01814
17	-4.01838	-4.01790	-4.01772	-4.01854	-4.01805	-4.01787	-4.01854
18	-4.02099	-4.02049	-4.02040	-4.02113	-4.02063	-4.02054	-4.02113
19	-3.70556	-3.70046	-3.69539	-3.70141	-3.69598	-3.69090	-3.69653
20	-4.01702	-4.01653	-4.01631	-4.01748	-4.01664	-4.01641	-4.01714
21	-4.01704	-4.01655	-4.01632	-4.01715	-4.01665	-4.01643	-4.01716
22	-4.02797	-4.02748	-4.02729	-4.02814	-4.02765	-4.02746	-4.02815
23	-4.03134	-4.03081	-4.03063	-4.03152	-4.03100	-4.03081	-4.03154
24	-4.03529	-4.03476	-4.03469	-4.03545	-4.03492	-4.03485	-4.03547
25	-3.73069	-3.72556	-3.72047	-3.72617	-3.72103	-3.71594	-3.72158
26	-4.04426	-4.04377	-4.04357	-4.04435	-4.04386	-4.04366	-4.04436
27	-4.04426	-4.04377	-4.04357	-4.04435	-4.04386	-4.04366	-4.04436
28	-4.05409	-4.05360	-4.05343	-4.05421	-4.05372	-4.05355	-4.05425
29	-4.06125	-4.06072	-4.06056	-4.06141	-4.06088	-4.06072	-4.06144
30	-4.06348	-4.06296	-4.06271	-4.06366	-4.06313	-4.06288	-4.06370

For information on codes, see Section 3.3.

Section 3.2.1.Schwarz Information Critera Test Results – Part II

	H	I	J	K	L	M	N	O
1	-3.66339	-3.65836	-3.68189	-3.68194	-3.68190	-3.67168	-3.67167	-3.67164
2	-3.98615	-3.98594	-3.98647	-3.98636	-3.98635	-3.98359	-3.98357	-3.98354
3	-3.98690	-3.98669	-3.98727	-3.98715	-3.98711	-3.98418	-3.98703	-3.98412
4	-3.98717	-3.98695	-3.98755	-3.98743	-3.98739	-3.98439	-3.98438	-3.98434
5	-3.99328	-3.98710	-3.98770	-3.98758	-3.98753	-3.98451	-3.98449	-3.98445
6	-3.98913	-3.98898	-3.98953	-3.98942	-3.98938	-3.98637	-3.98636	-3.98632
7	-3.65980	-3.65477	-3.67832	-3.67836	-3.67830	-3.66817	-3.66815	-3.66812
8	-3.98224	-3.98203	-3.98260	-3.98249	-3.98245	-3.97977	-3.97976	-3.97972
9	-3.98252	-3.98231	-3.98289	-3.98277	-3.98273	-3.97992	-3.97990	-3.97986
10	-3.98283	-3.98261	-3.98321	-3.98310	-3.98305	-3.98018	-3.98016	-3.98012
11	-3.98297	-3.98275	-3.98523	-3.98521	-3.98509	-3.98505	-3.98218	-3.98216
12	-3.98481	-3.98466	-3.98521	-3.98510	-3.98506	-3.98217	-3.98215	-3.98211
13	-3.68459	-3.67888	-3.70355	-3.70360	-3.70354	-3.69368	-3.69367	-3.69364
14	-4.00922	-4.00830	-4.00992	-4.00981	-4.00978	-4.00746	-4.00745	-4.00741
15	-4.00959	-4.00938	-4.00996	-4.00985	-4.00981	-4.00757	-4.00756	-4.00753
16	-4.01765	-4.01748	-4.01796	-4.01785	-4.01782	-4.01614	-4.01613	-4.01610
17	-4.01806	-4.01788	-4.01836	-4.01824	-4.01821	-4.01642	-4.01640	-4.01637
18	-4.02064	-4.02054	-4.02097	-4.02086	-4.02083	-4.01903	-4.01902	-4.01898
19	-3.69142	-3.68634	-3.71010	-3.71015	-3.71009	-3.70030	-3.70028	-3.70025
20	-4.01664	-4.01642	-4.01702	-4.01690	-4.01686	-4.01463	-4.01462	-4.01458
21	-4.01666	-4.01644	-4.01703	-4.01692	-4.01688	-4.01470	-4.01469	-4.01466
22	-4.02766	-4.02747	-4.02795	-4.02784	-4.02781	-4.02629	-4.02628	-4.02625
23	-4.03102	-4.03083	-4.03132	-4.03121	-4.03117	-4.02995	-4.02994	-4.02991
24	-4.03493	-4.03487	-4.03527	-4.03517	-4.03513	-4.03388	-4.03388	-4.03385
25	-3.71644	-3.71134	-3.73526	-3.73532	-3.73526	-3.72575	-3.72573	-3.72571
26	-4.04387	-4.04367	-4.04426	-4.04416	-4.04412	-4.04224	-4.04223	-4.04220
27	-4.04387	-4.04367	-4.04426	-4.04417	-4.04413	-4.04227	-4.04225	-4.04223
28	-4.05376	-4.05359	-4.05408	-4.05398	-4.05395	-4.05267	-4.05266	-4.05263
29	-4.06091	-4.06075	-4.06124	-4.06116	-4.06111	-4.06022	-4.06021	-4.06019
30	-4.06317	-4.06292	-4.06347	-4.06339	-4.06335	-4.06259	-4.06258	-4.06256

Objective: Minimise Schwarz Information Criteria

Optimal Regression: A30

For information on codes, see Section 3.3.

Section 3.3. Codes used for Sections 3.1. and 3.2.

Part I: Letter Codes

Dual dummy regressions

	D2	D2(-1)	D2(-2)
D1	A	B	C
D1(-1)	D	E	F
D2(-2)	G	H	I

Single dummy regressions

D1	J	D2	M
D1(-1)	K	D2(-1)	N
D2(-2)	L	D2(-2)	O

Part II: Number Codes

	DEMAND	DEMAND(-1)	DEMAND(-2)	DEMAND(-3)	DEMAND(-4)	DEMAND(-5)
PRICE(-1)	1	2	3	4	5	6
PRICE(-2)	7	8	9	10	11	12
PRICE(-3)	13	14	15	16	17	18
PRICE(-4)	19	20	21	22	23	24
PRICE(-5)	25	26	27	28	29	30

For example, Regression A30 has both dummy variables, each without lags, and five lags each of the price and demand variables.

3.5. The results of the analyses.

The first regression maintains the significance of the dummy representing the break-up of the first set of contracts for differences. The presence of this dummy is again seen as valid by means of the variable deletion test. The second regression, representing the beginning of the price spikes, does not attain significance. This is not as expected, as one would have anticipated the size of the spikes to have disrupted the relationship between pool prices and demand. However, the dummy fails to attain significance and may be successful deleted. The third regression, representing the announcement of the first pool price review did manage to attain significance, and its presence was seen to be required by the variable deletion test. This is not surprising, given the importance of this event in the earlier analysis and Gray, Helm & Powell (1995).

The fourth regression again generated a negative significant dummy, representing the publishing of the first pool price review. The variable deletion test again validated the presence of the dummy. The fifth dummy, representing a threat of an MMC reference for the generators, did not attain significance and its presence was again seen as unnecessary by the variable deletion test. The sixth dummy, that of the announcement of the second pool price review, also failed to attain significance and its presence was again rejected by the variable deletion test.

The seventh regression, containing the dummy for the publishing of the second pool price review, did generated the anticipated negative significant dummy. The presence of the dummy was also required by the variable deletion test. Significance was also attained by the dummy for the eighth regression, that of the break-up of the second set of contracts for differences. The presence of the dummy variable was again seen as necessary, as given by the variable deletion test. The ninth regression, containing the dummy for another threat of an MMC reference failed to achieve significance, as for the previous MMC threat.

The tenth and eleventh regressions, both of which represented further threats of MMC references, also failed to attain significance, and the presence of dummy variables in these regressions was not required. However, the twelfth regression - that of the price agreement between the regulator and the generators - did produce a negative significant dummy variable, and was accepted by the variable deletion test. The remaining regressions produced a similar response to that observed in the first empirical chapter, namely a series of insignificant dummies, with the exception of the February 1995 MMC reference. This should not be surprising due to these events being largely financial events.

This therefore leaves us with seven occasions on which a dummy variable gained significance as a consequence of some form of exogenous influence on the pool. The results are shown in Table 4 and may be summarised as follows.

- **Dummy 1:** Break-up of first set of CFDs
- **Dummy 3:** First pool price review begins with MMC threat
- **Dummy 4:** First pool price review published
- **Dummy 7:** Second pool price review published
- **Dummy 8** Break-up of second set of CFDs
- **Dummy 12:**National Power and Powergen establish price agreement
- **Dummy 14:** MMC reference threatened over plant sales

It should not be surprising that the break-up of the contracts for differences should generate positive significant dummies. This is because their significance over the entire three and a half-year period was already justified in the preceding section. The effect of the announcement of the first pool price review and with it the first occasion on which the generators faced an MMC reference has already been detailed in the preceding chapter. The publishing of the first and second pool price reviews brought with them pricing restrictions for the generators, and therefore the dummies' significance is not entirely unexpected. The same logic is true of the establishment of the price agreement between the generators and the regulator.

However, the key question linked to this section of the analysis still remains, as it did throughout the preceding chapter, namely the impact (or lack thereof) of the threat of an MMC reference. On the basis of this analysis, we could conclude that only the first occasion that an MMC reference was threatened did it have any effect on the generators. This announcement led to a disruption of the relationship between pool prices and demand in such a manner that prices declined to the benefit of the consumer. However, all subsequent threats (with the exception of that in February 1995) did not have any effect on the pool purchase price-demand relationship because the generators did not believe that it would be carried out. This would be a logical conclusion based upon the view of credible and incredible threats dictated by game theory analysis.

Table 4. Additional Price-Demand Regressions.

Event	DUMMY SIGN Anticipated/Actual	Significant	Coefficient	"Deletable"
1	Positive/Positive	Yes	0.0432070	No
2	Positive/Positive	No	0.0026414	Yes
3	Negative/Negative	Yes	-0.1503100	No
4	Negative/Negative	Yes	-0.1106100	No
5	Negative/Positive	No	0.0064264	Yes
6	Negative/Positive	No	0.0089321	Yes
7	Negative/Negative	Yes	-0.0449300	No
8	Positive/Positive	Yes	0.0751560	No
9	Negative/Negative	No	-0.0040639	Yes
10	Negative/Negative	No	-0.0150070	Yes
11	Negative/Negative	No	-0.0254490	Yes
12	Negative/Negative	Yes	-0.0734350	No
13	Unknown /Negative	No	-0.0318250	Yes
14	Negative/Negative	Yes	-0.1725000	No
15	Unknown /Negative	No	-0.0129170	Yes
16	Negative/Negative	No	-0.0262490	Yes
17	Unknown /Negative	No	-0.0106210	Yes
18	Negative/Negative	No	-0.0082587	Yes
19	Unknown /Positive	No	0.0012090	Yes
20	Negative/Negative	No	-0.0231130	Yes
21	Negative/Negative	No	-0.0436960	Yes
22	Negative/Positive	No	0.0023674	Yes
23	Negative/Positive	No	0.0882920	Yes

Section IV - Conclusions.

This study revisits the work of Helm & Powell in their groundbreaking study on the nature of interactions between the two markets for electricity, with the conclusions reached here reinforcing their results.

It is apparent that, based upon the evidence, the market for electricity contracts serves an important purpose, not only in the functioning of the electricity-generating sector, but also in the functioning of the pool. Although the pool is subject to considerable regulation by Offer, there is no **direct** regulation of the market for contracts, but the same broad regulatory announcements and rulings as the pool doubtless affect it. However, based upon these analyses, it is clear that more interest should be taken in the contract market as it is apparent that it does play an important role in determining pool prices.

The key results of this study are the same as those of Helm & Powell, with the only contradiction being the relative importance of the break-up of the first set of contracts. In their analysis, the dummy representing that event could not be successfully deleted, which is not the case here. However, this is by no means a flaw in their reasoning, and could be attributed to their smaller data set. Unfortunately, in addition to this analysis supporting the conclusions of Helm & Powell, it also bears some of its flaws: namely the poor diagnostic performance which those authors determined could affect the reliability of their results.

The success of the analysis to show the impact of contracts on the pool has also been supported by the results of the additional studies that show how the events selected for the previous chapter influence the price-demand relationship. This is in the case of both the standard and the non-standard relationships. The diagnostic performance of the regressions is not ideal, but autocorrelation in prices is due to the inevitability of pool price trends, while non-normality of residuals is due to the fact that the price distribution will be both skewed and truncated.

The vesting contracts themselves were established in three blocks. QUICS (Qualifying Industrial Customers' Scheme) that were nuclear backed and were dropped after one year; capacity compensation contracts that were designed to give National Power and Powergen incentives to close plant, and were therefore often plant specific; and the coal-backed CFDs designed to provide compensation to British Coal. It is possible that prices rose in the years after the contract dissolution as contract premia fell away and generators had to maintain profits. However, the CFDs themselves remain important transitional arrangements in the privatisation process.

It is possible that a full study of the contract market could be undertaken, were the required empirical data available. However, as long as the electricity companies demand commercial sensitivity of their contract information, such an analysis cannot be carried out. This is unfortunately a problem that will not be rectified until the regulator ensures disclosure of contract information from all parties in question. However, it is theoretically possible to establish general estimates of the strike prices of contracts, as based upon information published to date by Offer, the generators, and the RECs. Specifically, the fourth empirical chapter (Chapter VIII) will contain analyses based upon a data set that has been created to proxy the strike prices of the vesting contracts. This was achieved by the manipulation of the Horton IV estimates to establish a data set that corresponds to the pool price observations for the analysis period in question. This work will be contrasted with an empirical evaluation of the American electricity contract market using actual electricity forecast prices and the relevant spot prices for both peak and off-peak periods. It is hoped therefore, that subsequent analyses in this work will allow the determination of the nature (if any) of the interrelationships between the spot and forward markets for electricity.

CHAPTER VII: Electricity Regulation and the Stock Market - Contents.

Section I - Regulation and share returns.

1.1. The effects of regulation on returns.

As noted above, it is hypothesised that regulation will have an impact on the share returns of a regulated company. However, there are three frameworks that can be used to interpret the nature of regulation (Antoniou, Batty & Pescetto, 1995). Firstly, the public interest theory of regulation, under which regulation exists to counter potential detrimental consequences of the conduct of privatised utilities: the existence of monopoly power and the potential for externalities in supply. The former arises as a consequence of the fact that privatised utilities are typically large companies with considerable market power in an industry with few viable competitors. Such a structure often arises from economies of scale and/or scope, and with the possibility of monopoly power, underproduction and higher prices compared to a similar firm in a less concentrated market structure. The latter case of supply externalities could also be seen as consistent with underproduction vis-à-vis the socially optimal output level. In this case, regulation is aimed at restricting the exploitation of consumers and the exertion of the company's power. As such, regulation should result in a decline in the share price(s) of the regulated company (ies).

Secondly, the regulatory capture hypothesis (Stigler, 1971; Peltzman, 1976, 1984; Posner, 1974) argues that "it is in the private interest of a vote-maximising government to allow regulatory programmes to reflect the interests of powerful electoral groups, usually associated with industry interests," (Dnes & Seaton, 1995, pg. 3). Capture occurs when the regulator effectively becomes the firm's advocate - intentionally or not. For example, if the incumbent could persuade the regulator that it would be appropriate to restrict entry, then the incumbent would be allowed to maintain its position in the industry, which could result in the exploitation of consumers. Alternatively, the regulator could be persuaded to institute a price control system that allowed the firm to maintain high prices and profits. In either case, regulation helps the incumbent firm(s) to retain monopoly power, and potentially to harm consumers. Regulatory decisions would then ultimately influence share prices.

Finally, regulators could be operating in an attempt to maximise their own utility at the expense of both consumers and producers. In this case, regulators' objectives could be to increase their power and prove their worth. In such an environment, regulatory activity would be based around the need to be seen as useful rather than economic and social considerations. In this environment, regulation would influence share prices.

1.2. Studies into regulation and share returns.

Financial markets studies into the effects of regulation are quite common, with Schwert (1981) and Binder (1985a) providing notable early examples of these. Schwert (1981) notes that stock price data are highly useful in assessing the effects of regulation on companies when compared to other types of data, such as accounting data. Stock price data are seen as being more accurate than accounting data, and typically provide a higher number of observations with greater frequency. However, Binder (1985a) notes that regulatory event studies are prone to some additional difficulty, *vis-à-vis* standard event studies.

Firstly, unlike events such as the announcement of economic indicators, it is not always apparent exactly when expectations of regulation change. While there is a defined release date of the announcement from the regulator, the companies in the industry are typically made aware of an event prior to its release.

Secondly, it is not always the case that regulatory announcements have distinct positive or negative effects. Specifically, the effects of the same event may be asymmetric across a group of firms: some may gain and others may lose (see below).

As noted in the introduction, these types of studies have been most commonly performed using US data. A brief summary of such studies is provided in the next section, with the subsequent section examining UK studies.

1.2.1. American studies - A brief overview.

A range of models has been utilised to assess the impact of regulation on share returns for US companies. Schwert (1980) provides a detailed summary of such studies that rely upon such methods as the efficient markets hypothesis, the capital asset pricing model (CAPM), and cross-sectional models. As US regulatory structures have focused upon rates of return, many studies have relied upon examinations of the cost of capital and a comparison between the rate of return for regulated companies and the rate of return for either unregulated companies or the market as a whole. Such studies have relied upon a mixture of accounting and stock price information, and a variety of different methods, although the market model is one of the most common techniques. This can be attributed to its simplicity, yet its capacity to show clearly whether the profitability (returns) of an individual company exceed the market average (see below).

In order to examine how different forms of regulation affect firms' profitability, Stigler & Friedland (1962) tested for the presence of abnormal returns in the shares of twenty electric utilities in thirty-two US states, each of which regulated electricity prices directly between 1907 and 1920. This involved estimating the returns to common stocks as a means of examining the impact of regulatory change. The results of the study indicated that there was no difference between the regulated and unregulated utilities, implying that the regulation had no effect on the regulated companies. However, Schwert (1980) argues that this could be a false result as the averaging process used over the thirteen-year period could have masked the consequences of the event itself.

One of the most notable examples of a study that assesses how regulation affects different firms at different times utilises litigation as its basis. Ellert (1975) uses anti-trust legislation and violations over the period 1953-1971, incorporating the actions of the Justice Department, the Federal Trade Commission and private parties. Through an examination of the date on which the complaint was registered, the date of the initial decision, and the completion of a settlement, it is concluded that the actions of the Justice Department have the greatest impact on the offending firms. Schwert (1977) examines the effects of the actions of the Securities and Exchange Commission (SEC) on New York and American Stock Exchange membership prices. As membership is in the form of a seat on the exchanges, the price of these seats should be determined by the profitability of the activities in the exchanges. Schwert determines that the seat prices on both exchanges fell sharply in March 1934 - corresponding with the occasion on which the 1934 Securities and Exchanges Act was debated in Congress. It is also noted that seat prices on the New York exchange fell sharply when the SEC enforced reduced brokerage commissions on the exchange over the period 1968-1975.

Finally, in assessing the asymmetric nature of the effects of same announcement on different firms, Binder (1985a) notes that the 1973 and 1974 deregulation of the brokerage and railroad industries was both welcomed and objected to by different sections of the same industry. James (1982) shows that bank deregulation benefited wholesale banks, but harmed commercial banks. Binder (1985a) assesses the impact of a series of twenty regulatory announcements across different industries using both monthly and daily event windows. The industries under examination are railroad, electric utilities, banking, telecommunications, airlines, motor vehicles, gas, pharmaceuticals and textiles. Of the twenty events, twelve concerns either prices and/or entry, three are concerned with environmental issues, and one nationalised an industry. Although the events were chosen based upon the fact that they had been used previous studies and had been shown to exert an influence in those studies, the results generated by Binder (1985a) are somewhat mixed and are attributed to the difficulties associated with determining the timing of that event.

A more recent study is Teets (1992) in which the relationship between unexpected earnings and abnormal returns is assessed for a series of regulated electric utilities and a random sample of non-regulated firms. This article stresses the role of information flows on expectations through the analysis of rate of return regulation and the extent of the regulatory lag. It is argued that while competition could compete away excess returns for non-regulated firms in a relatively short period of time, the extent of regulatory lag serves to benefit regulated companies - in essence, the regulators effectively protect the companies under their jurisdiction from changes in the industry. Through the identification of a series of non-regulated firms based upon a previous study (Brown, Hagerman, Griffin & Zmijewski, 1987), and their comparison with the results for a group of regulated electricity utilities through the market model, it is concluded that the results are consistent with the author's hypothesis that the regulators serve to insulate firms from changes in their environment.

1.2.2. UK studies - A brief overview.

The history of investor-owned regulated utilities is more widespread in the US than in the UK, although this summary indicates the broad nature of the studies that have been undertaken. However, there are two studies of note in relation to this work: Dnes & Seaton (1995), and Antoniou, Batty & Pescetto (1995). The former article examines the behaviour of the share prices of the twelve Regional Electricity Companies (RECs) in response to sixty-seven events - both regulatory and non-regulatory - using a variant of the market model. As the market model requires an index against which to base the analysis of the company's share returns - with the event itself present as a dummy variable, the authors deem the Financial Times 100-Share Index as the most appropriate market index. (They do, however, make some modifications to it in order to compare the returns of the RECs against those of telecommunications companies). In addition, through experimentation, they determine that the most appropriate dummy event window for the analysis is -1 to +2 days around the event. The authors conclude that regulatory events most commonly produce significant dummies, e.g. DGES announcements on prices, the announcement and/or publication of price reviews, and the threat of an MMC reference. This result is attributed to the continued, active use of regulation and the lack of regulatory capture. However, the main objective of this study is an attempt to prove or disprove the existence of capture - a result which is disproved, as the RECs are seen to exhibit share returns not dissimilar to those of the FT-100. It should also be noted that of the sixty-seven events, twenty-two produce significant dummies at either the 5% or 10% level of significance: a rate of approximately one-third.

Antoniou, Batty & Pescetto (1995) undertake a similar study, but their analysis focuses upon the post-privatisation telecommunications industry by examining the impact of a series of events upon the share price of BT. In addition to attempting to determine whether the events produce significant dummies within the extended market model (see below), they also examine whether the event creates greater volatility in share prices through the use of TOBIT maximum likelihood regression analysis. Here, the FT All Share Index is utilised as the base index for market returns, while there are a total of 134 events, and the dummy variable window is three days (the day prior to, the day of, and the day after the event). Of these events, thirty-seven produce statistically significant dummy variables in the market model (twenty-eight percent), thirty-two produce significant dummies to indicate greater volatility (twenty-four percent), with twenty-three events producing both (seventeen percent). The main conclusions noted from this study are that while certain announcements have influenced both returns and volatility, actually predicting the consequences of certain events is difficult. Furthermore, events, which produce either a decline in prices or greater competition, do not always have a negative influence on returns.

I.3. Objectives and the structure of the chapter.

The ultimate objective of this analysis is to assess the impact of a series of announcements (both regulatory and non-regulatory) on the share prices and hence returns of National Power and Powergen, two companies chosen for their dominance of the electricity pool. Utilising these two companies permits an analysis of the broader consequences of the impact of certain events, both within the pool and in the perceptions of the profitability and risk of operating in the pool.

Due to the continued focus upon regulatory announcements (broken down into "competition" and "price" events, as discussed below), the following hypothesis may be stated. As the release of a new announcement from the regulator is typically concerned with the prospect of tighter or wider-ranging regulation, then such an announcement will lead to a decline in share returns, producing a negative coefficient on the dummy variable representing that event.

Although the majority of the events (two-thirds) under examination are regulatory, the remaining events are those that could have led to regulatory intervention (such as pool price rises); or could have led to greater uncertainty in the industry (mergers and take-overs of RECs). Alternatively, they could have an expected outcome based upon financial markets theory (generators' attempts to take over RECs should produce a certain response based upon the announcement effect). As such, it is hypothesised that the majority of events should produce results indicative of regulation influencing generators' share returns.

As the events may be grouped, it is possible to use these groupings to examine whether a certain type of event has a specific effect consistent across the group. If this is valid, it may enable a classification through which a limited degree of forecasting may be possible. The use of the market model is such that the analysis does not test for changes in the perceptions of risk associated with the generators' shares after an announcement, but rather the absolute changes in returns following an announcement.

Due to the closeness of some of the events, and the need to prevent overlapping of the analysis periods, a fifty-day analysis window was used. This was necessary because to ignore the problem would result in considerable difficulty in interpreting the results, as well as ultimately limiting their usefulness. The choice of a fifty-day analysis period is based upon the assumption that regulatory announcements will have a transitory, not a permanent effect on share returns. Of course, this is not to say that all regulatory events are only transitory in their impact, as it is possible that events could lead to the expectation of tighter regulation for the foreseeable future.

SECTION II - Data Selection and Methodology.

2.1. The market model.

The share price of a particular company should vary with the amount of information available about, and the expectations associated with, that company and the economy as a whole. In the case of this analysis, we are concerned only with information pertaining to the company itself, the industry in which that company operates, and the regulation of that industry. Given the assumption of an information set, changes in the share price are dictated by changes in the contents of that information set. It is in this way that the dummy variables are used in this model - they capture the release of new information and its incorporation into that information set.

The market model itself takes the following basic form:

$$R_{it} = a + bR_{mt} + u_t \tag{3.1}$$

R_{it} is the return (first difference of share price) on asset i at time t, R_{mt} is the return on market index m at time t, *and* u_t is the normally, independently distributed disturbance term. All variables in this and subsequent equations are in logs.

In examining the performance of the two companies, i will refer to NP and PG (in different estimations, of course), and m will refer to the FT-100.

The market model therefore states that the return on a particular asset is some percentage of the return on the market as a whole (the parameter, b). If this parameter is greater than unity, then the return on the asset varies more than that on the market as a whole, with the reverse being true if the parameter is less than unity.

In order to assess how a particular event influences the parameters of the equation, one may insert a dummy variable to represent the event and ascertain whether the resulting coefficient was significant over the required time period. As with the previous chapters, the dummy retains the value of zero until the event, and the value of unity thereafter and is used to assess the existence of abnormal movements in the variables in question: a positive dummy indicating an increase in share returns, with the reverse being true for a negative dummy. This produces the equation:

$$R_{it} = a + b\,R_{mt} + \gamma\ DUMMY_t + u_t \tag{3.2}$$

where $DUMMY_t$ represents the dummy variable, and i and m as noted above. This is the equation that will be used in this analysis. It should be noted that the market model (or a variant of it) has been used extensively to assess the impact of events on share returns in a range of studies since its introduction in

Fama et al (1969), and has subsequently become the most widely accepted tool of analysis.

2.2. Announcement selection and data.

The announcements and events used in this study are primarily those from Offer, while others take the form of important events which have led to regulatory announcements (break-up of contracts for differences, price spikes), and others are events which could influence the structure of the industry (mergers and take-overs announcements). It is therefore assumed that these events all exhibited some form of informational content that could influence the share prices of NP and PG. There are a total of thirty-six events, full details of which are given in Table 1.

In general, it is possible to establish groups of events around the following headings. Firstly, **events which relate to the pool**, which are events one, two, fifteen and nineteen. These events are those which influence the general level of pool prices, but which have not occurred as a consequence of regulation. In fact, these are events that would typically have induced regulatory intervention.

Secondly, **threatened and actual MMC references**, which are events three, seven, sixteen, seventeen, eighteen, twenty-six and thirty-five. These events concern the possibility of increased competition within the pool, and may therefore be classed as "competition" events. Thirdly, **announcement and publication of pool price reviews, price agreements and other regulatory announcements,** which are events four, five, six, eight, nine, ten, eleven, twelve, thirteen, fourteen, twenty, twenty-one, twenty-two, twenty-three, twenty-eight and thirty-six. (Although event three also belongs in this category, it is more appropriate for this analysis to include it in the second sub-heading.) These events concern the pricing behaviour of the generators, and may be classified as "price" events. The distinction between "competition" events and "price" events is that the former would typically influence the structure of the industry, while the latter would influence the conduct of those firms in the industry. It is these two groups of events that may be classed as **regulatory events.** The remaining analysis is **concerned solely with the financial markets** and therefore should be classified as "shares/take-overs and mergers" events. These are events twenty-four, twenty-five, twenty-seven, twenty-nine, thirty, thirty-one, thirty-two, thirty-three and thirty-four. Based upon these classifications, it can be seen that there are twenty-four regulatory events (two-thirds of the total). It is hoped that the groupings may make analysing the results more convenient.

The data set is comprised of the following variables. The share prices for NP and PG were obtained from their floatation in March 1991 through to late March 1996. In keeping with Dnes & Seaton (1995), and to allow a comparison between this study and their work, the FT-100 Index is used as the proxy for the return on the market as a whole. The data set contained a total of 1316 daily (i.e.

weekday) observations from 11th March 1991 to 25th March 1996.

As is consistent with the work present in the previous chapters, all efforts have been made to prevent the analysis periods for the event dummies from overlapping. This has led to the need for estimations undertaken over a fifty-day analysis period, which (for the most part) restricts the potential for the events to overlap. This is to allow the equivalent of one business month's of observations on either side of the event, which is useful due to the nature of regulatory announcements and the inherent possibility for noise in undertaking stock market analyses. Specifically, an initial announcement is made by the regulator that is typically followed by an additional announcement that either provides more information on, or clarifies the regulator's intentions. A narrower analysis period may not capture the full consequences of an event, while a longer period will result in considerable overlapping of analysis periods when examining many of the latter events, a problem which is minimised by the period chosen. (The analysis period should not be confused with the dummy event window, discussed below).

It was necessary to determine the most appropriate dummy window for the analyses. Based upon a system of examination utilising the R^2 statistics and the residual sum of squares from each equation (as in Dnes & Seaton, 1995), it was discovered that the dummy window used should be -1 to +2 observations around the event itself. This was based upon variations in the event window from -5 to +5 observations around the event. (It should be noted that the most viable alternatives to the chosen window were -1 to +1 and -5 to +5. The latter was dismissed as it risked the prospect of excessive noise around the events, and the former was dismissed as it presumed that the market adjusted immediately and completely to an event. However, given that regulatory announcements are often in the form of an initial announcement followed by an additional press release or report, this could imply a two-stage announcement for some events. For example, an event could produce an initial reaction, then a subsequent additional reaction if the initial reaction was excessive or insufficient, as given by any additional information. However, for completeness the results of these regressions are presented in full in the appendix.)

For full results on the coefficients and their diagnostic test results, see appendix. However, it should be noted that the majority of regressions failed no diagnostics, although among the regressions that did fail tests, the most common failure was the test for normality due to skenwess and truncation of the distribution. The test results presented are those generated by White's heteroscedasticity consistent standard errors - a method used to enhance the results. The results are presented in Tables 2 (National Power) and 3 (Powergen), indicating the event represented by the dummy, the parameter, its corresponding t-statistic, and whether it is significant at the 5% and 10% levels, again in keeping with

Dnes & Seaton (1995).

2.3. Results of the market model.

In examining the results, it can be seen that of the thirty-six events, nine (twenty-five percent) produce significant dummy variables for National Power, and eleven (thirty-one percent) produce significant dummy variables for Powergen. (Significance at either the 5% or 10% levels). The significant events for National Power are one, five, sixteen, twenty-four, twenty-nine, thirty-three, thirty-four, thirty-five, and thirty-six. Of these events, four are regulatory in nature. Event five represents the publication of a series of electricity price controls developed as a consequence of the first pool price review. The review itself contained proposals for the control of prices through the conditions on the re-submission of generating plants - a move which took place as a consequence of Powergen's practice of altering its plant availability to benefit from increased capacity payments. Event sixteen was the first of three occasions in 1993 that the generators were threatened with an MMC reference (the other occasions being in July and December of that year). However, as these other occasions did not produce significant dummies, the issue of credibility (covered in the first empirical chapter) could again be seen as relevant.

Event thirty-five is the occasion on which the two generators were referred to the MMC for their attempts to take over one of the RECs. It is not surprising therefore that the potential for new and more restrictive regulation should lead to a decline in share returns. The final significant regulatory event for National Power was event thirty-six: the DGES comments on the price undertaking that had been enforced since early 1994. This followed comments made earlier in the year regarding the restrictiveness and applicability of the price cap, and continued the DGES' attempts at tighter regulation for the generators.

Before examining the results for Powergen, it should be noted that there are five events that are significant for both companies, two of which are regulatory: events five, twenty-four, twenty-nine, thirty-three and thirty-five. As such, there is no need to re-examine these events for Powergen. Event four is significant for Powergen, but not for National Power. However, as this event was the first pool price review which began as a consequence of Powergen's strategy of manipulating the capacity payments system, it is not unexpected that this event would influence Powergen more than National Power. Event twenty-two (proposed break-up of Nuclear Electric) was an event which could be expected to lead to greater competition in the industry. As Powergen was the second largest generator in the industry at the time of the industry, it is possible that this event could have been accompanied by perceptions Powergen's position becoming untenable as a consequence of greater competition. Similarly, event twenty-three would have also led to greater competition - specifically in the non-baseload part of the electricity generation market. Event twenty-five could be seen as leading to increased uncertainty regarding the regulatory future of the industry as the prospects of mergers and take-overs became uncertain.

What is equally important in interpreting these regulatory events is the fact that all of their dummy coefficients (National Power and Powergen alike) are negative, implying that each of them was viewed with the prospect of tighter regulation. Further of the regulatory events for both companies, approximately seventy-five percent of them produce negative dummies.

Events thirty-three and thirty-four generated negative significant dummies for National Power, while event thirty-three was significant only for Powergen. These dummies are consistent with the announcement effect associated with merger and take-over intentions: the share price of the acquiring firm declines while that of the target firm increases.

In assessing the results in terms of their groupings, it is clear that there is no apparent pattern to the results. The only pattern which does result is in the case of regulatory announcements, where the dummies do tend to exhibit negative coefficients, implying a decline in returns, attributable to perceptions of tighter regulation. Given these results, it was deemed appropriate to perform a regression that combined all of the dummy variables into one variable in a regression that would be performed over the entire 1316 observation analysis period. This required the creation of an additional dummy variable that utilised the values of all of the regulatory dummies. The results of this regression are again shown in Table 2. Although the diagnostic test results were not as encouraging as for the pervious, individual dummy regressions (both regressions failed the tests for serial correlation and normality), it can be seen that the regulatory events as a whole produced statistically significant dummies for both companies. This implies that the actions of the regulator have led to a decline in the share returns of the companies.

Table 1. Events utilised for study of financial data.

No.	Date	Event	Obs.	Obs. Range
1	22/03/91	Break-up of first set of CFDs.	10	1-50
2	09/09/91	Price spikes begin.	131	105-155
3(R)	03/10/91	First pool price review begins w/ MMC threat.	149	125-175
4(R)	20/12/91	First pool price review published.	205	180-230
5(R)	06/02/92	Electricity price controls published.	239	215-265
6(R)	16/06/92	DGES to examine excessive electricity profits.	332	305-355
7(R)	27/06/92	Generators threatened with MMC reference.	340	315-365
8(R)	20/07/92	OXERA suggests regulatory changes.	356	330-380
9(R)	28/07/92	DGES to probe power price rises.	362	335-385
10(R)	08/10/92	Second pool price review launched.	414	390-440
11(R)	26/10/92	Commons to revise sale of generators.	426	400-450
12(R)	18/12/92	Second pool price review published.	465	440-490
13(R)	24/02/93	DGES seeking additional power over generators.	515	490-540
14(R)	10/03/93	DGES tells generators to sell surplus plants.	523	500-550
15	31/03/93	Break-up of second set of CFDs.	538	515-565
16(R)	24/05/93	Generators threatened with MMC reference.	576	550-600
17(R)	30/07/93	MMC reference and/or plant sales threatened.	625	600-650
18(R)	15/12/93	MMC reference unless agreement made.	723	700-750
19	06/01/94	Revised bidding system drives pool prices down.	739	715-765
20(R)	11/02/94	NP and PG establish price agreement.	765	740-790
21(R)	25/04/94	Reports indicate a tougher stance from DGES.	816	790-840
22(R)	04/10/94	DGES to encourage break-up of Nuclear Electric	957	930-980
23(R)	09/12/94	Generators warned on plant disposals.	980	955-1005
24	19/12/94	Trafalgar House bids for Northern Electric.	986	960-1010
25(R)	26/01/95	DGES' unsympathetic on Trafalgar House move.	1014	990-1040
26(R)	11/02/95	MMC reference threatened over plant sales.	1025	1000-1050
27	06/03/95	Sale of Government's 40% electricity holding.	1041	1015-1065
28(R)	07/03/95	Distribution price controls to be revised.	1042	1015-1065
29	13/07/95	Southern Electric bids for S.W. Electricity.	1134	1110-1160
30	25/07/95	Scottish Power bids for Manweb.	1142	1115-1165
31	31/07/95	Hanson bids for Eastern.	1146	1120-1170
32	10/09/95	North West Water bids for Norweb.	1176	1150-1200
33	21/09/95	Powergen bids for Midlands Electricity.	1184	1160-1210
34	02/10/95	National Power bids for Southern Electric.	1191	1165-1215
35(R)	23/11/95	NP and PG's REC bids to face MMC reference.	1229	1205-1255
36(R)	12/12/95	DGES' statement on price undertakings	1242	1215-1265

For future reference, these events will be referred to as events 1 through 36 respectively.

(R) indicates that the event was regulatory in nature.

Obs. range represents the observation range used for the market model.

Table 2. Market Model Dummy Variable Analyses - National Power.

Event	Coefficient	Stan. Error	T-Ratio[Prob]	Sig.: 5%	Sig.: 10%
1	-0.011744	0.005623	-2.08880[.042]	Yes	Yes
2	-0.003290	0.002564	-1.28340[.206]	No	No
3	-0.002990	0.003712	-0.80556[.424]	No	No
4	-0.004310	0.003999	-1.07800[.286]	No	No
5	-0.010538	0.003864	-2.72730[.009]	Yes	Yes
6	-0.002611	0.003998	-0.65304[.517]	No	No
7	0.002130	0.003703	0.57524[.568]	No	No
8	-0.002624	0.006612	-0.39688[.693]	No	No
9	-0.006487	0.012378	-0.52404[.604]	No	No
10	0.003935	0.007107	0.55367[.582]	No	No
11	0.000903	0.004928	0.18333[.855]	No	No
12	-0.006960	0.008635	-0.80596[.424]	No	No
13	-0.001807	0.003219	-0.56133[.577]	No	No
14	-0.003214	0.005713	-0.56253[.576]	No	No
15	0.007073	0.006650	1.06360[.293]	No	No
16	-0.007207	0.003942	-1.82810[.074]	No	Yes
17	-0.002687	0.009321	-0.28831[.774]	No	No
18	0.007004	0.005787	1.21040[.232]	No	No
19	0.002783	0.006544	0.42532[.673]	No	No
20	0.015897	0.012308	1.29160[.203]	No	No
21	-0.003786	0.004314	-0.87767[.384]	No	No
22	-0.001202	0.002142	-0.56104[.577]	No	No
23	-0.008619	0.008506	-1.01330[.316]	No	No
24	0.004723	0.002509	1.88250[.066]	No	Yes
25	-0.000606	0.001516	-0.39990[.691]	No	No
26	-0.007194	0.008972	-0.80181[.427]	No	No
27	0.000214	0.003770	0.05668[.955]	No	No
28	-0.009946	0.009315	-1.06770[.291]	No	No
29	0.006085	0.003065	1.98570[.053]	Yes	Yes
30	-0.000688	0.005392	-0.12765[.899]	No	No
31	-0.000271	0.002618	-0.10364[.918]	No	No
32	0.000354	0.006803	0.05199[.959]	No	No
33	-0.004890	0.002033	-2.40470[.020]	Yes	Yes
34	-0.018273	0.005425	-3.36810[.001]	Yes	Yes
35	-0.021618	0.004986	-4.33560[.000]	Yes	Yes
36	-0.008103	0.004068	-1.99210[.052]	Yes	Yes
ALL	-0.002939	0.001586	-1.85830[.064]	No	Yes

For more information on the events, see Table 1, Chapter 3.
"ALL" is the dummy variable that integrates all of the regulatory events.
Significance levels are based upon the 5% and 10% levels of significance.
Results are those produced using Adjusted White's Heteroscedasticity Consistent Standard Errors.

