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ABSTRACT

This paper argues that the market rules governing the operation of the England and Wales electricity market in combination with the structure of this market presents the two major generators—National Power and PowerGen—with opportunities to earn revenues substantially in excess of their costs of production for short periods of time. Generators competing to serve this market have two strategic weapons at their disposal: (1) the price bid for each generation set and (2) the capacity of each generation set made available to supply the market each half-hour period during the day. We argue that because of the rules governing the price determination process in this market, by the strategic use of capacity availability declarations, when conditions exogenous to the behavior of the two major generators favor it, these two generators are able to obtain prices for their output substantially in excess of their marginal costs of generation. The paper establishes these points in the following manner. First, we provide a description of the market structure and rules governing the operation of the England and Wales electricity market, emphasizing those aspects that are important to the success of the strategy we believe the two generators use to exercise market power. We then summarize the time series properties of the price of electricity emerging from this market structure and price-setting process. By analyzing four fiscal years of actual market prices, quantities and generator bids into the market, we provide various pieces of evidence in favor of the strategic use of the market rules by the two major participants. The paper closes with a discussion of the lessons that the England and Wales experience can provide for the design of competitive power markets in the US, particularly California, and other countries.

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1. Introduction

Since April 1, 1990, virtually all wholesale purchases of electricity in England and Wales (E&W) must, by law, take place through a spot market which sets day-ahead prices for all half-hour periods during the following day. These prices are determined from the day-ahead half-hourly supply schedules submitted by all generators serving the market and an estimate of the market-level demand for each half-hour period during the following day. The E&W market has been touted as the model for liberalizing the electricity generation industry in many regions of the United States and worldwide. For example, in late December 1995, the California Public Utilities Commission (CPUC) approved a plan which calls for establishing an electricity spot market or Power Exchange similar to the E&W electricity market, through which all generators sell power to electricity retailers and large customers in California.[1] This was followed by the September 23, 1996 signing by Governor Pete Wilson of Assembly Bill 1890 which clarified the specifics of the restructuring process. Currently, almost all states are considering restructuring or are in the process of restructuring their electricity industries.[2] A major aspect of all of these restructuring processes is the establishment of markets for trading electricity.

The E&W electricity market and the proposed California Power Exchange are often referred to as competitive electricity markets. However, the market structure and rules governing the operation of the privatized and re-structured E&W electricity industry are not the direct result of independent actions by generators, distributors and customers. Instead, they are the outcome of a

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[1]Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation; Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, Decision No. 95-12-063 (December 20, 1995), as modified by Decision No. 96-01-009 (January 9, 1996).

[2]The Edison Electric Institute's *Retail Wheeling & Restructuring Report*, Volume 3, Number 3, December 1996, gives a state-by-state summary of restructuring activity in the US.

deliberate government policy to privatize and re-structure the industry. Similarly, the form of the re-structured California electricity industry will be the result of a joint decision by the CPUC and the California State Legislature. The Federal Energy Regulatory Commission (FERC) must also approve California's re-structuring plan. As we discuss later, there has been an increasing amount of regulatory oversight in the E&W market since the re-structuring in 1990. The current plan for restructuring the California electricity industry calls for continued monitoring of the industry by the CPUC and other state and federal agencies. For all of these reasons, it is more appropriate to think of the re-structured E&W market and the proposed California market as alternative mechanisms to more traditional forms of regulation for achieving the goals of greater economic efficiency in the production and distribution of electricity.

From the perspective of economic efficiency, the optimal price for electricity should be set to mimic the market price in a competitive industry with many non-colluding firms and minimal barriers to entry. This price has several desirable properties. First, it gives firms the proper signals for the timing and magnitude of new investment expenditures. In addition, because firms have no influence over this market price, they have the maximum incentive to produce their output at minimum cost and can only earn higher profits by cost-reducing innovations not immediately imitated by competitors. The major impetus behind the liberalization of the E&W market was the belief that this new form of market organization would come closer to achieving these regulatory goals for the behavior of electricity prices than the pre-privatization industry structure. An important concern expressed in a 1981 study by the United Kingdom Monopolies and Mergers Commission (MCC) was that the pre-privatization market structure did not provide the proper signals for constructing the optimal amount and type of new generation capacity in a timely manner (Armstrong, Cowan and Vickers, 1994, p. 291). In California, a traditionally high-price electricity state, the promise of lower prices for all consumers seems to be the major impetus for the recent re-structuring efforts.

Despite these goals for re-structuring the E&W electricity industry, the desire of privately-owned generation companies to maintain and attract shareholders implies that they will attempt to exploit any profitable opportunities presented by the market structure and rules governing the operation of the market. For this reason, the success of the re-structuring of the E&W market can be judged by the degree to which these profit-making opportunities are eliminated by the design of the market rules and market structure in the E&W electricity industry. Because all privately-owned firms (including those in the E&W electricity industry) have strong incentives to maximize their profits, the competitiveness of an industry can be judged by the extent to which the attempts by firms to earn higher profits are foiled by the actions of other competitors and consumers. Markets with low entry barriers and many firms tend to be those where the actions of both actual and potential competitors limit the ability of any firm or group of firms to earn much higher than zero economic profits. We therefore judge the success of the re-organization of the E&W market by the absence of any persistent opportunities for large economic profits.

The purpose of this paper is to use half-hourly market-clearing prices and quantities, and the half-hourly bids submitted from the E&W electricity market over the four fiscal years from April 1, 1991 to March 31, 1995 to assess the extent to which this re-structured market has eliminated any significant profit-making opportunities for generators. We first illustrate how the major generators have used the existing market structure and rules to achieve prices significantly above marginal cost and average total cost. In the process we describe those circumstances in the E&W market which make it particularly likely that the profit-seeking activities of the two largest firms serving the market will be successful. We then present several calculations which are suggestive of the magnitude of the above-normal profits earned by these two major generators as a result of their profit-seeking efforts.

The major goal of our analysis is to understand the precise mechanism by which market power is exercised—how generators use the rules governing the operation of the market to obtain market clearing prices in excess of average cost. We believe that whether or not these firms are actually able to exercise market power, they will continually attempt to maintain prices in excess of average costs because of their desire to maximize profits. Our goal is to understand the strategies they use to raise prices given the market structure and rules of the E&W electricity market.

Our story differs from the traditional static industrial organization view of market power where the equilibrium price is maintained above marginal cost at all times in the following two ways. First, we argue that in most load periods the market price set is not substantially in excess of the average cost of supplying electricity for the two largest generators, National Power and PowerGen. However, by taking advantage of the rules of the E&W pool, when circumstances largely exogenous to their behavior make it possible, these two producers are able to temporarily obtain spot prices much higher than the average cost of supply in that load period. In particular, we argue that the majority of excess revenues due to the exercise of market power arise from extremely large within-day price swings. The second way our story differs from the traditional view is that producers do not exercise market power by explicitly bidding prices for each genset substantially in excess of its marginal cost. Of the two strategic weapons available to each generator selling into this market—(1) the maximum amount of its generating capacity made available to the pool and (2) the prices bid in for each generating set made available—we show that the first is the more high-powered strategic weapon used to obtain prices substantially above average costs. These capacity declarations are more attractive than bids as a means to exercise market power because of the rules governing the operation of the E&W market. These rules require the bid for each portion of a generation set during the next day to be the same for all load periods throughout that day, although how these bids are converted into market prices does compensate generators for the costs associated with starting-up their generator sets (hereafter abbreviated as gensets). In contrast, the market rules allow gensets to be declared available on a half-hourly basis during the day at the discretion of the electricity producer. This asymmetry in the flexibility of setting price versus capacity availability makes the strategic declaration of genset availability a very attractive way for National Power and PowerGen to obtain large values of the day-ahead spot price.

We find that this market power activity leads to prices substantially in excess of average costs for extremely short durations, often for no more than two or three half-hour load periods within the day. In addition, the days in which these two or three very high-priced half-hour load periods occur tend to follow one another in the same week. Despite many changes in the rules governing the E&W electricity market (to be described in the next section) from the beginning to the end of our sample period, this qualitative feature of the behavior of prices is constant across the four years in our sample.

The remainder of the paper proceeds as follows. The next section describes the rules governing the operation and market structure of the E&W system and characterizes the general features of the time series properties of the wholesale price of electricity and the total amount of electricity sold through the E&W market. Section 3 illustrates how the market rules and market structure of the E&W market can allow the generators to obtain periods in which the wholesale price is substantially above the average cost of supply. Section 4 integrates the evidence presented in Section 3 to provide recommendations about the design of market rules and market structure to achieve efficient pricing given the initial conditions in an electricity industry currently considering liberalization. Section 5 discusses several caveats associated with our results and suggests directions for future work.

2. Industry Structure and Regulation in England and Wales Electricity Market

The purpose of this section is to summarize the market structure and rules governing the operation of the E&W system and to characterize the behavior of market clearing prices and quantities from April 1, 1991 to March 31, 1995.[3] We first provide some historical background concerning the restructuring of the electricity industry in England and Wales. Second, we lay out the various stages of the price determination process, highlighting the potential opportunities for generators to influence the pool price through strategic price and capacity availability offerings. We then discuss the evolution of the regulation of this market attempting to limit market power by the two largest generators in the system. Finally, we summarize the general features of the times series properties of the market clearing prices and quantities from the E&W market during our sample period.

2.1. Market Structure

March 31, 1990 marked the vesting and operational beginning of an evolving economic restructuring of the electric utility industry in the United Kingdom. Generation, transmission, and distribution (suppliers to end-users) of electricity were divided into separate companies and largely privatized. Generation plants in England and Wales were separated into three large companies. National Power and PowerGen took over all existing fossil fuel power stations. Nuclear power plants remained state-owned, under the auspices of Nuclear Electric, through the 1995/96 fiscal

[3]Wolak and Patrick (1996a) describes the operation of the E&W system in more detail. Wolak and Patrick (1996b) analyzes the time series behavior of market clearing prices and quantities over our sample period.

year.[4] The twelve regional electricity boards comprising the distribution system became twelve regional electricity supply companies (RECs). The National Grid Company (NGC) provides transmission services from generators to the RECs and coordinates transmission and dispatch of electricity generators. In addition to the three large E&W generators, Scottish non-nuclear companies (Hydro-Electric and Scottish Power), Electricity de France (EdF), and a number of independent power producers (IPPs) also sell electricity to the pool. Figure 1 is a map of the United Kingdom delineating each of the REC's transmission and distribution service areas and the location of all major generator facilities by type of fuel.

National Power and PowerGen own the majority of generating capacity and have produced at least 54.5% of total electricity sold during each of the fiscal years (through 1995/96) the pool has operated. For reasons discussed in detail below, PowerGen and National Power, most notably, have reduced their respective generation capacities steadily since the pool began. Contrary to this trend by the two largest generators, several independent power producers (IPPs) have entered the market, and several other existing power producers have increased their capacities. The net effect of the deletions and additions to capacity in this market has been a decrease in the total generation capacity serving the market from April 1, 1990 to the present, despite growing electricity consumption in E&W over this same period. The market share of electricity sold by these two dominant producers has also declined, from 46% (National Power) and 28% (PowerGen) in the 1990 fiscal year to 31.38% and 23.1% for the 1995 fiscal year.[5] However, as we will argue, National Power and PowerGen are able to sell much of their generation during very high-priced load periods, so this

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[4]Fiscal years run from April 1 to March 31 of the following calendar year.

[5]Nuclear Electric's 1995/96 fiscal year market share was 22.49%, power imported from Scotland and France 8.71%, pumped storage 0.69%, and IPPs and others 13.63% (Electricity Pool of England and Wales, *Statistical Digest*, May 1996).

decline in the share of annual E&W electricity output should not bring about as large a decline in their share of annual pool revenues or their profits, because of the net capacity reductions described above. Indeed, over this time period sales revenues have decreased by 16.02% and net income has increased by 66.57% for National Power, while sales revenues have decreased by 2.53% and net income has increased by 114.46% for PowerGen. Earnings per share (EPS) have increased by 79.31% and 129.03% for National and PowerGen, respectively.[6]

Transmission and distribution services for all customers, and electricity supply for customers with no alternative sources of supply other than their local REC, so-called franchise customers (currently those with less than 100 kilowatt [KW] peak demands), are regulated by price caps.[7] Since the formation of the E&W market, RECs have had exclusive franchises to supply all consumers within their geographic regions, except for consumers with peak demands greater than 1 megawatt (MW). From the start, these customers were given the option of choosing their supplier from any of the 12 RECs as well as National Power or PowerGen directly. On April 1, 1994, the 1 MW limit on these non-franchised consumers was reduced to 100 KW. This size restriction on customer peak demand will cease to exist in 1998, when even residential customers will be offered this option (i.e., all customers become non-franchise). RECs are required, with compensation, to allow competitors to transfer electricity over their distribution systems.

[6]Annual Reports.

[7]Prices for transmission and distribution services from NGC and the RECs are restricted to grow no faster than the percentage change in the economy-wide price level, measured by the Retail Prices Index (RPI), less an X-factor adjustment for productivity increases. Until the 1994/95 fiscal year, the REC's electricity supply prices for all customers were regulated by RPI-X+Y, where Y is an adjustment factor which passes-through unexpected costs the REC incurs, as well as the purchased electricity costs, and transmission distribution services. Since the beginning of the 199495 fiscal year, supply price regulation has been restricted to franchise customers (those with peak demands less than 100 kW).

The vast majority of a REC's customers purchase electricity at rates fixed independent of within-year variations in the pool price. All residential customers pay fixed prices that may vary in a mutually agreed-upon manner on a daily or weekly basis, independent of fluctuations in the pool price, for the entire fiscal year. The most common form of this pricing plan has one fixed price per KWH for all consumption during daylight hours and another fixed price per KWH for consumption during nighttime hours. Almost all commercial and industrial users purchase power through similar annually negotiated fixed price contracts which also vary on a daily or weekly basis, independent of movements in the pool price. Consequently, within-day, day-to-day, or even month-to-month movements in the pool price have no impact on the prices all but a small fraction of customers pay because the price patterns they face do not change for the entire fiscal year. Only a very small fraction of E&W total system load, approximately 5%, is purchased by final consumers according to the variations in the half-hourly spot-market price.[8]

Because RECs provide electricity to the vast majority of their customers according to rate schedules fixed well in advance of the realization of pool prices, they normally hedge against this price volatility by purchasing "contracts for differences" (CFDs). CFDs are simply financial instruments insuring prices at which an agreed upon quantity of electricity can be purchased and sold. CFDs have been sold by generators as well as financial institutions and traders that deal in commodity markets and derivative securities. They are **not** contracts to deliver electricity.

CFD contracts were also used in the initial privatization process to maintain employment in the UK coal industry. As part of the privatization process, the Government required National Power and PowerGen to enter into contracts for the purchase of a higher volume of UK coal than they wished at higher-than-world-market prices, thus maintaining employment in the coal

[8]Patrick and Wolak (1997) describe these sorts of retail price contracts in more detail.

mining industry. Vesting CFD contracts between each REC and National Power, PowerGen, and other generators were designed to compensate these generators for the higher UK coal prices they paid for UK coal under these coal supply contracts. The strike price of these CFDs allowed the costs of the coal contracts to be passed on to the RECs, and the structure of the REC regulatory process—a price cap with a Y-factor to pass through extraordinary cost increases—allowed these costs to be passed on to final customers in the form of higher prices. In the first two years following privatization, it is estimated that CFD contracts covered 84.3% and 89.1%, respectively, of National Power's and PowerGen's generation, declining to 72.7% and 70.6% over the next two years (Helm and Powell, 1992).

2.2. The Pool Price Determination Process

Generators offer or "bid" prices at which they will provide various quantities of electricity to the E&W pool from their generating stations throughout the following day. In addition, the generators make availability declarations for each of these gensets for each half-hour during the following day.

These availability declarations cannot exceed what the *Pool Rules* call the Registered Capacity of the genset. This Registered Capacity can differ from the nameplate capacity of the genset and may even be zero. Zero Registered Capacity gensets will show up in the bid data with a zero capacity bid. However, according to the *Pooling and Settlement Agreement for the Electricity Industry in England and Wales, Agreed Procedures, Volume 1*, the Registered Capacity of a genset can be changed up to 10 am the day before the trading day under consideration, so that these gensets can and do make non-zero availability declarations on very short notice.[9]

[9]Such declarations may not be costless. There are transmission use of system charges which are paid to or by the generator the first time the genset actually generates during the fiscal year. These payments vary by genset location and range from a negative £8/kW in the South to £15/kW in the North.

Setting the Registered Capacity of a genset to zero precludes it from selling electricity into the pool during the next day, although it does not preclude the option of doing so on any subsequent day. Consequently, in our discussions of capacity for the remainder of the paper we make the distinction between Registered Capacity and actual capacity that both National Power and PowerGen possess, with the former being the usual number reported in UK Electricity Industry annual reports and the latter being the maximum amount of generation capacity that each firm can use to sell electricity into the E&W pool.

The day-ahead bid prices and availability declarations submitted by generators are input into the general ordering and loading (GOAL) program at NGC to determine the merit order of dispatching generation and reserve capacity. The lowest price generating capacity is dispatched first, unless such dispatch will compromise system integrity. Subject to this caveat, dispatching plants in this "least-cost merit order" gives rise to an upward sloping aggregate electricity supply function for each half-hour for the following day. The system marginal price (SMP) for each half-hour of the following day is the price bid on the marginal genset required to satisfy NGC's forecast of each half-hour's total system demand for the next day, i.e., the bid where this expected demand crosses the aggregate supply curve.

The methodology and data input into NGC's forecast of demand are readily available to generators prior to their submissions of bid prices and availability declarations for the next day [Baker (1992), The Electricity Pool (1997), and National Grid Company (1995)]. This implies that the generators can compute NGC's forecast of demand for all 48 load periods during the next day before they submit their bid prices and availability declarations. We will argue that this market rule has important implications for the strategies used by generators to exercise market power. Moreover, this forecast demand in perfectly price inelastic.[10]

The Pool Purchase Price (PPP), the price paid to generators per KWH in the relevant half-hour, is defined as

$$\text{PPP} = \text{SMP} + \text{CC},$$

where the capacity payment is CC = LOLP×(VOLL - SMP), LOLP is the loss of load probability, and VOLL is the value of lost load. The CC is intended to provide a signal to generators of the necessity of new generation capacity and to signal consumers that their consumption has a significant probability of requiring the maximum amount of generating capacity available in that load period. The VOLL represents the per KWH willingness of customers to pay to avoid supply interruptions. It was set at £2,000 per megawatt-hour (MWH) for 1990/91 and has increased annually by the growth in the RPI since. The LOLP is determined for each half-hour to represent the probability of a supply interruption due to generation capacity being insufficient to meet demand. The LOLP is a decreasing function of the expected amount of excess capacity available during each half-hour period. The greater the amount of capacity available relative to expected demand in any half-hour, the lower the LOLP

[10] According to the pool rules, each half-hour's forecast demand is the sum of reported pumped storage demand, reported demand by large customers (defined as those with a maximum demand of over 250 MWH during any half-hour, although there are no electricity consumers of this magnitude in the E&W market), and the Grid Operator's forecast based on "current and historic weather conditions and any other factors capable of affecting demand which the Grid Operator reasonably considers to be capable of independent verification." (The Electricity Pool 1997, p. S5-1, Section 5.1.2). Furthermore, in Section 5.1.3,

> In particular, but without limitation, such forecast shall not be adjusted for the expected output of Small Independent Generating Units, Non-Pooled Generators, Customer Demand Management or the response of demand to price, or any other factors capable of affecting demand notified to the Grid Operator by Generators or Consumers except to the extent that the Grid Operator reasonably considers such factors to be capable of independent verification.

In particular, the response of demand to price and demand-side bidding have not been considered sufficiently reliable to be considered in the forecast demand (see, e.g., Baker 1992 and OXERA Press 1997).

and therefore the lower the capacity charge per KWH paid to generators. We argue that this relationship has important implications for the two largest generators' strategies for obtaining high PPPs.

The pool selling price (PSP) is the price paid mostly by RECs purchasing electricity from the pool to sell to their final commercial, industrial and residential customers. For the purposes of determining this price, the 48 load periods within the day are divided into two distinct price-rule regimes referred to as Table A and Table B periods. During Table A half-hours the PSP is

$$\text{PSP} = \text{SMP} + \text{CC} + \text{UPLIFT} = \text{PPP} + \text{UPLIFT}.$$

UPLIFT is a charge used to collect costs incurred when demand and supply are actually realized each day, is only known *ex post,* is the only price uncertainty from the day ahead perspective, and is collected over at least 28 Table A pricing periods each day (UPLIFT is zero for Table B pricing periods). A major component of UPLIFT is to compensate generators for reserve, plant available but not actually used to meet demand, and startup costs. Generators are paid for capacity they choose to make available according to

$$\text{Availability Payment/MWH} = \text{LOLP}\times(\text{VOLL} - \max\{\text{SMP, bid price}\}).$$

This approach to setting availability payments compensates a relatively high-priced plant that is not used, but is available, less than a plant which bids close to the SMP. Generators can amend their day-ahead availability declarations used in this setting the SMP, CC, and Availability Payment at any time after these prices have been determined. The availability payment is made to generators on the capacity re-declared available, regardless of whether the capacity was originally declared or not. The remaining portion of UPLIFT is comprised of NGC's costs of ancillary services (reactive power, frequency control, hot standby, and black-start capability).

By 4 pm each day, the SMP, CC and the identities of the Table A and Table B periods for all 48 load periods for the following day are communicated to pool participants.

