Estimating the Opportunities for Market Power in a Deregulated Wisconsin Electricity Market

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Abstract

To date, a number of electricity markets have deregulated, relying on market forces to set prices. The results thus far are mixed. Therefore, policy makers must rely on ex ante analyses of the market power potential for generation owners. Recently, policy makers in the Wisconsin and Upper Michigan (WUMS) electricity market have contemplated deregulation. In this paper, we examine the ability of electric generation firms to exercise market power in a restructured WUMS market. We employ three different approaches to the analysis of market power in a restructured Wisconsin electricity market: traditional measures of market concentration, a measure of how frequently a given firm is a 'pivotal' supplier to the market, and a simulation of oligopoly competition between the largest firms. All three approaches indicate that, under its current structure, the Wisconsin electricity market is extremely vulnerable to the exercise of market power by generation owners. We next analyze a number of alternative scenarios that would mitigate the level of market power, such as transmission line capacity and increasing the responsiveness of demand to price changes.

1. Introduction

In this paper, we describe various approaches for estimating the capability of electricity generation firms to exercise market power in a restructured Wisconsin electricity market. We discuss some simple indexes of market power as well as methods for simulating oligopoly competition. We then describe in more detail the analysis we have undertaken to assess the opportunity for market power in a restructured Wisconsin electricity market and present the results of that analysis.

In our oligopoly simulation, we model three regions: the Wisconsin/Upper Michigan (WUMS) region, the Mid-America Power Pool (MAPP) region, and the southern (non-WUMS) Mid-America Interconnected Network (MAIN) region. The scenario we assume in formulating these simulations is one in which the Wisconsin market has been restructured along lines similar to those in other restructured markets in the U.S. The generation owned by investor-owned utilities is assumed to be divested into unregulated generation companies or affiliates. We do not assess the impact of any 'buy-back' or vesting contracts that may be initially imposed on the generation companies upon divestiture. We rather focus on the competitive landscape that would obtain in the absence, or upon the expiration, of any such contracts. Generation companies outside of Wisconsin, most of which are vertically integrated utilities operating under cost-of-service regulation, are assumed to operate as 'price-taking' firms that do not attempt to exercise market power. To the extent that firms outside of Wisconsin do have the ability and incentive to exercise market power, possibly as a consequence of restructuring in neighboring states, our estimates will understate the level of market power that could be exercised in Wisconsin.[1]

As with any study of this nature, a number of assumptions must be made about the incentives, costs, and capabilities of firms and the network in which they operate. In most cases, we make assumptions that would tend to *understate* the level of market power. This is because the extent and severity of market power in the WUMS region under the current market structure is likely to be very significant, even under a generous set of assumptions regarding unit outage rates and transmission availability. For these reasons, we feel that the results indicating a strong potential for market power are driven by the underlying market structure, rather than our modeling assumptions. Indeed, most of our key assumptions bias our study *against* finding opportunities for market power.

Given the current distribution of generation ownership in Wisconsin and the amount of transmission capacity into the state, our results indicate that a workably competitive market for wholesale electricity in Wisconsin is not possible. For this reason, we explore the viability of several scenarios for increasing the amount of competition in the Wisconsin electricity market. The first involves divesting the generation capacity owned by Wisconsin Electric Power Company (WEPCO) into 3 identical firms. Our simulation results show that workable competition is unlikely with only this level of divestiture. The second scenario triples the transmission capacity

[1] Following the enactment of restructuring legislation in Illinois in 1997, ComEd has divested its non-nuclear generation, and is no longer a traditional vertically integrated utility. The divestiture was accompanied by a contractual arrangement under which ComEd will buy back much of the output of these units over the next several years.

into the WUMS region. This scenario leads to workable competition in only the very low demand periods. The final scenario quadruples the absolute value of the price sensitivity of the aggregate demand in the WUMS region relative to the base scenario. These results show workable competition during virtually all load conditions. Unfortunately, this level of demand responsiveness is orders of magnitude larger (in absolute value) than levels found in actual empirical studies of demand responsiveness to hourly electricity prices. For this reason, our results should be interpreted as a quantifying the magnitude of aggregate demand responsiveness necessary for a workably competitive wholesale electricity market in the WUMS region.

2. Market Power Analysis

The fundamental measure of the degree of market power exercised is the price-cost margin.[2] However, in most industries, analysts are unable to measure price-cost margins, because marginal costs are usually the private information of producers. Thus, a significant amount of the literature relies on more easily available measurements that are often correlated with the price cost margin.

