

Market Power Mitigation in the UK Power Market

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1. Introduction

Market power has been a constant theme in the history of the electricity restructuring in England and Wales. When the industry was restructured, the government created three large generating companies, two of which shared almost all the stations capable of setting prices in the industry's centralised spot market. It soon became apparent that these companies had the ability and the incentive to raise prices to undesirable levels.

Over the course of the 1990s, the industry's regulators attempted to mitigate the duopolists' market power. They published reports on unacceptable behaviour, making it impossible for the companies to repeat those tactics, while defining what would be allowed in future. The generators twice divested plant to rival companies – once to avoid being referred to the Monopolies and Mergers Commission, once in return for being allowed to merge with electricity retailers. In the end, the regulator and the government together changed the market's rules, abolishing the Pool that had been at the centre of the original restructuring. At the end of the Pool's life, prices finally fell below the "competitive" level of new entrants' costs. We may never know whether abolishing the Pool would have reduced prices, had the market still been concentrated, for it had reached a competitive structure just before it was abolished. This paper discusses market power and its mitigation in the electricity industry of England and Wales.

2. Background

When the privatisation of the electricity industry in England and Wales was planned, the government was determined to sell the entire industry, including the 14 nuclear power stations owned by the Central Electricity Generating Board. These stations had

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a chequered history – the eight first generation Magnox plants had mostly performed to expectations, but had been acknowledged to be more costly than conventional plants, even while still under construction in the early 1960s. Construction started on four second-generation advanced gas-cooled reactors (AGRs) in the second half of that decade, but two of them had not been formally commissioned by 1987, and only one of the others had neared its design output. Work on a fifth AGR and a pressurised water reactor had started during the 1980s, although many outside observers questioned the investment appraisals that the CEBG had used to justify their construction.

In the hope of producing a saleable package, the nuclear stations were to be combined with 30 GW, or 60%, of the CEBG's conventional stations in a company later named National Power. The remaining conventional stations were given to PowerGen. It was hoped that PowerGen could act as a counterweight to National Power, despite the 70-30 split of the industry's overall capacity. Unfortunately, however, when the CEBG's nuclear costs were finally examined in enough detail, they proved so unattractive that the stations had to be withdrawn from the sale. The government would continue to own Nuclear Electric, with 20% of the industry's capacity, while National Power would now have "only" 50%. By the time that this decision was made, however, in November 1989, it was too late to consider more than a minor reshuffling of the industry's assets. The privatisation was forced to proceed with a highly concentrated structure in generation, although the original motive for this structure had been superseded.

The industry's new structure formally began at midnight on March 31, 1990, and the first privatisations took place in December. Twelve Regional Electricity Companies (RECs), successors to the former Area Boards responsible for distribution were privatised, jointly owning the National Grid Company, which had taken over the CEBG's transmission assets. From the beginning of the privatisation, the importance of ensuring fair access to the transmission grid had been recognised. NGC had been separated from the generators, and the RECs owned it through a holding company, to minimise their influence over the actual transmission company. National Power and PowerGen were privatised in March 1991, and two vertically integrated Scottish companies in June 1991. Because the companies were vertically integrated, generation prices in Scotland were regulated, using a formula that would lead them to converge with prices in England by the middle of the decade. This paper accordingly concentrates on events south of the border.¹

The industry was given a regulator, the Director-General of Electricity Supply, supported by a staff at the Office of Electricity Regulation (Offer). The first regulator was Professor Stephen Littlechild, appointed in 1989. In 1998, the new Labour government announced its desire to combine the regulation of gas and electricity, and appointed Callum McCarthy as the next gas regulator. Professor Littlechild stood down as electricity regulator at the end of 1998, a few months before his second term was due to end, to allow Mr McCarthy to combine both jobs. In due course, Offer

¹ The European Commission also plays practically no role in our story. While the Commission has pursued a policy of liberalisation in the electricity and gas industries, and launched an investigation into the level of competition in them during 2005, the industry in England and Wales has been an "early liberaliser", meeting almost all of the Commission's requirements well before they became binding on Member States. The Commission did have jurisdiction over several cross-border mergers involving electricity companies (EdF – London, RWE – Innogy, and E.On – PowerGen). The UK government attempted to have the first of these repatriated to the domestic competition authorities, but without success, given the Commission's view that competition would not be impeded by the merger. It is likely that the domestic authorities would also have allowed the merger, for the same reason.

merged with the supporting office for gas regulation to become the Office of Gas and Electricity Markets (Ofgem). Those changes were made without legislation, but the government also wished to move from individual regulators to commissions. Under the Utilities Act 2000, the responsibility for regulation passed to the Gas and Electricity Markets Authority (GEMA), with five executive and five non-executive members.

Every company in the electricity industry is required to have a licence, with some small-scale exemptions. Licences are not used as a barrier to entry, but contain provisions requiring the company to give information to the regulator, and allowing them to bury cables in streets, for example. The licences can also contain behavioural conditions – the prices for monopoly activities are regulated through licence clauses, for example. The larger companies were also banned from cross-subsidising any activities, or discriminating between any of their customers. Licences are contracts, issued by the regulator or the Secretary of State for Trade and Industry, and as such may only be changed with the consent of the company, or after the UK's competition authority² has ruled that to continue with the licence without modification would be against the public interest.

The RECs were responsible for distribution and regulated as monopolists, but the new activity of supply had been created in order to give customers a choice over which company they bought their electricity from. In 1990, 5,000 customers with a maximum demand of 1 MW or more had this choice (30% of units sold). In 1994, another 50,000 customers, with a maximum demand of 100kW or more joined the competitive market (another 20% of units sold). The remaining customers were originally due to become free to choose their supplier in April 1998, but the transition was actually phased between September 1998 and July 1999.

Generators were allowed to become suppliers, and RECs to build power stations, but there were limits to the extent of this vertical re-integration. The government wanted to increase competition, and feared that vertical re-integration would limit this, and make entry by outsiders particularly difficult. The major generators were allowed to supply electricity to large customers, but their share of this market was initially capped, at 15% of the total sales in each region.³ This limit turned out to be unsustainable, for the generators were offering better deals than the RECs, and customers who were left outside their quota complained. The limits were raised, and then abolished. The RECs were similarly allowed to invest in power stations, but with strict limits on the amount of capacity that they could own.⁴ The RECs were also required to purchase power “at the best effective price reasonably

² For most of the period, the competition authority was the Monopolies and Mergers Commission (MMC), renamed the Competition Commission in April 2000.

³ Since 30% of sales had been opened to competition, these limits represented half of the market on a nation-wide basis, but a smaller proportion in areas with high proportions of industrial customers.

⁴ These own-generation limits are a good test of whether someone really knows the details of the restructuring in England and Wales. The limits in the RECs' licences were expressed in MW of capacity. If a REC owned less than 50% of a station, then only that fraction of its capacity counted against the limit. The MW limits were approximately equal to 15% of the maximum demand in the REC's area, and varied between 1,000 MW for Eastern and 400 MW for Swalec and South Western. It is possible to find the limits described as 15% of the peak demand, or even as 15% of the REC's electricity purchases, in secondary sources. In practice, a REC with a 49% share in a station might have contracted to buy all of its output, if the other owners had no interests in UK electricity supply. An ownership interest equal to 10% of the peak demand in a REC's area could thus equate to purchases equal to 20% of this peak demand, or nearly 30% of the average demand in the REC's area. The REC could have self-supplied an even higher proportion of its purchases for its smaller customers, where supply competition would be longest delayed and potentially least effective.

obtainable, having regard to the sources available”, in an attempt to prevent them from buying from affiliated stations at inflated prices. Eleven of the twelve RECs invested in new power stations, efficient combined cycle gas turbine (CCGT) plants, in the first years after privatisation. Figure 1 shows the way in which the output from these Independent Power Producers (IPPs) gradually took market share from the major generators.