2.3. Regulatory Oversight

The Electricity Act of 1989 established the Office of Electricity Regulation (OFFER) , with Professor Stephen Littlechild serving as the Director General, to oversee the operation of the re-structured United Kingdom electricity industry, from generation to transmission and distribution to final customers. At privatization there were no explicit controls over the PPP. Since then, Professor Littlechild has instituted several regulatory changes in an attempt to inhibit strategic price and supply schedule offerings by the generators. These include (1) amending the original generation license to require generators to make public their plans on capacity availability, (2) price caps on PPP, (3) the divestiture of generating plant, and (4) introducing financial incentives for NGC to manage costs included in UPLIFT. In addition, the Pool members voted to amend rules on calculation of the LOLP prior to the conclusion of OFFER's 1991 Pool Price Inquiry which examined, among other things, the availability declarations by PowerGen and National Power.[11]

Originally, the LOLP calculation was based on the day-ahead declared availabilities which are used in setting the SMP. PowerGen admittrd to the practice of withholding offered capacity (i.e., reducing declared availability of some higher merit gensets) and then, after the SMP and CC components of half-hourly prices for the next day had been determined at the lower offered availability levels, re-offered these genesets at full capacity. PowerGen maintained that this strategy was used to reduce the number of Table B periods and that this strategy was discontinued in mid-October of 1991. The Pool revised the availability measure

[11]This Pool Price Inquiry was conclude in December of 1991, see OFFER (1991) for complete details.

used in calculating LOLP from the maximum of the day-ahead declared capaicity to the maximum of offered or re-offered availability prior to the conclusion of OFFER's pool price inquiry of 1991.[12] This change was effective at the beginning with the 1992/93 fiscal year.

The original generation license was revised, following the 1991 Pool Price Inquiry, to restrict the ability of generators to manipulate the PPP by reducing capacity made available to the pool. The changes require generators to provide, for public viewing, reports containing the generator's criteria for determining the availability of their capacity to the pool, closing generating stations, and otherwise reducing generating capacity.[13] Each year, generators must also file a detailed forecast of the availability of each generating unit for the coming year and, at year's end, file a "reconciliation" explaining any deviations from the anticipated availability. However, "Generators are under no obligation under Pool Rules to declare any of their Centrally Dispatched Generating Units (CDGUs) available to generate at any particular time, even though the CDGU may be operationally available."[14] Wolak and Patrick (1996a) describe various actions by the Director Generator to encourage the generators to declare capacity available.

Due to perceived excessive variability in the PPP, OFFER charged National Power and PowerGen with exercising market power to drive up pool prices. This matter was resolved with the institution of caps on pool prices over the fiscal years 1994/95 and 1995/96 as part of a voluntary agreement, reached February 11, 1994, between National Power, PowerGen, and OFFER after Professor Littlechild threatened to refer these generators to the Monopolies and

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[12]The Appendix provides details on the calculation of the LOLP.

[13]In addition, NGC gathers and markets operational information, including detailed data on each genset's availabilities.

[14]*An Introduction to Pool Rules (Issue 2)*, The Electricity Pool, p. 10.

Mergers Commission.[15] This agreement also included the divestiture of 4 GW and 2 GW of generating plant by National Power and PowerGen, respectively.[16]

As a result of uplift increases in 1993/94, OFFER instituted, in April of 1994, the "uplift management incentive scheme" (UMIS) in an attempt to encourage NGC to minimize "avoidable costs" incurred in operating the E&W power market. UMIS was then replaced with the Transmission Services Project (TSP) on October 1, 1995. TSP divided uplift into the costs associated with reactive power, system constraints, transmission losses, and other ancillary services. Each category has a price cap intended to provide an incentive for NGC to keep these costs down.

2.4. Time Series Properties of Pool Selling Price and Total System Load

In this section we characterize the time series properties of PSP and the total amount of electricity sold through the E&W pool during each half-hour period over our sample period, what is referred to as Total System Load (TSL). A notable feature of the behavior of PSP is its tremendous variability, even over very short time horizons. For example, the maximum ratio of the highest to lowest PSP within a day is 76.6, whereas the average of this ratio over all days in our sample period is about 4.1. The maximum ratio of the highest to lowest PSP within a month is 107.5 and the average of this ratio over all months in our sample is 11.0. Finally, the maximum ratio of the highest to lowest PSP within a fiscal year is approximately 117.8.

TSL exhibits dramatically less volatility according to this metric. For example, the maximum ratio of the highest to lowest TSL within a day is 1.89 and the average over all days

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[15]The Electricity Act of 1989 gives the Director General the authority to refer the firms to the Monopolies and Mergers Commission in order to make changes in the relevant license. Referrals can also be made under the Fair Trading Act of 1973 or the Competition Act of 1980, which could lead to structural changes.

[16]The Eastern Group, one of the RECs, was allowed to lease these 6 GW of coal generating plant and began operating them in July of 1996, which fulfilled this agreement.

in the sample is 1.49. Within a month, the maximum of the highest to lowest TSL is 2.38 and the average over all months in the sample is 2.04. For the time horizon of a fiscal year, the maximum ratio of the highest to lowest TSL is 3.08. Consistent with this difference in volatility, the TSL can be forecasted much more accurately at all time horizons than the PSP. In making this comparison, we define forecasting accuracy as the standard deviation of the forecast error as a percent of the sample mean of the time series under consideration. Wolak and Patrick (1996b) give a detailed analysis of the forecastability of PSP, PPP, CC, UPLIFT and TSL.

Figure 2 presents plots of the half-hourly PSP in (£/MWH) for the more than 17,000 prices for each of the four fiscal years in our sample. The highest values of PSP within a fiscal year tend to occur during the four-month period from November to February. These are also the months when there is an enormous amount of price volatility within the day and across days. The pattern and the magnitude of the volatility differs markedly across the four fiscal years. All of the price graphs are plotted using the same scale on the vertical axis to illustrate this point. Figure 3 plots the system capacity used in each of the half-hour load periods during each of the four fiscal years. Compared to the four graphs in Figure 2, the four graphs in Figure 3 indicate the very predictable pattern of TSL across days, weeks, and years. In particular, the total demand in a single day in one year is very similar to the demand in that same day in the previous year. The cycle of demand within a given week is similar to the cycle of demand within that same week in another year. Similar statements can be made for the cycles in TSL within months across different years.

The difference between the four price graphs and the four TSL graphs illustrates a very important implication of the design of the E&W market described in Section 2.2. Despite the large differences in the patterns of price movements across the four years, there is no discernable change in the pattern of TSL across the four years. Recall from Section 2.1 that only a very small fraction of electricity consumed by final customers is purchased at the PSP. Because the vast majority of business customers, and all residential customers, purchase power on fixed-price contracts set for the entire fiscal year, these customers do not face any unpredictable price changes related to the current value of the PSP which might trigger demand responses within that same load period. Each of the 12 RECs offers several fixed-price options to its customers. For residential customers, each REC offers a small number of standard price contracts, e.g., a single-price for all load periods contract, or a two-price contract (a fixed price for all daytime load periods and a fixed price for night-time load periods). For business customers, each REC offers several standard price contracts, but particularly for large customers who can choose their supplier from any of the 12 RECs or any of the generators, these fixed price contracts are often negotiated on a customer-by-customer basis. Consequently, for the same half-hour period, there are hundreds and potentially even thousands of different retail prices that different customers throughout the E&W system are paying for electricity. Although these fixed-price contracts are designed to yield annual revenues from a customer that at least cover the REC's cost of purchasing from the pool the actual electricity sold, movements in the PSP, or in any of its components, have no effect on the movements in these contract prices. Consequently, the lack of responsiveness of TSL to changes in PSP does not imply that individual customers do not respond to price changes. This lack of responsiveness is indicative of the fact that only a small fraction of customers purchase electricity at the half-hourly PSP, with the remaining vast majority purchasing electricity on these fixed-price contracts.

An important consequence of virtually no customers purchasing electricity at the half-hourly PSP is that it makes little, if any, economic sense to estimate an aggregate demand curve for electricity involving PSP or PPP as the price variable and TSL as the quantity demanded variable. Movements in the half-hourly or the daily average PSP or PPP, which identify the aggregate price response, are irrelevant to the vast majority of consumers of electricity who face prices that are unrelated to movements in the PSP or PPP for the entire fiscal year. Consequently, a price response recovered from this estimation is likely to be extremely misleading about the true aggregate price response because only approximately 5 percent of TSL is purchased by final customers at the PSP and the remaining is purchased according to prices that are invariant to changes in the PSP for an entire fiscal year.

Table 1 gives the means and standard deviations for PSP, SMP, CC and UPLIFT for each of the four fiscal years in our sample. There has been a slight increase in the mean value of PSP across the four fiscal years. The major explanation for this increase is the growth in the mean of CC from the first to last fiscal year. The mean of UPLIFT has also shown a similar upward trend over this time period. Another notable feature of this table is the tremendous amount of volatility in CC, and to a lesser extent in UPLIFT, particularly for the year 1994/95. For all four fiscal years, the ratio of the standard error to mean of CC exceeds two, indicating a substantial amount of relative volatility in this half-hourly charge.

On average, the major component of the PSP is the SMP. However, the large amount of volatility in both CC and UPLIFT indicates that, for many periods, the relative contribution of SMP to the PSP can be much smaller. To illustrate this point, Table 2 gives the mean, minimum, maximum and standard deviation for various ratios of the components of PSP for each of the fiscal years. Although the sample average of SMP/PSP over the four fiscal years is 0.92, there is a substantial amount of variability in this ratio within each year. The ratio CC/SMP illustrates the source of this variability. In 1991/92, mean of this ratio was 0.05, and the maximum was 10.36. In 1994/95, the mean was 0.09, but the maximum was 20.41. Even in 1992/93, when the mean of this ratio was only 0.01, the maximum was 1.87. Extremely large values of CC are the source of very small values of SMP/PSP. A crucial part of our story of how National Power and PowerGen attempt and succeed to obtain values of PPP or PSP substantially in excess of their average costs in certain load periods within the day stems from their ability to achieve these extremely large values of CC relative to SMP. In this next section, we will show that when events exogenous to their behavior make it possible, through strategic declaration of their available generation capacity, these producers can obtain very large values of CC and therefore very large values of PPP and PSP.

3. Strategic Use of Market Rules by National Power and PowerGen

We now describe a mechanism which it appears that National Power and PowerGen have used to take advantage of the rules governing the E&W pool to temporarily obtain prices substantially in excess of each generator's average cost of producing electricity. An explicit assumption in our analysis and in all existing theoretical and empirical work on this market is that it can be thought of a duopoly between National Power and PowerGen with the remaining firms acting as a competitive fringe. The logic for this assumption is as follows. Nuclear Electric, because it produces only baseload power, will bid low so as to always operate as much of its available capacity as possible. Because most of the IPPs have long-term take or pay fuel contracts (specifically, natural gas) and have signed long-term CFDs with RECs for the amount of electricity they expect to generate, their incentive is to bid low to guarantee that their plants will be dispatched. Because of substantial excess generating capacity in Scotland and transmission line capacity constraints from Scotland to the E&W pool, the Scottish producers will do the same. Finally, EdF primarily sells its excess nuclear capacity to the pool so that it has the same incentives to bid low as Nuclear Electric. EdF also faces transmission capacity constraints to the E&W market, which makes its effective available capacity small relative to the E&W market demand. For these reasons, it is reasonable to assume that the remaining E&W residual demand is served by a duopoly composed of National Power and PowerGen.

The general issue of generator market power in the E&W system has received attention from both theoretical and empirical researchers. The existing theoretical literature points out several modes for the exercise of market power. Unfortunately, there does not exist a comprehensive model which accounts for the features of the structure and operation of the E&W market which leads to the exercise of market power of the form we claim. We should caution that it would require an extremely sophisticated model to simultaneously capture the entire story we have in mind. Consequently, we first discuss the important features of the market structure and rules of the E&W market which allow the two major generators to obtain prices substantially in excess of average costs.   We then describe the existing research on this market and the lessons that are learned from it. Then we provide an argument which builds on this work to provide a story of how the two major generators make strategic use of the market rules to obtain prices substantially in excess of average cost. We present evidence for the use of this strategy by the two major generators using data from actual operation of the market. Finally, we attempt to quantify the magnitude of the increased profit rate to the two largest generators that results from their use of this strategy.

3.1. Important Features of E&W Market Structure and Market Rules

There are four important features of the economic environment which contribute to the ability of National Power and PowerGen to maintain prices in excess of average cost. The first is the presence of known upper bounds on the amount of electricity that any producer can bid into the pool during each load period, because of transmission line constraints in the case of EdF and the Scottish producers, and because of the actual amount of capacity owned by all of the other producers. If after accounting for the total capacity of all other producers, National

Power and PowerGen believe that they face a large residual demand relative to their capacity, these two generators can be expected to bid less aggressively into the pool.

The second feature of this market which allows the two dominant generators to obtain high prices is the finite upper bound on maximum residual demand these two firms face. As noted in Section 2.2, the rules of E&W market imply that all generators can construct the vector of expected TSL for each half-hour during the day before they submit their bids, so the only source of demand uncertainty to National Power and PowerGen for the purposes of the price-determination process is the amount of capacity that will be supplied by Nuclear Electric, the IPPs, Scottish producers and EdF. This implies that there is a finite upper bound, known to both National Power and PowerGen, on the expected residual demand they face for the purposes of determining the SMP and CC each load period. Recall that NGC's forecast of TSL for the next day, not the actual value of TSL for the next day, is the relevant magnitude used to determine the SMP and the CC (which is a function of the expected reserve margin via the LOLP). The pool rules, which require all generators to make their annual capacity availability plans public, and the genset availability information that NGC markets make it easier for National Power and PowerGen to estimate the residual demand they face, so that when expected aggregate demand conditions favor it, these two generators can use their availability declarations to obtain very high values of PPP and PSP.

The third way the rules governing the operation of the market enhance the success of the strategy we describe is that NGC's estimate of the 48 half-hourly demands for the next day is completely inelastic with respect to the value of SMP.[17] Recall that where NGC's day-ahead

[17]In December of 1993, the E&W Pool introduced demand-side bidding which could be used to builds some price-responsiveness into the forecasted total system demand that determines the SMP. However, during the 1995 calendar year, the maximum amount of capacity subject to demand-side bidding in any load period was 260 MW, which is a tiny fraction of half-hourly TSL, which ranges from slightly less than 20 GW to more than 45 GW. In addition, as noted earlier, demand-side bidding is not incorporated into NGC's day-ahead demand forecast.

demand estimate crosses the aggregate industry supply curve (the aggregate of the individual generator bid functions) directly determines the value of SMP and indirectly determines the value of CC through the value of the LOLP which, in turn, depends on the value of the expected reserve margin. When both National Power and PowerGen anticipate that a substantial residual expected demand will be left after the availability declarations of other generators have been subtracted from the NGC's forecast of TSL, these two generators have very little incentive to bid aggressively. For the purposes of determining the SMP and CC, both generators know that total residual expected demand they are competing over is independent of the bid prices they submit. The only uncertainty they face is which of the two firms captures more of this expected residual demand by having a larger fraction of their declared available capacity called into service.

The fourth feature of the market which increases the viability of the strategy we outline is the diverse mix of generating capacity owned by both National Power and PowerGen. Holding a mix of generating capacity which contains baseload (low-cost) coal and combined cycle gas turbine plants, intermediate load (intermediate cost) conventional turbine natural gas plants, and peaking (high cost) oil-fired plants implies a steadily increasing (at an increasing rate) marginal cost function (up to total capacity of the generator) within any load period. As of the end of the 1995, National Power's capacity had the following fuel mix percentages, 65.5% coal, 22.0% oil, 12.3% natural gas (both Open and Combined Cycle Gas Turbine Gensets), and 0.2% hydro. PowerGen's mix was 60.6% coal, 20.6% oil, 18.5% gas (both Open and Combined Cycle Gas Turbine Gensets) and 0.3% hydro. To construct these percentages, we first constructed a complete inventory of all gensets that bid into the E&W pool during 1995, including those that bid zero capacity into the pool (had zero Registered Capacity) for the entire year. We then compiled the ownership, fuel type and nameplate capacity of each genset from a variety of sources, with the major source the *NGC Seven Year Statement* [National Grid Company (1995)]. This was supplemented with information from annual reports of the UK Electricity Industry [Electricity Association (1994, 1995)], and a report by Aveline, Brough, and Lobban (1996). This mix of generation capacity possessed by both National Power and PowerGen yields company level marginal cost functions which are constant or only slightly increasing for a large range of output, and then increase at an increasing rate to account for the use of intermediate-load capacity and then peak-load capacity.

3.2. Previous Research on E&W Market

Green and Newbery (1992) is the first paper to explicitly analyze the issue of market power in the E&W electricity market. They model the competition between PowerGen and National Power as a noncooperative supply function equilibria with deterministic, but time-varying demand within the day, along the lines developed in Klemperer and Meyer (1989). Green and Newbery construct a simulation model for the annual amount of electricity sold through the E&W market assuming that the market clearing prices and quantities sold during each load period are solutions to a static one-shot symmetric supply function equilibria for three representative days of the year—summer, winter and mid-year—each of which is appropriately scaled to yield annual amounts of electricity sold and average prices similar to those actually occurring in the market. For each representative day, a player is assumed to submit a continuously differentiable increasing supply function giving the amount they will supply to the pool as function of the prevailing market clearing price. The authors then choose parameters for their simulation model that they feel reflect the demand and cost conditions in the E&W market.

Based on these simulations, the authors conclude that there is substantial monopoly power in this market as it currently exists. They then show that this market power could be reduced by increasing the number of competitors in the market. Green (1996) further extends this supply function equilibrium analysis of policies to increase competition in the E&W market. He uses linear supply function equilibria with asymmetric firms to consider impact of the partial divestiture policy of National Power and PowerGen actually implemented. He finds that this policy would lead to a substantial increase in the competitiveness of the market, although not as large of an increase as would occur by splitting Nation Power and PowerGen into smaller companies.

Despite an explicit statement that he does not try to analyze the operation of E&W market, Bolle (1992) considers three symmetric supply function equilibrium oligopoly models with stochastic demand. For the version of his model closest in spirit to the Klemperer and Meyer framework, Bolle finds that increasing the number of competitors leads to prices that converge to marginal costs, although the rate of convergence is slower the smaller is support of the demand uncertainty.

The supply function models of Newbery and Green and Bolle each assume that the half-hourly demand which sets the system marginal price is price-elastic. However, as noted Section 2.2, the pool rules state that NGC's demand forecast which sets the SMP and CC is completely price-inelastic. This lack of a significant price-response in NGC's demand forecast enhances the success of the strategy we describe for raising pool prices.

von der Fehr and Harbord (1993) construct a duopoly model of competition between National Power and PowerGen which acknowledges price-inelastic nature of the demand forecast that sets the SMP. They assume a price-inelastic market demand that is a realization of positive-valued random variable with compact support, which is also consistent with the actual operation of the market, because as discussed in Section 2.2, the only demand uncertainty faced by National Power and Power Gen is the amount of capacity that will be bid by remaining firms in the market. The von der Fehr and Harbord model requires generators to bid in each of their gensets at a fixed price less than $\overline{p}$ (what the authors call the maximum possible price), so that by aggregating over all generating units a producer owns yields its step-function supply curve, which becomes vertical at the point where its capacity is exhausted. In order to simplify the exposition of their results, but not without a cost in terms of the market-to-model match, von der Fehr and Harbord assume that each firm has a constant marginal cost of producing electricity across all of its generating capacity and no fixed costs.

These assumptions yield three results. First is that if, with probability one, either player has sufficient capacity to supply the entire market, then a pure-strategy equilibrium is price equals the marginal cost of the least efficient producer and only the most efficient producer sells to the market. The second result is that if the range of demand—the highest possible demand minus the lowest possible value—is greater than the maximum of the two generators' capacities, then no pure strategy equilibrium to the game exists. The third result is that if, with probability one, demand is greater than the maximum of the capacity of either producer, i.e., both producers must participate in the market with probability one, then all pure strategy equilibria are such that the market clearing price is $\overline{p}$, the maximum possible price. Although the specifics of these theoretical predictions depends on the simplifying cost and demand assumptions made, we will argue that the rules of the PSP determination process allow something analogous to these three results taking place, depending on the value of NGC's total system demand forecast for the next day.

There have been two attempts to quantify the extent of the price/marginal cost markup in this market using actual prices and TSLs from the E&W market. von der Fehr and Harbord

(1993) and Wolfram (1995) compute short run marginal cost functions for each generator based on the assumed fuel costs and operating efficiencies for the portfolio of generating technologies available to each firm. von der Fehr and Harbord also compute the bid schedule submitted by each generator to compare price to marginal costs across the entire range of output. Wolfram takes the actual market PPP and TSL and computes a price/marginal cost markup using the marginal cost function computed as described above. Wolfram also applies three different methodologies which, to varying degrees, leverage off of assumed duopoly models of the interaction between the two generators to recover an estimate of the price/marginal cost markup. The results of these three approaches are found to be broadly consistent with the finding of her first approach that the price/marginal cost markup is in the neighborhood of twenty-five percent.

This work on the E&W market points out several important aspects of the market structure and market rules which contribute to the ability of National Power and PowerGen to maintain prices in excess of average costs for extended periods of time. However, all of these papers focus only on the bid prices of the two generators, and not their capacity availability declarations, as the mechanism used to exercise market power. The strategy we describe involves simultaneous use of the bid price and availability declarations. In particular, we will argue that two generators rarely bid a price for a specific genset substantially in excess of it marginal cost. Instead, by strategic capacity declarations they are able to ensure that a high marginal cost genset sets the value of SMP during the peak load periods for the day which then yields a high value of SMP. This strategy also yields a low expected amount of excess generation capacity available, which leads to a high value of LOLP and a large value of CC, so that the PPP = SMP + CC is significantly higher than it would otherwise be.

3.3. The Strategic Availability Declaration Strategy for Exercising Market Power

We now describe our story of the exercise of market power in the E&W market. It involves the four aspects of the market structure and market rules described in Section 3.1 and builds on the previous theoretical and empirical literature described in Section 3.2. An important aspect of this strategy is the ability, noted in Section 2.4, of the capacity charge and uplift charge to yield extremely high values of the PSP. We believe that these periods of very high values of CC and UPLIFT are the result of strategic decisions by National Power and PowerGen. Because of this strategy, these periods of high values of CC and UPLIFT tend to coincide with periods of high values of the SMP, resulting in large values of the PPP and PSP.

