A Report on Generator Market Power in the Electricity Market of England and Wales

Volume I

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November 1997

Commissioned by Enron Europe, Ltd.

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November 28, 1997

We are pleased to present the attached report on the performance of the electricity market in England and Wales. Our brief was to examine the efficiency and competitiveness of the market and, where appropriate, to make recommendations for change. The findings of the report are principally based upon an analysis of actual bids submitted by the generating sets that supply electricity to the Pool, and upon the resultant half-hourly Pool prices.

Our study has benefited from the comments and assistance of Mark Schroeder, Paul Dawson, Keith Miller, and Carl Tomlinson of Enron. We also wish to express our gratitude to Hannes Pfeifenberger, Lauren Renshaw, and Megan Talbott at The Brattle Group. Stephen Aller's assistance with computer programming was also greatly appreciated. However, we remain solely responsible for the views expressed in this report.

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Executive Summary

The privatisation of electricity generation in England and Wales has led to significant improvements in operating efficiency. However, the success of the restructuring effort has been marred by the problem of generator market power. Entry by independent generating companies has not solved the problem, nor has the recent divestiture of generating plant to Eastern Group.

Control of plant that sets System Marginal Price ("SMP") continues to be highly concentrated, and Eastern has engaged in strategic bidding behaviour similar to that of National Power and PowerGen. The divestiture of generating plant to Eastern has not produced a reduction in SMP. Rather, SMP remains above competitive levels— by more than £700 million in 1996 alone. £700 million represents approximately 4% of total electricity costs to consumers, a significant percentage considering that electricity bills have fallen only 9% since privatisation. Moreover, our estimate of excessive SMP payments is conservative because it covers only half of the total electricity produced in the Pool, excludes the impact of generator market power on other components of electricity prices (such as capacity payments and Uplift), and excludes the impact of generator market power on forward contracts. Consistent with our findings of excessive electricity prices, generator market power has coincided with high profitability for National Power and PowerGen.

High electricity prices and high generator profits do not tell the whole story. Market power has also been compounded by inappropriate rules and other deficiencies in the electricity Pool of England and Wales. Market power and a lack of transparency have inhibited the development of a liquid forward market.

We recommend the additional divestiture of generating plant by the dominant generators. Divestiture need not take the form of a forced asset sale. Rather, divestiture could occur through the split of a generator's assets into different companies, with the shares retained by existing shareholders. The recent division of British Gas into BG plc and Centrica was such a transaction.

Other important reforms include the public disclosure of generator positions in electricity forward contracts and the introduction of effective demand-side bidding. However, divestiture remains unique among possible reforms in addressing directly the existence of generator market power. Other reforms may improve efficiency and complicate the exercise of market power, but do not eliminate the source of the problem. Simply to wait for more entry is a slow and expensive alternative. Additional divestiture would reduce market power immediately and increase efficiency, allowing consumers a greater share of the benefits to privatisation than they have enjoyed to date.

Introduction

1. Generator market power has been a problem in the England and Wales Pool since privatisation. OFFER has responded to the problem by imposing caps on Pool prices and by securing the agreement of National Power and PowerGen to divest approximately 6,000 MW of generating capacity. At the same time, independent companies have entered the market successfully. However, these events have not eliminated the problem of generator market power. The control of generating plant that can influence Pool prices remains highly concentrated, strategic bidding behaviour continues, and prices remain above the levels that would be expected in a fully competitive market.

2. Generator market power would best be addressed by the additional divestiture of plant by the dominant generators. We recommend divestiture by the spin-off or "de-merger" of SMP-setting plant into multiple companies, with existing shareholders retaining the shares to the companies so formed. The split of British Gas into Centrica and BG plc was such a transaction. Simply to wait for more entry as the solution to generator market power is a slow and inefficient alternative. Although other reforms would also be useful, divestiture is the only reform that offers to eliminate the underlying problem. As long as a small number of generators continue to possess market power, sealing off one avenue for its exercise may simply lead the generators to direct their power elsewhere.

3. We also recommend that generators be required to disclose their net trading positions in forward contracts. The combination of market power and a lack of transparency places third parties at an inherent disadvantage in signing forward contracts with the dominant generators. The development of a liquid forward market has been inhibited as a result. Disclosing the forward positions of all the generators would help remedy the current imbalance, increasing liquidity and improving the performance of the market for electricity.

4. The introduction of full and effective demand-side participation would also mitigate market power. Demand-side participation would allow Pool prices to reflect more directly the elasticity of demand in response to higher generator bids. Generators would have less of an incentive to raise prices above costs. Increased efficiency could also be anticipated, as consumers would communicate directly the value they place on the prospect of loss load, scheduling would be improved, and generators would have increased incentives to maintain reliable plant.

5. Our report is organised as follows: Chapter 1 discusses our findings with respect to generator market power, and Chapter 2 presents our recommendations. Details of various analyses are contained in Appendices. For those who are unfamiliar with the Pool and would appreciate some additional context, a brief description of Pool operating rules and an explanation of key terms can be found in Appendix 1.1.

6. Chapter 1 begins with a brief summary of the market power abuse cited both by OFFER and independent economists prior to the divestiture of generating plant to Eastern Group. The exercise of market power was indicated by bids and prices that

did not respond to changes in costs over time, by bids that varied significantly among plants of similar cost characteristics, and by the ability of strategic factors (rather than underlying costs) to explain bidding behaviour and Pool prices. For example, changes over time in the forward positions of National Power and PowerGen have affected Pool prices, as have regulatory threats from OFFER. In a competitive market, prices do not vary with the contractual positions of two producers, nor with their occasional desire to placate government officials. The high profitability of National Power and PowerGen since privatisation is also consistent with the exercise of market power.

7. OFFER anticipated that the divestiture of 6,000 MW by National Power and PowerGen would have a significant impact on the problem of generator market power. We address the following questions: did the divestiture produce a competitive market structure for the generation of electricity? Did the divestiture terminate the conduct that OFFER and others had cited as evidence of market power? Did the divestiture improve the competitive performance of the industry? All three questions are answered in the negative: the divestiture has not produced a competitive market structure, has not improved market conduct, and has not changed the performance of the industry.

8. Market structure remains a cause of concern after the divestiture of generating plant to Eastern. We use the Herfindahl-Hirschman Index ("HHI") to estimate the concentration of generating capacity that can set market prices. We also analyse the structure of the industry supply curve to assess competition. Control of generating capacity that can influence market prices remains highly concentrated, and the dominant generators face little constraint in raising prices significantly above costs.

9. Recent bidding behaviour by Eastern resembles that of National Power and PowerGen before the divestiture. We focus upon Eastern's conduct solely because, as the smallest of the three dominant generators, Eastern should have the greatest incentive to bid competitively. It was hoped that the introduction of Eastern to the market would stimulate competition. However, Eastern's bids have not been lower than the bids previously submitted for the same plants by National Power and PowerGen. The bids submitted by Eastern have varied over time and across plants in ways that are inconsistent with underlying cost factors. Eastern has used the complex set of bid items, including "incremental prices" and "elbow points" (explained in Appendix 1.1) in a manner that only makes sense for a generator with a large portfolio of plant. OFFER and independent economists have cited the same strategic bidding behaviour as calculated to raise Pool prices.

10. The divestiture has not changed the competitive performance of the industry. SMP remains above competitive levels, has not declined, and the persistence of high prices cannot be attributed to changes in demand, availability, or fuel costs.

11. The remainder of Chapter 1 focuses upon the impact of generator market power on consumers. Neither OFFER nor the dominant generators have evaluated bids by reference to short-run marginal cost, even though it inspired the design of the Electricity Pool of England and Wales. Supplemental capacity payments were intended to provide the proper incentives for the construction and retirement of plant, allowing the generators to submit bids equal to short-run marginal cost while simultaneously expecting the recovery of long-term costs for efficient plant in

equilibrium. We therefore adopt short-run marginal cost as the competitive benchmark for evaluating generator bids. We find that generator bids have significantly exceeded short-run marginal costs, and that consumers had to pay more than £700 million in 1996 alone as a result of the excess.

12. We explain our recommendations for change in Chapter 2, provide supporting detail, and anticipate possible objections. For example, we compare divestiture to the alternative of waiting for new entry and plant retirements to produce a competitive market structure. We explain how divestiture should be tailored to address the problem of regional market power associated with transmission constraints. We discuss the benefits of a liquid forward market and analyse the problems created by generator market power and a lack of transparency. Finally, we discuss the benefits that can be anticipated from effective demand-side participation and explain the shortcomings of the Pool's "DSB1 Enhanced" program.

1Generator Market Power

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Background

1.1. Generator market power has been a problem since the establishment of the electricity pool of England and Wales. OFFER has repeatedly analysed Pool prices and concluded that National Power and PowerGen exercised market power. Excerpts from five years of OFFER reports are shown in Table 1.1 below. OFFER's findings have been confirmed and supplemented by numerous economists who have analysed generator market power.

Table 1.1: OFFER Analyses of Generator Market Power

Year	OFFER Report	Excerpts
1991	*Report on Pool Price Inquiry*	"There is no doubt that the two major generators have recently been able to increase Pool Prices significantly."
1992	*Review of Pool Prices*	"National Power and PowerGen together have market power, and exercised it in a significant way."
1993	*Pool Price Statement*	"When both generators wish to increase Pool prices, they can do so, and by significant amounts."
1994	*Decision on a Monopolies and Mergers Commission Reference*	"Experience to date suggests that the present extent of competition is not sufficient to restrain National Power and PowerGen if they wish to increase prices."
1995	*Generators' Pool Price Undertaking 1994/5*	The dominant generators were "able to reduce average SMP by 70 percent over the course of two weeks in January 1995, and to hold it at an unprecedentedly low level for two months," constituting "further clear evidence of [their] market power."

