Why Did Electricity Prices Fall in England and Wales?

Market Mechanism or Market Structure?

John Bower

Oxford Institute for Energy Studies

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ABSTRACT

The objective of this paper is to measure the price impacts of the major regulatory interventions in the England & Wales wholesale electricity market from 1 April 1990 to 31 March 2002. More particularly, to establish whether falling prices during 1999–2002 were caused by the regulator ('Ofgem') forcing the dominant duopoly of fossil fuel generators to divest coal-fired plant, or because the Pool market mechanism was replaced with New Electricity Trading Arrangements ('NETA'). Backward regression analysis of functionally equivalent elements of day-ahead prices under the Pool and NETA shows that changing the trading arrangements produced no statistically significant response except for the removal of Capacity Payments. In contrast, coal plant divestment, increased imports of foreign coal, and overcapacity caused by the 'dash for gas', caused the majority of the price fall. The direct system development costs, associated management costs, and increased operational risk of implementing NETA were therefore unnecessary because industry restructuring had already brought about a significant price reduction by March 2001. A number of fossil fuel plants, as well as the nuclear plant operators are in financial distress as a result of falling prices but as NETA had no impact on prices there is no need for further fundamental NETA reform. As in any other bulk commodity industry, prices can only rise after some firms have gone bankrupt and their capacity either sold off or closed down for good. In this case, that means the nuclear industry should not be rescued by the UK Government but allowed to fail and their assets sold to the highest bidder. Extending NETA to Scotland, as the British Electricity Trading and Transmission Arrangements (BETTA) will not benefit consumers without also breaking the Scottish generation duopoly. To achieve this, generators in England & Wales must be allowed to enter the Scottish market via an open access agreement covering the entire capacity of the upgraded Scotland–England interconnector.

1. INTRODUCTION

The England & Wales Electricity Pool ('the Pool') began trading on 1 April 1990 and was the centrepiece of UK electricity market deregulation and price liberalisation. As one of the first examples of a competitive wholesale electricity market anywhere in the world[1] it was copied, almost in entirety in some cases, by a number of other countries seeking to reform their electricity industry.

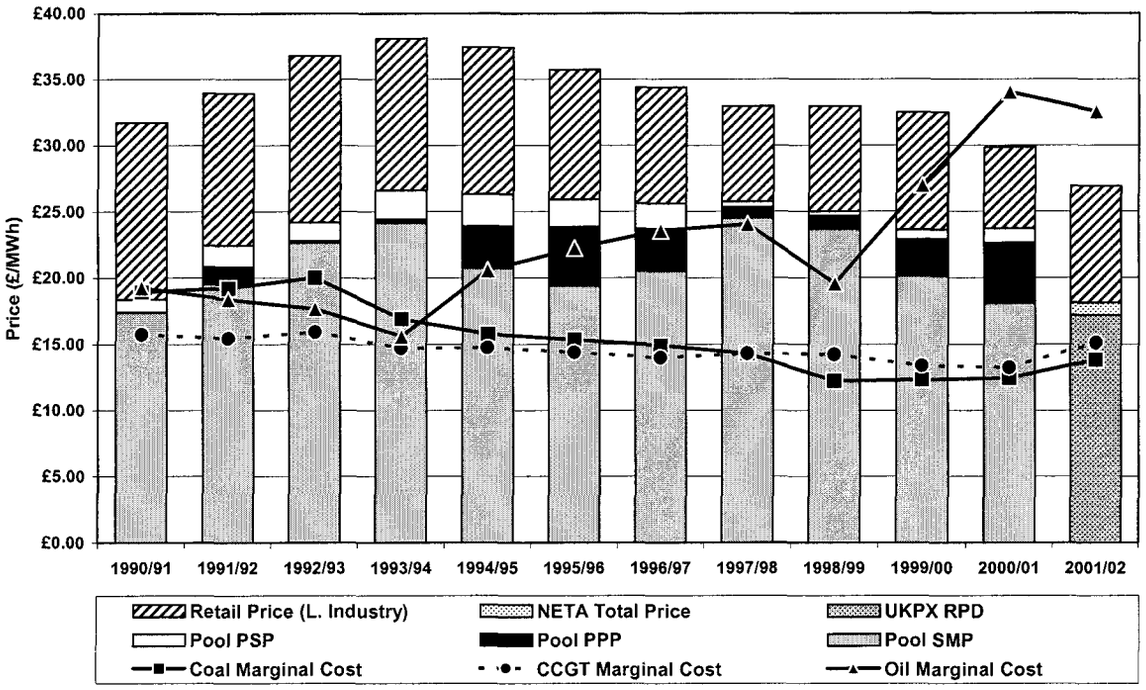
Operationally the Pool was a mandatory uniform price auction, repeated on a daily basis, into which generators submitted price-quantity bids to provide bulk wholesale supplies of electricity in each half-hour of the next day ('day-ahead'). Economic theory had predicted that Bertrand price competition would quickly cause Pool prices to fall to short-run marginal generation costs, however, as Figure 1 shows, mean annual Pool prices rose by 40%

I would like to thank Charles Henderson, Alex Henney, and many others in the UK electricity industry who prefer to remain anonymous, for their helpful comments on earlier drafts of this paper. All remaining errors and omissions are mine.

[1] Various Pool-based wholesale market forms have operated in the Scandinavian countries since the early 1970s, and in Chile since 1980.

(nominal) in the first four years of its operation, and remained well above marginal generation costs up to and including 2000/01.

Figure 1: England & Wales arithmetic mean annual electricity prices and costs 1990–2002



Retail Price = *DTI Quarterly Energy Prices*, Table 3.1.2 Prices of fuels purchased by manufacturing industry (www.dti.gov.uk/energy/inform/energy_prices/) with quarterly price for Large consumers in £/MWh calculated from formula p/kWh *10 then averaged over Q2, Q3, Q4 plus Q1

Marginal Cost = *DTI Quarterly Energy Prices*, Table 3.2.1 Average prices of fuels purchased by the major UK power producers (www.dti.gov.uk/energy/inform/energy_prices/) with quarterly marginal costs in £/MWh calculated from formula p/kWh *10 / Thermal Efficiency (coal 33%, CCGT 45%, oil 30%) then averaged over Q2, Q3, Q4, plus Q1.

Pool Price = *Statistical Digest* (www.elecpool.com) with prices in £/MWh averaged over Month 4–12 plus Month 1–3

NETA Total Price = *UKPX RPD* (www.ukpx.co.uk) plus Balancing Mechanism Costs (from anonymous correspondent) with prices in £/MWh averaged over Month 4–12 plus Month 1–3

The assumption that competition in the wholesale market would be sufficient to hold retail prices paid by consumers at or below pre-privatisation levels proved false. As a result, the Office of Gas and Electricity Markets[2] (Ofgem), which regulates the UK electricity and gas markets, was only able to deliver promised reductions in retail electricity prices to household/commercial consumers by imposing real terms reductions in the operating margins of the transmission, distribution, and supply sectors where formal price controls were still in place. For large industrial consumers, many of whom had enjoyed subsidised tariffs prior to

[2] Ofgem was created by merging the *Office of Electricity Regulation* (Offer) and the *Office for Gas Regulation* (Ofgas) in 1999 but for simplicity Ofgem will be used throughout.

price liberalisation, rising Pool prices had a more immediate impact because price controls did not apply to electricity supplied to sites with peak demand above 1 Megawatt (MW) after 1990/91.

Throughout the 1990s, consumer groups representing household users, and trade bodies representing industrial users, lobbied the UK government and Ofgem calling for action to be taken to curtail persistently high Pool prices and hence bring about a reduction in retail prices. Eventually, under pressure from the Department of Trade and Industry (DTI),[3] who were also increasingly concerned that high prices were encouraging excessive entry by new gas-fired Combined Cycle Gas Turbine (CCGT) capacity to the detriment of the UK deep-mined coal industry, Ofgem began a major Review of Electricity Trading Arrangements (RETA)[4] in November 1997. Its interim conclusion published in May 1998 produced the "Common Model" which proposed replacing the Pool with a bilateral market similar to a traditional commodity market. The final report in July 1998 confirmed that the Pool would be replaced with a bilateral wholesale market mechanism called the New Electricity Trading Arrangements (NETA). The DTI formally announced in October 1998, that it had accepted the Ofgem proposals.

The operational details of how NETA would function on a day-to-day basis were developed over the next year with a start date for NETA[5] of Autumn 2000. The fine detail of NETA systems functionality continued to evolve over the next two years and difficulties in developing and testing new software, as well as a further decision to delay the 'Go Live' date beyond the Millennium, meant NETA did not begin trading until 27 March 2001.

In total, the RETA consultation process lasted a year, and the subsequent systems development, implementation and testing for NETA took a further 30 months to complete. During this long interregnum, Pool prices began to fall towards the end of 1999/00 and continued to do so thereafter. Although retail prices to end-users did not fall as quickly as wholesale prices, by the time NETA had completed its first year of operation in 2001/02 large

[3] References to DTI generally mean the Secretary of State for Energy who was primarily responsible for the majority of regulatory initiatives relating to electricity within the department.

[4] The key RETA documents are listed in the References section of this paper under "Ofgem" and can be downloaded from: www.ofgem.gov.uk/elarch/aback.htm, further subsidiary documents, including inquiry terms of reference, conference presentations, and third party submissions to the inquiry are available at: www.ofgem.gov.uk/public/adownloads.htm#retabm.

[5] The key NETA documents are listed in the References section of this paper under Ofgem and can be downloaded at: www.ofgem.gov.uk/elarch/anetadocs.htm. Many more technical papers relating to the systems development can be downloaded at: http://www.ofgem.gov.uk/elarch/reta_contents.htm.

industrial consumers were paying 15% less in nominal terms, and 61% less in real terms,[6] than they had paid in 1990/91. Such was the magnitude of the price fall that the smallest (Fifoots, 363 MW), and largest (Drax, 4000MW), coal-fired plants both owned by AES were in actual or technical default on their debt by the end 2001/02. BNFL, the government-owned firm that had retained the UK's oldest nuclear plants after the remainder of the industry had been privatised, announced it would bring forward its closure programme. The privately-owned British Energy, operating the UK's fleet of more modern nuclear plant, announced its revenues would not be sufficient to cover its fixed costs in 2001/02 and subsequently was given an emergency loan by the DTI to allow it to remain in business until December 2002 until its debt could be restructured. Meanwhile Eastern Energy (TXU) and International Power announced they would each respectively mothball coal and CCGT plant from April 2002 onwards though these were reversed once prices rose partly as a result of nuclear plant outages, and news of British Energy's financial difficulties emerged during summer 2002.[7]

Viewed in isolation, NETA and the fall in wholesale prices appear to be connected as they both occurred over a roughly similar time period. However, NETA was only the final act in a long series of regulatory interventions that began before the Pool commenced trading. All of these could have had a potential impact on wholesale prices, up or down, both before and after NETA was introduced. The objective of this paper is to measure the price impact of the major regulatory interventions in the England & Wales wholesale electricity market between 1 April 1990 and 31 March 2002. In particular to examine the relative contribution of the following factors to falling prices in the period 1999–2002:

i. increasing plant overcapacity due to new CCGT plant commissioning;
ii. increasing use of competitively priced imported coal;
iii. divestment of coal-fired plant by the mid-merit duopoly generators; and
iv. replacement of Pool with NETA.

In the remainder of this section, the main elements of the market mechanism underlying the Pool, and NETA, are briefly described, and the diversity of opinion about its impact is briefly surveyed. In the second section, the main regulatory interventions in the operation of the

[6] Annual average prices deflated by annual average Retail Price Index (excluding Mortgage Interest Payments).
[7] Edison Mission Energy also closed some pump storage units as NGC switched its contracting policy in the BM to make use of recently reinstated oil-fired capacity that had been mothballed under the Pool.

wholesale electricity market are discussed. Then the data, methodology, and results from a backward regression analysis of year-on-year changes in day-ahead wholesale prices under the Pool and NETA are described. In section four, conclusions are drawn about the regulatory implications of the findings.

1.1. Pool and NETA Compared

Trading in the wholesale electricity market, under both the Pool and NETA, can be broken down into three sequential phases, forward trading, day-ahead trading, on-the-day trading. Each of these phases is briefly described below but for a more detailed analysis of the Pool mechanism see Electricity Pool (1994a, 1994b, and 1998).

Day-ahead Market

Essentially, the Pool day-ahead market was a series of mandatory uniform price auctions, one for each half-hour of the day-ahead, operated by a centralised auctioneer with the objective of producing an optimal schedule of generating plant to meet demand. NETA replaced this process with decentralised voluntary bilateral contracting which could take place directly between generators, suppliers, and traders with generating plant self dispatched by each generator according to its contractual commitments.

The primary purpose of the day-ahead price setting process in the Pool was to produce a least-cost schedule of plants that would be dispatched by the National Grid Company (NGC) who operated the transmission system, to meet forecast demand in each half-hour of the next day. The deadline for submission of bids by generators was 10.00 a.m. on the day before dispatch with each generator submitting a nine part bid made up of three price-quantity pairs plus a price that was intended to cover the fixed cost of starting the plant, a no load price, and a must run flag that was used to indicate inflexible plant. Having received all the bids NGC then created a supply curve by 'stacking' the bids low-to-high to produce an optimal Unconstrained Schedule of plant for dispatch. The bid price at which the supply function intersected with NGC's forecast demand schedule for each half-hour of the next day set the System Marginal Price (SMP).

After SMP had been set, NGC also calculated an additional Capacity Payment that reflected the probability of supply failing to meet demand, the Loss of Load Probability (LOLP), and the estimated marginal value of that unserved load, the Value of Lost Load (VOLL) as follows:

$$\text{Capacity Payment} = \text{LOLP} \times (\text{VOLL} - \text{SMP})$$

Capacity Payments were therefore an entirely administered charge calculated from a formula that was intended to compensate generators for retaining marginal plant on the system, which they might have otherwise closed. To provide the appropriate signal, LOLP had been designed to increase exponentially as demand approached total available system capacity. As VOLL was set at £2000/MWh in 1990, with increases in subsequent years in line with Retail Price Inflation (RPI), this meant that Capacity Payments could potentially become a significant percentage of the total wholesale price, especially during the winter months when demand was highest. The Capacity Payment was added to SMP during each half-hour to produce the Pool Purchase Price (PPP) as follows:

$$\text{PPP} = \text{SMP} + \text{Capacity Payment}$$

All generators included in the Unconstrained Schedule received PPP for their output, comprising SMP plus Capacity Payments where applicable, regardless of what bids they had actually submitted. This 'Pay-SMP' approach resulted in those generators operating low cost, but inflexible, nuclear and CCGT capacity consistently bidding zero in order to ensure their plant(s) were called to run. For more than half of the Pool's existence (until 1996/97) this effectively left the setting of SMP, and therefore PPP, under the control of a duopoly of firms, National Power and PowerGen, which owned or controlled almost all of the mid-merit[8] coal-fired generation capacity.