National Power and PowerGen have at their disposal two strategic weapons to influence the PPP and PSP each period: (1) the SMP function that they bid into pool and (2) the amount of capacity they decide to make available to the pool each half-hour, i.e., the point at which the bid function becomes vertical. This second choice is particularly crucial to the final PPP, because NGC uses the sum of these available capacity declarations to compute the expected reserve margin for each load period, the amount total available capacity is above the forecasted demand for that load period. The LOLP entering into the computation of CC is decreasing in the expected reserve margin. Furthermore, as Bunn and Larsen (1992) report, this function is extremely convex for low expected reserve margins, indicating that the marginal increase in LOLP brought about by a fall in the expected reserve margin is larger, the smaller is value of this margin. This nonlinear relationship between the expected reserve margin and the LOLP indicates that by strategically withholding capacity to obtain a small margin, large values of LOLP and hence large values of CC are possible.

Bidding prices in excess of marginal cost for each genset is one way for these producers to obtain large values of the SMP and therefore large values of the PPP and PSP. However, because it is relatively straightforward to perform the marginal generation fuel cost calculations for each genset using its fuel costs and heat rates as described in von der Fehr and Harbord (1993) and Wolfram (1995), bidding substantially above the marginal cost for any genset would be relatively easy for the Director General of OFFER to detect. The maximum value of the SMP for the entire sample is 180 £/MWH, whereas, as is shown in Figure 2, the value of PSP is often substantially in excess of this value, particularly in during the 1991/92 and 1994/95 fiscal years. Generators would face severe credibility problems rationalizing bids in excess of 100 £ /MWH for anything but peak load gensets. Given the CC determination process, bidding high prices for each genset owned and offering as much capacity as possible each period is not likely to be nearly as profitable as strategically withholding capacity. A large amount of available capacity would result in a high expected reserve margin in most periods and therefore a very small LOLP and hence a very small CC, so that the SMP would comprise all but a small fraction of the PSP. For these reasons, given the market rules, bidding prices substantially in excess of each genset's marginal cost to obtain high prices is not likely to be as successful at achieving this goal as a strategy involving capacity withholding.

A more high-powered and more difficult to detect strategy for the two major generators is to bid each genset at close to its marginal cost and then declare capacity unavailable in different load periods throughout the day so that the forecasted value of TSL for the next day crosses the day-ahead aggregate industry supply curve in the rapidly increasing portion of aggregate bid function for as many load periods during the following day as is feasible given the physical constraints of bringing gensets on and off line. By declaring unavailable capacity from the flat (baseload) portion or upward sloping (intermediate load) portion of the bid function, a generator can control where its bid function becomes very steep. This strategy achieves a large value of SMP and, more important, a small expected reserve margin and accompanying large value of CC during these load periods. During the other load periods within the day the forecasted value of TSL may not intersect the aggregate supply curve in its upward sloping portion because of the physical constraints on genset operation and the increased cost of starting-up gensets or running them at substantially less than full capacity. During these periods, the SMP is set by baseload and intermediate load gensets which results in low values of the CC and UPLIFT, because of the accompanying high expected reserve margin. Consequently, this bid price and availability declaration strategy yields a price pattern within the day that has the large ratio of the highest to lowest PSPs within the day referred to in Section 2.4.

Figure 4 illustrates the potential increase in SMP and CC that results from this capacity withholding strategy. The top two graphs plot representative marginal cost and bid functions for Firms 1 and 2. Notice that no gensets are bid in at significantly above their marginal cost of supply for either firm. In this case, capacity has been withheld from the flat portion of each firm's supply curve. The third graph plots the aggregate marginal cost and bid functions and gives the SMP that results from the intersection of these curves with the forecasted total system load (FTSL). Comparing the magnitude of total availability associated with the bid function, TAVAIL(Bid), and that from marginal cost function, TAVAIL(MC), to the value of FTSL, we can see that the expected excess available capacity will be significantly higher for TAVAIL(MC) versus TAVAIL(Bid), so that the LOLP(MC) will be much smaller than LOLP(Bid), so that CC(MC) will be much less than CC(Bid). Combining the results for the SMP and CC, yields a value for PPP(MC) than is substantially less than PPP(Bid), despite the fact that the actual amount bid for any genset is not significantly above it marginal cost of supply.

Before presenting our evidence in favor of this strategy, we discuss our choice of PSP as the relevant price for the purposes of assessing the exercise of market power. As discussed in Section 2.2, generators receive the PPP for all electricity they supply during each load period, so that a case could made for that being the relevant price to measure the ability of generators to earn above normal profits. However, generators also receive the availability payment described in Section 2.2 for all generating plant which is declared available but not used during each load period. These availability payments are made through the uplift charge. There are other payments made to marginal generators unexpectedly called upon to produce during the following day which are also paid for through UPLIFT. We focus our story on movements in the PSP rather than the PPP, because higher PSP means more revenues to generators in the form of availability payments, payments for activities associated with plant start-up at different times of the day, and payments for other ancillary services. Because of the relationship between the CC and the availability payments, there is a very high positive correlation between the CC and UPLIFT, so that whether we use PPP or PSP, the general conclusions of our analysis will continue to hold.

3.3. Evidence for Use of Strategic Capacity Availability Bidding

Because of both the mix of generating capacity owned by National Power and PowerGen and the likely non-strategic bidding behavior by other participants in the E&W power pool, evidence consistent with this available capacity withholding strategy would be that either of these two firms is the marginal bidder setting the SMP for the vast majority of load periods. Since November 1, 1995, NGC has collected information on the identity of the marginal genset each load period. From November 1, 1995 to March 31, 1996, National Power was the marginal genset 49% percent of the load periods, with PowerGen setting the SMP 35% of the load periods. NGC's Pumped Storage facilities were the marginal genset 11% of the load periods. The next highest fraction of load periods a producer was the marginal generator was approximately 2% by EdF. Consequently, the sum of the times that either National Power or

PowerGen sets SMP is 84%, which is substantially more than the 54.5% fraction of annual TSL that these two producers generated during the 1995/96 fiscal year and is more than the approximately 60% of 1995/96 capacity available to the E&W market that these two generators control.

The amount of capacity National Power and PowerGen offer to supply to the market varies considerably over the course of the year. Figures 5 and 6 plot for National Power and PowerGen, respectively, estimates of their marginal cost functions and actual bid functions for January 18, 1995 and July 19, 1995 during the load period ending at 10:30 am. Both days are a Wednesday, which tends to have the highest peak demand of any day of the week. We construct our estimate of the marginal cost function for each producer by the following procedure. For each genset owned by these two firms we first compute the maximum amount of actual availability declared within any load period during the calendar year 1995. We think of this as a lower bound on maximum capacity available from each genset. For each genset we then compute the minimum bid price offered for that genset in any load period when this maximum availability is offered during the year. We can think of this minimum genset bid as an upper bound on the marginal cost of that genset. Ordering these maximum genset availabilities from the lowest to highest minimum price, and then aggregating the total amount offered at less than or equal to each price yields the solid line given in each figure. We believe this process yields an upper bound on the true marginal cost function.[18] These marginal cost curves are plotted on both the July 19, 1995 and January 18, 1995 bid function graphs for both generators.

[18]Because there is evidence of seasonal variation in the marginal cost of generating electricity from a given genset due to weather and other factors, for this reason and various others, our procedure for estimating the marginal cost should be interpreted as yielding only a rough estimate of this function.

These figures show that the available capacity for both generators, where their bid functions end, is at a substantially higher capacity in February than in July. PowerGen's ends at 9.6 GW in July and 15.6 GW in February and National's ends at 14.5 GW in July and 20 GW in February. Although some of this capacity variation can be explained by scheduled maintenance or downtime for repairs, it is very difficult for the Director General of OFFER to verify the extent to which the scheduled or unscheduled maintenance was necessary. Consequently, generators can simply decide to declare capacity unavailable. As Section 2.3 notes, the regulator has attempted to impose more formal oversight over this capacity declaration process by requiring the submission of a yearly plan for plant availability and an *ex post* explanation for any deviations from this plan. However, this requirement seems unlikely to make strategic use of available capacity declarations by PowerGen and National Power less frequent, particularly in light of recent trends in net capacity reductions over the past five years by these two producers.

To demonstrate that the differences in the endpoints of the bid functions across peak and off-peak months given in Figures 5 and 6 are representative of all load periods throughout our sample period, the following exercise was performed. For each load period, the ratio of total system capacity used to the total system capacity actually declared available was computed. Figure 7(a) plots estimates of the density of this ratio for all weekday (Monday through Friday) load periods in peak months (November, December, January , and February) and for all weekday load periods in the remaining off-peak months. Note that the two densities are very similar in shape and location. Figure 7(b) plots the densities of the ratio of total system capacity used in each load period to the maximum of declared available system capacity over all load periods during that fiscal year for the peak-month and off-peak month samples. This maximum declared available system capacity over all load periods within a year is a lower bound on the actual maximum available system capacity to serve the market each year. The major difference from Figure 7(a) is that the density for off-peak months is a leftward shift of the density for peak months. Similar results hold if these two figures are constructed for weekend day load periods only.

Figure 7(a) shows that the average value of available system capacity in the peak months is 51 GW as compared to 43.7 GW in the off-peak months. This indicates that, on average, 7.3 GW (14.3% of peak available system capacity) is not made available during the off-peak months. Comparing this figure to 32% = [(6 + 5.5)/(15.6 + 20)], the percent reduction in total capacity made available by PowerGen and National Power combined (during the load period ending at 10:30 am) on July 19, 1995 relative to January 18, 1995, demonstrates that the primary source of these differences in total system capacity availabilities across peak and off-peak months is due to the strategic capacity withholding behavior of PowerGen and National Power.

Although the von der Fehr and Harbord (1993) modeling framework ignores the CC and UPLIFT determination process, their theoretical model yields several predictions about the relationship between the SMP and NGC's day-ahead forecast of TSL. To examine these predictions we divided load periods into four groups: those where we felt it was likely that generators believed with high probability that either of them could satisfy the entire forecasted market demand [where NGC's forecast of TSL (hereafter FTSL) is less than 20 GW], two intermediate demand periods consistent with the intermediate mixed strategy range of demand realizations from the von der Fehr and Harbord model (20 GW < FTSL ≤ 35 GW and 35 GW < FTSL ≤ 45 GW), and high demand periods where with high probability both generators know they would both be significantly in the market (FTSL > 45 GW), i.e., the maximum of the offered availabilities of PowerGen and National Power is less than the residual FTSL faced by both producers.

We choose the first regime to be those load periods with FTSL less than 20 GW on the belief that net of the 9.2 GW capacity of Nuclear Electric, the 1.6 GW capacity from Scotland (maximum generation capacity to E&W is constrained at this level by the transmission capacity) and the more than 5 GW of independent and REC generating capacity, and 2 GW from France (maximum generation capacity to E&W is constrained by transmission capacity) for a total of 17.8 GW, leaves a sufficiently small residual demand that either generator knows with virtual certainty that either can supply the entire expected residual demand.[19] Under these conditions, von Fehr and Harbor argue that the standard Bertrand price-setting equilibrium will result. However, crucial to this pure-strategy equilibrium holding are the simplifying assumption of no fixed costs of generation and constant marginal costs. The presence of fixed costs and increasing marginal costs does not rule out the conclusion of vigorous price competition for this level of demand, but this does imply that only mixed-strategy equilibria exist (Tirole, 1986, p. 215). The calculations reported in Table 3, for the most part, show this point to be true. The third and fourth columns of the table report the mean and standard deviation of the SMP for each year and each of the four regimes. For each of the four years, the mean value of SMP in the first FTSL regime is less the mean of SMP for the other three regimes.

Mean values of SMP within a year get successively higher moving from the first to fourth regime, although the volatility of SMP, as measured by its sample standard deviation,

[19]It is important to emphasize that this 17.8 GW is the maximum possible capacity that the remaining firms could supply. They will most likely often supply significanlty less, which is why we chose 20 GW as our cutoff for the first von der Fehr and Harbord pricing regime.

tends to exhibit an inverted U-shaped pattern. For all of the years, by far the largest increase in the mean of SMP is across the third to the fourth regime. This is particularly true for the fourth fiscal year (1994/95) where the mean increases from 30.54 £/MWH (in the third regime) to 68.36 £/MWH (in the fourth regime). von der Fehr and Harbord argue that, for their model, the largest possible feasible price is set in those periods where both generators know their capacity will be required with probability 1. We assume that this will occur for all values of FTSL greater than 45 GW on the belief that subtracting maximum amount of capacity available from other participants in the market besides National Power and PowerGen leaves 28 GW, which is greater than the capacity of National Power (the larger of the two producers) for all years in our sample.

Given the regulatory process in the UK one might argue that the maximum feasible price is the political limit price described by Glazer and McMillan (1992), where if the SMP rises above this point the Director General will step in and refer the generators to the Monopolies and Mergers Commission, as he has threatened to do several times. We would expect this limit price to depend on both the political strength of the Director General and the attitude of the Government towards the industry. There have been considerable changes in both of these variables over the four fiscal years in our sample. We would therefore expect differences in this maximum price across the years as is illustrated by the changing mean of SMP for the (FTSL > 45GW) regime across the four years.

A comparison of the sample standard deviation (SD) of the SMP across each of these regimes within years is also broadly consistent with the existence of the three pricing regimes described by von der Fehr and Harbord. First, with exception of the third year, the sample SD of the SMP for the first regime is substantially smaller than the sample SD of the SMP for the other three regimes within that year. The other interesting aspect of the behavior of the sample

SD across regimes is that for two of the four years, the sample SD of SMP for the fourth regime is smaller than the SD of the SMP for either two of the intermediate regimes in the same year despite the substantially larger mean value of SMP for the fourth regime. For the first year, the difference between the SD of SMP across the second and third regimes versus the fourth regime is not very large given the corresponding difference in the magnitudes of the means. Computing volatility as the ratio of the SD to the mean yields the inverted U-shaped relationship between volatility and the four FTSL regimes for all four years. These volatility results are broadly consistent with the von der Fehr and Harbord view that in those load periods when both National Power and PowerGen know they will be significant participants in the market the SMP is the political limit price, hence the high mean and relatively low volatility. The volatility of SMP in the intermediate range can be interpreted as consistent with the notion that only mixed strategy equilibria exist in the von der Fehr and Harbord model for this range of demand realizations. While these results cannot confirm the validity of the von der Fehr and Harbord view of the operation of the market, we do feel their model provides a useful theoretical lens through which to view the behavior of the SMP.

Abstracting away from their model, a possible interpretation of Table 3 is the following. During load periods in the day when demand forecast is known to be very low, National Power and PowerGen will bid very aggressively in terms of available capacity relative to demand and prices, so that SMP will be very low. During periods in the day of extremely high system demand National Power and PowerGen do not bid as aggressively in terms of available capacity and prices, because they know that regardless of the price they bid, a large fraction of each their respective capacities will be called upon to serve the forecasted demand. The generators therefore take advantage of their superior market position to raise SMP. In the intermediate demand periods, both PowerGen and National Power attempt to not bid aggressively in terms of available capacity and bid functions, but the temptation of one to undercut the other makes it difficult to consistently maintain high values of SMP during these periods, because aggressive bidding by one of the two participants when the other bids high results in it being able to supply a substantial portion of the forecasted residual demand at this high price and leaving the market-price-setting higher bidding competitor with only a small fraction of the market. This desire to avoid being the substantially out-of-the-market price-setting generator brings about the observed high volatility in SMP

Because we do not have information on generation costs for PowerGen and National Power, we cannot rule out the possibility that the SMP is being set in excess of the short-run marginal cost of running a generation unit in all load periods. The SMP/short-run marginal cost markups computed by von der Fehr (1993) and Wolfram (1995) provide evidence of prices above marginal costs. Their definition of short run marginal cost is a lower bound on the short run marginal cost of production because it accounts for only the fuel costs associated with running the plant. By this logic the short-run marginal cost to run a hydroelectric plant would be zero, although both authors do assign a positive marginal cost to hydroelectric plants. There are short-run labor and materials costs besides fuel costs which increase the short-run marginal cost. In addition, the short-run marginal cost, or so-called system-λ by the US Electricity Generation Industry, can vary considerably for a given plant depending on the manner in which a plant is operated. For example, several of the large coal-fired power plants in the UK are used to provide power for only a fraction of the day. Consequently, operating such plants in this load-following manner makes it much less energy-efficient, so that the short-run marginal cost of producing power is higher and very sensitive to the changing level at which the plant is operated. This aspect of plant operation further complicates the accurate calculation of short-run marginal cost.

Crucial to making strategic use of available capacity declarations produce high values of PPP and PSP is an extremely low expected reserve margin, which brings about nonlinear increases in the LOLP and large values for the capacity charge and availability payment. An easy way to make low expected reserve margins more likely given the very predictable level of total system demand referred to in Section 2.4 is to undertake net plant retirements. In the early years following privatization, there were very large number of announced capacity additions. For example, in early 1992, *The Economist* ran an article stating that if all stations are built and closed according to announced plans at the time, the E&W market would have excess capacity over peak winter demand on the order of 50% by 1995, well above the value of 20% in most countries, because of the so-called "dash for gas" in form of announced new Combined Cycle Gas Turbine capacity by PowerGen, National Power, independent electricity producers and the RECs.

The actual course of events has been quite different. Over the four fiscal years April 1, 1991 to March 31, 1995, approximately 5 GW of net capacity was retired in England and Wales (Electricity Association, 1995, p. 27). This is 8.7% of the approximately 60 GW of capacity in currently serving the E&W market.[20] These net retirements have taken place despite the fact that total electricity sales grew at a little less than 1% per year over this same time period. This course of events over the past five years has made it increasingly likely that National Power and PowerGen can, through their availability declarations, obtain low reserve margins during an increasing number of load periods. During the fiscal year 1994/95, 1.5 GW of the 5 GW of net retirements occurred, which explains, in part, the extreme volatility in CC and UPLIFT during this year relative to other years, with the other part of the story being the unexpected

[20]This figure includes the maximum transmission constrained capacity from both Scotland and France and gensets that are not closed or decommissioned but have zero Registered Capacity as of March 31, 1995.

unavailability of two Nuclear Electric stations during December and January, making it easier for National Power and PowerGen to obtain high values of LOLP.

The increasing variance in SMP over the four years of data in each of the last three supply regimes given in Table 3 implies that this capacity availability withholding bidding strategy is being used with increasing regularity. The large drop in the Registered Capacity of National Power from April 1, 1990 to March 31, 1995 of 28.3 GW to 20.2 GW and smaller fall in the Registered Capacity for PowerGen of 17.4 GW to 15.6 GW over the same period (Electricity Association 1995), implies that it takes smaller and smaller extremes in TSL to hit the residual demand regime where both PowerGen and National Power know with virtual certainty they will both be required to supply significant amounts of their capacity during the peak periods of the day, which are the conditions required for this strategy for temporarily raising the SMP and CC to work. The actual capacities of both National Power and PowerGen have also fallen over this same time period.

This pattern of Registered Capacity adjustments by PowerGen and National Power provides further evidence consistent with the use of this capacity availability limitation strategy. The maximum-price third regime of the von der Fehr and Harbord model requires that the probability of the event ($FTSL \geq \max(K_{PG}, K_{NP})$) is one, where K_{PG} is the amount of capacity bid in by PowerGen and K_{NP} is the amount of capacity bid in by National Power. Both firms would like to bid small capacities of approximately the same magnitude to make this regime most likely to occur. The greater the difference between the capacity holdings of National Power and PowerGen the less likely is the event that TSL will be above the maximum of both of these generators capacities. Given the initial substantially larger Registered Capacity of National Power, to obtain close to equal generation capacities would require a substantial reduction in National Power's initial 1990 Registered Capacity, as has in fact occurred. The pattern of adjustment in actual capacities since privatization has followed this same pattern, with the largest reduction in capacity from National Power.

To illustrate that the SMP is frequently set substantially in excess of the short run marginal cost of supply, we perform the following exercise. First we select bins of TSL from 15 GW to 48 GW increasing in 1 GW increments. For each of these TSL bins we compute the maximum, minimum and mean values of SMP, CC, UPLIFT and PSP over all 70,128 = [3*(365)+366]*48 load periods in our sample. We then plot these three values as a function of the level of TSL associated with that bin. Figure 8 plots these figures for PSP and the three components of PSP. The first thing to note from the figure for SMP is our claim that there is a substantial range for SMP for all TSL levels. In particular, the largest value of SMP occurs in the 31 GW TSL bin. The other point worth noting, but not shown in this graph, is that although the range of SMP is virtually invariant to the level of TSL, the frequency of very high values of SMP increases with the level of TSL. This is consistent with our logic that this strategy for obtaining temporarily high levels of SMP is most feasible to implement in the peak demand months. This plot for CC illustrates that significant capacity charges have occurred at TSL levels as low as 30 GW, and that there is the possibility of enormous capacity charges during the highest TSL load periods. Large capacity charges have also been implemented for TSLs in the range 31 GW to 42 GW, which contains the daily peak TSL of all off-peak months. The corresponding graph for UPLIFT illustrates that large values of UPLIFT occur primarily in the high TSL load periods, although there are some significant values in the range of the daily peak of the off-peak months. Finally, the PSP plot more closely resembles the CC and UPLIFT plot more than the SMP plot, with extremely high ranges of PSP associated with very large demand levels.

These figures also provide evidence that there exist many periods when price is set above short run marginal cost if we are willing to assume that the minimum SMP for each TSL bin is an upper bound on the short-run marginal cost to produce that level of output from the pool. This assumption seems reasonable since this minimum SMP did actually clear the market and result in the supply of that amount of electricity during one load period during our sample period. Subject to this assumption, the SMP graph illustrates that, on average, SMP is substantially above the short-run marginal cost for all ranges of output and that this margin is *lower* for higher levels of TSL.

This point deserves further comment. Recall that large values of SMP are obtained when the aggregate supply curve intersects the level of expected TSL at the marginal price associated with a high cost generating set. The success of our capacity availability withholding strategy at achieving large values of SMP and CC does not imply that either PowerGen or National Power bids significantly above the short-run marginal cost for any of its generating sets, only that for certain periods within the day the very high marginal cost peaking capacity will be called on line, and this will lead to a high value of SMP and a high LOLP and therefore a high value of CC. The decline in this price/marginal cost markup with higher values of TSL is consistent with this strategy of simultaneously withholding baseload capacity in low FTSL periods and bidding gensets at close to their marginal cost.