2.1 Concentration Measures

Often concentration measures, such as the Hirschmann-Herfindahl Index (HHI), are used instead of measures of price-cost margins for a first screen for market power.[3] The HHI measures the sum of the squared market shares of each firm competing to supply the relevant market.

$$HHI = \sum_{i=1}^{N} s_i^2 \qquad \textbf{(1)}$$

Where s_i represents the market share of firm *i* and *N* is the number of firms in the market. In most industries, the market share is measured as the percentage of total sales in physical units or dollars earned by a given firm. Because the historic sales of *regulated* firms may not be a useful predictor of the sales of a hypothetical unregulated firm, the application of this measure of market share is problematic for the analysis of electricity markets. Concentration measures based on historic sales of regulated monopoly firms provide little information as a screening tool. A major relevant question is whether one firm can sell more into the geographic market of another firm in a larger, restructured electricity market. This will depend on such factors as production costs and available transmission capacity between the former geographic monopolists. Often the percentage of installed generation *capacity* owned by a given firm is used instead of the percentage of gross sales when HHIs are calculated for analyses of electricity markets. This measurement might provide some information about the potential competitiveness of a market if the marginal costs of

[2] The price-cost margin, often referred to as the Lerner index, is defined as $\frac{P - MC}{P}$.

[3] One justification for use of the HHI is that under certain conditions, most critically constant marginal costs and no capacity constraints, the HHI divided by the elasticity of demand is equal to the Cournot equilibrium Lerner index. Both of these are unlikely to hold in an electricity market. See Tirole, 1988, page 221-223.

the units are fairly equal and significant transmission capacity exists between the former geographic monopolists. However, this is often not the case.

Governmental agencies concerned with market power, such as the Department of Justice (DOJ), have long relied on projected changes in concentration measures as a significant input into their analysis of the impact of structural changes in a market. The guidelines that were developed by DOJ and largely adopted by the Federal Energy Regulatory Commission (FERC) (see FERC, 1996) make clear that concentration measures should form only a component of a market power analysis. It is also common for both FERC and DOJ to use concentration measures as a screening tool. If a market concentration falls into a 'safe' level, often no further analysis is pursued. The market power analysis supporting the approval by FERC of market-based rates for electrical energy in both California and the PJM pool, for example, was dominated by concentration measures (see WEPEX, 1996 and Joskow and Frame, 1997).[4] During the Summer of 1998, FERC approved the application of a single firm to sell ancillary services in California based upon an analysis of its market share in a market in which its competitors were subject to regulatory price caps (see Henderson, 1998). Shortly thereafter, the ancillary service market experienced significant price spikes and emergency market price caps were imposed.[5] Despite the fact that the market structure in California has, through divestiture, become *less* concentrated than it was at the time it was approved for market-based rates by FERC, the California energy market has continued to experience high levels of market power, particularly during summer months.[6] As we show below, these concentration levels are considerably lower than in the WUMS market. The extremely high price levels in California during the summer of 2000, a significant portion of which can be attributed to market power, have led to calls for FERC to re-examine its process for granting market-based rate authority.

Defining the Geographic Market

A necessary first-step in any analysis of market power is specifying the relevant geographic market. Although our simulation analysis examines the entire U.S. portion of the MAPP and MAIN NERC planning regions, the sub-region of highest concern with regard to market power is the Wisconsin-Upper Michigan System (WUMS). The WUMS area is relatively isolated from its neighboring systems by significant transmission constraints on both the Illinois border and at the Eau-Claire/Arpin interface. For our HHI and pivotal bidder analysis, as well as our base-case market simulation we assume the WUMS import capabilities given in Table 1. In Section 4, we examine the impact of increasing these import capabilities.

[4] See also FERC, 1996, which includes the statement that "[b]y applying an analytic 'screen' early in the merger review process, the Commission will be able to identify proposed mergers that clearly will not harm competition."
[5] See Wolak, Nordhaus, and Shapiro (1998) for details.
[6] See Borenstein, Bushnell, and Wolak (2000).

From/To	Capacity
MAPP/WUMS	1100 MW
non-WUMS MAIN/WUMS	500 MW

Table 1: Base-case Transmission Path Ratings

To be of any practical relevance, concentration measures must be adjusted for the import capacity into the geographic market over which the concentration measure is applied. However, doing so necessitates making assumptions about *whose* supply will be imported. Will it belong to one of the firms in the market, or completely to outsiders? In general, the application of concentration measures to the electricity industry has necessitated many creative assumptions on the part of analysts that further weaken the ability of this measure to predict accurately the severity of market power.

