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An Empirical Assessment of the Competitiveness of the New England Electricity Market

James Bushnell and Celeste Saravia

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University of California Energy Institute
2539 Channing Way
Berkeley, California 94720-5180
www.ucei.org

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Summary

Underlying the current debates over the appropriate organization of the electricity industry and its wholesale markets is a need for metrics that allow for comparisons of the markets that are already operating. One such metric is provided by competitive benchmark analysis. The basic idea behind a competitive benchmark is to estimate the price that would result if no firm attempted to exercise market power and to compare it to observed market prices. In this paper we estimate competitive benchmark prices for the electricity market overseen by the Independent System Operator of New England (ISO-NE).

We study the period from May 1999 to September 2001. Using the Energy Clearing Price (ECP) of the ISO-NE as a measure of market price, we find the demand-weighted markup between the ECP and the competitive benchmark to be 12%. However, the ECP reflects adjustments for factors, including transmission congestion and other unit operating constraints, that are not explicitly considered in forming our competitive benchmark. Alternative measures of market prices that more closely match our methods for estimating a competitive price can be derived by intersecting market demand with the aggregate supply curve taken from the offer prices of generation units. One such measure intersects the aggregate offer curve of all generation units with overall market demand. Using this measure of price, we find a demand-weighted markup of 4% over our estimate of competitive price.

*Bushnell: University of California Energy Institute. Email: jimb@IEOR.Berkeley.edu. Saravia: Dept. of Economics, University of California, Berkeley, and University of California Energy Institute. Email: CSaravia@econ.berkeley.edu. This work was supported by the Massachusetts Office of the Attorney General and the ISO New England.

Another measure of price intersects the offer prices only of large fossil-fuel generation units with the actual demand served by that set of units. This price is usually higher than the previous offer-based measure because transmission and other operating constraints cause many fossil-fuel units to be called upon to operate even though their offer prices are higher than other units that are not operating. The margin produced from this latter offer-based measure is 11%. However this latter margin does not reflect ISO-NE's ex-post reduction of offer prices from certain transmission constrained units. Because of these reductions, the revenues earned by these units will be lower than indicated by this measure. It is extremely difficult to say how large the impact of ex-post market-power mitigation on this index is without more detailed data on specific mitigation events.

The differences among these three measures indicate that factors other than energy bids play an important role in market outcomes in New England. Unit operating constraints are raising the ECP above the levels produced by a simple aggregation of energy bids. In addition, the set of units actually called upon to operate appears to be working larger margins into their energy offer prices than are reflected in the bids of other units. It is likely that the strategic bidding of other unit operating parameters, such Low Operating Limits (LOL) also plays a role in these outcomes.

Other studies using similar methods have examined the competitive performance of the California and PJM electricity markets. The only time period over which all 3 studies overlap is May to December 1999. Over this period the performance of the New England market compares favorably to that of the California and PJM electricity markets. Further comparison of the New England and California markets during 2000 reinforces this impression.

From the perspective of market efficiency the results to date are encouraging, particularly when compared to California, but need to be considered in context. The continued vertical integration of some suppliers and the transition contracts imposed on others provide a powerful mitigating influence on the incentives of these firms to exercise market power. The pending expiration of transition periods and potential consolidation of supply portfolios will reverse this effect. It is difficult to predict the extent to which new entry will offset these trends. The market power created by transmission congestion and other unit operating constraints presents an ongoing challenge to the efficient operation of electricity markets. Last, the operations, monitoring, and market power mitigation functions of the ISO no doubt has contributed to the outcomes detailed in this report. It is important that we continue to examine both the short and long term impacts of these activities, particularly as widespread changes to the ISO-NE's operations and pricing protocols are adopted.

1 Introduction

Lost amid the current debates over the merits and shortcomings of electricity deregulation is the fact that the movement away from the traditional organization and regulation of the industry is now virtually irreversible in most parts of the country. The vertically integrated electric utility that is overseen by state public utilities commissions and regulated under cost-of-service principles is being phased out, rapidly in some states, more gradually in others. Very few new generation facilities have been planned or built by regulated utilities over the last 15 years, while there has been substantial construction of such facilities by non-utility generators (NUGs) over this period.

While the eclipse of the state-regulated, vertically-integrated utility as the dominant institutional form in the electricity industry is becoming a near certainty, it is far less clear what form of market organization will replace it. At the structural level, there is wide disagreement over the proper roles for transmission as well as distribution companies, retail providers, and for public ownership of facilities. At the regulatory level, the monitoring and mitigation of supplier market power at the wholesale level is replacing the state PUC rate-making process as the primary source of regulatory influence over electricity prices. Although technically overseen by the Federal Energy Regulatory Commission (FERC), different regions have been given substantial leeway in implementing a variety of market power mitigation regulations. Over the last 18 months, events in California and elsewhere have led the FERC to take a more active role in this new form of supplier regulation. Perhaps the most energy has been spent debating the various aspects of market design, such as the sequencing of market prices over time and space, over which the various regional markets in the U.S. differ substantially.

Underlying the growing debates over the appropriate organization of the industry and its wholesale markets is a critical need for metrics that allow for comparisons of the markets that are already operating. The FERC has stated that its delegation of decisions over market structure and design to local institutions was in part motivated by a desire to allow experimentation over these forms. A careful study of the relative performance of these markets over many dimensions is necessary to allow us to learn from the experiences of these markets. One such metric is provided by competitive benchmark analysis.

The competitive benchmark has formed the basis of a fundamental metric of market performance that has evolved from several studies of electricity markets. The basic idea is to develop an estimate of the market price that would result if all firms behaved as price-takers (*i.e.,* if no firm attempted to exercise market power) and to compare that price to the observed market price over that time period. Originally applied to the U.K. electricity market by Wolfram (1999), this approach was refined to include detailed production and demand data (Borenstein, Bushnell and Wolak, 1999) as well as environmental costs (Joskow and Kahn, 2001) in studies of the California market. Mansur (2001) adapts this approach to the PJM market. The ideal of a competitive benchmark price also forms the foundation, albeit imperfectly, for much of FERC's approach to market power mitigation, particularly in California.

In this paper, we estimate competitive benchmarks for the electricity markets operated by the Independent System Operator of New England (ISO-NE). As with the above studies, we have to adapt the general technique to the market rules and available data. The result, however, is still an index with which we can make at least preliminary comparisons of the competitiveness of the New England market to the others that have been studied. Section 2 describes the rules and structure of the ISO-NE operated markets. Section 3 describes the calculations of the competitive benchmark prices. In section 4 we present the results for the New England market and compare them to those from similar studies of California and the PJM interconnection. We summarize our findings in Section 5.

2 The New England Electricity Market

The New England region has a long history of closely integrated electricity operations. The New England Power Pool (NEPOOL), which was formed in 1971, has coordinated the planning and operations of electric utilities and other suppliers from 6 states.[1] The current incarnation of the electricity market in New England began formal trading in May 1999. It is centered around the Independent System Operator of New England (ISO-NE), which was created from the foundations of NEPOOL.

Since 1997, ISO-NE has been responsible for the real-time dispatch of the New England electric system. In May 1999, it also began operating markets for electric energy and several types of reserve services. The current market design falls somewhere in between the highly decentralized markets in California and the tightly integrated market functions of the PJM interconnection.[2] Various shortcomings with the market design have been highlighted since the markets inception (see Cramton and Wilson, 1998, and Cramton and Lein, 2000.). Despite preliminary concerns about the market design, the decision was made to open the markets for trading in the spring of 1999 and to identify and implement changes to the market design at a later date. The market is now in the process of a major overhaul that will substantially change the pricing of transmission and reserve services. However, during the sample period we study there were only minor changes to the procedures for calculating energy prices.

The NEPOOL system is a mandatory pool in the sense that all participating suppliers are required to submit daily bid prices and other operating characteristics for their available generation units. The scheduling and operation of individual power plants for the purposes of ensuring sufficient energy and reserves are to a large extent under the control of the ISO-NE. Firms do have the option of pre-scheduling the output of specific resources to accommodate bilateral or internal transactions. Unlike PJM, or to a lesser extent California, the ISO-NE's energy clearing price (ECP) does not vary by location within New England. Transmission congestion is instead dealt with through side-payments to generators in constrained regions that are recouped in an uplift charge shared by all customers.

[1]NEPOOL spans the states of Connecticut, New Hampshire, Maine, Massachusetts, Rhode Island, and Vermont.

[2]The PJM interconnection oversees electricity markets in Pennsylvania, Maryland, New Jersey, and Delaware.

One important difference between New England and PJM and California is the more active role the ISO plays in market power mitigation. The ISO-NE continually reviews offer prices and other parameters and will intervene if it determines that these parameters constitute an abuse of market power. By contrast, the California ISO maintained a maximum price cap, but did not interfere with market outcomes below that level. The PJM interconnection engages in active bid mitigation, but only in cases where transmission congestion has given a firm 'local' market power. In July 2000 the FERC ruled that the ISO-NE enjoyed too much discretion in determining the conditions under which it could impose bid mitigation and the ISO-NE developed new transparent criterion, which were implemented on May 15, 2001. This change falls too late in our sample period for us to examine its impact, but it remains an important topic for future work.

Market Structure

The NEPOOL system currently has about 26,500 MW of installed generation capacity within its borders. This includes the addition of over 2000 MW of capacity since the current markets began operating in 1999. The peak demand during our sample period was just over 25,600 MW. The system is almost always a net importer of power from its neighboring regions. Over our sample period, net imports into New England averaged about 2,300 MW, or just over 16% of load. By comparison, California had 54,000 MW of installed capacity and a peak demand of 51,782 MW during 1999.[3] Imports into the California ISO system averaged about 7400 MW, or 27% of load, in 1999 and less than 5500 MW, or 20% of load, during 2000 when resources were more scarce throughout the west.

Firm	Fossil Capacity	Hydro Capacity	Nuclear Capacity	Other Capacity	Total Capacity
PG&E N.E.G.	3264	1152	0	165	4581
NRG	2184	0	0	0	2184
Sithe	1904	0	0	0	1904
Northeast Util.	1391	83	0	175	1649
Northeast Gen. Services	308	1323	0	0	1631
FP&L Energy	973	365	0	0	1338
Mirant	1323	0	0	16	1323
Calpine	1016	0	0	0	1016
Wisvest	980	0	0	0	980
Duke Energy	962	0	0	13	975
Other	3584	257	4359	644	9132
Total	17858	3180	4359	1013	26428

Table 1: Generation Ownership as of 2001

[3]See "2000 Summary of Expected Loads and Resources," Western Systems Coordinating Council. The figures for California include utilities that are not members of the California ISO.

The current distribution of generation ownership is summarized in Table 1. By the end of 2000, a large share of the generation had been divested from the incumbent utilities to non-utility generation companies (NUGs). PG&E's National Energy Group holds the only portfolio with more than a 10% share of the system's capacity. However the purchase of this portfolio from the New England Electric System Co. (NEES) was accompanied by a contractual obligation to sell power back to NEES distribution companies at pre-specified prices. The extent of this contract coverage was linked to the number of retail customers that remained under the 'standard offer' service of the distribution companies and has been declining over time.