1.2. Generator market power is evident along several dimensions of the market:

A. ***Market Structure*****:** The control of generating plant that can influence System Marginal Price (SMP) is highly concentrated. Potential entry is not a sufficient competitive restraint.

Example*:* OFFER noted in 1994 that "National Power and PowerGen still have 70 per cent of the total capacity. They are the only significant owners of coal-fired and oil-fired plant… The two companies supply about 90 per cent of the demand above baseload. Their plant has also set SMP in the Pool over 90 per cent of the time since June 1991."[1]

B. ***Market Conduct:*** The dominant generators have engaged in strategic bidding behaviour that cannot be explained by underlying costs.

Example: Helm and Powell[2] concluded that the dominant generators increased bids in 1992 to maximise revenues as a series of long-term contracts expired: "the pool price has risen due to a set of contracts expiring: in other words, due to *nothing fundamental about the industry in terms of costs or demands or future demand or supply problems*. What then should a potential entrant make of this?" Given the lack of transparency in the contract market, "*any entrant must view such an industry with suspicion and risk*."

C. ***Market Performance****:* Pool prices have exceeded competitive levels and have coincided with high profitability for National Power and PowerGen.

Example: In 1993 Professor Littlechild asserted: "On my calculations, average Pool revenues presently exceed the avoidable costs of the two major generators... The need to cover avoidable costs does not justify any further price increase— nor did it justify a price increase as high as the recent one."[3]

1.3. The above examples are but a subset of the evidence concerning generator market power. Additional evidence includes the volatility of bids in contrast to underlying costs, discrepancies in bids across comparable plants, and the ability to explain bids by reference to strategic factors independent of costs. Bids can be explained by the abuse of bidding rules allowing for different incremental prices and "elbow points," by the generators' incentives artificially to increase Pool price volatility, by changes in their contractual positions, and even by the episodic desire to placate regulators. Appendix 1.2 discusses in greater detail the analyses of generator market power performed by OFFER and independent economists.

1.4. The profitability of National Power and PowerGen is also consistent with generator market power. The shares of National Power and PowerGen have outperformed investments of comparable risk by over 16% per year. Our analysis of accounting data also indicates that the two generators have enjoyed unusually high profitability. Our calculations are explained in Appendix 1.3.

1.5. In 1994, OFFER responded to generator market power by securing the agreement of National Power and PowerGen to sell 6,000 MW of generating plant.

The total divested capacity was leased by Eastern in 1996. Given the evidence of generator market power prior to this divestiture, we have focused on the following three questions:

A. ***Market structure****:* Did the divestiture of generating capacity to Eastern produce a competitive market structure?

B. ***Market conduct****:* Has strategic bidding behaviour ceased after the divestiture?

C. ***Market performance****:* Have prices become more competitive?

We answer all three questions in the negative: *the capacity that can influence market prices remains highly concentrated, strategic bidding behaviour has continued, and prices have not become more competitive.*

Market Structure

1.6. We use the Herfindahl-Hirschman Index or HHI[4] to analyse market structure after the lease of generating plant to Eastern. We focus upon the control of generating plant that can influence market prices, and define this ability in three different units. We look at those units that actually set SMP the vast majority of the time, at the set of all coal and pumped storage plants, and at the "black fossil" market cited by National Power and PowerGen as relevant in assessing market concentration. By all three measures, the control of capacity that can influence market prices remains highly concentrated. Our results are summarised in Table 1.2:

Table 1.2: Concentration in the England and Wales Pool

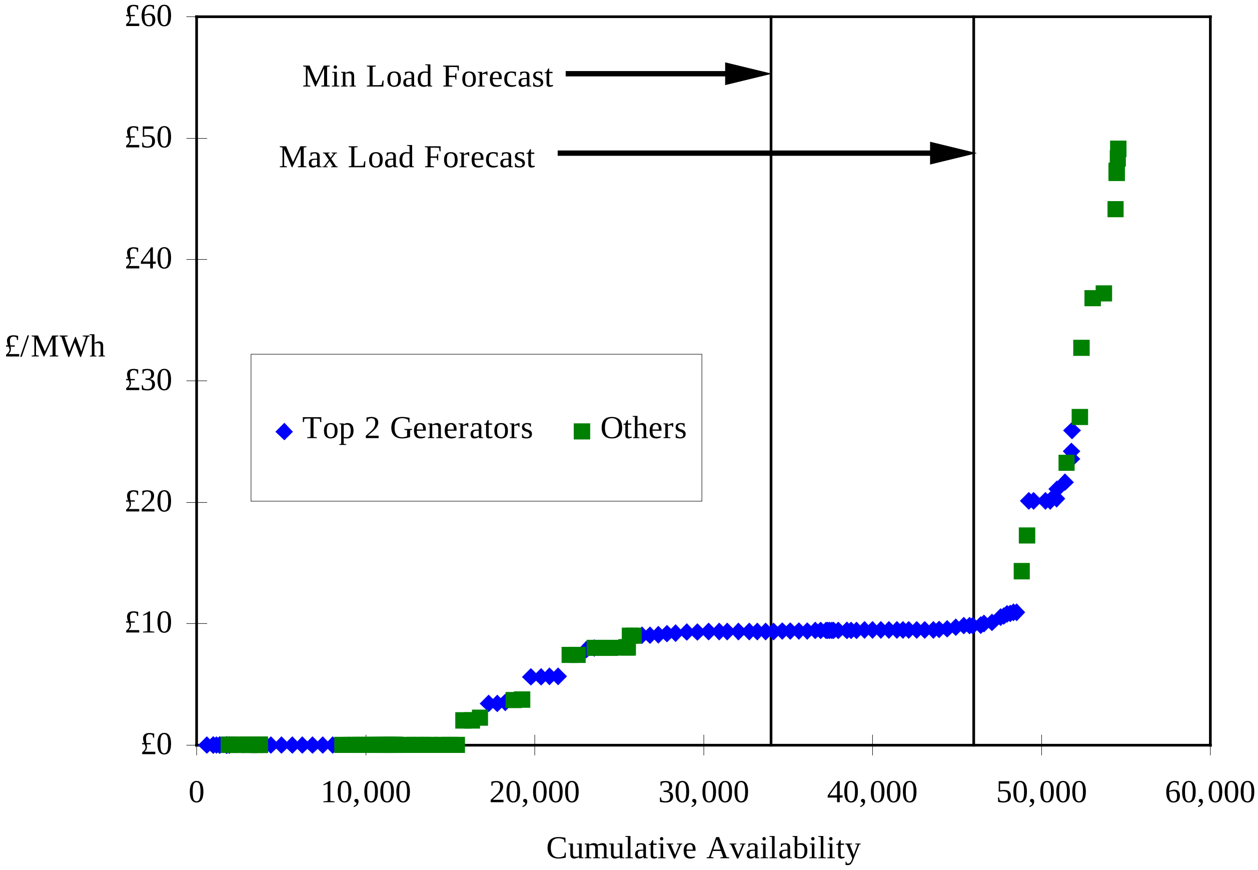
	HHI
Units that collectively set SMP over 90% of the time	2,774
All coal and pumped storage units	3,024
The "black fossil" market	3,559
HHI Standards for Electricity Generation	
Stephen Littlechild	1,750
David Newbery and Richard Green	2,000
Paul Joskow	2,500

Source: Appendix 1.4

1.7. Table 1.2 compares our results to HHI figures that have been cited in analyses of generator market power. Professor Littlechild has cited a figure of 1,750 as the dividing line between a moderately concentrated and a "highly concentrated" market. Professors Newbery and Green have estimated that an HHI of 2,000 could have eliminated most of the inefficiencies of a duopoly in generation, and Professor Joskow has argued that HHI figures above 2,500 indicate a risk of market power problems so severe as to justify regulatory intervention. Table 1.2 shows that *our HHI estimates* *uniformly exceed the levels cited by economists in analyses of generator market power*. Appendix 1.4 discusses these benchmarks in greater detail.

1.8. The highly concentrated nature of the market is supported by an analysis of the industry supply curve. As explained below, we derive an industry supply curve where the majority of capacity is assigned an estimate of its short-run marginal cost. Information is not available for all units; in the absence of information we assign generating units their actual bid prices. We combine this information with the declared availability of each genset in the England and Wales Pool at specific points in time. The resulting curve for January 26, 1995 is portrayed in Figure 1.1. The industry supply curve shows that, for a wide range of output, *few competing alternatives stand in the way of the dominant generators if they desire to raise SMP above costs***.** Nor does potential entry constitute an adequate competitive alternative. Since the divestiture of generating plant to Eastern, the primary change in this picture involves the substitution of the "Top 2" generators with the "Top 3," consistent with HHI figures still in excess of 3,000 for plant that can set SMP. This analysis is discussed further in Appendix 1.5.

Figure 1.1: Industry Supply Curve on 26 January 1995, Settlement Period 24



Market Conduct

1.9. Our analysis of market conduct focuses upon the bidding behaviour by Eastern after leasing 6,000 MW of generating capacity from National Power and PowerGen. We analyse Eastern's behaviour because, as the smallest of the three dominant generators, Eastern should have the greatest incentive to bid competitively. Furthermore, strategic bidding by National Power and PowerGen has been documented extensively by OFFER and other economists; the divestiture was undertaken with the hope that Eastern's arrival would improve competitive dynamics. However, we find that *Eastern's plants have submitted higher bids and set SMP at higher levels than when they belonged to National Power and PowerGen.* High bids under Eastern operation may arise in part from the requirement that Eastern pay National Power and PowerGen royalties on the amount of electricity produced. Our findings are presented in Appendix 1.6.