Table 3. Market Model Dummy Variable Analyses - Powergen.

Event	Coefficient	Stan. Error	T-Ratio[Prob]	Sig.: 5%	Sig.: 10%
1	-0.013055	0.008169	-1.59820[.117]	No	No
2	0.002704	0.002605	1.03810[.304]	No	No
3	0.000593	0.004734	0.12518[.901]	No	No
4	-0.003896	0.002342	-1.66390[.103]	No	Yes
5	-0.015311	0.005044	-3.03570[.004]	Yes	Yes
6	-0.003319	0.003136	-1.05820[.295]	No	No
7	0.005078	0.003440	1.47640[.146]	No	No
8	-0.005883	0.007201	-0.81698[.418]	No	No
9	-0.006128	0.012983	-0.47203[.639]	No	No
10	0.005597	0.006064	0.92308[.361]	No	No
11	-0.001416	0.004549	-0.31133[.757]	No	No
12	-0.008932	0.007862	-1.13610[.262]	No	No
13	-0.001781	0.003427	-0.51964[.606]	No	No
14	-0.004185	0.006056	-0.69117[.493]	No	No
15	0.007188	0.008134	0.88366[.381]	No	No
16	-0.006748	0.004885	-1.38130[.174]	No	No
17	0.000483	0.006746	0.07166[.943]	No	No
18	0.006735	0.004395	1.53250[.132]	No	No
19	0.001695	0.004313	0.39306[.696]	No	No
20	0.010293	0.012062	0.85339[.398]	No	No
21	-0.002525	0.003954	-0.63865[.526]	No	No
22	-0.004443	0.002428	-1.82960[.074]	No	Yes
23	-0.005015	0.002213	-2.26680[.028]	Yes	Yes
24	0.012047	0.002895	4.16160[.000]	Yes	Yes
25	-0.005997	0.002199	-2.72750[.009]	Yes	Yes
26	-0.007124	0.009628	-0.73988[.463]	No	No
27	-0.002897	0.003351	-0.86462[.392]	No	No
28	-0.010860	0.009415	-1.15350[.254]	No	No
29	0.012909	0.001760	7.33300[.000]	Yes	Yes
30	-0.006478	0.002458	-2.63540[.011]	Yes	Yes
31	-0.006463	0.001721	-3.75440[.000]	Yes	Yes
32	-0.000033	0.004579	-0.00726[.994]	No	No
33	-0.006178	0.002613	-2.36420[.022]	Yes	Yes
34	-0.006951	0.006339	-1.09650[.278]	No	No
35	-0.023171	0.005556	-4.17080[.000]	Yes	Yes
36	-0.004083	0.002988	-1.36650[.178]	No	No
ALL	-0.003635	0.001518	-2.39420[.017]	Yes	Yes

For more information on the events, see Table 1, Chapter 3.
"ALL" is the dummy variable that integrates all of the regulatory events.
Significance levels are based upon the 5% and 10% levels of significance.
Results are those produced using Adjusted White's Heteroscedasticity Consistent Standard Errors.

SECTION III - Conclusions.

This chapter has attempted to assess the potential for regulatory and non-regulatory events to influence share returns Specifically, it was hypothesised that regulatory events would induce a decline in share returns as the attractiveness of the companies to investors declined. The set of regressions utilising the market model indicated that this was indeed the case, although not all of the regressions generated significance in the dummy variables used to represent the events themselves. Although it was hoped that there would be a pattern consistent across certain types of events, the only pattern that emerged was the negative coefficients on the regulatory dummies. The results are not consistent across the firms, although such an outcome is consistent with financial markets theory.

Ultimately the issue at hand is one of credibility in the announcement, be it regulatory or otherwise. Generators will have better information than the stock market about their own industries, and will respond accordingly to the events of this study. Although the attitude of the market to an event can be inferred by the behaviour of returns, the analysis can be clouded due to difficulty in identifying precisely when the information concerning an event was actually released. The possibility of tighter regulation would bring with it a decline in shares, while generators might not respond to that possibility until more information on the potential regulation became available. Therefore, the key factor becomes the flow of information, and how the announcements (or rather the possibility of announcements) affect the information sets of the generators and of investors upon which they base their decisions.

Dnes & Seaton (1995), showed that there was a high percentage of significant dummies, reflecting the impact of announcements on RECs. Comparing this study with that work, there are sixteen events which are present in both studies (that work focused upon REC-orientated announcements), of which eight are significant (at either 5% or 10%). Of these eight events, two also produce significant dummies in this study: events four and twenty-five. Although the number of events is not high, such a conclusion strengthens this study and reinforces the conclusions of Dnes & Seaton (1995). The main obvious reason for the differences in results is the fact that the companies under examination are different. Although the companies all belong to the electricity industry, it is likely that the market has different perceptions of the risk associated with generation and supply and distribution, in addition to the different levels of competition which exist in the two different sectors of the industry.

Dnes & Seaton (1995) were able to show the existence of a high percentage of significant dummies through the simple market model - an outcome which is consistent with that of this study, although their percentage of significant dummies is higher: approximately thirty-three percent to an average of twenty-eight percent (averaged across the two generators). However, this result is encouraging given the high percentage of significant regulatory dummies.

The main conclusions of this study are that both regulatory and non-regulatory events can influence the share prices of the electricity generators. Further, that many of these regulatory events appear to have exerted a negative influence on share prices. As such, these results are consistent with similar studies undertaken into regulated utilities. However, the mixed results in terms of the impact of regulatory and non-regulatory events do make it difficult to establish any classification as to whether certain types of events will have specific effects.

CHAPTER VIII: The Electricity Spot and Forward Markets - A Domestic and Overseas Perspective - Contents.

SECTION I - The role of the electricity forward contract market.

1.1. A theoretical approach to the contract market.

In order to further examine the relationships within the contract market, consider the following algebraic approach (Powell, 1993, pp. 445-447).

At vesting, the "initial portfolio" of contracts between the RECs and the generators were not in fact contracts for the purchase or sale of electricity - they were purely financial arrangements representing options and cash-settled futures contracts.

"One-way" CFDs represent an arrangement equivalent to a portfolio of call options. In each half-hour that the pool purchase price (*PPP*) rises above the strike price (*K*), difference payments are made to the holders of such contracts to the sum of *Q*(*PPP-K*), where *Q* is the quantity covered by the contract. However, if *PPP* is below the strike price, no payment will be made.

"Two-way" CFDs represent a system similar to a portfolio of put-call combinations. In this case, a payment is made, from the writer to the holder of the CFD, if the *PPP* is above the strike, but the payment is reversed if the *PPP* is below the strike. The put and call combinations are written based upon the same capacity and a common strike price. The pay-off is then equivalent to a futures contract for each half-hour's contracted output.

Formally, the pay-off may be expressed as:

$$Pay\text{-}off = Q\sum_{t=1}^{n}(PPP - K) \quad \textbf{(4.a)}$$

Given that there existed a combination of one-way and two-way contracts with a variety of indexation and other provisions, simplifications must be made. This involves assuming that the generators have sold some fraction of their output ahead on futures contracts, while retaining the sale of the remainder in the pool (this is clearly not a heroic assumption). It is also necessary to assume that the generators have constant marginal costs and are profit maximisers (the former of these assumptions may be contested). If this is the case, then the objective function for generator *i* may be given as:

$$\pi_{Gi} = pq_{Gi} - kq_{Gi} - x_{Gi}(p - f_{Gi}) \quad \textbf{(4.b)}$$

where q is output, x is the quantity of output sold forward, f is the strike (futures) price, k is marginal cost and p is price. The subscripts G and i indicate generator i. Powell also assumes an inverse linear demand function with an additive, normally distributive error. As such, total demand at any price is uncertain and the inverse demand function is given in (4.c):

$$p = A - q_{Gi} - q_{Gj} + \varepsilon \quad where \quad \varepsilon \; is \; N(0, \sigma^2) \tag{4.c}$$

Assuming that there are two privatised generators operating co-operatively, then they could be modelled as either quantity setters or price setters. If the quantity and strike price of the contracts are fixed, then the first order condition of (4.c) with respect to quantity is given as:

$$q_G = \frac{1}{2}(A - k + x_G) \tag{4.d}$$

where q_G is the total output of both generators. This formulation is a positive function of the total number of futures contracts signed by the generators. In other words, the more two-way CFDs that have been signed by the generators, the greater will be output and the lower the expected price.

If the two privatised generators are Cournot players, then the first order condition for generator i will be:

$$q_{Gi} = \frac{1}{2}(A - k - q_{Gi} + x_G) \tag{4.e}$$

This equation possesses the format of a standard Cournot reaction function, except that the quantity produced by generator i is a positive function of the number of futures style contracts signed. Assuming cost symmetry between the generators, the solution to this game is:

$$q_{Gi} = \frac{1}{3}(A - k + x_{Gi}) \tag{4.f}$$

with total industry output $2q_{Gi}$ in this case. The effect of increasing x_{Gi} is to push out the Cournot reaction functions, thus making total output a positive function and price a negative function of x_{Gi}.

The Cournot assumption requires that generators make only one quantity decision. The conclusion which may be derived is that whether the generators are assumed to be either Cournot players or colluding players, a higher degree of contracting implies that output will be higher and price lower than otherwise. This follows because as the degree of contracting increases, the less profitable it becomes for generators to reduce quantity and increase price. In essence therefore, the contract market serves to control the market power of the generators.

1.2. The contract market in practice.

This summary is based upon Green (1996b) due to the lack of information on the contract market.

In the electricity industry, some larger customers buy their electricity with contracts linked directly to pool prices, but it is unlikely that National Power and Powergen would be willing to sell contracts of this type as they are interested primarily in direct sales as a means of hedging output. Based upon regulatory intervention, the generators' supply businesses (those divisions that sell electricity to consumers) were required to sign contracts guaranteeing non-discrimination between the generators' own supply businesses and other competitive supply businesses. The generators' prospectuses estimated their direct sales for 1990/1, from which point on Powergen published volume and revenue figures for its sales, while National Power published only its revenues.

These contracts are referred to in the literature as the "coal CFDs", as they were electricity contracts which were met through the sale of electricity generated by coal-fired stations. In establishing the coal CFDs, (used to recover the excess cost of British coal against imported fuels) the generators used the cost of imported coal when calculating their marginal costs, with the coal CFDs containing lump-sum payments equal to the difference between the cost of British coal and the cost of imported coal. This meant that the price of these coal CFDs was not expected to be significantly above pool prices, and so the cost could not be passed on to any consumer who had the option of buying at pool prices (or from a supplier at pool prices). The 1990 coal contracts were therefore limited to the franchise market, but covered most of the RECs requirements for this market.

Offer (1992) states that National Power's contracts covered 44% of the RECs total needs (including non-franchise sales) in 1992/3, and Powergen's 26%. The RECs' prospectus indicate that the maximum level of cover in 1991/2 was the same as 1992/3 (i.e. the volumes covered should be the same), while the generators' prospectus indicated that almost all of the contracts from 1990/1 which continued into 1991/2 were for the franchise market. The volume of coal covered by the associated contracts with British Coal was lower in 1992/3 than in the first two years of privatisation, but this probably depended upon the generators predicted fuel needs, rather than reflecting a fall in the volume of the electricity contracts.

A second set of fuel contracts was signed in March 1993 for the period until March 1998. The generators' annual reports have given the volume involved in 1993/4 and for the four years from 1994/5. The amount of coal covered has fallen considerably: British Coal's sales fell from 65 million tonnes (1992/3), to 40 million (1993/4), and 30 million in the following years, together with small amounts from other mines. These figures largely reflect the falling demand for coal - a move that can be attributed to the increasing number of CCGT plants being opened and the industry's shift away from coal. The amount of electricity covered also fell sharply in 1993/4 as RECs used their own stations to meet their needs in the franchise market, and in 1994/5 as the franchise limit fell.

In 1990, the generators started with one-year short-term contracts sold to the RECs for non-franchise customers. These contracts, together with the coal contracts, covered almost all of their expected output. These large contracts were negotiated before most large consumers were presented with the opportunity to change suppliers, and most of them contained termination clauses which allowed the RECs to drop the contracts if they wished. In the event, National Power and Powergen took about one third of the non-franchise market in the first year, and the RECs dropped many of their contracts.

At the same time, many large customers who had been paying low prices in the pre-privatisation period became recipients of subsidies in the first year after vesting to ensure that their prices did not rise in real terms. Nuclear Electric sold contracts to National Power and Powergen at low prices that were passed on to each customer's supplier, making the generators both buyers and sellers of contracts.

In the years 1991/2 and 1992/3, the generators sold very few short-term one-year contracts, presumably preferring to undertake direct sales with the RECs, which have the prospect of greater profits. Both generators sold one-year contracts in 1993/4, while the expansion of the non-franchise market in 1994/5 brought with it a greater demand for one-year contracts which was met by the generators. Of course, the generators were operating under the terms of the February 1994 price undertaking, and as unilaterally raising prices was out of the question, there was no incentive to be under-contracted over that period. In the years following vesting, the generators have covered almost all of their output with a combination of contracts and direct sales, whether such choices were voluntary or not.

In examining the level of prices in the post-privatisation period, it is appropriate to look at output-weighted prices and demand-weighted prices. As National Power and Powergen sell the majority of their output at peak times, the output-weighted price is slightly above the demand-weighted price. However, the difference only becomes significant in 1994/5, potentially as a consequence of the price undertaking.

The prices utilised in the initial series of coal contracts can be estimated utilising the Horton IV price estimates. The Horton IV estimates contain a subsidy for British Coal, which even when deducted means that they are above the forecasted pool prices. The estimates also noted the potential for excess capacity in the industry, the closure of which was expected to put pressure on prices to rise to a long-run equilibrium level by 1993. To that end, the prices contained a so-called "capacity premium" designed to take them closer to the long-run price level as a means of increasing the value of the generating companies.

The first year's pool prices were well below the Horton IV estimates as (presumably) generators attempted to capture market share than maintaining a spot price which influenced such a small proportion of their sales. By 1992/3, prices were higher but still at a level in excess of long-run costs - this should not be surprising as the excess capacity had yet to be eliminated. Prices appear to have risen above avoidable costs in 1993/4 in a move attributed to under-contracting.

This reliance upon the contract market has served to provide a considerable degree of security to the electricity industry. However, Gray, Helm & Powell (1995) note that the degree of contract coverage and the role of the government in determining that situation have possibly damaged the short-term future of the industry. The ending of the vesting contracts in 1993 was greeted with a considerable degree of concern by British Coal, leading to the eventual closure of many of their mines. This led to the revised coal contracts for the years 1993-8. However, when these contracts expire, it is argued that because the majority of contracts in the industry were imposed (directly or indirectly) by the government, that this has served to stunt the growth of liquid, market-orientated contract negotiations. As a consequence, the government's concerns about the coal industry may have resulted in the industry facing a dilemma in 1998, when the coal contracts finally expire, as there is no functioning contracts market which can replace contracts on the scale of the coal contracts. It is conceivable therefore that the continued growth in the trade in EFAs will continue. However, if the coal contracts are to be replaced by a market-based mechanism, then developments to that end will have to expedited.

1.3. The structure of the chapter.

Having already several of these elements in the earlier chapters, it is not necessary to repeat this analysis in depth, although frequent references will be made to the preceding chapters. The objective of this analysis is to introduce empirical evaluations of the market for electricity contracts, examining the market for contracts for differences in England and Wales and the market for contracts in California. Section II introduces the data set used to approximate the strike prices of the contract for differences in England and Wales. Section III incorporates the empirical analyses performed using the forward prices. Section IV introduces the Californian electricity industry and the need for reform. Section V examines deregulation in California in comparison to that in England and Wales and also considers the Californian electricity forward trading arrangements. Section VI comprises the empirical analysis of Californian deregulation and section VII concludes.

SECTION II - Constructing the Horton IV data set.

2.1. The role of the Horton estimates.

The Horton IV estimates are seen as the nearest approximation to the actual strike prices for the vesting contracts (Offer, Review of Economic Purchasing, 1992), and as such may be used to construct a synthetic contract load profile. In pursuing such an undertaking, one must consider the actual load factor (or load shape) of the contracts, i.e. the ratio of kwh consumed to the peak consumption, multiplied by the number of hours under examination - representing the percentage of hours in a year over which a contract operates. (Percentages are calculated based upon the 8760 hours in a year).

Although baseload contracts (i.e. contracts covering an entire year, possessing a 100% load factor) were made available to the RECs, these are less valuable than contracts with a lower load factor, and thus have a lower contract price. Electricity consumption in England and Wales is around the 64% load factor mark, while that in the franchise market is nearer to 52-54% because of sharper peaks in demand. The relative value of the contract prices is indicated in the appendix, which contains the Horton IV price estimates calculated by the Department of Energy in January 1990.

The estimates were based on the following assumptions. Firstly, imported coal prices would increase by approximately 1% per year, and heavy fuel oil (HFO) prices would increase by approximately 3% per year, both in real terms. Secondly, the price of gas used for power generation would remain constant in real terms. Thirdly, the fossil fuel levy would be constant over the period under examination at 10.3%.

As it was both impossible and inadvisable for a REC to establish full contract cover with a single generator, the RECs signed contracts at different load factors with different generators based upon individual needs. (The contract load factors may be derived from the Horton IV estimates and are shown in the appendix) Given REC contracting strategies and government policy, each company's contract portfolio covered almost all of its expected market in the first year.

Assuming the provision of sculpted contracts by the generators (i.e. tailored to meet the RECs' needs), or the construction of a sculpted load profile, it is possible to construct a load profile using the Horton IV PPP estimates (see appendix). Consequently, we may develop a similar approach to break down the observations into the standard half-hour format used in the pool (see appendix), to which the following notes are referenced.

2.2. Developing the Horton IV data set.

The Horton IV data set is - in the same manner as the pool purchase price (PPP) data set - based upon a series of daily averages. Given the importance of the half-hourly nature of the contract market, this represents a limitation of the validity of the subsequent analyses. However, computing restrictions precluded the use of over sixty thousand half-hourly observations. Despite this limitation, it is hoped that the daily averaging of the PPP data set will induce a certain degree of symmetry to the analysis.

From the hourly nature of the number of observations given, conversion to the half-hourly format is easily obtained by doubling the number of observations allocated to each hour. From this, conversion from a half-hourly format to a daily format allows an examination of the days on which certain contracts will be called (as opposed to in which half-hourly periods), detailed as follows by ranking the data sets. The PPP and Horton IV data sets are ranked side-by-side in ascending order in a tabular format, establishing the highest PPP observation with the highest Horton IV observation, and so on.

The PPP observations are then "marked" with their corresponding Horton IV observation, and the ranking process reversed to re-establish the PPP ordering, as well as establishing the correct Horton IV sequence. This creates a data set in which the highest PPP levels are assigned a certain number of contract periods, and so on to the lower priced time periods. In essence therefore, each PPP observation has been matched to the corresponding contract that would be called in the relevant time period, (assuming perfect foresight). This is done on a year-by-year basis to create an overall annual distribution of PPP levels and Horton IV estimates, representing a data set that can be used to represent the strike prices of the vesting contracts.

It should be noted that - had the use of the half-hourly format been feasible - the process would have been carried out in exactly the same manner. For example, the forty half-hour periods in which PPP was the highest would have been assigned the relevant contract prices, similarly with the next one-hundred-and-ninety-five highest observations, which would have been the forty-first to two-hundred-and-fifteenth observation, and so on. This would have created a more weighted data set, reflecting the nature of contract cover. However, as the PPP data set has had such variations eliminated by the use of daily averages, it is hoped that this will not impact excessively on the validity of the results.

One may use this information to derive a data set representing the strike prices of contracts corresponding to the relevant pool prices. This requires an examination of prices over the appropriate period and their breakdown into this 'step' format. Given the approximate 55% load factor in the electricity industry, the Horton IV data set also possesses this characteristic. Each observation in the PPP data set may then be assigned a corresponding observation in the contract set, based on the following assumptions. Firstly, the Horton IV estimates represent the basis for the strike prices of the vesting contracts and may be used as such. Secondly, the vesting contracts defined a sequence of timeslots between which generating cover was to be provided. Thirdly, all generators were willing and able to offer contracts based on 'firm' capacity, i.e. that which was certain to be supplied. Fourthly, demand profiles were derived from all available information, and there is no demand uncertainty.

These assumptions may be examined in turn. In the case of the first assumption, the Horton estimates represent an appropriate proxy for the strike prices of contracts, as stated by Offer (1992). In the case of the second and third assumptions, all of the generators were willing to offer these types of sculpted contracts as the government at privatisation effectively forced it upon them. (The actual degree of firm capacity may have been affected by the success of Nuclear Electric). Regarding the fourth assumption, while there would be some demand uncertainty, one would anticipate it to be minimal. Indeed, one would not anticipate demand fluctuations to be responsible for sharp, brief changes in prices - these are generally the result of supply shocks, e.g. plant malfunctions and system outages.

Given that the vesting contracts were only in operation from March 1990 to March 1993, this restricts the analysis to this time period. However, it should be possible to use the Horton estimates post-March 1993 for a general examination of the levels of commercially negotiated contracts. In addition, given that the first tranche of vesting contracts were partially dissolved in March 1991, this may disrupt any relationships derived from this information.

The role of CFD market on the level of pool prices was noted in Offer (1991), in which it was indicated that the generators believed that the vesting contracts were responsible for downward pressure on pool prices, particularly on the SMP, for the reasons below.

Firstly, the degree of contract cover in the vesting contracts effectively exposed the generators to overcalling at peak times. This meant that the generators had contract cover in excess of their generation limits - a dangerous situation as contracts were made against 'firm' capacity. As a consequence, the generators were bidding their plant into the pool to guarantee generation in a way that exerted downward pressure on pool prices at peak times.

Secondly, the computer algorithm that derives SMP interacted with plant dynamics to produce high SMPs relative to demand in some periods. This was a problem for generators if their contract cover was in excess of their generation capacity. In order to rectify this situation, the generators bid flexible plant into the pool with low or zero start-up prices. This effectively removed the possibility for sharp price spikes and a reduction in the overall level of pool prices.

Thirdly, the seasonal sculpting of the contracts reflected the anticipated output of fossil-fired plant. However, increased output from nuclear stations and the interconnectors reduced the operational requirements of low merit order plant. In the face of contractual commitments based on non-firm plant, National Power was forced to increase its market share by reducing bid prices, causing a decline in SMP. Finally, the increase in the level of baseload capacity (both fossil-fired and nuclear) following privatisation represents a key contributor to the reductions in the pool price.

An additional implicit assumption is that the assumptions made in the construction of the Horton IV estimates concerning the rate of increase of fuel prices and the level of the fossil fuel levy were all met. This was not the case.

However, because there is no information on how the breakdown of these assumptions was to have affected the contracts, it is impossible to attempt to incorporate these violations without resorting to pure speculation. These matters would have doubtless been negotiated on an individual basis between the contract parties based upon the contracts themselves. It is in this regard that the analysis can be criticised - for using a potentially obsolete data set. However, the Horton IV estimates remained in force until March 1993 and therefore despite the criticisms which may be levelled at them, they remain a valuable tool for the analysis of the forward price for electricity until that time.

It can therefore be concluded that, if it is assumed that the Horton IV estimates were derived on assumptions regarding the expected level of demand and capacity, then it should be possible to construct an approximation of a sculpted contract schedule. The subsequent problem is the actual relationship to be measured using this data. One would anticipate some kind of a relationship to exist between pool prices and estimates of contract prices, but this relationship may well be weakened steadily over time with the continued expiration of the contracts. Therefore, any regression of the two sets of prices should indicate the existence of a relationship between the two variables, but that any such relationship would weaken with time.

By using the methodology outlined above, it has been possible to generate a data set that could be used to represent the Horton IV strike prices. The most appropriate adjustment which can be undertaken with these prices is their indexation in line with the retail price index as a means of reflecting the overall increase in fuel prices - one factor which have almost certainly been incorporated into the contractual arrangements. The indexation of these prices produces a data set that is seen as **the** Horton IV data set from this point onwards. The estimates have been raised by the annual rate of inflation (RPI) in March of each year, corresponding with annual contracting rounds.

SECTION III - Empirical analysis of the contract market.

3.1. Introductory empirical analysis.

To perform an initial series of models, the use of a simple set of static equations has been adopted, each of which will attempt to show the relationship between pool prices and the strike prices of Horton IV estimates.

In theory, the Horton IV data set could be established until the year 1997/8, but as the vesting contracts based upon the Horton IV estimates expired at the end of March 1993, there is little basis for continuing the Horton IV data set beyond this point (observations 1-913). However, as it is an important part of this analysis to examine how the spot-forward price links were influenced by the break-up of the contracts in March 1993, the Horton set has been continued until March 1994 (observations 1-1278).

The confidential nature of the EFA market makes it impossible to establish a data set to represent the strike prices of the EFAs themselves. However, the EFA market will be referred to on several occasions as a basis for comparison vis-à-vis the Horton IV estimates. Examples of spot-forward analysis will be undertaken in subsequent sections by examining the US electricity markets.

The pool purchase price data set, as mentioned above, represents a series of daily averages (standard arithmetic mean) estimated over the entire analysis period. Variables are measured in p/kWh.

Having introduced the data sets, let us establish some of the hypotheses that will be tested. Firstly, it is hypothesised that the PPP-HIV relationship will be a poor one due to the problems resulting from the Horton IV estimates and the nature of the pool in the post-vesting period, as outlined above. This is compounded by the fact that the market for contracts based upon the Horton IV estimates met only once - at vesting. While the Horton IV estimates have been indexed corresponding to the annual rate of inflation (RPI), because the market for these contracts met only once, the Horton IV estimates will not have had the capacity to adapt to changes in the pool. As such, they will therefore not be as good an estimator. The hypothesis is based upon financial markets theory regarding the relationship between the spot and forward prices for a commodity, and may be outlined as follows.

The models under examination in the first set of analyses concern a simple linear relationship between the PPP and the Horton IV estimate. In this relationship, the PPP is given as a function of the relevant forward price and a constant term. Basic financial markets theory dictates that if the forward price is an unbiased predictor of the spot price, the coefficient on the forward price will be unity and the intercept term will equal zero.

The models will be performed over each of their respective full analysis periods, as outlined above. Secondly, as the standard contracting round is on an annual basis, the models will also be run on an annual basis (as appropriate) over the period of 1st April to 31st March the following year. Finally, as contracting is an ongoing process throughout the year, an intermediate bi-monthly analysis period is also used. The format was chosen as appropriate given the dynamic nature of the pool and the nature of trends in electricity pool prices which shows that pool prices tend to follow a standard process and trend from day to day and week to week.

Based upon the first hypothesis detailed above, one would expect that the Horton IV estimates would exceed the pool prices. If:

$$PH_t = H_t - PPP_t \tag{4.1}$$

If the hypothesis is valid, on average H_t should exceed PPP_t, i.e.:

$$Average\ PH_t = \frac{1}{N}\sum_{i=1}^{n_{TP}} PH_t > 0 \tag{4.2}$$

where "TP" indicates the test period of the analysis, as outlined above. Estimating equation (4.2) over the relevant periods, a summary of the results is provided as follows. While a standard technique would be to square the difference between the two variables, because this analysis rests upon the need to assess the potential for over- or under-estimation by the forward prices, the difference will not be squared in these examples.

As can be seen in Table 1, for all of the individual estimates, the hypothesis is valid. Furthermore, because the majority of the results for the average of PH_t are positive, this implies that the Horton IV estimates overestimate the pool price. It has already been noted that the fact that the pool prices were below the Horton IV estimates was a key factor in the RECs exercising their option to terminate in March 1991.

In an attempt to further evaluate the Horton IV data set, the set has been analysed with the pool price data set in an attempt to assess how the forward price performs as a predictor of the spot price. While the above models were rather rudimentary, more appropriate statistical technique of the Wald test on parameter restrictions is used in the next section.

However, as an additional technique, dummy variables will also be used to assess the impact of the various events on the electricity spot and forward prices. The dummy variables representing what are deemed to be twelve of the key events (both regulatory and non-regulatory) which occur over this analysis period, and have been selected due to their importance to the industry and the pool. In terms of anticipated dummy signs, the break-up of the vesting contracts (March 1991 and 1993) should have positive dummies, while events consistent with tighter regulation should exhibit negative dummies. The events are given in Table 2. This approach has been used with considerable success in Helm & Powell (1992) and Gray, Helm & Powell (1996) to assess the impact of similar events on the relationship between pool prices and electricity demand.

Unlike preceding studies however, the dummy equations are modelled based around the use of a short-term analysis window, which in this case is one hundred observations representing on average one month prior to and two months after the event. The use of this short window is based upon the observation that excessively high prices will result in regulatory intervention within approximately two months of the increase. As such, any excessive or unusual price shifts would be transitory in nature, and not permanent. This assumption is based around the hypothesis of the regulation of the electricity industry being characterised by a repeated adversarial game between the generators and the regulator. For example, if the regulator announces to the generators that he is considering an MMC reference, they will lower their prices so as to not prejudice the outcome of the regulator's decision. However, once the regulator has seen the decline in prices and has decided not to refer them to the MMC, then the generators may increase their prices back to the levels that they were at prior to the initial threat. Although all efforts were made to prevent the analysis periods from overlapping, this does occur to a certain extent, and it is therefore hoped that this will not contaminate the results.

The equation used is:

$$PPP_t = \alpha + \gamma_h H_t + \psi \, DUMMY_t + u_t \qquad \textbf{(4.3)}$$

The "Dummy" variable present in these equations possesses the value of zero up until the event and the value of unity thereafter.

An examination of the constant and gamma terms will be postponed for the moment, as the analysis turns to the dummy variable coefficients. One potential problem has been corrected for: the eighth event (the break-up of the second set of vesting contracts) coincides with an indexation adjustment. To that end, two versions of this analysis have been performed, both with and without the adjustment.

A summary of the results is given as follows (see Table 3 for the full results), but the key point is that the Horton IV estimates are prone to producing significant dummies (significance is at the 5% level). There are nine significant dummies for the Horton models (events one through four inclusive, six, seven. eight, adjusted event eight, and twelve), clearly indicating the potential for these types of events to influence the spot-forward relationship. It is to the specifics of this relationship that the analysis now turns.

3.2. Assessing the validity of the spot forward relationship.

Given the rather limited view that was taken of the restrictions which had to be imposed upon the equations used to model the relationships between the pool price of electricity and the forward prices, it is appropriate to introduce suitable statistical techniques to adequately test that relationship. In this section, the restrictions imposed upon these equations are directly assessed utilising the Wald test, which permits the simultaneous imposition of restrictions on the values of different parameters. With the analysis periods (full sample, annual and bi-monthly, to combine flexibility with the actual contract rounds) and the equations already examined, there are additional changes to the model which need to be examined. To assess these restrictions, the following equations are used:

$$PPP_t = \alpha_H + \gamma_H H_t + u_t \tag{4.4}$$

In examining the output of these regressions and their ability to meet the parameter restrictions, the results for the PPP-Horton IV regressions are disappointing. The parameter restrictions are not met on the extended (three and four year) sample periods, nor on the annual sample periods. Of the bi-monthly sample periods, the restrictions are valid on only two out of the twenty-one occasions (12/91 to 01/92 and 02/94 to 03/94). Therefore, it can be seen that the Horton IV estimates are a consistently poor relation to the electricity pool price, with the restrictions imposed upon the model being accepted only twice. These occasions are probably due to coincidence rather than anything concerning the pool price itself. Indeed, one could attribute the result to the regression itself, given that the CFDs are struck only once a year and that recent pool price behaviour probably has little, if any, impact on contracts.

One possible explanation for the high number of rejected hypotheses is that as the volume of electricity covered by CFDs has declined, this has led to increased reliance on the short-term security supplied by EFAs, and the subsequent increase in EFA trading volumes. In other words, as the volume of trading in the EFA market has increased, there has been less reliance on the CFD market. While this is a valid statement, the fact that the Horton IV estimates have not been altered to reflect market trading in EFAs renders this assumption invalid.

With respect to the standard spot-forward model mentioned above, a first difference version has also been estimated. Once again, if the relationship between the spot and forward prices is valid, the aforementioned restrictions on the intercept and slope parameters must hold. With these equations estimated over the same time periods as the static models, the results are not encouraging, as the restrictions are not valid for any of the equations. It would appear as though the forward prices do not have any success at all in predicting changes in the spot price. It is possible, however, that this is due to the forward prices' inability to compensate for the inherent dynamics and volatility associated with the electricity pool prices. In the vast majority of these cases, the problem arises with the slope parameter, as the intercept term is almost consistently statistically insignificant. Finally, we refer back to the first series of dummy variable analyses and test the validity of the slope and intercept parameter restrictions. Utilising the dummy variable equation (4.3), the results are shown in Table 4. Once again, the Horton estimates yield consistently poor results.

With the purpose of this investigation to examine the role of the electricity forward market, and the nature of the relationships between the electricity spot and forward markets. It has already been established that the electricity forward market plays an important role in determining pool prices, necessitating some kind of parallel regulatory structure for both the spot and forward markets. This is even more apparent when one considers the conclusion that the forward market helps to determine the pool price-setting ability of the generators.

The empirical models undertaken have focused upon the market for CFDs, with the prices of these contracts being approximated by the Horton IV estimates. In the case of these estimates, the results are consistent with the observation of lower than anticipated prices in the early years of the pool's operation. Having established these results, attempts were made to assess the exact links between the spot and forward markets, through standard static spot/forward links, dynamic links, as well as the extension of the analysis to assess the role of regulation and other stimuli on the underlying relationships. These regressions led to the following conclusions.

Firstly, it was formally established through the use of the Wald test that the Horton IV estimates were not a valid predictor of the pool price - a result consistent with the post-vesting behaviour of the RECs. Secondly, although the Horton IV estimates respond to the dummy variables to a considerable extent, their ability to predict the pool price is poor. This was doubtless one of the main reasons why the RECs were keen to be free of the vesting contracts as soon as possible. The implications of these conclusions are that, for the early years of the operation of the electricity pool, the market for CFDs produced poor predictions of the pool price. Although this is not surprising, the empirical foundation for this conclusion is dependent upon the validity of the Horton IV data set. As mentioned above, this remains the aspect of this analysis that is open to most criticism. However, given that to alter the Horton IV estimates beyond their RPI indexation would mean resorting to pure speculation, the result should still stand.

If this outcome is still valid, then in order to establish more adequate and efficient operations within the CFD market, then the market should adopt some of the characteristics of the EFA market, one of which must be greater standardisation of contracts compared to their present, more idiosyncratic nature. Of course, the main breakthrough to establishing efficiency and clarity in the market for contracts (EFAs and CFDs) would be the publication of actual contract prices and volumes in a more open (from a commercial standpoint) exchange. Such a market currently exists in the US where electricity futures contracts are traded openly on the New York Mercantile Exchange (NYMEX). Although the volumes traded are small, it is anticipated that as deregulation increases in the US, the need for risk management will increase and with it the demand for contracts. It is to the American electricity industry that the analysis now turns with a case study of deregulation in California. This will provide a contrast to the system of deregulation in England and Wales, as well as showing how the English experience is being used as a model for deregulation in other countries. Furthermore, having obtained spot and forward price data for the Californian electricity markets, an additional series of empirical analyses can be undertaken to illustrate the role of the forward market to the developing system of deregulation in much the same way as the contract market in England and Wales influenced the industry.

Table 1. Differences between electricity spot and forward prices.

HYPOTHESIS: The Horton IV estimates will overpredict the pool purchase price. If the hypothesis is valid, (HIV-PPP) > 0.

Period	Observations	HIV-PPP
Extended Sample Periods.		
10/90-03/94	1-1278	0.01725
10/90-03/93	1-913	0.01550
Annual Sample Periods.		
10/90-03/91	1-182	-0.01627
04/91-03/92	183-548	0.00979
04/92-03/93	549-913	0.03706
04/93-03/94	914-1278	0.02163
Bi-monthly Sample Periods.		
10/90-11/90	1-61	0.06474
12/90-01/91	62-123	-0.02922
02/91-03/91	124-182	-0.08642
04/91-05/91	183-243	-0.03765
06/91-07/91	244-304	0.00298
08/91-09/91	305-365	0.04290
10/91-11/91	366-426	0.02479
12/91-01/92	427-488	-0.00839
02/92-03/92	489-548	0.03479
04/92-05/92	549-609	0.21062
06/92-07/92	610-670	-0.02649
08/92-09/92	671-731	0.03094
10/92-11/92	732-792	-0.06329
12/92-01/93	793-854	0.05319
02/93-03/93	855-913	0.01644
04/93-05/93	914-974	0.01705
06/93-07/93	975-1035	-0.01166
08/93-09/93	1036-1096	0.04356
10/93-11/93	1097-1157	0.00183
12/93-01/94	1157-1219	0.08710
02/94-03/94	1220-1278	-0.01023

Table 2. Events used for the dummy variable analysis.

Date	Event	Obs.	No.	Anticipated Coefficient
22/03/91	Break-up of first set of CFDs.	173	1	Positive
09/09/91	Price spikes begin.	344	2	Negative
03/10/91	First pool price review starts w/MMC threat	368	3	Negative
20/12/91	First pool price review published.	446	4	Negative
27/06/92	MMC reference threatened.	636	5	Negative
08/10/92	Second pool price review launched.	739	6	Negative
18/12/92	Second pool price review published	810	7	Negative
31/03/93	Break-up of second set of CFDs.	913	8	Positive
24/05/93	MMC reference threatened.	966	9	Negative
30/07/93	MMC reference and/or plant sales threatened	1034	10	Negative
15/12/93	MMC reference unless price agreement made	1172	11	Negative
11/02/94	NP and PG establish price agreement.	1230	12	Negative

Table 3. Dummy variable results: Horton IV/PPP analyses.

Event	Constant (C)	Slope (S)	Dummy (D)	Sig.(C,S,D).
1	1.47600	0.49401	0.04158	S, S, S.
2	1.13010	0.62541	0.04195	S, S, S.
3	0.90101	0.73234	-0.05273	S, S, S.
4	1.27110	0.61896	-0.13078	S, S, S.
5	2.03730	0.35361	-0.00479	S, S, NS.
6	2.16230	0.31139	0.01094	S, S, S.
7	2.22490	0.29624	-0.01094	S, S, S.
8	2.04980	0.34910	0.07575	S, S, S.
8*	2.07300	0.34910	0.08366	S, S, S.
9	2.33610	0.28436	-0.00483	S, S, NS.
10	2.02150	0.37897	0.00119	S, S, NS.
11	1.56190	0.52081	-0.01014	S, S, NS.
12	0.71541	0.80562	-0.21505	S, S, S.

Significance is at the 5% level.

* Indicates non-indexed Horton IV estimates.

Table 4. Restricted static dummy variable analysis.

Parameter restrictions: Intercept term = 0, Slope coefficient = 1.

Critical value of Chi-squared distribution: Chi-squared (2) = 5.99.

Null hypothesis H0: Parameter restrictions are valid.

Alternative hypothesis H1: Parameter restrictions are not valid.

If calculated value < critical value, we accept H0 and conclude that the parameter restrictions are valid. Therefore, the forward price is an accurate predictor of the spot price.

If calculated value > critical value, we reject H0 and conclude that the parameter restrictions are invalid. Therefore, the forward price is not an accurate predictor of the spot price.