Because it is impossible to tell which generator is actually supplying the electricity consumed by any given customer, and because the CEGB had been very concerned to preserve the physical integrity of its system, a special market known as the Pool was created for wholesale trading. Generators would bid prices and availabilities for each of their plants, and NGC would calculate the least-cost schedule capable of meeting its forecast of demand. The price bids from the most expensive generator in normal use would be used to calculate the System Marginal Price (SMP), paid for every unit in the original schedule. Every station available to generate, or generating, would receive a capacity payment, based on the Value of Lost Load (set by the government at £2/kWh in 1990, and uprated with inflation), multiplied by the Loss of Load Probability. This was intended to provide an incentive to make capacity available when it was most needed, and corresponds to an element in the “optimal” price of electricity (Green, 2000). If NGC asked generators to deviate from the original schedule, to deal with forecast errors, plant breakdowns, or transmission constraints that reduced the amount of power that could be imported into an area, they would be paid on the basis of their own bid. The cost of these adjustments was recovered in a charge known as Uplift, added to the price paid by suppliers.

As part of the preparations for the privatisation, the government produced forecasts of the Pool price, in order to ensure that each company had sustainable finances. When trading started, however, Pool prices were significantly below the level that the government had predicted. This was largely because of the elaborate contracts that had been superimposed on the Pool.

To reduce the risk of trading in the Pool, most sales were covered by Contracts for Differences (CfDs), which required one party (typically a generator) to pay back the difference between the Pool Purchase Price and a strike price specified in the contract whenever the Pool price exceeded the strike price. When the Pool Purchase Price was less than the strike price, the other party (typically a supplier) would normally have to pay the difference to the generator.⁵ As long as the generator actually produced the volume of electricity covered by the CfD, the net effect of the CfD and its sales through the Pool would mean that its revenues would not be affected by the Pool price. This meant that the generators had little incentive to raise the Pool price in the short term, and could find themselves over-contracted, with CfDs covering more power than they expected to generate, in which case they would maximise profits by keeping the Pool price *low* (Newbery, 1998; Green, 1999).

Furthermore, the generators had signed three-year contracts with British Coal, requiring them to buy large volumes of coal at prices above those of imported coal. These were backed with electricity CfDs between the generators and the RECs, who were allowed to pass the cost on to their captive smaller consumers. Larger customers, who were allowed to shop around, were expected to pay prices based on the Pool price, which would be determined by the cost of imported coal, since that was the generators’ true marginal cost of fuel. The coal contracts, a term often used

⁵ A one-way contract for differences would only require payments if the Pool price was above the strike price, and would be sold for a lump sum linked to the expected payments. A two-way contract could be based upon the expected Pool price, in which case no lump sum was necessary.

to denote the generators' contracts with both British Coal and the RECs, were needed to allow British Coal to cover its high costs without a direct subsidy from the government. During 1990, the generators feared that they would be unable to burn all the coal that they were contracted to buy from British Coal, and started to reduce their bids in order to increase their output. The result was an artificially low price for the first year of the new arrangements, shown in figure 2. This probably suited the government and the industry, for it gave a period of calm for the privatisations, but it did produce a misleading basis for later comparisons.

3. Testing the regulator: 1991-93

The period of calm came to an end on September 9th, 1991, when the Pool Purchase Price spiked at £168/MWh. Many industrial customers, who had agreed to buy on terms which effectively passed the Pool price on to them unhedged, were furious. The largest industrial customers had also suffered from the end of a one-year transitional period which had pegged any price rises to the rate of inflation. While most industrial customers had seen price reductions once they were no longer subsidising British Coal, the largest customers had been paying prices well below what turned out to be the market price, and faced significant increases.

The regulator announced his first inquiry into Pool prices. When the report (Offer, 1991) was published, in December 1991, he had established that the price spike was due to the way in which NGC's computer program, GOAL, scheduled plant, and the interaction between the schedule and the price algorithm. GOAL had scheduled a gas turbine to produce a few MWh during the early evening peak, choosing this as the cheapest option available to it, far cheaper than turning on a coal-fired station. Nevertheless, the amount bid for those few MWh set the price for the entire industry's output, at a then-unprecedented level.

This part of the report was more of an explanation than an accusation, but the regulator did find things to criticise. PowerGen had discovered that it could declare some of its plant to be unavailable when bids were submitted, a day ahead, and that this would raise the Loss of Load Probability, and hence the capacity payment, which was very non-linear in the amount of spare capacity. Once the capacity payment had been set, PowerGen would declare its plant to be available, and hence eligible to receive the payment, which could not be reduced. This abuse could be prevented by a rule change, however – the Pool quickly agreed that LOLP would be calculated on the basis of each plant's highest availability over the previous eight days. Anecdotal evidence suggests that generators did sometimes delay the return of a station that had already been out of action for more than a week, but it was no longer possible to manipulate LOLP by declaring a station unavailable for just a day or two.

To prevent further manipulation of capacity, the regulator asked the three major generators to accept a new condition in their regulatory licences. Apart from the bans on cross-subsidy and discrimination, the generators' licences had not initially contained any significant restrictions on their economic behaviour. The new Condition 9A required them to inform him of their predictions for each unit's availability over the coming year, their strategy for making it available, and to reconcile the prediction with its actual availability at the end of the year. The licence condition did not impose any restrictions on what the generator's strategy might be,

but it gave the regulator the information to detect potentially anti-competitive conduct.

Another part of the condition required the generators to inform the regulator if they planned to close any of their capacity, and allow him to appoint an independent assessor who would judge whether the closures were economically justified (rather than an attempt to reduce the plant margin and drive up LOLP), and whether the generators should attempt to find a buyer for the plant, rather than closing it. In due course, the generators (independently) announced that they planned to close a number of small stations, and the regulator appointed an assessor. The assessor's report (Offer, 1993b) concluded that the closures were reasonable, since the costs of the plants were higher than the amount that they could expect to earn in the market from capacity payments and occasional operation. The industry had a substantial margin of spare capacity at this time, and new plants were under construction. The report also concluded that while the generators had made little effort to find buyers for the plant, it was unlikely that a new owner would be able to operate them at a profit, and so the failure to seek a buyer had no real impact. Over the following years, the main impact of this part of condition 9A was to encourage the generators to mothball stations, rather than closing them, and to close individual units at several stations (which could not be put up for sale) rather than complete stations.

While the regulator had criticised particular tactics used by the generators, he did not criticise them for raising the overall level of prices. Prices in 1990/91 had been below the generators' avoidable costs, and so an increase was appropriate. This is a recurrent theme in the reports published between 1991 and 1993 – the regulator objected to some of the generators' tactics, but initially accepted the results of those tactics, in terms of the overall level of prices. To some extent, the generators were testing the regulator to see what would be allowed.

We can see this clearly in the regulator's next Pool-related report. The 1991 report had mentioned the bidding by National Power's oil-fired station at Fawley, in the south of England. The relatively high cost of oil meant that this station was rarely required to run in the main schedule, but was sometimes used to relieve transmission constraints, for which it was paid a price based on its own bid, regardless of SMP. Since it was the only station capable of doing so, it could bid high prices, and did so. The regulator promised to investigate this. When the *Report on constrained-on plant* (Offer, 1992a) appeared, it covered a number of other stations subject to transmission constraints. The regulator agreed that National Power had based its bids on estimates of each station's costs, and had sometimes reduced its bids in order to avoid over-recovery against its targets. He viewed this as a responsible strategy. PowerGen, however, had submitted extremely high bids from two small stations scheduled for closure. Because of the closures, NGC had to reinforce its transmission system in each area, creating temporary transmission constraints that the stations exploited. PowerGen was criticised for its behaviour, which was not repeated. The regulator suggested that a contract between NGC and a station likely to be constrained would be a better way of ensuring that the station could cover its costs than relying on high bids in the Pool, and NGC duly introduced such contracts. Overall, the tone of the report was that the regulator was happy for the generators to find a way to cover their costs, and make some profit, but that excessive profits were undesirable.