The regulatory treatment of vertically integrated firms is another structural component not reflected in the above table. If the portfolios of Northeast Utilities and its unregulated affiliate, Northeast Generation Services, are considered together, the combined portfolio accounts for about 12% of NEPOOL capacity. As with PG&E's N.E.G., the incentives of Northeast Utilities are complicated by the continuation of state regulatory control over some of these assets. To the extent that vertically integrated firms are able to pass through wholesale generation costs through automatic rate adjustments, their load obligations will not mitigate their incentive to increase revenues for their generation units.

3 Estimating a Competitive Benchmark Price

The principles behind the estimation of competitive benchmarks have been described in detail elsewhere (see Borenstein, Bushnell, and Wolak, 1999), so we will limit our discussion here to how the basic concepts have been applied to the particulars of the ISO-NE operated markets. The competitive benchmark price is the price that would result if all firms acted as price-taking firms. In other words, the price that would result if no firm attempted to exercise market power. For the purposes of this analysis we define producer market power as the ability to raise prices above competitive levels. Market power is almost certain to exist to some degree in electricity markets, as it does in many markets, so that the goal of an analysis such as this is not to detect the presence of market power, but rather to gauge the scope and severity of it. The benchmark price can also be a useful tool for evaluating the impact of changes to the market structure or rules on the performance of the market.

The characteristic of price-taking behavior that is most relevant to this analysis is the fact that a price-taking firm will choose to produce power as long as the incremental costs incurred in producing it do not exceed the revenues from selling that power. The lowest-cost unit that does not produce power at a given moment will therefore have costs (slightly) above the market price at that moment. An hourly market price that would result from price-taking behavior can therefore be measured by estimating the incremental cost of the cheapest unit that *is not* needed to serve demand in a given hour. In this paper, we estimate such a price for the ISO-NE market. The details of the components used to construct the market prices and costs are described in the following subsections.

Market Clearing Quantities and Prices

Since the physical component of all electricity transactions is run through ISO-NE, it is relatively straightforward to measure market volume. We measure energy demand as the metered output of every generation unit within the NEPOOL system plus the net imports into the system for a given hour. Because of transmission losses, this measure of demand is somewhat higher than the metered load in the system.

ISO-NE reports an hourly Energy Clearing Price (ECP) that is derived from a time-weighted average of the Real Time Marginal Prices (RTMP) calculated by the ISO at least 6 times an hour. In general, the RTMP is set at the price of the next least expensive MW of generation to be dispatched to meet the system's need for energy and, if necessary, to accommodate the repositioning of generation units to provide certain reserves.[4] ISO-NE staff indicated in conversations that lower cost units are not frequently repositioned to provide these reserves. Reserves are instead usually provided by units with offer prices above the RTMP.

Without a detailed reconstruction of the extent to which reserve requirements influenced the RTMP, it is difficult to know how much of these reserves to allocate to the market quantity used to estimate the competitive price. Ignoring reserves altogether would understate market quantity while including the entire AGC and TMSR requirements would overstate it. In the estimates provided below, we add the AGC quantity to the actual generation output to derive the total market quantity.

The hourly ECP provides a single system-wide measure of market price to which we can compare a counterfactual estimate of a competitive price. However, the ECP also includes adjustments for factors not included in our counterfactual estimates. The ISO-NE dispatch calculation includes consideration of unit-commitment costs and other operating restrictions such as ramping rates. These factors can force the ISO to skip over some lower-cost units in the 'merit' order of generation in favor of more flexible units with higher direct fuel costs, thereby increasing the RTMP. The ISO will also at times call upon higher cost generation units 'out-of-merit' due to constraints caused by transmission congestion or because of other operating restrictions. For example, expensive generation units that are needed for peak load hours may not be able to quickly 'ramp' down and reduce their production and therefore will still be operating during later hours in which the RTMP is below their direct fuel costs. Generators in 'load pocket' areas that are at times isolated from the rest of the system by transmission constraints may also be needed to operate within the constrained pocket even though their offer prices are above the systemwide RTMP. Units called upon in these special situations are individually paid their as-bid offer prices or some other unit-specific price. This can have the effect of lowering the RTMP, and consequently the ECP, since the level of demand served by units paid at the market-clearing RTMP is lower after accounting for the load served by units called out-of-merit.

[4] The two most responsive reserves, Automatic Generation Control (AGC) and Ten Minute Spinning Reserve (TMSR) are explicitly identified as potentially impacting the RTMP. See ISO New England, "Market Rules and Procedures."

An alternative metric with which to compare our counterfactual competitive price is the price at which the supply curve formed by aggregating the energy bids of suppliers intersects with the market quantity. This is analogous to our cost-estimation method, which intersects a marginal cost curve formed from available generation units that is based upon direct fuel, maintenance, and environmental costs. An alternative bid-based price can be calculated by intersecting the bids of the generation units whose costs we explicitly model (see below) with the aggregate supply provided by that same set of generation for that hour. Table 2 compares the(unweighted) average of the ECP with the averages of the prices calculated from the energy bids over the 29 months from May 1999 through September 2001.

Price	Mean ($/MWh)	Std. Dev.
ECP	40.17	92.35
Bid Price at Demand + AGC	38.24	13.04
Bid Price from modeled units	42.90	16.70

Table 2: Average ECP and Energy Offer Prices

There has been considerable discussion about the relative impact on market prices of energy offer prices, unit operating characteristics, market rules, and ISO-NE operational decisions.[5] Overall, the mean price from the intersection of all bids with market demand was about 5% lower than the mean ECP. However, the bid price taken from the intersection of the bids of our modeled thermal units with the actual demand served by those units was nearly 7% higher than the ECP. The difference between the two bid prices is most likely due to either lower than anticipated production from non-modeled units, or out-of-merit selection of modeled (and higher priced) units. The ECP was also more volatile than either of offer prices. We discuss the implications of these differences in more detail in section 4.

Net imports into NEPOOL are not explicitly modeled. Instead, net imports in a given hour are subtracted from the overall market demand in that hour. To the extent that imports are price-responsive, this assumption can lead us to understate the marginal cost of serving NEPOOL load, and therefore overstate the level of market power. This is because a lower competitive price might induce a lower level of imports, thereby leaving more demand to be served by generation within the system than our measure of market demand would produce. We hope to address the shortcomings of this assumption in future revisions.

[5] Most recently the Independent Market Advisor to ISO-NE issued a study examining the impact of these factors on prices during peak demand hours of the summer of 2001 (see Patton, 2001).

Thermal Generation Costs

In general there are two classes of generation units in our study: those for which we are able to explictly model their marginal cost and those for which it is impractical to do so due to either data limitations or the generation technology. The category that is impractical to model includes energy limited units such as conventional and pumped-storage hydro generation, nuclear generation and assorted small conventional thermal, cogeneration, and renewable units.

We explictly model the costs of 111 thermal units within the NEPOOL system. These units comprise sixty percent of the installed summer capacity of the market. Nuclear and hydro generation comprise the bulk of the remaining capacity. The marginal cost of a modeled generation unit is estimated to be the sum of its direct fuel, environmental and variable operation and maintenance (O&M) costs.

Direct fuel costs for these units are estimated by multiplying a unit's average heat rate by the appropriate fuel price. The heat rate for each unit is obtained from one of two sources. The EPA Constant Emissions Monitoring System (CEMS) provides hourly data on the gross generation and emissions of monitored units. When possible, average heat rates are calculated using these data. ISO settlement generation data are used to construct a net to gross conversion factor. Then the CEMS heat input data are used to calculate the average net heat rate. For some assets, the level of aggregation across units that the ISO uses for settlement purposes is not the same as that of the EPA gross generation data. For units with this aggregation problem and for those that the EPA does not monitor, we use the heat rates provided by the ISO. The ISO provided us with data on the variable O&M of thermal units within its control area that was drawn from publicly available sources.

Many units in the NE-ISO control area are subject to environmental regulation that requires them to obtain NOx and SO2 pollution permits. Although firms are endowed with a certain number of permits, the opportunity cost of polluting is the price at which the permit can be sold. Thus, for units that must hold permits, the cost of polluting is estimated to be the emission rate multiplied by the price of permits and the unit's heat rate. For units subject to Phase I of the 1990 Clean Air Act Amendment's Title IV program, SO2 emission rates are calculated from the EPA 2000 compliance reports. Generating units in New Hampshire, Connecticut, Massachusetts and Rhode Island are also subject to regulation by the Ozone Transport Commission. The OTC requires generating units to obtain pollution permits for NOx during summer months. ISO data on NOx emission rates are used for affected units. [6]

The availability of generation units is modeled using a monte-carlo simulation on the probability that a given unit will have a forced outage in a given hour. If the generation units $i = 1, ..., N$ are ordered according to increasing marginal cost, the aggregate marginal cost curve produced by the j_{th} iteration of this simulation, $C_j(q)$, is the marginal cost of the k_{th} cheapest generating unit, where k is determined by

[6] Some fossil-fueled units are also subject to environmental restrictions on the total amount of energy they can produce during a given time-period. We do not consider these restrictions in our estimates.

$$k = \arg\min\{x \mid \sum_{i=1}^{x} I(i) * cap_i \geq q\}. \qquad [1]$$

where $I(i)$ is an indicator variable that takes the value of 1 with probability of $1 - fof_i$, and 0 otherwise, where fof_i is the probability that unit i will experience a forced outage in a given hour. For each hour, the Monte Carlo simulation of each unit's outage probability is repeated 100 times.[7] In other words, for each iteration, the availability of each unit is based upon a random draw that is performed independently for each unit according to that unit's forced outage factor. The marginal cost at a given quantity for that iteration is then the marginal cost of the last available unit necessary to meet that quantity given the unavailability of those units that have randomly suffered forced outages in that iteration of the simulation.

We do not explictly represent scheduled maintenance activities. This is in part due to the fact that maintenance scheduling can be a manifestation of the exercise of market power. The omission of maintenance schedules is unlikely to significantly impact our results for high demand periods, when few units traditionally perform scheduled maintenance, but may have some impact on results during lower demand periods. It is worth noting that the overall level of scheduled outages has increased since the opening of the ISO's markets in May 1999.

Nuclear, Cogeneration, and Small Thermal Resources

As described above, there are several categories of generation for which it is impractical to explicitly model marginal production costs. For units in this class that were not energy limited, we use the bid price and availability of the unit as a proxy for that unit's true marginal cost and availability. To the extent that these units are owned by firms attempting to exercise market power, this assumption will overestimate the competitive price and therefore understate the level of market power. Most of the generation that falls into this category, however, is either nuclear, renewable, or cogeneration. These units are not likely to be the marginal units setting the market price, so that the impact of this assumption is most likely not significant. We do not simulate the forced outages of units in this category, and instead use the declared availability of that unit for each respective hour. The scheduled maintenance of units in this category is also accounted for in this manner.

We use energy bids as proxies for the marginal cost of the conventional generation sources that we do not explictly model to capture the supply elasticity from these units. If the actual price is above our estimated price, then we might expect some of these units to produce less at the competitive price, thereby increasing the demand to be served by the modeled units and the marginal cost of doing so.