For purposes of calculating the HHI, we first make the assumption that *all* the import capacity into the WUMS region is supplied by many infinitesimal (1 MW) firms. This assumption will understate the concentration of the WUMS market, but as one can see from Table 2, this does not affect the conclusions reached from such an analysis. Table 2 lists the capacity controlled by each of the major firms or categories of firms in WUMS, including capacity planned to go on line during 2000. The generation capacities and costs used for the WUMS region are provided in Table 10 in the appendix.[7] Generation data sources are described in more detail in section 3. One firm, WEPCO, controls roughly half of the capacity within WUMS, and the dilution provided by imports is limited by the constraints of the transmission interfaces to 1600 MW (see below).

Firm	Size (MW)	% of Available Capacity	S^2
WEPCO	6494	47%	.2201
WP&L	2431	18%	.0308
WPS	2065	15%	.0221
MGE	720	5%	.0027
other WUMS	532	4%	-
imports	1600	12%	-
Total	**13842**	**100%**	**HHI=.2761**

Table 2: Largest WUMS producers

[7] It is our understanding that the output from three non-utility generation plants added after 1994, DePere, Neenah, and Whitewater Cogen, are under long-term contract to WPS and WEPCO, respectively. These units were added to the generation portfolios of the utilities to which they are contracted.

As can be seen from Table 2, the HHI in WUMS under the assumption of 1600 importing firms of 1 MW is roughly 2700.[8] This figure is driven by the large share of capacity controlled by WEPCO in the WUMS region. Significant amounts of capacity are also controlled by Wisconsin Power and Light (WP&L), Wisconsin Public Service (WPS) and Madison Gas and Electric (MGE). When the capacities of the WUMS firms are augmented by the transmission capacity controlled by those firms, the WUMS HHI increases to 3384 and the HHI for WEPCO becomes 2634.[9] Even a market-wide HHI of 2761 is well above the 1800 level considered to be a 'safe' level by the merger guidelines of Department of Justice. When the WEPCO portfolio is divided into 3 roughly equal parts and the transmission rights are assumed not to be controlled by any WUMS firms, the WUMS HHI drops to around 1300, considered by DOJ to be 'moderately concentrated.' However, as we discuss below, even moderate concentration in the electricity industry can lead to very uncompetitive market outcomes when all of these firms are strategic suppliers.

One example of the shortcomings of concentration measures can be taken from the California ISO electricity market, where only one firm controls more than a 10% share of the capacity available to serve that market (see Table 3).[10] That firm, PG&E is a net *buyer* of power and therefore unlikely, under the current regulatory regime, to have an incentive to raise prices. Yet market power has been a problem in California, particularly during periods of high demand when even firms with small market shares have been able to influence prices.[11]

Firm	Size (MW)	% of Peak Load (45 GW)	S^2
PG&E	6298	14%	.0196
AES	3921	9%	.0081
Reliant	3698	8%	.0064
Duke	3343	8%	.0064
Southern	3130	7%	.0049
Dynegy	2831	6%	.0036
SCE	2595	6%	.0036

Table 3: California Capacity Shares as a Percentage of Peak Demand

[8] The traditional practice is to multiply the HHI calculation by 10,000.

[9] The transmission capacity controlled by WUMS firms was estimated from the firm capacity reserved on OASIS from each firm. These capacities were 610 MW for WEPCO, 480 MW for WPL, 200 MW for WPS, and 134 MW for WPPI

[10] Because imports almost never reach the level of transmission capacity into California, market shares are expressed in Table 3 as a percentage of peak load, rather than as a share of installed capacity plus total import capacity. The two tables are therefore not directly comparable. These figures are presented for illustrative purposes only.

[11] See Borenstein, Bushnell, and Wolak (2000).

The Pivotal Supplier Index

The key question that determines the extent of market power possessed by a firm is if that firm attempts to withhold capacity from a market, are there substitutes available to replace that capacity? Concentration measures such as the HHI, because they rely upon static measures such as installed capacity, do not adequately address this central question. For this reason we will also calculate an alternative measure which we call the *Pivotal Supplier Index* (PSI). The PSI calculates the frequency that some quantity from a given supplier is required to serve market demand. Under such conditions, the firm is a monopoly supplier for the portion of demand that cannot be served by any other firm.