A second "specialised" report, on gas turbine plant (Offer 1992b), continued this theme. The generators had argued that they were unable to cover the costs of their open cycle gas turbine plants. These had high marginal costs, were used for peak power and to provide reserve, and should not be confused with combined cycle

gas turbines, which had a much higher thermal efficiency, lower costs, and were used for base load generation. The regulator agreed that the stations' costs were higher than the income that they were likely to earn from capacity payments, and the generators took this as permission to raise those stations' bids.

In the summer of 1992, however, the overall level of prices rose. The generators were now negotiating to replace their original three-year contracts, and were anxious that Pool prices should not stay "below ... realistic reference levels for the negotiation of future contracts" (National Power, quoted in Offer, 1992c, p 52). Offer reported on the increase after customers complained, but found that Pool prices in 1991/2 had been below the generators' avoidable costs, so that it was "difficult to object to an increase" (ibid p 2). At the same time, the regulator "conclude[d] that National Power and PowerGen together had market power and exercised it in a significant way" (ibid).

The original contracts finally expired in April 1993, and their replacements covered a lower proportion of the generators' sales and of their fuel requirements. This effectively raised their marginal costs, and their gain from higher prices, and SMP jumped again. The regulator's response (1993a) came much more quickly, in July. (The previous reports on price increases had been published in December). The regulator blamed the increases on National Power and PowerGen: "both companies wanted a price increase and they were able to achieve it" (Offer, 1993a, p ii). "The need to cover avoidable costs [did] not justify any further price increases - nor did it justify a price increase as high as the recent one" (p iii). He acknowledged that the generators also needed to cover their unavoidable costs and make a profit, but that they also received revenues from contracts. He announced that he would review these issues, and decide by the end of the year whether the generators should be referred to the Monopolies and Mergers Commission – bringing forward an earlier commitment to make such a decision by 1995. It seemed that the generators had finally pushed the regulator too far.

4. The generators' undertakings: 1994-96

After the third Pool Price Inquiry, the regulator moved towards putting direct constraints on the generators. He had three ways of doing this – by agreeing an amendment to their licences (as with Condition 9A), by imposing an amendment, which required a reference to the MMC under the Electricity Act 1989, or by asking the MMC to impose some other remedy under the Fair Trading Act 1973. This was potentially the most wide-ranging, as the MMC could have recommended that the generators be broken up. Referring the generators to the MMC was not without risk for the regulator, as either the Commission or the Secretary of State for Trade and Industry, who had the final decision on whether to implement a Fair Trading Act reference, might have decided to take no action. Like an early firearm, prone to misfire and slow to reload, the MMC was potentially more useful as a threat than in active use.

The regulator was able to use the threat of an MMC reference, which the generators were plainly keen to avoid, to win concessions from them, announced in February 1994 (Offer, 1994a). In the period since privatisation, the RECs had built several new power stations, and more were under construction. Almost all of these were combined-cycle gas turbines, with lower operating costs than the generators' coal-fired stations, which they started to displace in the merit order. The market for

base load, continuous, operation, which already contained Nuclear Electric and imports from France and Scotland, was becoming reasonably competitive. The pumped storage hydro stations owned by NGC were effective competitors at peak times, but the intervening segment of the market, for mid-merit stations, was still dominated by National Power and PowerGen. Reducing this dominance was the regulator's main aim.

National Power gave an undertaking to use all reasonable endeavours to sell or otherwise dispose of 4 GW of "mid-merit" plant, and PowerGen to dispose of 2 GW, within two years. These disposals would mean that each generator would face a more elastic residual demand curve in that part of the market, reducing their incentive and ability to raise prices. In return, the regulator effectively promised not to refer the companies to the MMC during the two-year period.

To protect customers in the period before the disposals could take effect, the generators undertook "to bid ... in such a way that, under reasonable assumptions for other generators' bids ... the annual average Pool Purchase Price would in normal circumstances" be less than 2.4 p/kWh on a time-weighted basis. On a demand-weighted basis, the price had to be less than 2.55 p/kWh, in October 1993 prices. They agreed to sell contracts at prices compatible with these, although a normal risk premium could be included.

For the first months of 1994/5, Pool prices were well below these levels (raised to 2.46 p/kWh time-weighted and 2.61 p/kWh demand-weighted in 1994/95 prices). During December 1994, however, prices rose significantly, although they were still compatible with the undertaking. By January 1995, two nuclear stations were unexpectedly out of action, reducing the margin of spare capacity and increasing LOLP, and the higher capacity payments pushed prices to record levels. On January 15th, a unit at National Power's Eggborough station failed. Under the Pool rules, this would feed through to LOLP in eight days' time, and duly did so.

The regulator published a statement (Offer, 1995a) pointing out that the generators had undertaken to keep prices down, and that if they had failed to do so at the end of the year, he would decide whether the failure constituted a breach of their undertaking, or was due to abnormal circumstances. PowerGen had already sharply reduced its bids, and National Power did so a couple of days later. The government was about to sell the second tranche of their shares, and would have had every reason to put pressure on the companies to avoid any threat of a reference to the MMC. Even so, National Power's prospectus implies that the company was not sure that it would be able to avoid a reference for failing to meet the price undertaking.

In the event, the time-weighted price was approximately two per cent below the level specified in the undertaking, because prices during February and March had been extremely low. The demand-weighted price was one per cent above the level in the undertaking, however. When the regulator published a report (Offer, 1995b) on the matter, he concluded that this was not a breach of the undertaking. The proximate cause of the high prices was an unusual level of plant failures. His staff had used data supplied under Condition 9A to calculate the probability of a combination of plant availability (which was lower than usual) and demand (also low, and therefore helping to reduce prices) that could have breached the undertaking, given the generators' behaviour up to the end of December. They concluded that the combination was relatively unusual, and that the generators' failure to keep prices down did not conflict with their undertaking to bid to produce that price level "in normal circumstances".

In the second year, 1995/6, out-turn prices were again very close to the level specified in the undertakings, but this time both were within the cap. There was a brief discussion of the possibility of continuing with a price undertaking, but the regulator made it clear that he preferred not to do so. The only attempt to regulate the level of prices was not a particularly happy experience. The undertakings certainly helped those large customers who were buying at Pool-related prices in the winter of 1994-95. They may have kept annual contract prices down, although we cannot know whether prices would in fact have continued to rise in the absence of the undertakings. They had no real impact on the prices paid by small consumers, which depended on five-year contracts unaffected by the undertakings. On the downside, some traders alleged that they had been disadvantaged in early 1994, when National Power and PowerGen knew of the undertakings that were about to be announced, and traded accordingly. The prices in the undertakings were chosen on an *ad hoc* basis. This was acceptable for a one-off negotiation, but a more formal process would have been required for a continuing price cap, and it would have been hard to calculate an appropriate level. The undertakings had the potential to affect the revenues of every company in the industry. Nuclear Electric in particular had been seriously disadvantaged, since it had generally sold more of its output in the Pool or on short-term contracts than other generators. In 1994, the company had been owned by the government, which could absorb the cost of its regulator's actions, but by 1996, the more modern stations had been privatised. Mitigating market power by capping the overall price of electricity would effectively have meant abandoning the market-based ethos of the privatisation.

In the long term, market power mitigation therefore depended upon the other undertaking, that designed to change the market structure. The formal undertaking did not require the generators to seek the regulator's approval for the manner of the disposal, but since the regulator had only committed himself not to seek an MMC reference during the two-year period in which the generators were to arrange the sales, it was obviously in their interest to ensure that he was happy with the manner in which they were carried out. The prospectus for the privatisation of the second tranche of PowerGen's shares (Kleinwort Benson Limited, 1995) hints at the negotiations that took place, and the company's fear that it would be unable to negotiate a mutually acceptable plan.