Under NETA, day-ahead trading continues right up to Gate Closure, which is three hours before the relevant half-hour dispatch period.[9] As NGC is no longer responsible for producing a day-ahead dispatch schedule all generators, suppliers, and traders, must notify NGC of the

[8] Mid-merit plant usually only run during daylight hours when demand is relatively high, as opposed to baseload plant run continuously both day and night, or peaking plant that only run infrequently during periods of unusually high demand.

[9] This was reduced to 1 hour in July 2002, which is after the period considered in this paper.

quantity of electricity they intend to physically inject or withdraw from the transmission system in the relevant half-hour. The first notification is only indicative, known as Initial Physical Notification (IPN), and must be submitted by 11.00 a.m. on the day before dispatch. A subsequent firm Final Physical Notification (FPN) must then be submitted by Gate Closure. Although vertically integrated firms that operate both as generators and suppliers, they must submit separate notifications for their generation and supply business, not an aggregate net production or consumption figure. In other words, for operational purposes, NGC still regards a vertically integrated generator with a supply business as if it were two legally separate firms with each making an independent decision about the quantity of electricity they will contract for, as well as inject or withdraw, in any given period.

To facilitate day-ahead, and longer-term, trading two rival market operators (APX and UKPX) began operating screen-based exchange market places where bids and offers could be anonymously posted. Despite this, most trading migrated to an informal over-the-counter market, operated on the telephone and bulletin boards via brokers, and the liquidity and transparency of the day-ahead market is lower under NETA than the Pool. However, the UKPX publishes a Reference Price Day-Ahead (RPD) index that facilitates the comparison of day-ahead prices under NETA with those in the Pool. Given its relative transparency, RPD has been used in this paper as an indicator of the actual level of day-ahead prices under NETA.

On-the-day Market

Once PPP had been set in the Pool day-ahead market generators were notified by around 5.00 p.m. that their plant would be required to run the following day. However, they were not obliged to produce the quantity of electricity they had bid into the day-ahead market earlier that same morning. Having been informed of PPP, generators were then free to redeclare the physical availability of any and all of their plant right up to the moment of dispatch, though they were not allowed to change the prices they bid. Sometimes, this was necessary because of unexpected plant failures, and sometimes because the price of gas made it more profitable to withdraw CCGT plant and sell the gas into the gas market. Withdrawing capacity in the day-ahead market also had the effect of driving up LOLP, and as Bunn & Larsen (1992) show, since LOLP is an extremely convex function strategically withdrawing capacity to increase Capacity Payments would substantially increase the revenues earned by generators.

Patrick & Wolak (1997) note that a more high powered and difficult to detect strategy than just bidding high prices to set a high SMP would be to bid each plant at close to marginal cost and then declare capacity available in different periods throughout the day.

Withdrawing capacity on-the-day could also produce a price advantage for generators with a large plant portfolio by forcing NGC to dispatch another of their plants not included in the Unconstrained Schedule that had bid at a higher price. Given that dispatch of the final half-hour of each day took place some 36 hours after the original day-ahead bid was submitted this gave generators considerable freedom to adjust their bids.

As well as being uncertain about what plant would be available on-the-day, as compared to that declared day-ahead, NGC could not be sure precisely what the status of the transmission system would be in real-time. The occurrence of transmission constraints might also prevent certain plant being dispatched as planned, or require other plant to be brought into production that had not been included in the Unconstrained Schedule. Some uncertainty inevitably also existed as to what the precise level of demand would be on-the-day as compared with the NGC day-ahead forecast. The day-ahead schedule was therefore only a starting point for the operation of the system on-the-day of dispatch and any departure from that schedule would necessitate NGC incurring additional costs to meet outturn demand. This additional cost was covered by the Uplift element added to PPP to make up the final Pool Selling Price (PSP) as follows:

$$PSP = PPP + Uplift$$

Uplift contained three elements. Energy Uplift covered the incremental costs arising as a result of errors in demand forecasting by NGC that either required plant included in the Unconstrained Schedule to be stood down if they were no longer needed, plant not included in the Unconstrained Schedule to be dispatched when demand was higher than forecast. In addition, any plant not included in the Unconstrained Schedule, and not despatched, was compensated for making plant available to the system by way of an Availability Payment calculated in a similar way as Uplift but with an incentive for generators to bid as close to SMP as possible. However, the inclusion of LOLP in the calculation potentially allowed generators to raise Availability Payments in the same way as Uplift by withdrawing capacity:

$$\text{Availability Payment} = LOLP \times (VOLL - \max[SMP, \text{bid price}])$$

Transmission Services Uplift included the cost of redispatching plant where generators had adjusted their schedules, as well as the costs incurred by NGC in bilateral purchases of ancillary services such as black start, frequency response, voltage support, and spinning reserve necessary to maintain the integrity, reliability, and quality of electricity supplied on the transmission system. Reactive power Uplift, as the name suggests, covered the cost of purchasing reactive power, usually contracted for by NGC on the same basis as other ancillary services.

A central feature of NETA is that any costs imposed by departures from the production and consumption patterns declared at Gate Closure were to be met by the parties that were responsible for them, and not smeared across the industry as Uplift had been. If generators produce more, or consumers consume less, than they had declared in their FPN then the imbalance volume is sold by NGC at System Sell Price (SSP) in a real-time market operating in each half-hour dispatch period called the Balancing Mechanism (BM). Likewise if generators produce less than they declare, or consumers consume more, then NGC will seek to eliminate the imbalance by buying additional supplies at the System Buy Price (SBP).

Imbalance costs are therefore functionally equivalent to Energy Uplift plus that part of the Transmission Services Uplift cost that related to generators rescheduling plant. The remainder of Uplift is functionally equivalent to the Balancing System Use of System (BSUoS) charge. Unscheduled Availability Payments that were part of Uplift are no longer paid for the same reason as applied to Capacity Payments. Any under or over collection of revenue through the BM is redistributed via the Residual Cashflow Reallocation Cashflow (RCRC) element on a pro-rata basis according to the volume of electricity physically generated or consumed by each firm. This was substantially positive in the first few months of NETA's operation but gradually became negative in later months as generators deliberately held spare generation capacity off the market ready to run if any plant declared in the FPN failed, while suppliers deliberately overcontracted in the forward market in excess of their expected demand. In both cases these strategies were adopted in order to avoid paying SBP. The total cost of the BM varied from firm to firm but is calculated as follows:

$$\text{BM Cost} = \text{Imbalance Costs} + \text{BSUoS} - \text{RCRC}$$

A notional day-ahead price paid by a supplier under NETA that is functionally equivalent to PSP under the Pool can be calculated as follows:

$$\text{NETA Day Ahead Price} = \text{RPD} + \text{BM Cost}$$

Forward Market

In practice generators, suppliers and consumers under both the Pool and NETA did not rely on the day-ahead market to determine the price they paid or received. Instead, they hedged most (>90%) of their output and consumption via forward contracts signed months or often years ahead of dispatch. Despite the volume of electricity that was covered by contracts, forward markets were highly illiquid and largely limited to semi-annual contracting rounds, held in April and October. Forward market liquidity only improved as the number of consumers eligible to choose their own supplier gradually increased, the element of cost pass through reduced, and the ownership of generation fragmented.

In both the Pool and NETA, forward trading occurred on a bilateral basis through private over-the-counter (OTC) contracts. The main difference being that under the Pool forward contracting was restricted to trading in contracts for difference (CFDs) and exchange traded forward agreements (EFAs) that were not for physical delivery but settled in cash by reference to PPP on the relevant delivery day(s). All physical delivery took place through the Pool and contracted plant usually bid zero prices to ensure they were included in the Unconstrained Schedule. Under NETA, almost all forward contracts are for physical delivery rather than financial settlement. The bilateral nature of the NETA day-ahead market, with so-called 'what-you-bid-is-what-you-get' (WYBIWYG or Pay Bid) pricing, meant that baseload generators could no longer bid zero and allow marginal generators to set the price as they had in the Pool.

1.2. Divided Opinions

Opinion had always been divided over whether day-ahead prices had remained high because of weaknesses in the complex market mechanism that underlay the Pool or because of the exercise of market power by the dominant duopoly of National Power and PowerGen. Initially, Ofgem had been unconvinced that replacing the Pool trading mechanism with a

mechanism where each generator got paid their own bid (Pay-Bid), rather than a uniform marginal price (Pay SMP), would have a beneficial effect. Indeed, an Ofgem consultation on trading outside the pool in 1994 concluded that:

> In sum, paying generators their bid prices would represent a major change which seems likely to have disadvantages in terms of increasing risks, particularly to smaller generators, without a strong likelihood that prices will be lower. In the longer term it could lead to higher prices. (Ofgem July 1994)

However, by the time that the conclusions from RETA had been published in 1998 Ofgem's earlier misgivings about replacing the Pool appear to have been overcome. By the beginning of 1999, considerable momentum had built up to replace the Pool, with a bilateral market mechanism that was supposed to be closer to the operation of a traditional 'commodity market'. However, there was little empirical or theoretical evidence to support Ofgem's view that NETA would reduce wholesale prices. Despite this, an Ofgem press release on 27 January 1999[10] began with the headline "Pool prices must come down". This was followed, one week later, by another entitled "Reform of Electricity Trading Arrangements is a Priority". It is therefore clear that Ofgem was increasingly of the view that there was a strong link between the trading arrangements, under the Pool, and the exercise of market power by generators. This had inexorably lead to the conclusion that reforming the way that the market operated was the key to lower prices. Indeed, two years before NETA was actually implemented, Ofgem stated categorically that it believed it would result in prices some 13% lower than had previously prevailed (FT 1999).

Outside of Ofgem, doubts still remained about whether NETA was really necessary, or even if it would be effective in lowering prices, and some observers argued that reforming the industry structure was more important. For example, Green (1999) suggested that the problems of market power in England & Wales were really due to industry structure and not Pool trading arrangements that he believed sent the correct signals to generators. He went on to point out that under certain circumstances prices might be higher under NETA if Pool trading were retained. Bower & Bunn (2000) also suggested that generator market power would be enhanced under NETA, and that simpler reforms to the Pool, and a reduction in industry concentration in the generation sector, would be just as effective in lowering prices.

[10] Ofgem press releases commenting on the effectiveness of RETA/NETA are listed in the References section of this paper under "Ofgem" and can be downloaded at www.ofgem.gov.uk/public/press_releases.htm or http://www.ofgem.gov.uk/public/pressframe.htm

However, Currie (2002) argued strongly that NETA had already and would continue to bring about price falls, citing the fact that forward prices had risen in September 2000 when it was announced that the introduction of NETA was to be temporarily delayed until March 2001. He rejected the suggestion that gradual plant divestment had brought about the price falls, not changes to the trading arrangements, and suggested that if the Pool had remained in place changes to the industry structure would have made little difference to the "scope for collusion" by the mid-merit duopoly. The Ofgem Director General endorsed Currie's conclusions, and in a letter to the DTI (McCarthy 2001) went further by claiming that:

i. large industrial customers reported a fall in contract prices of 25 per cent over three years in anticipation of NETA, with a further 10 per cent since NETA's introduction;

ii. in the over-the-counter (OTC) market, in the first three months of NETA prices fell by 6 per cent for base load, and 21 per cent for peak load; and

iii. day-ahead base load prices had fallen by 24 per cent, on a weighted average basis, compared with the year before.

On the first day of NETA trading, the DTI issued a press release also suggesting that NETA had been responsible for reducing prices before it had been implemented:

> The previous Pool arrangement was deeply flawed – it was effectively a means of generators setting a wholesale price which suppliers and large consumers had little choice but to accept. It was no better than a generators' club. In contrast, NETA is a genuine market in which, for the first time, generators have to seek out customers, giving the electricity suppliers and large customers real choice... (DTI 2001)

Ofgem supported this conclusion with a press release in March 2001 claiming that "these reductions have been driven by the impending introduction of NETA" and reinforced it at the end of the first year of NETA trading in April 2002, with another press release again implying that NETA had caused wholesale prices to fall, well before it had been implemented, by as much as 40% since mid 1998. Both Ofgem and the DTI clearly believed that the mere announcement that NETA would replace the Pool had been sufficient to influence market expectations and that market participants had responded rationally by reducing forward prices in anticipation of competition increasing under NETA. Not only that, once NETA had begun trading those price reductions seen in the forward market began to be reflected in prompt day-ahead prices as well. Apparently convinced of the efficacy of NETA in promoting competition, Ofgem subsequently announced that it would be further enhanced

to include the trading of transmission rights and extended north of the border to include Scotland by 2004 in the form of the British Electricity Trading and Transmission Arrangements (BETTA)[11].

The industry remained less than convinced that NETA had had any real impact. As Maclaine (2001a) pointed out, baseload forward prices being traded during February 2001 for delivery in the month directly after the introduction of NETA (April 2001) were only £1.00–1.50 higher than for forward prices being traded for delivery in the month directly preceding the introduction of NETA (March 2001). Given that generators already knew that they would have to pay an extra £1/MWh of transmission charges under NETA, as compared to the Pool, this suggests that market participants expected there to be a rise in post-NETA day-ahead prices to compensate for the additional cost of transmission and the potential new risks of trading in the BM. However, there is no indication from these forward prices that market participants expected there to be a fall in day-ahead prices due to increased competition once NETA began trading. McClaine went on to suggest that fragmentation of ownership in mid-merit coal-fired generation capacity, the cancellation of the Eastern leasing arrangements on divested plant, and the increasing amounts of CCGT plant coming on stream may all have impacted prices well before NETA was implemented. He concluded that: "there is no clear proof that the new electricity trading arrangements will deliver lower prices" and that it might introduce a number of disadvantages. In a later article (Maclaine 2001b), he noted that over the first month of NETA trading, between 27 March 2001 and end of April 2001, forward prices had risen by 9%.

The industry consensus as to why this had occurred was that prices in the BM had been more volatile than expected. This was especially true for SBP which had frequently been over £100/MWh, as compared to an average of around £18/MWh for day-ahead RPD, and therefore the incremental risk of imbalance cash out prices was being passed on by generators along with the additional transmission charge. Indeed generators with very flexible plant were initially able to take advantage of the volatility by bidding their plant into the BM at very high prices though changes to NGC purchasing strategy in later months ameliorated this to some extent. By the time that the October 2001 contracting round had been concluded it

[11] Key documents relating to interim administrative wholesale pricing arrangements in Scotland after implementation of NETA, as well as plans to include transmission pricing in NETA, and eventually extend it to Scotland, are listed in the References section of this paper under "Ofgem" and can be downloaded at: www.ofgem.gov.uk/projects/betta_index.htm.

had become clear that NETA had not brought any significant benefit to consumers in terms of lower prices and overall prices had risen by a couple of percentage points since the previous year (Maclaine 2002).