Dummy	Observations	Calculated Value	Accept/Reject H0
1	150-250	390.9397	Reject
2	325-425	154.8934	Reject
3	350-450	71.7739	Reject
4	425-525	110.4391	Reject
5	600-700	4480.8000	Reject
6	700-800	2845.4000	Reject
7	775-875	3600.4000	Reject
8	875-975	2183.3000	Reject
8*	875-975	2397.7000	Reject
9	925-1025	2682.2000	Reject
10	1000-1100	1311.8000	Reject
11	1150-1250	215.5113	Reject
12	1200-1278	56.5580	Reject

* See Table 3.

Significance is at the 5% level.

SECTION IV - The Californian Electricity Industry: The need for reform.

4.1. The problems faced by California and the need for reform.

In examining the development of electricity deregulation in other countries, one of the most notable examples at present is the United States, notably the state of California, where considerable reforms have been undertaken in a way which parallels the changes made in England and Wales at vesting. As will be shown, there has already been deregulation in California, where (as with each US state) the state authorities can effectively choose their own stance vis-à-vis regulation, provided that such a stance does not breach federal regulations. In this section, the specific problems faced by the Californian industry will be outlined, along with their prospective reforms, the actual path of reform, and how the system contrasts with that in England and Wales. Further, deregulation in other US states will also be examined as a means by which to contrast the progress in California, as well as placing the reforms within the context of the wider US reforms. The Californian industry is undergoing change from a structure where system operations are the responsibility of vertically integrated utilities which own and control the majority of the state's generating assets, to a vertically separated industry based around competition. It should be apparent that with the creation of a pool (power exchange) in California, that the major empirical analyses carried out in the preceding chapters could easily be replicated with data from California, following the new system's transition period and a suitable period of operation.

The California Public Utilities Commission (CPUC) examined several methods of alleviating the problems faced by both the industry and its consumers. Through discussion with industry representatives, it was determined that the industry and its regulatory framework were in need of considerable reform. Although the revised stance for regulation was apparent, the extent to which industry restructuring should occur was less clear. The main problems faced by the Californian electricity industry were as follows.

Firstly, it was believed that the existing regulatory framework was incompatible with the drive towards competition in the industry. This problem had been observed in other US states and, to a certain extent, was dealt with by the Energy Policy Act (EPA, 1992). Secondly, and a prime reason for reform, was that California's electricity prices were approximately 50% higher than the US average, and it was determined that a new regulatory and industrial framework was required to produce lower electricity prices. Thirdly, there was a need for the promotion of market forces and the establishment of market-based regulatory solutions. A common alternative to competition was litigation, which proved to be a highly unsatisfactory and protracted way of solving market problems. The CPUC promoted competitive solutions in line with the Public Utilities Regulatory Policies Act (PURPA, 1978), as well as undertaking more specific policies designed to improve competition.

In addition, there was concern that the industry was stagnating under proposals that encouraged the maintenance of the status quo rather than actually actively pursuing economic growth, greater competitiveness and new business opportunities.

To that end, it was hoped that a new structure could be devised and implemented which would alleviate these problems, while also establishing a comprehensive, long-term solution to the problems facing the Californian electricity industry, and also provide a practical alternative to the litigation which dominated the industry.

The Californian reforms had five basic objectives, which are detailed as follows (CPUC, 1994a and 1994b). Firstly, that consumers be able to receive direct access to generators, marketers (wholesale electricity traders), brokers, and other service providers in the market for energy services. Secondly, that all consumers be able to receive the benefits associated with the increasingly competitive structure. Thirdly, that consumers have direct access to the most efficient and environmentally sound electricity services and service infrastructure available. Fourthly, that the newly competitive electric services market provide a significant contribution to the state's economic growth, productivity, competitiveness, and job creation. Finally, that all customers have universal access to basic and affordable electric services that maintain the pace of innovation and change in the market for electricity as a whole.

It was anticipated that consumers would be granted the following choices: to retain the services of the traditional vertically integrated regulated utility for their energy services; to contact directly with generators and other service providers to establish a tailored service portfolio; contract with energy service brokers, marketers, or other service providers to act on behalf of the consumer to establish their service provision. Therefore, the essence is that consumers be allowed choice through direct access, known as "retail wheeling".

In order to achieve these goals, it was perceived that a wholesale market for electric services would have to be established, and that the appropriate institutional arrangements either be created from scratch or developed from their current levels. It was hoped that the policy of direct access combined with the pre-existing conditions of the EPA would expand the market and allow greater incentives for efficiency. The experience with wholesale power markets (such as the Western Systems Power Pool, see below) was such that not only was it hoped that consumers and producers would continue to benefit, but also that neither safety nor system reliability would be compromised. In addition, it was anticipated that the integration of electricity and telecommunications services would prove most beneficial to competition, as the use of telecommunications to transmit price data to consumers was seen as vital to competition, as it had been in the Western Systems Power Pool (see below).

Many of the institutional and contractual arrangements required for these reforms were already in place at the time these reforms were actually proposed. Interconnected distribution networks had already been established voluntarily, enhancing wholesale electricity transactions and aiding the development of contractual arrangements and financial instruments.

These arrangements were largely a consequence of the Western System Co-ordinating Council (WSCC), which not only has improved the degree of reliability provided by utilities, but it has also increased trade between members to the benefit of both members and their consumers. Established in 1991, the Western Systems Power Pool (the Pool) is another industry-created institution derived from the WSCC, which comprises twenty-two states, one Canadian province and sixty million consumers. This pool is centrally managed by a computer system located in Phoenix, Arizona, and relies on a sophisticated telecommunications-based computer system to allow its members to engage in short-term trades for energy, capacity, exchanges and transmission services, witnessing over one thousand monthly offers. The Pool allows members to engage in mutually beneficial transactions and make more efficient use of the West's generation and transmission infrastructure.

The operation of the Pool was indicative of the stance taken in California, namely the importance of separating the ownership and operation of the different bodies within the industry. For example, as outlined below, the CPUC were keen to make the service operator independent from the pool operator in order to prevent discrimination and to facilitate the increasing transparency of information. This separation did not compromise the high degree of central co-ordination and control required for the successful operation of such a complex set of institutional arrangements as that required to deliver power to California and the west coast of the United States. In fact, the pre-existing arrangements were such that the New York Mercantile Exchange (NYMEX) viewed them as a stable enough foundation upon which to base their first futures contracts for electricity, with such arrangements allowing buyers and sellers to manage their risk, as well as promoting further similar arrangements (see below).

The WSCC Pool is not the only pool in the US, but it's success, location and range make it a possible template for deregulation in California. However, the main concern apparent in California and other states was the need for vertical separation of ownership from use for a number of reasons. Firstly, the not all of the power producers which operate in the broader industry are pool members. Therefore, those suppliers who are not pool members must face information and transaction costs that can represent barriers to the use of the infrastructure. Secondly, these barriers may pose a threat to the successful expansion of the transmission system, as new members may be discouraged from joining the pool. Thirdly, those who seek to buy from the pool may face similar barriers as those seeking to supply into the pool.

The EPA, which effectively severed the link between ownership and use addressed these concerns, and in doing so, Congress took a considerable step towards eliminating barriers to efficiency in power markets. The passage of the EPA served to create another industry-led institution comprised of a group of different firms - the regional transmission group (RTG) - which it was hoped would create an effective forum in which to provide grid access. It is anticipated that at some point in the future, when the RTGs have grown in both size and efficiency, they will merge with the industry-led pools and reliability councils. This will result in an integrated market or set of markets for transmission in the Western United States (both inland and on the Pacific West Coast), thus increasing the system's efficiency.

4.2. The path to reform and the new market structure.

The reforms examined by the CPUC represent a two-track approach. Firstly, in the areas of the industry that exhibited natural monopoly elements, or where market power existed, the existing cost-of-service regulation was to be replaced with alternatives that focused upon utility performance and incentives to efficiency. Secondly, in those areas where competition was a more appropriate means by which to organise the development, delivery and consumption of energy services, the existing regulation was to be replaced by market forces. These potentially competitive areas are generation, energy efficiency, power brokers, marketers, and other service providers. In order to achieve the first track, the utilities existing initiatives to performance-based regulation had to be strengthened, while the second necessitated revisions to the state's regulatory framework, which it is anticipated will be based around a long-term, staged implementation strategy (see below).

4.2.1. The key elements of the reforms.

In order to achieve the reforms, the following components were seen as necessary by the CPUC. Firstly, the direct access strategy would be based on two tracks: those consumers who wished to continue to receive their services from the vertically integrated company (these consumers are termed utility service or full service consumers), and those who wished to take advantage of the competitive generation market (direct access consumers). The main problem in introducing such a dual system was ensuring that the utilities not be able to shift costs between their direct access and utility service consumers, as cross-subsidisation could occur. However, it was anticipated that accounting barriers would be created which would prevent such behaviour, including the identification and fair allocation of any uneconomic utility assets.

Secondly, the utility would retain its traditional right to service only in the case of those consumers who did not choose to undertake direct access, thus continuing to receive bundled service from the utility. This classification would initially include all but the largest consumers in the first stage of the proposed strategy of deregulation, which is based around a five-year phase-in period (see below). The utility would continue to supply utility service consumers with the traditional bundled service (generation, energy efficiency, co-ordination and system control, transmission and distribution), would acquire generation and energy efficiency services from competitive markets and existing utility assets, and would retain the option to construct new generation facilities to meet the demands of these consumers.

Thirdly, those consumers who wish to obtain direct access would have the right to acquire generation services directly from non-utility service providers. As such, the utility would lose its exclusive franchise for these customers, necessitating modifications to the utility's mandate in order to allow it to compete in this sector. Although utilities would be allowed to compete in this sector, regulatory oversight would still be necessary with regard to the ownership of transmission assets in order to limit the potential exploitation of monopoly power. The utility would remain obligated to provide transmission and distribution services on a non-discriminatory basis to those direct access consumers requiring them after having secured their own non-utility generation services.

Fourthly, the direct access classification would be voluntary, based upon the stages of eligibility to be introduced. Direct access is scheduled to begin on 1st January 1998, with all consumers scheduled to be eligible for direct access by the beginning of 2003 (or five years after the start of the transitional period if the January 1998 start date is delayed). Eligibility is by no means a reason to undertake direct access as those consumers who are eligible for direct access but do not exercise this option will continue to receive a bundled, regulated service.

Fifthly, the utility will remain the provider of last resort for all consumers. This means that those direct access consumers who wish to return to utility service status can do so, but only after providing the utility with notice of at least twelve months. A direct access consumer who has returned to utility service classification can go back to direct access, again only after an additional twelve-month notice period. Likewise, the utility itself is required to provide service to consumers wishing to return to the utility service system in less than twelve months. However, the utility is under no obligation to offer service to such customers at the tariffed rate. In contrast, the returning consumer must compensate the utility by an appropriate amount for the incremental costs incurred as a consequence of providing service until the twelve-month period has expired.

These conditions were seen as necessary to ensure that the utility has enough opportunity to plan its capacity such that it is capable of meeting demand, and preventing uneconomic decisions that could result if consumers were unrestricted in facing the choice between the utility service price and the competitive direct access price. If consumers were unrestricted, this could lead to constant changes between the two types of service, making it difficult for the utility to plan its decisions in such areas as investment in new generation facilities.

Sixthly, for direct access consumers, the CPUC will have the responsibility of ensuring non-discriminatory transmission, distribution and co-ordination and system control services. (The utility service customers will continue to be protected through their integrated service package.) While competition in the generation sector will provide a superior approach compared to regulation, transmission and distribution will still require regulatory oversight.

Finally, the regulatory structure concerning resource procurement will be eliminated. This system establishes the amount of generating capacity (thus the output of these plants) that the utilities can subject to competitive auction. With the introduction of direct access, the system will be modified such that the risk associated with these services will be borne by the shareholders. This will be undertaken against a backdrop of regulatory oversight to prevent cross-subsidisation, while also altering the regulator's role to reflect the competition present in the market.

4.2.2. Reforming the regulatory stance.

The traditional regulatory compact is comprised of several key components (CPUC, 1994a and 1994b). Firstly, the granting of monopoly franchise rights. Secondly, by allowing it to recover reasonable expenses and earn a fair rate of return on its investment, the utility's financial security is ensured. In return, the utility is subject to regulation by the CPUC under the state constitution and by statute. The CPUC must ensure that the utility provides a safe, reliable and reasonably priced service to all consumers within its monopoly franchise based upon the conditions of non-discrimination. Given the deregulation to date and the proposals outlined, it is also necessary that the regulatory system must adapt - specifically, regulation must be focused upon the establishment and encouragement of the competitive marketplace.

In the first track of the reforms (from early 1996 to the start of 1998), performance-based regulation will be introduced, thus altering the regulatory compact along with the way in which reasonable rates of return are ensured. A bundled utility service package must remain a viable option for consumers, especially for those who are seek to but are unable to take advantage of direct access. It is with this and other considerations in mind that the change in regulatory strategy has been proposed.

Firstly, as mentioned above, electricity prices in California are as excessively high - performance-based regulation should provide better incentives for efficient operations, investment, and in turn lower prices. In addition, performance-based regulation is seen as a means by which the regulation may be simplified in the long run. Secondly, given that performance-based regulation will not alter the industry franchise to any great extent, the system's safety, service and reliability should remain at their traditionally high levels. Thirdly, the regulatory reforms should generate an opportunity to earn returns that will be at least the same as under cost-of-service regulation. Finally, performance-based regulation should allow utilities to make a smooth transition from the existing regulatory-based structure to the planned consumer-orientated structure.

In the second track of reforms (1998 to 2003, and beyond), competition will replace regulation. Based around the recent history of California's investor- and public-owned utilities (CPUC, 1993), the extent of competition in generation is apparent. This is the domain where direct access will be introduced in stages, but it will necessitate adjustments to the regulatory compact in order to ensure that utility service consumers are not exploited either during or after the second transitional phase. Furthermore, regulation will still need to exist in those areas where competition is not feasible. In addition, areas such as ratemaking and investment criteria will require reform.

The EPA grants the Federal Energy Regulatory Commission (FERC) complete discretion in granting and determining the appropriate arrangements regarding access, which it is hoped will be improved by the new regulatory stance. In addition, the State of California (through the CPUC) will retain jurisdiction over the siting of new power plants and retail franchise issues, as given in the EPA. In order to facilitate transmission access, FERC has indicated a desire to see a greater number of RTGs, provided that consumer interests are guaranteed.

It is therefore apparent, that the degree of regulatory restructuring will be considerable. It is now appropriate to examine the industrial changes that will be undertaken as a consequence of this programme.

4.2.3. The new market structure.

By 1st January 1998 at the latest, there will be an independent service operator (ISO), a competitive wholesale power pool (Power Exchange), and a customer choice of service options. Each of these areas will be examined in turn, but first it is necessary to investigate more general issues. Firstly, the role of the utility in the newly restructured industry must be to provide a safe, reliable, non-discriminatory service to all electricity consumers. Secondly, it must also provide energy from the power exchange to all consumers who do not choose direct access or are not eligible for direct access (utility service customers). Finally, it must provide service under incentive ratemaking rather than cost-of-service ratemaking for distribution and utility-owned generating assets.

It is hoped that the new structure will address the problems of both vertical market power and horizontal market power: the former exists due to utilities controlling generation, transmission, and distribution; the latter exists because utilities control the majority of the generating capacity in the service territories. Vertical market power is expected to be removed by vertical separation - the creation of both the ISO and the power exchange, and a commitment by the utilities to additional unbundling of their operations.

Horizontal market power exists as the utilities control the majority of the generating facilities in their service areas. Horizontal market power is expected to be reduced by performance-based regulation as a means of preventing cross-subsidisation of inefficient generating units that would not be competitive in the Power Exchange. Performance-based regulation is based around the use of established benchmarks, with rewards or penalties being given to the firm based upon whether those benchmarks were exceeded or not met. In this situation, cross-subsidisation would preclude returning the full value of efficient generating facilities to consumers. Furthermore, market power will also be restricted by plant sales, with both Pacific Gas & Electric (PG&E) and Southern California Edison Company (SCE) committing to divest 50% of their fossil fuel generating assets.

Vertical market power would typically result from a single utility owning generation, transmission and distribution, and the abuse of this kind of power could occur if, for example, system operators gave priority to their affiliated generating units in transmission and distribution. The ability to limit the market power of companies in transmission will be based upon the successful establishment and operation of comparable and non-discriminatory open access tariffs. The potential for such manipulation should be successfully eliminated through isolation of transmission control in the ISO, and the establishment of an independent dispatch ordering system.

Horizontal market power can occur in the presence of significant barriers to entry or few market participants, and is reflected in an ability to influence prices. In the case of the electricity industry, this will focus upon generation. There is considerable concern in California regarding the extent of market concentration in generation, notably in the ownership and control of generating plant. As in the UK, the role of mid-merit generating plant, which typically influences prices, and that ownership of this particular type of plant could be more important than overall generation concentration. A firm that owned such generating capacity could control the marginal price for generation.

In addition to mid-merit plants, some generating units could be located in relative proximity to the transmission system, thus giving generators the possibility of abusing market power if the system becomes heavily loaded (see below). Some areas, which may be identified by the transmission system after restructuring, may not be prone to the immediate entry of lower priced competitors due to there being insufficient transmission capacity. It is therefore a concern that the sale of such units with the potential to influence prices to companies other than investor-owned utilities will not decrease the potential for market power or the possibility of its abuse. It is hoped that the divestiture plans will eliminate these concerns.

Public purpose programs are also addressed under the reforms. Such programmes are those based upon social objectives. These include renewable resource generation, discounts for low-income households, certain minority groups, energy efficiency, and promoting resource diversity. These arrangements are unlikely to be changed in the immediate term from the pre-existing conditions, but some modifications will focus upon the role of electric utilities as the providers of these services.

The new system will incorporate a renewable energy-purchasing requirement through a certain percentage of generation from renewable resources. It will adopt a surcharge to fund public goods (research, development and demonstration, energy efficiency and demand side management programs), as well as a separate surcharge to provide low-income assistance and efficiency services. Finally, the costs associated with RD&D for regulated functions and other programmes will continue to be collected as part of the regulated rates.

Finally, the role of the CPUC must be confirmed. In the system, the CPUC will monitor the market in order to detect if and when there are deviations from its ultimate goals, and will intervene if and when it is perceived necessary. It will increase the importance of and the emphasis on consumer protection, and will ensure that the safety and reliability of electric services are maintained.

4.2.4. The independent service operator (ISO).

This body will be responsible for the control and operation of the state's transmission system, and must undertake the following responsibilities. Firstly, it must provide non-discriminatory, open transmission access for wholesale and retail power sales. Secondly, it must co-ordinate the scheduling of despatch of power from all sources and balance the system load on a real-time basis. As such, it must also efficiently manage transmission congestion. Finally, it must maintain system reliability, recover the cost of ancillary services, and provide information on such areas as transmission constraints, load distribution and line losses.

Most importantly, the ISO must be structured such that it is independent of both the utilities and the power exchange. It will not own the transmission system (that will remain the responsibility of the utilities), but will make all operating decisions regarding the system. Its independence from generation should remove the potential for discriminatory transmission access. This system and the operators must be approved by the FERC, as well as its ownership status, i.e. Private Corporation, non-profit making organisation, governmental organisation, etc.

The ISO will co-ordinate day-ahead scheduling and balancing for all uses of the transmission grid, accepting nominations from market participants for both the day-ahead schedule and the hourly balancing transactions. The nominations from the power exchange will include the tentative dispatch, the locations of the generation and loads, and the associated bids for generation and loads. The bilateral nominations must include the amount and timing of deliveries, along with the source and destination for power transmission. The ISO will also accept bids for increments and decrements of nominated inputs or outputs that would be required to redispatch the system if the need arose. In co-ordinating demand and supply bids, the ISO must maintain quality, reliability and security of supply, and manage transmission constraints and system congestion. As in the pre-reform scenario, transmission services will continue to be regulated, but the ISO's structure will be modified along the above guidelines.

4.2.5. The power exchange.

The power exchange will provide a market for power based around a series of published hourly or half-hourly prices, and will be a competitive wholesale power pool. All power producers will have the right to compete within the pool based upon transparent bidding rules. The pool will match supply bids made by generators with demand bids for power from utilities, power marketers and other service providers. These bids will be ranked on a least cost basis, and the power delivery schedule that is created will be submitted to the ISO. As the prices are published, the prices will allow customers to make efficient purchasing decisions and adjust their consumption accordingly.

The power exchange will be separate and independent from the ISO and will not be permitted to possess any generating plant, or to have any financial interest in any source of generation. As with the ISO, it must be approved by the FERC, and its ownership status verified. In terms of actual participation, municipalities, independent power producers, out-of-state producers, and public utilities can all participate. (It should be noted that out-of-state producers can only compete in the power exchange on conditions of reciprocal access to their pools if and when they are established). All purchasing from and selling through the power exchange will be voluntary, but during the five-year transition period, Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison Company (SCE) must commit to the following conditions. Firstly, that they are required to purchase all of their energy used to meet the demands of utility service customers from the power exchange. Secondly, they are required to bid into the power exchange until such time as the generating plants undergo market valuation (i.e. through sale or other means), and a potential change of ownership under the divestiture plans outlined above. The reason why a change of ownership is not guaranteed is that the generator may bid for its own plant and become its eventual owner - subject to certain conditions. As such, these companies will remain under regulatory control in addition to being subjected to market disciplines.

The CPUC places important emphasis on the role of transparent price signals and their benefits to consumers and producers alike. It is believed that this information will send the most reliable signals with respect to the need for additional generating units, as well as the need for cost-cutting steps to keep existing units competitive.

The power exchange will be a daily auction system, with the exchange's operators receiving bids for generators stating the minimum price for which suppliers would be willing to dispatch a certain amount of power in hourly or half-hourly increments. The exchange must then match these generation bids with demand bids submitted by utilities, brokers, marketers, or other entities operating on behalf of end consumers. This will result in a series of market-clearing prices for electricity throughout the day. As determined by the ISO, the exchange will then determine a dispatch schedule for the generators based upon these prices and the bids, and then based upon this schedule, the ISO will integrate the schedule nominations based on direct access contracts.

The market-clearing locational prices will be obtained from the ISO as part of the integration and co-ordination of the alternative nominations and bids. Every winning generation bidder will be paid the market-clearing price at its location, with that price consistent with both the bid and the supply and demand equilibrium. The exchange will average the locational clearing prices, with end use customers served by the exchange receiving that price. The net payments to the power exchange will be allocated through the ISO to pay for transmission losses or as congestion payments.

4.2.6. Customer choice.

The principle of direct access is that retail consumers will be allowed the choice of arranging the purchase of electricity directly from non-utility generators. This system will be introduced with an initial twelve-month phase commencing no later than 1st January 1998, and will include all consumer classes. In the absence of technological barriers, all consumers will be eligible for direct access after the initial introductory period, but in the event that technical barriers do exist, then a phase-in schedule has been developed. Such barriers would typically concern the ability with which consumers could monitor the price of electricity on an hourly/half-hourly basis, and therefore depend upon the introduction and installation of appropriate metering technology. All consumers will have the option of participating in each phase, if not directly then through intermediaries. For example, third-party intermediaries could purchase unbundled electricity and then bundle it with other energy services for resale to consumers. Such an aggregation could include the loads of multiple consumers or a consumer's load at several individual sites. If customers wish to exercise their option to become direct access consumers, then they must inform their distribution utility.

Alternatively, the distribution utilities could offer real-time rates for power, which would mean that the tariffed electric service would be referenced to the real-time price in the power exchange. Such an option would allow consumers to redirect their power usage to lower-cost periods, thus reducing their bills. It would also discourage unnecessary investment in generation, and encourage efficient energy usage. Finally, it would allow those consumers who do not choose real-time rates to be billed based upon average cost, as they are at present.

Finally, the customer could arrange contracts for differences that would allow for the hedging of risks associated with price volatility. In these arrangements, the consumer would pay the contract price rather than the (spot) power exchange price. (See the earlier chapters on UK contracting arrangements for more details).

It is expected that even those consumers who do nothing in the face of this deregulation will still benefit. The full benefits of wholesale competition will be achieved through the price reductions seen as a result of the power exchange, and in the presence of real-time or time-of-use meters, customers should be able to optimise their energy usage to take advantage of the lower-priced off-peak rates. With the power exchange operating state-wide power dispatch and price competition on an hourly or half-hourly basis, efficiency will be increased, while the limits on cross-subsidisation imposed by performance-based regulation should reduce prices.

Direct access will benefit small and large consumers in different ways. The rates paid by small consumers receiving utility service will be capped at their 1st January 1996 nominal levels beginning 1st January 1998, and will remain capped for seven years - this will result in a 23% real decrease based on the assumption of 3% inflation. With direct access beginning in 1998 for a cross-section of consumers, it is anticipated that it will then be extended to all consumers no later than the five-year phase-in (as discussed above). The proposed schedule is as follows: 8MW or greater in 1998; 2MW in 1999; 500kW in 2000; 100kW in 2001; 50kW in 2002; and the remaining consumers in 2003. Large consumers should experience the same benefits as small users in terms of expected wholesale price reductions, as well as receiving the same right to direct access. In order to encourage efficient energy usage on an hourly or half-hourly basis, real-time meters will be required for those largest users with demand greater than 20kW to ensure that the proper price signals are responded to. Finally, large consumers will receive immediate access to contracts for differences taking into account the contract volume and the time that the contract is called.

4.2.7. Transition costs.

Unfortunately, the adjustment process to a more competitive environment brings with it costs of adjustment, resulting obligations which become uneconomic in the new competitive structure. These are typically in one of three forms: an above market proportion of undepreciated generation asset fixed costs; the costs of generation contracts in the face of uneconomic prices (similar to the "take-or-pay" contracts of British Gas); and other unavoidable generation-related costs.

These costs will be calculated based upon the commitment that by 2003, all non-nuclear generating assets will be held out for either sale or appraisal. If the market value of the asset is less than its book value (i.e. the asset's original cost minus depreciation and deferred taxes), the difference will increase transition costs. Likewise, if the market value is greater than the book value, the difference will reduce transition costs. In the case of contracts, the costs will be estimated based upon a comparison of the ongoing contract cost with the power exchange price.

In the case of nuclear assets, the following scheme has been established. There are two nuclear power stations in California: San Onofre (San Onofre Nuclear Generating Stations, SONGS), which is owned by SCE (80% ownership share, as well as being the plant's operator) and SDG&E (20% ownership share) and Diablo Canyon, which is owned and operated by PG&E. In addition, SCE owns approximately 16% of the Palo Verde nuclear generating facility in Arizona. The CPUC has established an alternative approach for SONGS Units 2 and 3 to that stated above. This approach sets the price of electricity equal to a forecast of prices in 2003. For Palo Verde, Edison has been ordered to submit an alternative proposal based on that for San Onofre. Finally, PG&E has been instructed to submit an alternative proposal for Diablo Canyon, such that rates are not increased above their levels on 1st January 1996, and are decreased to market levels by 2003.

It is expected that all consumers of the investor-owned utilities will pay their share of the transition costs. They will be collected in a non-bypassable charge, called the Competition Transition Charge (CTC), which will be collected until 2005. The options for collecting the charge were from distribution, on meters, or as a general levy (such as the fossil fuel levy in the UK). The option chosen was to add the charge to the bills of consumers in proportion to their consumption of electricity - the surcharge being reported separately in an "unbundled" bill. Utilities must recover all transition costs, but will earn a reduced return on equity for uneconomic assets. Finally, the rates for bundled electric service will not increase beyond their 1st January 1996 levels.

Transition costs will also arise as a consequence of a plant being unsuccessful in its bid to supply power through the exchange, as it will have no opportunity to recover its fixed costs. Even if a plant were to be successful in getting its bid into the exchange, transition costs will also accrue if the market-clearing price is insufficient to allow the company to recover its plant's fixed costs.

As is seen in the overview of deregulation in other US states, transition costs (or stranded costs) remain a considerable problem to be overcome, and it is unlikely that deregulation will have the support of all in the industry until solutions are proposed.

4.2.8. Concluding comments on the reforms.

While extent to which these reforms will prove successful is uncertain, the commitment to reform of some kind is apparent. The CPUC has built in several methods by which - if need be - the reforms can be adjusted based upon delays or technical factors, as well as allowing companies the right of appeal. The reforms listed here have concentrated on some areas (the ISO and the power exchange) at the expense of others (public purpose programmes), but it is apparent that the restructuring which has been proposed in California is unlike anything observed in the US, and its main notable comparison is with the deregulation of the electricity supply industry in England and Wales.

While the deregulation of the electricity supply industry in England and Wales has been well-documented in the previous chapters, a summary of the main points to date of deregulation in California is provided in Table 5, while an overview of the main aspects of the planned deregulation required by the start date is provided in Table 6.

Table 5. Chronology of major events in Californian electricity deregulation.

Event	Date
Orders issued on electricity restructuring and regulatory reform (CPUC, R.94-04-031 and CPUC I.94-04-032).	April 1994
Policy statement issued to determine:	August 1994
- eligibility for direct access;	
- utility participation in generation market for direct access consumers.	
Investigation opened into cost allocation and potential for uneconomic utility assets.	September 1994
Investigation opened into unbundling and pricing of utility services for direct access.	September 1994
Eligible transmission level consumers seeking direct access notify utilities.	July 1995
Proposals on restricting market power filed with FERC and CPUC (vertical separation and divestiture plans).	March 1996
Proposals on independent service operator filed with FERC and CPUC (establishing the operator and transmission regulation and pricing issues).	April 1996
Proposals on power exchange filed with FERC and CPUC (bidding protocols and establishing the exchange).	April 1996
Consumer choice phase-in schedule proposals filed (including eligibility and metering issues).	August 1996.
AB 1809 is passed by the state legislature - the first pieces of the competitive market start to come into place	September 1996.

Table 6. Essential components needed by start date (1st January 1998) and their functions.

Institution/arrangement	Role/Structure
Independent service operator	Control and operation of the state's transmission system. Providing non-discriminatory access for wholesale and retail power sales. Power dispatch co-ordination. Management of transmission congestion. Independent of utilities and power exchange. Operates but does not own the transmission system. (Ownership arrangements to be determined at the present time - Private Corporation, non-profit making organisation, state-owned.)
Power exchange	Operating the power market given published hourly or half-hourly prices. Competitive wholesale power pool. Matches power supply bids with demand bids from utilities to establish a delivery schedule and price details. Separate and independent from the service operator. Will not have financial interests of any kind in generation. (Ownership arrangements to be determined at the present time).

Table 6. (Continued)

Electric utilities	Provide a safe, reliable, non-discriminatory transmission service to all electricity consumers. Provide energy to all consumers ineligible or unwilling to take direct access
Direct access protocols	Eligibility and five-year phase-in schedule to be established, including billing and access charges.
Metering protocols	Metering arrangements established and relevant equipment installed.
Transition costs	All consumers to pay transition costs through the competitive transition charge. Transition costs to be calculated and charge arrangements to be established. (To be resolved - probably the main stumbling block in the pursuit of competition).
California Public Utilities Commission	Monitor the market and determine behaviour incompatible with the pursuit of competition. Intervene in the market as and when necessary. Increase and emphasise the role of consumer protection mechanisms. Ensure system safety and reliability.

SECTION V - Deregulation in California and forward trading.

5.1. Comparisons between the Californian and English systems.

It should be apparent from a description of the Californian system that it is highly similar to the system in England and Wales. From a basic standpoint: vertical separation; competitive generation; independent transmission network and competition in supply, it would be logical to conclude that the English system has possibly been used as a model. The similarities should be obvious: the NGC and the ISO (although the NGC does own the transmission system); the pool and the power exchange; progressive competition in supply phased in over a number of years based on electricity demand; and competition in generation. Given this, what should perhaps be noted more than the similarities between the systems are their differences.

Firstly, the Californian power exchange is voluntary - running the risk that it could be a "shallow" pool - but the largest companies in the state's industry - San Diego, Pacific and Edison - must bid a certain percentage of their power sales through the power exchange for at least the five year introductory period. While this is potentially a source of concern, the problems will probably not materialise. The three companies could choose to abandon the power exchange after the initial period, but it is logical to expect that as the utility service customers make the transition to direct access, at least some of them will continue to be served through the power exchange.

In addition, there is the concern that no other generator will seek to join the exchange, and the three companies will dominate the exchange. However, there are two reasons why this should not be the case: firstly, out-of-state generators already transmit power to California and will not abandon their market shares, and secondly Pacific and Edison have been instructed to divest 50% of their fossil fuel capacity, which should prevent them from exploiting the exchange. In addition, if the Californian reforms are matched in other states, then a series of state exchanges could develop, along with the potential for competition between pools.

A potential problem arises in terms of market share, as outlined by Perl (1996) in determining the geographical scope of the relevant market. This is a highly difficult undertaking in the context of the electricity industry as one must first predict the operations of the transmission system. When transmission links are not heavily loaded, the geographical scope of a market could be considerable, indicating a low concentration ratio. However, in the case of high loads on transmission wires, the network could become full in certain areas, thus granting certain companies effective regional monopolies. Even if transmission lines are not full, a single utility may possess considerable market power because a certain proportion of the demand in an area must be met locally in order to ensure stability. Such local stability constraints are an additional problem and may have to be addressed in much the same way as baseload and non-baseload power in England and Wales. As such, UI's proposals for the New England region represent an advancement in solving these problems.

Secondly, the independent ownership of the ISO is comparable to the NGC, but the key point is that the ISO is not permitted to hold generating assets. Of course, the NGC was allowed to own the pumped storage businesses until late 1995 before the regulator determined that it was inappropriate given the NGC's role as the pool operator to encourage competition in generation whilst owning generation assets.

Thirdly, allowing individual consumers to contract directly with generators on a large scale is akin to the (all but rejected) principle of trading outside the pool. In establishing contracts for differences between themselves and the generators, consumers run the risk of having their asymmetric bargaining position exploited. However, it is hoped that the regulatory system will prevent such an occurrence. A further issue that has been left to the market is the terms and prices of contracts for differences - if this remains the case then the contract market will be far from transparent and the risk of price discrimination could arise.

Finally, there is the fact that in the power exchange, the market clearing price is calculated based upon both supply schedules and demand bids, unlike the pool's supply bids only. It is logical to conclude that, *ceteris paribus*, the prices in the power exchange should exhibit less instability than those in the pool, due to the latter using only an estimate of demand in the construction of the system marginal price.

An additional point should be made concerning the actual reason for the reforms. While deregulation has been common in the United States electricity industry for some time, the Californian proposals went beyond those laid down in federal statutes at the time of their initial proposal. The goal for deregulation and privatisation in England and Wales could be described as being highly politically motivated but also based upon economic criteria. In California, the level of electricity prices are such that competition is expected to bring price declines which will result in a more competitive situation in terms of prices and consumer welfare. Therefore, one could argue that economic concerns dominate the Californian motives for deregulation.

To conclude, it should be noted that as with privatisation in England and Wales, the Californians are facing a set of similar problems: modifying the vertically integrated structure; how to prevent market power abuses; how to ensure competition in generation; how to operate a new regulatory system; how to ensure low prices; and how to meet the costs of reform. The UK government approached these problems in the ways outlined in the previous chapters, while the Californians have chosen the ways detailed in the preceding sections. The UK has mixed results in achieving its objectives, and it will take at least until the end of the five-year phase-in period until it can be ascertained how successful the Californian approach has been.

5.2. Electricity futures trading in the United States.

As the examination of the spot and forward/futures markets has formed an important part of this thesis, it is appropriate to briefly examine the state of progress in the futures market for electricity in the US, which is - as mentioned - based upon the California state market.

Electricity futures trading began on NYMEX in March 1996, based on two contracts, both of which have West Coast delivery points. The first is the California-Oregon border (COB) contract, which directs power to northern California, the second is the Palo Verde contract, which dispatches power from the Arizona facility to southern California. Both contracts possess a standard format: they call for the delivery of 736MW of power over a one month time period at a flow rate of 2MW per hour during the course of 16 peak hours (determined by the contract parties). Delivery is specified to occur over twenty-three business days within a month (there are suitable arrangements in the absence of twenty-three business days). Eighteen consecutive months are listed on the exchange, and as discussed, the California area was chosen due to the high degree of trading already being carried out there.

The establishment of the futures market in the electricity has been buoyed by the success of the gas futures market, which was introduced some years earlier. Electricity futures trading during April 1996 saw approximately one thousand contracts per day, in what was seen to be a relatively stable market, or at least a market more stable, given electricity price volatility. This fact may be attributed to the relatively low trading liquidity in the market, as contract trading has yet to develop to the same extent as the successful NYMEX gas futures market.

The adoption by NYMEX of electricity futures contracts was not without its difficulties. The continued deregulation of the industry has altered perceptions of electricity from a highly regulated industry to one that could satisfactorily support futures trading. The spread of competition is perceived as being conducive to futures trading for the following reasons. Firstly, competition should lead to lower prices as new suppliers join the industry, with lower prices and more firms making futures hedging a viable option. Secondly, increased competition reveals the existence of old inefficiencies, which must be eliminated in an attempt to cut costs - again leading to lower prices. Thirdly, a short-term market develops which increases reliance upon short-term contracts and a shift from longer-term contracts. All of these factors result in an increased variability in prices relative to the standard, regulated utility. NYMEX perceived that all of these changes were being undertaken with such pace in California that the state would be a suitable choice for the development of electricity futures.

In the first month of trading, the COB contract volume was three times that of the Palo Verde volume, a fact which may be attributed to the high volume of pre-existing California-Oregon trade in the Western Systems Power Pool, making it easier for traders to follow the COB prices. The balance of contract trades has been greeted with some surprise, as the COB contract is determined primarily through the capacity of hydroelectric generating facilities. The amount of electricity produced would be inherently influenced by the weather, and rainfall in particular. The water flow will affect the amount of electricity produced, and therefore the cost to the hydroelectric facilities, who consequently influence the price of the COB contracts. These facts introduce considerable potential for uncertainty into the contract price.

There is some concern that the Palo Verde contract may eventually cease trading unless it attracts greater interest. However, it is possible that such a move could paradoxically benefit the futures market, as the trading of two contracts lowers the liquidity in both markets. As such, a unified market could have greater liquidity as a whole.

Of the trades in the market, it is believed that approximately half are being undertaken by speculators or floor traders, and the remaining half by power marketers. At present, the utilities themselves and large electricity users would seem to be shying away from trading. Of the approximate 150 power marketers in the US, it is believed that some two dozen are trading electricity futures on NYMEX, and these are typically the largest of the marketers, such as Houston's Enron Power Marketing, Duke/Louis Dreyfus of Connecticut, and the Natural Gas Clearinghouse affiliate, Electric Clearinghouse.

The American power marketers tend to be either created by finance houses (e.g. Morgan Stanley), or are divisions of natural gas shippers (e.g. Enron), or are affiliates of generation companies (e.g. AES Power) or utilities (e.g. Brooklyn Union Gas), or are completely independent companies (e.g. New York City's NAEC). Power marketers take a physical position on electricity and then use the futures contracts to hedge their exposure to this position. Although they do not necessarily deliver power to the COB or Palo Verde, the contracts offer the ultimate objective of risk management - hence their attractiveness (for example, through spread trading - see the earlier chapters on UK EFA trading arrangements).

It is also highly likely that the limited trading in futures will be increased as a consequence of the FERC's orders of 24th April 1996. These orders (Order No. 888 and 889) require electric utilities to offer non-discriminatory access to their transmission lines to power marketers (No. 888) and to share information regarding available transmission capacity (No. 889). These orders could well have the same effect on the electricity industry as similar orders issued years earlier had upon the gas industry: it will be much easier to buy and sell electricity in the marketplace for delivery to consumers with direct access. It is possible that the direct access system will bring the utilities into the futures market on a much larger scale, as the utilities will have to establish new rules in the absence of the stability associated with the existing cost-pass through regime, be willing to accept greater price risk, and therefore participate actively in the futures market.