In the event, both companies were able to find deals that satisfied the regulator, and leased their plant to Eastern Group, one of the RECs. The key issue was that both generators wanted to impose an "earn-out", of £6/MWh, on each unit generated by the leased stations, alongside any annual lease payments. The problem, from the generators' point of view, was that most of the remaining coal-fired stations had very similar costs. The stations with higher costs included those recently fitted with Flue Gas Desulphurisation equipment to reduce emissions of sulphur dioxide, which reduced their thermal efficiency by about ten percent. The generators wanted to operate those stations at high load factors (and had come under political pressure when it appeared that their load factors were falling), which meant that their other stations were bidding above cost to stay further down the merit order. The divested stations could have undercut these stations, increased their output, and moved out of the mid-merit part of the market. The generators were worried that the regulator would then decide that mid-merit competition had not yet increased sufficiently, and call for further divestitures. In the end, the regulator allowed the disposals to go ahead on this basis. In one sense, the earn-out made the divested stations less

effective as competitors, but it did keep them in the right part of the market, increasing the elasticity of each major generator's residual demand curve.

One factor that helped persuade the generators to bite the bullet and actually dispose of their plant was their desire to merge with RECs. In September 1995, PowerGen announced a merger with Midlands Electricity, closely followed by National Power, which planned to merge with Southern Electric. Both mergers were referred to the Monopolies and Mergers Commission, which reported the following March (MMC, 1996a, b). Unusually, the commission's report was leaked before the relevant Minister⁶ had made his decision on the case. *The Economist* based its lead story on the leak, and was very critical of the Commission's majority view that the mergers could be acceptable, given certain conditions. A note of dissent by one of the five Commission members responsible for the report held that the structure of the industry was still in flux, and that allowing the mergers at this point, which would make entry into generation more difficult, could foreclose some of the more competitive options. Many other commentators took the same line, and the Minister in due course announced that he was blocking the merger.

Merger policy might seem remote from market power mitigation, but it can be important in minimising the amount of market power that has to be mitigated. If National Power and PowerGen had merged with RECs in 1996, potential entrants into generation would have found fewer would-be buyers for their output. At the time, almost all entrants had signed long-term sales contracts with RECs before starting to build their stations, and no-one knew whether "merchant plant" would be financially viable. Their greater risks would have been reflected in a significantly greater cost of capital than stations with long-term contracts, and hence a higher entry price. Since the fear of entry was a potential constraint on wholesale prices, mergers that would have made entry less likely, and raised the price at which entrants could compete, could have allowed the major generators to raise their prices.

5. Changing the rules: 1997-2001

In May 1997, a Labour government took office. The Labour Party still had strong emotional ties to Britain's coal miners, although their numbers had fallen from 300,000 in 1979 to barely 16,000 in 1997. Much of this decline had been due to greater productivity in the coal industry, as output had been concentrated on fewer, more mechanised, pits, but part was due to a reduction in the amount of coal burned in power stations. There had been a "dash for gas" in the early 1990s, as both the RECs and the major generators ordered CCGT stations. The RECs had wanted some unregulated income and a hedge against the major generators' market power (or perhaps the ability to share in it, if wholesale prices stayed high). The major generators saw gas-fired stations as the best way to meet targets for reducing sulphur emissions and maintain market share in the face of the inevitable threat from new entrants. A second "dash for gas" in the mid-1990s had continued the trend. By 2000, 39% of the UK's electricity came from gas-fired stations, compared with less than 1% in 1990.

The original set of linked coal and electricity contracts imposed at privatisation had ended in 1993, and the government had helped to broker a set of five-year contracts to replace them, albeit with much lower volumes of coal. In the autumn of 1997, it became clear that the electricity companies would be reluctant to

⁶ The Victorian title of President of the Board of Trade was being used by the Secretary of State in the Department of Trade and Industry at this time.

agree another set of long-term contracts, and that their coal requirements were set to fall further.

The government announced a moratorium on new gas-fired power stations, ostensibly to help the coal industry. This took the form of refusing to issue the formal consent⁷ needed before work could start on new stations, and accordingly had no impact on the stations already under construction, or the demand for coal over the next two years. To look at the long term issues, the government started a review of energy sources for power stations, and in October 1997, asked the regulator “to consider how a review of electricity trading arrangements might be undertaken” (Ofgem, 1999c, p13). The regulator produced his interim conclusions in June 1998, recommending that the Pool should be replaced (Offer, 1998b).

5a The market rules

The regulator had become disillusioned with the Pool. It had been designed to make rule changes difficult, in order to protect minority interests, but in practice this had allowed small numbers of companies to block changes widely thought to be desirable. Demand-side bidding was a case in point. An experimental scheme had been introduced to allow a few industrial and commercial customers to bid demand reductions into the Pool as a kind of “negative generation”, but while the scheme was cumbersome, and pleased no-one, it had been impossible to agree on a successor. NGC was required to schedule plant against a demand forecast, and was explicitly forbidden to predict any responses to market prices when producing this forecast.

The Pool Rules, and in particular the way in which prices were determined, were extremely complex. This deterred secondary trading in electricity, although since the coal-related contracts had covered a high proportion of most companies’ requirements until April 1998, the primary trading volumes that would have to lie at the heart of a secondary market were also very low. The complexity had also made it possible for the generators to learn how to “game” the rules and raise their revenues – each time the regulator had frowned on a particular practice, the generators had adopted another. The generators gained from the fact that their bids were not “firm” – if a station became unavailable, it had to buy back its scheduled output at its own bid price, which generally implied that it would retain a profit margin, rather than having to pay for the costs of replacement generation. Similarly, all demand paid the same price, whether it was completely predictable, requiring little in the way of reserve generation, or very unpredictable, imposing significant reserve costs.

The fact that the Pool was a compulsory market went against the instincts of some, even though it was generally possible to use a zero price bid to ensure that your plant was scheduled, and contracts for differences to lock in revenues, regardless of the Pool price. “On-site” generation was not required to pay for the system costs recovered through Uplift, and an earlier consultation on “Trading outside the Pool” (Offer, 1994b) had attracted some respondents who seemed to think that by-passing the Pool would also allow them to avoid these costs.

The most important charge against the Pool, however, was that its uniform price rule enhanced market power. The simplest version of this argument is based upon a fallacy – some stations bid zero, but get the market price, so if they were only paid their own bid, the average price would fall. The fallacy ignores the fact that the stations would promptly change their bidding strategy if the market rules were changed. In a competitive market with no risk aversion, the change in strategy would

⁷ Under the Section 36 of the Electricity Act 1989, the government had to give consent for all new power stations, but the consent had not been used as a barrier to entry before this time.

exactly offset the change in market rules – an implication of the revenue equivalence theorem in auction design. There were suggestions that some generators would be so anxious to ensure that they were scheduled that they would be willing to sell for less than the going market price, which would indeed reduce the cost of power. A counter-argument might suggest that some suppliers would be anxious to secure supplies and pay more than the going rate.

The key argument related to the way in which the uniform price rule reduced the risks of attempting to raise the market price. A generator could bid in most of its plant at low prices, ensuring that they would be scheduled to generate, and submit a few bids at significantly higher levels, hoping that these would set the price received by all stations. In practice, the fact that the bids had to last for twenty-four hours limited the impact of this. Stations that attempted to raise the over-night price might risk not being called when demand picked up in the early morning, although it could have been an attractive strategy at peak times.

Against this, low-cost plants would face a difficult problem in deciding how high to set their prices, aware that they lose money from bidding too low, but might not be scheduled if they asked for too much. Bower and Bunn (2000) use a simulation model to suggest that bilateral trading would in fact produce *higher* prices than the Pool, due to the generators' reactions to issues of this kind.

The Pool was also criticised for discriminating against coal, and in favour of nuclear and gas-fired plant. The complaint was actually more about market power than the Pool itself. Nuclear and gas-fired generators had increased their output, bidding low to ensure that they were scheduled but still receiving the Pool price. As discussed above, changing the rules would have changed their strategy, but not necessarily their revenues. The problem for the coal industry was that the major generators had preferred to keep prices up, reducing their output and their demand for coal, rather than to enter into a price war. The generators' preference for high prices did not depend upon the Pool's existence.