This markup over short-run marginal costs (defined as the ratio of the mean of SMP less the minimum SMP for that TSL bin divided by this minimum SMP value) averaged over the TSL bins from 16 GW to 45 GW yields a value of 193%. The very large, but variable, upper envelope on SMP illustrates that SMP can be far above the short-run marginal cost of supply in load periods particularly conducive to the supply-function/capacity-availability-limitation strategy. The PSP figure illustrates this same point. If we take the lower envelope for PSP as an upper bound on the minimum marginal cost of supplying electricity to the RECs, this figure illustrates a substantial price/marginal cost markup. The average value of this price/marginal cost markup over all TSL bins is 232%. This markup is particularly large at the high levels of TSL, different from case of SMP. This result is due in large part to the very nonlinear relation between the LOLP and the reserve margin, which makes CC increase at an increasing rate as the reserve margin gets smaller.

To investigate the impact of the presence of large amounts of sales covered by contracts for differences during the first two years of our sample, we reproduce these graphs for the first two and last two years of our sample separately in Figures 9 and 10, respectively. The qualitative features of all of the four graphs described above remain the same across the two-year periods. These graphs illustrate that magnitude of the coverage of electricity production by CFDs does not appear to have changed the frequency or success with which this strategy has been used. We are also concerned that this pattern in the graphs is purely a peak-month phenomenon. Consequently, we produce these four figures using only load periods from the off-peak months, reducing the highest TSL bin to 44 GW. Once again, the same features of the four graphs described above are present in these graphs given in Figure 11, but the ranges of the CC and UPLIFT are less in absolute value, indicating that this capacity availability withholding strategy appears to be used in both peak and off-peak months.

A final piece of evidence in favor of strategic capacity availability bidding by National Power and PowerGen is the simultaneous existence of average genset availabilities below industry availability standards for gensets owned by these two companies and average genset availabilities for the remaining gensets bidding into this market that are close to or exceed industry availability standards.[21] We compute average availability factors by fuel type for both National Power and PowerGen by taking the ratio of the sum of capacity declared available over all half hours for all gensets of each fuel type owned by each company for the entire calendar year 1995 divided by the total genset capacity of that fuel type owned by that company times the number of half-hour periods in 1995. This availability factor gives the percentage of each firm's annual potential generation capacity by fuel-type that is actually made available. For industry standard plant availabilities we use the North American Electric Reliability Council's (NERC) equivalent availability data.[22] Table 4 presents total capacity as of the end of 1995 and average actual availabilities by plant type, for National Power, PowerGen, Nuclear Electric, and several IPPs calculated as described above.[23] The last column of the table is the average availability factor that would result if the plants were made available according to the NERC average availability factors. These figures are computed as a genset capacity weighted average of the equivalent availabilities from the NERC database over all gensets of each fuel type for PowerGen, National Power and Nuclear Electric, because the NERC equivalent availability figures can vary by the size of the genset for each fuel type. Because there are no

[21]These type of numbers provide only a very rough picture of genset availability since, e.g., we could actually find no difference between the E&W availability averages and the NERC availability averages yet capacity availability could still be withheld during relatively high demand periods and made available during relatively low demand periods. This strategy would be consistent with profit maximizing behavior since National Power and PowerGen withholding capacity when they know they willl be substantially in the market (during higher demand periods)would lead to higher prices during those periods and withholding capacity during off-peak periods, when National Power and PowerGen could be substantially out of the market, would reduce revenue from availability payments.

[22]North American Electric Reliability Council (1996). NERC collects and supplies data for availability benchmarking, among other things, for more than 4,400 electricity generating units from 179 electric utilities in the United States and Canada. This data is widely used in electricity industries throughout the world, including National Power, PowerGen, and others in the E&W market.

[23]Capacities by fuel type are constructed using the inventory of gensets serving the E&W market described in Section 3.1. The capacity figures given in Table 4 include all gensets that bid into E&W pool during 1995, including those that bid zero availability, but excludes mothballed and closed plants since several months advance notice is required to bring them back on-line.

direct comparisons for some generating technologies—the MAGNOX and AGR nuclear generating technologies, which are unique to the U.K., are particularly problematic. Since there are other differences (e.g., weather, genset age, load factor, etc.) which may affect plant availability, we use the most conservative (in terms of providing evidence in favor of our arguments) NERC availabilities for our comparisons.[24] Because Combined-Cycle Gas Turbine (CCGT) generators are relatively new to the US and Canada, there is a single availability factor for this technology in the NERC database. The actual mean availabilities for National Power and PowerGen range from 11.6 to 63 percentage points below the benchmarks across the plant types. Because of the many differences between plant operation and technology in the US and UK, the magnitude of these differences is less important than the sign, particularly in light of the opposite sign of results of the same comparison for the IPPs. The two actual average availability figures for Nuclear Electric are similar to those computed using the NERC data. For all of the IPPs given in the table, the actual average availability exceeds the value computed using the NERC data. This difference between actual average availabilities of gensets owned by National Power and PowerGen versus Nuclear Electric and the IPPs is consistent with the use of strategic withholding of capacity by National Power and PowerGen. However, the difficulty in assessing the actual availability of genset capacity underscores the problems the regulator has in determining if gensets are being withheld for strategic reasons or for required maintenance and actual breakdowns.

3.4. Quantifying the Extent of Market Power

The fact that generators on average bid in excess of the short-run marginal costs of production is not surprising given the structure of the technology of generation. In particular,

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[24]Joskow and Schmalensee (1987) estimate the effects of unit age, vintage, scale, operating practices, and coal quality on coal burning generating units.

assuming the fixed cost and increasing marginal cost specification which is embodied in the short-run marginal cost functions computed by von der Fehr and Harbord (1993) and Wolfram (1995), the short-run cost function for a given load period takes the form

$$C(q) = F + c(q),$$

where F embodies the fixed capital, labor and materials costs for that period, and c(q) is an increasing function of TSL (which we denote by q) giving the variable costs of fuel, labor and materials for output level q. Given this specification, pricing at marginal cost can lead to losses because the price can be set below the average cost of production for ranges of output even on the steeply increasing portion of the short-run marginal cost curve if the fixed cost is a significant component of total costs. Consequently, in this section we attempt to obtain a estimate of the average margin by which the PPPs or PSPs these two generators obtain exceed their average costs.

According the Christensen and Greene (1976), the fixed cost (capital and labor) component for electricity generation is approximately 40% of the total costs of production for most fossil fuel generating capacity.[25] However, given the increasing energy efficiency of new capacity and the increasing amount of capital and labor expenditures required at fossil fuel plants to control SO_2, NO_X, and other emissions, this fixed cost fraction should be growing over time. Figure 12 plots the short-run marginal cost curve and average total cost curve under these assumptions to illustrate the point that pricing at marginal cost for wide ranges of output can yield losses, implying that in order to remain financially viable generators must on average bid in excess of average costs. For this reason it is difficult, if not impossible, based on the

[25]The US Energy Information Administration (1992) reports accounting capital and labor costs of coal-fired generating plants to be approximately 42% of total costs for 1990. Analogous data, from the same source, for nuclear plants implies an 88% cost share.

evidence presented, to determine definitively the extent to which generators are earning excess profits from their generation.

However, with a few extreme simplifying assumptions we can get a rough idea of the magnitude that the average PSP or PPP is above the average cost of production. Assume that $C(q)$ takes the form of a fixed-cost, constant marginal cost specification as: $C(q) = F + cq$. Let total costs be such that the ratio of $F/(cq+F)$, the fixed cost share, equals 50 percent (to account for fuel efficiency gains and the fact that not all of National Power's and PowerGen capacity uses fossil fuels) at the observed output level q. This implies that $F = cq$, so that $C(q) = cq + cq = 2(cq)$, so that average cost is equal to 2c at this output level. This implies that PSP must be set at approximately 100% above marginal cost on average to cover the total costs of production. From the graphs in Figure 6 for PSP we argued that PSP was set approximately 200% above short run marginal costs. Consequently, by these very rough calculations the PSP is set, on average, approximately 50% above average cost. Repeating this same calculation with a fixed cost share of 66% yields the result of a zero markup of price above average cost.

Increased revenues are earned by strategic use of capacity availability declarations because high values of the PSP coincide with high demand load periods. Simply looking at the annual average price charged within a year gives a misleading picture of the increased returns earned from this strategy. To illustrate this point, we first compute the product of price times the quantity sold in each load period over the entire year for the PSP, each component of the PSP and for the PPP. This is the actual total revenue produced from each of these charges. These numbers are reported in the third column of Table 5. The fourth column presents the percent of actual total revenue (the third column) that would be obtained if the price charged for all load periods within each day was the daily average price, the sum of the 48 within-day prices divided by 48. The fifth column computes the percent of total revenue that would be obtained if the price charged for all load periods within a week was the average weekly price, the sum of the 336 prices within the week divided by 336. The sixth column presents this same figure assuming the price charged for all load periods within a month is the monthly average price. Finally, the last column presents the figure assuming the price charged for all load periods within a year is the yearly average price. The remarkable feature of this table is the very small reduction in the percentages across any row in the table moving from using the daily average price to the yearly average price. However, using the daily average PSP relative to the actual PSP in each load period within the day can lead to substantial reductions in the total revenues. For PSP for the fourth fiscal year in our sample, the revenues using the daily average value of PSP are 94.27 percent of the actual revenues generated.

To provide a lower bound on the profitability of this capacity availability withholding strategy we make the following calculation. Assume that the actual total costs of generation are equal to the total revenue that would be generated if the yearly average price was applied to all load periods. This implies that averaging over all load periods within a year the market clearing PSP or PPP is equal to the average cost of generation. This assumption implies that total costs are approximately 95% of total revenues from PSP or PPP over the four years in our sample. Assume the cost shares of capital, labor and fuel are consistent with those from Christensen and Greene (1976): 20%, 20% and 60%, respectively. The increase in the return to capital from this strategy is 0.05(TC)/0.20(TC) = (Increased Return to Capital)/(Return to Capital Assuming Zero Profits) = 25%. In other words, the return to capital in this industry is increased by 25% as result of this strategy. To give some idea of the sensitivity of these results to our cost share assumptions, we repeat this calculation for a 30 percent capital share to yield at 16% increase in the returns to capital. Both of these increases in the returns to capital are conservative estimates of the increased returns to capital from the use of this capacity availability declaration strategy because we assume that the average cost for each load period is a yearly average price which includes the very high-priced load periods. This calculation does, however, go a long way towards explaining the rapid increase in the stock market values of National Power and PowerGen and increased levels of compensation paid to the chief executives of these firms over this same time period. Table 6 provides accounting values for National Power and PowerGen over fiscal years 1991/1992 through 1995/1996 for net income and earnings per share (EPS). Net income and EPS have substantially increased for both firms over these years.

4. Lessons from the England and Wales Electricity Market

The E&W electricity market offers many valuable lessons for a region of the US or country considering the design of a spot market for wholesale electricity. Many of these lessons follow directly from the market structure, but other more subtle and perhaps important lessons arise from the rules governing the operation of the market.

The most basic lesson is that competition in name is just that. Whether or not setting up an electricity market similar to the E&W market will deliver benefits to consumers in the form of lower electricity prices, depends on the market structure and the details of the market rules governing its operation. Subtle differences in the rules of the market can dramatically enhance the ability of generators selling into the market to set prices substantially in excess of their marginal and average costs. To ask these generators not to serve their shareholders and exploit these market rules to earn higher profits, is contrary to the purpose of privatizing these firms (thus giving firms the incentive to maximize profits) and introducing competition into this market. Instead, when designing these markets, the rules governing its operation might be specified so that there are few, if any, opportunities for generators to use them to set prices substantially in excess of their average costs.

On the issue of market structure, as recommended by the Director General, both National Power and PowerGen divested a fraction of their respective generation capacities. However, given the relatively small magnitude of the mandated reductions, it is doubtful these sales will significantly reduce the viability of the capacity availability withholding strategy. The end result is still two large producers each with a mixture of generation technologies and the ability to supply a large fraction of TSL, which are the essential ingredients for the success of this strategy.

Simply introducing more firms into the market will most likely have little effect of the success of this strategy. There are already many IPPs serving this market, so that simply increasing the number of competitors is not the solution. Given the current number of firms in the market and the market rules, what is important to limiting market power is reducing the size of the largest firm relative to all others. The key to the success of this capacity-withholding bidding strategy at obtaining high prices is that frequently the largest generator knows that a significant portion of its capacity will be called upon, regardless of the price it bids. If all generators are equal in size and total system load is significantly less than the sum of their capacities, then only very rarely, if ever, will the largest generator know with virtual certainty that a substantial fraction of its capacity will be required to serve the market. If the amount of available capacity from all generators is such that at the forecasted TSL, the capacity of the largest generator is not required to serve the market, then all generators will have an incentive to bid very aggressively, because all of them face the prospect of being left out of the market during that load period. The larger is the extent of demand uncertainty faced by the largest firm relative to its capacity, the less likely this capacity withholding strategy will be successful.

The current California pool plan entails two very large generating companies selling into the pool: Pacific Gas and Electric (PG&E)and Southern California Edison (SCE), each with a mix of high and low-cost generating technologies. While three competitors may be sufficient to encourage vigorous competition in a market not governed by the E&W rules of operation, the UK experience suggests that if the E&W rules are adopted, a necessary condition for this capacity withholding strategy to be unprofitable is that levels of TSL do not occur where all generators know that demand is such that they all must be significant participants in the market. If the demand condition that all generators are required to serve the market occurs sufficiently often, then there does not appear to be any reason to believe that three competitors will be any more successful than two competitors at keeping pool prices down. The CPUC and State Legislature have recognized this logic and have required both PG&E and SCE to divest themselves of substantial portions of their generating capacities.

Another major lesson from the E&W experience is that the rules governing the market can present opportunities for the large producers to exploit their market power and many of these modes of exercising market power are subtle, but high-powered in the sense that they can yield high rates of return. These strategies can be difficult to detect and even more difficult to correct. In the UK market, there are several factors that have made the strategy of withholding capacity an attractive way to raise the PSP. First, it is very difficult to detect. An alternative way to obtain a very high PSP (similar to those achieved in load periods when CC is very large) is for the two generators to submit bid functions with high prices for all levels of output supplied. However, this strategy would be relatively easy for the Director General to detect. All he would need to do is look to see the capacity offered and the price it is offered at and perform the marginal cost calculations outlined in von der Fehr and Harbord (1993) and Wolfram (1995) for each genset. The availability declaration strategy, has the advantage that the generators can disguise their intentions behind several veils. The Director General will have a very difficult, if not impossible, time telling plant unavailability due to required maintenance or actual breakdowns from those due to an unavailability declaration for strategic reasons. Because the two generators have a mix of technologies, they simply limit their baseload and intermediate load capacity made available to the pool so that, for as many load periods as possible, a few high-cost gensets are called into service, yielding high levels of SMP and CC.

A related lesson from the E&W market is that the regulator or a market designer may find it useful to consider all numbers or relationships not based on engineering or accounting identities as tools to achieve the desired regulatory outcome. The true value of the VOLL to consumers and the true relationship between the estimated reserve margin and LOLP are unknown to the regulator, but the magnitude of VOLL or the function specified to relate the expected reserve margin to the LOLP can have a tremendous impact on the observed market clearing prices. For example, setting the VOLL too high can make the payoff from strategic capacity choice timed with demand fluctuations during days and across the year a profitable strategy. If the relationship between the LOLP and the expected reserve margin is too steep in absolute value, this can also increase the profitability of this strategy. Consequently, the regulator overseeing the operation of the pool could view such variables as the VOLL and the function relating the reserve margin to the LOLP as instruments for obtaining the desired market outcomes, rather than as fixed constants or relationships.

Because the CC is a major source of very high PSPs, one may want to at least question the way in which it is calculated or why it is necessary in the first place. The motivation for instituting this charge was to provide the proper signals to the market for investment in new generation capacity to occur and to help recover the generators' fixed costs, under the assumption that gensets are bid into the pool at their marginal cost. The thought was that persistent periods of low reserve margin would trigger consistently high values of the CC, which would in turn signal the market to build more generation capacity. The ratio of the difference between total system capacity minus the highest annual half-hourly TSL divided by total system capacity is currently more than 20%. Despite having substantial reserve capacity, large CC charges occur throughout the year because of this available capacity withholding strategy. Prospective entrants interpreting these large capacity charges as signals to enter must exercise caution because of the strategic capacity availability withholding behavior of the two large generators. It seems reasonable to expect that if the CC was eliminated generators would figure out that they had to achieve higher values of SMP in order to maintain sufficient revenues to cover their total cost. These generators could no longer bid each genset into the market at close to its marginal cost and rely on high CC's to compensate them for their fixed costs. Getting rid of the CC would not eliminate the ability to withhold capacity to achieve higher SMPs, but it would eliminate the very profitable added benefit of this strategy that it triggers a high LOLP and therefore a high CC. Consequently, it does seem reasonable to seriously consider eliminating the CC from the E&W market. For all of the reasons described here and earlier in the paper, the CPUC and other state regulatory bodies considering establishing electricity markets within their boundaries may want to avoid implementing this type of capacity payment scheme.

Perhaps the most important lesson from the E&W experience is the necessity of building in the potential for demand-side responses by customers into the price determination process. As noted above, the expected demand that sets the SMP and CC is perfectly price inelastic. This aspect of the rules governing the market operation makes it substantially easier for National Power and PowerGen to produce high values of SMP and CC from the pool price determination process. The easiest way to build a significant price response into the expected demand determination process may be to allow large-scale demand-side bidding by RECs or other large customers. Demand-side bids could be of the form, "so long as the SMP or PPP is less than a certain value I will demand certain amount of capacity from the pool." If the SMP or PPP is above the cutoff value for the SMP or PPP, then that demand-side bidder will take less electricity from the pool according his demand-side bid function. Widespread demand-side bidding by RECs and large consumers would build in the demand-response to high prices necessary to help keep the values of SMP and PPP down. However, crucial to the success of demand-side bidding for limiting the exercise of market power is credibility. Therefore, demand-side bidders could be subject to same obligations for curtailing demand as the generators face for the supplying electricity according to their supply-side bids. Because of the way that electricity is currently sold to retail customers (according to fixed-price contracts), a significant amount of demand-side bidding by RECs will be very difficult to implement. RECs must either be able to curtail customers when the SMP or PPP exceeds their bid price or get more of their customers to pay the actual PSP for the power they customer during each load period.

5. Conclusions

This paper has suggested a mechanism that the two largest participants in this market use to set available capacity and prices to yield prices substantially in excess of marginal cost. This market power activity is a periodic and transitory phenomenon requiring the confluence of factors, some under the control of PowerGen and National Power, and others not under their control.

There are many caveats associated with these results. The most important is that although there is a substantial amount of evidence from the behavior of various components of the pool selling price, the behavior of total system load, the behavior of the E&W system reserve margin over time, the form of the bids submitted by National Power and PowerGen and the fraction of load periods each of the two generators sets the SMP consistent with the use of this strategy, it is impossible to state with complete certainty this strategy is in fact being used by the two firms. On the other hand, given the dramatic amount of price volatility and the large amounts of revenues that can easily be produced by this strategy, it is difficult to believe that these two generators do not set their available generating capacity and bid price with these considerations in mind in order to take advantage of the rules governing the operation of market when demand conditions favor this behavior.

APPENDIX

This appendix outlines the current LOLP calculation in the E&W market. As described in the text above, the only change that has occured in this calculation over the life of the Pool is in regard to item (3) in the next paragraph. The LOLP is evaluated by comparing the England and Wales system availability of generating capacity and forecast demand for each half-hour of the next day. For each half-hour of the following day, NGC, on behalf of the Pool, calculates $LOLP_j$, j=1,...,48.

PROMOD, a proprietary computer program,[26] is used by NGC to calculate a preliminary $LOLP_j$ for each half-hour j, which is called the $JOLP_j$ in *Schedule 9*. PROMOD uses the following inputs in this calculation:

(1) NGC's forecast demand for each half-hour ($TGSD\#_j$ in *Schedule 9*).

(2) The variability of the forecast demand (called the "Seasonal Error Allowance", denoted SE_S in *Schedule 9*, Section 21.1).

(3) The maximum of the offered availability in day 0 (the current day) and the previous seven days' offers (days -1 through -7) and the re-offered availability for days -2 through -7 for each genset (XMAX in *Schedule 9*, see Section 21.2).

(4) The probability that each genset is available (called the "disappearance ratio" and denoted DA_{jg} in *Schedule 9*, Section 21.3).

The forecast demand is assumed to follow a normal distribution. The mean value of this distribution for each half-hour is NGC's half-hourly forecast demand, $TGSD\#_j$, with a standard

[26]Energy Mangement Associates, Inc. (EMA), a consulting firm in Atlanta, Georgia, provides this program to electricity firms worldwide. PROMOD is primarily used for cost simulations but also calculates LOLP, which is use of the progarm by NGC.

deviation equal to the Seasonal Error Allowance, which is on the order of 1% and was set at vesting for each Standard Season (which begin at 5AM March 1, June 1, September 1, and November 1).

A genset with a disappearance ratio of zero would be seen as 100% reliable. For any genset commissioned prior to April 28, 1992, the disappearance ratio is set at a value agreed upon at vesting by the Pool's Executive Committee. External gensets (i.e., those in France and Scotland) and E&W gensets commissioned after April 28, 1992 are assigned disappearance ratios based on the variability of the respective genset's actual availability (excluding the first month of the genset's operation, during which the disappearance ratio is set to one). Section 21.3 of *Schedule 9* provides details.

The availability distribution is determined by convolving the density functions (assumed binary) for all gensets together. The availability of each genset is the maximum value for the genset for the current and previous seven days multiplied by ($1-DA_{jk}$), where DA_{jk} is the disappearance ratio for the genset k, $k=1,...,K_j$, and K_j is the aggregate of all gensets (for all generators) available during half-hour j.

The value of demand at given probabilities is multiplied by the probability of having insufficient availability to meet that demand. The sum of these values is designated $JOLP_j$. The $JOLP_j$ are adjusted in two stages, first to what is termed the $KOLP_j$. Calculating $KOLP_j$ is detailed in Section 21.5 of *Schedule 9* and includes the use of the following additional variables:

(5) Notional Marginal Price (NMP).

(6) $BASE_j$.