Indeed, it is anticipated that a new futures contract may develop some time during 1997. This contract, unlike the existing arrangements, will have an East Coast delivery point, possibly within the Pennsylvania/Jersey/Maryland areas. If this is achieved, it could represent the start of the "regionalisation" proposed by the EPA, thus facilitating competition and the possibility for further regulatory reforms. It is also anticipated that as the spread of direct access continues, and consumers become able to choose their own power supplier, then new hedging instruments will develop to meet this new type of electricity demand.

This flourishing, open system of forward markets in the US is in sharp contrast to the market in the UK. Despite the volume of electricity traded under contract in the UK, the lack of transparency in the market due to the commercial sensitivity of contract prices is probably hindering the development of the market itself. With there being a limited number of non-electricity company players in the forward market (the brokers), it is unlikely that this will be rectified due to the following problems.

Firstly, the operation of the pool is seen as too complex by some companies, with the contract market's limited transparency possibly limiting entry: as discussed previously, many IPP generators will only enter the industry with the backing of long-term contracts. Secondly, the market power of National Power and Powergen is discouraging entry as companies do not wish to be at the mercy of firms who have the ability to determine pool prices. Finally, the system of regulation is prone to such a degree of uncertainty (especially after the DGES's decision to revise the distribution price controls) that the market is seen as too unstable for trade. The main potential way in which these problems could be overcome is in April 1998 with the final stage of competition in domestic markets is opened up through direct access. This event will increase the potential size of the contract market, and hopefully the pursuit of new customers also. (These aspects have been discussed in the earlier chapters on UK deregulation).

It can therefore be said that although the US may be behind the UK in electricity deregulation, the US is well ahead of the UK in electricity futures trading, and perhaps the US system of standardising contracts (a system long-called for in the UK) could represent the way forward.

SECTION VI - Empirical analysis of the COB contract market.

6.1. Introducing the data set.

By researching the available resources of the Energy Online Internet Pages (www.energyonline.com), it was possible to access data on the prices at which the electricity contracts for the California-Oregon border system trade. The data consisted of actual and forecasted non-firm peak and off-peak prices for contracts ($/MWh) and was available on a daily frequency over the period September 1995 to October 1996 and was obtained from the web site's Energy Database.

It is appropriate to clarify these terms further. The California-Oregon border prices represent the average of the electricity (dollars per megawatt hour) sold at the California-Nevada border and the Nevada-Oregon border. Non-firm supply represents electricity sold along these routes that is subject to interruption at any time. Peak hours represent the period from 0600 hours to 2200 hours, Monday to Saturday, and off-peak hours represent the period from 2200 hours to 0600 hours, Monday to Saturday, and all day Sunday. These classifications introduce problems for the analysis. As the objective is to compare the actual and forecasted prices over the analysis period, in the absence of weekend observations for peak prices an adequate comparison would not be possible. Further, off-peak days are also the seasonal holidays (e.g. Christmas and New Year) and public holidays (e.g. Thanksgiving and Independence Day). Further, there are absences in certain data sets and not in others, and the computer program in use cannot estimate regressions if there are gaps in the data sets.

This problem has been solved by generating an observation for the data set by taking an average of the two observations on either side of the absent day. While this is open to contention, it represents the most appropriate way of providing for the missing observations.

The forecasts for prices are those undertaken by LGC Consulting, a California-based energy consulting company based in Los Altos which has been employed by the CPUC to undertake a recently published study (October 1996) into the consequences of the Californian path to reform.

6.2. The empirical analysis of the spot-forward relationship.

Using the data, it is possible to undertake regressions that attempt to ascertain whether the forecasts of peak and off-peak electricity prices correspond to their actual values. This is undertaken by a simple regression that measures the actual value as a function of the forecasted value and a constant term:

$$P^{a}_{i,t} = \alpha_0 + \lambda\, P^{f}_{i,t} + u_t \qquad \textbf{(4.5)}$$

The superscripts a and f correspond to the actual and forecasted prices respectively, i represents peak and off-peak prices, and u_t is the normally and independently distributed term. If it is assumed that the LCG forecasts represent the price at which COB trades were undertaken, this becomes a simple means of assessing the spot-forward relationship present in the COB contracts. As dictated by financial markets theory, the forward price is an accurate predictor of the spot price when the constant term (*alpha*) equals zero, and the intercept term (*lambda*) equals zero. This relationship may be tested by means of the Wald test for linear and non-linear restrictions, with equation (4.5) estimated over the full sample period (427 observations) and over each individual month. The results of these models are presented in Table 7.

To summarise the contents of the table, it can be seen that the off-peak forecast of the price is more accurate than the peak estimate. Although the results are the same for both sets of regressions in terms of the number of months (the test is valid on five occasions), the off-peak forecasts are a statistically valid estimate of the actual price when assessed over the entire fourteen month period. The most likely explanation for this outcome is that the peak estimates cannot fully predict the volatility associated with peak energy consumption and therefore peak energy prices. At face value, it cannot be said that the results for the off-peak regressions are any improvement. However, the fact that the result for the **entire** period indicates that the restrictions are valid lends credibility to this conclusion.

A less restrictive restriction was also applied to the regression results. This assumed that the slope parameter was equal to unity, but that there was no restriction on the value of the intercept term. This assumption allows there to be drift between the actual and forecast values, but that the trend of the actual and forecast values is the same for both variables. The results are presented in Table 8. To summarise however, it can be seen that in the case of peak contracts, the restriction is valid in seven out of the fourteen months, but is not valid over the period as a whole. For the off-peak contracts, the restriction is valid for six out of the fourteen months and for the period as a whole. It is the latter of these results which allow the conclusion that the off-peak forecast prices continue to remain the more accurate estimate of the actual prices. The fact that the restriction is accepted on more occasions than when both restrictions are in use implies that the constant term does represent a drift on at least some occasions.

One final test to determine which of the two forecasts is the most accurate may be undertaken by assessing the mean difference between the actual and forecasted values over each of the test periods. Consider the following:

$$P^{a}_{i,t} = P^{f}_{i,t} - E_t \tag{4.6}$$

where E_t represents a forecast error and a, f and i are as previously, and all variables are in logs. Rearranging the equation to place the forecast error on its own then taking the average over each of the test periods yields:

$$Average\ E_t = \frac{1}{N}\sum_{i=1}^{nTP} E_t \tag{4.7}$$

where "TP" indicates the test period of the analysis that - in this case - will be the full sample and the monthly periods outlined above. Although a common technique is to take the square of the forecast error, this will not be undertaken in this case as it will remove all negative signs and thus the capacity to assess the existence of an over- or under-prediction. The results are presented in Table 9.

To summarise, in the full test period both forecasts underpredict the actual values, although the off-peak prediction does so to a lesser extent. On a monthly basis, the peak estimates underpredict in nine out of fourteen months, and the off-peak in seven out of fourteen months. In assessing the differences in the errors between the peak and off-peak forecasts, the absolute peak forecast error exceeds the absolute off-peak error in eight out of the fourteen months and for the analysis period as a whole. This continues to support the result that the off-peak forecasts are more accurate than the peak forecasts.

One additional piece of information that would benefit this analysis is the use of trading volumes. However, it is known that since their introduction, trading in COB electricity futures has been at a rate of between thirty and two hundred and fifty contracts per day. This contrasts with the approximately twenty thousand natural gas futures contracts traded daily. The disparity has been attributed to the fact that the electricity industry is in the early stages of deregulation, and that trading volumes will increase as deregulation progresses. Although strip trading was introduced by NYMEX in September 1996 to encourage liquidity, the highest quantity of COB contracts traded in a single day is at present nine hundred and fifty-five (05/12/96), although trading in Palo Verde contracts remains well below that of COB contracts. Again, it is anticipated that as deregulation continues, contract demand will increase.

Table 7. Wald test results for peak and off-peak COB contract prices.

7.1. Peak analyses.

Time period	Observations	Test statistic	Accept/Reject H0[1]
Sep-95 - Oct-96	1-427	8.6522	Reject
Sep-95	1-30	39.5060	Reject
Oct-95	31-61	20.7406	Reject
Nov-95	62-91	7.6657	Reject
Dec-95	92-122	5.5833	Accept
Jan-96	123-153	25.7695	Reject
Feb-96	154-182	3.6072	Accept
Mar-96	183-213	20.4128	Reject
Apr-96	214-243	38.9951	Reject
May-96	244-274	2.7145	Accept
Jun-96	275-304	3.4470	Accept
Jul-96	305-355	11.4413	Reject
Aug-96	335-366	10.3221	Reject
Sep-96	367-396	4.7893	Accept
Oct-96	397-427	26.1645	Reject

7.2. Off-peak analyses.

Time period	Observations	Test statistic	Accept/Reject H0[1]
Sep-95 - Oct-96	1-427	2.2523	Accept
Sep-95	1-30	78.4909	Reject
Oct-95	31-61	0.4878	Accept
Nov-95	62-91	17.4181	Reject
Dec-95	92-122	32.6693	Reject
Jan-96	123-153	4.7733	Accept
Feb-96	154-182	9.1815	Reject
Mar-96	183-213	7.3544	Reject
Apr-96	214-243	4.8652	Accept
May-96	244-274	3.7817	Accept
Jun-96	275-304	19.0543	Reject
Jul-96	305-355	12.4646	Reject
Aug-96	335-366	33.0575	Reject
Sep-96	367-396	8.8204	Reject
Oct-96	397-427	2.5669	Accept

Wald test 5% critical value is C.S.(2) = 5.99. The null hypothesis is accepted if the calculated value of the Wald test is less than the critical value.

[1] H0: Restrictions on the equation's parameters (intercept and slope coefficients) are valid and therefore that the forecasted price is an accurate predictor of the actual price. H1: Restrictions are not valid and therefore that the forecasted price is not a valid predictor of the actual price.

Table 8. Revised Wald test results for peak and off-peak COB contract prices.

8.1. Peak analyses.

Time period	Observations	Test statistic	Accept/Reject H0[1]
Sep-95 - Oct-96	1-427	4.26090	Reject
Sep-95	1-30	33.45660	Reject
Oct-95	31-61	18.14400	Reject
Nov-95	62-91	6.53040	Reject
Dec-95	92-122	5.55870	Reject
Jan-96	123-153	1.59340	Accept
Feb-96	154-182	1.17240	Accept
Mar-96	183-213	7.52620	Reject
Apr-96	214-243	37.06620	Reject
May-96	244-274	0.37613	Accept
Jun-96	275-304	3.44160	Accept
Jul-96	305-355	0.07403	Accept
Aug-96	335-366	10.25760	Reject
Sep-96	367-396	2.64820	Accept
Oct-96	397-427	0.32484	Accept

8.1. Off-peak analyses.

Time period	Observations	Test statistic	Accept/Reject H0[1]
Sep-95 - Oct-96	1-427	2.21430	Accept
Sep-95	1-30	55.32450	Reject
Oct-95	31-61	0.15312	Accept
Nov-95	62-91	10.95820	Reject
Dec-95	92-122	26.91370	Reject
Jan-96	123-153	2.47920	Accept
Feb-96	154-182	0.16749	Accept
Mar-96	183-213	6.83120	Reject
Apr-96	214-243	1.48310	Accept
May-96	244-274	1.94530	Accept
Jun-96	275-304	19.04390	Reject
Jul-96	305-355	5.45300	Reject
Aug-96	335-366	29.18990	Reject
Sep-96	367-396	8.74900	Reject
Oct-96	397-427	0.02943	Accept

Wald test 5% critical value is C.S.(1) = 3.84. The null hypothesis is accepted if the calculated value of the Wald test is less than the critical value.

[1] H0: Restrictions on the equation's parameter (slope coefficient) are valid and therefore that the forecasted price is an accurate predictor of the actual price. H1: Restrictions are not valid and therefore that the forecasted price is not a valid predictor of the actual price.

Table 9. Differences between actual and forecast values.

Period	Observations	PEAK Actual-Forecast	OFF-PEAK Actual-Forecast
Sep-95 - Oct-96	1-427	0.19203	0.04530
Sep-95	1-30	0.56517	0.86367
Oct-95	31-61	-0.24435	-0.05516
Nov-95	62-91	-0.27517	-0.47017
Dec-95	92-122	0.05645	-0.29613
Jan-96	123-153	0.58306	0.14806
Feb-96	154-182	-0.50448	-0.41724
Mar-96	183-213	0.43194	0.08226
Apr-96	214-243	0.15065	-0.12677
May-96	244-274	-0.24433	-0.22417
Jun-96	275-304	0.01550	0.02400
Jul-96	305-355	0.98694	1.01660
Aug-96	335-366	-0.07677	-0.43290
Sep-96	367-396	0.32017	0.11833
Oct-96	397-427	0.86000	0.37677

If the number in the "Actual-Forecast" column is positive, the forecast underpredicts the actual value.

If the number in the "Actual-Forecast" column is negative, the forecast overpredicts the actual value.

SECTION VII - Conclusions.

The analysis of the electricity forward market in England and Wales indicated the importance of the contract market and its relationship with the spot market. However, in the absence of actual forward prices, it was necessary to create a synthetic data set to represent the forward prices. The resultant empirical analysis indicated a poor relationship between the electricity spot and forward markets - a result consistent with the divergence between the pool price and the anticipated pool prices that had been used as the basis for the contracts themselves. However, to a certain extent, it cannot be determined whether this result is attributable to the data set or the circumstances in the industry post-vesting.

This is not the case in the analysis of the Californian electricity spot and forward markets, where it is possible to undertake regressions using actual forecast prices which can be used as the basis for an empirical analysis of peak and off-peak electricity spot and forward prices. These regressions indicate that both the peak and off-peak forecasts are valid predictors of the spot price, but that the off-peak forecasts tend to produce closer relationships to the spot price. This result is seen as being attributable to the stability of off-peak prices in comparison to peak prices. It is therefore worthwhile to consider whether or not the analyses that have formed the backbone of this thesis could be repeated utilising data from California.

It is clear from the development of deregulation in California that a competitive power exchange could well operate there in much the same manner as the pool. While it is difficult to ascertain precisely how successful the deregulation will be or whether the timetable will be met, a clear commitment to deregulation is apparent. The type of deregulation chosen was influenced by that in England and Wales, and it should be noted that with sufficient time to observe the development of the power exchange, analyses similar to those which occupy the main body of this thesis should also be possible. Indeed, in the presence of data on the strike prices of contracts for differences, such a study could well build considerably upon some elements of this thesis.

What is clear, both from the Californian experience, and from the experience of other US states and indeed other countries, is that electricity deregulation is becoming an important part of the industry. Indeed, the Californian experience requires to a great extent on deregulation in the gas and telecommunications industries for its success (to ensure competition in fuel supplies and the quick and efficient delivery of price information), just as the UK experience relied heavily on gas and the reforms that made widespread CCGT generation possible. These structures show the importance of an integrated approach to utility deregulation.

CHAPTER IX - CONCLUSIONS.

The work of this thesis is a hybrid of market price analysis associated with financial economics, and regulatory economics. The common thread is an investigation of the impact of regulation on different facets of prices in the industry: the spot market, the contract market and the stock market.

Clearly, the work undertaken would have been impossible if not for the extensive changes to the electricity industry in England and Wales at privatisation - and particularly the introduction of the pool. The key aspect of deregulation in England and Wales was the vertical separation of the industry that occurred at privatisation. In addition, the continued (and indeed continuing) efforts to introduce competition into both generation and distribution illustrate the importance of restricting the extent of both horizontal and vertical market power in the revised industrial structure. Competition in generation should have been fostered by the creation of the electricity pool and the encouragement of new entrants, but with competition not taking hold direct regulatory action was used in the form of the price reviews, price caps and ultimately the forced sale of plant by National Power and Powergen. Similarly the continued spread of competition in distribution will culminate in the introduction of full domestic competition in 1998 - or as soon as is feasible thereafter. Within the overall framework of the industry, the regulator must operate within the terms of his mandate - which broadly states that he must ensure competition, protect consumers' interests and encourage low prices.

The spread of competition and deregulation in electricity is not restricted to England and Wales, as the overview of deregulation in California indicates. Electricity deregulation is gathering pace in the United States, with a federal mandate introduced in July 1996 committing all states to the deregulation of their utilities by the end of the year 2000. The ultimate objective in the American system is the attainment of full domestic competition. It is hoped that simultaneous deregulation at state level would lead to agreements between utilities across states and multi-state electricity pools (similar agreements already exist in some areas of the US), leading to a vast, competitive nation-wide energy market.

A possibly more ambitious programme was that put forward at the European Union summit in Florence in June 1996, where it was agreed that the EU's electricity market would be opened to competition. This deregulation will be a progressive adjustment to competition, with the actual agreement itself having taken eight years to be established, after the customary disagreements and re-writes associated with major EU decisions. If successful, the deregulation will produce competition on a parallel to that of the UK, with the largest electricity users having the possibility of contracting with other suppliers in other countries for their power.

These examples indicate the scope for electricity deregulation world-wide, and are a measure of the role that the UK's experience has played (and will continue to play) as a model for deregulation, as well as of the advantage that English companies will have as experienced participants in a competitive energy marketplace. With the development of pool-based electricity trading in many industrial nations (the United States is the most pertinent example), there is the possibility to repeat the research undertaken here utilising data from the appropriate countries. It was the creation of the pool that revolutionised the electricity industry in England and Wales - it also provided the data that underlie the analysis undertaken here, which consists of five separate studies.

Chapter IV introduced the theoretical basis for the empirical analysis that was to follow. Through an evaluation of the Folk Theorem and the Supply Function approach to oligopoly, the game theoretic modelling of the pool was introduced. It was shown that regulation could indeed influence the price bid by generators into the pool through variations in the probability of the game ending.

The goal of the first study (Chapter V) was to assess the impact of regulation on the electricity pool price as a means of assessing the impact of regulation on the generators' plant bidding strategy (actual bid data being unavailable). Through an evaluation of pool prices and uplift levels, it was determined that regulation has indeed influenced the strategy of the generators in the bidding of their plants. This result was reached through an evaluation of the impact of different regulatory events, with a key focus being on the effects of the threat of a reference to the MMC. In keeping with the game theory analysis, it was also indicated that if the day-to-day operation of the pool can be likened to a repeated adversarial game between the regulator and the firms under his jurisdiction. In this environment, a threat that might have been initially credible becomes incredible if it is made repeatedly and not carried out.

The second study (Chapter VI) replicated and expanded upon the work of Helm & Powell (1992) in an attempt to analyse the evidence on the role of the electricity forward market and the inter-reactions between the forward market and the pool. Having established the existence of an inverse relationship between the volume of electricity output covered by contracts and the level of prices in the pool using the work of Green & Newbery (1992), it was concluded that if contract cover fell, pool prices should rise. By modelling pool prices and electricity demand, it was shown that when the first and second set of major forward contracts expired in March 1991 and March 1993 respectively, pool prices rose significantly. As such, the expiration of these contracts represented an external shock that disrupted the relationship between price and demand – leading to an autonomous increase in pool prices.

Further analysis was undertaken to assess the impact of regulatory and non-regulatory events on the price-demand relationship. The results of this analysis indicated that regulation could also disrupt the price-demand relationship – thus further supporting the results of the preceding chapter. Both the studies of Chapter V and VI support the Folk Theorem approach to generator bidding outlined in Chapter IV.

The third study (Chapter VII) continued in a similar vein to the first two - by assessing the impact of regulation on the generators. However, rather than utilising pool prices as a proxy for generator responses, this chapter assessed the impact of regulation on the share prices of the two main privately-owned electricity generators, National Power and Powergen. These models were undertaken using the market model, the results of which indicated the (downward) impact that regulation has had upon the share prices of the aforementioned companies. With the market model an established tool for financial analysis, the successful application of it to this data set supports the hypothesis that the prospect of regulation will lead to a downturn in share returns as investors fear lower profits, prices, or some other form of control or intervention.

The fourth study (Chapter VIII) revisited the ground of the second - the electricity contract market. However, rather than focusing upon the broad relationships between the spot and forward markets, the actual spot-forward market links were assessed through the relationship between the pool price and the price of the forward contracts that dominated the industry at privatisation. The price of these vesting contracts was proxied by the Horton IV estimates. The regression results indicated that the Horton IV estimates were poor estimators of actual pool prices as they consistently over-forecasted outturn daily prices, indicating the need for the RECs to exit from these contracts as soon as was feasible. The reasons behind this forecast inaccuracy are also presented in this study and also in the earlier sections.

This analysis was then contrasted with the functioning market for forward contracts in California, in order to show how the deregulated electricity market is developing there and the extent to which the experience of the UK is guiding deregulation overseas. This concluded with an assessment of the spot-forward relationships present in the market for electricity contracts on NYMEX, where it was shown that both the peak and off-peak prices of electricity can be seen to be consistent with the forecast values of these variables. This implies that there is some degree of efficiency in these markets.

The study as a whole illustrates the pivotal role that regulation has to play in determining the behaviour of the participants of the electricity industry and, likewise, how the behaviour of the participating firms determines the possibility of regulatory action. This proposition has been evaluated from a number of different angles and through the use of a number of different variables and relationships, all evaluated through the market analysis method. In addition, the study also shows the relevance of the inter-relationships between the electricity spot and forward markets and the importance of the latter in determining the level of prices in the former. Furthermore, the study also attempts to evaluate the prospects for the forward price to be an accurate predictor of the spot price and how the validation (or lack thereof) of this relationship can influence the industry participants' contracting strategy. Finally, the study also examines the broader issue of electricity deregulation on a world-wide scale through the case study of California as the state struggles to reach full domestic competition through the use of a model akin to that used in England and Wales.

In the light of these results, one must consider the possibility of broadening the analysis to incorporate additional studies. Firstly, there were concerns voiced in the earlier chapters about the use of pool purchase price data, and how a more appropriate approach would be to use actual generator bid data to improve the models. Secondly, one could undertake a series of volatility studies using electricity price information similar to those performed using share prices. This would present a broader perspective on the analysis by allowing an evaluation of the full impact of regulation on share prices. Furthermore, one could revert to the use of the half-hourly data format for the analysis, although such a move might require modifications to the analysis to allow for the vast quantities of data in use. However, these suggestions are of a predominantly technical nature, and do not truly reflect the possibilities for an analysis of the nature of industry dynamics.

A more challenging approach would be to undertake studies into the possibility of arbitrage between the electricity and gas markets, (as both industries now have their own functioning spot markets and as more companies have cross-utility interests) or the broader issue of electricity/gas linkages.

In the case of arbitrage, an electricity company could face the possibility of utilising its gas supply to power a CCGT generating plant, or it could sell that gas into the spot market. In this situation, there are many factors to consider: the impact on the gas and electricity spot markets as a result of the decision, the profitability associated with such a decision, the company's contractual commitments in each market, the existence (or lack) of interruptible contracts in each market, and the actual feasibility of such a move.

This potential for such research is highlighted by the interruptions in gas supply which occurred in the 1995/96 winter (Ofgas, 1996). These events show the potential for arbitrage, as well as the need for greater collaboration and information exchange between NGC and the gas transportation network operator, TransCo. The situation may be summarised as follows. A certain percentage of gas is shipped to CCGT power stations on an interruptible supply basis, which allows TransCo to interrupt the supply via the relevant shipper. Similarly, the generator could choose to interrupt supply themselves and sell the gas through the spot market. In this situation, it would be the responsibility of both NGC and TransCo to manage these occurrences and determine the information requirements and the period of warning necessary to ensure the effective operation of such arbitrage arrangements. Gas and electricity deregulations have been closely related, and a study of the exact nature of the linkages could be a valuable addition to the field of energy analysis.

An ideal situation would allow for an evaluation of the electricity contract market in England and Wales through an analysis of both contracts for differences and electricity forward agreements and the motives of the industry participants in developing their contracting strategies. However, such an analysis - while both revealing and of considerable value - is precluded by the lack of commercially available data.

A final possible area of analysis is of an international nature. Firstly, the developing energy markets of the United States represent a wealth of possible areas of study. While each state must commit to full domestic electricity competition, each state legislature does have some freedom in determining the process of deregulation. This could allow for different approaches to deregulation, each with the same objective in mind, thus representing a tremendous opportunity to view different approaches to deregulation in action and the success (or lack thereof) of such approaches. In addition, one could examine the broader issue of inter-state relationships as larger organisations develop across state boundaries, as well as the continually developing electricity contract market(s) on the New York

Mercantile Exchange (NYMEX). Secondly, there is the possibility of inter-country comparisons in a broad study of electricity deregulation worldwide. The possibility of a deregulated European energy market would add impetus to such a study, and could provide insights into the possibility of such an ambitious undertaking.

This study evaluates the electricity-generating sector in England and Wales, focusing upon the impact of regulation and the role that it plays in determining the conduct of the generators themselves. As it is the generating sector which has (to date) been the most deregulated of the industry's sectors, this study should be seen as an attempt to interpret the behaviour of the generators as they have adapted to the pressures of the competition within their sector, and to the continuing transformation of the industry as a whole.

EPILOGUE – THE GAS MORATORIUM, THE 1998 ENERGY REVIEW AND THE END OF THE POOL ?.

Published in October 1998, the Labour Government's Energy Review mapped out the future of the coal and electricity sectors, as well as providing a lifeline to the British coal industry.

The Government's Energy Review that was launched ahead of the break-up of the final contractual arrangements in 1998 was intended to outline the future for the coal industry and to resolve the issues generated by the moratorium on the construction of gas-fired power stations implemented some eighteen months earlier.

With the ending of these contracts, a new wave of CCGT stations was becoming ever likely, and in order to preserve the short-term future of the coal industry, the government refused consents for any further CCGT stations.

The second dash for gas was effectively halted by the findings of the Energy Review bringing with it the promise of a more level playing field for coal generation in the electricity pool through abolishing the pool structure and replacing it with a system modelled on the gas trading arrangements. The review determined that the bid prices of coal stations were not reflective of their fuel costs, and as such gas generation has displaced coal generation in the baseload section of the load curve, despite the relative cheapness of coal.

Although the government does intend a future for coal, it does not see a specific market share, nor does it determine for how long the moratorium on CCGTs will last. This is in contrast to the stance of the DTI, which has set a target of 10% of electricity to be produced through renewable energy sources by 2010. The adoption of a consumer-based marketplace will make it difficult to define market shares for specific fuels, but the strength of gas in the UK – on both environmental and cost grounds is hard to dismiss.

Virtually all of the new demand for gas has come from the power sector, and the UK's gas surplus – despite the operation of the Bacton-Zeebrugge gas interconnector – will continue to fuel demand for CCGTs.

So where does this leave the electricity pool ? By using the gas market as a template, the government is aiming for a bilateral spot market in which all counterparties could conceivably trade their electricity requirements daily. Faced with the option of going long or short into the electricity spot market, larger players could exploit market power if transitional regulatory arrangements are not strong enough.

Offer's proposals – approved by the Energy Minister John Battle – will lead to substantial changes in the sector. The pool will cease to exist, necessitating substantial changes to generation, transmission and supply licences. Virtually all industry documentation will have to be replaced or re-written, including – but not limited to – power purchase agreements and contracts for differences. The revised trading arrangements have an implementation date of April 2000 and will incorporate:

- forwards and futures markets operating up to several years ahead;
- a short-term bilateral market, giving players day-ahead and within-day opportunities to achieve their optimal contractual position;
- a within-day balancing market modelled on the Transco flexibility mechanism, which will allow NGC to balance the system and resolve transmission constraints through the sale and purchase of electricity;
- a settlement process that will allow NGC to recover these costs and charge those participants who are out of balance.

If implemented as planned, these new structures will make any contracts dependent upon pool prices meaningless and hence will require renegotiation, a new reference point, or – if a new basis cannot be agreed – termination. In these circumstances, it is likely that new benchmarks will have to be established before April 2000 in order to prevent the multiple break-up of contracts, an over-reliance on litigation, or the intervention of any or all of NGC, Offer, or the MMC.

Those companies with generating plant financed using CFDs may have serious cause for concern – depending upon whatever new benchmark is used. This may lead to project re-financing, or – in extreme cases – may put the project at risk. Furthermore, under the new arrangements, plant cannot be bid based upon a low price strategy, as there is no guarantee that it will produce continuous running and pool revenues. As such, contract cover will have to be accumulated; or else the generator will face the risk of imbalance charges and/or periods of prolonged inactivity.

Similarly, suppliers will have to manage their volume risk through imbalance charge exposure. This is likely to be in the form of purchase contracts similar to CFDs. However, such contracts would most likely be modified to allow participation in the short-term bilateral market and/or the balancing market.

Therefore, the new contractual arrangements will radically alter the electricity pool and the roles of all of its participants. Whether this is to be seen as a good or bad event is debatable, as Offer's proposals were not met with enthusiasm by all of the industry's participants. What is clear is that by modelling the revised arrangements on the Transco flexibility mechanism and the on-the-day commodity market for gas, the continued learning curve that privatisation and deregulation has been since its inception will continue.

APPENDICES - Contents.

APPENDIX 1: Variables' summary statistics.

Table 1. Summary Statistics of Variables from Empirical Chapters 1 - 4.

Variable	Mean	Std. Dev.	Obs.
PPP (£/MWh)[1]	22.2274	7.3178	1887+
Demand (Gross Demand, MWh)[1]	15494.5000	2286.1000	1887+
Uplift (£/MWh)[1]	1.7849	1.1133	1887+
Horton IV estimate (non-indexed, £/MWh)[2]	20.8361	4.9612	1278*
Horton IV estimate (indexed, £/MWh)[2]	22.7377	5.7990	1278*
FTSE 100-Share index	2959.2000	385.2376	1316#
National Power share price	361.8761	111.1826	1316#
Powergen share price	394.6873	134.6354	1316#

[1] Daily averaged observations based upon forty-eight half-hourly observations.

[2] See Chapter VII for details on the construction of the Horton IV set.

[+] 1887 daily observations based upon a data set from October 1990 to November 1995.

[*] 1278 daily observations based upon a data set from October 1990 to March 1994.

[#] 1316 weekday observations based upon a data set from 11/03/1991 to 26/03/1996.

CHAPTER V, APPENDIX.

Table 1: Data sequences used in structural break analysis.

Section 1: Bi-Monthly blocks.

Date	Observations
10/90 - 11/90	1-61
12/90 - 01/91	62-123
02/91 - 03/91	124-182
04/91 - 05/91	182-243
06/91 - 07/91	244-304
08/91 - 09/91	305-365
10/91 - 11/91	366-426
12/91 - 01/92	427-488
02/92 - 03/92	489-548
04/92 - 05/92	549-609
06/92 - 07/92	610-670
08/92 - 09/92	671-731
10/92 - 11/92	732-792
12/92 - 01/93	793-854
02/93 - 03/93	855-913
04/93 - 05/93	914-974
06/93 - 07/93	975-1035
08/93 - 09/93	1036 - 1096
10/93 - 11/93	1097 - 1157
12/93 - 01/94	1158 - 1219
02/94 - 03/94	1220 - 1278
04/94 - 05/94	1279 - 1339
06/94 - 07/94	1340 - 1400
08/94 - 09/94	1401 - 1461
10/94 - 11/94	1462 - 1522
12/94 - 01/95	1523 - 1584
02/95 - 03/95	1585 - 1643
04/95 - 05/95	1644 - 1704
06/95 - 07/95	1705 - 1765
08/95 - 09/95	1766 - 1826
10/95 - 11/95	1827 - 1887

Table 1: Data sequences used in structural break analysis.

Section 2: Four-Monthly blocks.

Dates	Observations
10/90 - 01/91	1-123
12/90 - 03/91	62-182
02/91 - 05/91	124-243
04/91 - 07/91	183-304
06/91 - 09/91	244-365
08/91 - 11/91	305-426
10/91 - 01/92	366-488
12/91 - 03/92	427-548
02/92 - 05/92	489-609
04/92 - 07/92	549-670
06/92 - 09/92	610-731
08/92 - 11/92	671 - 792
10/92 - 01/93	732-854
12/93 - 03/93	793-913
02/93 - 05/93	855-974
04/93 - 07/93	914-1035
06/93 - 09/93	975-1096
08/93 - 11/93	1036 - 1157
10/93 - 01/94	1097 - 1219
12/93 - 03/94	1158 - 1278
02/94 - 05/94	1220 - 1339
04/94 - 07/94	1279 - 1400
06/94 - 09/94	1340 - 1461
08/94 - 11/94	1401 - 1522
10/94 - 01/95	1462 - 1584
12/94 - 03/95	1523 - 1643
02/95 - 05/95	1585 - 1704
04/95 - 07/95	1644 - 1765
06/95 - 09/95	1705 - 1826
08/95 - 11/95	1766 - 1887

Table 2. Monthly levels of key variables w/structural breaks.

Section 2.1. Monthly averages of key variables

Month	Uplift	PPP	Demand	Month	Uplift	PPP	Demand
Oct-90	1.1743	16.4539	15225.30	May-93	2.5439	26.2018	13703.00
Nov-90	0.8408	17.2052	16965.50	Jun-93	3.2973	26.5748	13126.50
Dec-90	1.0947	18.3919	16988.90	Jul-93	3.2318	25.7677	13251.40
Jan-91	0.9676	19.3864	18228.50	Aug-93	2.3304	25.5020	12953.70
Feb-91	1.1846	21.0385	18750.20	Sep-93	2.0003	25.2781	14362.10
Mar-91	1.0853	19.8159	16163.40	Oct-93	2.0466	25.6201	15850.20
Apr-91	1.2195	20.6897	15332.20	Nov-93	1.7540	26.6631	17635.00
May-91	1.2536	20.2450	14093.10	Dec-93	1.7870	24.7797	17062.50
Jun-91	1.2318	20.9081	13701.20	Jan-94	1.4772	24.8087	17609.30
Jul-91	1.5939	18.9321	13052.90	Feb-94	1.6115	21.4373	18123.20
Aug-91	1.5290	18.6817	12694.10	Mar-94	1.6165	14.7103	16736.80
Sep-91	2.7861	23.4189	13674.40	Apr-94	2.0330	24.0169	15490.00
Oct-91	2.2667	20.8472	15383.00	May-94	2.3205	19.7904	14157.90
Nov-91	1.7285	21.7679	16898.10	Jun-94	2.2163	21.8736	13717.80
Dec-91	2.0912	25.0742	16908.80	Jul-94	2.0888	20.6170	13370.20
Jan-92	1.5267	20.9921	17823.00	Aug-94	2.0843	18.0573	13424.00
Feb-92	1.0579	18.9274	17445.80	Sep-94	1.8741	16.9779	14635.00
Mar-92	1.0073	19.0289	16576.40	Oct-94	2.0191	23.8485	15633.50
Apr-92	0.8891	19.7759	15194.50	Nov-94	2.9076	30.5266	16724.70
May-92	1.0107	20.9961	13304.20	Dec-94	3.3525	34.0528	16881.40
Jun-92	1.7202	23.4151	13372.50	Jan-95	5.4406	50.9275	18272.30
Jul-92	1.4147	23.8807	13207.20	Feb-95	1.1518	13.9791	17882.50
Aug-92	2.0375	22.8066	12883.50	Mar-95	0.9366	12.0319	17625.00
Sep-92	1.6137	22.7938	14152.60	Apr-95	1.0941	17.4073	15267.70
Oct-92	1.7999	23.9104	15759.00	May-95	1.6880	20.6251	14531.10
Nov-92	1.3932	24.5859	16825.30	Jun-95	1.8548	20.2089	14243.00
Dec-92	1.0169	23.2859	16904.60	Jul-95	1.4769	16.4348	13822.10
Jan-93	0.9585	21.9596	17397.50	Aug-95	1.5634	18.4281	13879.10
Feb-93	1.0185	22.5700	17441.10	Sep-95	1.5419	17.8723	14700.80
Mar-93	1.7067	23.6229	16612.90	Oct-95	1.2528	17.2639	15531.70
Apr-93	2.4266	25.8315	14910.90	Nov-95	3.1625	33.4544	17452.20

PPP and Uplift are measured in £/MWh.

Demand is measured in MWh.

Section 2.2. Monthly percentage changes.

Time period	Uplift	PPP	Demand	Time period	Uplift	PPP	Demand
10/90-11/90	-28.40%	4.57%	11.43%	**04/93-05/93**	**4.83%**	**1.43%**	**-8.10%**
11/90-12/90	30.20%	6.90%	0.14%	05/93-06/93	29.62%	1.42%	-4.21%
12/90-01/91*	-11.64%	5.41%	7.30%	06/93-07/93	-1.99%	-3.04%	0.95%
01/91-02/91	22.47%	8.55%	2.86%	07/93-08/93*	-27.89%	-1.03%	-2.25%
02/91-03/91*	-8.38%	-5.81%	-13.80%	**08/93-09/93**	**-14.05%**	**-0.88%**	**10.87%**
03/91-04/91	12.37%	4.41%	-5.12%	09/93-10/93	2.31%	1.35%	10.36%
04/91-05/91	2.80%	-2.15%	-8.08%	10/93-11/93	-14.30%	4.07%	11.26%
05/91-06/91	-1.74%	3.28%	-2.78%	11/93-12/93	1.88%	-7.06%	-3.25%
06/91-07/91	**29.40%**	**-9.45%**	**-4.73%**	12/93-01/94*	-17.34%	0.12%	3.20%
07/91-08/91	-4.07%	-1.32%	-2.75%	01/94-02/94	9.09%	-13.59%	2.92%
08/91-09/91*	**82.22%**	**25.35%**	**7.72%**	**02/94-03/94**	**0.31%**	**-31.38%**	**-7.65%**
09/91-10/91	-4.27%	-10.98%	12.49%	03/94-04/94	63.27%	25.77%	-7.45%
10/91-11/91	**-23.74%**	**4.42%**	**9.85%**	04/94-05/94	-17.60%	14.14%	-8.60%
11/91-12/91	20.98%	15.19%	0.06%	05/94-06/94	10.53%	-4.49%	-3.11%
12/91-01/92*	-26.99%	-16.28%	5.41%	06/94-07/94	-5.74%	-5.75%	2.53%
01/92-02/92	-30.71%	-9.84%	-2.12%	07/94-08/94	-12.42%	-0.22%	0.40%
02/92-03/92*	-4.78%	0.54%	-4.98%	**08/94-09/94***	**-5.98%**	**-10.08%**	**9.02%**
03/92-04/92	-11.73%	3.93%	-8.34%	09/94-10/94	40.47%	7.74%	7.03%
04/92-05/92*	13.68%	6.17%	12.44%	10/94-11/94*	28.00%	44.00%	6.98%
05/92-06/92	70.20%	11.52%	0.51%	11/94-12/94	11.55%	15.30%	0.94%
06/92-07/92*	**-17.76%**	**2.02%**	**-1.24%**	12/94-01/95*	49.55%	62.28%	8.24%
07/92-08/92	44.02%	-4.50%	-2.45%	01/95-02/95	-72.55%	-78.83%	-2.13%
08/92-09/92*	**-20.80%**	**-0.06%**	**9.85%**	02/95-03/95*	-13.93%	-18.68%	-1.44%
09/92-10/92	11.54%	4.90%	11.35%	03/95-04/95	44.68%	16.82%	-13.37%
10/92-11/92	-22.60%	2.83%	6.77%	04/95-05/95*	18.49%	54.28%	-4.82%
11/92-12/92	-27.01%	-5.29%	0.47%	05/95-06/95	-2.02%	9.88%	-1.98%
12/92-01/93*	-5.75%	-5.70%	2.92%	06/95-07/95	-18.68%	-20.37%	-2.96%
01/93-02/93	6.26%	2.78%	0.25%	07/95-08/95	12.13%	5.86%	0.41%
02/93-03/93	**67.57%**	**4.67%**	**-4.75%**	08/95-09/95	-3.02%	-1.38%	5.92%
03/93-04/93*	42.18%	9.35%	-14.58%	09/95-10/95*	-3.40%	-18.75%	5.65%
				10/95-11/95	**94.30%**	**152.43%**	**12.37%**

Those periods underlined are those when a structual break has occurred in both prices and demand.