The regulator concluded that the Pool should be abolished and replaced with "trading arrangements more in line with those being adopted in other competitive commodity and energy markets" (Offer, 1998, p 3). Eventually, these New Electricity Trading Arrangements (NETA) consisted of bilateral forwards and futures markets, and (originally) three power exchanges for trading until shortly before delivery, organised independently of the NETA programme, a balancing mechanism run by NGC, and a process for imbalance settlement. In the balancing mechanism, NGC accepts offers to raise output or reduce demand, if it is short of power, and bids to reduce output or raise demand if it has a surplus. All of the accepted trades are bilateral transactions with NGC, paid their own bid or offer. Any market participant that is short of power when its physical position and its contract holdings are compared has to pay the System Buy Price, originally the average cost of the accepted offers in the balancing mechanism. Any market participant that has a surplus of power when its physical position and its contract holdings are compared was paid the System Sell Price, originally based on the average cost of the accepted bids in the balancing mechanism. In NETA's first year, the mean System Buy Price was £38.66/MWh, while the mean System Sell Price was £9.20/MWh. The difference was intended to penalise those participants who were out of balance, and give them an incentive to balance their positions before bilateral trading between participants stopped, at "Gate Closure".

In October, the government accepted the regulator's proposals (DTI, 1998), and the detailed design work started. The original plan was to switch to NETA in the

autumn of 2000, but the timetable slipped, due to the complexity of the systems involved. NETA eventually started on March 27, 2001, at a cost of £580 million.⁸

5b The generators' rules

The electricity market did not stand still while NETA was being discussed and implemented. National Power and PowerGen had divested 6 GW of plant in 1996, but this proved inadequate to restrain their market power. In real terms, the annual average (time-weighted) Pool price had fallen each year from 1993/94 to 1996/97, but the following year, it rose slightly. More significantly, there was a dramatic increase in SMP, offsetting a sharp reduction in capacity payments. This implied that the generators had been setting SMP at a level that they believed produced an “acceptable” overall price, even after the end of the undertaking on prices. The regulator returned to his previous practice, of publishing a report examining events and recommending remedies. He stated that there was “no justification” for the higher prices, and concluded that “the most effective route for increasing competition in the short term would seem to be to transfer more of National Power’s and PowerGen’s coal-fired plant into the hands of competitors” (Offer, 1998a, p 36).

In July 1998, PowerGen bought East Midlands, one of the RECs. The Director General of Fair Trading, the government’s general advisor on competition policy, considered that this deal should be referred to the Monopolies and Mergers Commission, like the 1995 merger attempts. The regulator, however, believed that the deal could be used as a lever for plant divestments. He recommended that the merger should be allowed, provided that PowerGen divest 6 GW of plant, out of the 14 GW it then owned. The RECs’ franchised monopoly over supply to small customers was about to end, and the regulator must have believed that greater competition in generation would offset any problems that vertical integration might create. The government followed the regulator in allowing the deal, but only required the divestiture of 4 GW of plant. These divestitures must not contain any earn-out provisions, and PowerGen was also required to end the earn-out clauses in its existing lease with Eastern.

In November, National Power announced that it was buying the supply business of Midlands Electricity, and that it wished to sell Drax, a 4 GW coal-fired station. National Power was slightly larger than PowerGen (with 16 GW of plant at this time), and the new electricity regulator joined the Director General of Fair Trading in arguing for an MMC reference. The Secretary of State for Trade and Industry, however, treated National Power in the same way that his predecessor⁹ had treated PowerGen – 4 GW of plant disposals and the end of the earn-out with Eastern would be sufficient to allow the merger.

While the generators were negotiating these sales, in February 1999, Offer published its eighth report on Pool prices (Offer, 1999a). The main issue was the number of “spikes” that were being produced – high levels of SMP that only lasted for a short period. The generators were bidding an increasing number of units with a low “incremental” price for most of their capacity, but a high incremental price for the

⁸ NAO (2003, p.2) cites costs of £39 million for Ofgem and the Department of Trade and Industry, and an Ofgem estimate of up to £580 million in costs for the industry. It also states that closing the Pool cost £40 million less than expected, which I am offsetting against the other estimates.

⁹ The regulator’s advice on a reference was given after Callum McCarthy had taken over from Stephen Littlechild as Director General of Electricity Supply in January 1999, while Peter Mandelson resigned as Secretary of State for Trade and Industry in December 1998, and Stephen Byers succeeded him.

last few MW. The scheduling programme, SUPERGOAL, would normally avoid scheduling the high-priced MW, but would occasionally find that they were the cheapest way of meeting a small increase in demand – the cost of those MW would be less than the cost of starting up another station. Unfortunately, the Pool rules set SMP very close to the price of those few MW, and applied it to all the electricity traded in that half-hour.¹⁰ The average level of prices was no higher in 1998/9 than the previous year, but the regulator was concerned that the increasing volatility would lead to an increase in contract premia.

The Pool had already agreed to make some changes to the scheduling software that would reduce the incidence of these price spikes. The report suggested that further changes might be desirable, in particular requiring generators to bid a single incremental price per MWh scheduled for each unit (in addition to a price for starting up and for running in each half-hour). This would make it impossible to bid a few units at a high price. The report also suggested that “inflexibility markers”, which allowed generators to declare that their plant would have to run in a particular way, guaranteeing its output, but removing it from the price-setting process, might also be abolished. Inflexibility markers had been intended to reflect operational constraints, but their “commercial” use was commonplace. Reducing the number of stations able to set SMP made the price more volatile.

Following consultation, the regulator decided not to make any of these changes to the rules (Offer, 1999b), but promised to monitor the Pool closely, and adopt them if problems recurred. Problems did recur, in the regulator’s opinion, in July. In the first two weeks of the month, the Pool Purchase Price was £32.52/MWh, some 80% higher than in the same period of the previous year, partly due to higher capacity payments, and partly due to an increase in SMP. National Power and PowerGen had taken the opportunity to raise their bids, compensating for an earlier period of lower prices. The regulator’s view was that in a competitive market, it would not be possible to behave in this way (Ofgem, 1999a).

The regulator largely rejected changes to the Pool Rules as a means of preventing similar problems in future – the actions taken against price spikes had worked, and National Power and PowerGen could have raised prices, even if the pricing rules had been much simpler. He did raise concerns about the way in which capacity payments were calculated – the high payments had not been due to a particular shortage of plant, but to the way in which newer stations were often treated as relatively unreliable when calculating the loss of load probability (Ofgem, 1999b).

His preferred approach was to insert a new condition into the licences of the larger generators. The market abuse licence condition, as it would become known, would prohibit the abuse of a position of substantial market power. In particular, the generator might be abusing its position if it “(a) acts in such a way as materially to prejudice the efficient and economical balancing of the transmission system; (b) without good cause limits generation or capacity availability in such ways as materially to increase wholesale prices for electricity; or (c) pursues discriminatory pricing policies by determining wholesale prices for electricity that differ unduly between times when market demand and cost conditions are otherwise similar” (Competition Commission, 2000, p 382). If the regulator believed that a generator

¹⁰ Ironically, if the station had generated the additional MW throughout the day, the price-setting formula would have produced a much lower price. The formula gave the average cost of power from the unit if it stayed in the same output range throughout the day, and the addition of a few high-priced MW in each half-hour would have little impact on this average cost. The formula failed to adjust correctly for a unit that switched between incremental prices during the day.

was in breach of the condition, he would investigate, and could issue an Order requiring the company not to repeat the behaviour. Failure to comply with the Order could be penalised.

Following further consultations, the regulator asked the seven largest generators to accept the condition in their licences on January 31, 2000. National Power, PowerGen, TXU (formerly Eastern), Edison (which had bought plant from PowerGen the previous year) and BNFL Magnox (the state-owned company running the oldest nuclear stations) all accepted the condition. London Electricity also did so a few months later, when it bought Sutton Bridge power station and became large enough to qualify. British Energy (the nuclear generator privatised in 1996) and AES (which had bought Drax from National Power) refused to accept the condition, however, and the issue was referred to the Competition Commission.