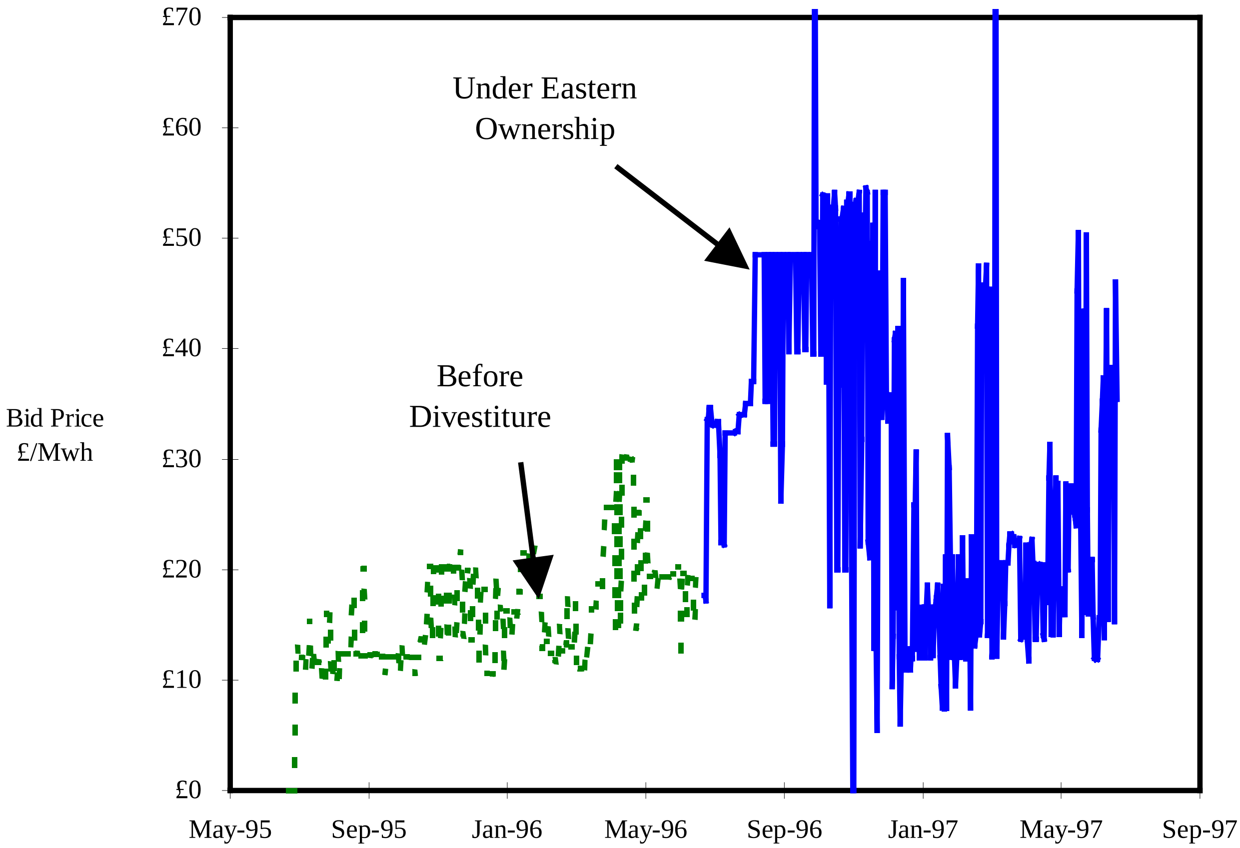
1.10. *Moreover, we find that Eastern has engaged in the same type of strategic bidding behaviour that was cited as evidence of market power prior to the divestiture.* Eastern's bids have been extremely volatile in comparison to underlying costs, bids have varied dramatically among plants with comparable cost characteristics, and the evidence suggests a manipulation of elbow points and incremental prices to secure high levels of SMP.

1.11. As one example of strategic bidding behaviour, Figure 1.2 shows the bids on "Ironbridge 1" before and after the transfer to Eastern. Generally, bids have increased since the plant's transfer to Eastern, have become significantly more volatile, and have shown unusual differences between weekends and weekdays. To accept this behaviour as competitive, one would have to believe that:

- Underlying costs increased by around 250% shortly after the transfer to Eastern,
- The cost increase was then erased between November and January,
- Costs have since experienced another dramatic increase,
- Daily spikes in bid prices are actually caused by daily spikes in costs,
- For unknown reasons, costs were far more stable under National Power ownership,
- Differences in costs on weekends and weekdays are extreme and fluctuate unexpectedly. Weekend costs were about one third of weekday costs in November, but more than double weekday costs in May.

It is not plausible that underlying costs could explain such behaviour. This example and others are explored in greater detail in Appendix 1.7.

Figure 1.2
Ironbridge 1 Bid Prices



Market Performance

1.12. Consistent with evidence that the market remains highly concentrated and that strategic bidding continues, we find that the divestiture of generating plant to Eastern has failed to yield competitive market performance. Although SMP already exceeded competitive levels prior to the divestiture, *SMP increased in the twelve months after the divestiture of generating plant to Eastern.* The persistence of high prices cannot be attributed to changes in fuel costs, demand or availability. The details of this analysis are presented in Appendix 1.8.

1.13. In addition to establishing the continued presence of generator market power, we estimate its impact on consumers. Generator market power forces consumers to pay higher prices than would be charged for the same amount of electricity under competitive circumstances. We estimate the difference between historic levels of SMP and those that would have prevailed if the dominant generators had bid competitively throughout 1996.

1.14. The electricity pool of England and Wales is specifically designed to prompt generator bids equivalent to short-run marginal cost. Capacity payments are intended to ensure that *bids equal to short-run marginal cost are consistent with long-term cost* *recovery.* In Appendix 1.9 we explain how bids equal to short-run marginal cost are intended to operate in conjunction with capacity payments to ensure efficient despatch, to promote efficient decisions concerning the addition and retirement of generating plant, and to offer long-term cost recovery for efficient base-load plant and peak plant alike.

1.15. Neither OFFER nor the dominant generators have evaluated bids by reference to short-run marginal costs. At various times they have looked at either generator bids or aggregate Pool revenues and called for the recovery of longer-term operation and maintenance costs, allocated administrative and overhead costs, future capital investment, and "reasonable" profits on invested capital. Bids equal to short-run marginal cost may also recover these items and more in the England and Wales pool. However, cost recovery should depend on the efficiency of existing plant and on the relationship of available capacity to demand. As in other markets, competitive bids in the England and Wales Pool should produce less than full cost recovery for inefficient plant or when excess capacity exists. The dominant generators have inconsistently advocated full recovery of long-term costs while acknowledging both the ownership of inefficient plant and the existence of widespread excess capacity. We analyse their claims and relevant statements and measures by OFFER in Appendix 1.10. We explain why *different standards cannot substitute for short-run marginal cost in evaluating the competitive performance of the Pool.*

1.16. *We therefore adopt short-run marginal cost as the benchmark for assessing the impact of generator market power* on consumers. Our analysis reveals that:

A. In 1996, National Power plants and comparable plants submitted bids that *exceeded short-run marginal costs by roughly 50%.* The excess of bids over marginal costs was comparable before and after the divestiture.

B. In 1996, total payments for *SMP exceeded competitive levels by at least £700 million.*

Estimates of Short-Run Marginal Cost

1.17. Our estimates of short-run marginal cost are based on information provided by National Power. So that average prices for the fiscal year 1995/6 would comply with the price cap imposed by OFFER, *National Power reduced "its bids down to short run marginal cost in one step. It did this on 25 January.*"[5] The bids submitted on January 25 were for the period beginning on 5:00 a.m. January 26 and extending to 5:00 a.m. the following day, as per Pool scheduling rules. We therefore obtained National Power's bids on all its plants at 5:00 a.m. on January 26, and compared them to the bids made the previous half hour. Consistent with the representation that National Power made to OFFER, a dramatic decrease in bids occurred at precisely this point in time.

1.18. Table 1.3 summarises the changes in bids by fuel type. National Power's coal plants had submitted bids as high as £24/MWh for 4:30 a.m., with a capacity-weighted average of £15/MWh. At 5:00 a.m. the maximum bid for a National Power coal plant was only £11/MWh and the average was only £10/MWh. The implication is that National Power had previously submitted bids that exceeded short-run marginal cost by 60%.

1.19. Bids for the oil plants also decreased significantly. Average bids for the Fawley, Littlebrook and Pembroke plants at 4:30 a.m. were 29% higher than the average 5:00 a.m. bid.

1.20. Other National Power plants saw very little change in bids on January 26. However, these plants were least likely to set SMP. Bids barely fell for the auxiliary gas turbines located at the larger fossil stations. With bids in excess of £120/MWh, the auxiliary gas turbines rarely set SMP. At the other end of the spectrum, bids remained stable for the Killinghome combined-cycle gas turbine, which operated as a base-load plant with a bid less than £8/MWh, rarely setting SMP. Some units actually showed a modest increase in bids at 5:00 a.m. but these too involved bids beyond the range that most frequently set SMP—increases for these units made sense as slight updates to National Power's short-run marginal cost estimates.