Energy Limited Resources

Energy-limited units (*i.e.,* hydro units) present a different challenge than other units in the non-modeled category since the concern is not over a *reduction* in output relative

[7] The capacity used in equation [1] is either the summer or winter capacity (according to the date simulated) provided by the ISO.

to observed levels but rather a *reallocation* over time of the limited energy that is available. The bids of hydro units provide less information about their usage in a perfectly competitive market than might at first glance be expected. The bids of hydro units do not reflect a production cost but rather a cost associated with the lost opportunity of using the hydro energy at some later time. In the case of a hydro firm that is exercising market power, this opportunity cost would also include a component reflecting that firm's ability to impact prices in different hours.[8] It is important to note even the observed bid prices of price-taking hydro units provide little information about the opportunity cost of their water in a competitive market. This is because the actual opportunity cost of water for these units will be influenced by the expectation of future prices, which is in turn impacted by the ability of other firms to raise those prices.

For these reasons, we make the assumption that the actual, observed output of these resources is the output that would be produced by a price-taking firm acting in a perfectly competitive market. In other words we take the observed releases of reservoir energy as the optimal schedule that would result in least-cost production in a competitive market.

In practice, this assumption means that, in constructing our estimate of the marginal cost of meeting load in any given hour, we apply the observed production of hydro and geothermal resources for each hour and then calculate the marginal cost of satisfying the remaining demand with the state's thermal resources.

The optimal hydro schedule will, by definition, lead to weakly lower production cost than any other hydro schedule. To the extent that actual production differed from the optimal schedule, any distortion created by our assumption could only bias upward our estimate of perfectly competitive total production cost. For the purpose of measuring market power, however, we also need to consider the impact of our assumption on our estimates of marginal, as well as total, production cost. Of concern is the possibility that the observed hydro schedule, which may include a response by hydro firms to the exercise of market power by others, could somehow produce a *lower average marginal cost* than the optimal hydro schedule when combined with a counterfactual perfectly competitive production of thermal resources. However, it can be shown that when marginal production costs are convex, any reallocation of hydro energy from the least-cost allocation will raise marginal costs more in the hours from which energy is removed than it will reduce marginal cost in the hours to which energy is added.[9] Thus our assumption of optimal hydro production can only bias our time-weighted estimates of marginal cost upwards, and therefore our estimates of price-cost margins downward.

We also present results in which price-cost margins are weighted by the market volumes in each hour. To consider the effect of our hydro assumptions on these results, we need to address the possibility of a reallocation of hydro energy from off-peak to peak hours relative to the optimal schedule. Such a production schedule, with too much energy produced during peak hours, could result from competitive hydro firms responding to the exercise of market power by other firms. As argued above, this reallocation (if allowed by the flow

[8]See Bushnell, 1998.

[9]This is because at the least-cost allocation of hydro energy, marginal thermal costs will be equalized over all hours for which hydro flow constraints allow a discretionary use of hydro energy.

constraints) would raise off-peak marginal costs more than it would lower on-peak marginal costs. However, since (uncontracted) market volumes are likely to be higher on-peak, the impact on the quantity-weighted average of marginal cost is uncertain.

By contrast, a hydro firm that is attempting to exercise market power would likely allocate less hydro energy during peak hours than would be the case for a price-taking firm (see Bushnell, 1998). This latter, strategic, hydro allocation when combined with competitive thermal production would produce a higher weighted average of marginal cost than would the optimal schedule. To the extent the firms controlling hydro resources attempted to exercise market power with those resources, our results will therefore understate the overall level of market power. It should be noted from table 1 that the bulk of the hydro resources in the system are controlled by NUGs, although the incentives of NEG will be impacted by its contractual arrangements with NEES.

4 Results

The ISO has provided us with hourly bid and dispatch information for generation units within the NEPOOL system. These data cover a two-year period from the market's opening in May 1999 through September of 2001. During this period, petroleum-based fuel prices rose steadily while natural gas prices sharply increased over the winter of 2000-2001 and then declined. Figure 1 shows the trajectory of natural gas and no. 6 fuel oil, the two most frequent marginal fuels, along with electricity prices over our sample period.

We calculate price-cost margins for the three different measures of prices that were discussed above. A common measure of the severity of market power is the Lerner Index,[10] which reports the magnitude of the price-cost margin relative to price, $(p - MC)/p$. Because our estimates produce negative as well as positive margins and the Lerner Index is not symmetric around zero, we adopt a quantity-weighted version of the index in the tables below. Our index weights the relative price-cost margins over T time periods according to the market demand.

$$QLI(T) = \frac{\sum_{t=1}^{T}(p_t - MC_t) * q_t}{\sum_{t=1}^{T} p_t * q_t} \qquad [2]$$

Table 3 lists by month the average demand, the average ECP, the average of our counterfactual estimate of a perfectly competitive price, and our weighted average Lerner Index for that month. Table 4 lists the same information using the price calculated from intersection of all energy bids with the market quantity. Using the ECP, the quantity-weighted purchase cost of power was 12% higher than our estimates of the perfectly competitive cost over the 29 months that we modeled. Using the bid price, the margin between purchased and competitive cost is only 4% over the same time period. Table 5 lists the results using the offer prices only of modeled units as the price measure. The margin over the 29 month sample period for this measure was 11%.

[10] See Viscusi, Vernon, & Harrington, 1992

The results for May 2000 in Table 3 are dominated by the events of May 8th, when the ECP reached \$6000/MWh for 4 hours. These prices were set by import bids and not units within NEPOOL.[11] This is why the margins in Tables 4 and 5, which are based upon the bid prices of units within the ISO are much lower than the margin based upon the ECP for this month. If the 4 hours in which the ECP reached \$6000/MWh are excluded, the average ECP in May 2000 drops from \$73/MWh to \$41/MWh and the quantity-weighted Lerner drops from 61% to 22.5%. The quantity-weighted Lerner over the entire 29 month sample drops from 12% to 9% when we exclude these hours.

The months of December 2000 and January 2001 are also notable as the ISO was transitioning to a set of new operational protocols known as 'electronic dispatch' during this period. This transition also appears to coincide with an increase in market power by all three measures of our Lerner indices. The residual demand to be met by fossil units within the ISO system was also high during these months, however (see Table 5), particularly in December 2000.

As seen from Table 2, the market price is significantly higher if we restrict the analysis solely to the pricing behavior of the modeled thermal units. This is likely due to the out-of-merit dispatch of some of these units. If these units were being selected over others with lower offer prices due to transmission or other operating constraints, it is reasonable to expect that the marginal cost of producing power is also higher from these units. Therefore, in addition to calculating the overall marginal cost of meeting total system demand (as shown in tables 3 & 4), we also calculate the marginal cost of serving the demand actually supplied by modeled units from that set of modeled units. Table 5 compares the marginal offer price from this set of units with the marginal cost of serving that quantity from that same set of units. The demand shown in the 2nd column of Table 5 is the mean demand served by modeled generation.

The difference between the results in Table 5 and those in Table 4 is at times quite striking. The weighted average price-cost margin for just the modeled units was 11% over the full sample, and 16% from January through December of 2000.[12] These margins are not the efficiency rents enjoyed by low-cost firms when higher cost firms set the market price. In fact, just the opposite is true since the bids of other units are lowering the overall market price. This index is directly measuring the margin present in the bids of modeled units. These margins are comparable to the margins calculated using the ECP. However, as described below, the margins in Table 5 do not reflect the ISO's ex-post reduction of offer prices from certain transmission-constrained units.

[11] See ISO-NE, "Special Report on the Events of May 8th & 9th."

[12] To be consistent with the results reported in Tables 3 and 4, the weighted Lerner Indices in Table 5 are weighted according to total market demand. When the index is weighted according to the demand served only by modeled units, the margin over the sample period is also 11%.

Month	Mean Demand	Mean ECP	Mean MC	Quantity weighted Lerner
May-99	12350	28.20	29.49	-3%
Jun-99	14755	49.18	30.08	47%
Jul-99	16166	41.14	31.11	31%
Aug-99	15124	29.25	33.14	-11%
Sep-99	14246	28.37	30.54	-5%
Oct-99	13120	24.79	27.76	-10%
Nov-99	13514	24.90	27.36	-7%
Dec-99	14656	24.33	30.06	-22%
Jan-00	15681	37.15	36.94	3%
Feb-00	15004	34.17	34.96	-1%
Mar-00	13757	23.90	27.87	-14%
Apr-00	13177	26.16	28.04	-5%
May-00	13218	72.78	34.12	61%
Jun-00	14734	38.80	41.99	-4%
Jul-00	14715	37.14	39.20	-2%
Aug-00	15407	42.23	41.49	5%
Sep-00	14333	43.15	46.97	-6%
Oct-00	13674	50.33	49.04	4%
Nov-00	14201	49.30	49.68	1%
Dec-00	15779	62.55	55.20	12%
Jan-01	15616	62.57	52.54	18%
Feb-01	15143	43.01	45.78	-4%
Mar-01	14578	50.19	46.28	9%
Apr-01	13312	36.27	39.74	-7%
May-01	13488	41.01	39.89	7%
Jun-01	15409	35.41	36.35	1%
Jul-01	15040	52.24	32.13	48%
Aug-01	16839	43.34	36.56	21%
Sep-01	14276	31.74	27.97	14%
Overall	14528	40.17	37.29	12%

Table 3: Results using ECP as Price

Month	Mean Demand	Mean Bid Price	Mean MC	Quantity weighted Lerner
May-99	12350	27.69	29.49	-6%
Jun-99	14755	29.12	30.08	0%
Jul-99	16166	29.32	31.11	-4%
Aug-99	15124	28.04	33.14	-17%
Sep-99	14246	27.14	30.54	-11%
Oct-99	13120	25.61	27.76	-7%
Nov-99	13514	27.49	27.36	2%
Dec-99	14656	27.52	30.06	-8%
Jan-00	15681	36.60	36.94	1%
Feb-00	15004	36.43	34.96	5%
Mar-00	13757	31.12	27.87	12%
Apr-00	13177	33.56	28.04	18%
May-00	13218	42.61	34.12	22%
Jun-00	14734	42.69	41.99	4%
Jul-00	14715	40.31	39.20	4%
Aug-00	15407	48.77	41.49	18%
Sep-00	14333	44.68	46.97	-4%
Oct-00	13674	50.25	49.04	4%
Nov-00	14201	51.15	49.68	4%
Dec-00	15779	65.14	55.20	15%
Jan-01	15616	61.16	52.54	14%
Feb-01	15143	42.53	45.78	-7%
Mar-01	14578	47.40	46.28	3%
Apr-01	13312	37.46	39.74	-6%
May-01	13488	39.02	39.89	-1%
Jun-01	15409	36.30	36.35	3%
Jul-01	15040	31.38	32.13	0%
Aug-01	16839	38.37	36.56	8%
Sep-01	14276	29.51	27.97	6%
Overall	14528	37.82	37.29	4%