The regulator showed how the condition would work in practice in July 2000, when he published an investigation into the withdrawal of capacity by Edison. The company had closed a 500 MW unit at one of its coal-fired stations at the end of March, expecting prices too low to sustain its profitable operation. Prices subsequently rose significantly, and on 15 June, Ofgem announced that it would launch a formal investigation, after (confidential) correspondence and discussions with Edison had failed to resolve the situation. On 12 July, Ofgem announced that it had found Edison's withdrawal to be in breach of the condition, but that, since Edison had agreed to return the unit to service, Ofgem would take no further action (Ofgem, 2000). Ofgem's position was that Edison had substantial market power, for taking the unit out of service had increased Pool prices by 11.5% over the first 47 days of 2000/1, due to higher capacity payments. Ofgem argued that Edison's avoidable costs were lower than the station's revenues would have been, and so withdrawing the unit was not a normal competitive response. In later submissions to the Competition Commission, Edison disputed Ofgem's views, arguing that the key factor had been the failure to obtain a contract for the unit's output before it was withdrawn. Once a suitable contract was obtained, the company took the decision to return the unit to service (Competition Commission, 2000, 2.214).

The Commission commented that it was unfortunate that the investigation had not resolved the issues of when Edison might have been able to obtain a suitable contract, and whether Edison could reasonably have foreseen the impact of its withdrawal on prices. If Edison had not been able to foresee that prices would rise so much (i.e., if the conditions in which they did rise were unusual), then the regulator's actions effectively relied on hindsight.

One other unusual feature of the case is that there was no public investigation into TXU, which had actually withdrawn 2 GW of plant, four times as much, at the same time as Edison, but announced that it would return 500 MW to service on June 13. The Competition Commission's report, however, contains five paragraphs referring to another investigation, but with all the text removed from the published version, which normally implies that the matters discussed there are commercially confidential. Because the Commission tries not to change the formatting of the report, it is possible to infer that the subject of this other investigation had a very short name. Could TXU have held the same kind of confidential correspondence as Edison during May and early June, and avoided adverse publicity by agreeing to return a single unit (out of four withdrawn), two days before Ofgem reported that Edison was under investigation?

Did the market abuse licence condition fulfil its intended purpose, protecting consumers by forcing a reluctant generator to return plant to service? Alternatively,

were Edison's worries about the regulator's calculations, and the Commission's about the possible reliance upon hindsight, justified? Was it desirable that Ofgem's discussions with a second company were kept secret? This is particularly relevant when Ofgem had promised that companies would be able to obtain confidential guidance if they were unsure whether particular bidding tactics would be in breach of the condition. Any general principles that emerged would be published, but there was still "a risk that market participants which have received such guidance will have an information advantage over those which have not" (ibid, 2.255).

In the event, the Commission decided that leaving British Energy's and AES' licences unmodified could not be expected to operate against the public interest, reporting in December 2000. The regulator accordingly withdrew the market abuse licence condition from the licences of the companies that had already accepted it, as he had promised to do in the interests of non-discrimination. He had argued that the Commission should take this action, and its effects, into account as a consequence of failing to include the condition in the licences of the companies they were reporting on. The Commission, however, took a narrower view, and concentrated on the potential behaviour of the two companies alone.

The Commission distinguished between the abuse of market power and the manipulation of market rules, considering that the latter should be dealt with mainly by changing those rules. All wholesale electricity markets rely on some rule-based arrangements for short-term balancing, but the Pool had been more vulnerable than NETA would be, because prices for all generators were based upon rules. The Commission paid more attention to the danger of market manipulation under the Pool than under NETA, in part because it was hard to predict what would happen. AES held a long-term contract to sell its output to TXU, which meant that it had no incentive to raise Pool prices by reducing its output.¹¹ British Energy also held enough contracts for the expected life of the Pool, which was then due to end on 27 March 2001, to have no incentive to withhold capacity before that time. The Commission saw a small danger that if the life of the Pool was prolonged (which did not in fact happen) and British Energy chose to remain under-contracted during that period, it would have an incentive to raise Pool prices. The Commission did not believe that keeping itself under-contracted in the run-up to the introduction of NETA would be a sensible strategy for the company.

The Commission acknowledged that it was difficult to predict the opportunities that might exist to manipulate market rules or to abuse market power once NETA had started. However, NETA had been designed to be less vulnerable to manipulation, and the Commission expected all of its components apart from the balancing mechanism to be reasonably competitive, given the number of traders (ibid, 2.231). The Commission also noted that the governance arrangements were designed to allow rapid rule changes in response to problems. The Commission was concerned that the broadly-based market abuse licence condition would cause uncertainty, "because of the difficulty of distinguishing between abusive and acceptable conduct, and would risk deterring normal competitive behaviour" (1.12). The Commission believed that "competition should be given the opportunity to work in the new circumstances of NETA, and with a less concentrated generation sector, without the introduction at this stage of new broadly-framed regulation" (ibid).

The government and the regulator considered reintroducing a modified, narrower, version of the condition, using the Secretary of State's "NETA power"

¹¹ Reducing output would presumably have made the company into a net buyer in the Pool, just as prices had risen!

(DTI, 2001a). For a limited period, the Secretary of State could impose licence amendments on electricity companies, without either their consent or a reference to the Competition Commission, if this was necessary as part of NETA. A number of generators argued that to use this power to impose a condition so close to the one that had been rejected by the Commission was inappropriate, and in December 2001, the government quietly announced that it did not believe that it was “at present ... necessary or expedient to use the Secretary of State’s NETA power in this area” (DTI, 2001b).

6. Market power after NETA

Although the condition’s reception had been hostile, the main reason for the change of heart is likely to be the performance of NETA. The average level of prices was initially much lower than under the Pool, to the extent that a number of generators faced financial difficulties, most notably British Energy and AES. TXU Europe also left the market, although given its physical position as a net buyer in the wholesale market, it should have gained from lower prices – the problem was that it had agreed too many long-term contracts to buy power at what turned out to be excessive prices. Prices in the balancing mechanism have been volatile, but a number of rule changes to reduce this volatility have been agreed, and NGC has learned to operate the system without calling on high-priced generators as often as it used to. It appeared that the problem of market power in England and Wales may have been solved.

One of NETA’s design objectives was to give the regulator more ability to change the market rules. Rule changes must be proposed by the industry, and are assessed by the Balancing and Settlement Code Panel, which is required to make recommendations to Ofgem as to whether a proposed change will help meet specified objectives. Ofgem, or rather its governing Authority, then decides whether to approve the change. This has allowed a large number of modifications to be made since NETA came into effect, some of them processed very quickly.¹²

One significant modification changed the timescale for the balancing mechanism. At first, bilateral trading had to stop three and a half hours before real time, to give NGC as much time as possible to balance the system, after the deadline for gas suppliers with interruptible contracts to notify power stations that their fuel was going to be cut off. As NGC gained experience, it was willing to allow bilateral trading for longer, and the gate closure at which bilateral trading had to cease was moved up to one hour before real time. This reduces the length of time for which generators will be exposed to imbalance charges if they have an unexpected outage, reducing risks and hence costs. NGC, meanwhile, is allowed to start to trade before gate closure, so that plant that requires more time to get ready can be prepared.

Another modification concerned the imbalance prices. There had been concern that most market participants were trying to have a positive imbalance, rather than to be perfectly balanced, and succeeding in this, on average. This made NGC’s life harder, as it had to cope with the consequences of generators wanting to produce more power than they had sold to suppliers who were trying to buy more power than their customers would take. Since generation has to equal customer demand, NGC had to get rid of the surplus in the balancing mechanism, or try to reduce it by trading

¹² Since August 2005, market participants have been able to appeal to the Competition Commission if the Authority and the BSC Panel disagree on whether to implement a modification, providing a balance to the regulator’s powers that had previously been missing.

beforehand.¹³ Furthermore, it seems harsh to penalise a market participant for an imbalance in the opposite direction to the market as a whole – the individual imbalance is then lowering the market imbalance, and reducing costs. A modification to the rules for setting imbalance prices took effect in February 2003, so that imbalances in the “neutral” direction will be cashed out at a price based on trades in the short-term markets, rather than at NGC’s accepted offers or bids. The gap between the System Buy Price and the System Sell Price fell significantly once this rule change took effect.