1.21. The general pattern evident in the morning of January 26 was therefore a significant decrease in bids for the coal plants and oil plants most likely to set SMP. Figure 1.3 confirms this pattern by plotting the aggregate bid schedules supplied by

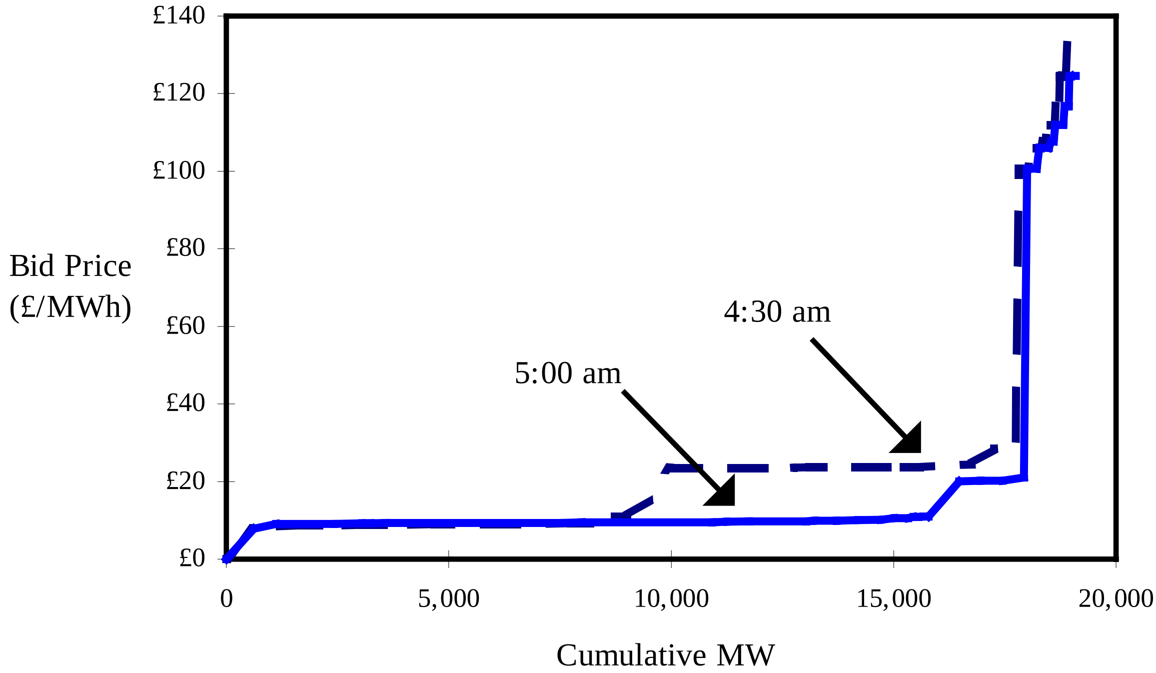
Table 1.3: Comparison of National Power Bids by Fuel Type

	Bid Price 26 January, 1995		
	4:30 AM [1]	5:00 AM [2]	Mark-up [3]
Auxiliary Gas Turbines			
Min	£112	£112	
Max	£132	£125	
Average	£118	£117	1%
Combined Cycle Gas Turbines			
Min	£8	£8	
Max	£8	£8	
Average	£8	£8	0%
Coal			
Min	£9	£9	
Max	£24	£11	
Average	£15	£10	60%
Open Cycle Gas Turbines			
Min	£101	£101	
Max	£108	£108	
Average	£104	£104	0%
Oil			
Min	£24	£20	
Max	£29	£21	
Average	£26	£20	29%

Note: [3] = ([1]/[2]) - 1

National Power at 4:30 a.m. and 5:00 a.m. on January 26. It shows that National Power declared approximately 8,000 MW of capacity available for both half-hours at a price below £10/MWh. For the next 8,000 most expensive MW of available capacity, up to a cumulative 16,000 MW, a significant decrease in bid price was evident. The decrease was from the £20/MWh range down to about £10/MWh, principally reflecting the reduction in bids on coal plants. Between 16,000 and 18,000 MW, the more modest decreases in bids on the oil plants are evident. The next most expensive units at these half-hours were the open-cycle and auxiliary gas turbines, which experienced negligible bid adjustments.

Figure 1.3:
National Power Bids on January 26, 1995



1.22. The bids submitted for 5:00 a.m. on January 26 are consistent with estimates of short-run marginal cost derived independently by economists. For example, Von der Fehr and Harbord[6] estimated short-run marginal costs of £10/MWh along the portion of National Power's supply schedule represented by coal plants. OFFER estimated that the price of international coal delivered into Europe implied costs of £10/MWh.[7] Both estimates were derived in 1991, and coal prices were flat or declining in nominal terms from 1991 through 1995.[8] Furthermore, the average efficiency of UK coal plants improved in the interim, exerting downward pressure on short-run marginal costs. PowerGen recently claimed that it had become the "lowest-cost producer of electricity in the world, for the class and age of coal-fired power stations it operates" after years of striving to improve performance.[9] Thus short-run marginal costs around £10/MWh are reasonable for coal plants in 1995.

1.23. The bids submitted for 5:00 a.m. on January 26 also make sense in the context of National Power's prior bids. As explained in Appendices 1.2 and 1.8, bids before and after the divestiture have varied significantly over time and across comparable plants in ways that are difficult to explain by reference to underlying costs. National Power's own bids for 4:30 a.m. showed significant variations among the coal plants: at £24/MWh, the maximum bid in Table 1.3 was 166% higher than the minimum bid of £9/MWh. Yet the bids for 5:00 a.m. on January 26 show a remarkable narrowing across plants: the maximum bid was only 22% higher than the minimum bid. The logical interpretation of this behaviour is that National Power previously submitted bids close to short-run marginal cost for only some of its coal plants to ensure their efficient despatch, while submitting higher bids on other plants for strategic reasons. The variations among plants then diminished, and all bids fell to a level quite close to the prior minimum bid, as National Power reduced all bids to short-run marginal cost.

Comparing Bids to Short-Run Marginal Costs

1.24. We examined data over a longer time period and over a larger set of plants to verify that bids in excess of short-run marginal costs were not peculiar to National Power or unique to the bids for 4:30 a.m. on January 26.

1.25. We identified other power plants comparable to those National Power plants that submitted bids on January 25, 1995. A plant owned by another generator was deemed comparable if it met four criteria: a) it used the same fuel and combustion technology as a National Power plant, b) it was built within four years of the same National Power plant, c) its registered capacity was within 15% of the same plant's capacity, and d) it was located in the same area of the country. We identified a total of 37 gensets that met these criteria, all of them owned at the time by PowerGen, although some have since been transferred to Eastern. A list of these plants, and the National Power gensets to which they were deemed comparable, can be found in Appendix 1.11.

1.26. We then obtained information on the bid prices submitted by the entire set of National Power plants and "comparable" plants once every fifteen days throughout 1996. We calculated the percent by which each bid price submitted by each plant exceeded its estimated short-run marginal cost.

1.27. On some occasions, the relevant plant was not available, so no bid was made. On other occasions, plants submitted bids that were slightly less than our estimated short-run marginal costs. Our estimates may have been too high, or the plants in question may have submitted unusually low bids, perhaps because CfD contracts required despatch (Contracts for Differences or "CfDs" are explained in Appendix 1.1). Rather than report a "negative" mark-up relative to short-run marginal costs, we replaced these observations with a figure of 0%, indicating that the relevant plants were bidding competitively. We then calculated a simple average of the resulting data across 1996.

1.28. We found that *bids exceeded short-run marginal cost by 49% on average in 1996.* We also examined whether the excess of bids over short-run marginal cost changed after the divestiture of generating plant to Eastern. The divestiture does not appear to have reduced the excess, as *the average markup over short-run marginal cost was 41% before the divestiture and 54% after*. The average for PowerGen was 25% and the average for Eastern was 91%. Eastern has a significantly higher figure because all its plants are coal plants, which have consistently exhibited the highest markups over short-run marginal cost. The results are shown in Table 1.4.

Table 1.4: Average Difference Between Bids and Short-Run Marginal Costs in 1996

Jan-Jun	41%
July-Dec	54%
Full Year 1996	49%
National Power	50%
PowerGen	25%
Eastern	91%

1.29. For the sake of simplicity, we did not pursue several possible refinements to our analysis. For example, we could have calculated a weighted average based on the declared availability of each genset at the time each bid was submitted. We could have developed fuel cost indices to adjust our short-run marginal cost estimates over time. However, because coal and natural gas prices have been generally flat or declining in nominal terms, we do not believe that this omission biased our estimate upward. We could have examined different times of day. Our averages are based on bids submitted at 5:00 a.m. on different days throughout the year, a time when total availability is low. Another refinement would have involved the estimate of short-run marginal costs for more generating units. Our analysis, by contrast, is limited to the National Power units that submitted bids for January 26, 1995 and units that were deemed comparable. We could have included all days of the year, rather than just a sample, and we could have made the adjustments to bid prices discussed in Appendix 1.6 with respect to Eastern, considering changes in availability over time. The final numbers would doubtless have been different if all these refinements were explored, but our relatively straight-forward analysis suffices to demonstrate that bids significantly in excess of short-run marginal cost were in no way isolated to National Power on January 26; they have been a sustained phenomenon for National Power, PowerGen and Eastern.

1.30. Table 1 in Appendix 1.6 presents a somewhat more refined analysis of bids submitted by those Eastern plants acquired from National Power. The results are consistent with the figures in Table 1.4. The demand-weighted average of Eastern bids on these plants, considering changes in availability over time, exceeded average short-run marginal costs by 80%.