Table 4: Results Using Aggregate Bids to Estimate Price

Month	Mean Demand	Mean Bid Price	Mean MC	Quantity weighted Lerner
May-99	7011	29.68	30.40	-1%
Jun-99	7724	35.36	30.73	19%
Jul-99	7932	34.67	31.83	13%
Aug-99	7042	29.82	34.27	-12%
Sep-99	5694	29.41	32.41	-8%
Oct-99	4559	29.43	30.26	-1%
Nov-99	4986	31.43	29.21	9%
Dec-99	5657	31.65	31.50	2%
Jan-00	7028	41.48	39.06	8%
Feb-00	6432	40.56	36.07	12%
Mar-00	5037	39.85	30.20	26%
Apr-00	4505	44.18	30.45	33%
May-00	5104	51.76	36.41	32%
Jun-00	6333	47.30	43.68	10%
Jul-00	6446	45.42	40.36	13%
Aug-00	7220	55.49	42.33	27%
Sep-00	6598	48.42	48.69	1%
Oct-00	7524	55.20	50.12	11%
Nov-00	7572	54.32	50.70	8%
Dec-00	8538	70.56	58.71	16%
Jan-01	7733	65.78	54.85	17%
Feb-01	7012	44.97	46.99	-4%
Mar-01	7842	53.56	47.18	13%
Apr-01	5001	40.57	42.13	-3%
May-01	5657	43.07	41.87	5%
Jun-01	6911	40.12	37.32	11%
Jul-01	7112	34.65	33.30	9%
Aug-01	9059	42.13	37.44	16%
Sep-01	7077	32.40	29.55	10%
Overall	6636	42.27	38.89	11%

Table 5: Results using Bid Price and Quantity from Modeled Units

Why do modeled units as a class systematically receive a larger share of the market than would be produced from a simple aggregation of all energy bids? The answer is most likely that units in the modeled category are disproportionately selected 'out-of-merit' because of transmission or other operating constraints. These units may have higher operating costs. They are also bidding higher margins above those operating costs than are non-modeled units. Figure 2 depicts the difference between the margin calculated from the bids and costs of modeled units alone and the margin calculated from aggregating all bids. The spread between the two margins peaks in the period around April 2000, and averages above 5$/month in June 1999 and March 2001 as well as August 2000.

The ISO-NE reports that both energy uplift payments and transmission congestion uplift payments are well above average in the months around April of 2000.[13] Energy uplift payments also spike in August 2000 and are above average in March 2001. Monthly energy uplift payments are also shown in figure 2. Over 3 or 4 month spans there appears to be a strong relationship between energy uplift payments and the difference in margins, although there are months with high uplift payments and relatively small differences. We also examined the relationship between monthly average transmission uplift payments and the differences in margins, which appears to be much weaker. We do not have the detailed time series of uplift payments so that we cannot explore the linkage in much more detail at this time.

It is important to note that these margins may not reflect the actual revenues received by these units as many of them were subject to significant ex-post reductions in their payments through ISO-NE's market power mitigation rules. The ISO reports that the congestion-uplift payments were subsequently reduced by as much as 50% in some months through market power mitigation measures. To the extent that the differences between Tables 4 & 5 are explained by the bids of units in transmission-constrained regions, the margins in Table 5 will overstate the actual revenues earned by producers, since at least some of these bids were subsequently lowered by the market power mitigation process.

4.1 Market Performance as a Function of Load

In their study of the California market, Borenstein, et al. examine the Lerner Index (*i.e.,* the market price relative to the competitive benchmark price) in the context of capacity margins. The general finding, consistent with economic intuition, is that the severity of market power increases as the amount of excess capacity decreases. As demand rises, more firms reach their capacity limits, and the remaining firms with unused capacity face less competition to serve any additional demand. Usually available capacity is directly inversely related to system demand: higher demand means less unused capacity. Other factors such as hydro conditions, nuclear outages, and the availability of imports can also have an impact on the extent to which local thermal resources are relied upon to meet local demand.

[13] See "May 2000 - April 2001 Annual Market Report," ISO-NE.

One way to examine the relationship between market power and available unused capacity is to plot the Lerner Index against the residual market demand that remains after accounting for imports, nuclear and hydro supply. For comparisons across markets, we can normalize this demand level according to the installed capacity of conventional thermal generation in each region. The result is a *capacity ratio*, which divides residual demand by installed capacity and ranges from 0 to 1.[14] A ratio close to 1 indicates a very 'tight' capacity condition in that hour. This measure of residual capacity is not ideal. Imports and to some extent hydro supply are not independent of the market price and are therefore endogenous to the Lerner Index. More sophisticated analysis can account for these problems, but for now we leave this to future work.

In the context of the New England market, we use the quantity supplied by modeled units as our measure of residual demand. This is analogous to the instate fossil load used by Borenstein, et al. for a measure of residual demand in California. Figure 3 plots the Lerner Indices calculated from using the ECP and the Bid Prices of all units, respectively, for the period of June - Sept. 1999. As with the previous results, the margins are significantly lower when measured using the bid price rather than the ECP. This is more apparent in Figure 4, which shows a kernel density regression of the Lerner indices for the entire sample period calculated using each of the 3 methods described above. The horizontal axis of Figure 4 is the capacity ratio, which reflects the new capacity added since 1999. For each of the three measures of market power, there is clearly an increasing relationship between mark-ups and the level of residual demand. This relationship is very similar for the indices based upon the ECP and those based upon the offer prices of modeled units. The Lerner index based upon the offer prices of all units rises more slowly with demand than do the indices based upon the other two measures.

We can also examine the performance of the market over time. Figure 5a illustrates a kernel density regression of the relationship between the ECP-based Lerner index and residual demand for the May - Sept. period in each of the three years of our sample. In each successive year, margins are lower at higher levels of residual demand, although they are slightly higher at lower levels of demand in the later years than in 1999. As can be seen from figure 5b, which shows the distribution of residual demand for each of these summer periods, the market experienced the highest levels of residual demand in 2001. The new capacity added to the system between 1999 and 2001 appears to have allowed the market to maintain lower mark-ups at higher residual demand levels.

4.2 Comparisons with other Electricity Markets

Several studies comparable to this one have examined market performance in other electricity markets. In this section we compare the results for the ISO-NE markets with those from the PJM market and from California. Borenstein, et al. estimate a competitive benchmark price for California from that market's opening in 1998 through October 2000. Mansur (2001) examines the performance of the PJM market during 1998 and 1999. During 1998 firms in the PJM market had not yet been granted permission from FERC to

[14]We do not make adjustment for forced of planned outages in computing this ratio.

charge market-based prices, and this affords Mansur the opportunity to compare benchmarks across two regulatory phases of that market. There are some differences in the methodologies of the studies that make direct comparisons somewhat difficult, and we hope to address these differences in future work.[15]

The only time period in which all three studies currently overlap is May through December, 1999. Table 6 summarizes the average market price, competitive benchmark price, and quantity-weighted Lerner Index for the three markets during this time frame. During 1999, the PJM market produced the largest margins of the three markets, both weighted and unweighted. It should be remembered that this was a particularly difficult summer in the eastern U.S. and a relatively mild one in California. Nonetheless we can make some adjustments to crudely control for demand levels across these markets.

Market	Market Price (\$/MWh)	Comp. Benchmark Price (\$/MWh)	quantity-weighted Lerner Index
PJM	32.66	28.54	25%
California	32.07	28.06	17%
New England	31.23	29.95	10%

Table 6: Market Comparison for May - December 1999

For each of the three markets, we have a measure of residual 'local' demand, demand that remains after accounting for imports, nuclear, hydro, and other small generation sources. We again normalize this measure of demand by dividing by installed capacity.[16] Figure 6 shows the frequency with which demand fell into various ranges of the capacity ratio for the three markets. The distribution of residual demand had the highest tail for the PJM market, with 55 hours at 80% or higher. The New England market had the highest mean ratio, at 43% compared to 40% for PJM and only 26% for California.

So, although the PJM market had the highest average margins of the three markets, it also experienced some of the tightest capacity conditions of the three over the summer of 1999. We can compare the overall market performance, relative to residual demand by again plotting the Lerner Index against the capacity ratio for each hour. Figure 7 shows a kernel regression of this relationship for each of the three markets. Both PJM and New England exhibit very low margins over a broad range of capacity ratios, and then a sharp increase in margins when this ratio reaches around 75%. By contrast, the California market exhibited lower margins on the high end of capacity ratios, but significantly greater margins at lower levels of demand.[17]

[15] In particular, the lack of import elasticities in the current results for New England may make the ISO-NE markets look less competitive relative to California and PJM. Mansur also treats reserves differently in his study of PJM, and has to adjust his market price index to account for that market's nodal transmission pricing methods. These differences would tend to bias downward the extent of market power in PJM.

[16] The New England market has added more that 2,000 MW of capacity since late 1999. These differences were accounted for in the capacity ratio.

[17] The reader may note that these kernel density functions are not always monotonic in residual demand. This is not surprising in markets with price caps as the probability of a capacity shortage can dramati-

Although results for the PJM market are not available for 2000, we can make a similar comparison between California and New England for the period of May - October, 2000. Figure 8 illustrates how, in contrast to 1999, the capacity ratio was the highest in California during 2000. As can be seen from figure 9, the relative competitive performance of New England and California is similar to that experienced in 1999.

Again, since some important differences underlay the methods in calculating these results, so this is meant as an initial, qualitative, comparison. As such, it indicates that the performance of the two eastern markets was comparable, and that both were more competitive than California at all but the highest capacity ratios. We account for market demand relative to capacity. There are other important differences in market structure, design and regulation across these markets. In particular, California had a firm price cap set at a relatively low level compared to the eastern markets during this time. The eastern markets took a much more active role in regulating market power on a daily basis, but also experienced some market prices well above those seen in California during 1999. The level of contracting and vertical integration is also much greater in the eastern markets. Both regulatory and structural differences could explain some of the differences between these markets. All of these elements should be examined in more detail to determine which factors are most important in driving market performance.

5 Conclusions

One fundamental measure of a market's performance is the difference between observed market prices and a competitive benchmark price that would result if no firm attempted to exercise market power. In most industries, such direct comparisons are extremely difficult due to the lack of available data on production quantities and costs and the nature of the production process. In the electricity industry, however, the data provided by economic and environmental regulatory activities make such estimates possible.

We have estimated a competitive benchmark price for the New England market and compared it to three measures of market prices in New England for the two years between May 1999 and September 2001. One price measure uses the ISO-NE Energy Clearing Price (ECP), and the other two price measures intersect the aggregate energy bids of generation units with a level of market demand. Using the ECP as the market price, we find that quantity-weighted market prices were about 12% higher than the competitive benchmark. Using the aggregate energy bids of all generation units as a proxy for market price, this margin was 4% over the sample period. When we focus on the energy bids and quantities supplied from major fossil generation units, we find an 11% quantity-weighted margin between offer prices and the competitive benchmark.