Ofgem’s own view is that “available evidence suggests that the electricity generation sector in the UK is competitive” (2003a, p 2). This has become clear from the way in which it has treated a number of regulatory decisions since NETA came into effect. In September 2002, PowerGen applied to have the licence condition that required it to give the regulator information about its stations’ availability and its closure plans removed from its licence.¹⁴ Following a consultation, Ofgem agreed that the condition would be disapplied – it is still in the licence, so can be turned on again if required, but for the time being, the company does not have to provide the information specified in the condition. Ofgem’s reasons for disapplying the condition were that it had adequate powers to obtain most of the information in other ways, and that the market had become much more competitive than when it was first introduced. Innogy (the former National Power) and British Energy soon followed suit and had the condition disapplied in their own licences.

The industry has become increasingly vertically integrated over time. When Eastern acquired plant from National Power and PowerGen, taking it well over its own-generation limit, the REC was required not to buy any more electricity from affiliated power stations in order to resell it to small consumers in its own area. Since the restriction would apply to new contracts with the REC’s existing power stations, the intention was that such self-dealing would eventually wither away. Other mergers between generation and incumbent supply businesses were subject to similar restrictions. In 2002, however, Ofgem started a consultation on lifting these restrictions. One reason was that it had become unenforceable – the companies just did not have identifiable portfolios of contracts that could be assigned to particular customer groups. The second reason, again, was the increase in competition. Ofgem decided that the retail market was sufficiently competitive, and the wholesale market sufficiently liquid, that vertical integration did not pose a threat to competition (2003b). It finally lifted all the self-supply restrictions in April 2004.

Ofgem’s response to recent merger proposals, however, is the clearest indication of its views on the state of the industry. Without exception, every merger proposal since 2002 has been waved through without suggesting that it may be necessary to make a reference to the Competition Commission. This includes even the October 2002 merger between PowerGen and TXU Europe, the former Eastern Group, which added 3 GW of capacity and two REC supply businesses to what was still one of the largest generators in the country. To allow such a merger without

¹³ NGC could sell power to a supplier as if it were a generator itself, thus reducing the amount that the real generators would try to produce. Some market participants were very wary of allowing NGC to trade energy, warning of the company’s privileged access to information, particularly about the transmission system and how this might affect the way it would be balancing the market. While NGC had been prohibited from trading energy in 1990, presumably because of such fears, the regulator has been willing to allow this in the context of NETA.

¹⁴ The old condition 9A had been renumbered as Licence Condition 18 when licences were reissued at the time of NETA.

suggesting further investigation is a clear sign that Ofgem believes that the industry is now sufficiently competitive.

7. Assessment

The structure created at privatisation is widely acknowledged to have been a mistake. In the early years, the major generators had a lot of market power, and the regulator had a difficult task in preventing its abuse. His main weapons were publicity and the threat of a reference to the MMC. A series of reports highlighted what he saw as acceptable practices (bidding to allow a constrained station to recover its estimated annual costs) and unacceptable ones, and put the generators under pressure to avoid the latter. At the same time, he recognised that Pool prices in the first few years of the restructuring were artificially low, and that some increase was justified. Wolfram (1999) finds that the generators could have supported a much higher Lerner index (price-cost margin relative to price) than they actually obtained, implying that their market power was restrained over this period.

When the increase in Pool prices went too far, the regulator used the threat of a reference to the MMC to persuade the generators to divest some of their plant, and to agree to the price undertaking. This did protect some consumers to some extent, but was controversial when it was introduced, and would have been impossible to continue, except as a formal price control, completely inappropriate in a competitive market. Long-term benefits thus depended on the divestitures. Unfortunately, Eastern proved almost as happy to keep prices high as National Power and PowerGen had been, and the earn-out clause certainly raised its marginal costs. At the same time, without the earn-out, the stations could well have been operated at base load, failing to create competition in the market segment where that was most wanted. Prices fell, but were still above estimates of new entrants' costs. Sweeting (2004) finds that the generators' bids were roughly in line with their best response functions¹⁵ between 1997 and September 2000, whereas they had been supplying more than was privately profitable in 1995 and 1996. In other words, the divestitures reduced their market power, but they started to use all, rather than just a part, of it.

The generators' second attempts at vertical integration gave the opportunity for further regulatory divestitures, which were followed by voluntary plant sales during 2000. These sales fragmented the market and SMP finally fell significantly. The overall level of prices did not fall as much, for capacity payments were high in the Pool's last two years. This seems to have been due to the mix of plant, and occasionally high levels of outages, rather than to strategic behaviour on the part of generators. At some times in the past, low levels of SMP had been in part a reaction to high capacity payments, in order to produce "reasonable" overall prices. If this was still the case, then the Pool was arguably still prone to market power. Given the increasingly fragmented market and the vertical integration by most of the large generators (reducing their incentive to raise wholesale prices), however, it is more likely that the reduction in SMP was a genuine competitive effect. Evans and Green (2005) find that a supply function model of generators' behaviour predicts monthly

¹⁵ These best response functions were the most profitable schedules of prices and quantities that a generator could have chosen for each day, given the industry demand and rival firms' bids, and hence the residual demand facing that generator. In another set of simulations, taking the generators' likely contractual positions into account, Sweeting finds that they may even have been selling less than would have been privately profitable, behaviour consistent with tacit collusion to raise prices.

average prices (using SMP and then the closest equivalent, the UKPX Reference Price Data) reasonably well throughout this period, with no evidence of a structural break at, or near, the change in market rules.

The way in which the Competition Commission approached the market abuse licence condition was partly responsible for the latter's demise. If the Commission had considered the implications of withdrawing the condition from every generator's licence, rather than just those of AES and British Energy, would they have found more cause for concern? There is a potential gap in the regulator's powers to deal with abuses in electricity markets. General competition legislation in both the UK and the EU deals with the abuse of a dominant position, generally defined as a market share of 40% or more. In electricity markets, when the supply-demand balance gets tight, much smaller firms can abuse their position. However, it can be nearly impossible to identify the particular firm that was "responsible" for an episode of high prices.

The best way to achieve a competitive electricity market is to ensure that the rules can be changed if loopholes are manipulated, and that the structure is competitive, with a reasonable number of generators. For most of its life, the Pool performed very poorly on the first count, although it became somewhat more responsive towards the end of its existence, and NETA is clearly an improvement on this front. The market structure in England and Wales became far more competitive during the final years of the Pool, and prices fell.

Can changing the rules mitigate market power in general? Ofgem and the government have implied that the price reductions from 1998 onwards were, at least in part, "in anticipation ... of NETA" (e.g. Ofgem, 2001, p 12), and that by changing the market rules, NETA had a significant impact on generators' ability to exercise market power. Bower (2002) and Newbery and McDaniel (2003) suggest that the reduction in energy prices was due to increased competition, not the change in the rules, although the abolition of capacity payments clearly contributed to the lower overall price level. Evans and Green (2005) confirm this result by showing that the relationship between market fundamentals and prices did not change at any time close to the introduction of NETA.

One final point is that contracts (for a year or more) affect behaviour in spot markets. Their very high levels of contract cover in the early 1990s meant that National Power and PowerGen could afford low prices in the Pool. Short-lived price spikes cause little damage if most trades are covered by contracts. Contracts are not a panacea, however, for they have to be renewed, and generators with market power will then want to ensure that spot prices are at a level that makes the contract prices they desire attractive to buyers. The best way to mitigate market power is by starting with a competitive structure, and making sure that concentration does not rise over time.