The Impact of Excessive Bids on SMP

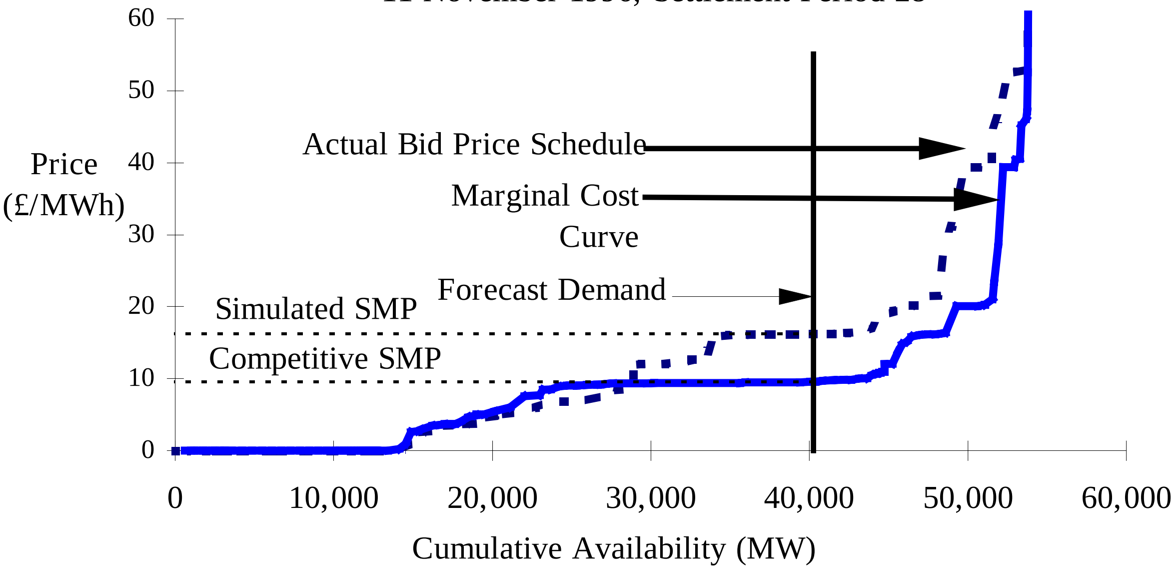
1.31. Simply because the bids on some plants may exceed short-run marginal costs does not mean that SMP itself has been affected. To determine the impact on SMP requires an estimate of what SMP might have been if National Power, PowerGen, and Eastern had bid competitively. Our analysis indicates that total SMP payments through the Pool would have been at least £700 million lower in 1996.

Methodology

1.32. Our analysis involved several steps. For the forty-eight half-hour periods on every fifteenth day commencing 1 January 1996 and extending throughout the year, we obtained the bid price and declared availability of each genset participating in the electricity auction. If the relevant genset was not owned by National Power and was not deemed comparable to a National Power plant, we left its bid prices as they were. However, the National Power gensets were assigned the same bid prices that had been submitted on January 25, 1995 as estimates of short-run marginal costs. The comparable units were also assigned the bids submitted on January 25, 1995 by their matching National Power gensets. This procedure allowed us to recreate a bid schedule that we sorted from lowest to highest bid price, and for which we tracked the cumulative available capacity at each different price level. We refer to the result as the "marginal cost curve."

1.33. A representative marginal cost curve for one day is shown in Figure 1.4 and

Figure 1.4:
Actual Bid Price and Marginal Cost
11 November 1996, Settlement Period 28

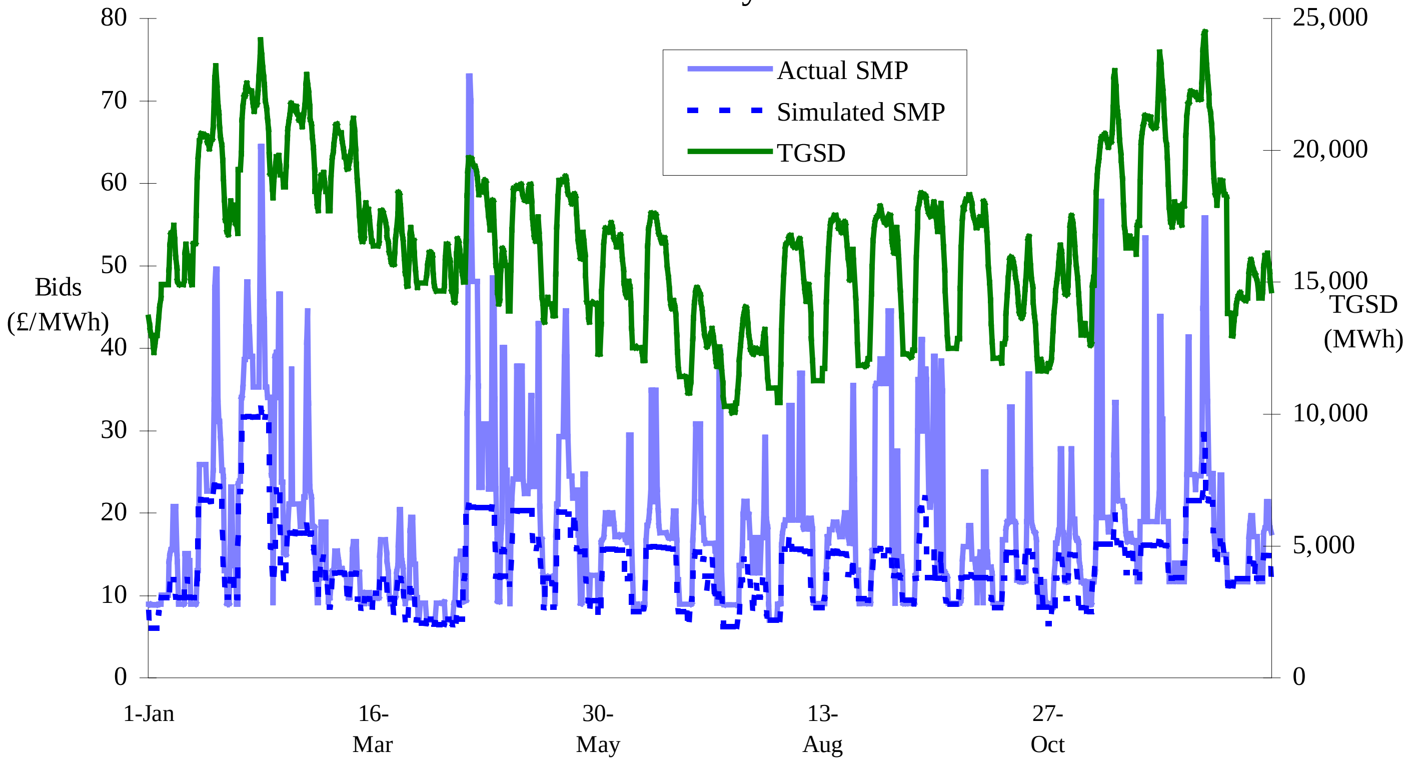


contrasted with the contemporaneous actual bid price schedule. We used the marginal cost curve and the actual bid price schedule to estimate the impact on SMP of bids in excess of short-run marginal cost. We estimated SMP for each "Settlement Period" (or half hour) as the price corresponding to the intersection of forecast demand and cumulative availability at that time. For example, Figure 1.4 shows that the marginal cost curve would have yielded SMP of £9.53/MWh on 11 November 1996 from 1:30 p.m. to 2:00 (Settlement Period 28), rather than the £16.24/MWh implied by actual bid prices.

1.34. This method of simulating SMP is quite simple relative to the complex linear programming actually used to despatch plant, so we checked how closely we could simulate actual SMP if we repeated the procedure on a schedule of actual bid prices without adjustment. With actual bid prices, we obtained a correlation of 0.75 between our simulation of SMP and actual SMP throughout 1996. Our results are shown in Figure 1.5, which also plots forecast demand.

1.35. Figure 1.5 shows that our simple SMP simulation performs well during off-peak periods, but systematically understates SMP at peak times. There are two principal explanations for this pattern. First, actual bid prices allocate start-up and no-load costs over the quantity of output that would be produced by each plant if it were despatched at its maximum declared availability for the entire day. During peak times, or when demand is changing rapidly, some plant may be called upon for only a

Figure 1.5
Actual vs Simulated SMP
Selected Days in 1996



brief period, resulting in the allocation of start-up and no-load costs over a smaller range of output, thereby increasing the price on a £/MWh basis. Second, the plant that actually sets SMP at these times might not be found strictly at the intersection point of the bid schedule and forecast demand. Some plants have flexibility characteristics that render them preferable for satisfying demand at peak, despite their location at a slightly more expensive point on the bid schedule. In either case, our simulated version of SMP can be expected to understate actual SMP at peak times or at times of rapidly changing demand.

1.36. Despite the high aggregate correlation between our simulated SMP and actual SMP, we decided to focus our analysis only on those periods where our simulation technique produced relatively accurate results. Although we could have searched for a sophisticated statistical equation that would allow us to predict SMP more accurately with the actual bid price schedule, we did not have the confidence that the same statistical relationship would have meaning when applied to the marginal cost curve.

Results

1.37. The results of our analysis are shown in Table 1.5. Limiting our analysis to only those half-hours where our simulation was at least 80% accurate, we estimate that SMP payments to generators would have been approximately £700 million lower in 1996 with bids equal to short-run marginal costs. Average SMP was approximately £15/MWh for those periods examined, while the marginal cost curve suggests that SMP could have been as low as £10/MWh on average. For these periods, our analysis therefore suggests that SMP has been overstated by 50%.