The differences among the three measures are most likely a combination of four factors. The first is the extent to which there are differences between day-ahead bid commitments

cally increase the estimates of marginal cost at high levels of demand, while prices remain capped. The adjustment for imports in the calculation of residual demand can also contribute to non-monotonicities in these figures.

and real-time operations. The second is the ISO-NE's management of transmission congestion, in which units with more expensive offer prices displace those with lower offer prices because the more expensive units are advantageously located within the network. The third factor is the extent to which unit operating constraints such as ramping times and minimum operating levels force the ISO's dispatch to diverge from the merit order produced by aggregating energy bids. A fourth factor is the ability of firms to self-schedule the production of generation units, which could also cause a divergence between actual production and the merit order. It is important to note that, while these differences are to some extent produced by cost-based constraints many of those constraints are in turn subject to the exercise of market power through other means. The scheduling of generation, the bidding of ramping and minimum operating levels, and even energy bids, could take advantage of the system's procedures for dealing with these constraints. We are not able to distinguish the relative impact of these causes, or the extent to which they reflect competitive or strategic behavior on the part of firms. The full consequences of such activities would not necessarily be reflected in our indices, since we do not examine the side-payments made to deal with transmission and other constraints.

The competitive performance of the New England market compares favorably to that of other electricity markets in the U.S. Using data from comparable studies of the PJM and California electricity markets, the quantity-weighted margins in PJM and California were roughly double that in New England over the last eight months of 1999. The market conditions that produced those margins differed widely, however, as the eastern U.S. experienced a severe heat wave while the western U.S. enjoyed a relatively mild summer. After adjusting for the level of demand relative to the installed capacity in each market, the performance of PJM and New England were roughly equivalent. Both PJM and New England were more competitive than California at all but the highest demand levels. There are important differences in the structure, regulation, and design of these 3 markets, and further research is necessary to determine the contribution of each of these differences to the relative performance of these markets. This cross-market comparison uses only one of many possible metrics with which one could measure market performance. It is not intended to address issues such as the efficiency of dispatch operations, transmission congestion management, demand-side participation, or investment. Measures of performance along these and other dimensions should be developed in order to facilitate market comparisons and gain from the disparate experiences of the various markets.

The results to date are encouraging, particularly when compared to California, but need to be considered in context. The results described above occur in a market with many layers of continued regulation. The vertical integration of some suppliers and the transition contracts imposed on others provide a powerful mitigating influence on the incentives of these firms to exercise market power. Any new contracts that replace those imposed during the transition will be set at terms determined by market conditions, rather than regulatory proceedings. The pending expiration of transition periods and potential consolidation of supply portfolios will reverse this effect. It is difficult to predict the extent to which new entry will offset these trends. The market power created by transmission congestion and other unit operating constraints presents an ongoing challenge to the efficient operation of electricity markets. Lastly, the operations, monitoring, and market power mitigation functions of the ISO no doubt has contributed to the outcomes detailed in this report. It is important that we continue to examine both the short and long term impacts of these activities, particularly as widespread changes to the ISO-NE's operations and pricing protocols are adopted.

Our market analysis and others like it provide useful assessments of the performance of markets. Standing alone, however, they cannot produce a generic standard upon which to base a determination of whether a market is sufficiently competitive or in need of remedial measures. The analyses require assumptions that introduce potential biases, sometimes of offsetting direction, in the measures of market power. Any use of the measures must take account of the range of values they actually represent. Last, a percent mark-up is only one of several factors that policy-makers must consider when determining the appropriate level of regulatory intervention in a market. The central question is whether the benefits of intervention outweigh their costs.

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[10] ISO New England (2001). "May 2000 - April 2001 Annual Market Report." Holyoke, MA.

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Appendix: Data Sources

Thermal Generation Data

As noted in the text, average heat rates are either calculated using data from the EPA's Continuous Emissions Monitoring System (CEMS) or provided by the ISO. The variable O&M costs used were also provided by the ISO.

The natural gas spot prices we use are those reported by Natural Gas Intelligence (NGI). For the first four months of the market, we use the spot price at New York Transco 6 and for the rest of the study we use the Tennessee Zone 6 spot price. We use the New York Transco 6 price for the first four months because NGI does not report a spot price at Tennessee Zone 6 for this period. We assume the average marginal distribution price of natural gas is $0.20.

We use Energy Information Administration (EIA) reported data of the New York Harbor spot prices of heating oils 2 and 6 and jet fuel. Coal prices are obtained from FERC form 423. For low sulfur coal, the average monthly reported spot price by state is used. For the majority of the study period spot prices for high sulfur coal are not available. Thus, we are use the state average reported contract price of high sulfur coal. Coal is only marginal 2% of the time. Therefore, any possible bias from using the contract price instead of the spot price (which is the opportunity cost of coal) are minimal.

The EPA reports the average price of SO2 permits traded at two brokerage firms (Cantor Fitzgerald and Fieldston). The average of these two prices is used in the calculation of environmental costs. NOX permit prices are from Cantor Fitzgerald. Because of a lag in EPA reporting time, the most recent available SO2 price is from December 2000. We use this price for all months in 2001. The most recent NOX price available to us, $0.83/pound, is from May 2001. We use this price for all subsequent summer months of 2001. The unit forced outage factors used in the Monte Carlo simulations are taken from National Electricity Reliability Council's (NERC) 1995-1999 Generating Unit Statistical Brochure.

Demand and Generation Output Data

NEPOOL system generation for each hour is the sum of metered generation reported by the ISO. These data include hourly generation of every unit in the ISO control area. Thus, we can separate the total in-system generation into that which is provided by the 111 modeled units and that of other units. The ISO has also provided the bid curves that are submitted day ahead for each generation unit. When calculating prices based upon day ahead bids, we adjust the bid curves to account for re-declared high operating limits (HOL) by truncating the bid curve at the new HOL.