The PSI for a given firm subtracts the total expected generation capacity *of all other* firms, as well as all available imported capacity, from a given level of the market demand. If this residual demand is greater than zero, then firm *i* is a pivotal supplier for this market. This means that the firm under consideration is essential to serve the market demand, given that all of the capacity of other firms is being used to serve this level of market demand. For a demand level D_t in period *t*, the PSI is defined as follows:

$$PSI_{it} = \begin{cases} 1 & \text{if } D_t - \sum_{j \neq i} Gencap_j - MaxIMPORTS > 0 \\ 0 & \text{if } D_t - \sum_{j \neq i} Gencap_j - MaxIMPORTS \leq 0 \,. \end{cases} \qquad \textbf{(2)}$$

Where $Gencap_j$ is the capacity of firm *j*, and *MaxIMPORTS* is the aggregate import capability into the region. When its residual demand is positive, a firm faces no competition for the supply of this (residual) portion of the market and is therefore effectively a monopolist over this quantity of output. If the market demand is *perfectly inelastic* (unresponsive to price) for the pivotal quantity, the supplier can raise prices to almost any level—subject to regulatory intervention—if it is willing to sell only this quantity.[12] The *PSI* calculates the percentage of time over a given period for which a firm achieves this pivotal status by summing the number of hours during a time period *T* (in our case one year) in which that firm is pivotal.

$$PSI_i = \frac{1}{T} \sum_{t=1}^{T} PSI_{it} \qquad \textbf{(3)}$$

We calculated the PSI for the four largest investor-owned utilities in the WUMS region, again assuming a total import capability into WUMS of 1600 MW. As can be seen from Table 4, WEPCO again stands out as the dominant supplier to the WUMS region. It is a pivotal supplier to WUMS for all loads above 7348 MW. Using the 1996 state-wide annual load duration curve from Wisconsin's Advance Plan 8, we created an estimated load-duration curve for the WUMS region by assuming the same load-shape for WUMS and scaling that load shape according to the

[12] This is almost certainly the profit maximizing output if there is no price cap. The pivotal firm would be willing to supply a very small residual demand if the price reaches very high levels.

forecast peak load for 2000. The load-duration curve is shown in Figure 1. The peak load in WUMS, taken from MAIN planning documents,[13] was assumed to be 11781 MW. With this level as the peak-load, WEPCO is a pivotal supplier for roughly *half* of the hours in the year. The other suppliers are pivotal less than 1% of the hours, if at all.

Firm	Capacity	Pivotal Level	Number of Pivotal hours	% of hours pivotal (PSI)
WEPCO	6494	7348	4834	55.03%
WPL	2431	11411	12	0.14%
WPS	2065	11777	1	0.01%
MGE	720	13122	-	-
other WUMS	532	-	-	-
imports	1600	-	-	-

Table 4: Pivotal Supplier Analysis

We include *no* reserve margin in the pivotal supplier calculations presented in Table 4. Adding a 4% operating reserve to the peak demand level raises the percentage of hours in which WEPCO is pivotal to roughly 63%.[14] As with our HHI calculation, we have initially assumed that *none* of the transmission capacity is controlled by the firms within WUMS. If we add the firm OASIS reservation capacities to the generation controlled by each firm (610 MW in the case of WEPCO), with no reserve margin WEPCO is pivotal 70% of the time.

It is important to note that the PSI is a very liberal screening tool for market power in electricity markets. It essentially detects the frequency of *monopoly* power held by a given firm. As can be seen from our oligopoly simulations and from empirical studies of existing restructured electricity markets, firms can effectively raise prices well above marginal costs in an oligopoly (*i.e.* few firm) setting. Even given these shortcomings however, we feel that pivotal supplier analyses are more informative about the competitive potential of an electricity market than the HHI because the PSI explicitly recognizes that the ability to exercise market power in a deregulated electricity market depends crucially on the level of demand.

Because of how electricity has been priced historically, there is virtually no price-response of retail demand to hourly changes in wholesale prices. Consequently, the primary mechanism that disciplines the exercise of market power is the competitive supply response by other market participants. The pivotal supplier index gives the percentage of hours (and associated load levels) when that competitive response has the potential to limit the exercise of market power by the market participant under consideration. In addition, there are still very strong incentives for all market participants to attempt to elevate prices during hours when one or a small number of firms are pivotal or nearly pivotal. To assess these incentives requires a formal model of the competitive interaction, which we construct and analyze later in this paper.