Table 1.5: Excess of Bids Over Short-Run Marginal Cost in 1996

[1]	Average Actual SMP	£15.80
[2]	Average Simulated SMP	£14.27
[3]	Total Settlement Periods in Sample	1,200
[4]	Settlement Periods Where Simulated SMP was within 20% of Actual	607
[5]	Percent of Settlement Periods	51%
[6]	Short-Run Marginal Cost	£9.69
[7]	Excessive SMP	£4.58
[8]	Percent Excess	53%
[9]	Annual Overpayment	£697,000,000

Notes:
All data are for periods in which simulated SMP was within 20% of actual.
[1] TGSD-weighted average
[2] TGSD-weighted average
[6] TGSD-weighted average

1.38. The £700 million is likely to understate the impact on SMP of bids in excess of short-run marginal cost. First, we were not able to obtain estimates for the short-run marginal costs of all gensets participating in the Pool, just those of National Power and comparable units. We left the bid prices of all other units as they were. Although we were able to match roughly two thirds of PowerGen's total capacity to comparable National Power units, we had no estimates for the short-run marginal costs of the remaining 5,750 MW. The bids on these units may well have exceeded PowerGen's short-run marginal costs, but we did not consider the possibility in the analysis.

1.39. Second, we understate the impact of excessive bids on SMP by limiting our analysis to those half-hour periods where a simplified SMP simulation procedure generated relatively accurate results. Our estimates covered only about 50% of the aggregate demand in the sample. Nevertheless, we are hesitant to quantify the total impact on SMP, as it depends on the sophisticated software that is used for scheduling units.

1.40. Third, by limiting our analysis to SMP we have excluded the impact of noncompetitive behaviour on other components of electricity prices. OFFER and economists have acknowledged incentives to increase SMP and exaggerate capacity payments through the strategic withdrawal of capacity (see Appendix 1.8). The analysis above excludes the capacity element entirely, and our estimates of SMP assume no increase in available capacity. We explain in Appendix 1.2 and Chapter 2 the ability of generators to extract excess profits through CfD premiums. Nevertheless, CfD premiums are also excluded from the £700 million estimate.

1.41. Fourth, generator market power leads to allocative inefficiencies which are not the subject of our estimate. For example, in Appendix 1.10 we cite work by Newbery and Green concluding that generator market power was responsible for excess investment in new capacity. In Chapter 2 we explain that generator market power and a lack of transparency have inhibited the development of a liquid forward market. However, the difficulty of quantifying these inefficiencies has led to their exclusion from our analysis.

1.42. Even though the £700 million estimate understates the total impact of excessive bids on consumers, it still indicates that SMP was at least 13% higher on a demand-weighted basis than if the generators had bid competitively. Thus a significant fraction of SMP payments can be attributed to the exercise of market power in the Pool. Excessive SMP payments represent approximately 4% of the average residential bill (see Appendix 1.12), and this represents a minimum bound on the total costs of market power to consumers.

2Recommendations

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Summary

2.1. In Chapter 1 we have documented evidence of deficiencies in the England and Wales electricity market. In particular we have shown that Pool prices are both more volatile than underlying costs and have exceeded competitive levels. These characteristics have persisted despite the divestiture of plant to Eastern.

2.2. Our primary recommendation is the divestiture of additional generating plant to reduce market concentration immediately. We also recommend measures to improve the performance of the forward market in electricity and to implement effective demand-side participation.

2.3. Other reforms may also be useful, such as changes to Pool governance or modifications to the structure of the electricity auction, but they are not the subject of this Report. By omitting a discussion of these issues, we do not wish to imply the absence of room for improvement. We believe that other reforms should be examined in addition to, but not as substitutes for, the recommendations provided below.

Divestiture of Generating Plant

2.4. We recommend the further divestiture of coal-fired generating plant. Below we discuss the possible form and extent of the divestiture, and compare it to the alternative of waiting for additional entry and plant retirements to increase competition over time. Other reforms, while offering to mitigate the exercise of market power, would not address the source of the problem. We also recommend that divestiture be tailored to redress situations of regional market power, which can lead to the abuse of transmission constraints.

The Form and Extent of Divestiture

2.5. We recommend that additional divestiture be accomplished through a *spin off or "de-merger," where a firm's assets are divided into two or more independent companies, and the shares in the new entities are retained by existing shareholders*. British Gas recently undertook a similar transaction to address market power concerns, separating its assets to create both Centrica and BG plc.

2.6. Although divestiture could also take the form of an asset sale, we note that concerns may arise with respect to the adequacy of the purchase price, from the absence of sufficient bidders or the possibility of collusion among them. A de-merger would avoid these concerns. Furthermore, an asset sale may have little impact on competition if it involves royalty provisions similar to those accepted by Eastern, which motivate the acquirer to keep prices high (see Appendix 1.6).

2.7. The necessary extent of divestiture remains a subject for additional debate, but we believe it should be calculated by reference to the structure of the market as analysed in Chapter 1. Divestiture should be targeted at eliminating high concentration in the ownership of plant that can set SMP. Table 2.1 illustrates the impact of possible de-mergers on our HHI estimates.

Table 2.1: The Impact on Market Concentration of "De-merger" Possibilities

Generating Plant that Can Set SMP	Current HHI [1]	NP De-merger: Divide in 2 [2]	NP De-merger: 3 Parts [3]	Both NP and PGen: Divide in 2 [4]	Both NP and PGen: 3 Parts [5]
Units that set SMP > 90% of the time	2,774	2,153	1,946	1,651	1,277
All coal and pumped storage units	3,024	2,259	2,004	1,794	1,384
The "black fossil" market	3,559	2,684	2,392	2,009	1,493
HHI Standards for Electricity Generation					
Stephen Littlechild	1,750				
David Newbery and Richard Green	2,000				
Paul Joskow	2,500				

2.8. Column 2 of Table 2.1 shows that *a separation of National Power's SMP-setting plant into two independent companies would reduce market concentration significantly.* Greater impact could obviously be obtained by creating three independent companies out of the same assets rather than two (column 3), or by including PowerGen as well (columns 4 and 5).

Divestiture Compared to Other Options

2.9. Natural competitive forces could independently reduce market concentration over time, but the process would be long and expensive relative to immediate divestiture. New entry remains risky in a market that is growing only slowly and is dominated by a few large generators. Unless an entrant can sign long-term contracts, its profitability must rely upon Pool prices that can be manipulated by the incumbents. Almost all new entry to date has therefore relied upon long-term electricity contracts, leaving the ownership of plant that can set SMP highly concentrated. Moreover, significant construction of new plant would be required before entry could erode the market power of incumbents. To illustrate, the de-merger of National Power into two companies would have a similar impact on market concentration as:

- The construction of 5,000 MW of *SMP-setting capacity* by a hypothetical new entrant owning no other plant, combined with

- The net retirement by National Power and PowerGen of 10% of their SMP-setting plant.

Given that new entry to date has not involved the construction of plant that can set SMP, such a scenario is unlikely to develop within any reasonable time frame. The costs of waiting for new entry include the possibility of wasteful investment in new plant that would not otherwise be constructed, and the costs that consumers incur in the form of excessive electricity prices in the interim. *Waiting for plant retirements and new entry is not an effective approach to the problem of generator market power*.

2.10. A possible counter-argument to further divestiture might point to evidence that the divestiture to date has not solved the problem. If a medicine does not improve the patient's health, it is not necessarily the case that the dose was insufficient. An alternative explanation is that the patient was not sick in the first place, or that the medicine was inappropriate. In the present case, however, neither alternative seems plausible. The pattern of bids and SMP indicates that the market is not working well, and we have shown that the divestiture to Eastern was sufficiently modest to leave in place a highly concentrated market.

2.11. Another possible objection to divestiture is that it would impose additional costs, notably in the form of duplication of central administration. This is not an issue that we have examined closely, though we note that PowerGen's administrative costs per MWh are similar to those of National Power, despite PowerGen's smaller size (see Appendix 1.3). We therefore do not expect that scale economies in administrative costs would pose a problem.

2.12. Although other reforms may also be useful, the divestiture of generating plant is unique in addressing directly the existence of generator market power. Other proposed reforms deal primarily with symptoms of the problem. To focus upon specific symptoms would leave the market at risk; generators could respond by simply directing their market power elsewhere in ways that are difficult to anticipate or control.

2.13. In 1994 OFFER established price caps with the objective of restraining generator market power. We show in Appendix 1.2 that the price caps created a new incentive for the generators to maximise profits by increasing the volatility of Pool prices. The volatility of Pool prices responded by increasing four-fold. Nor does it appear that the price cap made any dent in the profile of generator profitability over time, estimated in Appendix 1.3. When only specific symptoms of market power are addressed, new ones have a way of preventing any net improvement in market performance.

Addressing Local Market Power

2.14. In addition to reducing concentration for the market as a whole, *we urge that divestiture be designed to minimise pockets of local market power*. Local market power arises from the concentration of generating capacity in regions affected by transmission constraints. When a transmission constraint is activated, the units that must be despatched or idled as a consequence receive either "constrained-on" or "constrained-off" payments based on their bids, pursuant to rules that are explained in Appendix 1.1. The rules have a certain economic logic and can perform as intended when diverse units compete to alleviate transmission constraints. However, at times only a few units are suitably positioned to redress a constraint, and the rules for both "constrained-on" and "constrained-off" payments can be abused if the ownership of these units is concentrated. We discuss the problem of regional market power in Appendix 2.1.

2.15. Regional market power is difficult to solve simply by experimenting with different possibilities for compensating constrained-on and constrained-off plant. We recommend that local market power be considered directly in determining the optimal divestiture of generating plant. Divestiture should therefore focus on the ownership of generation by region as well as within the entire Pool. OFFER hinted at this approach in its 1992 report on constrained-on plant:[10]

> The generators have argued that a change in ownership would not solve the problem of local monopoly. In [deciding upon an MMC referral], I will take into account the possibility that a different pattern of station ownership could have beneficial effects on competition and Pool prices generally and on the Operational Constraints component of Uplift in particular.