Average Fuel Prices & ECP

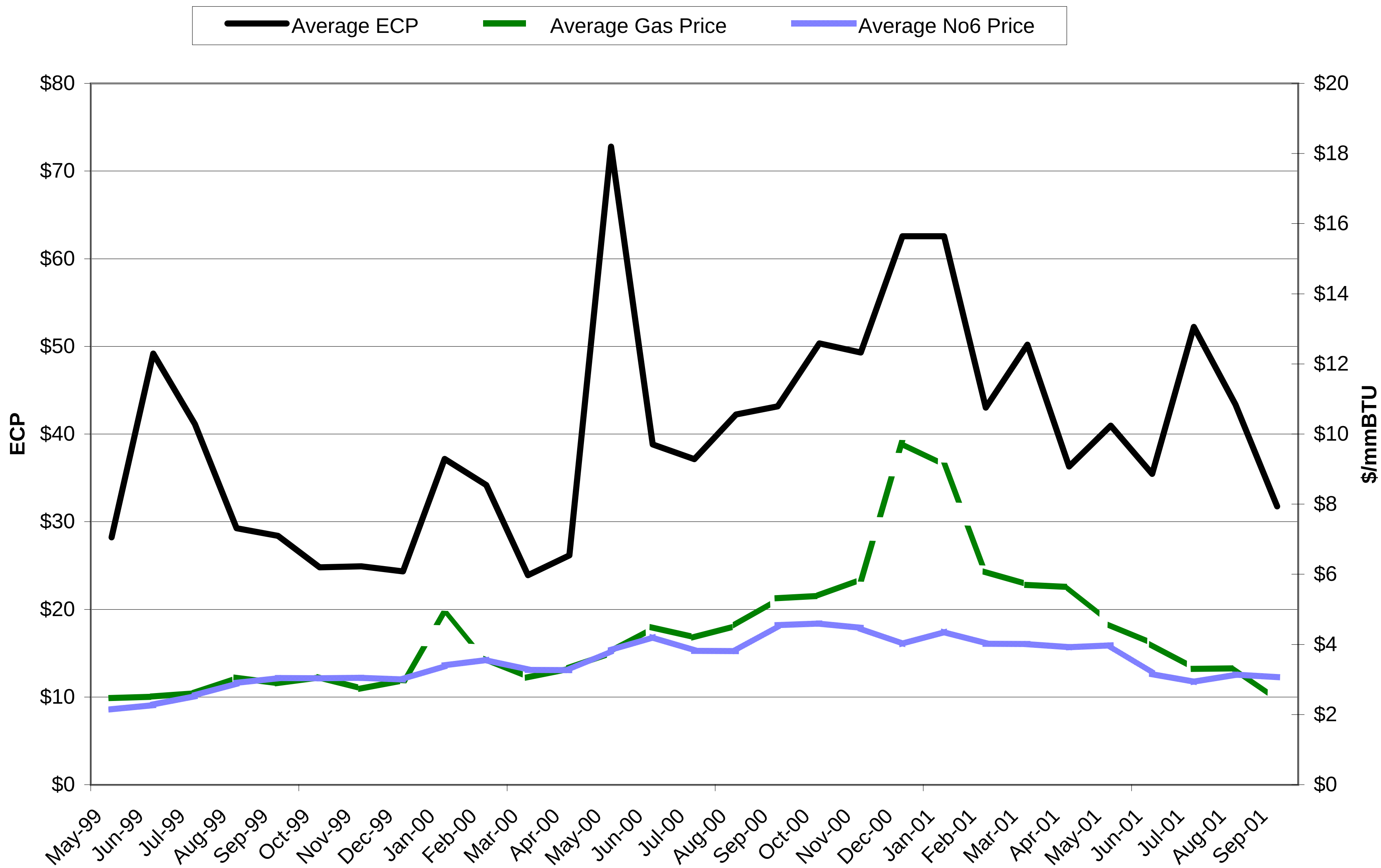


Figure 2

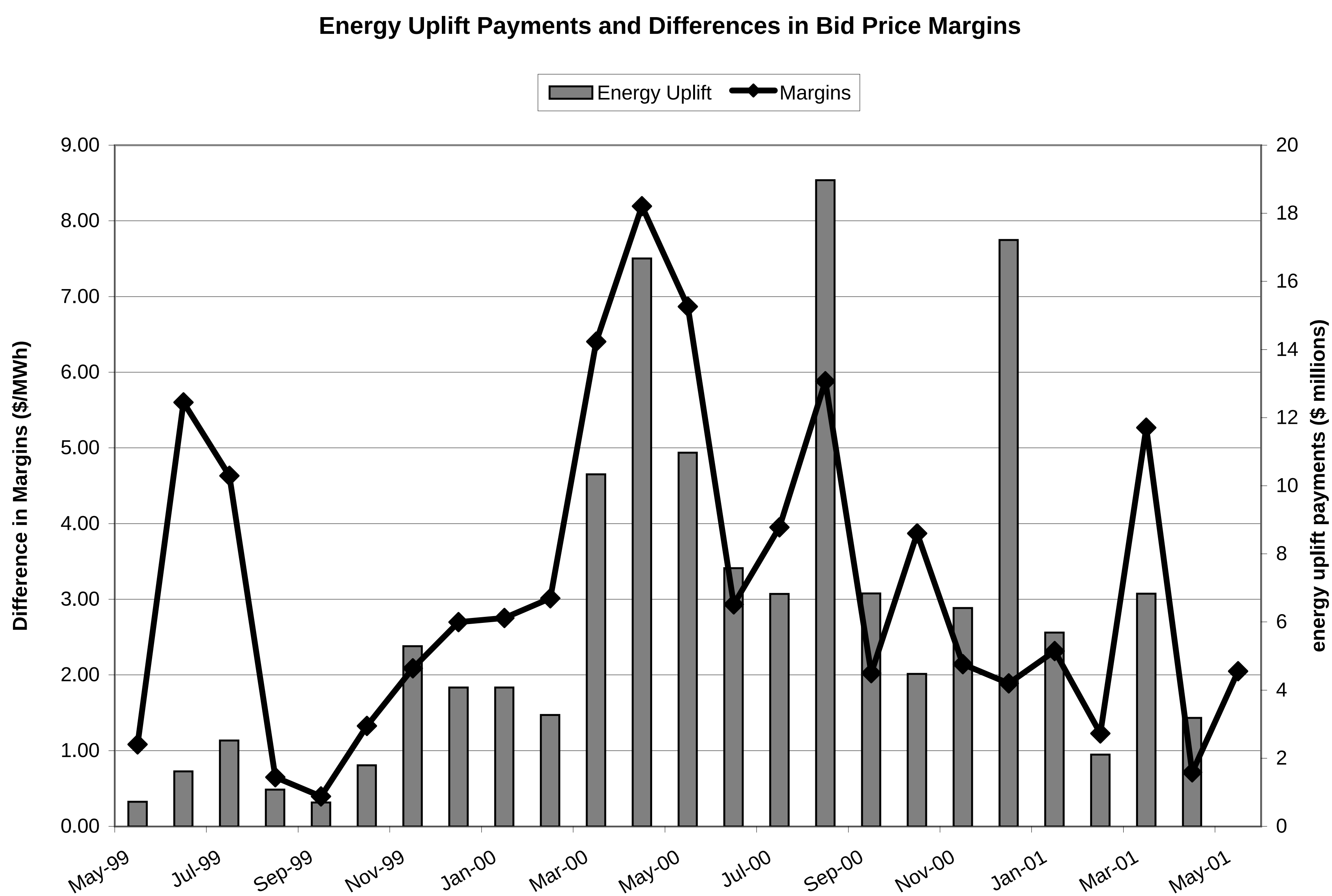
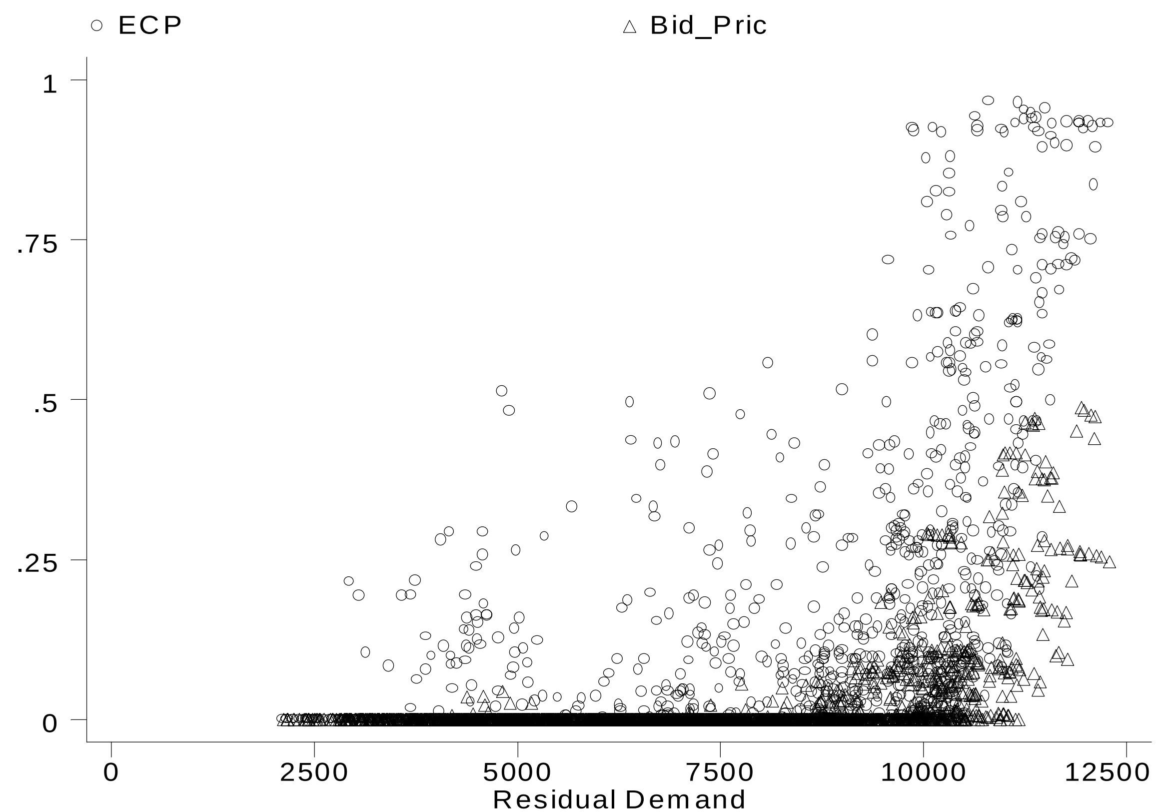
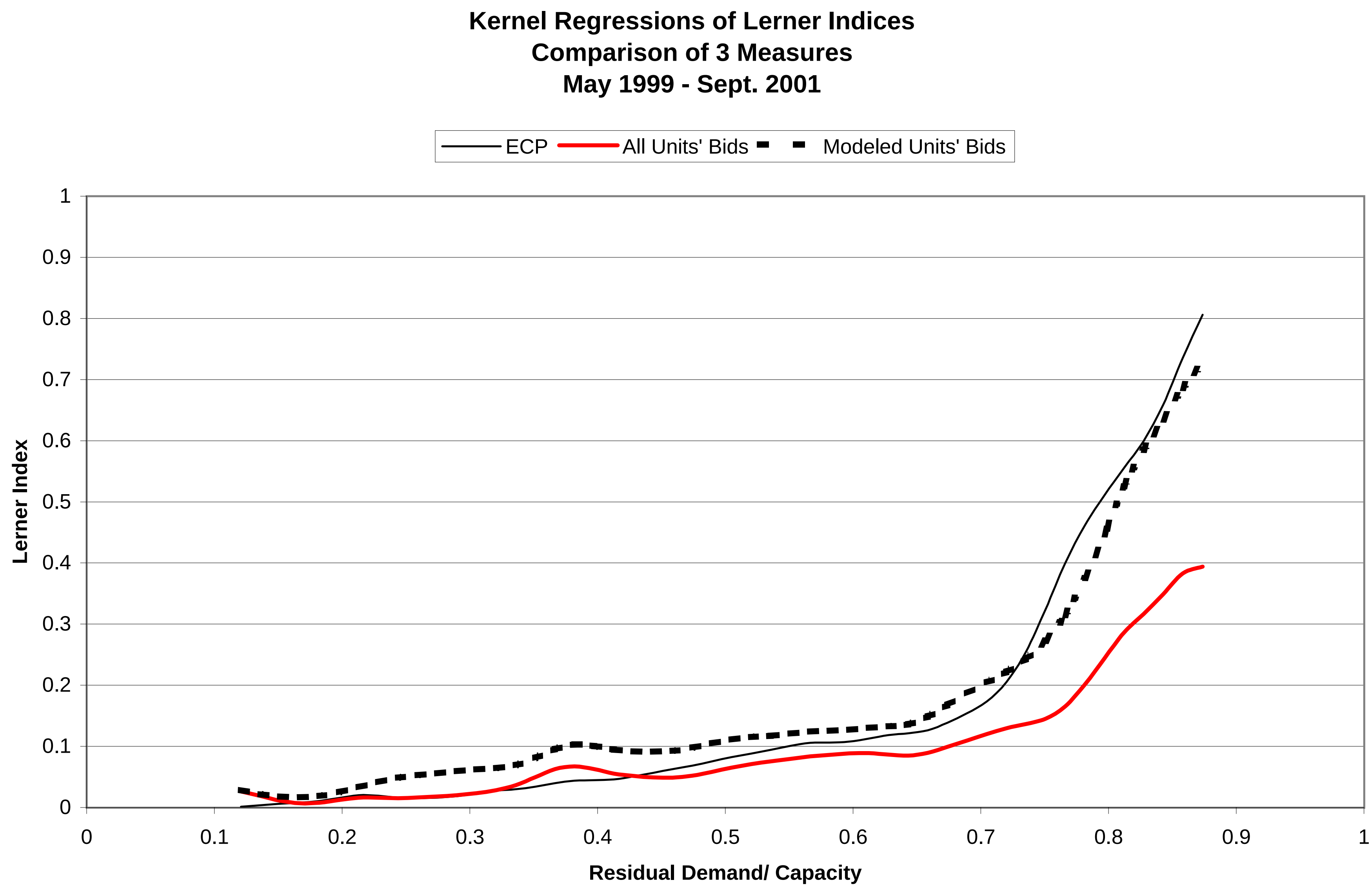

Energy Uplift Payments and Differences in Bid Price Margins
Energy Uplift
Margins
Difference in Margins ($/MWh)
energy uplift payments ($ millions)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
20
18
16
14
12
10
8
6
4
2
0
May-99
Jul-99
Sep-99
Nov-99
Jan-00
Mar-00
May-00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01

Figure 3



ECP
Bid_Pric
1
.75
.5
.25
0
0
2500
5000
7500
10000
12500
Residual Demand

Figure 4



Kernel Regressions of Lerner Indices
Comparison of 3 Measures
May 1999 - Sept. 2001
ECP
All Units' Bids
Modeled Units' Bids
Lerner Index
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Residual Demand/ Capacity