In a preliminary analysis of the first year of NETA, Newbery (2002) concluded that it had been a "costly mistake that others should avoid" and by the time that Ofgem produced its formal review of the first year of NETA in July 2002 it appeared to have retreated from its earlier firmly held view that NETA was entirely, or mainly, responsible for the fall in prices between 1999/00 and 2001/02. It now appeared to accept that other factors could have played a part in the reduction in prices:

> Anticipation of NETA appears to have been a clear influence on the downward trend in forward contract prices from 1998. However, other factors, including further developments in the generation market, and a stable plant margin are also likely to have played a part. Over this period fuel prices have remained broadly constant (coal) or increased (gas) in real terms. Ofgem (July 2002).

A year after the introduction of NETA it was therefore still an open question, as to what the relative impact of replacing the Pool with NETA, industry restructuring, and the long series of additional regulatory interventions that occurred throughout the history of the Pool, had been on wholesale electricity prices in England & Wales.

2. REGULATORY INTERVENTIONS

The UK Government in the form of the Treasury, Competition Commission,[12] DTI, and Ofgem, intervened at various times, to modify the way that the wholesale electricity market operated in England & Wales from 1990 onwards. As a result, the Pool never really operated as a truly free market. In the absence of effective competition Ofgem was particularly active in controlling wholesale, and retail, prices through a series of regulatory interventions that had the implicit or explicit objective of placing a cap on prices. As Figure 2 shows, from 1996/97 onwards the frequency and duration of these regulatory interventions increased dramatically as compared with the previous six years.

2.1. Coal Contracts

On 31 March 1990, all of the coal-fired and oil-fired generating plant in England & Wales that had previously been under the control of the state-owned Central Electricity Generating Board (CEGB) were allocated ('vested') to two new companies, National Power, and PowerGen, in a 60:40 ratio.[13] The Regional Electricity Companies (RECs)[14] also had matching vesting contracts imposed upon them that obliged them to buy fixed amounts of electricity from the generators at a price that would provide a guaranteed margin to the generators and RECs. These vesting contracts, which lasted from 1 April 1990 to 31 March 1993, therefore effectively subsidised the UK coal industry by passing the cost of its deep-mined coal, which was higher than world prices, through to end users. Generators and RECs were therefore insulated from both the impact of high input prices as well as volatility in the Pool price.

During the term of these contracts the combined contractual volume of UK deep mined coal consumed by UK generators was 70 million tonnes per year, in 1990/91 and 1991/92, then 65 million tonnes for 1992/93. Despite direct intervention by the DTI in the negotiations, generators were unwilling to continue contracting for large tonnages of UK coal after 31

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[12] Formerly the Monopolies and Mergers Commission (MMC).

[13] For a chronology of the key events in the legislation, deregulation, privatisation, regulation of the UK electricity industry between 1988 and 2002 see *Electricity companies in the United Kingdom - a brief chronology* at http://www.electricity.org.uk/services_fr.html.

[14] RECs were vertically disintegrated from generation at vesting, as was the National Grid Company (NGC) that owned and operated the transmission system. Initially each REC operated exclusively in one of 12 regions, where it had monopoly control of the distribution system and monopoly rights to supply household and commercial consumers with peak demand below 1 MW, the so-called 'franchise market'. After 31 March 1993, the franchise market threshold was reduced to 100kW, and the RECs finally lost their remaining supply monopolies in 1998/99 when domestic and small commercial consumers were allowed to choose their own supplier.

March 1993 because of the prospect of coal plants increasingly being displaced by new entrant IPPs running CCGT plant. The deal that was eventually agreed saw contracted UK coal fall to 40 million tonnes for 1993/94 and 30 million tonnes for the following four years (Parker 2000). Thereafter, the UK coal industry essentially had to compete with imported supplies at world market prices and much of the remaining deep-mine capacity closed as a result. In 2000/01, total UK deep-mined coal production fell to 18 million tonnes, as compared to 34 million tonnes of imports (DTI 1990–2002a and 1990–2002b). Newbery (1995) argued that if a generator has sold forward contracts equal to the amount dispatched in a given period then its income is determined by the strike price of the forward contract not by the Pool price, and therefore it would have no incentive to raise SMP as this would not affect its revenue. Indeed the firm could do no better than bidding at short-run marginal cost.

Vesting contracts had a pro-competitive effect as they encouraged all generators to bid their plants as if the market were perfectly competitive. Thus vesting contracts reduced the incentive for mid-merit generators to exercise market power. As the volume of vesting contracts declined, the incentive for mid-merit generators to exercise market power in order to raise Pool prices increased. Indeed, as each anniversary of vesting approached pool prices did rise and the consensus view was that the duopoly generators used this as a signal to buyers that forward prices in the next contracting round would be above previous levels.

2.2. Pool Price Cap

As Pool prices had consistently risen since 1990 Ofgem had little choice but to place an explicit cap on them[15]. By threatening to refer the matter to the Competition Commission, Ofgem had extracted an undertaking from National Power and PowerGen that they would bid their plant in such a way as to ensure that mean annual demand weighted prices did not rise above £24.00/MWh on a time-weighted and £25.50/MWh on a demand-weighted basis (in October 1993 prices) for two years between 1 April 1994 and 31 March 1996. Although Pool prices did slightly exceed the target level in 1994/95 on a demand-weighted basis, they were a few percent below the cap on a time-weighted basis and no punitive action was taken. However, as plant owned by National Power and PowerGen had set SMP over 90% of the time throughout the duration of the cap, and outturn price levels had so precisely matched the

[15] Key documents relating to the regular inquiries into price levels, and interventions such as the imposition of a price cap, are listed in the References section of this paper under "Ofgem" and can be downloaded at http://www.ofgem.gov.uk/public/adownloads.htm#pool

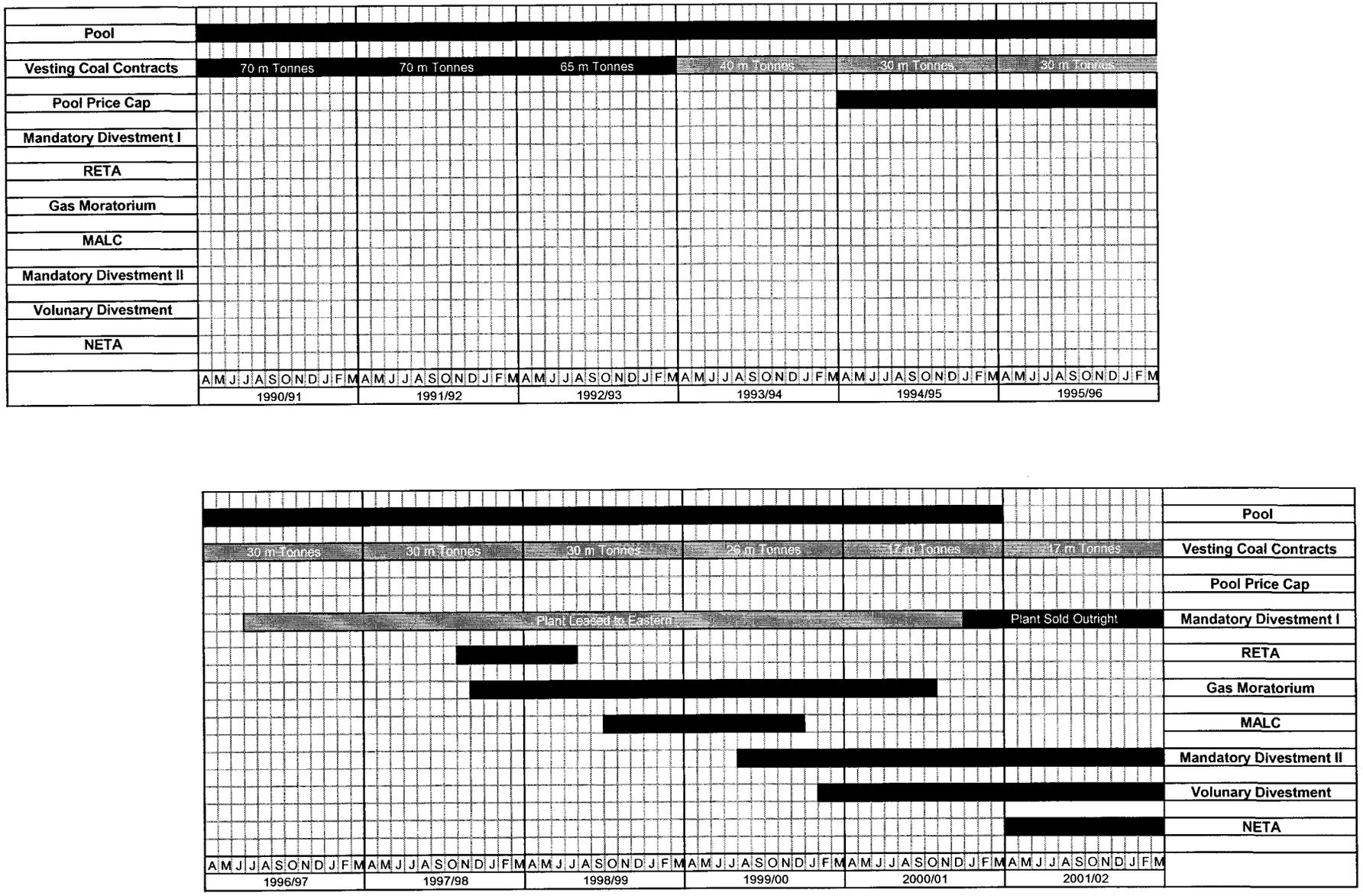
level agreed with the regulator some two years earlier, this suggests that they had exercised an extraordinary degree of control over the level of prices.

2.3. Plant Divestment

The Pool price cap was only ever intended to be a temporary measure and integral to a wider agreement reached by Ofgem with National Power and PowerGen that they would respectively divest 4000 MW, and 2000 MW of capacity in the intervening period. Eventually, all the capacity was leased, but not sold, to Eastern Electricity, a REC in mid 1996. The terms of these deals meant that Eastern paid a fixed charge, at the beginning of each year, plus a variable charge of around £6/MWh of output, that effectively raised its marginal production cost, and so prevented it being used to undercut the remaining National Power, and PowerGen, plant portfolio.

It was hoped that the plant divestment, to create a third mid-merit generating firm, would increase competition sufficiently to keep prices under control once the price cap was removed. However, despite the divestment of plant to Eastern, arithmetic mean annual PSP only fell by about £1/MWh over the next four years. Though prices had on average been lower in 1997/98 than under the Pool price cap, severe price spikes in winter of that year promoted a further round of investigations into the price setting behaviour of the duopoly generators which carried on for most of 1998. This was quickly followed by yet another investigation into the price spikes that occurred in January 1999. Almost as soon as this review had finished in May 1999 further spikes occurred in July, reported on in October of that year. Prior to the imposition of the price cap there had been a similar litany of investigation beginning as early as 1991, and it quickly became clear that this first round of plant divestment had only reduced mean annual prices slightly. Not only that, prices had become significantly more volatile, especially during the winter months. Green & Newbery (1992) had argued that five price-setting (i.e. mid-merit) generators would be sufficient to ensure a competitive market. Green (1996) extended the work to show that although there would be an increase in competitiveness of the market due to the partial divestiture it would not be as large as if the duopolists had been split into several much smaller firms. Fundamentally, the creation of a third, relatively small generator, left the market substantially more concentrated than it would have been had five equal sized generators been created and the empirically observed price response to the divestment is not surprising.

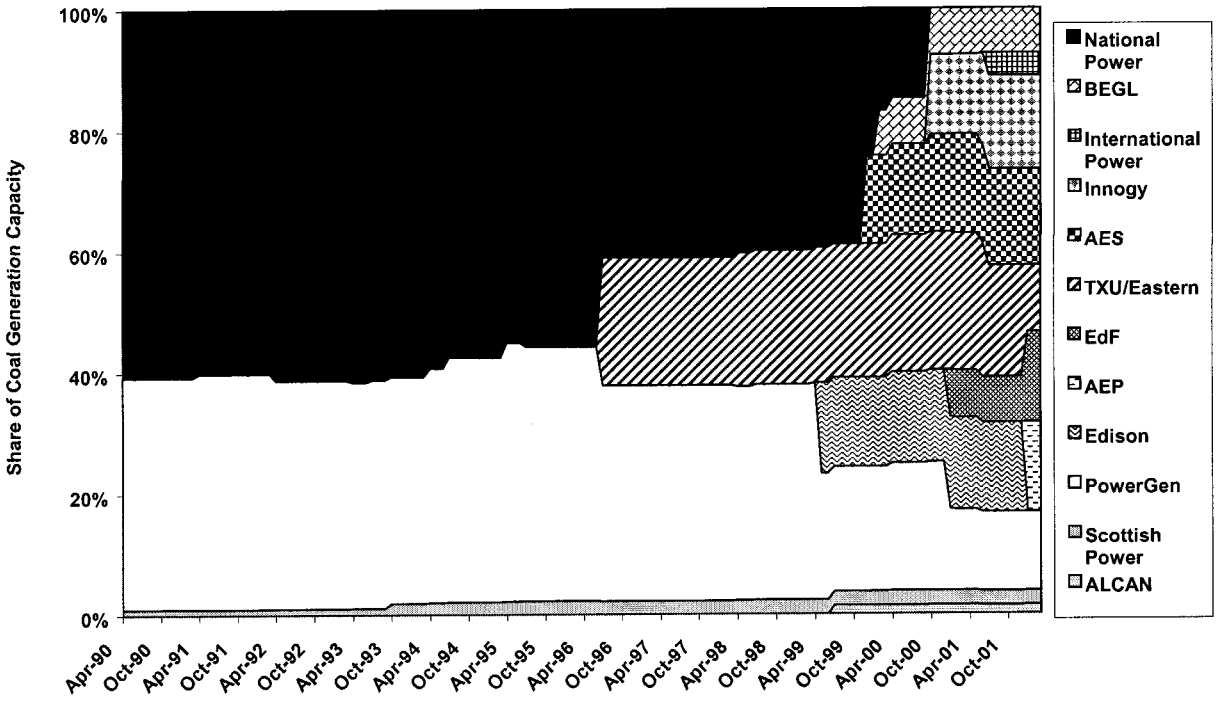
Figure 2: Major regulatory interventions in the wholesale electricity market 1990–2002



Ofgem and the DTI came under further pressure to take action and, simultaneous to the RETA public consultation process, they entered into a joint negotiation with National Power and PowerGen over further plant divestment. Eventually it was agreed that each firm would be allowed to vertically reintegrate its generation businesses with the supply business of a REC in return for further divestment of around 4000 MW of plant. As a result, PowerGen bought the retail supply business of East Midlands Electricity, in July 1998, and National Power bought the retail supply business of Midlands Electricity Board (MEB) in June 1999. Subsequently, PowerGen completed the sale of their Fiddlers Ferry (1960MW) and Ferrybridge (1956MW) plants in July 1999 to Edison Mission Energy. National Power likewise sold its Drax plant (3870MW) in November 1999 to AES. In each case the divestments amounted to approximately 40% of their respective coal-fired plant portfolios. In addition, it was agreed that all of the lease arrangements on Eastern plant that had previously been divested were to be cancelled in exchange for a one-off lump sum payment. Despite the public pronouncements about the likely effectiveness of NETA, the Ofgem/DTI actions to force further plant divestment suggest they were less than wholly confident that reforming the electricity trading arrangements would be sufficient to reduce prices to a competitive level.