(7) Elasticities for demand ($DD<0$) and supply ($SS>0$).

(8) $JOLP_j$ elasticities ($0 \leq BB_j \leq 100$).

Items (5), (7), and (8) are provided by the Executive Committee and may be changed at any time with six months notice to all pool members. The demand elasticity is a single negative value, the supply elasticity is a single positive value, and the NMP is a single value in place of SMP (the rationale for using the NMP was to reduce complexities in calculating LOLP since the SMP changes every half-hour of every day). The NMP is adjusted by the RPI every April 1. The BB_j are given in a table corresponding to values of the $JOLP_j$, where linear interpolation is used to calculate BB_j values for $JOLP_j$ between those in the table provided by the Executive Committee. $BASE_j$ is the arithmetic mean of the previous seven day's $LOLP_j$ (days -1 through -7).

Finally, the $KOLP_j$ is adjusted as follows to arrive at the $LOLP_j$, which is the figure actually used in CC and availability payment calculations.

$$LOLP_j=(KOLP_{j-1}+KOLP_j+KOLP_{j+1})/3.$$

If j=1 then j-1=1(i.e., $KOLP_{j-1}=KOLP_j$) and if j=48 then j+1=48.

The net effect of the second and third stages to calculating the $LOLP_j$ is to reduce the variation and smooth spikes in the $LOLP_j$ measure used in calculating the CC and availability payments. Note that the above calculations imply that the only variation in $LOLP_j$ across half-hours within each day results from variation in forecast demand ($TGSD\#_j$) across half-hours (i.e., if forecast demand is constant throughout the day then LOLP will be constant across all half-hours within the day).

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Table 1

Sample Means and Standard Deviations of Components of PSP (Daily Average and Actual Values)

		Daily Average Values		Actual Values	
	Year	Mean	Std Dev	Mean	Std Dev
SMP	1	19.52	1.57	19.52	4.10
CC	1	1.29	3.05	1.29	8.76
UPLIFT	1	1.61	1.01	1.61	2.31
PSP	1	22.42	4.72	22.42	12.72
SMP	2	22.64	1.62	22.64	4.24
CC	2	0.17	0.49	0.17	1.70
UPLIFT	2	1.39	0.48	1.39	1.12
PSP	2	24.19	2.08	24.19	5.75
SMP	3	24.16	3.56	24.16	6.71
CC	3	0.28	0.99	0.28	2.97
UPLIFT	3	2.18	0.72	2.18	1.62
PSP	3	26.62	4.13	26.62	8.76
SMP	4	20.78	7.22	20.78	12.28
CC	4	3.22	8.57	3.22	24.49
UPLIFT	4	2.38	1.72	2.38	4.53
PSP	4	26.38	14.82	26.38	35.08

Table 2

Distribution of Ratios of Various Components of PSP

	Year	Mean	Min	Max	Std Dev
CC/SMP	1	0.05	0.00	10.36	0.30
UPLIFT/SMP	1	0.07	0.00	1.50	0.09
SMP/PSP	1	0.92	7.89e-02	1.00	0.11
CC/PSP	1	0.02	0.00	0.82	0.08
CC/SMP	2	0.01	0.00	1.87	0.05
UPLIFT/SMP	2	0.06	0.00	0.49	0.04
SMP/PSP	2	0.94	3.01e-01	1.00	0.05
CC/PSP	2	0.00	0.00	0.56	0.03
CC/SMP	3	0.01	0.00	3.65	0.08
UPLIFT/SMP	3	0.09	0.00	0.56	0.06
SMP/PSP	3	0.92	1.92e-01	1.00	0.06
CC/PSP	3	0.01	0.00	0.70	0.03
CC/SMP	4	0.09	0.00	20.41	0.58
UPLIFT/SMP	4	0.10	0.00	4.79	0.13
SMP/PSP	4	0.90	3.82e-02	1.00	0.12
CC/PSP	4	0.03	0.00	0.80	0.10

Table 3
Mean and Standard Deviation of SMP by Load Period Regimes

	Year	Mean	Std Dev	StdDev/Mean(%)
FTSL ≤ 20GW	1	15.75	1.35	8.57%
20GW < FTSL ≤ 35GW	1	18.81	3.73	19.82%
35GW < FTSL ≤ 45GW	1	21.88	4.03	18.41%
45GW < FTSL	1	30.71	4.36	14.20%
FTSL ≤ 20GW	2	18.43	1.47	7.96%
20GW < FTSL ≤ 35GW	2	22.01	4.13	18.76%
35GW < FTSL ≤ 45GW	2	25.05	3.55	14.18%
45GW < FTSL	2	31.54	3.03	9.61%
FTSL ≤ 20GW	3	23.30	7.80	33.49%
20GW < FTSL ≤ 35GW	3	23.72	6.65	28.05%
35GW < FTSL ≤ 45GW	3	25.27	6.38	25.25%
45GW < FTSL	3	37.66	3.85	10.21%
FTSL ≤ 20GW	4	9.64	0.45	4.63%
20GW < FTSL ≤ 35GW	4	18.69	9.43	50.44%
5GW < FTSL ≤ 45GW	4	30.54	14.28	46.76%
45GW < FTSL	4	68.36	20.97	30.68%

Table 4
Actual and NERC Availabilities by Generator by Fuel Type

Generator	Fuel Type	Capacity*	Availability	
		(MW)	Actual (%)**	NERC** (%)
National Power	CCGT	1,832	53.17	80.20
National Power	OCGT	1,494	53.44	84.52
National Power	coal	17,643	71.51	80.92
National Power	hydro	40	0.00	90.80
National Power	oil	5,938	28.94	78.39
PowerGen	CCGT	3,140	64.10	80.20
PowerGen	OCGT	463	73.79	84.65
PowerGen	coal	11,792	69.96	79.61
PowerGen	hydro	53	0.00	90.20
PowerGen	oil	4,003	29.18	77.50
Nuclear Electric	AGR	5,590	71.78	76.25
Nuclear Electric	MAGNOX	3,391	75.38	76.25
Central Power	OCGT	27	95.16	84.70
Lakeland Power	CCGT	229	93.15	80.20
Teeside Power	CCGT	1,875	88.59	80.20
Regional Power	CCGT	272	89.70	80.20
Fellside Power	CCGT	168	81.69	80.20

*Capacity at the end of the 1995 calendar year, including zero Registered Capacity gensets..

**Includes all gensets declaring availability in the 1995 calendar year, including zero Registered Capacity gensets.

CCGT = combine-cycle gas turbine, OCGT = open-cycle gas turbine

Table 5

Annual Revenue from Each Component of PSP Computed Using Different Time-Averaged Prices

			% of Actual Annual Revenue			
	Year	Actual Annual Revenue Millions of £	Daily Average Price	Weekly Average Price	Monthly Average Price	Yearly Average Price
PSP	1	6,152	96.96%	96.17%	95.87%	95.65%
PPP	1	5,678	97.39%	96.67%	96.40%	96.12%
SMP	1	5,225	98.39%	98.00%	97.91%	97.84%
CC	1	453	85.85%	81.34%	78.99%	76.30%
UPLIFT	1	474	91.72%	90.08%	89.58%	89.95%
PSP	2	6,460	98.02%	97.75%	97.68%	97.67%
PPP	2	6,083	98.25%	97.98%	97.90%	97.80%
SMP	2	6,023	98.38%	98.15%	98.10%	98.06%
CC	2	60	85.02%	80.59%	78.17%	72.64%
UPLIFT	2	377	94.41%	94.12%	94.15%	95.45%
PSP	3	7,194	97.81%	97.51%	97.45%	98.23%
PPP	3	6,604	98.05%	97.72%	97.66%	98.27%
SMP	3	6,499	98.23%	97.98%	97.96%	98.70%
CC	3	105	86.77%	81.62%	79.29%	71.68%
UPLIFT	3	589	95.18%	95.14%	95.06%	97.79%
PSP	4	7,787	94.27%	92.76%	92.42%	90.61%
PPP	4	7,147	94.42%	92.93%	92.60%	90.77%
SMP	4	5,929	95.97%	95.08%	94.88%	94.62%
CC	4	1,220	86.90%	82.47%	81.51%	72.03%
UPLIFT	4	725	92.78%	91.05%	90.60%	89.11%

Table 6. Fiscal Year Net Income and EPS (£).[27]

National Power plc		
Fiscal year ending	Net Income (000's)	EPS
Mar-96	608,000	0.52
Mar-95	525,000	0.41
Mar-94	522,000	0.41
Mar-93	420,000	0.33
Mar-92	365,000	0.29
PowerGen plc		
Fiscal year ending	Net Income (000's)	EPS
Mar-96	519,000	0.71
Mar-95	388,000	0.50
Mar-94	345,000	0.44
Mar-93	285,000	0.36
Mar-92	242,000	0.31

[27] Annual Reports.

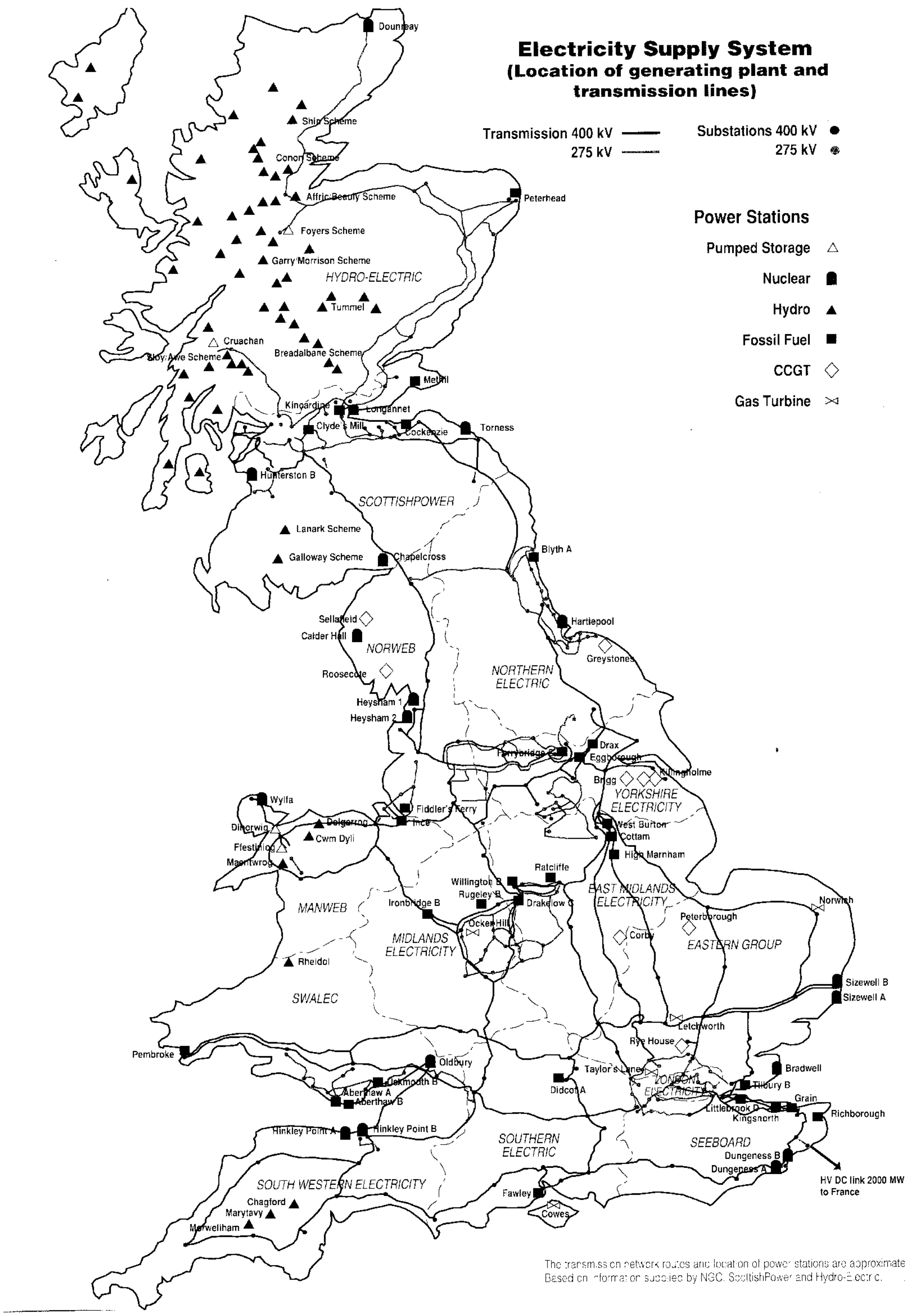
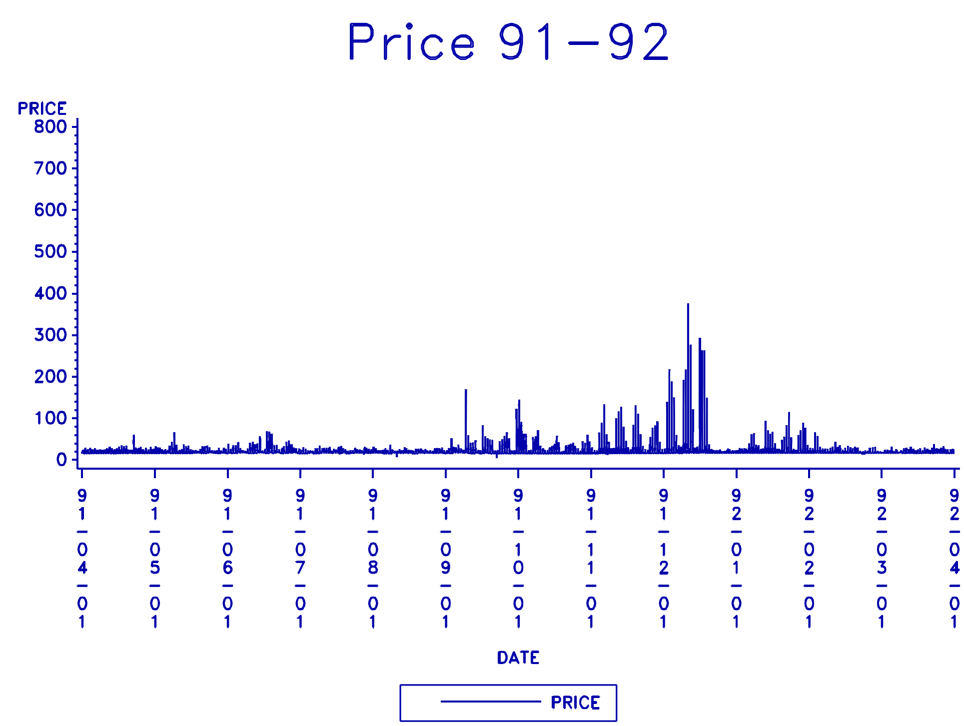


Figure 1: Map of United Kingdom Electricity Industry

Figure 2 (a)



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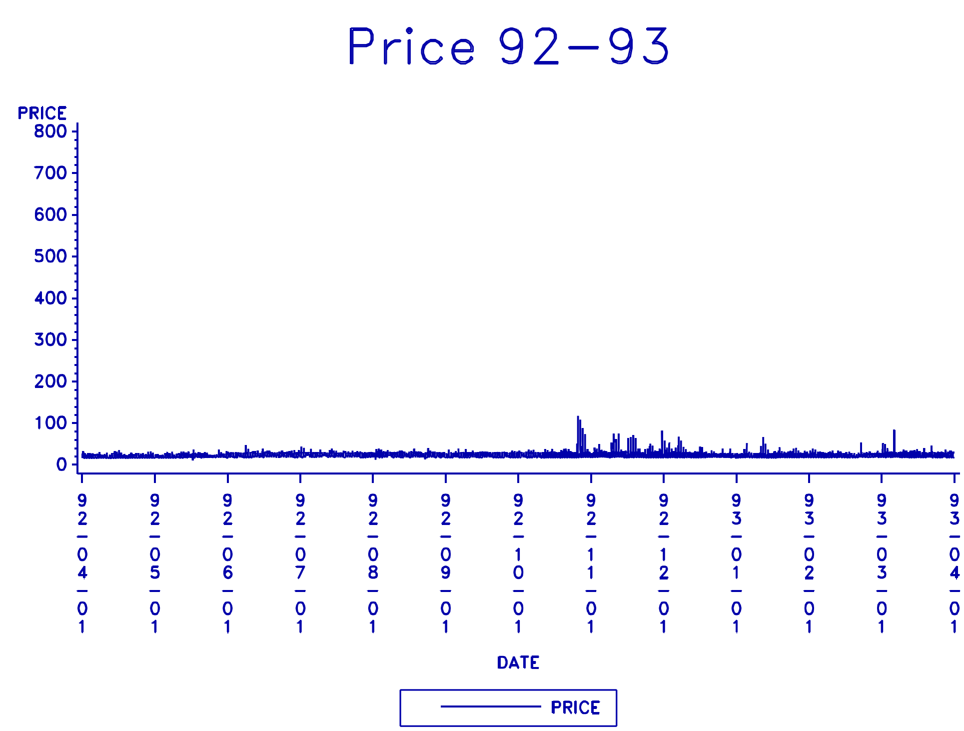

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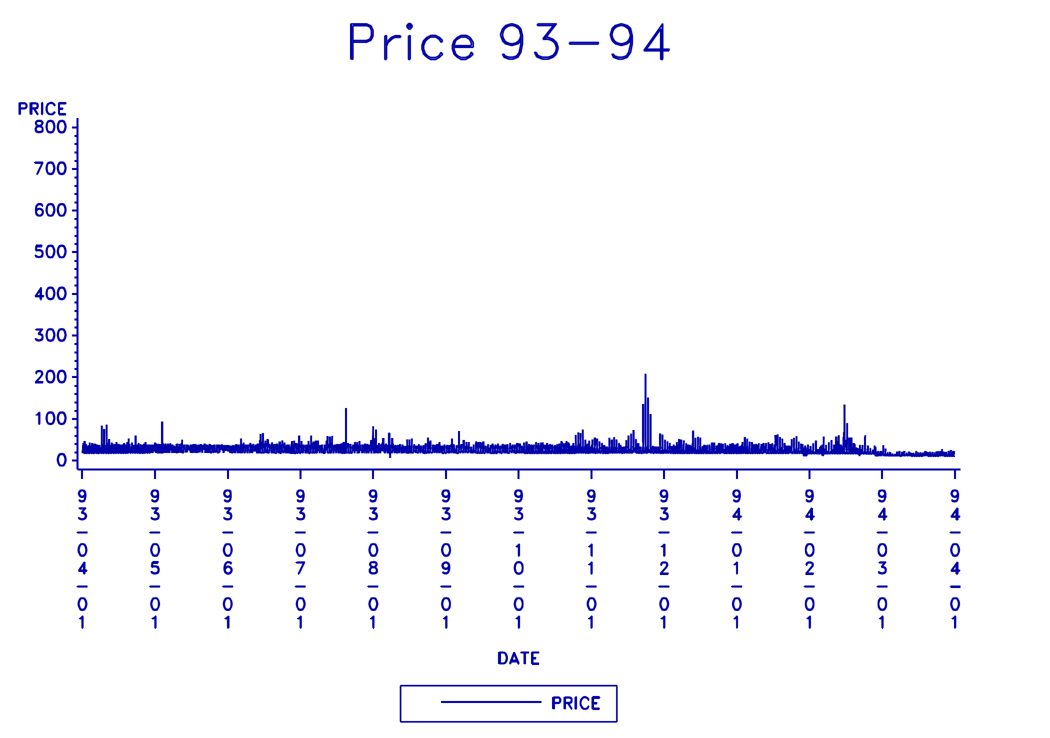

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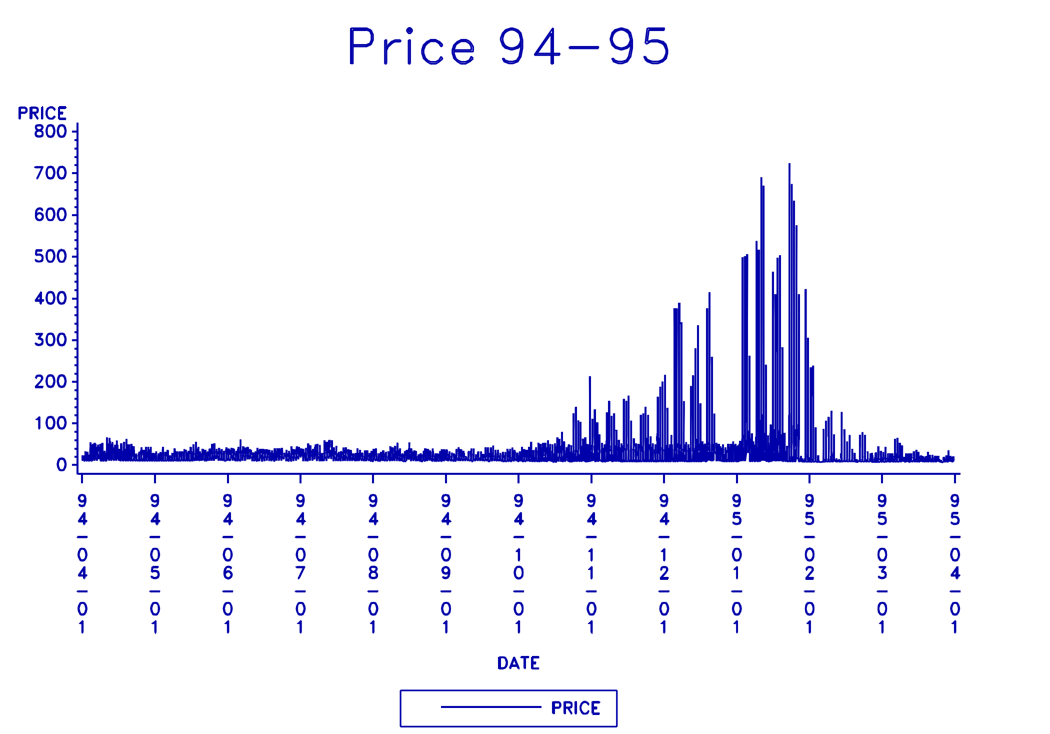
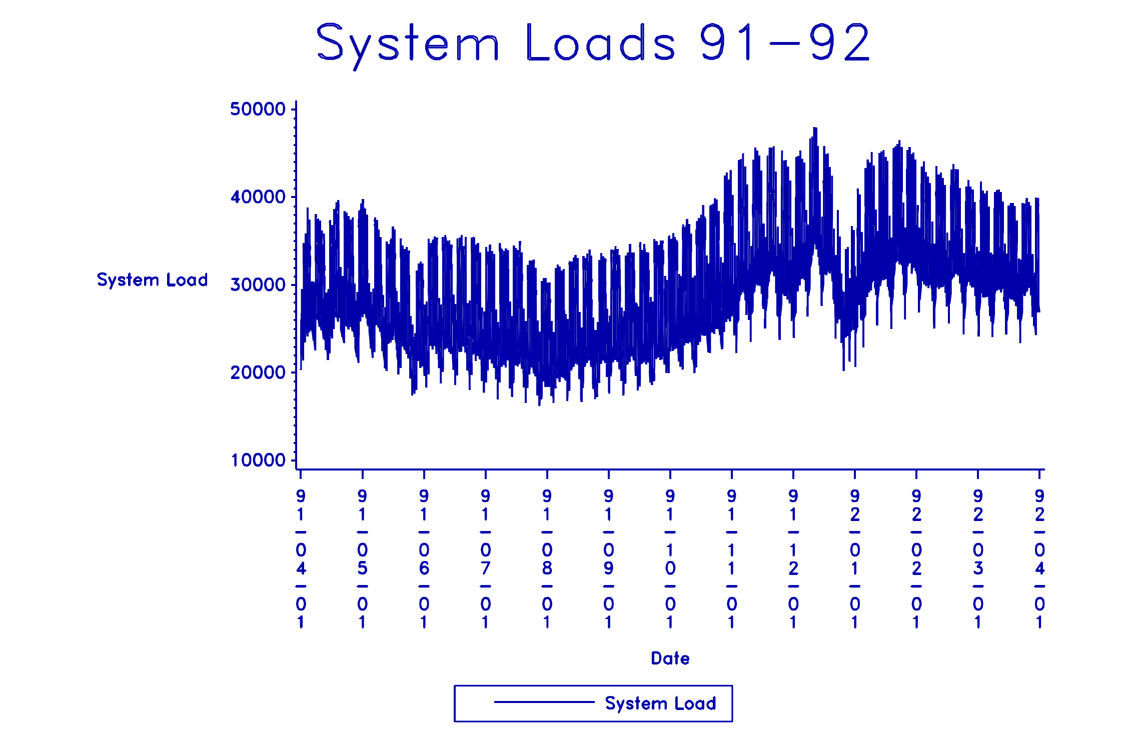