[13] See "MAIN Load and Resources Audit, Summer of 2000."

[14] A 1999 survey of NERC regional reserve policies calculated that the typical reserve level for MAIN was around 1700 MW, or roughly 4% of 1998 peak demand.

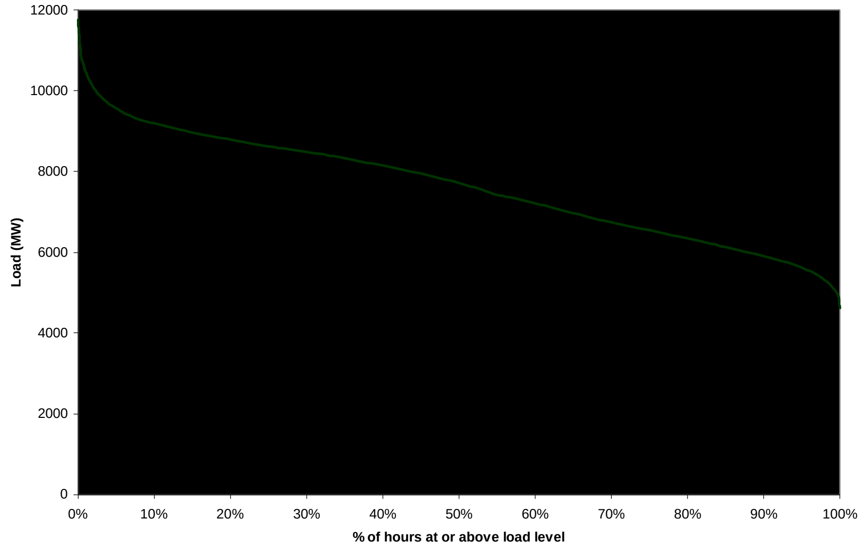

Figure 1: Load-duration Curve for WUMS

The Shortcomings of Concentration Measures

A major conclusion from market power analyses performed on existing wholesale electricity markets is that the amount of market power exercised depends upon current market conditions, including the level of demand, the amount of available transmission capacity, and the amount of available generation.[15] The HHI based on generating capacity is unable to capture the dynamic nature of the potential for market power. The PSI index captures a part of this dynamic nature of the market power possessed by a firm, but only detects the most extreme level of market power. A simulation model based on estimates of actual market participant costs can come the closest to capturing the actual dynamic process governing the extent of the market power exercised in actual competitive electricity markets.

2.2 Simulating the Strategic Behavior of Firms

The approach to analyzing market power that we take here is to simulate the strategic behavior of firms in the market. These simulations are based on the cost and production characteristics of the actual set of generation units that a firm owns, or the generation units that it would own under a certain restructuring scenario. To specify fully the basis for such a simulation, we must describe the strategic variables that firms control and the assumptions about the behavior of other firms. As with, most of the work that we have done in this area,[16] we implement the oligopoly equilibrium approach by analyzing a variant of the Cournot-Nash concept of firm strategies and beliefs. The Cournot-Nash approach is to assume that strategic firms employ *quantity strategies:* each strategic firm chooses its quantity to produce taking as given the output

[15] For a more thorough discussion of these issues, see Borenstein, Bushnell and Knittel (1999).

[16] See Borenstein and Bushnell (1999), Borenstein, Bushnell and Knittel (1998) and Borenstein, Bushnell and Knittel (1999).

being produced by all other strategic firms. We recognize, however, that not all firms are likely to behave strategically. Very small firms are more likely to simply take the market price as given and produce all output for which its incremental cost is less than the market price. Similarly, public power agencies and cooperatives, with no explicit goal of maximizing profits, will also likely behave competitively. Thus, we model only the portfolios of the larger, investor-owned firms as Cournot competitors. Very small firms, public power agencies, and cooperatives are modeled as price-takers, both in their own behavior and in how they are viewed by strategic players in the market.[17]

3. Oligopoly Simulation Methodology

In this section we describe the modeling approach we use for modeling the potential for market power in a restructured Wisconsin electricity market. We first describe the geographic divisions of the market, then discuss how demand and supply are represented.

3.1 Defining Geographic Markets

We model three markets: the US portion of the Mid-America Power Pool (MAPP) region -- including western Wisconsin, the Wisconsin/Upper Michigan (WUMS) region, and the non-WUMS MAIN region -- including Illinois and eastern Missouri. Each is separated by transmission interface limits. For the basic simulation, we assume that there are no binding transmission constraints *within* each of these regions.