After the second mandatory round of divestment, National Power and PowerGen management teams appear to have concluded that, in light of the prices that potential new entrants were willing to pay for existing coal plant, and in order to avoid further regulatory confrontation, it would be in the best interests of their shareholders to make further voluntary plant divestments. Over the next three years PowerGen reduced its capacity share of the coal generation sector down to 13% by divesting further plant to British Energy and the French utility EDF. Eventually, the entire firm was taken over by E.ON a German utility in July 2002. National Power reduced its coal generation capacity share to a similar level and then separated its now vertically integrated UK business from its international business to form two new companies, Innogy that was subsequently taken over by the German utility RWE in May 2002, and International Power. Eastern Electric also divested coal plant and a wave of generation asset trading, including CCGT and oil plants, took place throughout 2000/01 to 2001/02. The result was that, by the time NETA began trading, the coal-fired generation sector became fragmented between eight firms. The industry structure of the mid-merit coal-fired generation sector that prevailed during the first year of NETA was therefore starkly different to that over the life of the Pool, as shown in Figure 3.

Figure 3: Coal-fired generation capacity ownership structure 1990–2002



2.4. Review of Electricity Trading Arrangements

Beginning in May 1998, RETA was launched with the stated aim of developing an entirely new wholesale market mechanism to replace the Pool. Ofgem identified the following major weaknesses in the Pool trading arrangements:

i. price setting in the Pool is overly complex since it required the submission of at least nine different bid parameters for each genset with the merit order effectively produced from a 'black box' optimisation program that lacked transparency;

ii. capacity and availability payments reward generators for making plant available, not operating it, and it has limited value as a price signal to the generation or demand side of the market to respond to short-term changes in market conditions;

iii. bids do not reflect costs as many baseload generators consistently bid a zero price, so-called zero-zero bids, relying on the mid-merit generators to set SMP;

iv. prices have risen substantially, and become increasingly volatile, since the Pool began trading even though fossil fuel prices have fallen;

v. market liquidity, and the lack of publicly available price data for forward contracts, puts consumers at a disadvantage when negotiating forward cover against Pool prices;

vi. the non-firm nature of the day-ahead market transfers costs and risks of plant failures from generators to consumers, through Energy Uplift payments;

vii. the security of electricity supply is being threatened because generators can sign cheap 'interruptible' gas supply contracts, or sell gas from 'firm' gas supply contracts when spot gas prices rise, without paying a penalty in the electricity market; and

viii. the participation of the demand side in price setting is limited to a few very large industrial consumers.

Consumer groups had generally echoed these concerns in their submissions to RETA. Outside commentators had also made similar criticisms (Newbery 1997) and proposed a number of alternative models that Ofgem synthesised into the final NETA proposal which sought to address the weaknesses listed above by essentially adopting trading arrangements mimicking those in traditional commodity markets. These included:

i. simplifying generators' bids so that they are only for a given price, quantity, and delivery period which means that generators must internalise all the associated costs of start-up and fixed costs of operating a plant;

ii. eliminating capacity and availability payments;

iii. forcing all generators and consumers to compete more actively in setting market prices by introducing Pay Bid pricing;

iv. introducing screen-based trading, and a balancing market, to promote real-time price transparency and encourage independent price reporting as in other commodity futures markets;

v. making all bids and offers 'firm' which means that a generator must deliver, and a consumer take delivery, against their contracted positions, or face the uncertain consequences of the system operator (NGC) buying or selling in the balancing market, on their behalf, and passing the costs back to them;

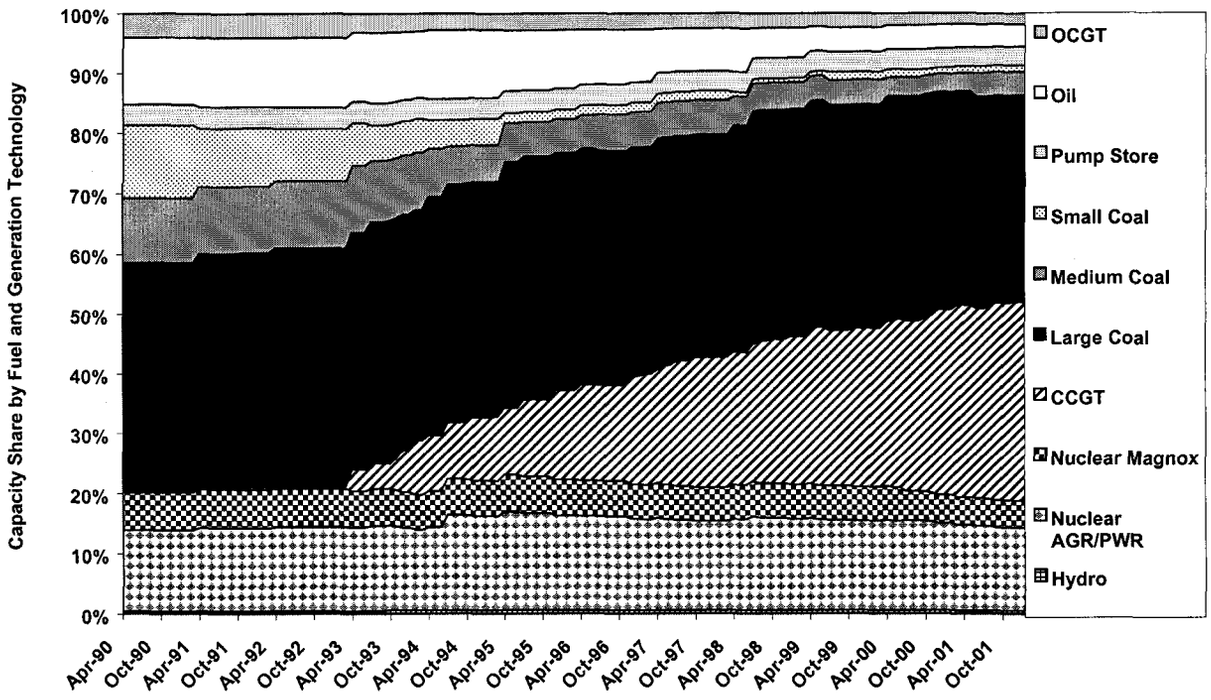
vi. imposing the full cost and risk of interruptible gas contracts and firm gas sales, back on the generators, and allowing the ISO to buy or sell in a balancing market against any under or over delivery against notified contract positions; and

vii. giving large consumers, and suppliers, an incentive to undertake active load and price risk management, and allow the ISO to buy or sell against any over, or under consumption, against their notified contract purchases.

2.5. Gas Moratorium

Demand-weighted average prices for coal bought by UK generators fell as volumes of low cost imported coal took an increasing share of the UK market. However, the guaranteed generation margin that vesting contracts provided had the unintended effect of encouraging incumbent generators, the RECS, and new entrants to build new CCGT plant. These early CCGT entrants were able to undercut small and medium sized coal plant, on a short-run marginal cost basis, and also displaced more efficient large coal plant from the baseload segment of the load duration curve. A combination of new entry by CCGT, and rising oil prices, also meant that much of the conventional oil-fired generation capacity was closed or mothballed under the Pool. Increasing thermal efficiency through rapidly advancing turbine technology, falling gas prices, falling capital costs, and relatively short construction times for CCGT lead to the 'dash for gas' that resulted in 22500 MW of new capacity being commissioned by 2002. Figure 4 shows the capacity share of each generation technology throughout the life of the Pool and first year of NETA. The technologies have been sorted according to their approximate marginal production costs and this shows how coal plant was displaced by the rapid entry of CCGT that amounted to around one third of total generation capacity by the end of 2001/02 and approximately 40% of generation output.

Figure 4: Capacity share by fuel and generation technology 1990–2002



By the mid 1990s, the DTI was becoming alarmed at the increasing dependence of the UK on gas-fired generation capacity and in November 1997, coincident with launching RETA, it imposed a moratorium on issuing of new CCGT plant construction licences. This was designed to provide a breathing space during which energy policy could be reviewed, especially in relation to UK coal, and a final decision to be made about whether to reform or replace the Pool trading arrangements. When the DTI published its final report in June 1998 (DTI 1998), it concluded that the growth in CCGT capacity, and depletion of gas reserves in the North Sea, meant that the UK was likely to become a net importer of gas by 2010. Moreover, growth projections to 2020 suggested gas could account for 60% of total UK primary energy consumption, and 75–90% of electricity generation fuel by 2020 (DTI 2000).

The main proposal coming out of the review was that the gas moratorium should continue until the electricity market had been reformed, on the grounds that if no action was taken "the country could effectively lose a coal option". The clear intention was to allow NETA sufficient time to reduce wholesale prices to a level that would make further CCGT investment unattractive and preserve the remaining coal-fired generation capacity. However, Ofgem disagreed with the Gas Moratorium policy and publicly stated that:

> The policy of restricting new entry into generation is now the main obstacle to a more competitive electricity market. A continuing threat to incumbents from new entrants is of the utmost importance in preventing collusion, and in ensuring that reforms to trading arrangements are successful and deliver benefits to consumers, particularly in the form of lower prices. (Ofgem 1999)

In practice, little could be done to increase the amount of UK coal contracted for by generators after 31 March 1998, even if all the existing coal-fired capacity remained open. Facing intense lobbying from foreign firms who wished to enter the UK electricity market with new CCGT plant, and without the support of Ofgem, the DTI had little choice but to abandon its policy. Once RETA had been completed, and the DTI and Ofgem had agreed the structure of NETA in October 1999, the gas moratorium was formally lifted in November 1999. As it did not cover plants already under construction, or that had already been licensed, the moratorium's impact was limited to delaying the construction of a few plants by a matter of a year to eighteen months.

Even if the gas moratorium had not been lifted, it is likely that compensating mechanisms in the fuel and capital markets would have rendered it unnecessary anyway. As Figure 1,

showed, the artificial cost advantage that CCGT enjoyed due to the coal vesting contracts had already been eroded by 1997/98 as the quantity of imported coal increased. Short-run marginal costs for coal and CCGT converged which meant that in the later years of the Pool and first year of NETA coal and gas were competing head-to-head for fuel share of the electricity market. Under NETA, the BM rewarded flexible plant that could run at short notice and generators reinstated oil plants to take advantage of occasional very high SBP, displacing lower cost but relatively inflexible CCGT and coal plants in the merit order.

2.6. Market Abuse Licence Clause

In the intervening period, between the completion of RETA and the introduction of NETA, Ofgem attempted to control the wholesale price of electricity by introducing a new market abuse licence clause (MALC) in generation licences.[16] The objective was to limit the scope for generators to exercise market power throughout the remaining life of the Pool, and for at least the first year after the introduction of NETA. However, there was no definition of what price level, or trading activity, would constitute market abuse. Indeed, Ofgem explicitly stated that it was against the introduction of any form of price regulation because it was "likely to stifle innovation, have harmful effects on competition by limiting the incentives on new entry into the market and, additionally, have a detrimental effect on the development of the forward contract market". However, the proposal effectively gave Ofgem absolute discretion to determine a maximum permissible level for wholesale market prices, and define any trading activity as market abuse. By introducing MALC, it appears that Ofgem was attempting to signal to generators that wholesale market prices would either be reduced to competitive levels by competition or, if necessary by regulatory intervention.

In effect, Ofgem gave generators little option but to accept MALC and reduce Pool prices. Only two generators refused to accept the modification to their generation licences, AES and British Energy, and both were immediately referred to the Competition Commission. However, the findings of the subsequent inquiry did not support Ofgem. The Competition Commission concluded that MALC was unnecessary in the context of the plant divestment that had taken place already, and further divestments that were likely to take place in future, as well as new entry by CCGT plant operators. It also noted the 17% fall in real terms in Pool

[16] Key documents relating to the introduction of MALC and the Ofgem response to the Competition Commission decision are listed in the References section of this paper under "Ofgem" and can be downloaded at: http://www.ofgem.gov.uk/public/pubframe.htm.

prices that had already occurred in the five years up to 1999/2000 (Competition Commission 2001). In the particular case of AES and British Energy, the Competition Commission noted that the behaviour of the two firms in forward contracting substantially all of their output on a long-term basis made it virtually impossible for them to exercise market power either by withdrawing capacity or raising the price at which they offered that capacity to the market.

In view of the Competition Commission decision, Ofgem was forced to remove MALC from all the generator licences that had already agreed to its introduction. However, the Ofgem Director General's comments in response to the decision reveals that he was far from certain that the plant divestment that had already taken place, and/or the introduction of NETA in a few months time, would be sufficient to deliver lower prices without MALC:

> I regard this as a substantial loss of measures needed by Ofgem to do our job. This is to the detriment of consumers whose protection is Ofgem's primary objective under the law. Ofgem will continue to look at other ways of tackling market abuse although none of these is likely to be as effective as the licence condition which we have now had to withdraw. (Ofgem 2001)

With the backing of the DTI, Ofgem attempted to reintroduce MALC by producing fresh proposals in August 2001 but in a form that might be more acceptable to the Competition Commission. However, as wholesale prices continued to fall throughout 2001/02, it became increasingly untenable to argue that MALC was needed in any form and the matter was quietly dropped.

3. ANALYSIS

In the first six years of the Pool's existence, up to the end of 1995/96, regulatory interventions fell into two distinct sequential phases. The first phase was the vesting contracts that were essentially driven by the UK Treasury's need to facilitate privatisation of the electricity industry and provide support to UK coal without recourse to public funds. The second phase was the imposition of the Pool price cap beginning on 1 April 1994. However, in the period from 1996/97 onwards, covering the last five years of the Pool and the first year of NETA, Ofgem and the DTI appear to have abandoned the earlier incremental approach to regulation in favour of a more aggressive multi-layered approach that manifested itself in a continuous stream of overlapping interventions. Against this background, the claims and counterclaims about the relative effectiveness of NETA in reducing wholesale prices, versus any of the other regulatory interventions that occurred over the same period, are difficult to assess.