Figure 3 (a)



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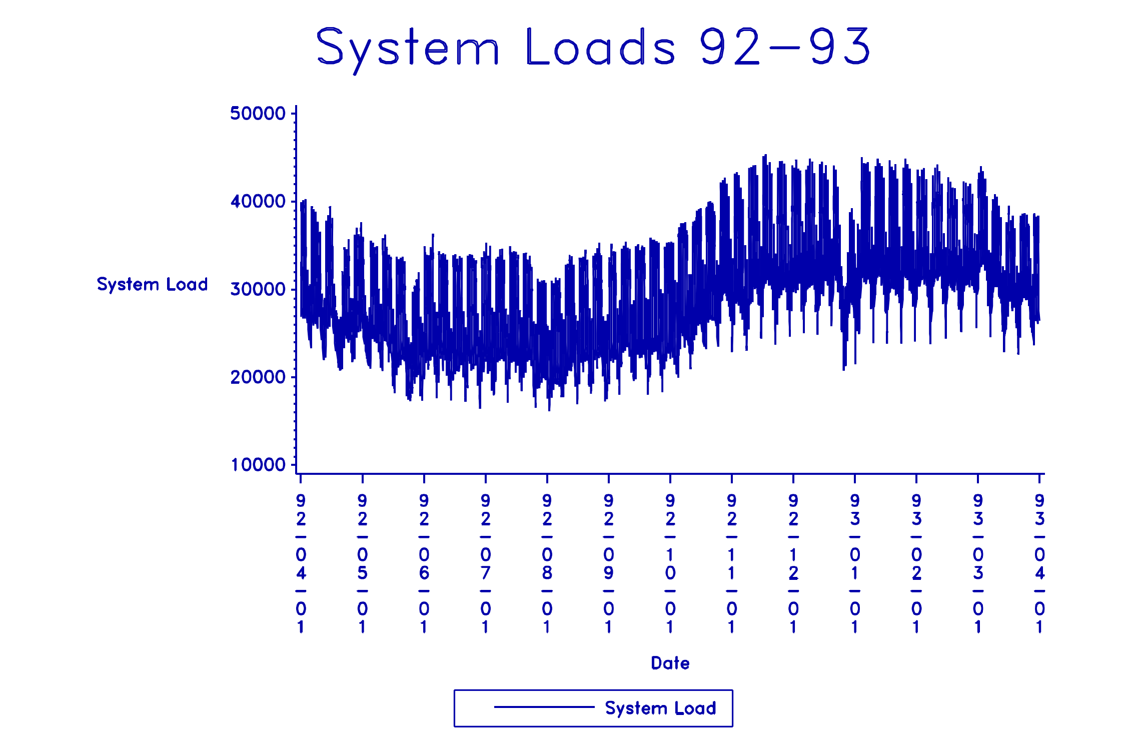

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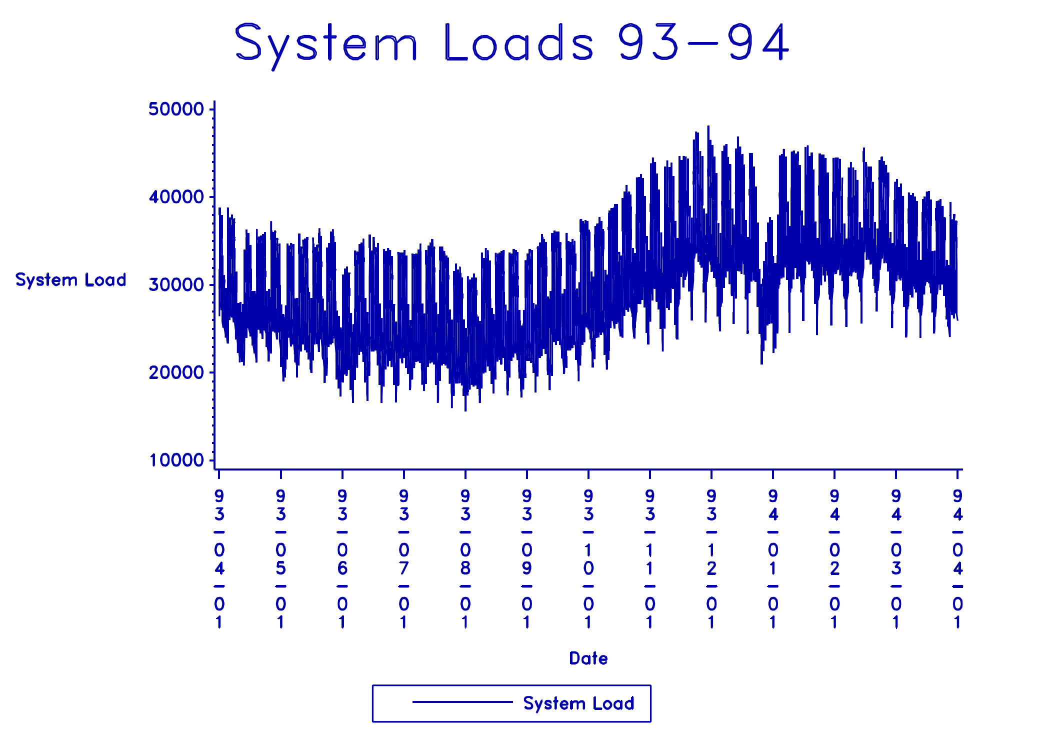

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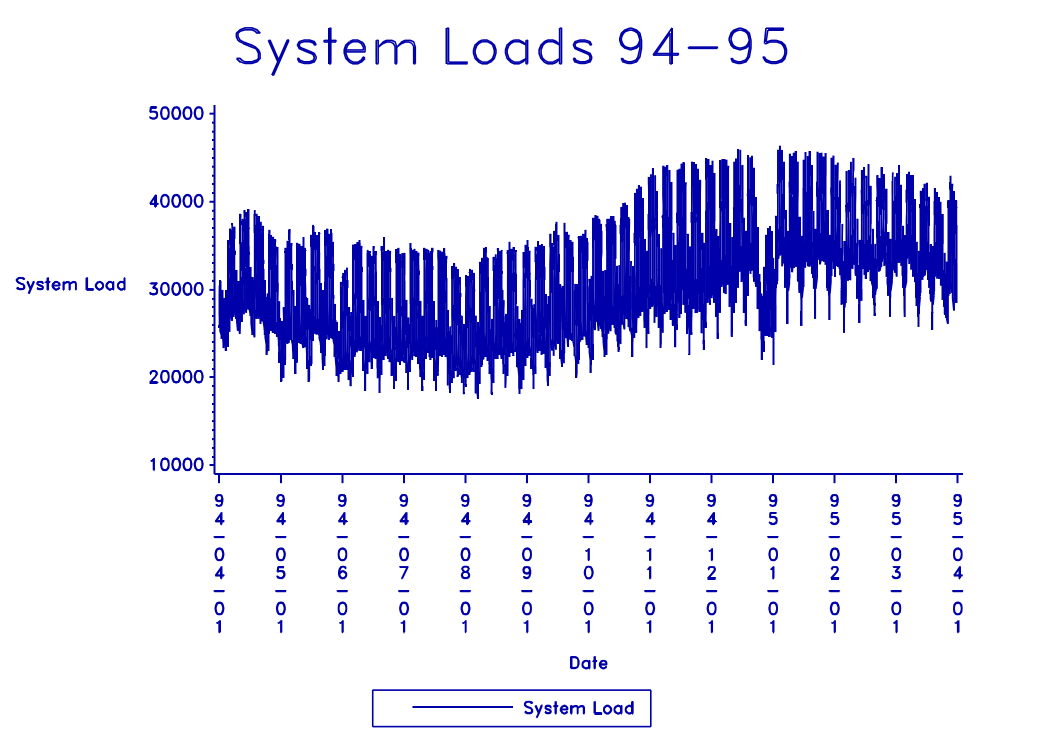


Figure 4
Increased SMP and CC Resulting from Capacity Withholding Strategy

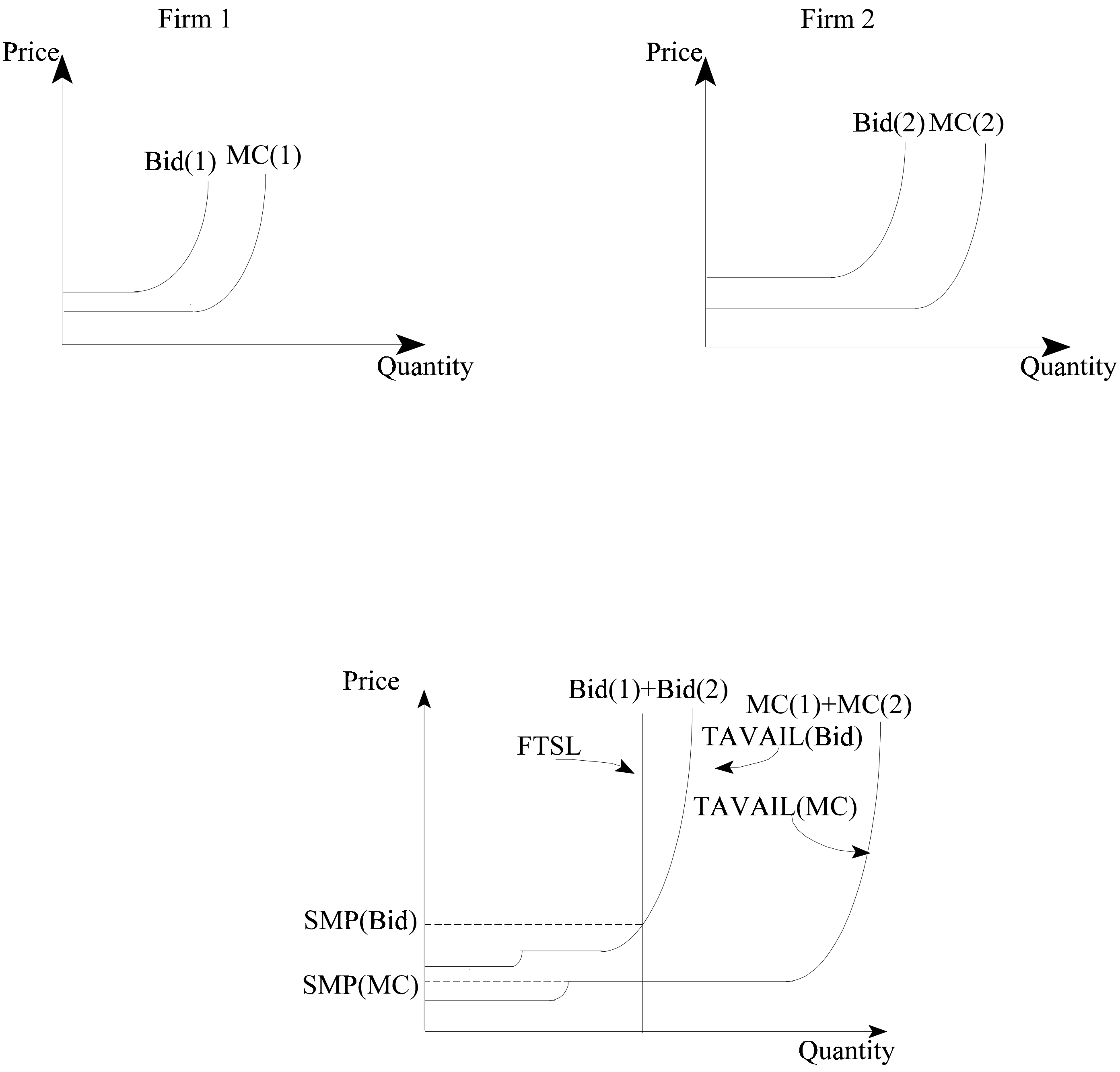
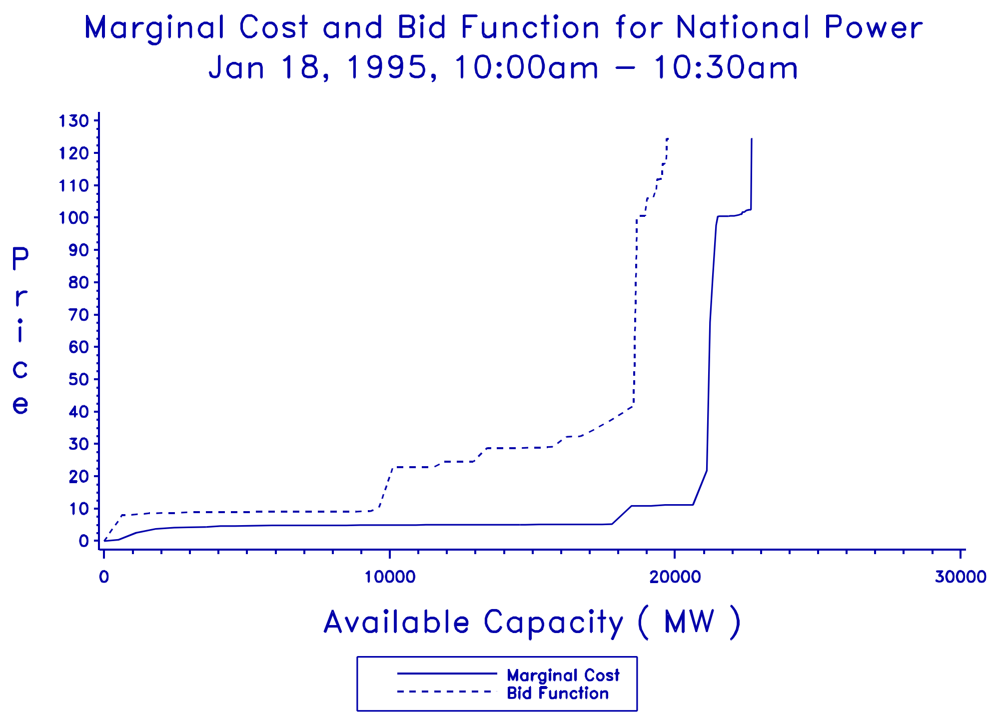


Figure 5 (a)



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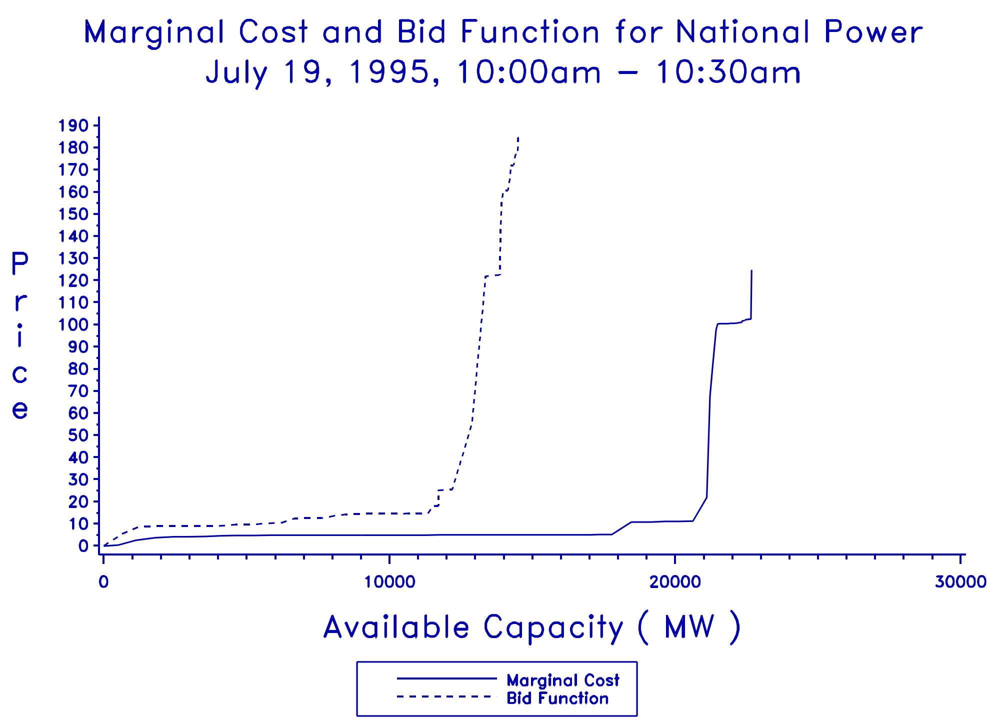
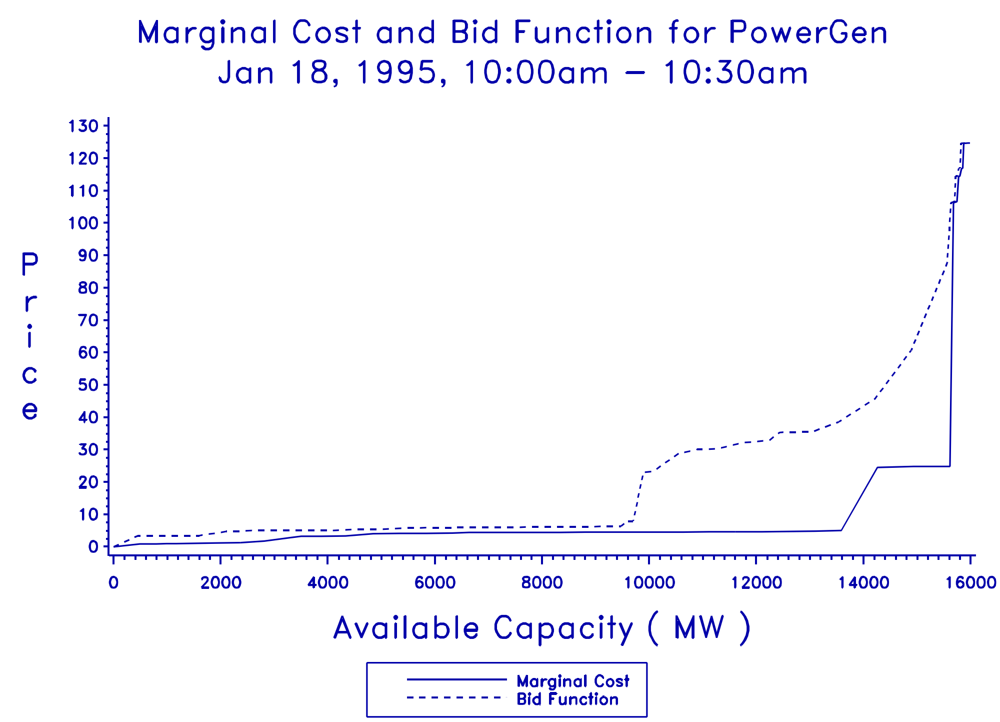


Figure 6 (a)