Those periods **in bold** are when a structural break has occurred in uplift.

Those periods marked with an asterisk (*) are those when a structural break has occurred in demand.

Combinations of any of these three indicate that more than one of the variables exhibited a structural break as appropriate.

PPP and Uplift are measured in £/MWh.

Demand is measured in MWh.

Table 3 - Timeframes used for dummy analyses.

Regression	Starting Observation	Final Observation
1	150	250
2	325	425
3	350	450
4	425	525
5	600	700
6	700	800
7	775	875
8	875	975
9	925	1025
10	1000	1100
11	1150	1250
12	1250	1350
13	1200	1300
14	1500	1600
15	1550	1650
16	1575	1675
17	1575	1675
18	1700	1800
19	1715	1815
20	1750	1850
21	1770	1870
22	1778	1878
23	1787	1887

Table 4: Diagnostic performance for the analysis of structural breaks in prices.

Given the nature of the data in use, it would be highly unlikely to expect that all of the diagnostics would be passed in all of the regressions. In examining the price regressions it was determined that the most commonly failed diagnostic was the test for normality of residuals, failing in approximately 67% of all of the regressions. This result obviously limits the success derived from the Chow test, but it should be noted that almost all of the regressions performed using pool prices since this research began have had problems with normality. The test for functional form was failed in approximately 55% of all cases, while the test for serial correlation was failed in only 6% of the regressions. The main problem for the approach utilised here is that the Chow test becomes invalid in the presence of heteroscedasticity. Therefore, any regressions which indicate the presence of heteroscedasticity must be viewed with a degree of suspicion. A total of 34% of the regressions failed the diagnostic for heteroscedasticity. These are given as follows: (by observation numbers and months respectively) 305-365 (August-September 1991), 671-731 (August-September 1992), 62-182 (December 1990-March 1991), 244-365 (June-September 1991), 610-731 (June-September 1992), 671-792 (August-November 1992), 732-854 (October 1992-January 1993), 914-1035 (April-July 1993), 975-1096 (June-September 1993), 1523-1584 (December 1994-January 1995), 1585-1643 (February-March 1995), 1705-1765 (June-July 1995), 1827-1887 (October-November 1995). In addition, there is also a large proportion of analyses contained within the four-month blocks for which this diagnostic is invalid, namely 1401-1887 (August 1994 - November 1995). It is important to note that there is an eight month block (610-854, June 1991-January 1992) and a six-month block (914-1096, April-September 1993) for which this diagnostic is invalid. This result corresponds to a series of structural breaks occurring within these periods.

Table 5.

Univariate price analyses with dummy variables.

Regression	Serial Correlation	Functional Form	Normality	H'Sced/Arch
1	Pass	Pass	Fail	Pass/Pass
2	Pass	Pass	Fail	Pass/Pass
3	Pass	Pass	Fail	Pass/Pass
4	Pass	Pass	Fail	Fail/Pass
5	Pass	Pass	Fail	Fail/Pass
6	Pass	Pass	Fail	Pass/Pass
7	Pass	Pass	Pass	Pass/Pass
8	Pass	Fail	Fail	Pass/Pass
9	Pass	Pass	Fail	Fail/Pass
10	Pass	Pass	Fail	Pass/Pass
11	Pass	Fail	Fail	Pass/Pass
12	Pass	Pass	Fail	Pass/Pass
13	Pass	Pass	Fail	Pass/Pass
14	Pass	Pass	Fail	Pass/Pass
15	Pass	Fail	Fail	Fail/Pass
16	Pass	Fail	Fail	Fail/Pass
17	Pass	Pass	Fail	Pass/Pass
18	Pass	Pass	Fail	Pass/Pass
19	Pass	Pass	Fail	Pass/Pass
20	Pass	Pass	Fail	Pass/Pass
21	Pass	Pass	Fail	Pass/Pass
22	Pass	Pass	Fail	Pass/Pass
23	Pass	Pass	Fail	Pass/Pass

These are the results for the optimally structured regressions.

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

Table 6.

Univariate uplift analyses with dummy variables.

Regression	Serial Correlation	Functional Form	Normality	H'Sced/Arch
1	Pass	Pass	Pass	Pass/Pass
2	Pass	Pass	Fail	Pass/Pass
3	Pass	Pass	Fail	Pass/Pass
4	Pass	Pass	Fail	Pass/Pass
5	Pass	Pass	Pass	Pass/Pass
6	Pass	Pass	Pass	Pass/Pass
7	Pass	Pass	Fail	Pass/Pass
8	Pass	Pass	Fail	Fail/Pass
9	Pass	Pass	Pass	Pass/Pass
10	Pass	Pass	Fail	Pass/Pass
11	Pass	Pass	Fail	Pass/Pass
12	Pass	Pass	Fail	Pass/Pass
13	Pass	Pass	Fail	Pass/Pass
14	Pass	Pass	Fail	Pass/Pass
15	Pass	Pass	Fail	Pass/Pass
16	Pass	Pass	Fail	Pass/Pass
17	Pass	Pass	Fail	Pass/Pass
18	Pass	Pass	Fail	Pass/Pass
19	Pass	Pass	Fail	Pass/Pass
20	Pass	Pass	Fail	Pass/Pass
21	Pass	Pass	Fail	Pass/Pass
22	Pass	Pass	Fail	Pass/Pass
23	Pass	Pass	Fail	Pass/Pass

These are the results for the optimally structured regressions.

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

Table 7.

Diagnostic performance for the analysis of structural breaks in uplift.

Based upon the analyses performed on prices, one would anticipate a similar performance in the diagnostics for uplift levels. It was determined that the test for normality of residuals was the most commonly failed diagnostic, failing in 44% of all cases (the same disclaimer applies to this outcome as for prices). The test for functional form was failed in approximately 34% of all cases, while the test for serial correlation was failed in only 5% of all cases. The main problem in this analysis is again the existence of heteroscedasticity, which was failed in approximately 9% of all the regressions. These regressions are as follows: (by observation numbers and months respectively) 305-365 (August-September 1991, corresponding to the structural break), 855-913 (February-March 1993, corresponding to the structural break), 1036-1096 (August-September 1993, corresponding to the structural break), 1097-1157 (October-November 1993), 1158-1219 (December 1993-January 1994), 244-365 (June-September 1991, corresponding with the structural break), 489-609 (February-May 1992), 855-974 (February-May 1993, corresponding to the structural break), 975-1096 (June-September 1993, corresponding with the structural break), 1036-1157 (August-November 1993, corresponding with the structural break), 1097-1219 (October 1993-January 1994), and 1462-1584 (October 1994 - January 1995). The same caution must be taken in assessing these results as for prices.

Table 8.

Uplift-Price and Uplift-Demand regressions.

Uplift-Price regression (Equation 1.7)

Slope coefficient: 1.2081

Wald test: Null hypothesis: Slope coefficient = 1

Alt. Hypothesis: Slope coefficient ≠ 1

Wald statistic: Chi-Squared (1): 47.3800 Chi-Squared (1) critical value: 3.84

The null hypothesis is not valid and the coefficient is statistically significantly different from unity.

Uplift-Demand regression (Equation 1.8)

Slope coefficient: 0.011271

Wald test: Null hypothesis: Slope coefficient = 0

Alt. Hypothesis: Slope coefficient ≠ 0

Wald statistic: Chi-Squared (1): 0.023232 Chi-Squared (1) critical value: 3.84

The null hypothesis is valid and the coefficient is not statistically significantly different from zero.

Revised Uplift-Price regression (Equation 1.7a)

Slope coefficient: 1.1794

Wald test: Null hypothesis: Slope coefficient = 1

Alt. Hypothesis: Slope coefficient ≠ 1

Wald statistic: Chi-Squared (1): 29.0014 Chi-Squared (1) critical value: 3.84

The null hypothesis is not valid and the coefficient is statistically significantly different from unity.

Uplift-Demand regression (Equation 1.8a)

Slope coefficient: 1.05080

Wald test: Null hypothesis: Slope coefficient = 1

Alt. Hypothesis: Slope coefficient ≠ 1

Wald statistic: Chi-Squared (1): 0.50985 Chi-Squared (1) critical value: 3.84

The null hypothesis is valid and the coefficient is not statistically significantly different from unity.

All of these regressions failed all of their diagnostic tests, as did their optimal counterparts as determined by the Akaike Information and Schwarz Information Criteria (see D7 and D8).

Table 9: Optimal structure for extensive form uplift price regressions

Section 1: Akaike Information Criterion.

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-2.83553	-2.83356	-2.83997	-2.84523	-2.85204	-2.85647	-2.90752	-2.92011	-2.91873	-2.91705	-2.91816
1	-2.88167	-2.91462	-2.91821	-2.92612	-2.92458	-2.94144	-3.01364	-3.02550	-3.02402	-3.02226	-3.02254
2	-2.94593	-2.98932	-3.00322	-3.00767	-3.01969	-3.02867	-3.11925	-3.12790	-3.12780	-3.12860	-3.12917
3	-2.98883	-3.02850	-3.04889	-3.05287	-3.06092	-3.07131	-3.17655	-3.18242	-3.18187	-3.18356	-3.18209
4	-3.05092	-3.08961	-3.10588	-3.11430	-3.11680	-3.12470	-3.24204	-3.24736	-3.24613	-3.24697	-3.24509
5	-3.16179	-3.19454	-3.20841	-3.21265	-3.21985	-3.22855	-3.35151	-3.35472	-3.35418	-3.35367	-3.35215
6	-3.22064	-3.29285	-3.32864	-3.34739	-3.36474	-3.38524	-3.40213	-3.40676	-3.40575	-3.40554	-3.40451
7	-3.22871	-3.30136	-3.33641	-3.35508	-3.37203	-3.39232	-3.40680	-3.40668	-3.40558	-3.40549	-3.40451
8	-3.22828	-3.30037	-3.33561	-3.35437	-3.37123	-3.39182	-3.40637	-3.40641	-3.40489	-3.40497	-3.40407
9	-3.22687	-3.29958	-3.33690	-3.35520	-3.37232	-3.39304	-3.40797	-3.40806	-3.40677	-3.41310	-3.41184
10	-3.22924	-3.30198	-3.34072	-3.36222	-3.37865	-3.40527	-3.41545	-3.41572	-3.41447	-3.42216	-3.42085

The values for the eighth, ninth and tenth uplift lags are inadmissable as their coefficients are statistically insignificant.

Section 2: Schwarz Information Criterion.

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-2.82670	-2.82178	-2.82523	-2.82753	-2.83137	-2.83282	-2.88090	-2.89051	-2.88614	-2.88146	-2.87957
1	-2.86990	-2.89988	-2.90052	-2.90546	-2.90095	-2.91483	-2.98405	-2.99292	-2.98845	-2.98369	-2.98097
2	-2.93120	-2.97163	-2.98257	-2.98405	-2.99309	-2.99909	-3.08668	-3.09234	-3.08925	-3.08705	-3.08461
3	-2.97115	-3.00786	-3.02528	-3.02628	-3.03135	-3.03875	-3.14101	-3.14388	-3.14033	-3.13902	-3.13453
4	-3.03029	-3.06601	-3.07930	-3.08475	-3.08426	-3.08917	-3.20352	-3.20584	-3.20160	-3.19944	-3.19454
5	-3.13820	-3.16797	-3.17887	-3.18013	-3.18434	-3.19005	-3.31000	-3.31021	-3.30667	-3.30314	-3.29860
6	-3.19409	-3.26332	-3.29613	-3.31189	-3.32625	-3.34376	-3.35765	-3.35927	-3.35525	-3.35201	-3.34797
7	-3.19920	-3.26886	-3.30093	-3.31662	-3.33056	-3.34786	-3.35933	-3.35619	-3.35208	-3.34897	-3.34496
8	-3.19580	-3.26490	-3.29715	-3.31293	-3.32679	-3.34437	-3.35591	-3.35294	-3.34839	-3.34545	-3.34151
9	-3.19142	-3.26115	-3.29547	-3.31077	-3.32489	-3.34260	-3.35451	-3.35159	-3.34727	-3.35057	-3.34627
10	-3.19082	-3.26056	-3.29631	-3.31481	-3.32823	-3.35184	-3.35900	-3.35625	-3.35197	-3.35663	-3.35228

The values for the eighth, ninth and tenth uplift lags are inadmissable as their coefficients are statistically insignificant.

In all cases, the less complex (i.e. possessing fewer lags) regressions had more success with their diagnostics, but the more elaborate forms had problems with all diagnostic testing, exhibiting serial correlation, non-normality and heteroscedasticity

Table 10: Optimal structure for extensive form uplift demand regressions

Section 1: Akaike Information Criterion.

	Demand lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-2.45271	-2.45071	-2.45270	-2.45287	-2.45548	-2.45344	-2.47390	-2.47684	-2.47995	-2.47850	-2.47749
1	-2.48175	-2.48956	-2.49043	-2.49144	-2.49432	-2.49229	-2.52640	-2.52762	-2.52910	-2.52858	-2.52785
2	-2.62303	-2.62808	-2.62626	-2.62950	-2.63815	-2.63662	-2.63663	-2.63772	-2.64021	-2.63914	-2.64022
3	-2.67880	-2.68445	-2.68513	-2.68299	-2.68988	-2.68903	-2.68951	-2.69025	-2.69243	-2.69124	-2.69145
4	-2.77807	-2.78337	-2.78352	-2.78379	-2.78168	-2.77992	-2.78026	-2.78050	-2.78305	-2.78168	-2.78199
5	-2.92648	-2.93166	-2.92977	-2.92957	-2.92790	-2.92926	-2.92964	-2.93013	-2.93256	-2.93136	-2.93123
6	-2.99483	-2.99583	-2.99377	-2.99219	-2.99017	-2.99185	-2.99262	-2.99453	-2.99660	-2.99527	-2.99557
7	-2.99048	-2.99332	-2.99616	-2.99899	-3.00183	-3.00465	-3.00748	-3.00679	**-3.01010**	-3.00871	-3.00922
8	-3.00901	-3.01127	-3.00930	-3.00781	-3.00584	-3.00630	-3.00635	-3.00565	-3.00851	-3.00715	-3.00766
9	-3.01023	-3.01289	-3.01121	-3.00953	-3.00755	-3.00836	-3.00819	-3.00766	-3.00999	-3.00833	-3.00840
10	-3.01746	-3.02010	-3.01865	-3.01781	-3.01569	-3.01625	-3.01615	-3.01579	-3.01758	-3.01568	-3.01488

The values for the eighth, ninth and tenth uplift lags are inadmissable as their coefficients are statistically insignificant.

Section 2: Schwarz Information Criterion.

	Demand lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-2.44388	-2.43893	-2.43796	-2.43517	-2.43481	-2.42979	-2.44728	-2.44724	-2.44736	-2.44291	-2.43890
1	-2.46997	-2.47483	-2.47273	-2.47078	-2.47068	-2.46568	-2.49680	-2.49504	-2.49352	-2.49001	-2.48628
2	-2.60831	-2.61039	-2.60561	-2.60587	-2.61155	-2.60704	-2.60407	-2.60216	-2.60166	-2.59758	-2.59565
3	-2.66112	-2.66381	-2.66152	-2.65641	-2.66031	-2.65648	-2.65396	-2.65171	-2.65089	-2.64669	-2.64389
4	-2.75743	-2.75977	-2.75694	-2.75424	-2.74914	-2.74440	-2.74174	-2.73898	-2.73852	-2.73414	-2.73144
5	-2.90289	-2.90510	-2.90023	-2.89705	-2.89239	-2.89076	-2.88814	-2.88562	-2.88504	-2.88084	-2.87768
6	-2.96828	-2.9663	-2.96127	-2.9567	-2.95169	-2.95037	-2.94814	-2.94704	-2.9461	-2.94175	-2.93902
7	**-2.96096**	-2.96083	-2.96068	-2.96052	-2.96036	-2.96019	-2.96001	-2.95631	-2.9566	-2.95219	-2.94967
8	-2.97653	-2.97581	-2.97084	-2.96636	-2.9614	-2.95885	-2.95588	-2.95217	-2.95201	-2.94763	-2.9451
9	-2.97478	-2.97445	-2.96978	-2.96511	-2.96012	-2.95792	-2.95473	-2.95119	-2.9505	-2.9458	-2.94284
10	-2.97904	-2.97869	-2.97424	-2.9704	-2.96528	-2.96282	-2.9597	-2.95632	-2.95508	-2.95015	-2.94631

The values for the eighth, ninth and tenth uplift lags are inadmissable as their coefficients are statistically insignificant.

In all cases, the less complex (i.e. possessing fewer lags) regressions had more success with their diagnostics, but the more elaborate forms had problems with all diagnostic testing, exhibiting serial correlation, non-normality and heteroscedasticity.

Table 11: Interactive variable analysis – Univariate pool price regressions.

INSTDUM01	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-3.3481	-3.4921	-3.4613	-3.4350	-3.4408	-3.5165	-3.6199	-3.7863	**-3.8475**	-3.7155	-3.7754
SSC:	-3.2956	-3.4130	-3.3552	-3.3015	-3.2796	-3.3271	-3.4020	-3.5396	**-3.5716**	-3.4100	-3.4398
Dummy T-Ratio	-0.2264	0.9181	0.8868	0.9116	0.8274	0.4229	0.3984	-0.4886	-0.4786	-0.8073	-0.7185
R-Bar 2	0.3722	0.4676	0.4624	0.4599	0.4747	0.5238	0.5803	0.6529	0.6491	0.6777	0.6845

INSTDUM02	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-5.5938	-6.1249	-6.0956	-6.0676	-6.0510	-6.0249	-6.1181	-6.2450	**-6.3815**	-6.3640	-6.3484
SSC:	-5.5413	-6.0458	-5.9894	-5.9341	-5.8897	-5.8355	-5.9003	-5.9983	**-6.1055**	-6.0585	-6.0128
Dummy T-Ratio	-0.2684	-0.9079	-0.9569	-0.9981	-1.0735	-1.0599	-0.9549	-1.0664	-0.8274	-0.7522	-0.7843
R-Bar 2	-0.0094	0.4188	0.4141	0.4104	0.4136	0.4116	0.4762	0.5494	0.6162	0.6190	0.6226

INSTDUM03	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-5.6463	**-5.6549**	-5.6372	-5.6069	-5.5868	-5.5746	-5.5446	-5.6317	-5.5992	-5.5638	-5.5310
SSC:	**-5.5939**	-5.5757	-5.5311	-5.4733	-5.4255	-5.3852	-5.3268	-5.3850	-5.3233	-5.2583	-5.1954
Dummy T-Ratio	0.5366	0.4794	0.5039	0.5155	0.5747	0.6221	0.5843	0.5670	0.5749	0.5696	0.5578
R-Bar 2	-0.0072	0.0220	0.0255	0.0170	0.0191	0.2923	0.0292	0.1250	0.1176	0.1081	0.1013

INSTDUM04	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-5.2566	-5.2809	-5.2982	-5.3335	-5.3371	-5.3349	-5.3530	**-5.5034**	-5.4833	-5.4476	-5.4410
SSC:	-5.2042	-5.2017	-5.1921	-5.1999	-5.1758	-5.1455	-5.1351	**-5.2567**	-5.2074	-5.1420	-5.1054
Dummy T-Ratio	0.5156	0.2736	0.4336	0.6692	0.8813	0.9736	0.8335	0.5887	0.5037	0.5147	0.5165
R-Bar 2	-0.0074	0.0370	0.0735	0.1247	0.1470	0.1642	0.1980	0.3261	0.3288	0.3409	0.3339

INSTDUM05	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-3.7568	-4.6796	**-4.6969**	-4.6681	-4.6391	-4.6255	-4.6295	-4.6097	-4.5758	-4.5830	-4.5466
SSC:	-3.7044	**-4.6005**	-4.5907	-4.5345	-4.4778	-4.4361	-4.4117	-4.3630	-4.2998	-4.2774	-4.2111
Dummy T-Ratio	0.8283	0.8200	0.1998	0.2262	0.2262	0.2130	0.1810	0.1757	0.1757	0.1238	0.1171
R-Bar 2	-0.0032	0.6209	0.6222	0.6212	0.6190	0.6224	0.6339	0.6325	0.6303	0.6419	0.6379

INSTDUM06	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-0.7106	-1.8001	-1.7801	-1.8209	-1.7953	-1.8210	-2.0412	-2.0358	**-2.2576**	-2.2281	-2.1918
SSC:	-0.6582	-1.7210	-1.6740	-1.6874	-1.6341	-1.6316	-1.8233	-1.7891	**-1.9817**	-1.9226	-1.8563
Dummy T-Ratio	1.3802	1.4204	1.3158	1.2781	1.2608	1.1247	0.4273	0.2424	0.1675	0.0894	0.0693
R-Bar 2	0.0090	0.6735	0.6739	0.6937	0.6926	0.7071	0.7704	0.7745	0.8237	0.8288	0.8209

Regressions 01 through 06 refer to the relevant threats of an MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

SIC: Schwarz Information Criterion (Optimal value is minimal).

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

Table 12: Interactive variable analysis – Univariate uplift regressions.

INSTDUM01	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-1.2630	-1.5465	-1.7092	-1.6775	-1.6694	-1.6634	-1.7527	-1.8600	**-1.9325**	-1.8994	-1.8974
SSC:	-1.2105	-1.4673	-1.6031	-1.5439	-1.5081	-1.4740	-1.5348	-1.6133	**-1.6566**	-1.5939	-1.5618
Dummy T-Ratio	3.0872	0.7797	2.2801	2.2523	2.3688	2.1260	1.4054	1.4040	0.5363	0.3244	0.0792
R-Bar 2	0.0786	0.3204	0.4346	0.4289	0.4368	0.4461	0.5050	0.5658	0.6058	0.6024	0.6115

INSTDUM02	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-2.4680	-3.2334	-3.2972	-3.2720	-3.2575	-3.2682	-3.2705	-3.2430	**-3.3021**	-3.2858	-3.2824
SSC:	-2.4156	-3.1542	**-3.1911**	-3.1384	-3.0962	-3.0788	-3.0526	-2.9963	-3.0262	-2.9803	-2.9469
Dummy T-Ratio	1.8734	0.7912	0.8204	0.8906	0.9434	0.9222	0.7521	0.6787	0.8533	0.9251	0.9630
R-Bar 2	0.0245	0.5556	0.5918	0.5904	0.5935	0.6068	0.6167	0.6125	0.6459	0.6489	0.6565

INSTDUM03	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-3.0391	**-3.7728**	-3.7497	-3.7258	-3.6945	-3.6686	-3.6395	-3.6242	-3.5928	-3.5741	-3.5450
SSC:	-2.9866	**-3.6937**	-3.6436	-3.5923	-3.5332	-3.4792	-3.4216	-3.3775	-3.3169	-3.2686	-3.2095
Dummy T-Ratio	-0.7014	-0.5122	-0.5326	-0.5633	-0.5851	-0.5429	-0.4396	-0.3623	-0.3669	-0.4325	-0.4966
R-Bar 2	-0.0051	0.5274	0.5265	0.5255	0.5211	0.5195	0.5166	0.5206	0.5172	0.5200	0.5181

INSTDUM04	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-2.2479	-3.4363	-3.4524	**-3.4554**	-3.4236	-3.3912	-3.3935	-3.3593	-3.3247	-3.2894	-3.2564
SSC:	-2.1955	**-3.3571**	-3.3462	-3.3218	-3.2623	-3.2018	-3.1756	-3.1126	-3.0488	-2.9839	-2.9209
Dummy T-Ratio	2.0432	0.6827	0.5361	0.3853	0.3483	0.3483	0.4367	0.4433	0.4658	0.4607	0.4458
R-Bar 2	0.0308	0.7107	0.7214	0.7281	0.7255	0.7228	0.7298	0.7269	0.7240	0.7211	0.7189

INSTDUM05	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	-2.8546	**-3.1895**	-3.1596	-3.1276	-3.1026	-3.1162	-3.1315	-3.1244	-3.1208	-3.0918	-3.0755
SSC:	-2.8022	**-3.1104**	-3.0534	-2.9940	-2.9413	-2.9268	-2.9137	-2.8777	-2.8448	-2.7863	-2.7399
Dummy T-Ratio	1.7671	1.3458	1.3725	1.3639	1.3246	1.1643	1.0040	0.7983	0.7621	0.8163	0.8601
R-Bar 2	0.0208	0.3139	0.3079	0.3008	0.2988	0.3275	0.3562	0.3837	0.3797	0.3771	0.3827

INSTDUM06	Lag 0	Lag 1	Lag 2	Lag 3	Lag 4	Lag 5	Lag 6	Lag 7	Lag 8	Lag 9	Lag 10
AIC:	0.1089	-0.5693	-0.5818	-0.6167	-0.5841	-0.6155	-0.9617	-0.9912	**-1.1805**	-1.1457	-1.1149
SSC:	0.1613	-0.4902	-0.4756	-0.4831	-0.4228	-0.4261	-0.7439	-0.7446	**-0.9045**	-0.8401	-0.7794
Dummy T-Ratio	1.6620	1.6293	1.4412	1.4474	1.4386	1.3920	0.7697	0.4374	0.1718	0.1108	0.0068
R-Bar 2	0.0173	0.5115	0.5277	0.5537	0.5490	0.5728	0.7047	0.7200	0.7738	0.7715	0.7702

Regressions 01 through 06 refer to the relevant threats of an MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

SIC: Schwarz Information Criterion (Optimal value is minimal).

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

Table 13: Interactive variable analysis – Multivariate uplift-price regressions.

Section 1: First MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-3.19677	-3.22825	-3.19744	-3.23167	-3.19904	-3.17393	-3.15047	-3.15421	-3.11984	-3.09590	-3.05959
1	-3.17755	-3.30506	-3.27298	-3.30250	-3.28004	-3.25353	-3.24801	-3.43290	-3.22817	-3.20187	-3.16951
2	-3.16045	-3.29156	-3.43693	-3.52063	-3.49492	-3.45991	-3.48424	-3.46864	-3.44918	-3.41233	-3.38082
3	-3.18010	-3.31432	-3.45776	-3.54631	-3.54014	-3.50447	-3.51010	-3.48141	-3.45553	-3.41778	-3.37991
4	-3.14690	-3.29233	-3.44068	-3.53952	-3.50522	-3.46883	-3.47340	-3.44360	-3.41813	-3.37976	-3.34109
5	-3.16921	-3.29199	-3.41690	-3.50934	-3.47395	-3.45787	-3.44997	-3.41647	-3.39446	-3.35439	-3.31502
6	-3.21550	-3.35770	-3.47742	-3.53527	-3.49868	-3.48117	-3.45131	-3.42464	-3.39298	-3.35383	-3.31790
7	-3.18765	-3.32580	-3.44231	-3.49828	-3.46107	-3.44262	-3.41203	-3.41885	-3.39272	-3.35158	-3.31023
8	-3.17961	-3.30665	-3.42764	-3.47932	-3.44081	-3.42533	-3.39170	-3.39233	-3.35219	-3.30978	-3.27174
9	-3.15216	-3.27105	-3.39067	-3.44195	-3.40272	-3.38758	-3.35277	-3.35158	-3.31078	N/A	N/A
10	-3.11862	-3.23392	-3.35287	-3.40339	-3.36332	-3.34726	-3.31134	-3.31017	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-3.11764	-3.12208	-3.06388	-3.07037	-3.00965	-2.95608	-2.90377	-2.87829	-2.81431	-2.76035	-2.69362
1	-3.07137	-3.17150	-3.11168	-3.11311	-3.06218	-3.00683	-2.97210	-3.12737	-2.89262	-2.83590	-2.77270
2	-3.02689	-3.13026	-3.24753	-3.30277	-3.24823	-3.18399	-3.17871	-3.13310	-3.08321	-3.01551	-2.95273
3	-3.01880	-3.12492	-3.23990	-3.29961	-3.26422	-3.19894	-3.17455	-3.11544	-3.05872	-2.98969	-2.92011
4	-2.95750	-3.07448	-3.19398	-3.26360	-3.19969	-3.13329	-3.10743	-3.04679	-2.99005	-2.91996	-2.84914
5	-2.95136	-3.04529	-3.14098	-3.20381	-3.13840	-3.09190	-3.05316	-2.98839	-2.93467	-2.86244	-2.79045
6	-2.96880	-3.08178	-3.17189	-3.19972	-3.13271	-3.08436	-3.02323	-2.96485	-2.90103	-2.82927	-2.76025
7	-2.91173	-3.02027	-3.10677	-3.13231	-3.06426	-3.01453	-2.95224	-2.92690	-2.86815	-2.79393	-2.71901
8	-2.87408	-2.97110	-3.06167	-3.08251	-3.01273	-2.96553	-2.89975	-2.86776	-2.79454	-2.71856	-2.64646
9	-2.81661	-2.90508	-2.99386	-3.01386	-2.94293	-2.89562	-2.82820	-2.79393	-2.71956	N/A	N/A
10	-2.75265	-2.83710	-2.92478	-2.94360	-2.87136	-2.82269	-2.75369	-2.71895	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	0.38846	0.59122	0.65750	0.25002	0.23556	0.85904	0.23100	-0.25799	-0.35200	-0.17642	-0.16520
1	0.44670	0.77812	0.69326	0.29941	0.24411	0.20023	0.27112	-0.22510	-0.53879	-0.37121	-0.34718
2	1.06595	1.05020	0.47545	-0.09074	-0.13444	-0.13604	-0.05595	-0.39396	-0.76636	-0.80099	-0.77312
3	0.31741	0.66470	0.11527	-0.10230	-0.18797	-0.18476	-0.11166	-0.32309	-0.63182	-0.66574	-0.65662
4	0.31596	0.57057	0.00202	-0.25705	-0.21907	-0.21805	-0.13719	-0.32347	-0.67524	-0.71270	-0.70332
5	0.28595	0.53164	0.00633	-0.24678	-0.21466	0.02013	0.03181	-0.13507	-0.52471	-0.52536	-0.52011
6	0.58023	0.87530	0.35096	0.06787	0.08692	0.30717	0.48090	0.25669	-0.06358	-0.12695	-0.08889
7	0.29786	0.64288	0.23141	0.03057	0.41444	0.27841	0.46842	0.68998	0.29764	0.24987	0.25168
8	-0.35584	0.08519	-0.35973	-0.48817	-0.47683	-0.28379	-0.09153	0.17656	0.19535	0.17585	0.17497
9	-0.13641	0.16148	-0.28982	-0.40352	-0.38957	-0.17108	0.00027	0.23230	0.38641	IDS	IDS
10	-0.14531	0.16916	-0.30116	-0.41360	-0.40058	-0.18326	-0.01316	0.20961	IDS	IDS	IDS

Table 13: Interactive variable analysis – Multivariate uplift-price regressions.

Section 2: Second MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-3.07346	-3.06739	-3.04508	-3.01618	-2.98388	-2.96950	-2.93917	-2.90473	-2.87698	-2.84650	-2.83670
1	-3.20568	-3.20462	-3.19997	-3.17642	-3.14315	-3.12157	-3.08730	-3.05281	-3.02660	-2.99066	-2.99997
2	-3.19197	-3.18416	-3.18164	-3.16313	-3.12883	-3.10666	-3.07217	-3.03614	-3.00968	-2.97239	-2.97685
3	-3.19226	-3.18037	-3.16873	-3.15152	-3.11665	-3.09544	-3.06071	-3.02396	-2.99321	-2.95484	-2.95492
4	-3.22209	-3.20076	-3.18399	-3.15720	-3.12171	-3.10518	-3.06986	-3.03221	-3.00022	-2.96208	-2.95807
5	-3.23307	-3.20726	-3.18559	-3.15685	-3.12099	-3.10616	-3.06852	-3.03054	-2.99768	-2.95921	-2.96244
6	-3.20805	-3.18536	-3.16223	-3.13243	-3.09588	-3.07660	-3.03808	-2.99899	-2.96636	-2.92718	-2.93083
7	-3.25254	-3.21962	-3.18704	-3.15688	-3.11964	-3.09773	-3.05862	-3.01974	-2.99093	-2.95254	-2.95594
8	-3.22700	-3.19336	-3.15814	-3.12497	-3.08699	-3.06408	-3.02414	-2.98400	-2.95559	-2.91525	N/A
9	-3.20908	-3.17681	-3.14131	-3.10469	-3.06776	-3.04559	-3.00498	-2.96472	-2.93337	N/A	N/A
10	-3.20484	-3.17367	-3.14066	-3.10358	-3.07151	-3.03879	-2.99730	-2.95543	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-2.99433	-2.96122	-2.91152	-2.85489	-2.79449	-2.75164	-2.69247	-2.62882	-2.57144	-2.51095	-2.47073
1	-3.09951	-3.07106	-3.03867	-2.98703	-2.92530	-2.87488	-2.81138	-2.74728	-2.69105	-2.62469	-2.60316
2	-3.05841	-3.02286	-2.99225	-2.94527	-2.88213	-2.83074	-2.76663	-2.70060	-2.64371	-2.57558	-2.54877
3	-3.03097	-2.99097	-2.95087	-2.90482	-2.84073	-2.78991	-2.72516	-2.65799	-2.59640	-2.52676	-2.49512
4	-3.03270	-2.98290	-2.93729	-2.88128	-2.81618	-2.76963	-2.70389	-2.63540	-2.57214	-2.50229	-2.46612
5	-3.01521	-2.96057	-2.90967	-2.85132	-2.78545	-2.74019	-2.67171	-2.60246	-2.53789	-2.46726	-2.43787
6	-2.96135	-2.90944	-2.85670	-2.79689	-2.72991	-2.67979	-2.61000	-2.53920	-2.47441	-2.40261	-2.37318
7	-2.97662	-2.91409	-2.85149	-2.79091	-2.72283	-2.66965	-2.59883	-2.52779	-2.46636	-2.39488	-2.36472
8	-2.92146	-2.85782	-2.79217	-2.72816	-2.65890	-2.60429	-2.53219	-2.45943	-2.39793	-2.32403	N/A
9	-2.87354	-2.81084	-2.74449	-2.67661	-2.60796	-2.55364	-2.48041	-2.40706	-2.34215	N/A	N/A
10	-2.83886	-2.77686	-2.71257	-2.64379	-2.57955	-2.51422	-2.43965	-2.36421	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	0.09531	0.27928	0.32977	0.35415	-0.29001	0.32858	0.30158	0.29522	0.27271	0.28183	0.36772
1	0.27499	0.47861	0.57817	0.62198	0.62509	0.59303	0.57687	0.56765	0.54289	0.54242	0.67061
2	0.43521	1.54470	0.70245	0.78253	0.78006	0.74762	0.72963	0.71961	0.69558	0.69139	0.79506
3	0.53441	0.66848	0.75384	0.84091	0.83469	0.80255	0.78268	0.77242	0.74779	0.74301	1.84790
4	0.53641	0.63793	0.71469	0.77669	0.77050	0.73023	0.71029	0.70208	0.67911	0.67307	0.76469
5	0.41629	0.50507	0.57809	0.63728	0.63320	0.58756	0.58064	0.56914	0.54744	0.54089	0.63009
6	0.36557	0.46503	0.53668	0.59456	-0.21716	0.55511	0.55129	0.54321	-0.79439	0.51215	0.60059
7	0.46968	0.51070	0.54661	0.60561	0.60158	0.56771	0.56756	0.55394	0.52438	0.51650	0.60540
8	0.50290	0.54292	0.56432	0.63553	0.60526	1.18610	0.12335	-0.25755	0.52924	0.43736	N/A
9	0.49862	0.55319	0.57724	0.60400	0.59918	0.56425	0.56472	0.54953	-0.96038	N/A	N/A
10	0.45429	0.51836	0.55653	0.58570	0.57852	0.55508	0.55547	-0.22456	N/A	N/A	N/A

Table 13: Interactive variable analysis – Multivariate uplift-price regressions.

Section 3: Third MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-3.64362	-3.62703	-3.62194	-3.60321	-3.57211	-3.55118	-3.53609	-3.51139	-3.48327	-3.44697	-3.41113
1	-3.61923	-3.59877	-3.59435	-3.57767	-3.54674	-3.52508	-3.51038	-3.48790	-3.46130	-3.42421	-3.38757
2	-3.63693	-3.60813	-3.59106	-3.57656	-3.54814	-3.52939	-3.51148	-3.49171	-3.47139	-3.43411	-3.39871
3	-3.61105	-3.58112	-3.55981	-3.54260	-3.51368	-3.49503	-3.47670	-3.45588	-3.43593	-3.39831	-3.36289
4	-3.61023	-3.57912	-3.55561	-3.52934	-3.49592	-3.47775	-3.46243	-3.44152	-3.42085	-3.38379	-3.35153
5	-3.59621	-3.56496	-3.54094	-3.51362	-3.47756	-3.45255	-3.43791	-3.41949	-3.39907	-3.36141	-3.33148
6	-3.59738	-3.56697	-3.54575	-3.51920	-3.48250	-3.45022	-3.42606	-3.40996	-3.39420	-3.35676	-3.32731
7	-3.56232	-3.53130	-3.50946	-3.48241	-3.44499	-3.41196	-3.38683	-3.37160	-3.35389	-3.31528	-3.28473
8	-3.55838	-3.52393	-3.50116	-3.47516	-3.43758	-3.40504	-3.37749	-3.35298	-3.32661	-3.28879	N/A
9	-3.53552	-3.50045	-3.47404	-3.44716	-3.40933	-3.37696	-3.35139	-3.32370	-3.29374	N/A	N/A
10	-3.49899	-3.46325	-3.43604	-3.40794	-3.36931	-3.33622	-3.30985	-3.28188	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-3.56449	-3.52086	-3.48838	-3.44191	-3.38272	-3.33333	-3.28939	-3.23547	-3.17774	-3.11142	-3.04516
1	-3.51306	-3.46521	-3.43305	-3.38827	-3.32888	-3.27838	-3.23446	-3.18237	-3.12576	-3.05824	-2.99076
2	-3.50337	-3.44684	-3.40166	-3.35871	-3.30145	-3.25347	-3.20595	-3.15617	-3.10542	-3.03730	-2.97062
3	-3.44975	-3.39173	-3.34195	-3.29590	-3.23776	-3.18949	-3.14116	-3.08991	-3.03912	-2.97023	-2.90309
4	-3.42083	-3.36127	-3.30891	-3.25342	-3.19038	-3.14220	-3.09646	-3.04470	-2.99276	-2.92400	-2.85958
5	-3.37835	-3.31826	-3.26502	-3.20809	-3.14201	-3.08658	-3.04109	-2.99140	-2.93928	-2.86946	-2.80691
6	-3.35068	-3.29105	-3.24022	-3.18365	-3.11653	-3.05341	-2.99797	-2.95016	-2.90225	-2.83220	-2.76965
7	-3.28641	-3.22577	-3.17391	-3.11643	-3.04818	-2.98388	-2.92704	-2.87965	-2.82932	-2.75763	-2.69351
8	-3.25284	-3.18838	-3.13519	-3.07835	-3.00949	-2.94525	-2.88554	-2.82842	-2.76895	-2.69757	N/A
9	-3.19998	-3.13448	-3.07722	-3.01908	-2.94954	-2.88501	-2.82682	-2.76604	-2.70252	N/A	N/A
10	-3.13302	-3.06643	-3.00796	-2.94814	-2.87736	-2.81166	-2.75220	-2.69065	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-0.28300	-0.29682	-0.29900	-0.28069	-0.28455	-0.27794	-0.33031	-0.37967	-0.40836	-0.40180	-0.40106
1	-0.27642	-0.28995	-0.29144	-0.27009	-0.27444	1.08620	1.36780	1.09450	0.93715	-0.40619	-0.40533
2	-0.39828	-0.39752	-0.38301	-0.36411	-0.37561	-0.37336	-0.41863	-0.48455	-0.53801	-0.54422	-0.54696
3	-0.34988	-0.35102	-0.35276	-0.35042	-0.36007	-0.35168	-0.39525	-0.46237	-0.51110	-0.51868	-0.51920
4	-0.30706	-0.30847	-0.31117	-0.31418	-0.32201	-0.31248	-0.35713	-0.42494	-0.47364	-0.48616	-0.48573
5	-0.14734	-0.14781	-0.15096	-0.15606	-0.16279	-0.18176	-0.22088	-0.27984	-0.32584	-0.33898	-0.32687
6	-0.10021	-0.10014	-0.10188	-0.10683	-0.11459	-0.13065	-0.16772	-0.22826	-0.27641	-0.29201	-0.27885
7	-0.10043	-0.10047	-0.10296	-0.10908	-0.11724	-0.13296	-0.16567	-0.22559	-0.27310	-0.28841	-0.27615
8	-0.23465	-0.22904	-0.23033	-0.24020	-0.25395	-0.27335	-0.29948	-0.32955	-0.34948	-0.37308	N/A
9	-0.34992	-0.34406	-0.33177	-0.34020	-0.35922	-0.38394	-0.42499	-0.44164	-0.44625	N/A	N/A
10	-0.37026	-0.36494	-0.35145	-0.34661	-0.36495	-0.39355	-0.43628	-0.46641	N/A	N/A	N/A

Table 13: Interactive variable analysis – Multivariate uplift-price regressions.