3.1. Analytical Method

In the remainder of this section an attempt is made to measure precisely the significance, and quantify the impact on day-ahead prices, of each of the major regulatory interventions described above. To achieve this, dependent variables representing different functionally equivalent components of the wholesale price under the Pool and NETA are regressed on a range of explanatory variables representing each of the major regulatory interventions, as well as external factors such as weather, and plant investment. The objective is to identify which, if any, of these interventions were responsible for the year-on-year wholesale price changes that were observed over the period 1990/91–2001/02. Table 1 summarises the data sources, units, and time periods covered by each of the dependent and independent variables.

A backward linear least squares multiple regression procedure was applied to the variables in which the initial regression run contains all the candidate independent variables. The independent variable with the highest p-value (i.e. statistically least significant) is then eliminated and the regression repeated. The sequential elimination of insignificant independent variables is repeated until the p-values of all the remaining variables are equal to or less than 0.10. In other words, the final regression model only contains independent variables that have coefficients that are statistically significant at the 90% confidence level.

Wolfram (1998) analysed time series of Pool prices with a multiple regression approach to measure the impact of regulatory interventions on Pool price mark up over short-run marginal generation costs. From the results, she was able to conclude that generators were not taking full advantage of their ability to exercise market power, given the inelastic demand for electricity, but that they were modifying their behaviour in response to regulatory interventions, and that generators were restraining prices either to deter entry or stave off substantial regulatory action. Although the approach proposed in this paper does not attempt to replicate these results, this earlier study does indicate that it is feasible to detect the response of generators to regulatory interventions from an analysis of price time series and provides support for the choice of analytical approach. The construction of the variables, their analysis, and the results are discussed in detail throughout the remainder of this section.

3.2. Dependent Variables

The starting point for the analysis was the construction of Pool day-ahead wholesale price time series. Monthly arithmetic mean SMP, PPP, PSP, were collected from the period 1 April 1990 to 26 March 2001 (Electricity Pool 1990–2002). A Capacity Payment time series for the same period was calculated by subtracting SMP from PPP, and an Uplift time series calculated by subtracting PPP from PSP. NETA wholesale price time series were calculated for the period 1 April 2001 to March 2002.[17] Monthly arithmetic means for the day-ahead Reference Price Data index (RPD) was calculated from hourly data supplied by UKPX.

Capturing a representative value for the BM cost was more difficult since each firm pays (or receives) a different amount depending on the accuracy with which it forecasts its demand, and what contracting strategy it adopts before gate closure. As a result, a BM cost could only be estimated for a theoretical supplier that was assumed to be producing an unbiased forecast of its demand on a day-ahead basis, and deliberately purchasing contracts to cover 102.5% of its forecast demand. It was further assumed that the supplier carries out the final 2.5% of overcontracting in the day-ahead market at mean monthly RPD and that the actual outturn demand, faced by theoretical supplier on-the-day, is symmetrically distributed between 97.5% and 102.5% of its day-ahead demand forecast. Any overcontracted supply in excess of actual demand is subsequently sold ('spilled') at SSP in the BM.

[17] Pool prices for March 2001 are calculated up to 26 March 2001 when the Pool ceased trading. NETA began trading on 27 March 2001, but April 2001 monthly average RPD is calculated from 1 April 2001.

Table 1: Dependent and independent variables

Name	Underlying Time Series [1]	Frequency [2]	Units [3]	Data Source	Utilised
			Dependent Variables		
SMPRPD	SMP concatenated with RPD	Daily	£/MWh	SMP: Statistical Digest at www.elecpool.com, RPD: UKPX at www.ukpx.co.uk)	Y
PPPRPD	PPP concatenated with RPD	Daily	£/MWh	PPP: Statistical Digest at www.elecpool.com, RPD: UKPX at www.ukpx.co.uk	Y
PSPNETA	PSP concatenated with RPD and BM costs	Daily	£/MWh	PSP: Statistical Digest at www.elecpool.com, RPD: UKPX at www.ukpx.co.uk, BM: Elexon at www.bmrep	Y
CAPACITY	PPPRPD - SMPRPD	Daily	£/MWh	Own calculation	Y
UPLIFTBM	PSPNETA - PPPRPD	Daily	£/MWh	Own calculation	Y
			Independent Variables		
COALMC	(Mean price of coal purchased by UK generators in p/kWh / 33%) x 1000	Quarterly	£/MWh	DTI Quarterly Energy Prices at www.dti.gov.uk/energy/inform/energy_prices/	Y
CCGTMC	(Mean price of gas purchased by UK generators in p/kWh / 45%) x 1000	Quarterly	£/MWh	DTI Quarterly Energy Prices at www.dti.gov.uk/energy/inform/energy_prices/	Y
OILMC	(Mean price of oil purchased by UK generators in p/kWh / 30%) x 1000	Quarterly	£/MWh	DTI Quarterly Energy Prices at www.dti.gov.uk/energy/inform/energy_prices/	Y
COALCCI	Sum of squared % coal plant capacity owned by each firm	Monthly	Index	CEGB Statistical Year Book 1988/89, NGC Seven Year Statements at www.nationalgrid.co.uk/library/	Y
CCGTCCI	Sum of squared % CCGT plant capacity owned by each firm	Monthly	Index	CEGB Statistical Year Book 1988/89, NGC Seven Year Statements at www.nationalgrid.co.uk/library/	Y
OILCCI	Sum of squared % oil plant capacity owned by each firm	Monthly	Index	CEGB Statistical Year Book 1988/89, NGC Seven Year Statements at www.nationalgrid.co.uk/library/	Y
OCGTCCI	Sum of squared % OCGT plant capacity owned by each firm	Monthly	Index	CEGB Statistical Year Book 1988/89, NGC Seven Year Statements at www.nationalgrid.co.uk/library/	N
HYDROCCI	Sum of squared % hydro plant capacity owned by each firm	Monthly	Index	CEGB Statistical Year Book 1988/89, NGC Seven Year Statements at www.nationalgrid.co.uk/library/	N
PSTORECCI	Sum of squared % pump storage plant capacity owned by each firm	Monthly	Index	CEGB Statistical Year Book 1988/89, NGC Seven Year Statements at www.nationalgrid.co.uk/library/	N
INDCCI	Sum of squared % total plant capacity owned by each firm	Monthly	Index	CEGB Statistical Year Book 1988/89, NGC Seven Year Statements at www.nationalgrid.co.uk/library/	N
PMARGIN	(Plant Capacity - Annual Peak Demand) / Annual Peak Demand	Monthly	%	CEGB Statistical Year Book 1988/89, NGC Seven Year Statements at www.nationalgrid.co.uk/library/	Y
TEMPMEAN	Mean Monthly Air Temperature	Monthly	Celsius	DTI Digest of UK Energy Statistics at www.dti.gov.uk/energy/energystats/	N
TEMPHEAT	MAX (Mean Monthly Air Temperature - 15 , 0)	Monthly	Celsius	DTI Digest of UK Energy Statistics at www.dti.gov.uk/energy/energystats/	Y
TEMPCOOL	MAX (15 - Mean Monthly Air Temperature , 0)	Monthly	Celsius	DTI Digest of UK Energy Statistics at www.dti.gov.uk/energy/energystats/	N
TEMPDEV	Mean Monthly Air Temperature - Long Term Mean (1961-1990)	Monthly	Celsius	DTI Digest of UK Energy Statistics at www.dti.gov.uk/energy/energystats/	N
COALCONR	Publicly reported estimates	Annual	1000 tonnes	Parker, M. J. (2000) *Thatcherism and the Fall of Coal* and press archive searches	Y
COALCONI	Supply of UK deep-mined coal	Annual	1000 tonnes	DTI Digest of UK Energy Statistics at http://www.dti.gov.uk/energy/inform/energy_stats/coal/	N
CAP	Dummy Variable (April 1994 - March 1996)	Monthly	0 , 1	Ofgem Publications (www.ofgem.gov.uk/public/pubframe.htm) and press archive searches	Y
EASTLEASE	Dummy Variable July 1996 - December 2000)	Monthly	0 , 1	Ofgem Publications (www.ofgem.gov.uk/public/pubframe.htm) and press archive searches	Y
GASMORAT	Dummy Variable (December 1997 - October 2000)	Monthly	0 , 1	Ofgem Publications (www.ofgem.gov.uk/public/pubframe.htm) and press archive searches	Y
RETA	Dummy Variable (November 1997 - July 1998)	Monthly	0 , 1	Ofgem Publications (www.ofgem.gov.uk/public/pubframe.htm) and press archive searches	Y
MALC	Dummy Variable (October 1999 - December 2000)	Monthly	0 , 1	Ofgem Publications (www.ofgem.gov.uk/public/pubframe.htm) and press archive searches	Y
NETA	Dummy Variable (April 2001 - March 2002)	Monthly	0 , 1	Ofgem Publications (www.ofgem.gov.uk/public/pubframe.htm) and press archive searches	Y

Notes:
1. All underlying time series were transformed by calculating year-on-year monthly changes to produce the dependent and independent variables
2. Frequency corresponds to that in underlying time series that were converted to a common monthly frequency before producing the dependent and independent variables
3. Units correspond to those in the dependent and independent variables

The theoretical firm is therefore never exposed to SBP, but is on average purchasing 2.5% of its day-ahead forecast demand at mean monthly RPD, in the day-ahead market, and then selling it at SSP in the BM. The cost of imbalances is therefore equal to the difference between RPD purchase price and the SSP sale price multiplied by the volume of over contracting. Although this is a simplifying assumption, it captures the forward contracting strategy that has increasingly being adopted by supply firms, and represents the costs that would have been faced by those employing state-of-the-art forecasting methods. Daily data for BSUoS, RCRC, and SSP were collected from Elexon[18] and monthly arithmetic mean time series constructed for each over the period 1 April 2001 to 31 March 2002. Mean monthly BM costs were then calculated from the following formula:

$$\text{BSUoS} + \text{RCRC} + (\text{RPD} - \text{SSP}) \times 2.5\%))$$

Raw wholesale price time series for the period 1 April 1990 to 31 March 2002 (144 monthly observations) covering the entire history of the Pool and first year of NETA were constructed by concatenating the following combinations of raw time series data described above:

i. SMP and RPD

ii. PPP and RPD

iii. PSP and RPD plus BM Cost

These series were then transformed to produce three dependent variables, respectively called SMPRPD, PPPRPD, and PSPNETA, each consisting of a series of 132 monthly year-on-year price changes, using the following formula:

$$P_{\text{Differenced}} = P_{\text{Current Month}} - P_{\text{Month -12}}$$

A CAPACITY variable consisting of monthly year-on-year changes in Capacity Payments was constructed by subtracting the SMPRPD series from the PPPRPD series. Likewise, an UPLIFTBM series, consisting of monthly year-on-year changes in Uplift Payments and BM costs, was constructed by subtracting PPPRPD from PSPNETA.

[18] Elexon is the firm that was set up to oversee clearing and settlement of trades in the BM. Summary data are available on the www.bmreports website, however, I am grateful for the generous assistance of an anonymous third party who made a more detailed dataset available to me in electronic form that was used in this paper.

3.3. Independent Variables

As for the dependent variables the process began by constructing time series consisting of 144 monthly observations stretching from 1 April 1990 to 31 March 2002.

To capture the impact of changes in ownership of generation capacity, the fuel source, registered capacity, and ownership of every power plant connected directly to the transmission system of England & Wales[19] was tracked on a monthly basis using publicly available data published by CEGB (1989), NGC (1991–2002), Electricity Association (1991–2001), Power UK (1994–2002), as well as press archive searches. In the absence of contradictory data, plant closures were assumed to take place on 31 March, which is the deadline imposed by NGC on generators to declare plant as Transmission Contracted for the following year. Commissioning of new plant, especially CCGT is assumed to take place on the first day of the month following that in which plant testing and final hand-over from the contractor to generator were completed. The evolution of capacity on interconnector transmission circuits that allow imports from France and Scotland into England & Wales was tracked from the same sources as for plant capacity.

A Capacity Concentration Index (CCI) was then calculated on a monthly basis for Coal, CCGT, Nuclear, and Oil plant, by summing the squared capacity share of each firm for each plant type. A CCI for the entire industry was also calculated by summing squared shares of total capacity owned by each firm, regardless of plant type. However, as changes in the Industry CCI essentially tracked the change in CCI of the underlying plant technologies this variable was not used in the final analysis in order to avoid multicollinearity between variables. The Open Cycle Gas Turbine (OCGT) CCI was not used because these small auxiliary plants were generally operated from the same site as coal plant and changes in OCGT CCI were therefore highly correlated with changes in Coal CCI. The CCI for hydro, and pump storage, plant were also calculated but not used as both were constant throughout. Interconnector capacity from France was included in the nuclear CCI, and interconnector capacity from Scotland was split on a pro-rata basis between hydro and coal capacity to reflect the interconnector shares and generation capacity held by the two Scottish generators,

[19] This Transmission Contracted Plant excludes the embedded generation capacity connected directly to local distribution systems, which was excluded from the obligation to submit bids into the Pool.

Scottish & Southern Energy and Scottish Power respectively. Any dual fuel plant on the system was assumed to be burning coal and included in the Coal CCI.

The CCI is non-linear with a theoretical maximum of 10,000 if one firm owns all of the capacity of a given type and zero if that capacity is spread between an infinite number of firms. It is therefore identical in concept to the Hirschman-Herfindahl Index (HHI), commonly used by competition authorities to measure the impact of industry concentration. The only difference being that the sum of squared market shares in an industry, used in the HHI, has been replaced with the sum of squared capacity shares in the CCI. At the inception of the Pool in 1990, National Power, and PowerGen, owned all the coal-fired generation capacity in an approximate 60:40 ratio, corresponding to a Coal CCI of around 5200. By 2001/02 the Coal CCI had fallen to around 1400 because of plant divestment. By comparison, an industry with coal capacity split equally between 5 firms, as proposed by Green & Newbery (1992), would have resulted in a Coal CCI of 2000. As the first CCGT plant in existence did not become fully operational until around November 1991, the CCGT CCI is assumed to be 10,000 before this date and thereafter until the second CCGT plant came on stream in April 1993 when the CCGT CCI begins to fall rapidly.

Short-run marginal generation costs were calculated for Coal, CCGT, and Oil plants based on the average cost of each fuel used in UK power stations, and the estimated thermal efficiency for a marginal plant of each type, as reported in DTI statistics (DTI 1990–2002a and DTI 1990–2002b) using the following formula:

Marginal Generation Cost = (Fuel Price in p/kWh / Thermal Efficiency in %) x 1000

Average thermal efficiencies have gradually increased for the entire fleet of UK Coal plant from 34% to 36% and for CCGT from 43% to 50%, over the period 1990–2001 but marginal thermal efficiency data were not reported. For simplicity, it has been assumed that they remained constant at 33% for coal, 45% for CCGT, and 30% for oil.