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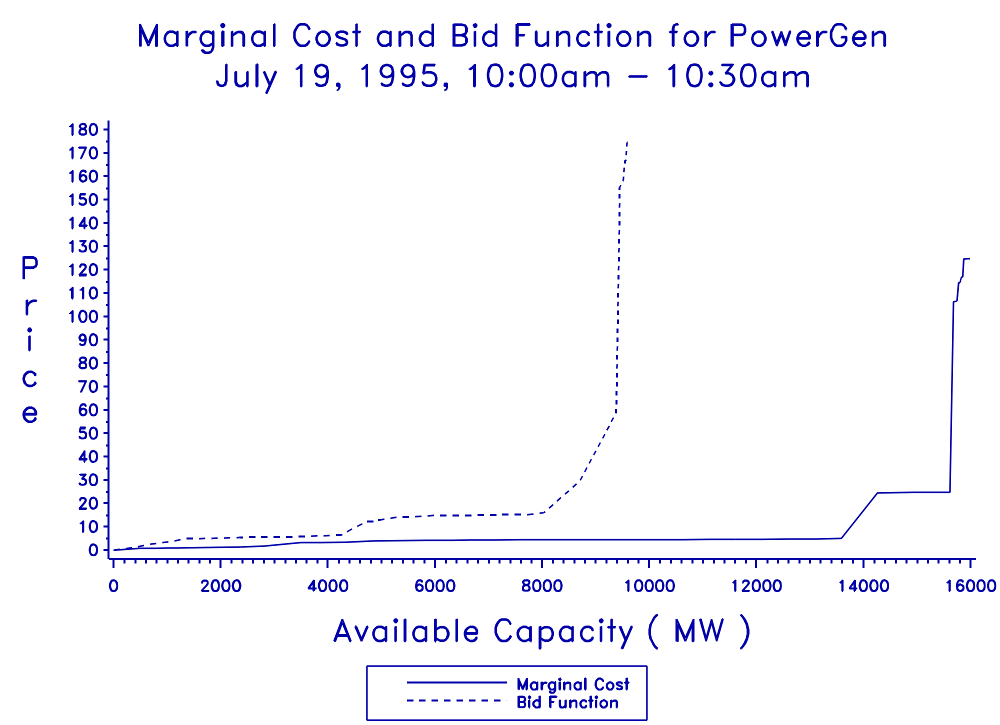

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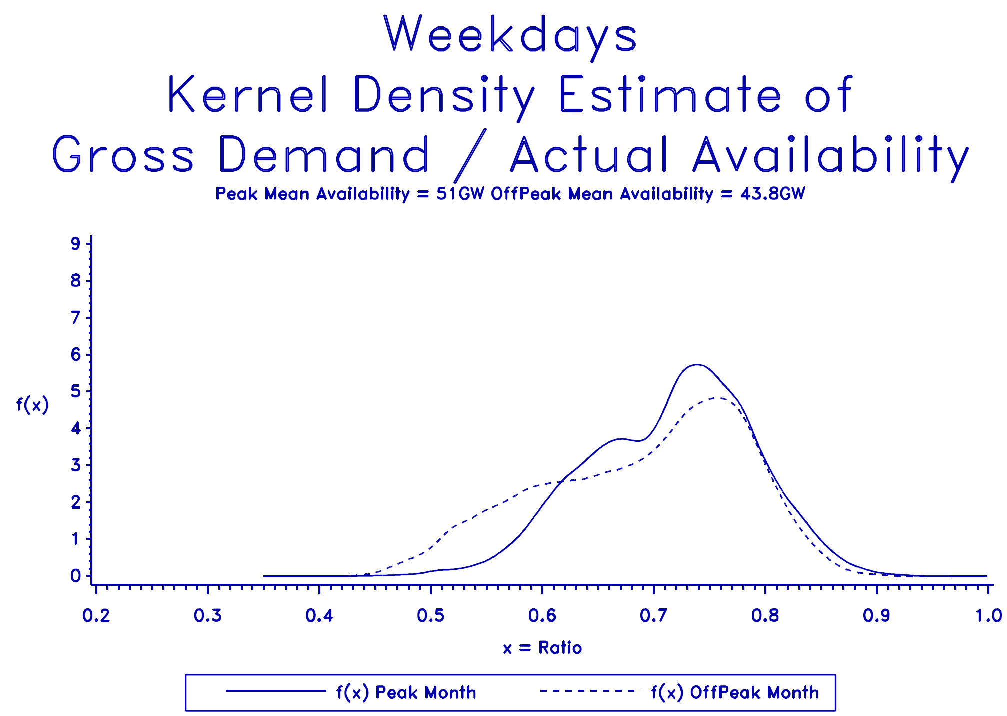

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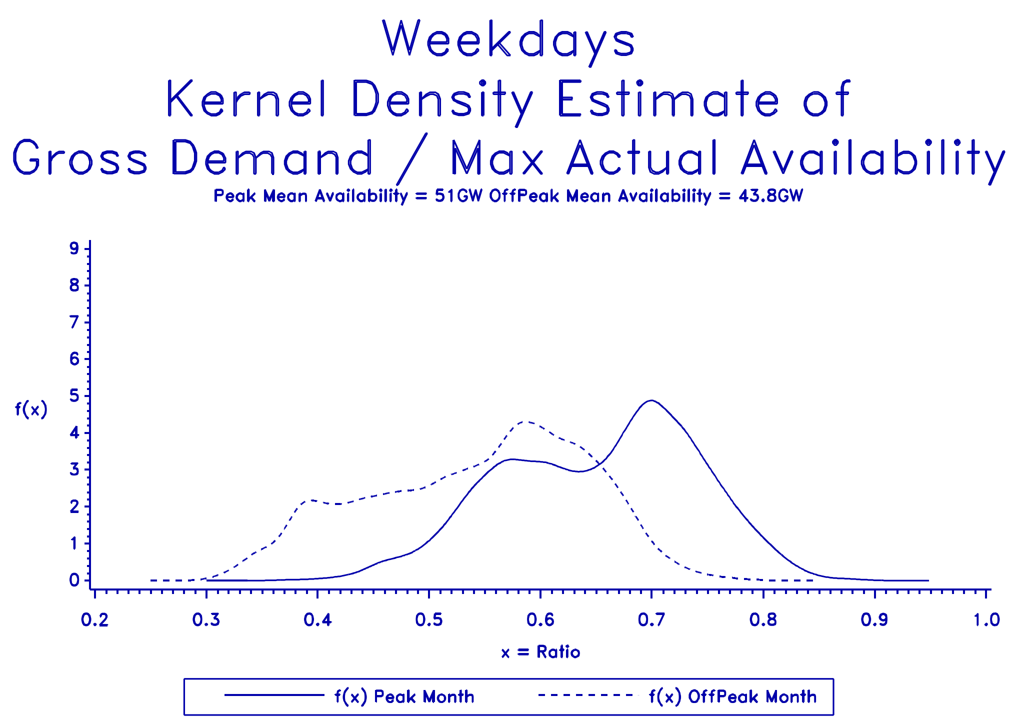
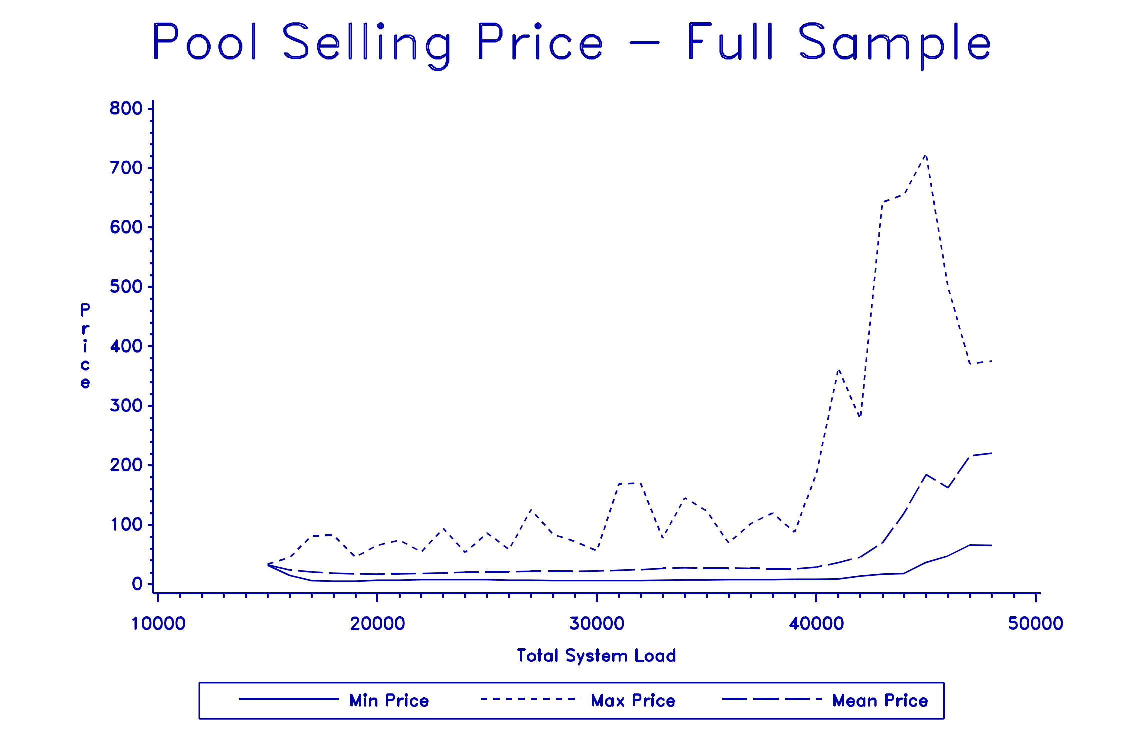


Figure 8 (a)



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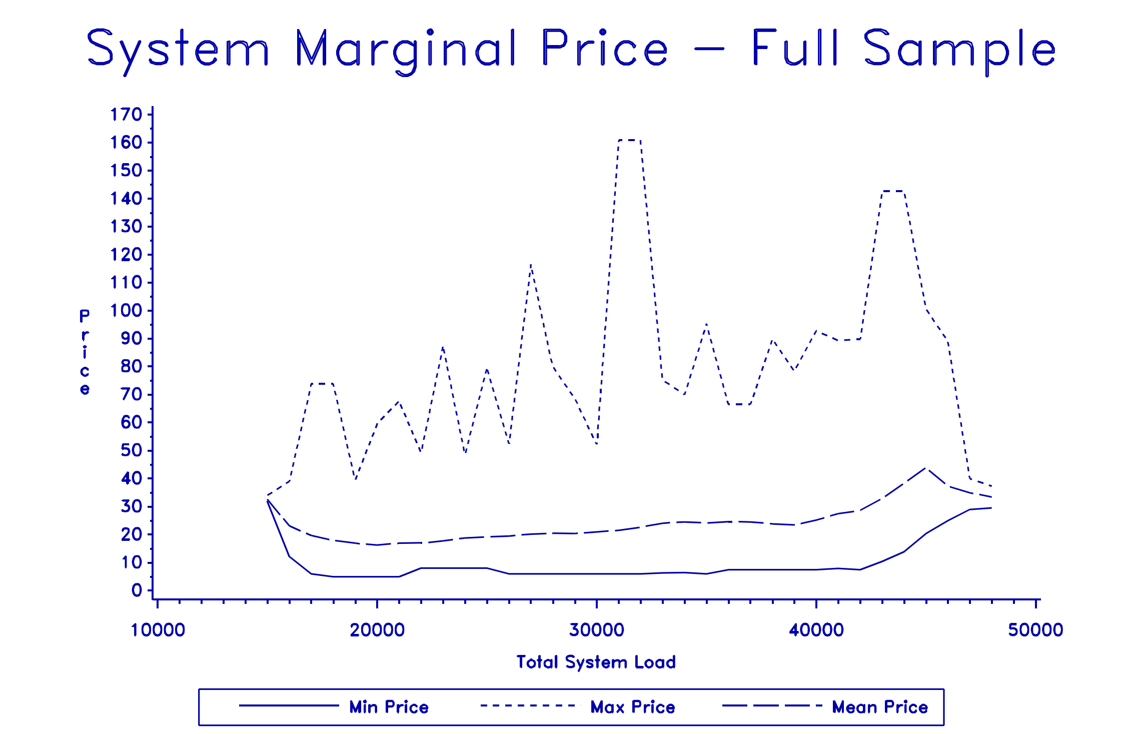

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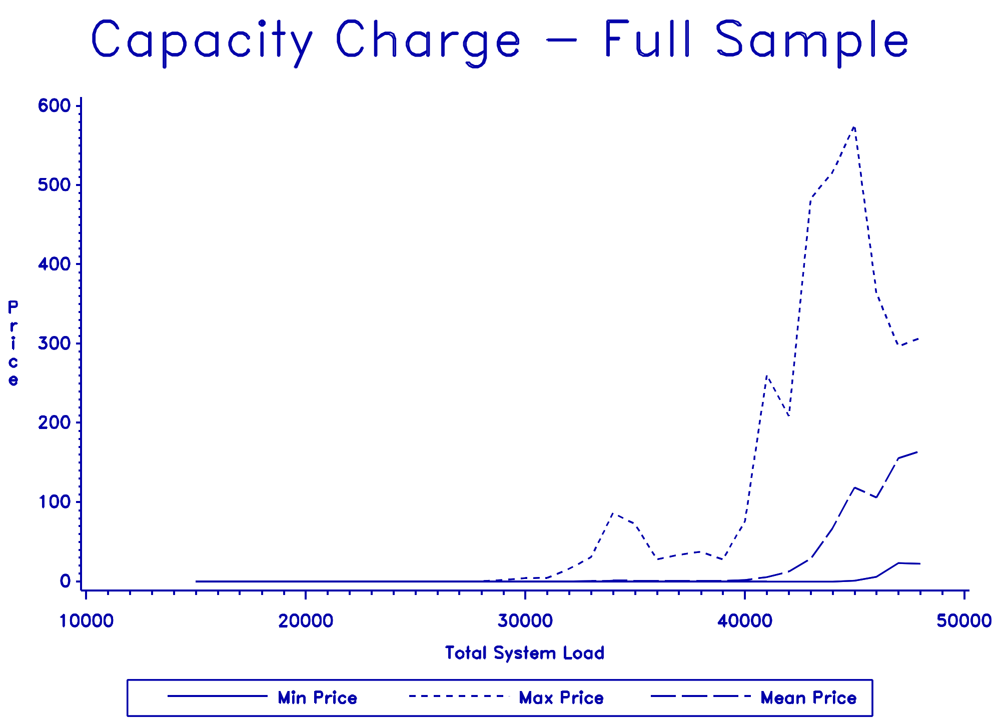

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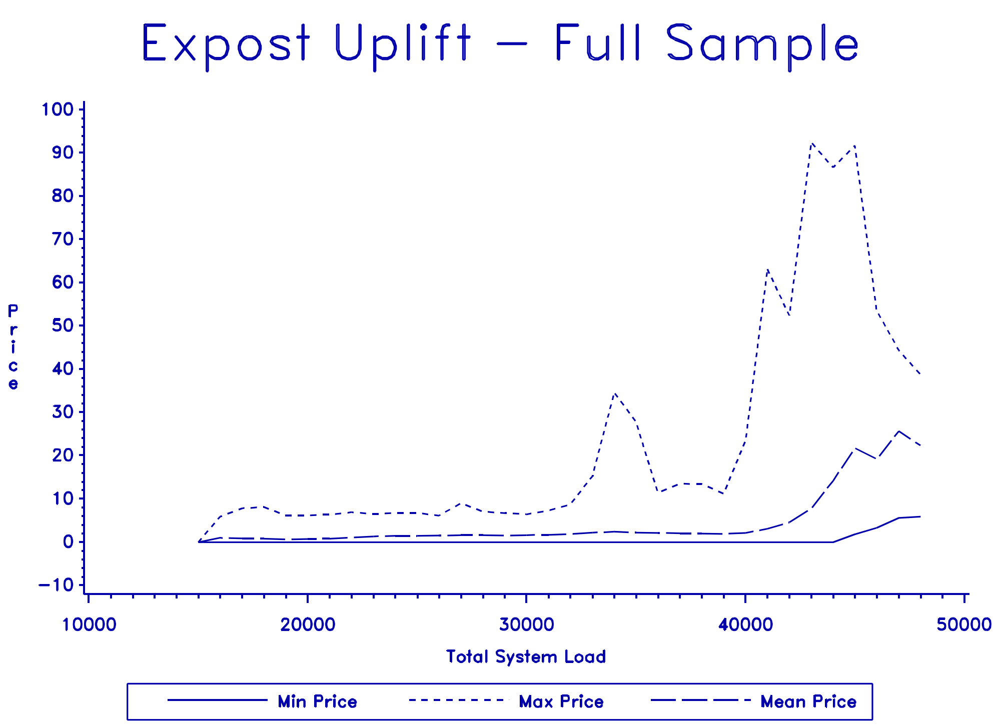
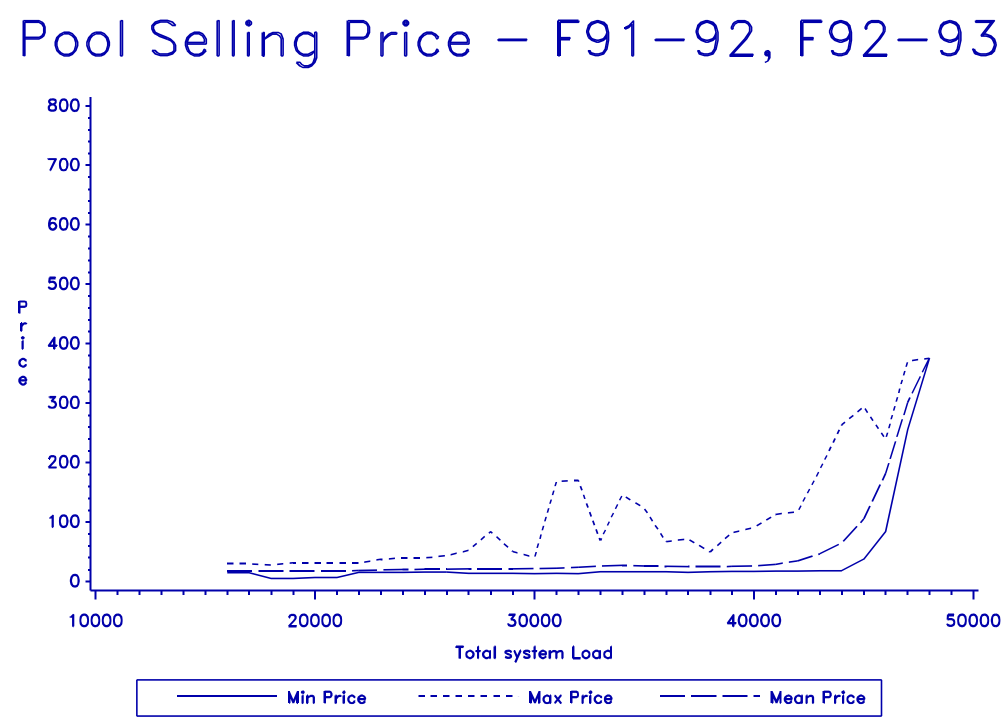


Figure 9 (a)



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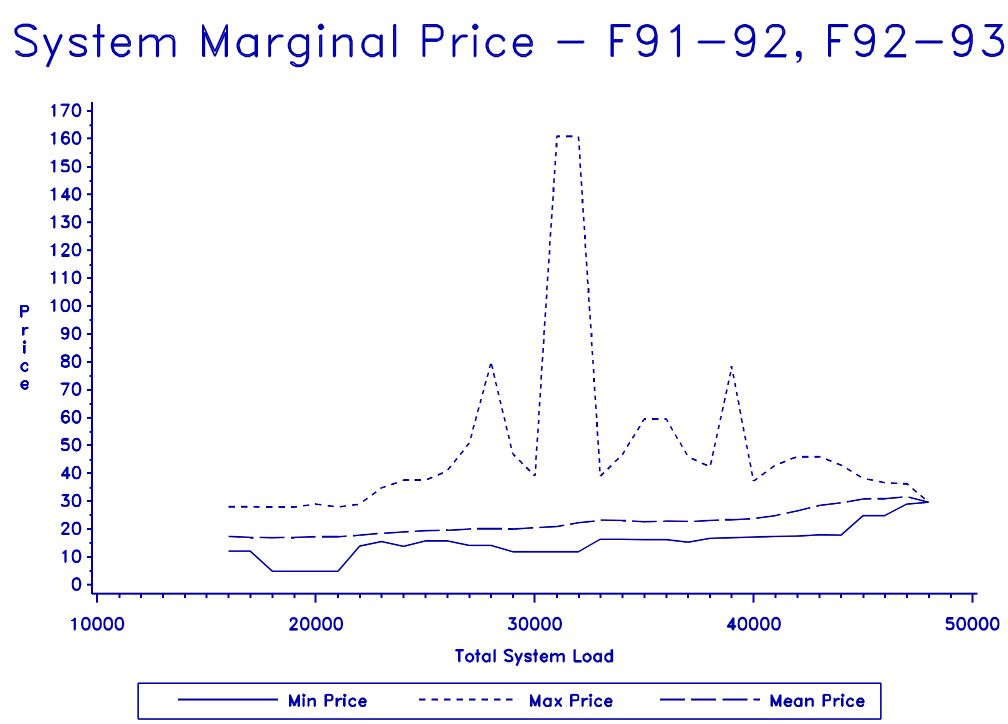

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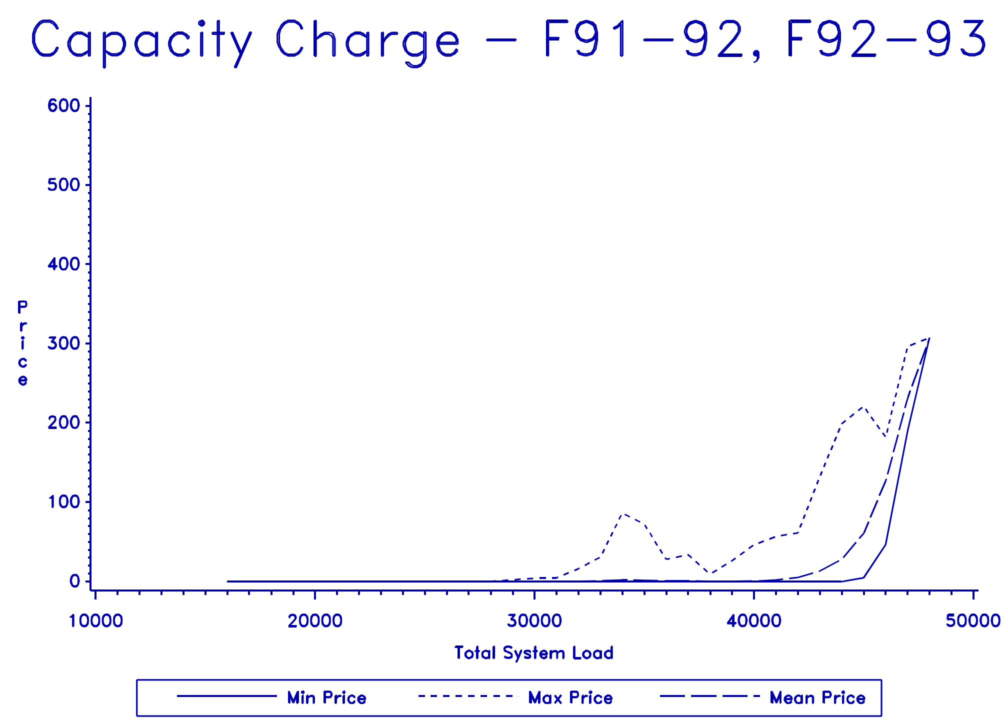