Section 4: Fourth MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-3.34303	-3.32196	-3.29444	-3.27708	-3.27415	-3.24781	-3.22509	-3.19007	-3.18282	-3.14777	-3.11686
1	-3.38748	-3.36853	-3.33900	-3.31435	-3.32176	-3.30053	-3.27908	-3.24384	-3.23858	-3.20187	-3.16849
2	-3.41132	-3.38038	-3.35087	-3.32680	-3.32385	-3.30291	-3.28081	-3.24509	-3.23332	-3.19682	-3.16808
3	-3.38323	-3.35129	-3.32446	-3.29952	-3.29916	-3.27617	-3.25538	-3.21913	-3.20703	-3.16922	-3.14184
4	-3.35010	-3.31774	-3.29057	-3.26461	-3.26374	-3.23993	-3.21913	-3.18204	-3.16961	-3.13095	-3.10358
5	-3.36412	-3.33089	-3.29668	-3.27063	-3.25169	-3.22864	-3.21423	-3.17575	-3.16164	-3.12180	-3.09680
6	-3.33078	-3.29742	-3.26260	-3.23907	-3.21985	-3.19284	-3.17741	-3.13836	-3.12508	-3.08442	-3.05801
7	-3.29724	-3.26285	-3.22702	-3.20299	-3.18687	-3.16020	-3.14014	-3.10033	-3.08446	-3.04302	-3.01595
8	-3.26163	-3.22654	-3.18996	-3.16522	-3.14831	-3.12146	-3.10156	-3.06065	-3.04371	-3.00119	N/A
9	-3.23085	-3.19428	-3.15687	-3.12910	-3.11271	-3.08433	-3.06857	-3.02713	-3.01925	N/A	N/A
10	-3.20025	-3.16319	-3.12576	-3.09901	-3.07877	-3.05274	-3.03735	-2.99693	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-3.26390	-3.21578	-3.16088	-3.11579	-3.08475	-3.02995	-2.97840	-2.91415	-2.87729	-2.81222	-2.75089
1	-3.28130	-3.23497	-3.17770	-3.12496	-3.10391	-3.05383	-3.00316	-2.93830	-2.90304	-2.83590	-2.77168
2	-3.27776	-3.21908	-3.16148	-3.10894	-3.07715	-3.02700	-2.97527	-2.90955	-2.86735	-2.80001	-2.74000
3	-3.22193	-3.16190	-3.10660	-3.05282	-3.02324	-2.97064	-2.91983	-2.85316	-2.81022	-2.74114	-2.68205
4	-3.16070	-3.09988	-3.04387	-2.98869	-2.95821	-2.90439	-2.85316	-2.78523	-2.74153	-2.67116	-2.61163
5	-3.14627	-3.08419	-3.02076	-2.96510	-2.91614	-2.86267	-2.81742	-2.74767	-2.70185	-2.62985	-2.57224
6	-3.08408	-3.02150	-2.95706	-2.90352	-2.85388	-2.79602	-2.74933	-2.67856	-2.63313	-2.55985	-2.50035
7	-3.02132	-2.95732	-2.89147	-2.83702	-2.79005	-2.73212	-2.68034	-2.60838	-2.55989	-2.48537	-2.42472
8	-2.95610	-2.89099	-2.82399	-2.76840	-2.72022	-2.66166	-2.60961	-2.53608	-2.48606	-2.40997	N/A
9	-2.89530	-2.82831	-2.76006	-2.70102	-2.65292	-2.59238	-2.54401	-2.46948	-2.42803	N/A	N/A
10	-2.83428	-2.76638	-2.69767	-2.63921	-2.58682	-2.52818	-2.47969	-2.40571	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	PPP lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	0.84004	1.06660	0.89635	0.09552	-0.01317	-0.04465	-0.05235	-0.05301	-0.00183	-0.02108	0.06889
1	0.01567	0.01476	0.01542	0.02287	-0.10904	-0.15406	-0.16297	-0.15774	-0.10552	-0.09588	-0.01806
2	-0.08829	-0.08208	-0.08153	-0.95326	-0.17911	-0.22608	-0.23454	-0.22841	-0.17544	-0.15879	-0.04824
3	-0.13784	-0.12993	-0.14848	-0.14012	-0.26278	-0.30054	-0.31762	-0.31114	-0.25930	-0.24418	-0.13042
4	-0.13619	-0.12652	-0.10426	-0.14071	-0.26388	-0.30054	-0.32020	-0.31372	-0.26280	-0.24813	-0.13262
5	0.06311	0.07021	0.05627	0.06014	-0.07087	-0.10468	-0.10256	-0.10141	-0.05630	-0.04857	0.08662
6	0.09143	0.10601	0.09216	0.12569	-0.00345	-0.06157	-0.05798	-0.05407	0.00814	0.01575	0.14127
7	0.14918	0.15501	0.13628	0.17381	0.09210	0.04419	0.00390	0.00805	0.03179	0.04235	0.17123
8	0.14600	0.15200	0.13499	0.17344	0.09141	0.04533	0.00496	0.00697	0.30570	0.03800	N/A
9	-0.70800	0.14776	0.13231	0.16804	0.08285	0.03924	-0.01065	-0.00639	0.01532	N/A	N/A
10	0.13905	0.14341	0.11848	0.15562	0.07823	0.02782	-0.02358	-0.01424	N/A	N/A	N/A

Table 13: Interactive variable analysis – Multivariate uplift-price regressions.

Section 5: Fifth MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-3.21649	-3.21514	-3.18490	-3.15323	-3.16674	-3.15016	-3.11759	-3.08266	-3.04724	-3.01354	-2.98602
1	-3.23725	-3.34911	-3.31791	-3.28533	-3.29640	-3.31145	-3.28634	-3.25066	-3.21442	-3.18154	-3.15182
2	-3.23535	-3.36251	-3.38032	-3.35596	-3.37324	-3.39532	-3.40006	-3.36711	-3.33058	-3.29614	-3.26416
3	-3.20293	-3.33051	-3.34663	-3.32587	-3.33873	-3.36177	-3.36831	-3.33799	-3.30142	-3.26671	-3.23366
4	-3.22274	-3.31947	-3.33089	-3.31437	-3.30355	-3.32554	-3.33139	-3.30065	-3.26394	-3.22911	-3.19497
5	-3.32969	-3.43193	-3.42159	-3.40197	-3.37922	-3.34472	-3.33880	-3.31283	-3.27859	-3.25794	-3.21899
6	-3.32587	-3.43926	-3.43365	-3.40840	-3.38564	-3.34922	-3.31628	-3.28695	-3.25400	-3.23813	-3.19633
7	-3.29321	-3.40406	-3.39805	-3.37273	-3.35022	-3.31306	-3.27891	-3.24705	-3.21356	-3.19633	-3.15365
8	-3.25853	-3.36831	-3.36131	-3.33603	-3.31216	-3.27441	-3.23946	-3.20652	-3.17292	-3.14535	N/A
9	-3.24132	-3.34810	-3.34746	-3.31846	-3.28943	-3.25036	-3.21667	-3.18357	-3.14765	N/A	N/A
10	-3.20827	-3.31744	-3.31669	-3.28461	-3.25368	-3.21472	-3.18100	-3.14549	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-3.13736	-3.10897	-3.05134	-2.99193	-2.97734	-2.93231	-2.87090	-2.80674	-2.74171	-2.67800	-2.62005
1	-3.13107	-3.21555	-3.15661	-3.09594	-3.07854	-3.06475	-3.01042	-2.94513	-2.87887	-2.81557	-2.75500
2	-3.10179	-3.20121	-3.19093	-3.13810	-3.12655	-3.11940	-3.09452	-3.03157	-2.96461	-2.89933	-2.83607
3	-3.04164	-3.14112	-3.12877	-3.07918	-3.06281	-3.05624	-3.03276	-2.97202	-2.90461	-2.83862	-2.77387
4	-3.03335	-3.10161	-3.08419	-3.03845	-2.99802	-2.99000	-2.96542	-2.90384	-2.83586	-2.76931	-2.70302
5	-3.11183	-3.18523	-3.14567	-3.09644	-3.04367	-2.97875	-2.94199	-2.88475	-2.81879	-2.76599	-2.69442
6	-3.07918	-3.16334	-3.12812	-3.07285	-3.01967	-2.95241	-2.88820	-2.82715	-2.76205	-2.71357	-2.63868
7	-3.01729	-3.09853	-3.06250	-3.00676	-2.95340	-2.88498	-2.81911	-2.75510	-2.68900	-2.63868	-2.56243
8	-2.95300	-3.03276	-2.99534	-2.93922	-2.88407	-2.81462	-2.74751	-2.68195	-2.61526	-2.55413	N/A
9	-2.90578	-2.98213	-2.95065	-2.89038	-2.82963	-2.75841	-2.69210	-2.62592	-2.55643	N/A	N/A
10	-2.84230	-2.92063	-2.88861	-2.82482	-2.76173	-2.69015	-2.62335	-2.55426	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	PPP lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	0.70956	0.74677	0.76845	0.73012	0.69571	0.71389	0.71539	0.70758	0.71002	0.74454	0.71749
1	0.64575	0.68345	0.65304	0.62187	0.59063	0.61446	0.62120	0.61856	0.61972	0.66476	0.63821
2	0.52830	0.54260	0.22502	0.09743	0.05106	0.06138	-0.00659	-0.00250	0.00565	0.05163	0.03436
3	0.50488	0.49563	0.21224	0.11304	0.05755	0.07450	0.01082	0.02303	0.03622	0.08544	0.06791
4	0.47186	0.47375	0.20499	0.08861	0.05724	0.07422	0.01018	0.02224	0.03867	0.09262	0.07484
5	0.45230	0.45624	0.25746	0.14850	0.12240	0.11882	0.05890	0.07807	0.10706	0.23564	0.22113
6	0.38684	0.38067	0.15911	0.07398	0.04723	0.04576	0.03355	0.05271	0.08548	0.22855	0.22787
7	0.42908	0.38398	0.18027	0.10066	0.08102	0.07948	0.06437	0.04152	0.06950	0.22421	0.22360
8	0.43730	0.36996	0.17441	0.08784	0.07267	0.06991	0.05472	0.03444	0.09010	0.25993	N/A
9	0.54018	0.46697	0.26919	0.18697	0.16345	0.15935	0.14700	0.12727	0.17343	N/A	N/A
10	0.52833	0.45183	0.25316	0.18315	0.16119	0.15585	0.14273	0.12513	N/A	N/A	N/A

Table 13: Interactive variable analysis – Multivariate uplift-price regressions.

Section 6: Sixth MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-1.44694	-1.41589	-1.38430	-1.35169	-1.31938	-1.38432	-1.35229	-1.42271	-1.39396	-1.35765	-1.36139
1	-1.42493	-1.40247	-1.37008	-1.33689	-1.30361	-1.36343	-1.32867	-1.39782	-1.37657	-1.33991	-1.34212
2	-1.41514	-1.39570	-1.39577	-1.36197	-1.32873	-1.40147	-1.36622	-1.40592	-1.38498	-1.35585	-1.35190
3	-1.40503	-1.38124	-1.38837	-1.40907	-1.37521	-1.45369	-1.41806	-1.44961	-1.41847	-1.39125	-1.36346
4	-1.38977	-1.36819	-1.36795	-1.39229	-1.37639	-1.46990	-1.43485	-1.45287	-1.42104	-1.38902	-1.35792
5	-1.63457	-1.60314	-1.63097	-1.62326	-1.63600	-1.61170	-1.58412	-1.59456	-1.55775	-1.52551	-1.50374
6	-1.60843	-1.57744	-1.60029	-1.59576	-1.60397	-1.58118	-1.54569	-1.55527	-1.51790	-1.48463	-1.46219
7	-1.67287	-1.64901	-1.65549	-1.64633	-1.63739	-1.61483	-1.58655	-1.54457	-1.50853	-1.47537	-1.44946
8	-1.63914	-1.61508	-1.61890	-1.61036	-1.60101	-1.58002	-1.54920	-1.50921	-1.50117	-1.46385	N/A
9	-1.60713	-1.58151	-1.58342	-1.57722	-1.56513	-1.54311	-1.51314	-1.47248	-1.46095	N/A	N/A
10	-1.59048	-1.56297	-1.56790	-1.56016	-1.54270	-1.52290	-1.49167	-1.45250	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-1.36781	-1.30972	-1.25074	-1.19039	-1.12998	-1.16646	-1.10560	-1.14679	-1.08843	-1.02210	-0.99542
1	-1.31876	-1.26891	-1.20878	-1.14750	-1.08575	-1.11674	-1.05275	-1.09229	-1.04103	-0.97394	-0.94531
2	-1.28158	-1.23440	-1.20638	-1.14411	-1.08203	-1.12556	-1.06069	-1.07037	-1.01901	-0.95903	-0.92382
3	-1.24373	-1.19185	-1.17051	-1.16238	-1.09929	-1.14815	-1.08251	-1.08364	-1.02165	-0.96317	-0.90367
4	-1.20037	-1.15033	-1.12125	-1.11637	-1.07085	-1.13435	-1.06888	-1.05606	-0.99295	-0.92922	-0.86597
5	-1.41671	-1.35644	-1.35505	-1.31773	-1.30046	-1.24573	-1.18730	-1.16648	-1.09796	-1.03356	-0.97917
6	-1.36173	-1.30153	-1.29475	-1.26021	-1.23800	-1.18436	-1.11761	-1.09548	-1.02594	-0.96006	-0.90453
7	-1.39695	-1.34348	-1.31994	-1.28036	-1.24058	-1.18674	-1.12675	-1.05262	-0.98397	-0.91771	-0.85824
8	-1.33361	-1.27954	-1.25293	-1.21354	-1.17293	-1.12022	-1.05725	-0.98465	-0.94351	-0.87262	N/A
9	-1.27159	-1.21554	-1.18661	-1.14914	-1.10534	-1.05116	-0.98857	-0.91483	-0.86973	N/A	N/A
10	-1.22451	-1.16616	-1.13982	-1.10036	-1.05075	-0.99833	-0.93402	-0.86128	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	PPP lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	0.51689	0.53426	0.53666	0.53419	0.52398	0.20019	0.24487	0.18726	0.09640	0.08073	0.38151
1	0.61637	0.57974	0.58004	0.57331	0.56812	0.24633	0.25883	0.20125	0.06765	0.03207	0.03298
2	0.68222	0.64544	0.67453	0.67092	0.65890	0.32621	0.34182	0.27439	0.13727	-0.01570	0.26316
3	0.74473	0.70716	0.75252	0.88555	0.87230	0.53983	0.51410	0.44245	0.34216	0.16882	0.31093
4	0.75844	0.71762	0.75647	0.89561	0.97185	0.63934	0.60118	0.52502	0.42385	0.27787	0.39753
5	0.36452	0.34900	0.38562	0.49913	0.60279	0.66556	0.58767	0.51796	0.45092	0.30218	0.47911
6	0.26891	0.24548	0.30703	0.40390	0.52459	0.57883	0.57621	0.51771	0.45039	0.30404	0.48065
7	0.05758	0.00996	0.08012	0.17630	0.29340	0.34898	0.33728	0.34598	0.25426	0.10272	0.27550
8	0.13918	0.10113	0.11872	0.25174	0.37271	0.46965	0.46467	0.48560	0.55135	0.41208	N/A
9	0.04382	0.01779	0.05030	0.15451	0.28890	0.38691	0.36393	0.38614	0.47584	N/A	N/A
10	0.44780	0.19430	0.24359	0.34035	0.44106	0.55756	0.53244	0.58367	N/A	N/A	N/A

Table 14: Interactive variable analysis – Multivariate uplift-demand regressions.

Section 1: First MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-2.23923	-2.21017	-2.19153	-2.16416	-2.13552	-2.11609	-2.08174	-2.18620	-2.15189	-2.11569	-2.09701
1	-2.21990	-2.23698	-2.21168	-2.18763	-2.15874	-2.13571	-2.10068	-2.18955	-2.15387	-2.11702	-2.09886
2	-2.21380	-2.24351	-2.22094	-2.19435	-2.17037	-2.15038	-2.11468	-2.19841	-2.16132	-2.12644	-2.11141
3	-2.19730	-2.22411	-2.20766	-2.17526	-2.14833	-2.12958	-2.09319	-2.17105	-2.13324	-2.09658	-2.07426
4	-2.22962	-2.26777	-2.24757	-2.22356	-2.23215	-2.20230	-2.16522	-2.24443	-2.20606	-2.16852	-2.15646
5	-2.20426	-2.23967	-2.21978	-2.19280	-2.20233	-2.16650	-2.12873	-2.20662	-2.16744	-2.12903	-2.11615
6	-2.22270	-2.22087	-2.19876	-2.17055	-2.16899	-2.13300	-2.09661	-2.18187	-2.14188	-2.10329	-2.09271
7	-2.18862	-2.18525	-2.16297	-2.13373	-2.13119	-2.09444	-2.05731	-2.14618	-2.10529	-2.06616	-2.05289
8	-2.16046	-2.14886	-2.12595	-2.09706	-2.09346	-2.05610	-2.01820	-2.10527	-2.06353	-2.02217	N/A
9	-2.13728	-2.12616	-2.09282	-2.06254	-2.06554	-2.02717	-1.98729	-2.07730	-2.03509	N/A	N/A
10	-2.10033	-2.08856	-2.05437	-2.02734	-2.03163	-1.99450	-1.95383	-2.05803	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-2.16010	-2.10400	-2.05797	-2.00287	-1.94612	-1.89823	-1.83505	-1.91028	-1.84636	-1.78015	-1.73104
1	-2.11373	-2.10342	-2.05038	-1.99824	-1.94088	-1.88902	-1.82476	-2.04059	-1.81833	-1.75105	-1.70204
2	-2.08024	-2.08221	-2.03154	-1.97649	-1.92367	-1.87446	-1.80914	-1.97917	-1.79535	-1.72962	-1.68332
3	-2.03600	-2.03471	-1.98980	-1.92856	-1.87242	-1.82404	-1.75764	-1.91664	-1.73643	-1.66850	-1.61447
4	-2.04023	-2.04991	-2.00087	-1.94764	-1.92662	-1.86675	-1.79925	-1.85297	-1.77798	-1.70872	-1.66450
5	-1.98640	-1.99297	-1.94386	-1.88727	-1.86678	-1.80053	-1.73191	-1.78813	-1.70764	-1.63708	-1.59159
6	-1.97600	-1.94495	-1.89323	-1.83500	-1.80302	-1.73619	-1.66853	-1.72208	-1.64993	-1.57872	-1.53506
7	-1.91270	-1.87972	-1.82742	-1.76775	-1.73438	-1.66636	-1.59752	-1.65423	-1.58072	-1.50851	-1.46167
8	-1.85492	-1.81332	-1.75998	-1.70025	-1.66538	-1.59631	-1.52625	-1.58071	-1.50588	-1.43094	N/A
9	-1.80174	-1.76019	-1.69601	-1.63445	-1.60575	-1.53522	-1.46273	-1.51965	-1.44386	N/A	N/A
10	-1.73436	-1.69175	-1.62628	-1.56755	-1.53968	-1.46993	-1.39617	-1.46680	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-1.84370	-1.84440	-1.64220	-1.57760	-1.54430	-1.55830	-1.55050	-1.80210	-1.79280	-1.75690	-1.58940
1	-1.90350	-2.14360	-1.96130	-1.89410	-1.85940	-1.86100	-1.85110	-2.04130	-2.03950	-1.99960	-1.83090
2	-1.58870	-1.94780	-1.59760	-1.54820	-1.47930	-1.47040	-1.46250	-1.66450	-1.65340	-1.67060	-1.48290
3	-1.19180	-1.38340	-1.29850	-1.20400	-1.16880	-1.14280	-1.13660	-1.37950	-1.36930	-1.39040	-1.33880
4	-0.86083	-1.04510	-0.97761	-0.76577	-0.48969	-0.49748	-0.49494	-0.73452	-0.71889	-0.74406	-0.65348
5	-0.80766	-0.99446	-0.92246	-0.74101	-0.45872	-0.47283	-0.47035	-0.71274	-0.69896	-0.72402	-0.63415
6	-0.47001	-0.72864	-0.67548	-0.51366	-0.36108	-0.37243	-0.33182	-0.51524	-0.50360	-0.53134	-0.42171
7	-0.37721	-0.67232	-0.70919	-0.53304	-0.35047	-0.35691	-0.30179	-0.31527	-0.30692	-0.33321	-0.27009
8	-0.67577	-0.61766	-0.68444	-0.60552	-0.41816	-0.43142	-0.38020	-0.27213	-0.05523	-0.28737	N/A
9	-0.89828	-0.84988	-0.80559	-0.71955	-0.61137	-0.62058	-0.57128	-0.49896	1.07790	N/A	N/A
10	-0.89049	-0.84165	-0.79913	-0.66918	-0.54933	-0.62058	-0.50575	-0.38791	N/A	N/A	N/A

<u>Table 14: Interactive variable analysis – Multivariate uplift-demand regressions.</u>

Section 2: Second MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-3.08638	-3.09602	-3.07712	-3.04477	-3.01175	-2.98525	-2.97105	-2.98069	-2.95134	-2.91742	-2.88142
1	-3.23722	-3.23429	-3.24024	-3.21177	-3.17865	-3.14948	-3.13087	-3.11994	-3.08358	-3.05355	-3.01609
2	-3.22375	-3.21378	-3.21743	-3.19254	-3.15825	-3.12833	-3.10965	-3.09853	-3.06151	-3.02752	-2.98906
3	-3.22699	-3.21512	-3.20607	-3.17937	-3.14447	-3.11638	-3.09752	-3.08490	-3.04712	-3.01409	-2.97651
4	-3.27079	-3.25312	-3.23768	-3.20390	-3.16856	-3.14244	-3.12128	-3.11206	-3.07354	-3.03878	-2.99915
5	-3.27055	-3.24487	-3.23058	-3.19574	-3.16184	-3.13330	-3.10698	-3.09427	-3.05498	-3.01901	-2.97879
6	-3.24047	-3.21604	-3.19883	-3.16355	-3.12886	-3.09830	-3.07190	-3.06243	-3.02230	-2.98480	-2.94381
7	-3.28550	-3.25213	-3.22520	-3.19167	-3.09868	-3.07017	-3.02041	-3.09934	-3.06029	-3.02095	-2.97835
8	-3.25690	-3.22250	-3.19260	-3.15743	-3.12892	-3.08564	-3.05854	-3.06550	-3.02454	-2.98589	N/A
9	-3.23918	-3.20574	-3.17484	-3.13712	-3.10784	-3.04773	-3.04432	-3.04371	-3.00115	N/A	N/A
10	-3.23502	-3.20145	-3.17674	-3.13836	-3.10828	-3.07447	-3.04388	-3.03647	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-3.00724	-2.98984	-2.94356	-2.88348	-2.82235	-2.76739	-2.72435	-2.70478	-2.64581	-2.58187	-2.51545
1	-3.13105	-3.10073	-3.07894	-3.02238	-2.96079	-2.90279	-2.85495	-2.81441	-2.74803	-2.68758	-2.61928
2	-3.09019	-3.05248	-3.02803	-2.97468	-2.91155	-2.85242	-2.80411	-2.76299	-2.69554	-2.63071	-2.56097
3	-3.06570	-3.02572	-2.98821	-2.93267	-2.86855	-2.81085	-2.76198	-2.71893	-2.65031	-2.58601	-2.51672
4	-3.08140	-3.03526	-2.99098	-2.92798	-2.86302	-2.80689	-2.75531	-2.71525	-2.64545	-2.57898	-2.50720
5	-3.05269	-2.99818	-2.95467	-2.89020	-2.82630	-2.76733	-2.71016	-2.66619	-2.59519	-2.52706	-2.45422
6	-2.99378	-2.94012	-2.89329	-2.82800	-2.76289	-2.70148	-2.64381	-2.60264	-2.53035	-2.46024	-2.38616
7	-3.00958	-2.94659	-2.88966	-2.82570	-2.70187	-2.64209	-2.56061	-2.60739	-2.53572	-2.46330	-2.38713
8	-2.95137	-2.88696	-2.82663	-2.76062	-2.70084	-2.62585	-2.56659	-2.54093	-2.46688	-2.39467	N/A
9	-2.90364	-2.83977	-2.77803	-2.70904	-2.64805	-2.55578	-2.51975	-2.48606	-2.40993	N/A	N/A
10	-2.86905	-2.80464	-2.74865	-2.67856	-2.61633	-2.54990	-2.48622	-2.44525	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	Demand lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-0.09934	-1.34230	-0.74538	-0.72708	0.19560	0.18530	0.17018	0.20187	0.20074	0.20671	0.21254
1	0.08580	0.24276	0.39919	0.43076	0.45005	0.43868	0.42156	0.43265	0.43057	0.44401	0.44518
2	0.25210	0.35937	0.50127	0.56731	0.57171	0.55931	0.54402	0.55662	0.55334	0.54966	0.54746
3	0.36265	0.46331	0.56178	0.62061	0.60667	0.59446	0.57931	0.59076	0.58729	0.58472	0.58768
4	0.34762	0.43513	0.52197	0.54470	0.55340	0.53903	0.52557	0.53691	0.53377	0.53177	0.53226
5	0.25756	0.33122	0.41898	0.43820	0.46302	0.45257	0.44750	0.46292	0.46013	0.45922	0.46051
6	0.22609	0.30194	0.39008	0.41173	0.43620	0.43050	0.42318	0.42988	0.42735	0.42783	0.42949
7	0.33330	0.36373	0.42267	0.46457	0.43818	0.42942	0.43050	0.50480	0.50385	0.50296	0.50110
8	0.36426	0.39134	0.43742	0.47125	0.46183	0.49650	0.49078	0.51086	0.50862	0.50935	N/A
9	0.35503	0.39226	0.43715	0.45462	0.44553	0.49837	0.48382	0.50285	0.50013	N/A	N/A
10	0.32649	0.36647	0.52625	0.44842	0.43945	0.50877	0.50036	0.51634	N/A	N/A	N/A

Table 14: Interactive variable analysis – Multivariate uplift-demand regressions.

Section 3: Third MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-3.64064	-3.61898	-3.58713	-3.59283	-3.56865	-3.53682	-3.51837	-3.50367	-3.52666	-3.49099	-3.48216
1	-3.61141	-3.59077	-3.55849	-3.56371	-3.53717	-3.50521	-3.48536	-3.46855	-3.49389	-3.45695	-3.44763
2	-3.62311	-3.59905	-3.56738	-3.57748	-3.55150	-3.51667	-3.49129	-3.47813	-3.49254	-3.45503	-3.43308
3	-3.59565	-3.57010	-3.53752	-3.55063	-3.52296	-3.48767	-3.46454	-3.45395	-3.47404	-3.43553	-3.40830
4	-3.59276	-3.56707	-3.53278	-3.54141	-3.51195	-3.47599	-3.44975	-3.43122	-3.45731	-3.41855	-3.39218
5	-3.58132	-3.55265	-3.51792	-3.52007	-3.49056	-3.45361	-3.42725	-3.41151	-3.42802	-3.38921	-3.35976
6	-3.58692	-3.55828	-3.52256	-3.53019	-3.50497	-3.46797	-3.44380	-3.42559	-3.45773	-3.41679	-3.38066
7	-3.55186	-3.22257	-3.48617	-3.49325	-3.46822	-3.43048	-3.40576	-3.38694	-3.41888	-3.37714	-3.33912
8	-3.54541	-3.51910	-3.48211	-3.49524	-3.47584	-3.43651	-3.41103	-3.39388	-3.42815	-3.38564	N/A
9	-3.52418	-3.49818	-3.46107	-3.47701	-3.45159	-3.41146	-3.39349	-3.37754	-3.41555	N/A	N/A
10	-3.48709	-3.45533	-3.42251	-3.43880	-3.41238	-3.37143	-3.35197	-3.33548	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-3.56151	-3.51281	-3.45357	-3.43153	-3.37925	-3.31896	-3.27167	-3.22775	-3.22113	-3.15544	-3.11619
1	-3.50523	-3.45721	-3.39719	-3.37432	-3.31931	-3.25852	-3.20944	-3.16301	-3.15835	-3.09098	-3.05081
2	-3.48955	-3.43776	-3.37799	-3.35962	-3.30480	-3.24076	-3.18576	-3.14259	-3.12657	-3.05822	-3.00499
3	-3.43435	-3.38070	-3.31966	-3.30393	-3.24705	-3.18214	-3.12900	-3.08798	-3.07722	-3.00745	-2.94850
4	-3.40337	-3.34921	-3.28609	-3.26549	-3.20642	-3.14044	-3.08378	-3.03440	-3.02922	-2.95876	-2.90023
5	-3.36347	-3.30596	-3.24200	-3.21454	-3.15501	-3.08764	-3.03044	-2.98343	-2.96822	-2.89726	-2.83519
6	-3.34022	-3.28236	-3.21703	-3.19464	-3.13900	-3.07115	-3.01572	-2.96580	-2.96578	-2.89222	-2.82301
7	-3.27594	-2.91704	-3.15063	-3.12728	-3.07141	-3.00239	-2.94597	-2.89499	-2.89432	-2.81948	-2.74790
8	-3.23988	-3.18355	-3.11614	-3.09843	-3.04775	-2.97671	-2.91908	-2.86931	-2.87049	-2.79442	N/A
9	-3.18863	-3.13221	-3.06426	-3.04892	-2.99180	-2.91951	-2.86893	-2.81988	-2.82432	N/A	N/A
10	-3.12112	-3.05852	-2.99443	-2.97901	-2.92043	-2.84687	-2.79431	-2.74426	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-0.21227	-0.09385	-0.82767	-0.02870	0.01249	-0.00204	0.01558	0.01386	-0.02215	-0.02967	-0.01394
1	-0.21287	-0.08542	-0.07177	-0.01780	0.01692	0.00108	0.01755	0.01506	-0.02018	-0.02391	-0.00808
2	-0.34518	-0.22914	-0.20280	-0.15330	-0.11703	-0.14993	-0.09962	-0.10818	-0.12577	-0.12145	-0.09300
3	-0.30513	-0.19985	-0.17734	-0.11644	-0.08513	-0.08875	-0.05958	-0.06258	-0.07124	-0.06976	-0.51525
4	-0.27954	-0.17167	-0.16351	-0.10626	-0.07780	-0.08149	-0.05548	-0.05866	-0.06712	-0.06232	-0.04278
5	-0.10600	-0.02593	-0.01422	0.01568	0.04700	0.04329	0.07143	0.08165	0.03664	0.47634	0.05349
6	-0.04653	0.03730	0.03803	0.07386	0.11816	0.11059	0.14363	0.15186	0.11389	0.11025	0.11165
7	0.76108	0.03706	0.03800	0.07317	0.11926	0.11174	0.14491	0.15332	0.11301	0.11009	0.11118
8	-0.17896	-0.08255	-0.07648	-0.04973	-0.00281	-0.00197	0.03166	0.03819	-0.00565	-0.00959	N/A
9	-0.30156	-0.20446	-0.19153	-0.17529	-0.11822	-0.11815	-0.10663	-0.10523	-0.16163	N/A	N/A
10	-0.30042	-0.29112	-0.19193	-0.21005	-0.15021	-0.14903	-0.12417	-0.07557	N/A	N/A	N/A

Table 14: Interactive variable analysis – Multivariate uplift-demand regressions.

Section 4: Fourth MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	Demand Lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-3.33917	-3.31211	-3.28067	-3.26823	-3.25224	-3.22767	-3.19535	-3.16094	-3.13115	-3.09697	-3.06576
1	-3.39800	-3.36930	-3.33749	-3.32972	-3.32382	-3.29409	-3.25921	-3.22361	-3.19483	-3.15810	-3.12457
2	-3.43540	-3.40281	-3.36968	-3.36745	-3.36250	-3.33200	-3.29647	-3.26081	-3.23096	-3.19315	-3.16386
3	-3.40518	-3.37198	-3.33818	-3.33470	-3.33092	-3.29897	-3.26296	-3.22687	-3.19694	-3.15838	-3.12868
4	-3.37202	-3.33821	-3.30379	-3.30031	-3.29717	-3.26462	-3.22776	-3.19133	-3.16024	-3.12091	-3.09051
5	-3.37743	-3.34305	-3.31065	-3.29529	-3.28705	-3.25315	-3.21684	-3.17891	-3.14450	-3.10446	-3.07395
6	-3.34380	-3.30874	-3.27580	-3.26385	-3.25228	-3.21787	-3.18093	-3.14188	-3.10629	-3.06538	-3.03472
7	-3.31028	-3.27456	-3.24151	-3.22911	-3.22658	-3.19102	-3.15398	-3.11401	-3.07576	-3.03396	-3.00075
8	-3.27497	-3.23817	-3.20461	-3.19179	-3.18810	-3.15173	-3.11389	-3.07306	-3.03400	-2.99132	N/A
9	-3.24464	-3.20789	-3.17344	-3.15760	-3.15514	-3.11872	-3.08442	-3.04274	-3.00258	N/A	N/A
10	-3.21042	-3.17306	-3.13720	-3.12185	-3.11731	-3.07931	-3.04416	-3.00148	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-3.26004	-3.20593	-3.14711	-3.10693	-3.06285	-3.00981	-2.94865	-2.88502	-2.82562	-2.76142	-2.69979
1	-3.29183	-3.23574	-3.17619	-3.14032	-3.10596	-3.04739	-2.98329	-2.91807	-2.85929	-2.79213	-2.72776
2	-3.30184	-3.24151	-3.18029	-3.14959	-3.11581	-3.05608	-2.99094	-2.92527	-2.86499	-2.79633	-2.73578
3	-3.24388	-3.18259	-3.12032	-3.08800	-3.05501	-2.99344	-2.92742	-2.86090	-2.80013	-2.73030	-2.66888
4	-3.18262	-3.12036	-3.05710	-3.02439	-2.99163	-2.92907	-2.86179	-2.79452	-2.73216	-2.66112	-2.59856
5	-3.15957	-3.09635	-3.03473	-2.98976	-2.95150	-2.88718	-2.82003	-2.75083	-2.68471	-2.61251	-2.54938
6	-3.09710	-3.03282	-2.97027	-2.92830	-2.88631	-2.82105	-2.75285	-2.68209	-2.61434	-2.54081	-2.47707
7	-3.03436	-2.96903	-2.90597	-2.86314	-2.82977	-2.76294	-2.69419	-2.62206	-2.55119	-2.47630	-2.40952
8	-2.96944	-2.90262	-2.83864	-2.79498	-2.76002	-2.69194	-2.62194	-2.54850	-2.47634	-2.40009	N/A
9	-2.90909	-2.84192	-2.77663	-2.72952	-2.69535	-2.62677	-2.55985	-2.48508	-2.41135	N/A	N/A
10	-2.84445	-2.77625	-2.70911	-2.66205	-2.62536	-2.55474	-2.48651	-2.41026	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	0.05047	-0.02262	-0.03385	-0.07249	-0.07363	-0.22843	-0.11790	-0.17145	-0.28098	-0.23930	-0.31967
1	0.00089	-0.06317	-0.07573	-0.12005	-0.12436	-0.23173	-0.19184	-0.20893	-0.33230	-0.31255	-0.37898
2	-0.09769	-0.10272	-0.10557	-0.15619	-0.16087	-0.26567	-0.22421	-0.27599	-0.39428	-0.39395	-0.49556
3	-0.13771	-0.13379	-0.13311	-0.17843	-0.19385	-0.28399	-0.23025	-0.29237	-0.41672	-0.41662	-0.45140
4	-0.13631	-0.13306	-0.13203	-0.18077	-0.19886	-0.28963	-0.24510	-0.32026	-0.43771	-0.43559	-0.53914
5	0.02754	0.03210	0.02423	-0.03599	-0.06371	-0.14949	-0.05260	-0.10774	-0.21298	-0.21880	-0.32420
6	0.05331	0.05521	0.04866	0.01733	-0.02558	-0.11255	-0.01434	-0.05367	-0.15872	-0.16268	-0.26216
7	0.11133	0.11221	0.11517	0.08768	0.13421	0.04844	0.16150	0.12566	0.03002	0.02864	-0.07778
8	0.11653	0.11221	0.11809	0.09381	0.13578	0.04335	0.05125	0.12044	0.02474	0.02236	N/A
9	0.11369	0.12602	0.12726	0.10153	0.14715	0.04462	0.24946	0.21173	0.11729	N/A	N/A
10	0.10697	0.12117	0.12268	0.09546	0.14120	0.04977	0.25358	0.24556	N/A	N/A	N/A

Table 14: Interactive variable analysis – Multivariate uplift-demand regressions.