2.16. At times transmission constraints may be so highly localised that one plant may occupy a unique position of market power. Local market power may also be shared by two or three plants in close proximity, where separate ownership would not be sufficient to eliminate the problem. In these circumstances, we recommend that the division of ownership within particular plants be explored. For example, if a plant with local market power has two different gensets, then greater competition can be fostered by establishing a different owner for each genset. Logistical arrangements need not be changed by the existence of different owners at the same plant. Fuel handling and other operating services could still be shared. However, separate ownership would be intended to produce independent and competing bids among different owners. Multiple ownership interests within plants is common in the United States. For example, the Four Corners Plant in New Mexico is operated by Arizona Public Service but has the following division of ownership:

Table 2.2: Ownership Interests in the Four Corners Plant

Unit(s)	Owner	Share
1	Arizona Public Service	100%
2	Arizona Public Service	100%
3	Arizona Public Service	100%
4 & 5	Southern California Edison	48%
	Arizona Public Service	15%
	PSC of New Mexico	13%
	SRP	10%
	Tucson Electric Power	7%
	El Paso Electric	7%
	Total:	100%

The experience of the United States indicates that split ownership within a plant is feasible. Although split ownership among competitors will present a challenge to neutral plant operation, we recommend that arrangements for split ownership be explored as an option for reducing local market power.

Summary

2.17. The market remains highly concentrated despite the divestiture of generating plant to Eastern. Continued market power has allowed generators to maintain prices significantly above competitive levels. Divestiture in the form of a “de-merger” would reduce market concentration immediately. Compared to the alternative of an asset sale, a “de-merger” would avoid the problems of finding buyers for divested plant. For new entry to produce a similar effect would require the construction of significant capacity in SMP-setting plant. This is not likely to happen, as entry to date has principally involved base-load plant alone. While other reforms may also be useful, divestiture offers to address generator market power most directly. The case for requiring further divestiture is strong.

2.18. Divestiture can also be used to address the problem of regional market power. Regional market power arises in the presence of transmission constraints, exposing the rules for “constrained-on” and “constrained-off” payments to abuse. We recommend that the divestiture of generating plant consider the ownership of capacity in regions subject to transmission constraints. Where transmission constraints are highly localised, the possibility of split ownership within a plant should be considered.

Improving the Forward Markets

2.19. Below we discuss the benefits of a liquid forward market for electricity, and analyse its failure to develop in England and Wales. *A combination of two problems appears to be responsible: generator market power and a lack of transparency***.** Neither problem alone should inhibit liquidity in a forward market, but the combination of the two is damaging. We therefore believe that the following reforms would offer significant improvement:

- A direct reduction in market power through the *additional divestiture* of generating plant, or
- An increase in transparency through the *required disclosure of all generator forward positions,* or
- *Preferably both reforms* would be implemented.

The Current Forward Market for Electricity

2.20. Forward market activity in the England and Wales Pool occurs primarily through CfDs. CfDs are typically negotiated bilaterally, are highly customised, last for several years, and their terms remain confidential. These characteristics make CfDs difficult to trade or renegotiate after they have been signed.

2.21. Some forward trading also occurs through Electricity Forward Agreements (“EFAs”). EFAs were introduced in the hope that a standardised over-the-counter (“OTC”) contract would facilitate trading. They are based on a division of the week into twelve trading slots. The minimum trading unit is one week in duration, and the minimum volume is 1 MW per hour. EFA contracts can be signed for as little as 8 MWh, covering a four-hour period on a Saturday and a Sunday. In practice, EFAs are used as building blocks for the assembly of larger contracts that span longer time periods. Despite the hope that EFAs would promote liquidity, the EFA market remains small and illiquid.

2.22. Since RECs are likely to revise their forecasts of demand as long-term forward contracts approach maturity, there would appear to be a natural demand for either an OTC or exchange-traded market in a standardised forward contract of relatively short duration. Such exchange-traded markets co-exist with relatively long-term OTC derivatives markets in other commodities such as oil, natural gas and metals. Yet the OTC market in EFAs has not performed as hoped, nor is there an exchange-traded contract for electricity in the United Kingdom. *The forward market therefore remains illiquid***.**

The Importance of Liquidity

2.23. A liquid forward market would improve the efficiency of the England and Wales electricity market in several respects. Liquidity provides important price information about expected market conditions over time. This information promotes more efficient temporal decisions, such as entry by competitors and the timing of plant maintenance, plant retirement, and fuel supply decisions. Liquidity also reduces transaction costs, allowing firms to come together and sign contracts that satisfy diverse risk preferences at minimal cost. Liquidity makes it more difficult for those who possess market power to engage in price discrimination.

2.24. Academic literature suggests that liquid forward markets can reduce, but not eliminate, the incentives to exercise market power in the cash market. Forward contracts effectively remove volume from the cash market and thereby reduce the benefits to the generators of increased spot prices. Market power is not eliminated, however, because some excess of spot prices over costs remains lucrative despite the existence of forward contracts. Generators may also prop up spot prices to provide leverage for the negotiation of new forward contracts as old ones expire. Thus economic theory suggests that improved performance of the forward market can help, but not solve, the problem of generator market power. We elaborate upon these arguments and the benefits of liquid forward markets in Appendix 2.2.

Market Power and a Lack of Transparency

2.25. There are certain broad requirements for a successful forward market, such as the existence of an homogenous underlying asset and an easily identifiable spot price. These basic requirements are satisfied by the Electricity Pool of England and Wales. A less straightforward issue is whether the development of a liquid forward market is likely to be inhibited by the existence of a few dominant electricity producers.

2.26. The generators in submitting their bids rationally consider the effect of the Pool price on their profits in both the cash market and the forward market. Most CfDs relate to PPP, so incremental profits are driven by the difference between PPP and marginal cost. A generator who is unhedged or only partially hedged has an incentive to maximise the excess of PPP over marginal cost. A generator who is "over-hedged" gains by minimising the excess of PPP over marginal cost. The gain from influencing prices in this way increases with the extent of the exposure.[11]

2.27. Market power and a lack of transparency combine to limit the development of the forward market. Market power grants the generators control over PPP, while the confidentiality of the dominant generators' forward positions places them in the position of insiders with the opportunity to earn excess profits from trades**.** The scope for excess profits is limited by the awareness of rational buyers that they are dealing with insiders. Buyers in this position expect to earn a negative return on their derivatives trading. If buyers were risk neutral, they would avoid the forward market and deprive the generators of any opportunities for profitable trading. However, buyers are not risk neutral and have a natural reason to buy electricity forward, even if required to pay an insurance premium to the generators. Indeed, their incentive to buy forward is accentuated by volatility in the cash market, which may itself be encouraged by variations in the forward positions of the generators. In other words, the existence of a market for CfDs increases the generators' profits, and the generators have an incentive to increase price volatility, to increase the demand for profitable CfDs.

2.28. Consistent with this reasoning, CfD premiums on average have constituted a significant source of additional revenue for the dominant generators, especially for those owning peak plant. For several years, National Power's annual reports distinguished between revenues at existing Pool prices and the incremental revenues attributable to CfDs. Although the contribution of CfD premiums has varied over time in accordance with the expiration of vesting CfDs and other factors, Table 2.3 shows that CfD premiums remain significant.

Table 2.3
National Power Pool and CfD Revenues

(m£)	1992	1993	1994	1995	1996
Electricity Sales at Pool Prices	2,703	2,708	2,546	2,804	2,765
Ancillary services	47	52	123	128	62
Pool revenues	2,750	2,760	2,669	2,932	2,827
Forward Contracts					
Related to coal purchases		297	132	79	62
Other, net of difference payments		949	432	151	174
CfD Premiums	1,341	1,246	564	230	236
Total Revenues	4,091	4,006	3,233	3,162	3,063
Total electricity produced (TWh)	117.1	108.6	94.6	92.3	90.8
Pool Revenues per MWh	23	25	28	32	31
CfD Premiums per MWh	11	11	6	2	3

Source: National Power Annual Reports, 1992-1996.

2.29. The danger that a generator's CfD position may influence its bidding strategy and allow it to earn excess profits is accentuated by the absence of market transparency in forward trading. Since forward buyers are unaware of the open positions of the dominant generators, they do not know the incentives of those generators to maximise or minimise Pool prices and do not know the likely insurance premium extracted. This interaction between futures prices and Pool prices increases the cost of hedging by buyers and reduces (but does not eliminate) their demand for forward contracts.

2.30. Since the dominant generators have an information advantage in their forward activity, there is limited scope for profitable speculation by other traders. The participation of other traders is important for the development of liquidity, and can also contribute to the development of more effective trading arrangements. For example, we explain in Appendix 2.3 the apparent room to improve performance in the EFA market by focusing on different trading instruments, but to date independent exchanges have not been willing to introduce a competing product. Lack of transparency can both inhibit liquidity directly and impede the development of innovations to forward instruments.

2.31. Notice that the incentives of the dominant generators to alter Pool prices are largely independent of the prices at which the forward contracts are written.[12] Therefore, *the problems arising from the lack of transparency could be largely overcome by publishing the CfD positions of the generators*. Even knowing just the aggregate CfD position across generators would be helpful. Disclosure would simultaneously reduce the opportunities for the dominant generators to use their forward positions to influence prices, allow electricity buyers to estimate the cost of insuring against Pool price uncertainty, and encourage liquidity.

2.32. Some have argued that market power alone is sufficient to inhibit the development of a liquid forward market. If so, then increased transparency would offer little benefit. In Appendix 2.4 we note the problems with these theoretical arguments, and we point to evidence of active futures trading in commodities where producers have market power. We also respond to the argument that increased transparency could facilitate collusive behaviour by the generators.