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Generators' Output in England & Wales

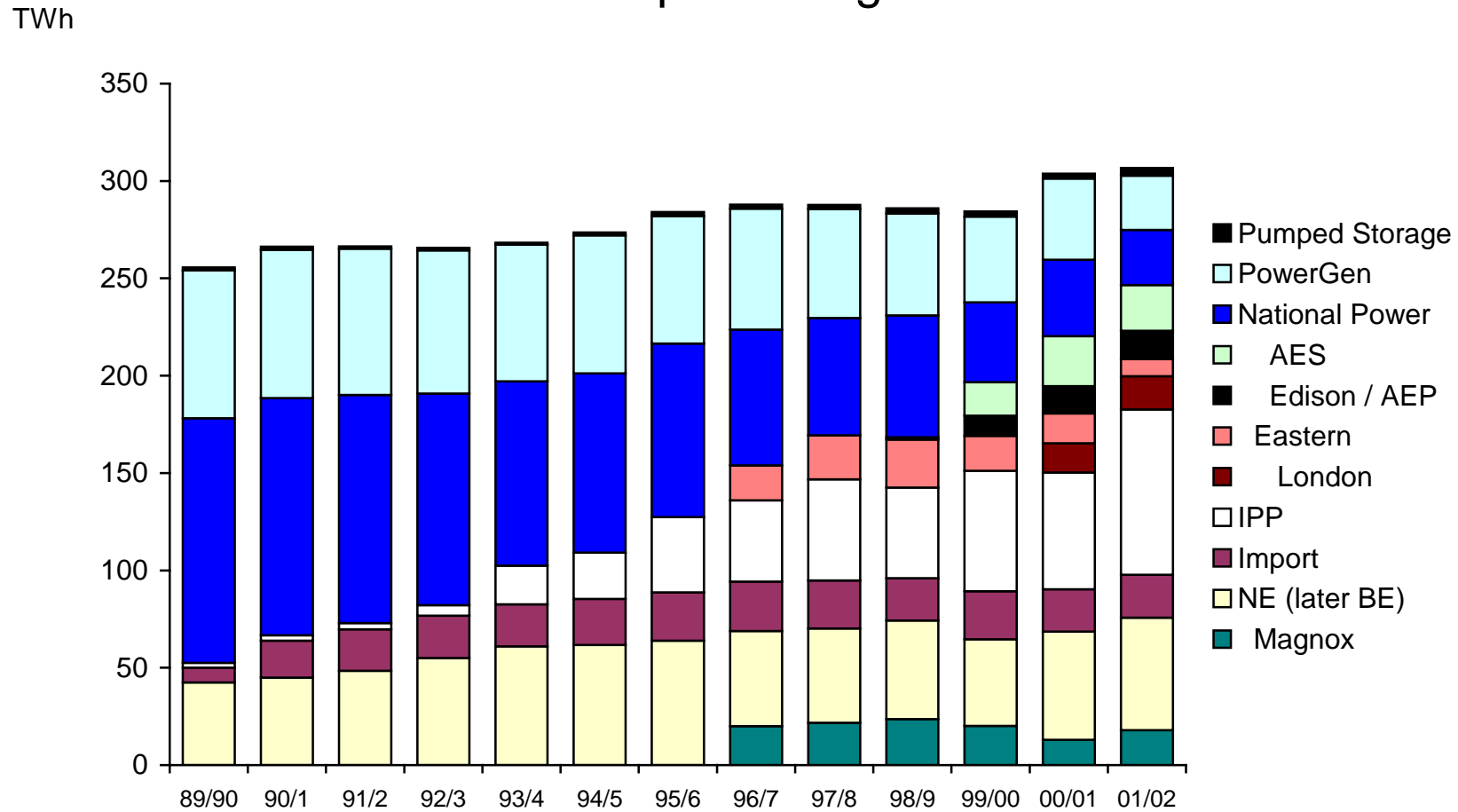
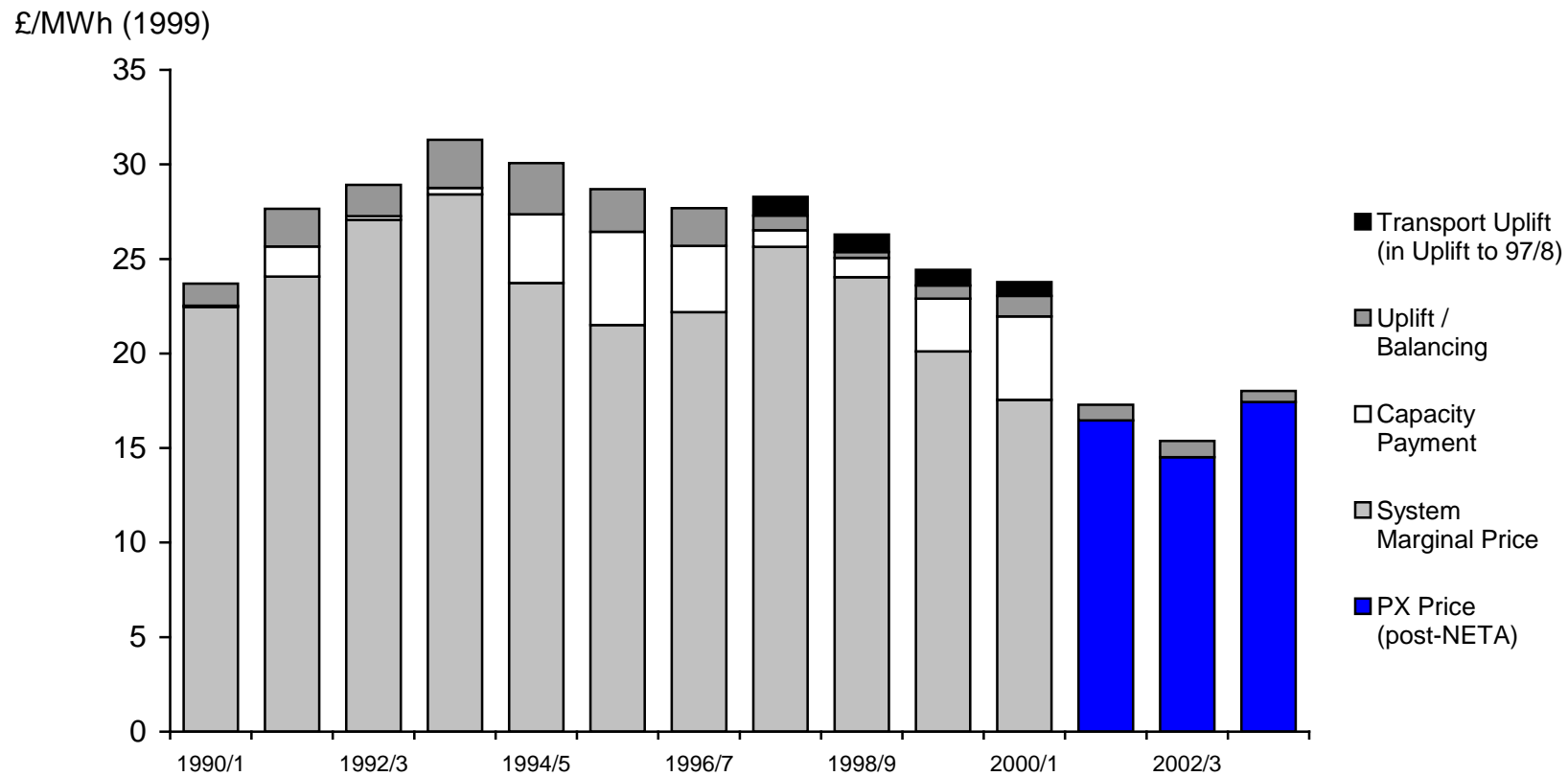


Figure 1 (Output from Eastern and London is included in Independent Power Producers while those companies only had a little capacity)

Real Electricity Prices in England & Wales



PX price refers to the UKPX Reference Price Data, used with permission

Figure 2