Section 5: Fifth MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-2.94096	-2.91095	-2.91081	-2.88349	-2.89351	-2.86355	-2.82913	-2.79681	-2.77287	-2.73710	-2.70955
1	-2.97748	-2.95362	-2.94373	-2.92457	-2.93314	-2.90077	-2.86696	-2.83129	-2.80208	-2.76668	-2.73584
2	-3.00147	-2.99555	-2.96901	-2.94521	-2.97249	-2.94160	-2.90664	-2.87064	-2.85057	-2.81308	-2.78437
3	-2.97251	-2.97017	-2.94017	-2.91318	-2.93868	-2.90641	-2.87085	-2.83420	-2.81323	-2.77518	-2.74560
4	-3.01315	-3.00279	-2.96876	-2.93424	-2.93880	-2.90926	-2.87220	-2.83466	-2.81100	-2.77181	-2.75078
5	-3.08182	-3.07466	-3.04741	-3.01392	-3.00436	-2.97696	-2.93972	-2.90116	-2.88139	-2.84139	-2.81974
6	-3.12298	-3.10153	-3.07456	-3.03884	-3.01914	-2.99600	-2.95922	-2.91881	-2.90477	-2.86489	-2.84579
7	-3.08796	-3.06597	-3.03817	-3.00175	-2.98186	-2.95963	-2.92279	-2.88301	-2.86489	-2.82430	-2.80475
8	-3.05275	-3.02961	-3.00108	-2.96394	-2.94330	-2.92091	-2.88292	-2.84219	-2.82309	-2.78162	N/A
9	-3.05507	-3.03788	-3.00246	-2.96476	-2.94499	-2.93145	-2.89067	-2.84984	-2.81875	N/A	N/A
10	-3.01826	-3.00010	-2.96390	-2.92550	-2.90487	-2.92122	-2.84893	-2.80736	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	-2.86183	-2.80478	-2.77725	-2.72220	-2.70411	-2.64569	-2.58243	-2.52089	-2.46734	-2.40155	-2.34358
1	-2.87131	-2.82006	-2.78243	-2.73518	-2.71529	-2.65407	-2.59104	-2.52576	-2.46653	-2.40071	-2.33903
2	-2.86791	-2.83426	-2.77962	-2.72736	-2.72580	-2.66569	-2.60111	-2.53509	-2.48460	-2.41626	-2.35628
3	-2.81121	-2.78077	-2.72232	-2.66648	-2.66276	-2.60088	-2.53530	-2.46823	-2.41642	-2.34709	-2.28581
4	-2.82376	-2.78493	-2.72206	-2.65832	-2.63326	-2.57372	-2.50623	-2.43784	-2.38292	-2.31202	-2.25882
5	-2.86396	-2.82796	-2.77150	-2.70839	-2.66881	-2.61099	-2.54290	-2.47307	-2.42160	-2.34944	-2.29517
6	-2.87629	-2.82561	-2.76903	-2.70330	-2.65317	-2.59919	-2.53114	-2.45902	-2.41282	-2.34033	-2.28814
7	-2.81204	-2.76044	-2.70262	-2.63578	-2.58504	-2.53155	-2.46299	-2.39106	-2.34033	-2.26665	-2.21352
8	-2.74722	-2.69406	-2.63511	-2.56713	-2.51521	-2.46111	-2.39096	-2.31762	-2.26544	-2.19040	N/A
9	-2.71953	-2.67191	-2.60565	-2.53668	-2.48520	-2.43950	-2.36610	-2.29218	-2.22753	N/A	N/A
10	-2.65229	-2.60329	-2.53582	-2.46571	-2.41292	-2.39666	-2.29128	-2.21614	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	Demand lags										
Uplift Lags	0	1	2	3	4	5	6	7	8	9	10
0	0.62381	0.59778	0.81871	0.86066	0.68077	0.69204	0.68743	0.66703	0.76263	0.76095	0.82382
1	0.54666	0.48622	0.67860	0.74190	0.56541	0.57383	0.55756	0.55255	0.62968	0.62881	0.68449
2	0.38661	0.24711	0.37194	0.43530	0.17407	0.18312	0.17730	0.16652	0.26406	0.26537	0.32840
3	0.45475	0.33952	0.41749	0.45918	0.19394	0.19493	0.18566	0.17905	0.27331	0.27785	0.33845
4	0.41818	0.31955	0.34150	0.35286	0.15228	0.15216	0.15288	0.14786	0.23701	0.23899	0.32101
5	0.41982	0.31451	0.44264	0.42228	0.25335	0.25435	0.24770	0.24662	0.34999	0.35072	0.43205
6	0.32561	0.25758	0.38222	0.39418	0.25902	0.26094	0.25044	0.24274	0.35824	0.36532	0.45367
7	0.31774	0.24296	0.37666	0.38763	0.27709	0.30145	0.29614	0.28792	0.38129	0.39000	0.48340
8	0.32351	0.24259	0.37522	0.38502	0.27617	0.30929	0.30045	0.29149	0.37752	0.38770	N/A
9	0.47377	0.38814	0.44827	0.45940	0.34746	0.39826	0.39311	0.37775	0.43022	N/A	N/A
10	0.46839	0.38629	0.44567	0.45794	0.34538	0.39856	0.39322	0.37863	N/A	N/A	N/A

Table 14: Interactive variable analysis – Multivariate uplift-demand regressions.

Section 6: Sixth MMC reference.

AIC: Akaike Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-0.96048	-1.01423	-0.98540	-0.96650	-0.94532	-0.91252	-0.89884	-0.86383	-0.82934	-0.80076	-0.76892
1	-0.97434	-0.98315	-0.95325	-0.93348	-0.91181	-0.87839	-0.86411	-0.82847	-0.79333	-0.76396	-0.73158
2	-1.02062	-1.00257	-1.03016	-1.03042	-1.00452	-0.97179	-0.95997	-0.92422	-0.89127	-0.86140	-0.82790
3	-0.99921	-0.98200	-1.03758	-1.00837	-0.98708	-0.95321	-0.93958	-0.90321	-0.87068	-0.83746	-0.80268
4	-1.05287	-1.03295	-1.07598	-1.04108	-1.00784	-0.98112	-0.96728	-0.92988	-0.89672	-0.85909	-0.82047
5	-1.24499	-1.22077	-1.24270	-1.20713	-1.19541	-1.19056	-1.15356	-1.11768	-1.08160	-1.04522	-1.00428
6	-1.23089	-1.20984	-1.22530	-1.18926	-1.17288	-1.17456	-1.15102	-1.11214	-1.07728	-1.04046	-0.99872
7	-1.30292	-1.27041	-1.28673	-1.25018	-1.22841	-1.22232	-1.18601	-1.16044	-1.13646	-1.10059	-1.05792
8	-1.26740	-1.23402	-1.25090	-1.21357	-1.19079	-1.18340	-1.14616	-1.12222	-1.09473	-1.05843	N/A
9	-1.23518	-1.20179	-1.21370	-1.17546	-1.15231	-1.14417	-1.10592	-1.08168	-1.05206	N/A	N/A
10	-1.22306	-1.18988	-1.20645	-1.16728	-1.13613	-1.12302	-1.08340	-1.05297	N/A	N/A	N/A

SIC: Schwarz Information Criterion (Optimal value is minimal).

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	-0.88135	-0.90806	-0.85184	-0.80521	-0.75593	-0.69467	-0.65214	-0.58792	-0.52381	-0.46522	-0.40295
1	-0.86817	-0.84959	-0.79196	-0.74408	-0.69395	-0.63169	-0.58819	-0.52294	-0.45778	-0.39799	-0.33477
2	-0.88706	-0.84127	-0.84077	-0.81256	-0.75782	-0.69587	-0.65443	-0.58867	-0.52530	-0.46459	-0.39982
3	-0.83791	-0.79260	-0.81973	-0.76167	-0.71116	-0.64768	-0.60403	-0.53724	-0.47387	-0.40937	-0.34288
4	-0.86347	-0.81509	-0.82928	-0.76516	-0.70231	-0.64557	-0.60131	-0.53307	-0.46863	-0.39929	-0.32852
5	-1.02713	-0.97407	-0.96678	-0.90159	-0.85987	-0.82459	-0.75674	-0.68960	-0.62181	-0.55327	-0.47971
6	-0.98420	-0.93393	-0.91977	-0.85371	-0.80691	-0.77775	-0.72293	-0.65234	-0.58533	-0.51589	-0.44106
7	-1.02700	-0.96487	-0.95119	-0.88421	-0.83160	-0.79424	-0.72622	-0.66849	-0.61190	-0.54294	-0.46670
8	-0.96187	-0.89847	-0.88493	-0.81676	-0.76271	-0.72361	-0.65421	-0.59765	-0.53707	-0.46720	N/A
9	-0.89963	-0.83582	-0.81688	-0.74738	-0.69252	-0.65222	-0.58136	-0.52402	-0.46084	N/A	N/A
10	-0.85709	-0.79307	-0.77836	-0.70749	-0.64418	-0.59846	-0.52575	-0.46175	N/A	N/A	N/A

Dummy T-Ratio: 5% significance level, 1.96; 10% significance level, 1.645.

	Demand lags										
Uplift Lags	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	0.11478	0.43700	0.40418	0.43745	0.44142	0.42778	0.53965	0.53630	0.51494	0.55244	0.62442
1	0.26929	0.43512	0.40429	0.43620	0.44045	0.42689	0.53833	0.53494	0.51351	0.55032	0.62364
2	0.40483	0.48763	0.36436	0.41373	0.41737	0.39812	0.51750	0.51336	0.47742	0.51491	0.58285
3	0.44965	0.53863	0.43164	0.43505	0.44542	0.42746	0.54200	0.53769	0.49854	0.52693	0.59286
4	0.46162	0.54372	0.44428	0.44103	0.43301	0.39395	0.50939	0.50560	0.46652	0.48184	0.51817
5	0.19303	0.26663	0.19599	0.19533	0.15667	0.16910	0.19335	0.18781	0.16054	0.18522	0.17982
6	0.06473	0.14000	0.08965	0.08910	0.06562	0.05896	0.13468	0.13313	0.09749	0.12337	0.13027
7	-0.10321	-0.06008	-0.11120	-0.11086	-0.12581	-0.12385	-0.07967	-0.12394	-0.20658	-0.17661	-0.17830
8	-0.07482	-0.05443	-0.17065	-0.16883	-0.17600	-0.15573	-0.10686	-0.22059	-0.18688	-0.12821	N/A
9	-0.16507	-0.14990	-0.20039	-0.19418	-0.21181	-0.19264	-0.14127	-0.26634	-0.18907	N/A	N/A
10	0.04461	0.06401	0.03166	0.03083	-0.00687	-0.00788	0.03341	-0.09615	N/A	N/A	N/A

Table 15: Regression Results: Interactive variable analysis.

Section 1: Univariate price analysis.

Regression	Serial Correlation	Functional Form	Normality	H'Sced/Arch
1	Pass	Pass	Fail	Pass/Pass
2	Pass	Pass	Pass	Pass/Pass
3	Pass	Pass	Pass	Pass/Pass
4	Pass	Pass	Fail	Pass/Pass
5	Pass	Pass	Fail	Fail/Pass
6	Pass	Pass	Fail	Pass/Pass

Section 2: Univariate uplift analysis.

Regression	Serial Correlation	Functional Form	Normality	H'Sced/Arch
1	Pass	Pass	Fail	Pass/Pass
2	Pass	Pass	Pass	Pass/Pass
3	Pass	Pass	Pass	Pass/Pass
4	Pass	Pass	Fail	Pass/Pass
5	Pass	Pass	Fail	Fail/Pass
6	Pass	Pass	Fail	Pass/Pass

Section 3: Multivariate uplift-price analysis.

Regression	Serial Correlation	Functional Form	Normality	H'Sced/Arch
1	Pass	Pass	Pass	Pass/Pass
2	Pass	Pass	Pass	Pass/Pass
3	Pass	Pass	Fail	Pass/Pass
4	Pass	Pass	Fail	Pass/Pass
5	Fail	Pass	Pass	Pass/Pass
6	Pass	Pass	Fail	Pass/Pass

Section 4: Multivariate uplift-demand analysis.

Regression	Serial Correlation	Functional Form	Normality	H'Sced/Arch
1	Fail	Pass	Fail	Pass/Pass
2	Pass	Pass	Pass	Pass/Pass
3	Pass	Pass	Pass	Pass/Pass
4	Pass	Pass	Pass	Pass/Pass
5	Pass	Fail	Fail	Pass/Pass
6	Pass	Pass	Fail	Pass/Pass

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

<u>Table 16: DF and ADF tests for the existence of stationarity.</u>

<u>Pool Purchase Price (Log).</u>

<u>Dickey-Fuller test for unit roots.</u>

1886 observations from 2 to 1887.

Calculated value (without trend)	-14.4835	Critical value	-2.8636
Calculated value (with trend)	-14.4900	Critical value	-3.4147

<u>Augmented Dickey-Fuller test for unit roots.</u>

1885 observations from 3 to 1887.

Calculated value (without trend)	-14.7661	Critical value	-2.8636
Calculated value (with trend)	-14.7732	Critical value	-3.4147

<u>Electricity Demand (Log).</u>

Unit root tests for residuals

<u>Dickey-Fuller test for unit roots.</u>

1886 observations from 2 to 1887.

Calculated value (without trend)	-15.0834	Critical value	-2.8636
Calculated value (with trend)	-15.0792	Critical value	-3.4147

<u>Augmented Dickey-Fuller test for unit roots.</u>

1885 observations from 3 to 1887.

Calculated value (without trend)	-18.0898	Critical value	-2.8636
Calculated value (with trend)	-14.0850	Critical value	-3.4147

<u>Uplift (Log).</u>

Unit root tests for residuals

<u>Dickey-Fuller test for unit roots.</u>

1886 observations from 2 to 1887.

Calculated value (without trend)	-14.9705	Critical value	-2.8636
Calculated value (with trend)	-15.6811	Critical value	-3.4147

<u>Augmented Dickey-Fuller test for unit roots.</u>

1885 observations from 3 to 1887.

Calculated value (without trend)	-14.5587	Critical value	-2.8636
Calculated value (with trend)	-15.3364	Critical value	-3.4147

Table 17: Assessing the existence of trends.

Pool Purchase Price (Log).

Unrestricted Residual Sum of Squares:	50.6900
Restricted Residual Sum of Squares:	56.5721
DF F-test calculated value:	109.0980
DF F-test critical value:	6.2500

The significance of the coefficient on the parameter of the lagged dependent variable permits the utilisation of the standard t-test to conclude the analysis. This allows us to conclude that the pool purchase price data contains an insignificant deterministic trend.

Note: of all the standard diagnostic tests, the only one passed by both the restricted and unrestricted models is that for functional form.

Electricity Demand (Log).

Unrestricted Residual Sum of Squares:	15.6266
Restricted Residual Sum of Squares:	18.3438
DF F-test calculated value:	163.5530
DF F-test critical value:	6.2500

The significance of the coefficient on the parameter of the lagged dependent variable permits the utilisation of the standard t-test to conclude the analysis. This allows us to conclude that the electricity demand data contains an insignificant deterministic trend.

Note: both sets of regressions fail all of the standard diagnostic tests.

Uplift (Log).

Unrestricted Residual Sum of Squares:	174.1268
Restricted Residual Sum of Squares:	195.9006
DF F-test calculated value:	117.5625
DF F-test critical value:	6.2500

The significance of the coefficient on the parameter of the lagged dependent variable permits the utilisation of the standard t-test to conclude the analysis. This allows us to conclude that the uplift data contains a significant deterministic trend.

Note: both sets of regressions fail all of the standard diagnostic tests.

<u>Table 18: Cointegration analysis</u>

In all cases, the validity of the null hypothesis in Step One of the Engle-Granger two-step procedure has been established:

Section 1. PPP-Demand analyses.

<u>Stage 1</u>: Critical value (CRDW, 5%) = 0.386 Critical value (CRDW, 10%) = 0.322

Calculated value = 1.9804

<u>Stage 2:</u>

Critical value (5%) = 3.17 Critical value (10%) = 2.84

Calculated value = -13.0975

We may therefore conclude that PPP and demand are cointegrated.

Section 2. Uplift-PPP analyses.

<u>Stage 1:</u> Critical value (CRDW, 5%) = 0.386 Critical value (CRDW, 10%) = 0.322

Calculated value = 1.9524

<u>Stage 2:</u> Critical value (5%) = 3.17 Critical value (10%) = 2.84

Calculated value = -14.6354

We may therefore conclude that Uplift and PPP are cointegrated.

Section 3. Uplift-Demand analyses.

<u>Stage 1:</u> Critical value (CRDW, 5%) = 0.386 Critical value (CRDW, 10%) = 0.322

Calculated value = 1.9524

<u>Stage 2:</u> Critical value (5%) = 3.17 Critical value (10%) = 2.84

Calculated value = -15.8342

We may therefore conclude that Uplift and demand are cointegrated.

CHAPTER VI, APPENDIX.

Table 1: Unit root tests

Section 1. Pool purchase price.

$$\Delta PPP_t = \alpha + \beta_1 PPP_{t-1} + \beta_2 \Delta PPP_{t-1} + \Delta PPP_{t-2} + u_t \tag{2.1}$$

Unit root tests for residuals

1884 observations from 4 to 1887.

DF test.

Calculated value = -44.3999 Critical value = -4.4371

ADF test.

Calculated value = -31.9289 Critical value = -4.4371

Section 2. Electricity demand.

$$\Delta ED_t = \alpha + \gamma_1 ED_{t-1} + \gamma_2 \Delta ED_{t-1} + \gamma_3 \Delta ED_{t-2} + u_t \tag{2.2}$$

Unit root tests for residuals

1884 observations from 4 to 1887.

DF test.

Calculated value = -43.4579 Critical value = -3.3409

ADF test.

Calculated value = -34.0294 Critical value = -3.3409

Table 2. Pool purchase price as a function of demand w/ dummy variable representing first set of contracts.

$$PPP_t = \alpha + \lambda_0 ED_t + \lambda_1 DUMMYA_t + u_t \tag{2.4}$$

DUMMYA possesses the value of zero from 1st October 1990 to 22nd March 1991, and the value of one thereafter.

1887 observations from 1 to 1887.

Dummy Statistics

Coefficient	Standard Error	T-Ratio [Prob.]
0.22741	0.020672	11.0007[.000]

Diagnostic Results

S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.
Fail	Fail	Fail	Fail	Fail	Pass

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

Table 3. Pool purchase price as a function of demand w/ dummy variable representing second set of contracts.

$$PPP_t = \alpha + \lambda_0 ED_t + \lambda_1 DUMMYB_t + u_t \qquad \textbf{(2.5)}$$

DUMMYB possesses the value of zero from 1st October 1990 to 31st March 1993, and the value of one thereafter.

1887 observations from 1 to 1887.

Dummy Statistics

Coefficient	Standard Error	T-Ratio [Prob.]
0.04394	0.011988	3.6555[.000]

Diagnostic Results

S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.
Fail	Fail	Fail	Fail	Fail	Pass

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

Table 4. Pool purchase price as a function of demand w/ both dummies present.

$$PPP_t = \alpha + \lambda_0 ED_t + \lambda_1 DUMMYA_t + \lambda_2 DUMMYB_t + u_t \qquad (2.6)$$

1887 observations from 1 to 1887.

Dummy Statistics

Coefficient	Standard Error	T-Ratio [Prob.]
DUMMYA: 0.22067	0.021876	10.3343[.000]
DUMMYB: 0.00232	0.012341	0.18780[.851]

Diagnostic Results

S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.
Fail	Fail	Fail	Fail	Fail	Pass

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

Table 5. The dynamic regression with the first dummy variable.

$$\Delta PPP_t = \alpha + \lambda_0 \tau + \lambda_1 ED_t + \lambda_2 ED_{t-1} + \lambda_3 PPP_{t-1} + \lambda_4 DUMMYA_{t-1} + u_t \quad (2.8)$$

1886 observations from 2 to 1887.

Dummy Statistics

Coefficient	Standard Error	T-Ratio [Prob.]
0.03536	0.013472	2.62460[.009]

Diagnostic Results

S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.
Pass	Fail	Fail	Fail	Fail	Pass

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

Table 6. The dynamic regression with the second dummy variable.

$$\Delta PPP_t = \alpha + \lambda_0 \tau + \lambda_1 ED_t + \lambda_2 ED_{t-1} + \lambda_3 PPP_{t-1} + \lambda_4 DUMMYB_{t-1} + u_t \quad (2.9)$$

1886 observations from 2 to 1887.

Dummy Statistics

Coefficient	Standard Error	T-Ratio [Prob.]
0.01431	0.012667	1.13000[.259]

Diagnostic Results

S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.
Pass	Fail	Fail	Fail	Fail	Pass

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

Table 7. The dynamic regression with both dummies present.

$$\Delta PPP_t = \alpha + \lambda_0 \tau + \lambda_1 ED_t + \lambda_2 ED_{t-1} + \lambda_3 PPP_{t-1} + \lambda_4 DUMMYA_{t-1} + \lambda_5 DUMMYB_{t-1} + u_t \quad (2.10)$$

1886 observations from 2 to 1886.

Dummy Statistics

Coefficient	Standard Error	T-Ratio [Prob.]
DUMMYA: 0.04463	0.014187	3.14600[.000]
DUMMYB: 0.02756	0.013220	2.06880[.851]

Diagnostic Results

S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.
Pass	Fail	Fail	Fail	Fail	Pass

Serial Correlation - Serial Correlation of Residuals (Lagrange-Multiplier test)

Functional Form - Functional Form (Ramsey RESET)

Normality - Normality of Residuals (Skewness and Kurtosis)

H'sced. - Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values).

ARCH - Autoregressive Conditional Heteroscedasticity

All regressions passed the relevant unit root tests for stationarity.

Table 8: Diagnostic test results of additional price-demand regressions.

Obs. Range	Dummy	S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.	V.D.T.
150-250	A	Pass	Pass	Fail	Pass	Pass	Pass	Pass
325-425	B	Pass	Pass	Fail	Fail	Pass	Pass	Fail
350-450	C	Fail	Pass	Fail	Fail	Pass	Pass	Pass
425-525	D	Fail	Fail	Fail	Fail	Pass	Pass	Pass
600-700	E	Fail	Fail	Fail	Fail	Pass	Pass	Fail
700-800	F	Pass	Fail	Fail	Fail	Pass	Pass	Fail
775-875	G	Fail	Pass	Pass	Pass	Pass	Pass	Pass
875-975	H	Pass	Pass	Fail	Pass	Pass	Pass	Pass
925-1025	I	Pass	Fail	Fail	Pass	Pass	Pass	Fail
1000-1100	J	Fail	Pass	Pass	Pass	Pass	Pass	Fail
1150-1250	K	Fail	Pass	Fail	Fail	Fail	Pass	Fail
1200-1300	L	Fail	Pass	Fail	Pass	Pass	Pass	Fail
1500-1600	M	Pass	Pass	Fail	Fail	Pass	Pass	Fail
1550-1650	N	Pass	Pass	Fail	Fail	Pass	Pass	Pass
1575-1675	O	Pass	Pass	Fail	Fail	Pass	Pass	Fail
1575-1675	P	Pass	Pass	Fail	Fail	Pass	Pass	Fail
1700-1800	Q	Pass	Pass	Fail	Fail	Pass	Pass	Fail
1700-1800	R	Pass	Pass	Fail	Fail	Pass	Pass	Fail
1715-1815	S	Pass	Pass	Fail	Fail	Pass	Pass	Fail
1750-1850	T	Pass	Pass	Fail	Fail	Pass	Pass	Fail
1770-1870	U	Pass	Pass	Fail	Fail	Fail	Pass	Fail
1778-1878	V	Fail	Fail	Fail	Fail	Pass	Pass	Fail
1787-1887	W	Fail	Fail	Fail	Fail	Pass	Pass	Fail

S.C.R.	Serial Correlation of Residuals (Lagrange-Multiplier test)
F.F.	Functional Form (Ramsey RESET)
N.R.	Normality of Residuals (Skewness and Kurtosis)
H.S.	Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values)
ARCH	Autoregressive Conditional Heteroscedasticity
Stat.	Stationarity (Unit Root Tests for Residuals)
V.D.T.	Variable Deletion Test ("Pass" indicates that the variable cannot be deleted)

CHAPTER VII, APPENDIX.

Table 1: Market Model Results – National Power

Event 1: Break up of first set of CFDs.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00471	0.0046	1.0226[.312]
DLFTSE	0.61328	0.21928	2.7968[.008]
DUMMY1	-0.01174	0.00562	-2.0888[.042]

Event 2: Price spikes begin.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00158	0.00156	1.0115[.317]
DLFTSE	0.75639	0.16083	4.7030[.000]
DUMMY2	-0.00329	0.00256	-1.2834[.206]

Event 3: First pool price review begins with MMC threat.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00027	0.0015	0.17885[.859]
DLFTSE	0.55362	0.21264	2.6036[.012]
DUMMY3	-0.00299	0.00371	-0.80556[.424]

Event 4: First pool price review published.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00066	0.00155	-0.42717[.671]
DLFTSE	0.65929	0.11737	5.6172[.000]
DUMMY4	-0.00431	0.004	-1.0780[.286]

Event 5: Electricity price controls published.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00034	0.00224	-0.15211[.880]
DLFTSE	1.0142	0.33758	3.0043[.004]
DUMMY5	-0.01054	0.00386	-2.7273[.009]

Event 6: DGES to examine excessive electricity profits.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00431	0.00191	2.2528[.029]
DLFTSE	0.69154	0.22089	3.1306[.003]
DUMMY6	-0.00261	0.004	-0.65304[.517]

Event 7: Generators threatened with MMC reference.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00136	0.00232	0.58813[.559]
DLFTSE	0.33338	0.24901	1.3388[.187]
DUMMY7	0.00213	0.0037	0.57524[.568]

Event 8: Oxera suggests regulatory change

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00057	0.00214	0.26398[.793]
DLFTSE	0.39718	0.23011	1.7261[.091]
DUMMY8	-0.00262	0.00661	-0.39688[.693]

Event 9: DGES to probe power price rises.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00139	0.00224	0.62265[.539]
DLFTSE	0.26261	0.24783	1.0596[.298]
DUMMY9	-0.00649	0.01238	-0.52404[.604]

Event 10: Second pool price review launched.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00024	0.00319	0.074597[.941]
DLFTSE	0.40937	0.178	2.2998[.026]
DUMMY10	0.00394	0.00711	0.55367[.582]

Event 11: Commons to revise sale of generators.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00053	0.00269	0.19793[.844]
DLFTSE	0.58822	0.19103	3.0792[.003]
DUMMY11	0.0009	0.00493	0.18333[.855]

Event 12: Second pool price review published.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00194	0.00204	0.95334[.345]
DLFTSE	0.93383	0.33692	2.7717[.008]
DUMMY12	-0.00696	0.00864	-0.80596[.424]

Event 13: DGES seeking additional power over generators.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.0035	0.00208	1.6825[.099]
DLFTSE	0.53623	0.29085	1.8437[.071]
DUMMY13	-0.00181	0.00322	-0.56133[.577]

Event 14: DGES tells generators to sell surplus plants.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00322	0.00179	1.8021[.078]
DLFTSE	0.81862	0.25397	3.2233[.002]
DUMMY14	-0.00321	0.00571	-0.56253[.576]

Event 15: Break-up of second set of CFDs.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00024	0.00164	0.14555[.885]
DLFTSE	0.86321	0.22245	3.8805[.000]
DUMMY15	0.00707	0.00665	1.0636[.293]

Event 16: Generators threatened with MMC reference.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00155	0.0017	0.91335[.366]
DLFTSE	1.1498	0.25317	4.5415[.000]
DUMMY16	-0.00721	0.00394	-1.8281[.074]

Event 17: MMC reference and/or plant sales threatened.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00061	0.00126	-0.48546[.630]
DLFTSE	0.76549	0.24886	3.0760[.003]
DUMMY17	-0.00269	0.00932	-0.28831[.774]

Event 18: MMC reference unless agreement made.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00042	0.00206	0.20648[.837]
DLFTSE	1.4081	0.32458	4.3383[.000]
DUMMY18	0.007	0.00579	1.2104[.232]

Event 19: Revised bidding system drives pool prices down.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00123	0.00234	0.52856[.600]
DLFTSE	1.2692	0.36284	3.4979[.001]
DUMMY19	0.00278	0.00654	0.42532[.673]

Event 20: NP and PG establish price agreement.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00027	0.00213	-0.12577[.900]
DLFTSE	0.85607	0.21938	3.9021[.000]
DUMMY20	0.0159	0.01231	1.2916[.203]

Event 21: Reports indicate a tougher stance from DGES.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.0005	0.00222	-0.22717[.821]
DLFTSE	0.88089	0.21135	4.1679[.000]
DUMMY21	-0.00379	0.00431	-0.87767[.384]

Event 22: DGES to encourage break-up of Nuclear Electric.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00088	0.0017	0.51589[.608]
DLFTSE	1.2103	0.18247	6.6328[.000]
DUMMY22	-0.0012	0.00214	-0.56104[.577]

Event 23: Generators warned on plant disposals.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00066	0.00134	0.49293[.624]
DLFTSE	0.90408	0.15434	5.8577[.000]
DUMMY23	-0.00862	0.00851	-1.0133[.316]

Event 24: Trafalgar House bids for Northern Electric

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00036	0.00148	-0.24627[.807]
DLFTSE	0.84448	0.19961	4.2307[.000]
DUMMY24	0.00472	0.00251	1.8825[.066]

Event 25: DGES unsympathetic on Trafalgar House move.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00108	0.00122	-0.88878[.379]
DLFTSE	0.51556	0.16483	3.1279[.003]
DUMMY25	-0.00061	0.00152	-0.39990[.691]

Event 26: MMC reference threatened over plant sales.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.002	0.00149	-1.3465[.184]
DLFTSE	0.59595	0.19325	3.0838[.003]
DUMMY26	0.00021	0.00377	0.056682[.955]

Event 27: Sale of Government's 40% electricity holding.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00194	0.0013	-1.4868[.144]
DLFTSE	0.50551	0.21058	2.4005[.020]
DUMMY27	-0.00719	0.00897	-0.80181[.427]

Event 28: Distribution price controls to be revised.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.0017	0.00123	-1.3854[.172]
DLFTSE	0.4919	0.20888	2.3549[.023]
DUMMY28	-0.00995	0.00932	-1.0677[.291]

Event 29: Southern Electric bids for S.W. Electricity.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00028	0.00138	0.20479[.839]
DLFTSE	0.73399	0.21309	3.4445[.001]
DUMMY29	0.00609	0.00306	1.9857[.053]

Event 30: Scottish Power bids for Manweb.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.0013	0.00135	0.96097[.341]
DLFTSE	0.76067	0.23076	3.2964[.002]
DUMMY30	-0.00069	0.00539	-0.12765[.899]

Event 31: Hanson bids for Eastern.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00215	0.00116	1.8538[.070]
DLFTSE	0.82231	0.21199	3.8790[.000]
DUMMY31	-0.00027	0.00262	-0.10364[.918]

Event 32: North West Water bids for Norweb.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00072	0.00146	-0.49340[.624]
DLFTSE	0.72047	0.21142	3.4078[.001]
DUMMY32	0.00035	0.0068	0.051987[.959]

Event 33: Powergen bids for Midlands Electricity.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00056	0.00152	-0.37044[.713]
DLFTSE	0.63608	0.20155	3.1560[.003]
DUMMY33	-0.00489	0.00203	-2.4047[.020]

Event 34: National Power bids for Southern Electric

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.0001	0.00123	-0.085103[.933]
DLFTSE	0.8575	0.1899	4.5155[.000]
DUMMY34	-0.01827	0.00543	-3.3681[.001]

Event 35: NP and PG's REC bids to face MMC reference.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00064	0.00147	-0.43094[.668]
DLFTSE	1.1036	0.31726	3.4785[.001]
DUMMY35	-0.02162	0.00499	-4.3356[.000]

Event 36: *DGES' statement on price undertakings.*

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.0024	0.00171	-1.4088[.165]
DLFTSE	1.0677	0.38815	2.7508[.008]
DUMMY36	-0.0081	0.00407	-1.9921[.052]

Event (All): Combined regulatory dummy (all events integrated).

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00072	0.00037	1.9475[.052]
DLFTSE	0.81437	0.05677	14.3459[.000]
DUMMYREG	-0.00294	0.00159	-1.8538[.064]

Table 2: *Diagnostic test results: Market Model – National Power,*

Regression	Serial Correlation	Functional Form	Normality	H'Sced/Arch
1	Pass	Pass	Fail	Pass/Pass
2	Pass	Pass	Fail	Pass/Pass
3	Pass	Pass	Pass	Pass/Pass
4	Fail	Pass	Pass	Pass/Pass
5	Pass	Pass	Pass	Pass/Pass
6	Pass	Pass	Pass	Pass/Pass
7	Pass	Pass	Fail	Pass/Pass
8	Pass	Pass	Fail	Pass/Pass
9	Pass	Pass	Fail	Pass/Pass
10	Pass	Pass	Fail	Pass/Pass
11	Pass	Pass	Pass	Pass/Pass
12	Pass	Pass	Pass	Pass/Pass
13	Pass	Fail	Pass	Pass/Pass
14	Pass	Pass	Pass	Pass/Pass
15	Pass	Fail	Fail	Pass/Pass
16	Fail	Pass	Pass	Pass/Pass
17	Pass	Fail	Pass	Pass/Pass
18	Pass	Fail	Pass	Pass/Pass
19	Pass	Pass	Pass	Pass/Pass
20	Pass	Pass	Pass	Pass/Pass
21	Pass	Pass	Pass	Pass/Pass
22	Pass	Fail	Pass	Pass/Pass
23	Pass	Fail	Pass	Pass/Pass
24	Pass	Fail	Pass	Pass/Pass
25	Pass	Pass	Pass	Fail/Pass
26	Pass	Fail	Pass	Pass/Pass
27	Pass	Pass	Pass	Fail/Fail
28	Pass	Pass	Pass	Fail/Fail
29	Pass	Fail	Pass	Pass/Pass
30	Pass	Fail	Pass	Pass/Pass
31	Pass	Fail	Pass	Pass/Pass
32	Pass	Pass	Pass	Pass/Pass
33	Pass	Fail	Pass	Pass/Pass
34	Pass	Fail	Pass	Pass/Pass
35	Pass	Fail	Pass	Pass/Pass
36	Pass	Pass	Pass	Pass/Pass
ALL	Fail	Pass	Fail	Pass/Pass

Table 3: Market Model Results – Powergen.

Event 1: Break up of first set of CFDs.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00538	0.00456	1.1790[.244]
DLFTSE	0.45352	0.21245	2.1347[.038]
DUMMY1	-0.01306	0.00817	-1.5982[.117]

Event 2: Price spikes begin.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00143	0.0013	1.0996[.277]
DLFTSE	0.7409	0.20683	3.5822[.001]
DUMMY2	0.0027	0.0026	1.0381[.304]

Event 3: First pool price review begins with MMC threat.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00025	0.00145	-0.17430[.862]
DLFTSE	0.60523	0.2386	2.5367[.014]
DUMMY3	0.00059	0.00473	0.12518[.901]

Event 4: First pool price review published.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00088	0.00151	-0.58078[.564]
DLFTSE	0.6119	0.12945	4.7268[.000]
DUMMY4	-0.0039	0.00234	-1.6639[.103]

Event 5: Electricity price controls published.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00008	0.00246	0.032386[.974]
DLFTSE	0.91507	0.41306	2.2154[.032]
DUMMY5	-0.01531	0.00504	-3.0357[.004]

Event 6: DGES to examine excessive electricity profits.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00433	0.00194	2.2328[.030]
DLFTSE	0.76445	0.2507	3.0493[.004]
DUMMY6	-0.00332	0.00314	-1.0582[.295]

Event 7: *Generators threatened with* MMC reference.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00126	0.00229	0.55086[.584]
DLFTSE	0.30003	0.26824	1.1185[.269]
DUMMY7	0.00508	0.00344	1.4764[.146]

Event 8: Oxera suggests regulatory change

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00136	0.00197	0.69099[.493]
DLFTSE	0.21869	0.21446	1.0197[.313]
DUMMY8	-0.00588	0.0072	-0.81698[.418]

Event 9: DGES to probe power price rises.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00219	0.00162	1.3505[.183]
DLFTSE	0.27058	0.18444	1.4671[.149]
DUMMY9	-0.00613	0.01298	-0.47203[.639]

Event 10: Second pool price review launched.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00089	0.00309	-0.28896[.774]
DLFTSE	0.35048	0.17981	1.9492[.057]
DUMMY10	0.0056	0.00606	0.92308[.361]

Event 11: Commons to revise sale of generators.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00017	0.00282	-0.060104[.952]
DLFTSE	0.54957	0.21195	2.5929[.013]
DUMMY11	-0.00142	0.00455	-0.31133[.757]

Event 12: Second pool price review published.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00218	0.002	1.0898[.281]
DLFTSE	0.97096	0.33304	2.9154[.005]
DUMMY12	-0.00893	0.00786	-1.1361[.262]

Event 13: DGES seeking additional power over generators.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00295	0.0025	1.1800[.244]
DLFTSE	0.4828	0.28321	1.7047[.095]
DUMMY13	-0.00178	0.00343	-0.51964[.606]

Event 14: DGES tells generators to sell surplus plants.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.0034	0.00214	1.5895[.119]
DLFTSE	0.67016	0.25714	2.6062[.012]
DUMMY14	-0.00419	0.00606	-0.69117[.493]

Event 15: Break-up of second set of CFDs.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00035	0.00191	0.18277[.856]
DLFTSE	0.64177	0.21309	3.0117[.004]
DUMMY15	0.00719	0.00813	0.88366[.381]

Event 16: Generators threatened with MMC reference.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00226	0.00175	1.2868[.204]
DLFTSE	1.1489	0.2854	4.0255[.000]
DUMMY16	-0.00675	0.00489	-1.3813[.174]

Event 17: MMC reference and/or plant sales threatened.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00039	0.00125	-0.30791[.759]
DLFTSE	0.72631	0.21831	3.3270[.002]
DUMMY17	0.00048	0.00675	0.071660[.943]

Event 18: MMC reference unless agreement made.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00077	0.00178	0.43088[.668]
DLFTSE	1.2277	0.2852	4.3046[.000]
DUMMY18	0.00673	0.00439	1.5325[.132]

Event 19: Revised bidding system drives pool prices down.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.0018	0.00214	0.83927[.405]
DLFTSE	1.1271	0.32082	3.5132[.001]
DUMMY19	0.0017	0.00431	0.39306[.696]

Event 20: NP and PG establish price agreement.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00096	0.00187	0.51465[.609]
DLFTSE	0.83424	0.19081	4.3722[.000]
DUMMY20	0.01029	0.01206	0.85339[.398]

Event 21: Reports indicate a tougher stance from DGES.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00241	0.00238	-1.0106[.317]
DLFTSE	0.8721	0.19278	4.5239[.000]
DUMMY21	-0.00253	0.00395	-0.63865[.526]

Event 22: *DGES to encourage break-up of Nuclear Electric.*

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00007	0.00163	-0.041400[.967]
DLFTSE	1.0573	0.13828	7.6460[.000]
DUMMY22	-0.00444	0.00243	-1.8296[.074]

Event 23: Generators warned on plant disposals.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00022	0.00157	-0.14085[.889]
DLFTSE	1.0399	0.14147	7.3506[.000]
DUMMY23	-0.00502	0.00221	-2.2668[.028]

Event 24: Trafalgar House bids for Northern Electric

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00123	0.00151	-0.81626[.418]
DLFTSE	0.67051	0.14525	4.6161[.000]
DUMMY24	0.01205	0.00289	4.1616[.000]

Event 25: DGES unsympathetic on Trafalgar House move.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00085	0.00125	-0.67779[.501]
DLFTSE	0.32437	0.19127	1.6959[.096]
DUMMY25	-0.006	0.0022	-2.7275[.009]

Event 26: MMC reference threatened over plant sales.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00203	0.00158	-1.2862[.205]
DLFTSE	0.49209	0.23127	2.1278[.039]
DUMMY26	-0.0029	0.00335	-0.86462[.392]

Event 27: Sale of Government's 40% electricity holding.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00273	0.00137	-1.9977[.051]
DLFTSE	0.53991	0.22313	2.4198[.019]
DUMMY27	-0.00712	0.00963	-0.73988[.463]

Event 28: Distribution price controls to be revised.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00241	0.00132	-1.8275[.074]
DLFTSE	0.51839	0.2225	2.3298[.024]
DUMMY28	-0.01086	0.00942	-1.1535[.254]

Event 29: Southern Electric bids for S.W. Electricity.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00133	0.00122	1.0916[.280]
DLFTSE	0.70913	0.20548	3.4511[.001]
DUMMY29	0.01291	0.00176	7.3330[.000]

Event 30: Scottish Power bids for Manweb.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00294	0.00135	2.1781[.034]
DLFTSE	0.79645	0.20653	3.8563[.000]
DUMMY30	-0.00648	0.00246	-2.6354[.011]

Event 31: Hanson bids for Eastern.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.0027	0.00137	1.9781[.054]
DLFTSE	0.79253	0.2009	3.9450[.000]
DUMMY31	-0.00646	0.00172	-3.7544[.000]

Event 32: North West Water bids for Norweb.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00011	0.00177	-0.064311[.949]
DLFTSE	0.78829	0.24129	3.2669[.002]
DUMMY32	-0.00003	0.00458	-0.0072572[.994]

Event 33: Powergen bids for Midlands Electricity.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00036	0.00178	0.20440[.839]
DLFTSE	0.78619	0.22751	3.4556[.001]
DUMMY33	-0.00618	0.00261	-2.3642[.022]

Event 34: National Power bids for Southern Electric

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00042	0.00157	-0.26903[.789]
DLFTSE	0.80222	0.21509	3.7297[.001]
DUMMY34	-0.00695	0.00634	-1.0965[.278]

Event 35: NP and PG's REC bids to face MMC reference.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00018	0.00138	0.13151[.896]
DLFTSE	0.73636	0.28003	2.6296[.011]
DUMMY35	-0.02317	0.00556	-4.1708[.000]

Event 36: DGES' statement on price undertakings.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.00256	0.00174	-1.4675[.149]
DLFTSE	0.72899	0.36869	1.9772[.054]
DUMMY36	-0.00408	0.00299	-1.3665[.178]

Event (All): Combined regulatory dummy (all events integrated).