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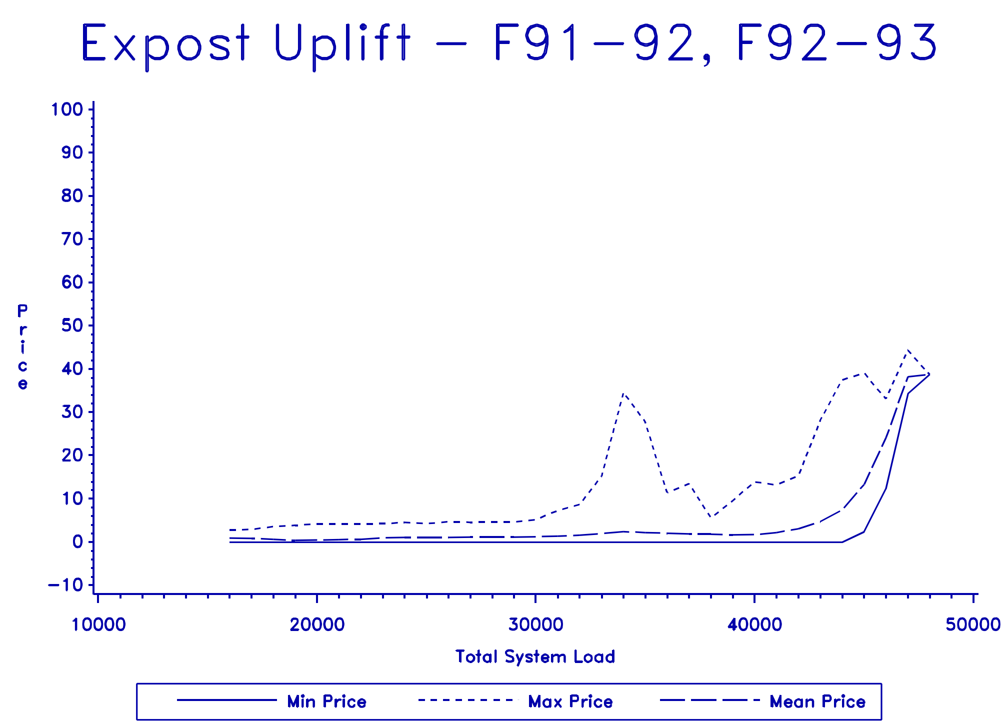

Figure 10 (a)

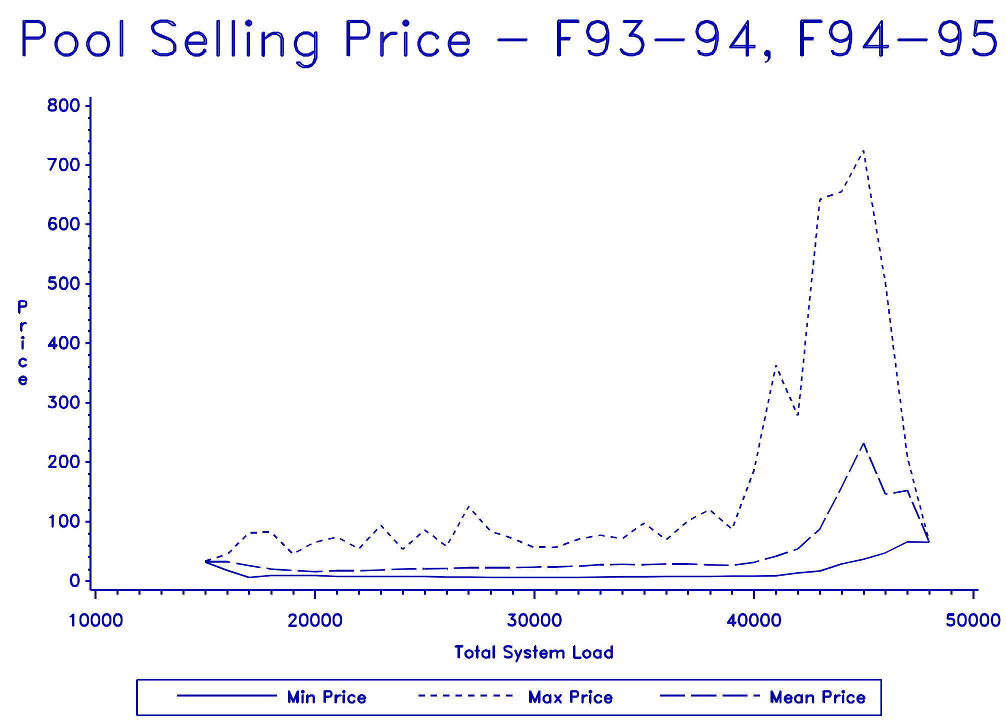

Figure 10 (b)

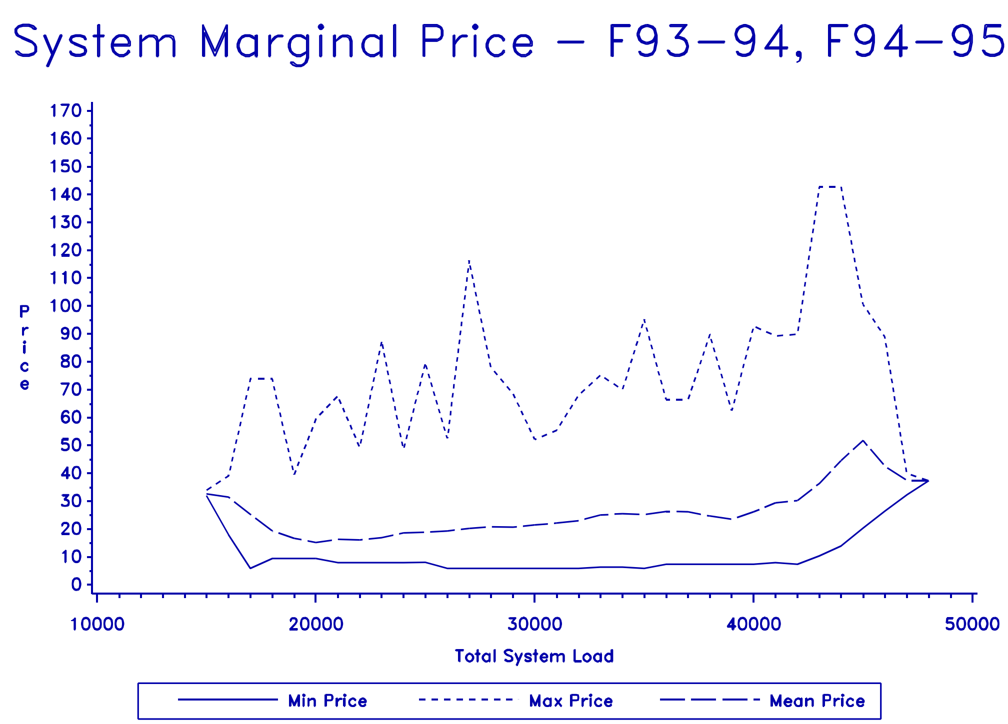

Figure 10 (c)

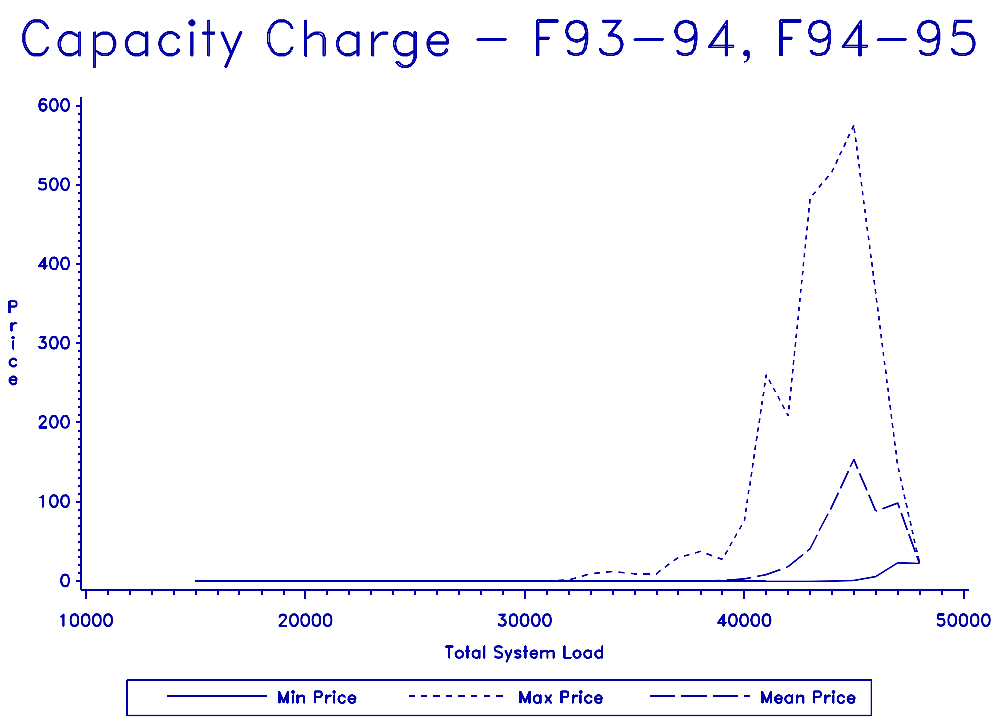

Figure 10 (d)

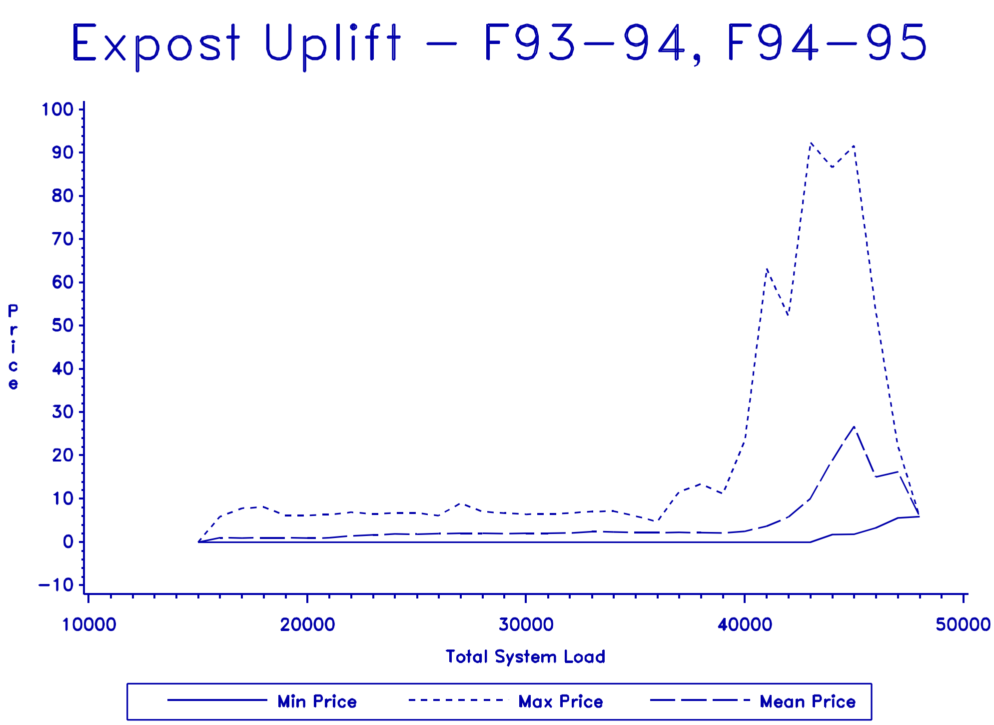

Figure 11 (a)

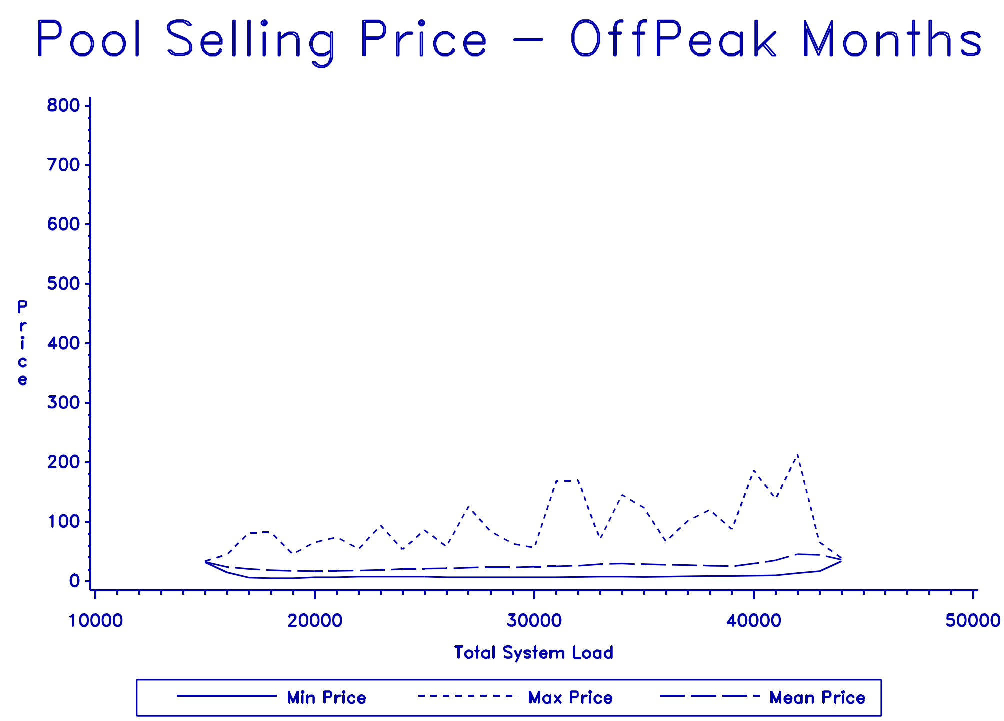

Figure 11 (b)

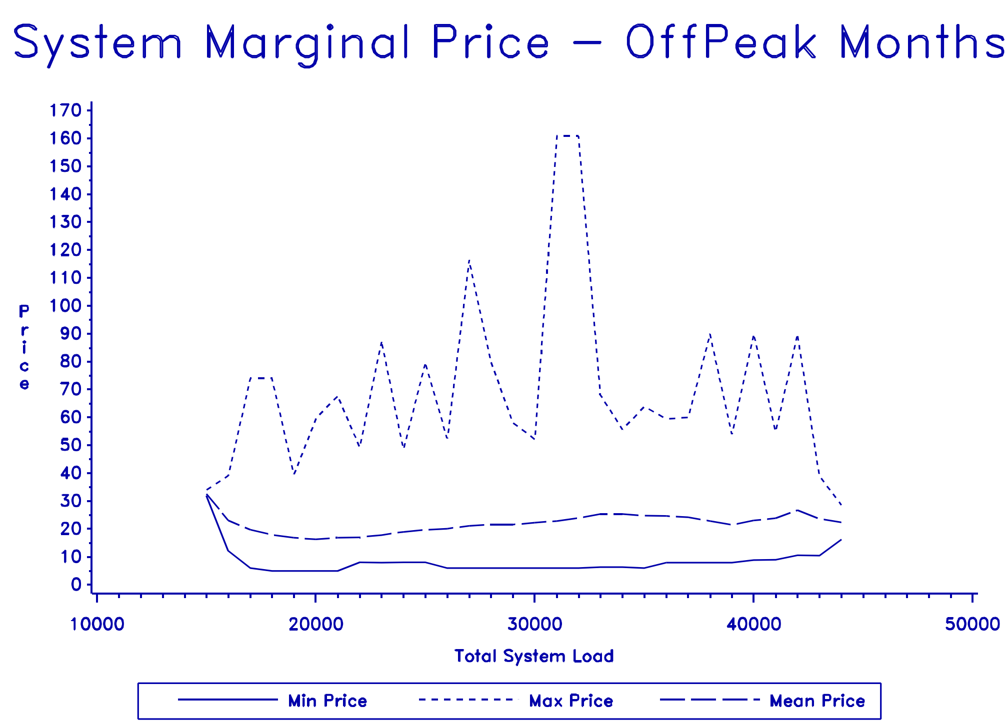

Figure 11 (c)

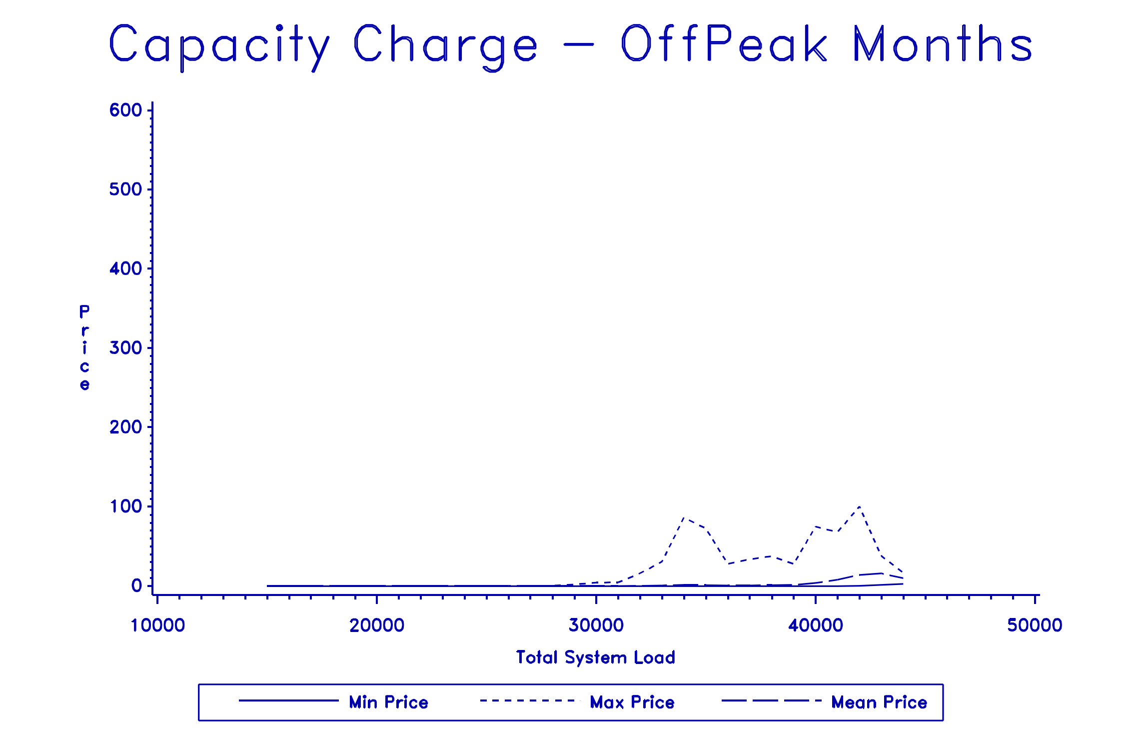

Figure 11 (d)

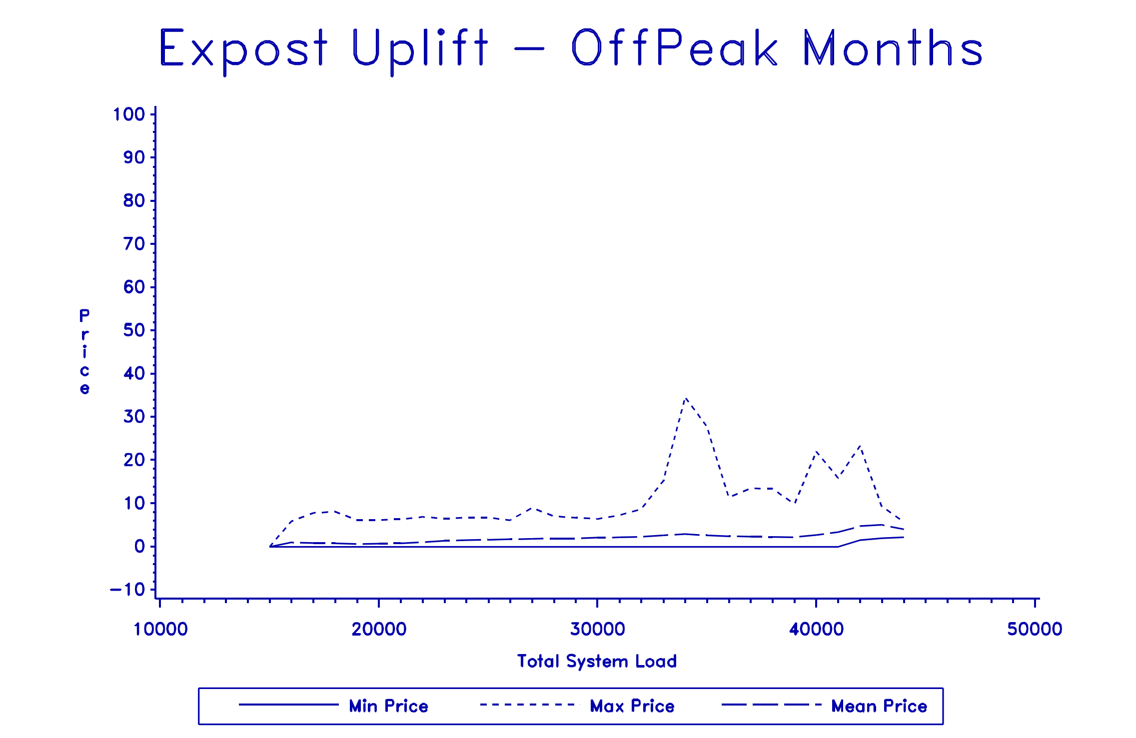

Figure 12: Marginal Cost Function and Associated Average Cost Function