Data on annual tonnages of UK deep-mined coal production were also collected from DTI statistics (DT1 1990–2002a and DTI 1990–2002b) in an attempt to estimate annual contracted volumes of UK coal sold to power generators. However, after some preliminary

testing it was found that contracted tonnages reported by Parker (2000), and drawn from searches of press archives, were a relatively more powerful explanatory variable.

The impact of new entry was modelled by estimating the plant margin for each month. As data on total system demand, and the quantity of plant available to the system after outages were not available, a proxy was estimated from total plant capacity and annual peak demand (NGC 1991–2002) and (EA 1991–2001) as follows:

$$\text{Plant Margin}_{\text{Mthly}} = (\text{Plant Capacity}_{\text{Mthly}} - \text{ACS Peak}_{\text{Yrly}}) / (\text{Plant Capacity}_{\text{Mthly}} \times 100)$$

The final quantitative variable considered was temperature. To capture its effect on prices, mean monthly temperature data as well as deviations from the long-term mean were collected. Mean Heating Degree and Mean Cooling Degree parameters were also calculated from the following formulas:

$$\text{Mean Heating Degrees} = \text{Max}\ (15 - \text{Mean Monthly Temperature}, 0)$$
$$\text{Mean Cooling Degrees} = \text{Max}\ (\text{Mean Monthly Temperature} - 15, 0)$$

After preliminary analysis, it became apparent that Mean Heating Degrees was the only significant temperature variable, and the others were discarded. This is consistent with UK peak electricity demand occurring in the winter, but this variable captures any increase in electricity demand above and beyond that normal winter seasonal pattern. As UK winter temperatures are generally higher than for similar north European latitudes, periods of unusually cold temperatures tend to have a disproportionate effect on demand for electricity, and hence price. Though the majority of UK space heating is from gas-fired and oil-fired boilers, relatively inefficient electrical appliances are often used to meet incremental heating demand above normal winter levels, especially for domestic and small commercial users.

Regulatory interventions including the Pool price cap, RETA, MALC, Gas Moratorium and NETA are modelled as qualitative factors with dummy variables taking a value 1, for each month that an intervention was in place, and 0 in months where it was not. For example, NETA is represented by a dummy variable taking a value 1 in the twelve months from 1 April 2001 to 31 March 2002, and 0 in all preceding months. The period covered by the lease

arrangements on the plant divested to Eastern was also modelled with a dummy variable but the concentration effect of the disposal was also separately accounted for in the Coal CCI.

As with the dependent variables, all of the raw time series described above were transformed to construct a set of independent variables, each consisting of a time series of 132 monthly year-on-year changes.

3.4. SMP-RPD Results

The SMPRPD series was analysed by backward regression, as described above, and a summary of the resulting coefficients and selected test statistics is set out in Table 2.[20]

Table 2: SMPRPD regression output

Variable	Coefficient	Std. Error	t-statistic	p-value
CAP	-1.7893	0.8997	-1.9887	0.0489
CCGTCCI	0.0010	0.0003	3.6285	0.0004
COALCCI	0.0019	0.0008	2.2951	0.0234
COALCONR	-0.0002	0.0001	-2.5949	0.0106
NETA	3.8931	1.4710	2.6466	0.0092
OILCCI	0.0056	0.0010	5.6266	0.0000
OILMC	-0.3356	0.0899	-3.7331	0.0003
C	1.3765	0.4573	3.0100	0.0032

R-squared	0.4011	Mean dependent var	-0.0167
Adjusted R-squared	0.3672	S.D. dependent var	4.3227
S.E. of regression	3.4385	Akaike info criterion	5.3667
Sum squared resid	1466.1075	Schwarz criterion	5.5414
Log likelihood	-346.1991	F-statistic	11.8617
Durbin-Watson stat	1.3775	Prob(F-statistic)	0.0000

The most important result is for the NETA variable that suggests that the introduction of NETA had no effect on curtailing the exercise of market power and/or reducing SMP. The NETA variable is statistically significant at the 99% level (p-value of 0.0092) but it does not support the Ofgem contention that NETA caused prices to fall because the coefficient is both large and positive. Instead, it is consistent with a rise of £3.89/MWh in day-ahead prices if NETA had been implemented alone, in the absence of other mitigating factors. To be

[20] The results published in this paper were generated using *Eviews 4.0* software. As a crosscheck for accuracy and consistency the analysis was repeated using *StatPro* software that produced identical results to two decimal places.

consistent with a price reduction, the NETA coefficient should have been negative, or if it had made no difference to prices, it should have been close to zero and/or eliminated from the final regression model by virtue of a low statistical significance.

In contrast, the COALCCI variable is statistically significant at the 97% level (p-value of 0.0234) and also has a magnitude and direction that are consistent with a fall in day-ahead prices brought about by divestments. Over the entire period 1 April 1990 to March 2002 the Coal CCI fell by 3856 which, when multiplied by the COALCCI coefficient value, represents a price fall of £7.14. The COALCONR coefficient is also statistically significant and shows that there was a reciprocal (negative) relationship between the tonnage of UK coal that generators contracted for and day-ahead prices. This result supports the previously cited academic research conclusions, and the empirical observation that vesting contracts made the market more competitive with Pool prices rising as contract volumes decreased. As the total annual tonnage of UK coal contracted for over the life of the Pool and NETA fell by around 53 million tonnes the COALCONR coefficient is consistent with a rise of £8.80/MWh in the absence of other mitigating factors.

The CAP coefficient is negative and shows that the Pool price cap caused a temporary reduction in SMP of around £1.94 that was reversed immediately after it was lifted. The lack of statistical significance in the COALMC coefficient is not surprising given that Pool prices were consistently well above short-run marginal generation costs. Indeed, the absence of COALMC as a significant variable is consistent with the exercise of generator market power in an imperfectly competitive market. If a fully competitive market had been operating, especially over the life of the Pool, then COALMC coefficient should theoretically have been close to 1 because any change in marginal coal-fired generation costs would have instantaneously been reflected in a change in electricity prices of an equal magnitude.

Taken together, the significance, magnitude, and direction of the COALCCI, COALCONR, CAP, and COALMC coefficients confirm the widely held view that, the coal-fired generation duopoly of National Power and PowerGen was able to exercise a considerable amount of market power in the Pool. This was especially so after 31 March 1993 when the vesting Coal contracts expired. Furthermore, the results suggest that without the ameliorating effects of the Pool price cap, followed by the multiple rounds of plant divestment from 1996 onwards, the

two firms would have continued to exercise significant market power and raise SMP significantly above the levels that were actually observed.

The CCGTCCI, OILCCI, and OILMC variables are more difficult to explain in the context of the exercise of market power by mid-merit coal-fired generators. Since CCGT normally ran as baseload plant, and oil plant marginal costs rose to such an extent that it quickly became so uneconomic that much of it was closed or mothballed after 1993/94, neither plant type played a significant role in price setting under the Pool. However, the result suggests that entry by CCGT plant, and the convergence of coal and gas marginal generation costs in the later years of the Pool, may have had a more significant impact on prices than has previously been acknowledged. For oil plant, the CCI remained almost constant throughout the life of the Pool but fell during the first year of NETA's operation when one plant was sold to a new entrant in 2001. The inherent flexibility of oil-fired plant has made it an important factor in the operation of the BM once NETA was introduced and the statistically significant OILCCI supports the empirical observation that oil plants displaced inflexible coal plant at the margin in both the day-ahead market, and BM, under NETA. This may have been encouraged by NGC because of the way in which it changed its contracting strategy for reserve capacity that allowed oil-fired plant to cover their fixed costs associated with ramping up their boilers to operating temperatures[21]. The unexpected reinstatement of partially mothballed oil plant also effectively increased total available generation capacity, especially on a day-ahead and on-the-day basis, which may have put further downward pressure on prices in 2001/02.

As the pricing of long-term gas supply contracts signed by new entrant IPPs were partly indexed to oil prices, the negative OILMC coefficient probably reflects the cross-price elasticity between coal and gas. Long-term take-or-pay gas contracts signed by operators of the early CCGT plants were indexed to oil, and still are across much of Europe. Given the physical pipeline interconnection of the UK and European gas markets via the Bacton-Zeebruge pipeline across the North Sea, this tends to lead to a rise in both forward and day-ahead UK gas prices as oil prices rise. CCGT operators tend to curtail electricity generation whenever it is more profitable to sell their contracted gas supplies rather than convert it to electricity. This reduces the availability of CCGT capacity, especially in winter peak demand periods, with the shortfall generally taken up by marginal coal plant capacity. This has

[21] That is the cost of fuel burnt in the initial heating stage before electricity can be produced.

especially been the case since short-run marginal generation costs for CCGT and coal converged in 1997/98.

An earlier version of these results (Bower 2002) prompted significant feedback from the industry and other sources. The consensus view was that RPD was not the functional equivalent of SMP, but that it had in reality replaced PPP. The ensuing discussion gave rise to three observations:

i. excluding the impact of other factors, the industry expected RPD to be higher than SMP as generators sought to offset the loss of Capacity Payments, and the imposition of an additional transmission charge[22], after NETA was introduced;

ii. the duopoly generators were able to exercise market power in the Pool by interchangeably choosing to either increase SMP or the Capacity Payment component of PPP;

iii. if the introduction of NETA had no impact, and excluding the impact of other factors, then the level of RPD under NETA should not have been significantly different from the level of PPP under the Pool.

The SMPRPD regression model, summarised in Table 2, does appear to support the first observation that, excluding the impact of other factors, RPD was higher than SMP because generators were attempting to offset the loss of Capacity Payments and the increased transmission cost, when NETA was introduced. Subtracting the £1.00/MWh extra transmission cost from the £3.89/MWh increase indicated by the NETA coefficient suggests generators would have raised RPD by £2.89/MWh to compensate for the loss of Capacity Payments, had it not been for other mitigating factors. Given the standard error of £1.47/MWh on the NETA coefficient, and that mean Capacity Payment was £1.99/MWh over the life of the Pool, the result therefore appears to support the industry view. In the absence of other mitigating factors, generators would have rationally responded to NETA by maintaining RPD at least at a level that offset the loss of Capacity Payments, and the introduction of the additional transmission charge. However, even if this interpretation is not correct, the result still does not support the Ofgem contention that NETA caused day-ahead prices to fall. At best, the result suggests that changing the market mechanism from Pool to NETA had no impact on the revenues that generators received in the day-ahead market.

[22] Under the Pool consumers paid the cost of transmission from the 'station gate' to the 'grid supply point' where the electricity is converted to a lower voltage for consumption but under NETA generators pay 45% of this cost.

Though a coherent and consistent explanation of the results can be presented for the SMPRPD regression model, its robustness is somewhat weakened by the Durbin Watson statistic that indicates marginally significant serial correlation between the regression residuals. In addition, the statistically significant constant term in the model indicates an arithmetically increasing long-term trend in day-ahead prices, of the order of £1.38/MWh per annum. This cannot easily be explained by reference to economic theory, or empirical observation, and may have arisen because the constant term is acting as a proxy for other dependent variables not included in the initial run, or variables that were subsequently excluded. To address these issues, and to test the industry hypothesis observation that PPP and RPD would have remained approximately equal if NETA had had no effect, an alternative regression model was developed but with PPPRPD replacing SMPRPD.

3.5. PPP-RPD Results

Analysing the PPPRPD series in exactly the same way as for the SMPRPD series described above produced the results summarised in Table 3.

Table 3: PPPRPD regression output

Variable	Coefficient	Std. Error	t-Statistic	p-value
CCGTCCI	0.0014	0.0005	2.8566	0.0050
COALCCI	0.0018	0.0011	1.7313	0.0859
COALCONR	-0.0003	0.0001	-2.3563	0.0200
GASMORAT	3.4807	1.3090	2.6592	0.0089
OILCCI	0.0036	0.0013	2.7613	0.0066
TEMPHEAT	0.6348	0.3528	1.7995	0.0744
C	0.9804	0.8037	1.2198	0.2248

R-squared	0.2082	Mean dependent var	-0.0213
Adjusted R-squared	0.1702	S.D. dependent var	6.5336
S.E. of regression	5.9515	Akaike info criterion	6.4568
Sum squared resid	4427.6119	Schwarz criterion	6.6096
Log likelihood	-419.1456	F-statistic	5.4794
Durbin-Watson stat	1.6710	Prob(F-statistic)	0.0000

Not surprisingly, the COALCCI, CCGTCCI, and OILCCI coefficients, identified as significant in the SMPRPD model, remain in the PPPRPD model. This confirms the importance of concentration in the ownership of plant capacity as a key driver of day-ahead prices. However, the most significant change from the SMPRPD regression model is that the

NETA variable is no longer statistically significant. This indicates that in the absence of other factors, RPD under NETA would have been at a similar level to PPP under the Pool. This observation appears to confirm the industry observation that under NETA generators would have raised RPD above the level of SMP to compensate for the loss of Capacity Payments.

The inclusion of the TEMPHEAT as a new coefficient in the PPPRPD model, not in the SMPRPD model, is consistent with the operation of the LOLP calculation that increased the Capacity Payment component of PPP as plant margin fell. The direction and magnitude of the coefficient reflects the short-term impact of unusually cold weather on electricity demand for heating in winter and suggests that PPP rose by approximately £0.63/MWh for each 1 degree Celsius that mean monthly temperatures fell below the normal winter level. However, the impact is relatively small as the unusually warm weather in the months December–February of 2001/02 appears to have only contributed a £0.60/MWh reduction in RPD below the PPP of the previous year.

The GASMORAT coefficient indicates that the gas moratorium allowed generators to raise PPP by £3.48/MWh. Although it was only a temporary intervention, given that the moratorium was imposed shortly after coal and gas marginal generation costs had converged, this result supports the Ofgem view that the threat of new entry by CCGT helped to curtail the exercise of market power by the duopoly generators. The coal-fired duopoly appears to have responded rationally to the initial DTI announcement that it intended to leave the moratorium in place for an extended period by raising prices. The fact that GASMORAT affected PPP, but not SMP, also indicates that the price impact came through an increase in Capacity Payments. This again confirms the industry observation that the coal-fired duopoly exercised market power by interchangeably raising bid prices to increase SMP and or withdrawing generation capacity to raise Capacity Payments.

Overall the PPPRPD result appears to be more robust than the SMPRPD result because all of the significant variables included in the model, as well as their magnitude and direction, are consistent with economic theory and empirical observation. In addition, the Durbin Watson statistic now indicates that the serial correlation in the residuals of the SMPRPD model has been eliminated. Finally, the unexplained arithmetic upward trend, previously indicated by the statistically significant constant term in the SMPRPD model, does not appear in the

PPPRPD model. To further confirm the robustness of the conclusions from the PPPRPD model, a model of the CAPACITY variable was also developed as summarised in Table 4.