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.00087	0.00037	2.3401[.019]
DLFTSE	0.75461	0.05785	13.0446[.000]
DUMMYREG	-0.00364	0.00152	-2.3942[.017]

Table 4: Diagnostic test results: Market Model – Powergen.

Regression	Serial Correlation	Functional Form	Normality	H'Sced/Arch
1	Pass	Pass	Fail	Pass/Pass
2	Pass	Pass	Pass	Pass/Pass
3	Pass	Pass	Pass	Pass/Pass
4	Pass	Pass	Pass	Fail/Pass
5	Pass	Pass	Pass	Pass/Pass
6	Pass	Pass	Fail	Pass/Pass
7	Pass	Pass	Fail	Pass/Pass
8	Pass	Pass	Fail	Pass/Pass
9	Pass	Pass	Pass	Pass/Pass
10	Pass	Pass	Fail	Pass/Pass
11	Pass	Pass	Pass	Pass/Pass
12	Pass	Pass	Pass	Pass/Pass
13	Pass	Fail	Pass	Pass/Pass
14	Pass	Pass	Pass	Pass/Pass
15	Pass	Fail	Fail	Pass/Pass
16	Pass	Pass	Fail	Pass/Pass
17	Pass	Pass	Pass	Pass/Pass
18	Pass	Pass	Pass	Pass/Pass
19	Pass	Pass	Pass	Pass/Pass
20	Pass	Pass	Pass	Pass/Pass
21	Fail	Pass	Pass	Pass/Pass
22	Pass	Fail	Pass	Pass/Pass
23	Pass	Fail	Pass	Pass/Pass
24	Pass	Fail	Pass	Pass/Pass
25	Fail	Pass	Pass	Fail/Pass
26	Pass	Pass	Fail	Pass/Pass
27	Pass	Pass	Fail	Fail/Pass
28	Pass	Pass	Pass	Fail/Fail
29	Pass	Pass	Fail	Pass/Pass
30	Pass	Pass	Pass	Pass/Pass
31	Fail	Pass	Pass	Pass/Pass
32	Pass	Pass	Fail	Pass/Pass
33	Pass	Pass	Fail	Pass/Pass
34	Pass	Pass	Fail	Pass/Pass
35	Pass	Pass	Fail	Pass/Pass
36	Fail	Pass	Pass	Pass/Fail
ALL	Fail	Pass	Fail	Pass/Pass

Table 5. Dummy results: +/- 1 observation.

	National Power			Powergen		
Dummy	**Coefficient**	**Standard Error**	**T-Ratio[Prob]**	**Coefficient**	**Standard Error**	**T-Ratio [Prob]**
A	-0.01437	0.01767	-0.81331[.420]	-0.0204	0.01753	-1.16370[.251]
B	0.00501	0.00619	0.80835[.423]	-0.00621	0.00518	-1.19820[.237]
C	0.00089	0.00604	0.14807[.883]	-0.00466	0.00585	-0.79722[.429]
D	0.00801	0.00662	1.20990[.232]	0.0096	0.00613	1.56520[.124]
E	-0.00283	0.00752	-0.37618[.708]	-0.00112	0.00737	-0.15210[.880]
F	0.02021	0.01221	1.65580[.104]	0.01976	0.0109	1.81280[.076]
G	-0.01014	0.00835	-1.21380[.231]	-0.00734	0.00859	-0.85496[.397]
H	0.01385	0.00648	2.13710[.038]	0.01578	0.00763	2.06670[.044]
I	-0.01093	0.0067	-1.63160[.109]	-0.011	0.00697	-1.57980[.121]
J	0.00786	0.00573	1.37340[.176]	0.00758	0.00533	1.42350[.161]
K	0.00956	0.00849	1.12630[.266]	0.00403	0.00772	0.52200[.604]
L	0.01889	0.00804	2.34950[.023]	0.01038	0.00769	1.35080[.183]
M	0.00334	0.00595	0.56221[.577]	0.00283	0.00628	0.44964[.655]
N	0.00543	0.0055	0.98723[.328]	0.00416	0.00602	0.69123[.493]
O	-0.00665	0.00593	-1.12250[.267]	-0.00336	0.00622	-0.54030[.591]
P	0.00116	0.00618	0.18821[.852]	0.00523	0.00638	0.81967[.416]
Q	-0.00211	0.00536	-0.39381[.695]	-0.00785	0.00491	-1.59770[.117]
R	0.00099	0.00451	0.21944[.827]	-0.00566	0.00536	-1.05530[.297]
S	0.00024	0.00442	0.05374[.957]	0.00229	0.00533	0.42848[.670]
T	-0.00026	0.00613	-0.04236[.966]	-0.0074	0.00714	-1.03680[.305]
U	-0.00649	0.00608	-1.06730[.292]	-0.00379	0.00712	-0.53312[.597]
V	-0.00571	0.00699	-0.81701[.419]	-0.00361	0.00821	-0.43936[.663]

Table 6. Dummy results: +/- 5 observations.

	National Power			Powergen		
Dummy	Coefficient	Standard Error	T-Ratio[Prob]	Coefficient	Standard Error	T-Ratio [Prob]
A	-0.00864	0.01019	-0.84772[.401]	-0.01061	0.01015	-1.04520[.301]
B	-0.00083	0.00349	-0.23877[.812]	-0.00350	0.00290	-1.20790[.233]
C	0.00378	0.00346	1.09360[.280]	0.00425	0.00336	1.26660[.211]
D	0.00392	0.00371	1.05460[.297]	0.00436	0.00345	1.26200[.213]
E	-0.00080	0.00427	-0.18758[.852]	-0.00104	0.00418	-0.24787[.805]
F	0.00516	0.00718	0.71887[.476]	0.00714	0.00640	1.11620[.270]
G	-0.00353	0.00477	-0.73900[.464]	-0.00278	0.00488	-0.56891[.572]
H	0.00149	0.00389	0.38437[.702]	-0.00194	0.00456	-0.42419[.673]
I	0.00936	0.00368	2.53900[.014]	0.00758	0.00392	1.93080[.059]
J	-0.00352	0.00341	-1.03000[.308]	-0.00064	0.00321	-0.19905[.843]
K	0.00621	0.00481	1.28900[.204]	0.00809	0.00425	1.90430[.063]
L	0.00604	0.00474	1.27220[.209]	0.00531	0.00438	1.21130[.232]
M	0.00392	0.00337	1.16220[.251]	0.00769	0.00344	2.23920[.030]
N	0.00538	0.00308	1.74820[.087]	0.00773	0.00327	2.36190[.022]
O	-0.00582	0.00333	-1.74600[.087]	-0.00409	0.00352	-1.16060[.252]
P	-0.00613	0.00338	-1.81530[.076]	-0.00547	0.00354	-1.54650[.129]
Q	0.00247	0.00305	0.80885[.423]	0.00028	0.00288	0.09788[.922]
R	-0.00028	0.00259	-0.10658[.916]	-0.00511	0.00302	-1.69020[.097]
S	-0.00116	0.00257	-0.45345[.652]	0.00055	0.00311	0.17821[.859]
T	-0.00136	0.00348	-0.39167[.697]	-0.00302	0.00408	-0.74046[.463]
U	-0.00904	0.00330	-2.74300[.009]	-0.00780	0.00397	-1.96350[.056]
V	-0.00638	0.00373	-1.71040[.096]	-0.00196	0.00451	-0.43487[.666]

Table 7: National Power and Powergen, Dummy Window -1/+2 obs.

	National Power			Powergen		
Dummy	R-Squared	R-Bar-Squared	R.S.S.	R-Squared	R-Bar-Squared	R.S.S.
1	0.040112	-0.001622	0.040440	0.030736	-0.011406	0.040313
2	0.264160	0.233500	0.005105	0.313760	0.285170	0.003576
3	0.130030	0.093786	0.004855	0.139430	0.103580	0.004643
4	0.264930	0.234310	0.005208	0.251240	0.220040	0.004806
5	0.214830	0.182110	0.010554	0.186600	0.152710	0.012871
6	0.155740	0.120570	0.006959	0.182440	0.148370	0.007097
7	0.041804	0.001879	0.009034	0.044069	0.004238	0.008890
8	0.068855	0.030057	0.009806	0.047235	0.007536	0.008082
9	0.085876	0.047788	0.010353	0.044515	0.004703	0.008476
10	0.065034	0.026077	0.022877	0.057102	0.017814	0.020928
11	0.116690	0.079882	0.015699	0.098692	0.061137	0.016830
12	0.077845	0.039422	0.009066	0.149540	0.114110	0.009524
13	0.147671	0.112684	0.009405	0.045495	0.005724	0.012994
14	0.171330	0.136800	0.007062	0.096913	0.059284	0.009883
15	0.228910	0.196780	0.006245	0.114480	0.077580	0.008787
16	0.258470	0.227570	0.006173	0.241930	0.210340	0.006690
17	0.159870	0.124860	0.004286	0.173270	0.138830	0.003742
18	0.367080	0.340710	0.009702	0.355910	0.329070	0.007839
19	0.275110	0.244910	0.012259	0.270560	0.240170	0.009833
20	0.258000	0.227090	0.011042	0.262640	0.231920	0.008999
21	0.187690	0.153840	0.008849	0.169720	0.135130	0.009904
22	0.484310	0.462820	0.006101	0.443950	0.420780	0.005543
23	0.359730	0.333050	0.004844	0.441420	0.418140	0.005568
24	0.305580	0.276650	0.005147	0.328930	0.300970	0.004691
25	0.135000	0.098959	0.003212	0.081042	0.042752	0.003304
26	0.161690	0.126760	0.004468	0.110490	0.073428	0.005023
27	0.189990	0.156240	0.003891	0.176520	0.142210	0.004657
28	0.225260	0.192980	0.003722	0.219030	0.186490	0.004416
29	0.265170	0.234550	0.003766	0.370760	0.344540	0.002825
30	0.244750	0.213290	0.003949	0.290010	0.260420	0.003592
31	0.365300	0.338860	0.002749	0.285890	0.256140	0.003820
32	0.160640	0.125660	0.005043	0.148650	0.113180	0.006595
33	0.168060	0.133400	0.004757	0.184390	0.150400	0.006530
34	0.357410	0.330630	0.003643	0.168190	0.133530	0.005852
35	0.361550	0.334950	0.005175	0.353490	0.326550	0.004368
36	0.194880	0.161330	0.006800	0.104110	0.066780	0.006314

Table 8. National Power Dummy variants.

	National Power A (-1/+1 obs.)			National Power C (-5/+5 obs.)		
Dummy	R-Squared	R-Bar-Squared	R.S.S.	R-Squared	R-Bar-Squared	R.S.S.
1	0.041866	0.000208	0.040366	0.043038	0.001431	0.040317
3	0.263340	0.232650	0.005110	0.264010	0.233340	0.005106
4	0.125370	0.088926	0.004881	0.151520	0.116170	0.004735
7	0.257080	0.226130	0.005264	0.285030	0.255240	0.005066
10	0.043863	0.004024	0.009015	0.050312	0.010742	0.008954
12	0.063355	0.024328	0.022918	0.116330	0.079510	0.021622
15	0.135190	0.099156	0.009698	0.138810	0.102930	0.009657
16	0.211830	0.178990	0.006383	0.315060	0.286520	0.005547
17	0.275970	0.245800	0.006028	0.326290	0.298220	0.005609
18	0.186870	0.152990	0.004149	0.173190	0.138740	0.004218
20	0.372190	0.346030	0.009624	0.377150	0.351200	0.009548
24	0.257770	0.226840	0.011046	0.213910	0.181150	0.011698
26	0.304630	0.275650	0.005154	0.302640	0.273580	0.005169
27	0.165330	0.130550	0.004448	0.166350	0.131610	0.004443
28	0.246020	0.214600	0.003622	0.239280	0.207580	0.003654
29	0.177740	0.143480	0.003950	0.213330	0.180550	0.003779
30	0.255470	0.224450	0.003816	0.260500	0.229690	0.003790
31	0.266810	0.236260	0.003834	0.244620	0.213140	0.003950
32	0.365880	0.339460	0.002747	0.365390	0.338950	0.002749
33	0.163430	0.128570	0.005027	0.183470	0.149440	0.004906
34	0.160120	0.125120	0.004802	0.174980	0.140610	0.004717
35	0.241860	0.210270	0.004298	0.332380	0.304560	0.003785
36	0.339560	0.312040	0.005353	0.209170	0.176220	0.006410

Table 9. Powergen Dummy variants.

	Powergen A (-1/+1 obs.)			Powergen C (-5/+5 obs.)		
Dummy	R-Squared	R-Bar-Squared	R.S.S.	R-Squared	R-Bar-Squared	R.S.S.
1	0.043833	0.002260	0.039768	0.038518	-0.003286	0.039989
3	0.308930	0.280140	0.003601	0.323170	0.294970	0.003527
4	0.145050	0.109420	0.004613	0.141950	0.106200	0.004630
7	0.244170	0.212680	0.004851	0.263180	0.232480	0.004729
10	0.044949	0.005155	0.008882	0.047671	0.007990	0.008857
12	0.052286	0.012798	0.021034	0.095173	0.057472	0.020083
15	0.141180	0.105400	0.009618	0.138200	0.102290	0.009651
16	0.102130	0.064720	0.008910	0.168740	0.134110	0.008249
17	0.261580	0.230810	0.006516	0.279170	0.249140	0.006361
18	0.206590	0.173530	0.003591	0.173770	0.139350	0.003739
20	0.346240	0.319000	0.007956	0.388710	0.363240	0.007439
24	0.249590	0.218320	0.009158	0.241130	0.209510	0.009261
26	0.322780	0.294570	0.004734	0.279280	0.249250	0.005038
27	0.105030	0.067741	0.005054	0.113340	0.076393	0.005007
28	0.209610	0.176670	0.004470	0.206050	0.172970	0.004490
29	0.191940	0.158270	0.004570	0.175270	0.140900	0.004664
30	0.347800	0.320620	0.002928	0.310470	0.281740	0.003096
31	0.300570	0.271430	0.003539	0.319040	0.290660	0.003445
32	0.274250	0.244010	0.003883	0.299130	0.269920	0.003749
33	0.149460	0.114020	0.006589	0.148770	0.113300	0.006594
34	0.173770	0.139350	0.006615	0.232740	0.200770	0.006143
35	0.144240	0.108590	0.006021	0.220700	0.188230	0.005483
36	0.367160	0.340790	0.004276	0.087233	0.049201	0.006167

CHAPTER VIII, APPENDIX

Table 1a: Pool Purchase Price (PPP): Horton IV estimate (p/kWh, 1989 money values).

	1990/1	1991/2	1992/3	1993/4	1994/5	1995/6	1996/7
20 hrs	46.24	57.72	90.31	121.21	89.47	124.63	132.20
215 hrs	3.39	3.55	3.89	4.92	3.86	5.07	5.15
1085 hrs	2.42	2.49	2.62	2.78	2.80	2.77	2.81
2745 hrs	2.27	2.36	2.45	2.60	2.64	2.60	2.68
4620 hrs	2.05	2.10	2.18	2.25	2.33	2.29	2.41
6133 hrs	1.84	1.89	1.98	2.03	2.09	2.02	2.15
7443 hrs	1.54	1.65	1.74	1.81	1.86	1.81	1.88
8435 hrs	1.31	1.36	1.44	1.57	1.64	1.59	1.62
8760 hrs	1.22	1.25	1.33	1.47	1.51	1.47	1.50
Average	2.20	2.32	2.55	2.80	2.69	2.83	2.94

The sums in the table do not include the subsidies granted to British Coal.

Table 1b: Pool Purchase Price (PPP): Horton IV estimate (p/kWh, 1989 money values).

	1990/1	1991/2	1992/3	1993/4	1994/5	1995/6	1996/7	1997/8
20 hrs	227.33	203.29	167.65	119.79	120.05	119.06	120.77	120.80
215 hrs	3.39	3.55	3.89	4.92	3.86	5.07	5.15	3.90
1085 hrs	2.42	2.49	2.62	2.78	2.80	2.77	2.81	2.86
2745 hrs	2.27	2.36	2.45	2.60	2.64	2.60	2.68	2.69
4620 hrs	2.05	2.08	2.18	2.25	2.31	2.26	2.41	2.44
6133 hrs	1.84	1.89	1.97	2.03	2.08	2.02	2.14	2.17
7443 hrs	1.54	1.60	1.74	1.81	1.85	1.81	1.84	1.86
8435 hrs	1.31	1.36	1.44	1.57	1.63	1.58	1.60	1.63
8760 hrs	1.22	1.25	1.33	1.46	1.51	1.44	1.46	1.48
Average	2.89	2.86	2.84	2.79	2.80	2.80	2.89	2.87

The sums in the table include the subsidies granted to British Coal.

Table 2a. Contract load factors.

Time period	Load Factor
20 hrs	0.22831%
215 hrs	2.45434%
1085 hrs	12.38584%
2745 hrs	31.38584%
4620 hrs	52.73973%
6133 hrs	70.01142%
7443 hrs	84.96575%
8435 hrs	96.28995%
8760 hrs	100.00000%

Table 2b. Synthetic load profile derived from Horton IV estimates.

Using the 1990/1 PSP estimates indicated above:

The first 20 hrs of electricity cost	228.94 p/kwh
The next 195 hrs of electricity cost	3.46 p/kwh
The next 870 hrs of electricity cost	2.50 p/kwh
The next 1660 hrs of electricity cost	2.35 p/kwh
The next 1875 hrs of electricity cost	2.12 p/kwh
The next 1513 hrs of electricity cost	1.93 p/kwh
The next 1310 hrs of electricity cost	1.63 p/kwh
The next 992 hrs of electricity cost	1.31 p/kwh
The last 325 hrs of electricity cost	1.22 p/kwh

Table 2c. Load profile established in half-hour format.

The first 20 hrs of electricity represent 0.22831% of the year (40 half-hours)
The next 195 hrs of electricity represent 1.11301% of the year (390 half-hours)
The next 870 hrs of electricity represent 9.93151% of the year (1740 half-hours)
The next 1660 hrs of electricity represent 18.94977% of the year (3320 half-hours)
The next 1875 hrs of electricity represent 21.40411% of the year
The next 1513 hrs of electricity represent 17.27169% of the year
The next 1310 hrs of electricity represent 14.95434% of the year (2620 half-hours)
The next 992 hrs of electricity represent 11.43836% of the year (1984 half-hours)
The last 325 hrs of electricity represent 3.71005% of the year (625 half-hours)

Table 3 – Coefficient restrictions on Horton IV estimates and PPP levels (Static equations).

Parameter restrictions: Intercept term = 0, Slope coefficient = 1.
Critical value of Chi-squared distribution: Chi-squared (2) = 5.99.
H0: Restrictions valid
H1: Restrictions invalid
If calculated value < critical value, accept H0 - parameter restrictions are valid.
Therefore, the forward price is an accurate predictor of the spot price.
If calculated value > critical value, reject H0 - parameter restrictions are invalid.
Therefore, the forward price is not an accurate predictor of the spot price.

Date	Observations	Calculated Value	Accept/Reject H0
Extended periods.			
10/90-03/94	1-1278	1313.8000	Reject
10/90-03/93	1-913	1558.6000	Reject
Annual results.			
10/90-03/91	1-182	563.2172	Reject
04/91-03/92	183-548	419.7655	Reject
04/92-03/93	549-913	15420.0000	Reject
04/93-03/94	914-1278	217.8029	Reject
Bi-monthly results.			
10/90-11/90	1 - 61	396.7454	Reject
12/90-01/91	62 - 123	189.5379	Reject
02/91-03/91	124 - 182	151.5493	Reject
04/91-05/91	183 - 243	267.9557	Reject
06/91-07/91	244 - 304	226.5947	Reject
08/91-09/91	305 - 365	109.6296	Reject
10/91-11/91	366 - 426	98.5794	Reject
12/91-01/92	427 - 488	4.0015	Accept
02/92-03/92	489 - 548	1566.8000	Reject
04/92-05/92	549 - 609	3492.7000	Reject
06/92-07/92	610 - 670	1468.6000	Reject
08/92-09/92	671 - 731	2700.3000	Reject
10/92-11/92	732 - 792	2031.4000	Reject
12/92-01/93	793 - 854	5321.3000	Reject
02/93-03/93	855 - 913	2430.7000	Reject
04/93-05/93	914 - 974	1334.5000	Reject
06/93-07/93	975 - 1035	1783.7000	Reject
08/93-09/93	1036 - 1096	1083.1000	Reject
10/93-11/93	1097 - 1157	1830.7000	Reject
12/93-01/94	1158 - 1219	1400.9000	Reject
02/94-03/94	1220 - 1278	0.7025	Accept

Table 4 – Diagnostic test results: Horton IV/PPP analysis.

Obs. Range	S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.
Extended sample periods.						
1-1278	Fail	Pass	Fail	Pass	Pass	Pass
1-913	Fail	Fail	Fail	Pass	Fail	Pass
Annual results.						
1-182	Fail	Pass	Fail	Fail	Fail	Pass
183-548	Fail	Fail	Fail	Fail	Fail	Pass
549-913	Fail	Fail	Fail	Pass	Pass	Pass
914-1278	Fail	Fail	Fail	Fail	Fail	Pass
Bi-monthly results.						
1-61.	Pass	Pass	Fail	Pass	Pass	Pass
62-121	Pass	Pass	Fail	Fail	Pass	Pass
124-182	Fail	Pass	Fail	Pass	Pass	Pass
183-243	Pass	Fail	Fail	Pass	Pass	Pass
244-304	Pass	Fail	Fail	Fail	Pass	Pass
305-365	Fail	Fail	Fail	Fail	Pass	Pass
366-426	Pass	Fail	Pass	Pass	Pass	Pass
427-488	Pass	Fail	Fail	Pass	Pass	Pass
489-548	Pass	Fail	Fail	Pass	Pass	Pass
549-609	Fail	Fail	Pass	Pass	Fail	Fail
610-670	Fail	Pass	Pass	Fail	Fail	Pass
671-731	Pass	Pass	Fail	Fail	Pass	Pass
732-792	Pass	Pass	Fail	Pass	Pass	Pass
793-854	Fail	Pass	Fail	Fail	Fail	Pass
855-913	Pass	Fail	Fail	Pass	Fail	Pass
914-974	Pass	Pass	Fail	Fail	Pass	Pass
975-1035	Pass	Fail	Fail	Pass	Pass	Pass
1036-1096	Pass	Fail	Pass	Pass	Pass	Pass
1097-1157	Pass	Fail	Fail	Fail	Pass	Pass
1158-1219	Fail	Fail	Fail	Pass	Fail	Pass
1220-1278	Fail	Fail	Pass	Pass	Fail	Fail

Table 5 – Coefficient restrictions on Horton IV/PPP levels (Dynamic equations).

Parameter restrictions: Intercept term = 0, Slope coefficient = 1.
Critical value of Chi-squared distribution: Chi-squared (2) = 5.99.
H0: Parameter restrictions are valid.
H1: Parameter restrictions are not valid.
If calculated value < critical value - accept H0, parameter restrictions valid.
Therefore, the forward price is an accurate predictor of the spot price.
If calculated value > critical value - reject H0, parameter restrictions invalid.
Therefore, the forward price is not an accurate predictor of the spot price.

Date	Observations	Calculated Value	Accept/Reject H0
Extended sample periods.			
10/90-03/94	1-1278	3651.2000	Reject
10/90-03/93	1-913	1330.4000	Reject
Annual results.			
10/90-03/91	1-182	364.3951	Reject
04/91-03/92	183-548	204.7218	Reject
04/92-03/93	549-913	2288.2000	Reject
04/93-03/94	914-1278	657.7891	Reject
Bi-monthly results.			
10/90-11/90	1-61.	180.9843	Reject
12/90-01/91	62-121	60.2607	Reject
02/91-03/91	124-182	181.4143	Reject
04/91-05/91	183-243	52.0171	Reject
06/91-07/91	244-304	61.3756	Reject
08/91-09/91	305-365	20.7358	Reject
10/91-11/91	366-426	23.6346	Reject
12/91-01/92	427-488	45.1149	Reject
02/92-03/92	489-548	158.9228	Reject
04/92-05/92	549-609	1229.1000	Reject
06/92-07/92	610-670	115.2681	Reject
08/92-09/92	671-731	158.2681	Reject
10/92-11/92	732-792	218.6782	Reject
12/92-01/93	793-854	518.3131	Reject
02/93-03/93	855-913	220.1533	Reject

Table 6 – Dummy variable regression results.

Event 1: Break-up of first set of CFDs (Observation 173).
101 observations used for estimation from 150 to 250

Regressor	*Coefficient*	Standard Error	T-Ratio[Prob]
CONSTANT	1.47600	0.10214	14.4512[.000]
LHIVEIN	0.49008	0.03316	14.7790[.000]
DUMMY1	0.04158	0.00970	4.2857[.000]

Event 2: Price spikes begin (Observation 344).
101 observations used for estimation from 325 to 425

Regressor	*Coefficient*	Standard Error	T-Ratio[Prob]
CONSTANT	1.13010	0.09434	11.9797[.000]
LHIVEIN	0.62541	0.03106	20.1340[.000]
DUMMY2	0.04195	0.02073	2.0239[.046]

Event 3: First pool price review launched with MMC threat (Observation 368).
101 observations used for estimation from 350 to 450

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.90101	0.10777	8.3602[.000]
LHIVEIN	0.73234	0.03376	21.6920[.000]
DUMMY3	-0.05273	0.02467	-2.1375[.035]

Event 4: First pool price review published (Observation 446).
101 observations used for estimation from 425 to 525

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	1.27110	0.12872	9.8745[.000]
LHIVEIN	0.61896	0.03926	15.7672[.000]
DUMMY4	-0.13078	0.02243	-5.8317[.000]

Event 5: Generators threatened with MMC reference (Observation 636).
101 observations used for estimation from 600 to 700

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	2.03730	0.03154	64.5842[.000]
LHIVEIN	0.35361	0.01028	34.3895[.000]
DUMMY5	-0.00479	0.00350	-1.3666[.175]

Event 6: Second pool price review launched (Observation 739).
101 observations used for estimation from 700 to 800

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	2.16230	0.04021	53.7834[.000]
LHIVEIN	0.31139	0.01293	24.0746[.000]
DUMMY6	0.01094	0.00554	1.9736[.051]

Event 7: Second pool price review published (Observation 810).
101 observations used for estimation from 775 to 875

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	2.22490	0.04131	53.8642[.000]
LHIVEIN	0.29624	0.01265	23.4117[.000]
DUMMY7	-0.01883	0.00511	-3.6850[.000]

Event 8: Break-up of second set of CFDs (Observation 913).
101 observations used for estimation from 875 to 975
Standard (Indexed) Horton estimates.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	2.04980	0.04484	45.7185[.000]
LHIVEIN	0.34910	0.01407	24.8058[.000]
DUMMY8	0.07675	0.00384	20.0095[.000]

Event 8: Break-up of second set of CFDs (Observation 913).
101 observations used for estimation from 875 to 975
Non-indexed Horton estimates.

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	2.07300	0.04390	47.2169[.000]
LHIVE	0.34910	0.01407	24.8058[.000]
DUMMY8	0.08366	0.00378	22.1370[.000]

Event 9: Generators threatened with MMC reference (Observation 966).
101 observations used for estimation from 925 to 1025

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	2.33610	0.04555	51.2851[.000]
LHIVEIN	0.28436	0.01393	20.4092[.000]
DUMMY9	-0.00483	0.00517	-0.93444[.352]

Event 10: Offer threatens MMC reference and/or plant sales (Observation 1034).
101 observations used for estimation from *1000* to *1100*

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	2.02150	0.05584	36.2037[.000]
LHIVEIN	0.37897	0.01727	21.9498[.000]
DUMMY10	0.00119	0.00613	0.1943[.846]

Event 11: MMC reference threatened unless price agreement made (Observation 1172).
101 observations used for estimation from 1150 to 1250

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	1.56190	0.10890	14.3425[.000]
LHIVEIN	0.52081	0.03296	15.8001[.000]
DUMMY11	-0.01014	0.01927	-0.5262[.600]

Event 12: NP and PG establish price agreement (Observation 1230).
79 observations used for estimation from 1200 to 1278

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.71541	0.21491	3.3289[.001]
LHIVEIN	0.80562	0.07094	11.3571[.000]
DUMMY12	-0.21505	0.02867	-7.5001[.000]

Table 7 – Diagnostic test results.
Horton IV/PPP analyses.

Diagnostic tests.

Obs. Range	S.C.R.	F.F.	N.R.	H.S.	ARCH	Stat.
150-250	Pass	Fail	Fail	Pass	Pass	Pass
325-425	Fail	Fail	Fail	Fail	Fail	Pass
350-450	Fail	Fail	Fail	Fail	Pass	Pass
425-525	Fail	Fail	Fail	Fail	Fail	Pass
600-700	Fail	Pass	Fail	Fail	Fail	Pass
700-800	Pass	Pass	Fail	Fail	Pass	Pass
775-875	Pass	Pass	Fail	Fail	Fail	Pass
875-975	Pass	Pass	Fail	Pass	Pass	Pass
875-975*	Pass	Pass	Fail	Pass	Pass	Pass
925-1025	Pass	Fail	Fail	Fail	Fail	Pass
1000-1100	Fail	Fail	Fail	Fail	Pass	Pass
1150-1250	Fail	Fail	Fail	Pass	Fail	Fail
1200-1278	Fail	Fail	Pass	Fail	Fail	Fail

* Indicates non-indexed Horton estimates.

S.C.R.	Serial Correlation of Residuals (Lagrange-Multiplier test)
F.F.	Functional Form (Ramsey RESET)
N.R.	Normality of Residuals (Skewness and Kurtosis)
H.S.	Heteroscedasticity (Regression of Squared Residuals on Squared Fitted Values)
ARCH	Autoregressive Conditional Heteroscedasticity
Stat.	Stationarity (Unit Root Tests for Residuals)

Table 8 – Restricted dummy variable analysis.

The restrictions and critical values are as previously stated.

Table 8.1. Horton IV-PPP (Static).

Dummy	Observations	Calculated Value	Accept/Reject H0
DUMMY1	150-250	390.93970	Reject
DUMMY2	325-425	154.89340	Reject
DUMMY3	350-450	71.77390	Reject
DUMMY4	425-525	110.43910	Reject
DUMMY5	600-700	4480.80000	Reject
DUMMY6	700-800	2845.40000	Reject
DUMMY7	775-875	3600.40000	Reject
DUMMY8	875-975	2183.30000	Reject
DUMMY8*	875-975	2397.70000	Reject
DUMMY9	925-1025	2682.20000	Reject
DUMMY10	1000-1100	1311.80000	Reject
DUMMY11	1150-1250	215.51130	Reject
DUMMY12	1200-1278	56.55800	Reject

Table 8.2. Horton IV-PPP (Dynamic).

Dummy	Observations	Calculated Value	Accept/Reject H0	Coefficient	Significant
DUMMY1	150-250	430440.90000	Reject	0.05261	Yes
DUMMY2	325-425	62640.60000	Reject	0.09485	Yes
DUMMY3	350-450	39530.30000	Reject	-0.10560	Yes
DUMMY4	425-525	111190.40000	Reject	-0.31493	Yes
DUMMY5	600-700	6207450.90000	Reject	-0.00422	No
DUMMY6	700-800	3242480.60000	Reject	0.02167	Yes
DUMMY7	775-875	5024650.50000	Reject	-0.03387	Yes
DUMMY8	875-975	5128240.50000	Reject	0.11558	Yes
DUMMY8*	875-975	156.59000	Reject	0.01907	No
DUMMY9	925-1025	3646610.20000	Reject	-0.00602	No
DUMMY10	1000-1100	1820790.00000	Reject	-0.00095	No
DUMMY11	1150-1250	148560.90000	Reject	-0.08855	Yes
DUMMY12	1200-1278	103960.30000	Reject	-0.22992	Yes

* Indicates non-Indexed Horton estimates.
Significance is at the 5% level.
For further details of the events, see Table 1, Chapter IV (p. 123).

Table 9 – Regression results: COB contract analysis.

9.1: Peak results: Actual = f(Forecasted).

September 1995 - October 1996: 427 observations used for estimation from 1 to 427

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.12251	0.054404	2.2519[.025]
LFNFP	0.95675	0.020954	45.6604[.000]

Diagnostic test results: Fail Serial Correlation, Normality, ARCH.

September 1995: 30 observations used for estimation from 1 to 30

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	2.1094	0.35878	5.8795[.000]
LFNFP	0.26338	0.12735	2.0681[.048]

Diagnostic test results: Fail Serial Correlation, Normality.

October 1995: 31 observations used for estimation from 31 to 61

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	1.2412	0.29534	4.2024[.000]
LFNFP	0.52151	0.11233	4.6425[.000]

Diagnostic test results: Fail Serial Correlation.

November 1995: 30 observations used for estimation from 62 to 91

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	0.57524	0.23247	2.4745[.020]
LFNFP	0.77318	0.08876	8.7109[.000]

Diagnostic test results: Fail Serial Correlation, Normality.

December 1995: 31 observations used for estimation from 92 to 122

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	1.631	0.69429	2.3491[.026]
LFNFP	0.30859	0.29326	1.0523[.301]

Diagnostic test results: Fail Normality.

January 1996: 31 observations used for estimation from 123 to 153

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
CONSTANT	-0.1765	0.17637	-1.0007[.325]
LFNFP	1.091	0.072058	15.1400[.000]

Diagnostic test results: Fail Serial Correlation.

February 1996: 29 observations used for estimation from 154 to 182

Regressor	Coefficient	Standard Error
CONSTANT	0.22282	0.2508
LFNFP	0.88897	0.10254

Diagnostic test results: Fail Normality.

March 1996: 31 observations used for estimation from 183 to 213

Regressor	Coefficient	Standard Error
CONSTANT	0.75585	0.25937
LFNFP	0.68381	0.11526

Diagnostic test results: Fail Serial Correlation, Heteroscedasticity, ARCH.

April 1996: 30 observations used for estimation from 214 to 243

Regressor	Coefficient	Standard Error
CONSTANT	3.0338	0.49637
LFNFP	-0.25201	0.20565

Diagnostic test results: Fail Normality.

May 1996: 31 observations used for estimation from 244 to 274

Regressor	Coefficient	Standard Error
CONSTANT	0.43548	0.74663
LFNFP	0.81186	0.30677

Diagnostic test results: Fail Normality, Heteroscedasticity.

June 1996: 30 observations used for estimation from 275 to 304

Regressor	Coefficient	Standard Error
CONSTANT	0.75427	0.4063
LFNFP	0.69654	0.16358

Diagnostic test results: Fail Serial Correlation.

July 1996: 31 observations used for estimation from 305 to 335

Regressor	Coefficient	Standard Error
CONSTANT	0.14898	0.33001
LFNFP	0.96682	0.12196

Diagnostic test results: Fail Normality.

August 1996: 31 observations used for estimation from 336 to 366

Regressor	Coefficient	Standard Error
CONSTANT	1.6889	0.52994
LFNFP	0.4022	0.18665

Diagnostic test results: Fail Serial Correlation.

September 1996: 30 observations used for estimation from 367 to 396

Regressor	Coefficient	Standard Error
CONSTANT	0.45874	0.40307
LFNFP	0.84468	0.14304

Diagnostic test results: Fail None.

October 1996: 31 observations used for estimation from 397 to 427

Regressor	Coefficient	Standard Error
CONSTANT	-0.20252	0.42905
LFNFP	1.0825	0.14468

Diagnostic test results: Fail Serial Correlation, Normality, ARCH.

9.2. Off-Peak results: Actual = f(Forecasted).

September 1995 - October 1996: 427 observations used for estimation from 1 to 427

Regressor	Coefficient	Standard Error
CONSTANT	0.061657	0.04291
LFNFOP	0.97133	0.019264

Diagnostic test results: Fail Serial Correlation, Normality, Heteroscedasticity,

September 1995: 30 observations used for estimation from 1 to 30

Regressor	Coefficient	Standard Error
CONSTANT	3.0486	0.40112
LFNFOP	-0.17474	0.15794

Diagnostic test results: Fail None.

October 1995: 31 observations used for estimation from 31 to 61

Regressor	Coefficient	Standard Error
CONSTANT	0.13512	0.36074
LFNFOP	0.94303	0.1456

Diagnostic test results: Fail Normality.

November 1995: 30 observations used for estimation from 62 to 91

Regressor	Coefficient	Standard Error
CONSTANT	0.71658	0.22815
LFNFOP	0.69316	0.09269

Diagnostic test results: Fail Serial Correlation.

December 1995: 31 observations used for estimation from 92 to 122

Regressor	Coefficient	Standard Error
CONSTANT	1.2417	0.24684
LFNFOP	0.36552	0.1223

Diagnostic test results: Fail None.

January 1996: 31 observations used for estimation from 123 to 153

Regressor	Coefficient	Standard Error
CONSTANT	0.51006	0.31335
LFNFOP	0.76664	0.14821

Diagnostic test results: Fail Normality.

February 1996: 29 observations used for estimation from 154 to 182

Regressor	Coefficient	Standard Error
CONSTANT	-0.15232	0.20011
LFNFOP	1.0421	0.10283

Diagnostic test results: Fail None.

March 1996: 31 observations used for estimation from 183 to 213

Regressor	Coefficient	Standard Error
CONSTANT	0.67784	0.25474
LFNFOP	0.61805	0.14614

Diagnostic test results: Fail Functional Form.

April 1996: 30 observations used for estimation from 214 to 243

Regressor	Coefficient	Standard Error
CONSTANT	0.2114	0.18985
LFNFOP	0.87696	0.10103

Diagnostic test results: Fail Functional Form, Normality.

May 1996: 31 observations used for estimation from 244 to 274

Regressor	Coefficient	Standard Error
CONSTANT	0.53626	0.42072
LFNFOP	0.67847	0.23053

Diagnostic test results: Fail Serial Correlation, ARCH.

June 1996: 30 observations used for estimation from 275 to 304

Regressor	Coefficient	Standard Error
CONSTANT	1.9972	0.45956
LFNFOP	-0.074045	0.24612

Diagnostic test results: Fail Normality.

July 1996: 31 observations used for estimation from 305 to 335

Regressor	Coefficient	Standard Error
CONSTANT	1.2809	0.50344
LFNFOP	0.42074	0.24806

Diagnostic test results: Fail Normality.

August 1996: 31 observations used for estimation from 336 to 366

Regressor	Coefficient	Standard Error
CONSTANT	2.2572	0.42445
LFNFOP	0.092576	0.16796

Diagnostic test results: Fail Serial Correlation, ARCH.

September 1996: 30 observations used for estimation from 367 to 396

Regressor	Coefficient	Standard Error
CONSTANT	2.4357	0.82197
LFNFOP	0.071371	0.31395

Diagnostic test results: Fail Serial Correlation, Normality, ARCH.

October 1996: 31 observations used for estimation from 397 to 427

Regressor	Coefficient	Standard Error
CONSTANT	0.10635	0.49791
LFNFOP	0.96925	0.17925

Diagnostic test results: Fail None.

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