Figure 5a

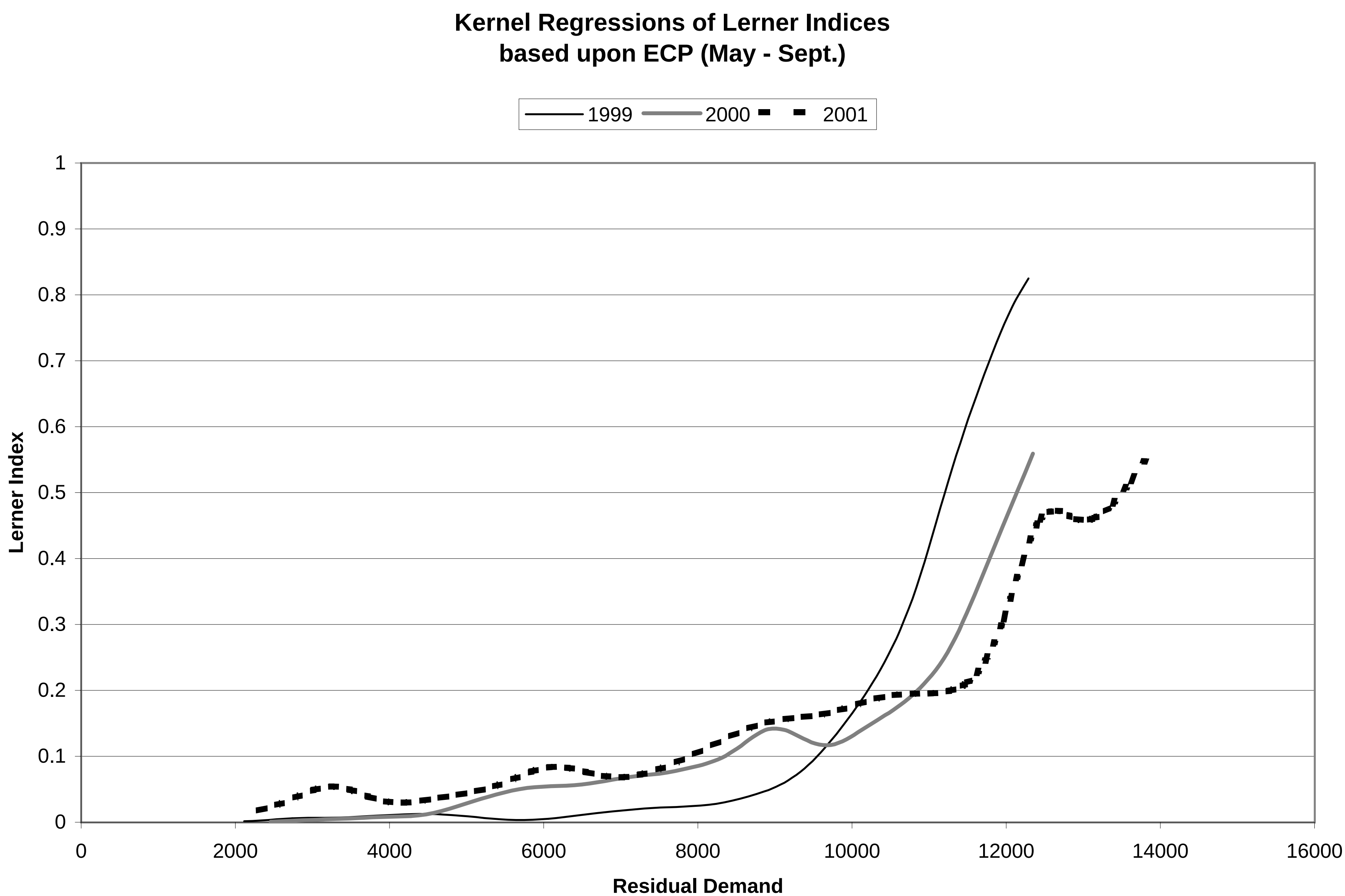

Kernel Regressions of Lerner Indices
based upon ECP (May - Sept.)
1999
2000
2001
Lerner Index
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
2000
4000
6000
8000
10000
12000
14000
16000
Residual Demand

Figure 5b

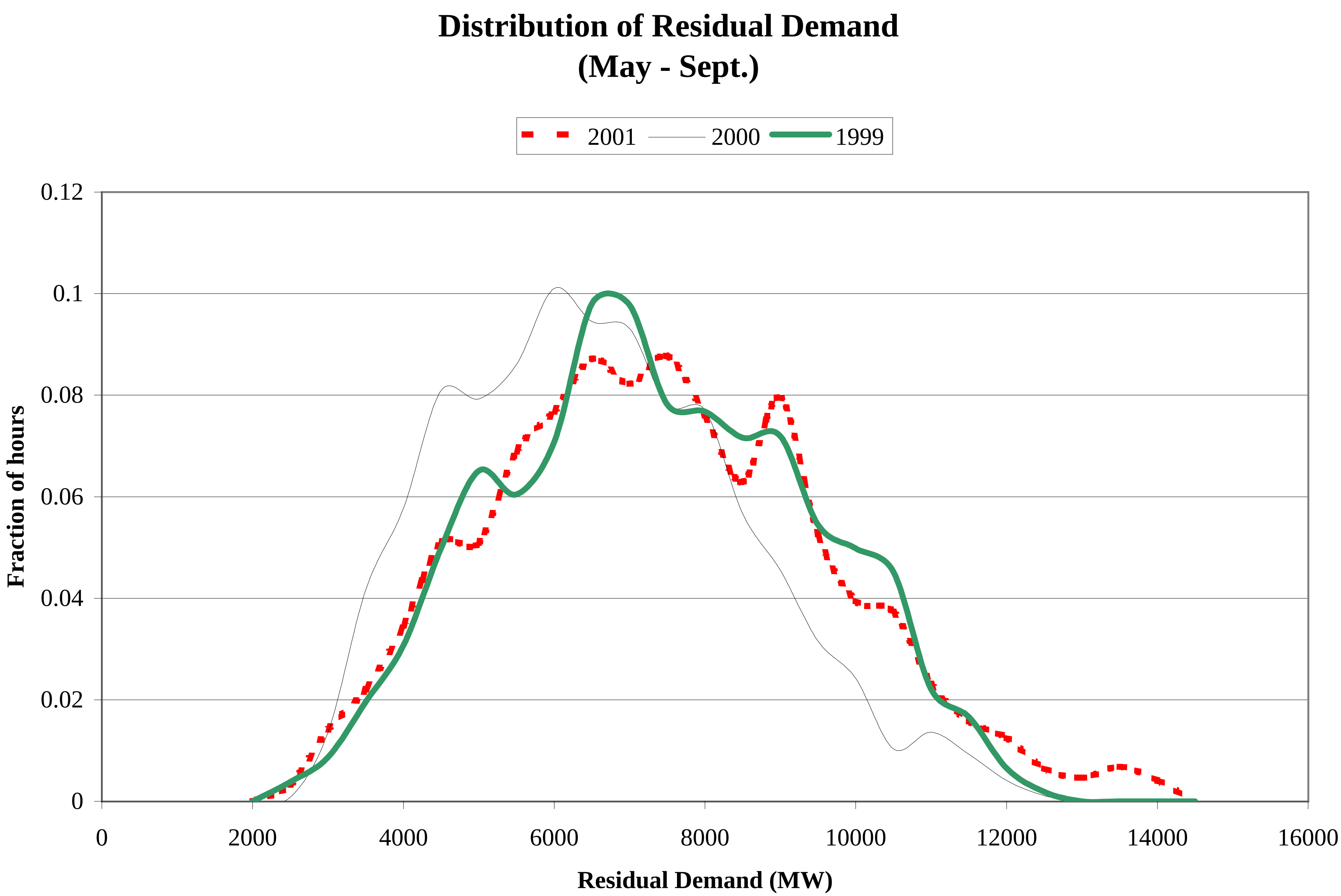

Distribution of Residual Demand
(May - Sept.)
2001
2000
1999
Fraction of hours
0.12
0.1
0.08
0.06
0.04
0.02
0
0
2000
4000
6000
8000
10000
12000
14000
16000
Residual Demand (MW)

Figure 6

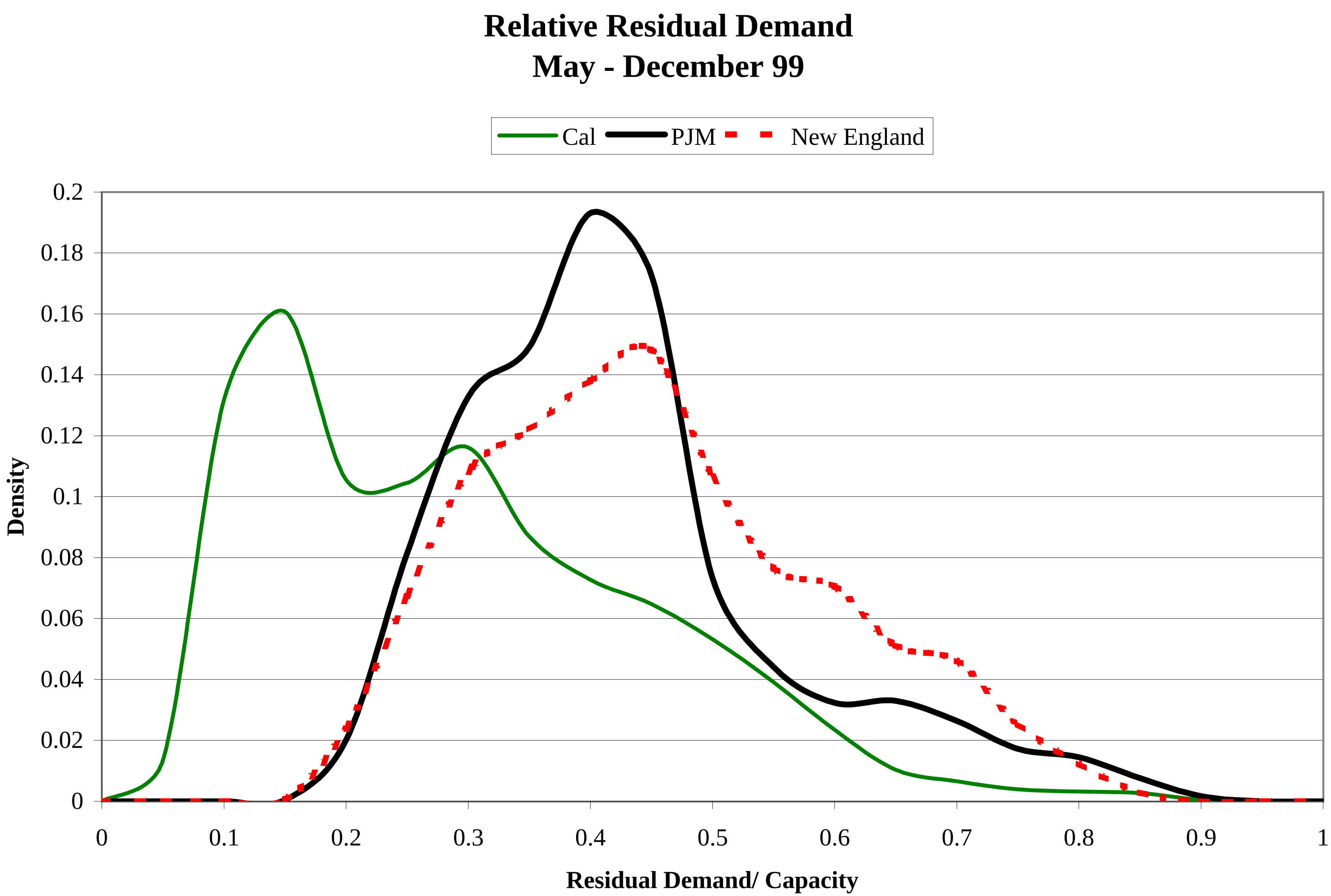

Relative Residual Demand
May - December 99
Cal
PJM
New England
0.2
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
Density
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Residual Demand/ Capacity