Table 4: CAPACITY regression output

Variable	Coefficient	Std. Error	t-statistic	p-value
CAP	3.1956	0.9041	3.5346	0.0006
CCGTMC	-1.4596	0.3862	-3.7798	0.0002
COALCCI	-0.0020	0.0008	-2.6530	0.0090
PMARGIN	-0.3887	0.1391	-2.7948	0.0060
RETA	2.2270	1.0084	2.2085	0.0290
TEMPHEAT	0.4124	0.2420	1.7044	0.0908
C	-0.7144	0.4369	-1.6351	0.1045

R-squared	0.2773	Mean dependent var	-0.0046
Adjusted R-squared	0.2427	S.D. dependent var	4.6240
S.E. of regression	4.0241	Akaike info criterion	5.6741
Sum squared resid	2024.1745	Schwarz criterion	5.8269
Log likelihood	-367.4875	F-statistic	7.9954
Durbin-Watson stat	1.8788	Prob(F-statistic)	0.0000

The inclusion of TEMPHEAT and PMARGIN coefficients in this CAPACITY model is consistent with the response of Capacity Payments to cold weather, and changes in plant margin, respectively, and also confirms the hypothesis that the mid-merit duopoly could respond to a fall in SMP by withdrawing capacity to increase Capacity Payments. In this respect the CAP coefficient indicates Capacity Payments increased by around £3.20/MWh when the Pool price cap was imposed and that this therefore more than offset the £1.79/MWh reduction indicated by the CAP coefficient in the SMPRPD model. This explains why CAP was not significant in the PPPRPD model, and is also consistent with the empirical observation that overall Pool prices did not fall under the Pool price cap.

The positive RETA coefficient suggests that, rather than reducing prices, the regulatory scrutiny that the review brought simply caused generators to change bidding strategies in order to increase Capacity Payments. Likewise, the negative COALCCI and CCGTCCI coefficient also indicates that as SMP fell due to increased competition caused by plant divestment, and new entry by CCGT burning lower priced gas, from 1996/97 onwards the duopoly generators responded by withdrawing marginal capacity to produce an offsetting rise in Capacity Payments.

3.6. PSP-NETA Results

The analysis presented so far focuses on the revenues earned by generators, in the form of SMP, PPP, and RPD, but NETA was motivated by concerns over rising prices to consumers not the revenues of generators. It is therefore still possible that although NETA may not have affected SMP or PPP it could have had some effect on the final day-ahead wholesale price being paid by suppliers and ultimately passed on to consumers. To complete the analysis, a PSPNETA regression model was developed, as described previously for SMPRPD and PPPRPD, with the results presented in Table 5.

The PSPNETA model is less rich than the PPPRPD model, as it contains fewer variables. However, it echoes the previous conclusions, and confirms that NETA played no significant role in reducing prices paid by suppliers. Not surprisingly, the CCGTCCI, COALCONR and GASMORAT variables remain from the PPPRPD model. However, CCGTMC comes in with COALCCI, OILCCI, and TEMPHEAT variables excluded. Though this model explains much less of the variability in the underlying data than the previous models it is still robust in the sense that the variables that are included are statistically significant, the Durbin Watson statistic indicates that there is no serial correlation in the residuals, and the constant plays no significant role as an unexplained variable.

Table 5: PSPNETA regression output

Variable	Coefficient	Std. Error	t-Statistic	p-value
CCGTCCI	0.0014	0.0005	2.6202	0.0099
CCGTMC	-1.2507	0.6691	-1.8692	0.0639
COALCONR	-0.0003	0.0001	-2.4237	0.0168
GASMORAT	3.9247	1.4803	2.6512	0.0090
C	-0.4645	0.7198	-0.6453	0.5199

R-squared	0.1569	Mean dependent var	-0.0567
Adjusted R-squared	0.1303	S.D. dependent var	7.2628
S.E. of regression	6.7732	Akaike info criterion	6.7010
Sum squared resid	5826.2367	Schwarz criterion	6.8102
Log likelihood	-437.2633	F-statistic	5.9065
Durbin-Watson stat	1.7059	Prob(F-statistic)	0.0002

To test the PSPNETA results further a model of the UPLIFTBM variable was also developed. This contains many more variables than the PSPNETA model, as indicated in Table 6. Again,

NETA appears to be an insignificant factor in explaining changes in UPLIFTBM. However, as for the CAPACITY model, it appears that the reduction in SMP that arose as a result of the imposition of the Pool price cap, and the intense scrutiny surrounding RETA, was to some extent offset by an increase in revenues from Uplift. Since Uplift partly covered the increased cost associated with generators rescheduling plant on-the-day this result also supports the hypothesis that the mid-merit duopoly were able to exercise market power by manipulating their bids to exploit the complex Pool rules through the strategic withdrawal of capacity. These results not only provide evidence that this so-called 'gaming' behaviour took place but that it influenced every component of the final Pool price, not just SMP.

The significance and direction of the CCGTCCI, CCGTMC, and COALCONR are consistent with the previous discussions, though the COALMC and EASTLEASE variables appear for the first time as statistically significant variables. The EASTLEASE coefficient indicates that Uplift fell by £0.71/MWh once the plant leases arising from the first round of mandatory investment were cancelled in favour of an outright sale. Although it is not immediately obvious how the cancellation of Eastern leases, or falling coal prices, could have affected Uplift the relatively small price response combined with the lack of an EASTLEASE variable in any of the previous models, suggests that the mid-merit duopoly were not able to exercise significant incremental market power through the terms of the leases.

Table 6: UPLIFTBM regression output

Variable	Coefficient	Std. Error	t-Statistic	p-value
CAP	0.4165	0.2113	1.9706	0.0510
CCGTCCI	0.0002	0.0001	2.0768	0.0399
CCGTMC	-0.4875	0.1022	-4.7698	0.0000
COALCONR	-0.0001	0.0000	-4.6166	0.0000
COALMC	0.2119	0.0863	2.4544	0.0155
EASTLEASE	0.7115	0.2620	2.7153	0.0076
OILCCI	-0.0011	0.0003	-3.9829	0.0001
RETA	0.6079	0.2624	2.3166	0.0222
C	-0.3313	0.1005	-3.2965	0.0013

R-squared	0.3249	Mean dependent var	-0.0352
Adjusted R-squared	0.2810	S.D. dependent var	1.0231
S.E. of regression	0.8675	Akaike info criterion	2.6194
Sum squared resid	92.5735	Schwarz criterion	2.8160
Log likelihood	-163.8831	F-statistic	7.3995
Durbin-Watson stat	1.5763	Prob(F-statistic)	0.0000

As discussed previously, marginal coal-fired generation costs were not reflected in Pool prices because the mid-merit duopoly were able to exercise market power. The COALMC variable here therefore probably only reflects the impact of falling coal prices on BM costs under NETA. Although flexible coal plant frequently participated in setting very high SBP in peak hours, well above short-run marginal costs, coal plants generally only ran to meet contractual commitments, or provide reserve capacity, during peak hours. Empirical observation of SSP and SBP suggests that generators were willing to bid this coal capacity into the BM during off-peak hours at the short-run marginal cost of fuel in order to avoid the fixed cost of shutting down and then reheating their boilers for the following day. This may explain why coal marginal costs are being reflected in UPLIFTBM but not elsewhere in this analysis.

3.7. Results Summary

Overall, the results confirm that the introduction of NETA alone, in the absence of other regulatory interventions, would not have resulted in a statistically significant reduction in wholesale prices. However, the RETA inquiry that preceded it did appear to be a significant variable in both CAPACITY and UPLIFTBM models though with a positive sign which probably reflects the fact that intense regulatory scrutiny during the RETA investigation caused generators to change their bidding behaviour to reduce SMP, but offset this by simultaneously changing their bidding strategies to increase Capacity Payments, and Uplift, in ways that were more difficult for Ofgem to detect.

Despite significant effort, attempts to collect and analyse forward prices on the same basis as the day-ahead prices proved impossible because forward market liquidity was so poor before 1996/97. However, the fact that the NETA coefficient was positive in the SMPRPD model, and not statistically insignificant in all other cases, casts doubt on the Ofgem contention that the announcement that the Pool would be replaced cast a forward shadow on prices well before NETA was actually implemented on Go Live date.

It is possible to draw this conclusion by observing the impact that NETA had on day-ahead prices. If the expectation of NETA really had caused prices to fall for long dated forward contracts that were due to mature after the NETA's expected Go Live date, as Ofgem suggested, then as that date approached there should have been a sequential cascade of price

reductions in shorter dated forward contracts maturing after NETA Go Live as well. Taking this process to a logical conclusion, a fall in the day-ahead price should have been the final event in the sequential forward price cascade. However, this would only have happened at the point of NETA's implementation, and not before, because day-ahead prices are forward contracts with a one-day maturity. There is no evidence in any of the analysis presented above that NETA caused a fall in mean day-ahead prices in the month after NETA Go Live date, as compared to the month before. Given this observation, the only logical conclusion is that the expectation of NETA's implementation could not have caused year-ahead, month-ahead, week-ahead, or even day-ahead, forward prices to fall.

The real reason that day-ahead wholesale prices fell, well before NETA was actually implemented, is revealed by the other significant variables that repeatedly appeared throughout the regression models presented above. The principal causes of falling prices in the last year of the Pool, and first year of NETA, were reductions in the concentration of ownership in coal-fired generation capacity, combined with new entry by CCGT that caused overcapacity, and an increase in plant margin.

Empirical observation of the behaviour of day-ahead prices, forward prices, as well as contracting by generators, is also consistent with this conclusion. A graphical presentation of one-year forward EFA prices from 1999 to 2002 in Newbery (2002) provides qualitative support for the argument that plant divestment caused forward prices to fall. His analysis shows that EFA prices fell by £5.00/MWh (around 20%) in just two months during February–March 2000. This price fall was immediately preceded by the contractual completion on the second round of mandatory coal plant sales by PowerGen (Fiddlers Ferry/Ferry Bridge in July 1999), National Power (Drax in November 1999), as well as the first voluntary sale of a coal plant by National Power (Eggborough in January 2000). As McClaine (2002) notes, once the new owners had taken formal control of these plants, they began to operate quite differently from when they were under the ownership of National Power and PowerGen. It appears that in an attempt to recoup the purchase cost of these plants, and cover the substantial financing costs, the new owners increased their output in early 2000 as compared to the same period in 1999. At around the same time, it was rumoured that a trading company, Dynegy had also sold a significant quantity of forward contracts short, hoping to buy them back at lower prices later. The combination of these factors inevitably had an immediate impact on day-ahead prices because it effectively

increased the capacity available to the market at the same time as new CCGT plants were also being commissioned.. In addition, AES, Mission Energy, and British Energy almost simultaneously began to sell large quantities of forward contracts, in an attempt to lock-in future profit margins before the end of the 1999/00 financial year-end. This forward contracting also assumed an increase in the level of output from these plants as compared to their previous owners. Simultaneously, operators of newly commissioned CCGT plant would have been attempting to achieve the same objective, and the sudden increase in the amount of forward contracts on offer seems the most likely reason why forward prices fell so sharply in February–March 2000.

In general, the analysis shows that the impact of the other regulatory interventions, apart from RETA and NETA, was mixed. In the case of the gas moratorium, prices increased, even though the DTI that introduced it was simultaneously voicing concerns about the high level of Pool prices. In the case of the Pool price cap it reduced SMP as intended but the results of this analysis reveal that it was relatively easy for National Power and PowerGen to offset the loss by increasing Capacity Payments and Uplift. MALC apparently had no effect on modifying generator behaviour or day-ahead prices.

In principle the removal of Capacity Payments under NETA should have reduced at least one potential mechanism for gaming the Pool, and in theory should have resulted in an increase in efficiency and a fall in day-ahead prices. However, these results show that if NETA had been introduced without the forced plant divestments that took place before Go Live date then even this potential benefit could easily have been offset by the mid-merit generation duopoly by a corresponding increase in RPD.

4. REGULATORY IMPLICATIONS

Over the period 1990/91–2001/02 analysed in this paper, the two regulatory interventions that had the most impact were the imposition of vesting contracts for coal that kept prices low in the early years of the Pool, and the forced divestment of coal plant that reduced prices in later years and in the first year of NETA. The rapid reduction in the quantity of UK coal contracted for after March 1993 revealed the true extent to which the National Power and PowerGen duopoly were able to wield market power. It was only restructuring of the ownership of coal capacity through forced plant divestment in 1996, and again in 1999, combined with the unforeseen impact of the 'dash for gas' on overcapacity, that effectively offset this effect and reduced prices back to the level they had been during 1990/91.

In the remainder of the paper, the regulatory implications of the findings are discussed. In particular, a cost benefit analysis of the main regulatory interventions is attempted, and conclusions drawn about the impact on prices if NETA is extended to Scotland and other countries where Pool-based electricity wholesale markets still operate.

4.1. Cost Benefit Analysis

The analysis presented above, shows that day-ahead prices fell in response to coal plant divestments not to the introduction of NETA. In addition, while Ofgem's primary focus had been on increasing efficiency in the wholesale electricity market, compensating mechanisms in the capital market that had been unleashed at vesting in 1990 meant that high rates of investment in CCGT in response to high Pool prices resulted in over capacity. Efficiency in the wider UK energy market had also increased in response to deregulation of the electricity market and, as the *Law of One Price* predicts, the marginal cost of coal and CCGT generation converged in 1997/98. The analysis shows that all of these factors had begun to affect both day-ahead, and probably also forward prices, by the end of 1999/00. In other words, at least a year before NETA Go Live date. Given the observation that the price reductions Ofgem and the DTI were seeking had already largely taken place before NETA was introduced, and as there was no evidence that NETA would reduce prices once implemented, a fact that is confirmed by the analysis in this paper, then the decision to replace the Pool was an unnecessary and costly regulatory step. Although the Pool had some technical weaknesses, for example in the way that the dispatch schedule was calculated, there is no evidence that its

centralised auction, with uniform Pay SMP pricing, was not economically inferior to the decentralised market with Pay Bid pricing of NETA.

It could be argued that attempting to apportion the price fall to one or other regulatory action is an irrelevant analytical exercise because the crucial economic issue is that wholesale electricity prices fell to a competitive level, and what caused it is not important. Ofgem essentially confirms this was its view in a single paragraph in the summary of its report on the first year of NETA:

> Before NETA was introduced the expectation was that the new trading arrangements, together with the more competitive generation market, more demand-side influence on price setting in the newly emerging markets, and lower generation input costs, offered the prospect of reductions in wholesale prices. These price reductions have occurred. (Ofgem 2002)

In essence, this argument suggests that any number of simultaneous regulatory interventions can be justified providing the overriding objective is ultimately achieved. However, this ignores the impact of regulatory cost and risk arising from the industry-wide systems development and implementation that was required to operate NETA. The conclusions of the Competition Commission inquiry into MALC effectively criticised the multi-layered approach to regulation, that Ofgem and the DTI had adopted in the late 1990s, by refusing to back the imposition of another regulatory intervention without first seeing the impact of industry restructuring, and the introduction of NETA. The results of the analysis above support the Competition Commission conclusion because it shows that the wholesale market did become substantially more competitive as a direct result of the second round of mandatory plant divestment that Ofgem was simultaneously implementing alongside the MALC consultation, and NETA system development process, during 1999/00.