2.33. The relationship between transparency and forward market performance is illustrated by the experience of the Chicago Board of Trade in the early 1900s. Grain warehouses engaged in the practice of trading after the closing hours of the commodities exchange. The information from these trades was not available to all exchange members. Transparency was reduced as a result, facilitating the exercise of market power by the warehouses.[13] The Chicago Board of Trade responded by requiring that all trade after hours be conducted at the prices that prevailed upon closing. This "Call Rule," which was subsequently analysed and found reasonable by the Supreme Court of the United States,[14] transformed the liquidity of the market and reduced the market power of the warehouses.[15] The impact of the Call Rule is summarised in Appendix 2.5. Thus *the experience of the Chicago Board of Trade, which also faced market power problems, suggests that increased transparency can dramatically improve forward market performance*

Summary

2.34. Generator market power and a lack of transparency have combined to inhibit the development of a liquid forward market in England and Wales. *Additional divestiture of plant by the dominant generators would improve liquidity*, by limiting their ability to manipulate Pool prices in accordance with their forward positions. Economic reasoning and the experience of the Chicago Board of Trade both suggest that *increased transparency would also improve market performance*, even without the divestiture of generating plant.

Effective Demand-Side Participation

2.35. Although buyers of electricity may alter their usage in anticipation of electricity prices, the Pool does not directly solicit demand or price information from buyers in the day-ahead market. This is likely to contribute to the volatility of Pool prices. The Pool could usefully be changed from a one-way auction to a two-way auction in which each buyer were free to submit a demand schedule for electricity. Effective demand-side participation offers several benefits to the Pool, including a reduction in generator market power, the elimination of unnecessary price spikes, better signals for the value of generating capacity and improved scheduling of units.

The Impact on Generator Market Power

2.36. Demand-side participation offers to mitigate generator market power in several ways. First, a two-way auction would introduce the price elasticity of demand more directly into the generator bidding process. We contemplate a two-way auction where the RECs and other consumers would nominate price and quantity schedules one day in advance, and where deviations from bid commitments would be subject to separate prices in an ex-post market. By contrast, the level of demand currently used to set SMP is set a day in advance pursuant to a forecast. If low bids by the generators stimulate greater demand than forecast, then the excess is handled through "constrained-on" running rather than any adjustment to SMP. Nor is any adjustment made to SMP if higher bids prompt less demand than forecast. Some units in the Unconstrained Schedule will not be needed as a result, but the generators are compensated with constrained-off payments.[16] By using a fixed demand estimate to set SMP, and using constraint payments to address any deviations from the forecast, the *Pool rules effectively present the generators with a short-run price elasticity of zero*. The result is an increased incentive to keep prices high**.**

2.37. In most oligopolies, the incentive to raise prices is tempered by two factors: the possibility of losing business to rivals, and the prospect of an adverse impact on total industry demand. Although the first possibility certainly exists in the England and Wales Pool, generators are immunised from the latter on a short-run basis. Consumer responses only affect SMP to the extent that they eventually become part of the historic consumption data that NGC uses to forecast demand.

2.38. A two-way auction would also limit generator market power by increasing the elasticity of demand over time. This system would place an economic premium on the ability to manage loads and to make them more sensitive to price. As a consequence, the RECs would have greater incentives to develop pricing schemes that rewarded consumers for responding to price. The resulting increase in demand elasticity would reduce the dominant generators' incentives to charge excessive prices.

2.39. An effective two-way auction would also reduce the incentives of dominant generators to exploit market power through the strategic withdrawal of capacity. The deliberate withdrawal of generating capacity can, under the right circumstances, prove lucrative to a generator with a large portfolio of plant. Reductions in available capacity increase the loss of load probability, which forms the basis for both the capacity element and Unscheduled Availability payments. The equation for capacity payments is:

Loss of Load Probability x (Value of Lost Load - SMP)

2.40. The incentives for large generators are discussed in Appendix 1.8. The predictability of capacity payments is increased by the use of a fixed mathematical equation. The use of a fixed number for the Value of Lost Load, which is set by the regulator, further increases the predictability of capacity payments. Generators know that high capacity payments arise in nonlinear fashion when the loss of load probability exceeds specific levels. Predictability increases the temptation of generators to manipulate the relationship. Under effective demand-side participation, consumers would implicitly signal both their valuation of lost load and the expected possibility of load-loss in the day-ahead market. The capacity element could be abolished. Although the deliberate withdrawal of capacity by a dominant generator could still raise Pool prices, the value of capacity would no longer follow a known mathematical equation. Some of the historic spikes in the capacity element could be avoided. With a less certain impact on Pool prices, risk-averse generators would have less temptation deliberately to withdraw capacity.

2.41. The factors described above are difficult to quantify, but they all point in the same direction. Increased elasticity and increased uncertainty for strategic bidding tactics both reduce the incentives to raise bids above costs.

Increased Efficiency

2.42. In addition to its impact on generator market power, demand-side participation would increase efficiency. Most of the factors discussed above with respect to generator market power have implications for efficiency. Introducing demand elasticity more formally into the scheduling process would prevent units from being scheduled if their costs exceeded the value of their output from the perspective of consumers. Demand forecasts in the day-ahead market would be replaced with information solicited directly from consumers. The value placed by consumers on the risk of lost load would substitute for the current capacity formula. Serving as the functional equivalent of a one-day liquid forward market, the system would allow for efficient hedging and the allocation of risk among different parties with different expectations of on-the-day prices. Artificial spikes in capacity payments would be minimised. Increased incentives to manage load and to make it more responsive to price would also reduce the need to construct new capacity over time.

Problems with “DSB1 Enhanced”

2.43. The Pool recently chose to implement a program called “DSB1 Enhanced” as opposed to a more comprehensive demand-side participation proposal. DSB1 Enhanced has two fundamental problems: participation in the program is limited to only a few large industrial consumers, and the program fails to validate load reduction. This failure is explained in Appendix 2.6.

Summary

2.44. Current Pool rules aggravate the problem of generator market power by excluding the demand-side from the market. The rules effectively present the generators with a short-term price elasticity of zero. Total demand may actually decrease if generators raise their bids, but the deviations between actual and forecast demand are ignored in determining SMP. Adverse demand responses may also prevent some units from running as scheduled, but the generators are insulated from such responses by constrained-off payments. Furthermore, the Pool employs a fixed mathematical formula as a proxy for the value that consumers might place on the prospect of loss load. The predictability of the formula increases the temptation to withhold capacity strategically.

2.45. Effective demand-side participation would introduce consumer valuations and expectations more directly into the determination of electricity prices. Demand elasticity would also increase over time, because the ability of consumers to manage load would be rewarded. The generators would, as a result, have less temptation to raise prices above costs. Greater efficiency could also be expected in scheduling, in the construction of new capacity. DSB-1 Enhanced falls far short of effective demand-side participation because it is too narrow in scope and fails to validate load reduction.

[1] *Decision on a Monopolies and Mergers Commission Reference* (Feb. 1994), p. 23.

[2] Helm, Dieter and Powell, Andrew, "Pool Prices, Contracts and Regulation in the British Electricity Supply Industry," *Fiscal Studies,* No. 13 (Feb. 1992), pp. 89-105, at 102 (emphasis added).

[3] Offer, *Pool Price Statement* (July 1993), pp. ii-iii.

[4] The index is equal to the sum of the squared percentage market shares. Thus in a pure monopoly the index is $100^2 = 10{,}000$. If an industry is perfectly competitive, the index is zero.

[5] OFFER, *Generators' Pool Price Undertaking 1994/5* (June 1995), pp. 12-13.

[6] "Spot Market Competition in the UK Electricity Industry," *The Economic Journal* (1991), Fig. Ib, p. 540.

[7] OFFER, *"Report on Pool Price Inquiry"* (Dec. 1991), Figure 3.4, p. 33.

[8]The International Monetary Fund publishes an index of Australian import coal prices that shows a value of 102.5 for 1991 and a value of 98.9 for 1995, indicating an aggregate nominal decline (*International Financial Statistics* (Jun. 1997), p. 112). The price of coal delivered to Europe has also been declining since 1995, as shown in Figure 5 of Appendix 1.7.

[9] Simon Holberton, "Lessons From Your Peers," *Financial Times* (2 Jul. 1997), p. 4.

[10] *Report on Constrained-on Plant* (Oct. 1992), pp. 98-9.

[11] These results are similar to those in the standard literature on the effect of derivatives positions on the production decisions of oligopolists.

[12] This is not true, however, in the case of one-way CfDs, where the generators' incentives to influence the Pool price depend both on the quantity subject to CfDs and the exercise price.

[13] Pirrong, Stephen C., "The Efficient Scope of Private Transactions-Cost-Reducing Institutions: The Successes and Failures of Commodity Exchanges," *Journal of Legal Studies,* Vol. 24 (Jan. 1995), pp. 229-255, at 252-3.

[14] *Chicago Board of Trade v. United States,* 246 U.S. 231 (1918).

[15] Zerbe, Richard O., Jr., "The Chicago Board of Trade Case, 1918," *Research in Law and Economics,* Vol. 5 (1983), pp. 17-55.

[16] Professor Bunn has described the situation as an asymmetry favouring the generators, and claims that they only stand to benefit from errors in forecast demand, "Market-Based Pricing and Demand-Side Participation in the Electricity Pool of England and Wales," *EPRI Conference* (Mar. 1996) and Bunn, "Rewarding Demand-Side Participation in the Electricity Pool of England and Wales," *London Business School Decision Technology Centre* (Apr. 1997).