Figure 7

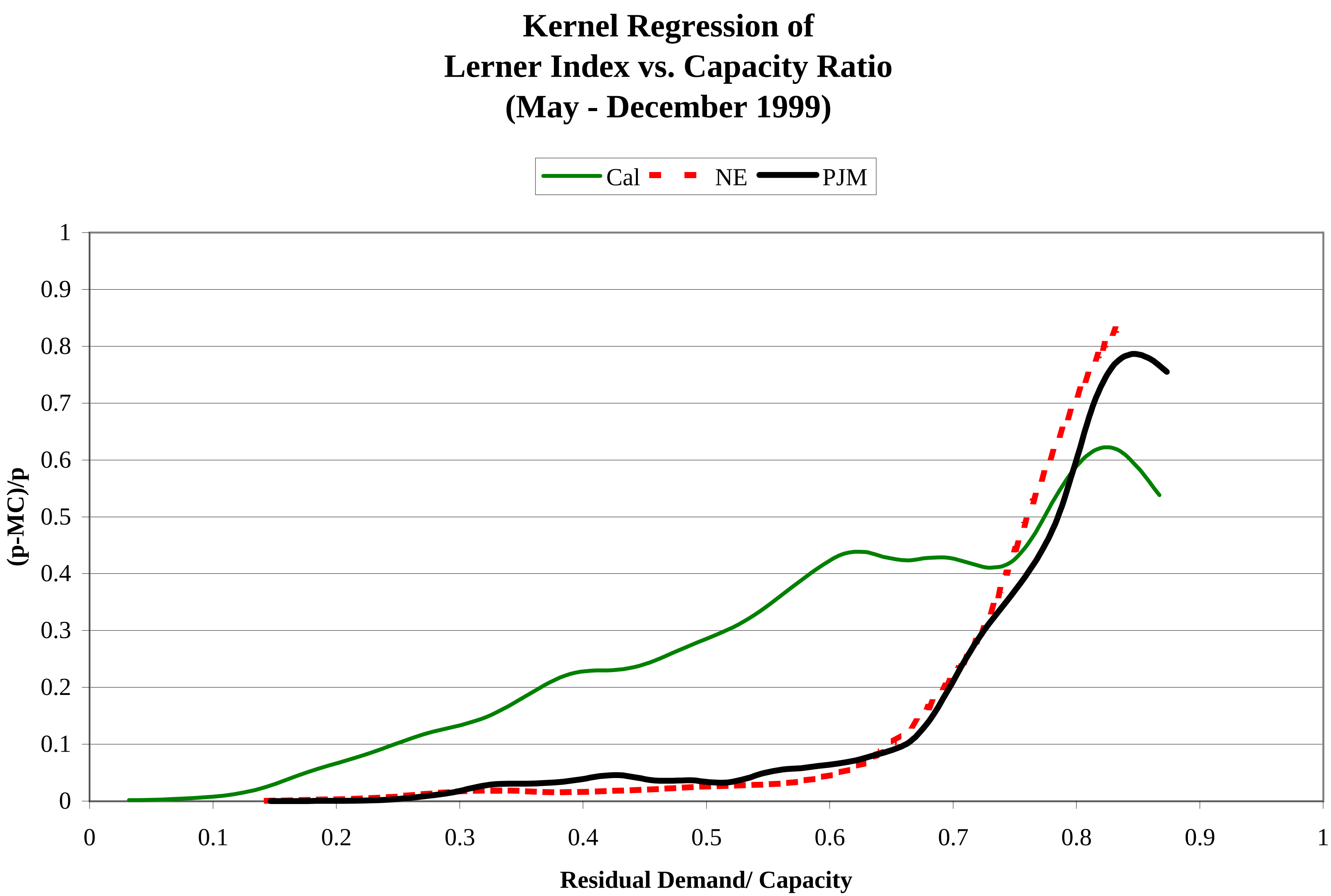

Kernel Regression of
Lerner Index vs. Capacity Ratio
(May - December 1999)
Cal
NE
PJM
(p-MC)/p
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Residual Demand/ Capacity

Figure 8

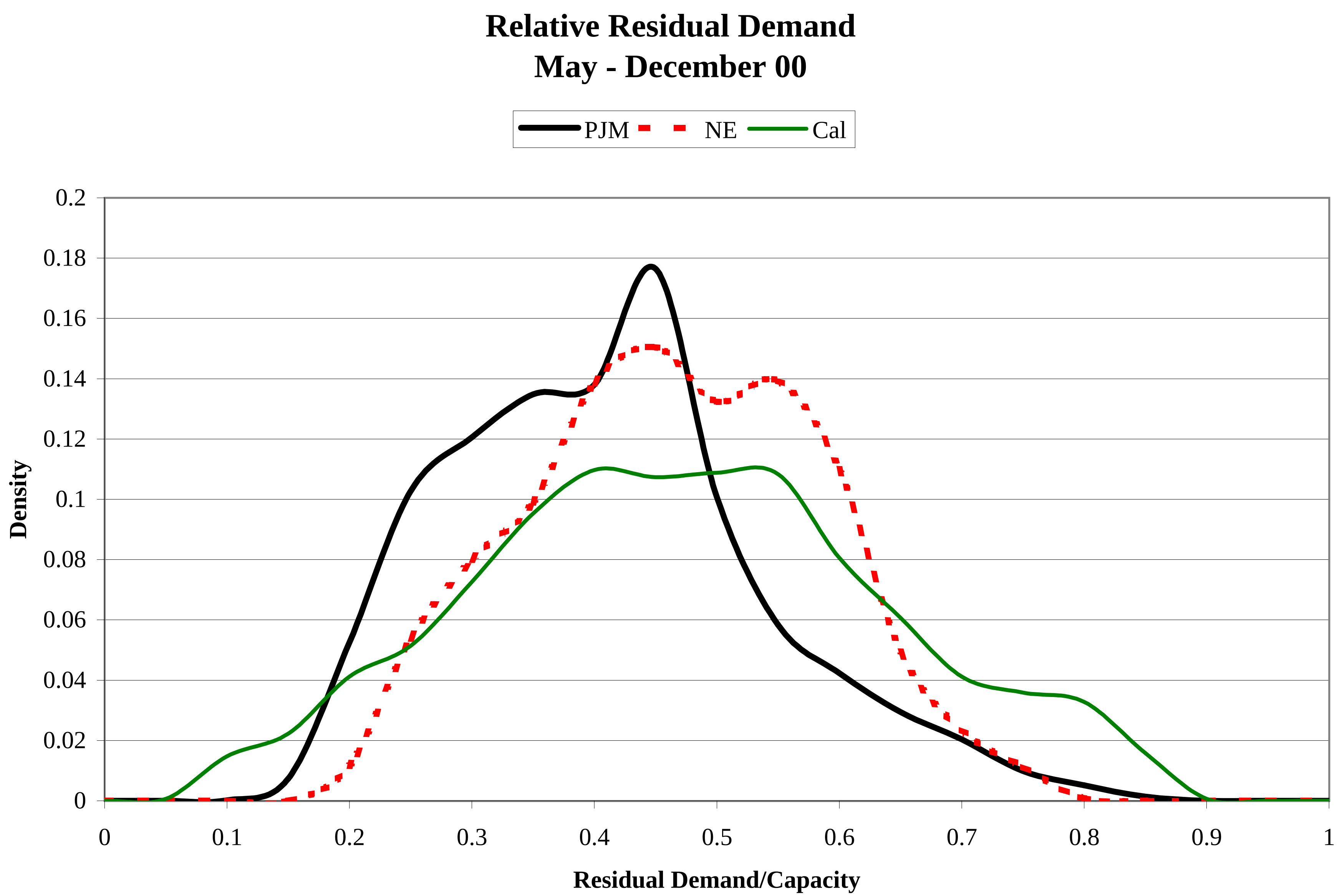
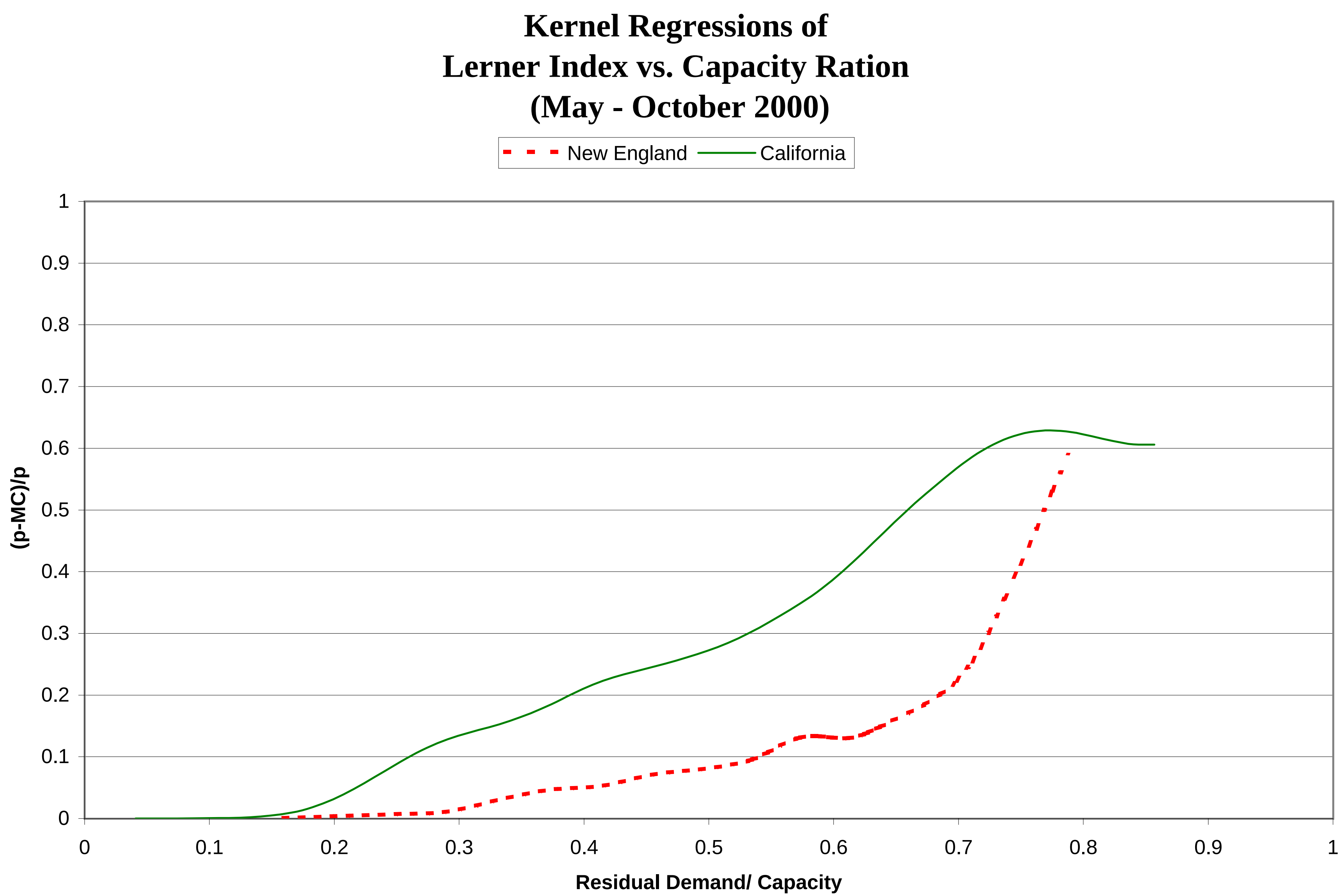

Relative Residual Demand
May - December 00
PJM
NE
Cal
Density
0.2
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Residual Demand/Capacity

Figure 9


Kernel Regressions of
Lerner Index vs. Capacity Ration
(May - October 2000)
New England
California
(p-MC)/p
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Residual Demand/ Capacity