Ofgem's own estimate of the direct cost of implementing NETA, published in October 1999, suggests a figure between £136m and £146m per annum for a five-year period, and a further £30m per annum thereafter for ongoing system modifications. In total this amounts to an estimated direct cost of £1000m, though inevitable cost overruns have since inflated this figure. However, this estimate does not take into account any of the associated management costs borne by the industry, or the operational risk associated with the transition from the Pool to a real-time trading system under NETA.

The cost of implementing the computer systems necessary to support NETA, and the fact that Go Live date was later than planned, indicates the complexity of the task of introducing this entirely new electricity trading system, especially the real-time BM. Although the NETA transition was achieved without any system disruption, this was not a guaranteed outcome, and the impact of a total collapse of the UK electricity system on the wider economy would have been substantial.

In contrast, the direct costs associated with the mandatory plant divestments are considerably lower than those for NETA. Typically, the banking, legal, and advisory costs, on transactions of this size are around 3% of the total value. Since the first round in 1996 raised £2150m, and £3175 million for the second round in 1999, this amounts to a total regulatory cost imposed on the industry by mandatory plant divestment of the order of £160m.

In addition to lower regulatory costs, the operational risk imposed on the transmission system by incrementally transferring the ownership of six power plants, spread over a period of five years, is obviously much easier to manage than changing the entire system of scheduling, dispatch, and real-time balancing, on a single day. Since the employment contracts of the personnel who operate power plants usually transfer to the new owner, along with the generation assets, the day-to-day management know-how embedded in a particular plant's operation does not change significantly. Even if subsequent changes to the management practices of a power plant cause an increase in unplanned outages this can easily be managed within the normal grid operational process. It is therefore difficult to see how plant divestment could have caused any significant increase in operational risk to the system as compared with that on NETA Go Live date.

The estimates presented above underline the fact that regulatory interventions can impose significant costs, and potential risks, that must ultimately be borne by consumers. Moreover, the magnitude of those can vary dramatically depending on the nature of the choices made by the regulator. The cost and benefit of introducing NETA versus the two rounds of mandatory plant divestment were quite different. Plant divestment cost less than 10% of the cost of setting up and running NETA up to March 2002. Moreover, the plant divestments that took place imposed a one-off cost that will not be repeated beyond the date of completion. In contrast, NETA is expected to continue requiring upgrades and maintenance for the foreseeable future. Given that NETA also appears to have produced no measurable impact on

wholesale day-ahead prices, while mandatory plant divestments had an immediate effect at a fraction of the cost, it is difficult to conclude that the introduction of NETA was anything other than a costly mistake.

4.2. System Security

By the time that NETA completed its first year of operation it began to be criticised by both the DTI and the industry, because of the low level of prices in 2000/01. Fears began to grow about system security as nuclear plants were no longer profitable, and a number of coal and CCGT plant were withdrawn from production. However, as there is no evidence that NETA caused prices to fall, it cannot logically be blamed for threatening system security.

All the evidence in this paper points to the downward move in prices, and the closure of plants, being caused by fragmentation of the mid-merit sector and overcapacity. Calls by generators to reintroduce Capacity Payments, to ensure sufficient marginal capacity remained on the system to meet unexpected peaks in demand and plant outages, were therefore largely ignored. Neither Ofgem, nor the DTI, appeared to agree with this suggestion but the threat of the entire nuclear industry being pushed into a default on its debt, and decommissioning obligations to the UK Government, continued to be the major focus of concern.

In summer 2002, the DTI suggested that NETA would have to be reformed in some unspecified way to allow British Energy, along with operators of other types of inflexible or inherently unreliable capacity, especially renewable and Combined Heat and Power (CHP) plants, to get a fair price for their output (FT 2002a). Already alarmed by the growing UK dependency on gas, the DTI saw nuclear energy following the same declining path as coal, while the output from renewable and CHP capacity had already fallen due to the impact of high SBP in the BM. As an interim measure, the DTI intervened directly to broker a deal to save British Energy from bankruptcy by granting it a short-term £410 million credit line from public funds (FT 2002b), while a long-term solution could be considered including putting the company into administration and/or restructuring its debts and decommissioning liabilities.

Meanwhile, the company, along with major shareholders and bondholders, continued negotiations with the DTI over handing control of some of the Magnox nuclear plants, still owned by BNFL, to British Energy along with a 'management fee' of £100 million. A 50%

reduction in the cost of fuel reprocessing services, supplied by BNFL to British Energy's plants, was also proposed along with a cut in business rates (local property tax) of 20–30%, which together amounted to a further potential £100 million saving. Consideration was also given to redefining nuclear capacity as a form of renewable energy so allowing it to avoid paying the climate change levy (carbon tax) and producing another £80 million saving. As all of these sums would effectively involve a direct transfer of tax revenue from the public purse to British Energy the Treasury was reluctant to agree. As at the end of September 2002, no solution had been agreed and the DTI credit facility was increased to £650m and extended to December 2002. Ironically, the DTI that had so vigorously pursued the objective of reducing prices to consumers, through increased competition in the wholesale market, was now effectively agreeing to shelter British Energy from the impact of that competition.

In practice there was no need for any intervention, and certainly not to introduce further NETA reforms. Wholesale prices were 11% higher in the months following March 2002, as a result of the closure of some marginal capacity, and plans to mothball some thermal plants were cancelled or reversed. Outages on one nuclear plant that had contributed to British Energy's fall in profits further increased day-ahead prices during summer of 2002.

Plant margin on the England & Wales system, which is defined by NGC as percentage surplus available capacity in excess of winter peak demand, amounted to 26% by the end of 2000/01. Although this is low by international standards, where margins of 30% are typical, this simply reflects an efficiency gain brought about by the introduction of competitive electricity markets. Only if the plant margin were to fall to the previous low of 15% reached in 1996/97 would it begin to threaten system security. However, as a further 5000 MW of CCGT capacity was already under construction or in final stages of commissioning by mid year 2002 and 4600 MW of zero registered (mothballed) capacity was available to return to the system at short notice this does not seem likely. Although construction of a further 6700 MW of CCGT that had already received final licensing consent might not go ahead if prices remained too low to justify investment costs, NGC estimated in June 2002 (NGC 2002) that if only currently existing transmission contracted plant, were available in 2007/08 and no zero registered capacity plant were able to return to the system, then the plant margin would still be 17.3%. If all planned CCGT were built then plant margin would remain above 24% until 2008/09. If planned closures of Magnox nuclear plant were delayed and all mothballed plant was returned to production, plant margin would be well over 30%. If British Energy

were to fall into bankruptcy, then shareholders would lose their investment, and managers their jobs, although the plants could carry on operating as before but relieved of the burden of paying interest on some or all of their debt, and/or potentially their decommissioning liabilities. The same applies to the fossil fuel plant that was in default, and plant margin would therefore be unaffected.

Prices were still low by historic standards and firms were rationally responding to overcapacity without intervention. Ofgem appeared unconcerned about system security. Indeed, the Ofgem Director General publicly opposed the DTI plans to rescue British Energy, instead suggesting that a natural result of competition was that some capacity would close, and firms would fail (FT 2002a). In light of the historically high plant margin, the industry response to falling prices by closing capacity is consistent with that observed in other capital intensive industries such as oil refining, chemical manufacturing, or computer chip fabrication. Reintroducing Capacity Payments, and giving special concessions to British Energy, would effectively only subsidise capacity that was uneconomic. Both the short-run, and eventually the long-run, economic efficiency of the wholesale market would be impaired as a result. Indeed, as the analysis above shows the potential for manipulation of the Capacity Payments by withdrawing capacity was significant under the Pool, and reintroducing a similar scheme under NETA might even provide generators with adverse incentives to undertake a joint plant closure programme so as to artificially reduce plant margin to a dangerously low level and so increase Capacity Payments.

Not only is shielding nuclear capacity from the effects of competition inconsistent with the stated regulatory objective of the DTI and Ofgem to put consumer interests first, but retaining plant on the system that is not economically viable will also keep prices at lower levels for longer than they otherwise would be. This could force other plant to be closed that would have stayed open if prices were higher. In addition, investment in new more efficient CCGT plant would be curtailed.

4.3. BETTA in Scotland

Using the coefficients from the analysis above, it is possible to estimate the potential impact of integrating Scotland into NETA. Electricity market deregulation in Scotland followed a different path to that in England & Wales and consumer prices will remain under regulatory

price control until the end of 2003/04 with the level set by Ofgem by reference to prices in England & Wales. As for England & Wales, the biggest regulatory problem that Ofgem faces in introducing a competitive market to Scotland is the dominant vertically integrated duopoly position of Scottish Power, and Scottish & Southern, in the mid-merit generation sector. If Scotland had been included in NETA in 2001/02, the limited capacity, and inadequate access rights to the England-Scotland interconnector would have exacerbated this industry concentration effect by generators south of the border in England & Wales.

Given that Scottish Power controlled a little over 69% of the mid-merit coal capacity in Scotland during 2001/02, and Scottish & Southern owned the remainder, this equates to a CCI of 5700.[23] This is slightly higher than the level of the Coal CCI in England & Wales in 1990/91, and compares to a mean Coal CCI of 1382 in England & Wales during 2001/02. Multiplying this 4343 difference between the Scotland mid-merit CCI and the England & Wales Coal CCI by the COALCCI coefficient in Table 4 reveals that if Ofgem had lifted Scottish retail price controls, and simultaneously introduced NETA into Scotland during 2001/02, the Scottish duopoly would have been able to reap a wholesale price advantage of £8.10/MWh over generators in England & Wales.

The estimated price differential between England & Wales and Scotland therefore shows that Scottish Power, and Scottish & Southern, would jointly have been able to exercise market power that could not have been curtailed by the threat of imports from south of the border. However, assuming that the inteconnector capacity is increased to 2200MW by the year 2003/04, and that generators in England will have full access rights to that capacity thereafter, 11 firms could potentially enter the Scottish market with 200MW of marginal coal-fired capacity in 2004/05. Further assuming that Scottish Power closed 1000 MW of its existing coal-fired plant to offset the likely overcapacity that would arise, the CCI for the mid-merit sector in Scotland could fall to around 1750. This is approximately 280 higher than the average Coal CCI in England & Wales during 2001/02. On this basis, and assuming there will be no retail price controls in Scotland after 2003/04, that produces a forecast day-ahead wholesale price premium of around £0.50/MWh in Scotland over the level seen in England & Wales during 2001/02.

[23] Includes the recently repowered Peterhead power plant

The success of BETTA will therefore critically depend on guaranteed access to the Scottish market by marginal coal-fired plant generation capacity south of the border through an interconnector with sufficient capacity to meet a significant proportion of total Scottish demand. If this level of access is not guaranteed, Scottish consumers will not see the 1–2% retail price reductions forecast by Ofgem. Indeed, prices would most likely rise unless price controls were extended beyond 2003/04.

4.4. NETA and Other Countries

In Europe the Nord Pool market covering Norway, Sweden, Finland, and Denmark employs a similar day-ahead uniform price auction format to the Pool, as does the Netherlands, Spain, Germany and Poland. France also introduced a market mechanism similar to Nord Pool in November 2001. Italy, Greece, and Austria are in the process of implementing Pool-based electricity markets. Elsewhere, several US states such as New York, New England, Pennsylvania-New Jersey-Maryland, as well as Alberta in Canada, employ a pool-based system. California's PX market also did until trading was permanently halted by the 1999–2000 electricity price crises. In light of the experience in England & Wales there is a real danger that regulators in countries with pool-based systems will observe the fall in wholesale prices after NETA's introduction, along with the DTI/Ofgem conclusions, and conclude that replacing their own Pool with a NETA style market will reduce prices in their country. This is particularly likely to happen in countries such as Spain, and the Netherlands, where prices are well above the European average. In practice both of these countries suffer from similar industry concentration issues as England & Wales in that there is a concentrated oligopoly of generators in the mid-merit sector and heavily constrained cross-border transmission capacity that prevents sufficient imports entering the market from elsewhere.

The results of the analysis presented in this paper show that it is the distribution of plant between firms, as well as the absolute number of firms, in the generation sector that has the most important impact on the exercise of market power in the wholesale market – not whether a Pool or bilateral market mechanism is implemented.

4.5. Conclusion

The analysis in this paper has allowed the relative impact of the full range of regulatory interventions that Ofgem implemented throughout the life of the Pool, culminating in the

implementation of NETA, to be compared for the first time. It shows that Ofgem was right to put a cap on Pool prices in 1994 and to insist that the duopoly of National Power and PowerGen be broken by divestment of plant. However, the results also show that the decision to fragment the mid-merit into only three, rather than five or more firms in 1996 was a missed opportunity that Ofgem took a further three years to rectify. The results also show that Ofgem was right to press for the removal of the gas moratorium, and the DTI was right to continue allowing more low-cost foreign coal to be imported, even though it displaced indigenous deep-mined UK coal. This increased the overall efficiency of the UK energy market by inducing inter-fuel competition between coal and gas and thereby contributed to a further reduction in electricity prices above and beyond what industry restructuring alone would have brought. The introduction of NETA was unnecessary, and a waste of resources, because it did not curtail market power or lower prices. In this light, the Ofgem decision to delay the introduction of BETTA to Scotland in 2001/02, and to continue price controls instead, was correct given the existing duopoly industry structure.

From a regulatory standpoint, perhaps the most important finding in this paper is that a broad policy failure occurred when Ofgem and the DTI jointly adopted a multi-layered approach to regulation in 1996/97. This ultimately resulted in NETA being implemented without any real proof that it would reduce prices, and insufficient attention being given to the ongoing impact of other regulatory interventions that had already been introduced. Ironically, the results of the analysis in this paper confirm that Ofgem's initial scepticism over the likely beneficial impact of 'Pay Bid' versus 'Pay SMP' market mechanisms, as expressed in 1994, was entirely correct. NETA did not induce a price fall, and experience has shown that the BM favours generators with larger plant portfolios containing flexible plant.

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OXFORD INSTITUTE FOR ENERGY STUDIES
57 WOODSTOCK ROAD, OXFORD OX2 6FA ENGLAND
TELEPHONE (01865) 311377
FAX (01865) 310527
E-mail: publications@oxfordenergy.org
http://www.oxfordenergy.org