We assume that transmission resources will be priced efficiently under a "marginal cost" pricing approach consistent with the requirements of the FERC Order 2000 on regional transmission organizations (RTOs). This means that the 'cost' of a transmission interface will reflect the opportunity cost of not using that interface (*i.e.* the price of transmission is implicitly defined by the market price for energy on each side of the constrained transmission interface).[18] The ratings of the interfaces between each region depend upon system conditions, and we examine the sensitivity of the results to these import constraints. For the basic simulation, we assume that the ratings on the transmission interfaces between the two larger regions and WUMS are as given in Table 1 above.

3.2 Market Demand

In most electricity markets there is little potential for market power in off-peak, low demand hours. In many markets, however, market power is a significant problem during peak hours. This is due, in part, to the fact that when demand rises beyond a given level, both the

[17] Even if we were to model the smallest firms as acting strategically, the simulation results would change very little. This is because the residual demand faced by a very small player is nearly flat, imply the marginal revenue curve of a small player is essentially its demand curve.

[18] It should be noted that many observers of the MISO process are skeptical that this level of efficient market pricing of transmission will be achieved for several years, if at all.

transmission and generation capacity of potential competitors becomes exhausted, leaving the residual market to just a few dominant firms on the margin.

Because of this pervasive characteristic of competition in electricity markets, we examine a broad range of demand levels in the markets defined above. By a range of demand levels, we, in effect, mean a range of demand *curves*, because we assume that demand is at least somewhat price-responsive. Because most electricity customers today face a constant marginal price for electricity, we fix our demand curves to reference points that relate to currently observed or forecast price-quantity pairs. In other words, our demand curves are calibrated so that the market demand, at current prices, would equal the current quantities demanded. Figure 2 illustrates the construction of the demand curves used in one set of simulations. The demand function D_1 is chosen such that at current prices, market demand would be 1,000 MW, while D_2 is defined such that market demand would be 2,500 MW at current prices. In the results presented below, demand functions are identified by their "anchor" demand quantity (e.g. the anchor quantity of D_1 is 1,000) at some pre-determined reference price level. Thus, fluctuations in demand can be captured by varying this "anchor quantity," while keeping the reference price the same. For our simulations, we will utilize constant elasticity demand curves of the form $D(p) = KP^{-\varepsilon}$ where ε is the elasticity of demand and K is a constant defined by the anchor demand level.

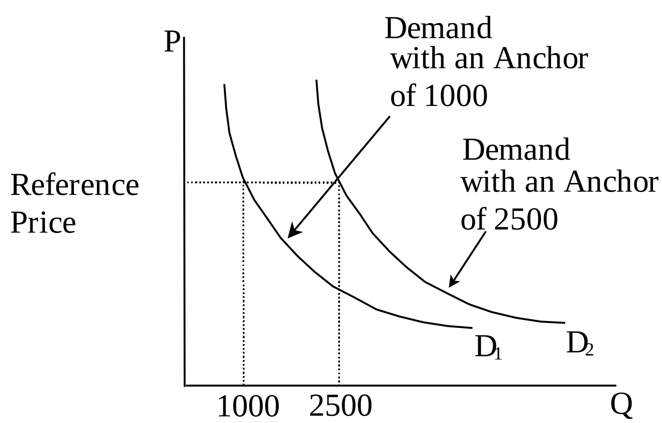

Figure 2: Simulation Demand Functions

Anchor Demand Levels

Peak forecast demand levels in the three market areas, taken from the most recent MAPP and MAIN load and resource reports, are shown below in Table 5.[19] Demand in the exporting regions of MAPP and non-WUMS MAIN is assumed to be inelastic. The most recently reported average rate for all consumers in Wisconsin is 5.4 cents/kWh.[20] Using the calculations of White (1998), energy accounts for roughly 40% of total rates nation-wide. The remaining 60% represents the non-bypassable transmission and distribution expenses. The difference ($22/MWh) will be used as the wholesale price level to which the demand curve for energy is anchored.

[19] Sources for demand data were the "MAIN Load and Resource Audit, Summer of 2000" and the "2000 MAPP Load and Capability Report (U.S.)."
[20] Energy Information Administration. "Electric Sales and Revenue 1998."

Region	2000 Summer Peak (MW)
WUMS	11781
non-WUMS MAIN	37834
MAPP U.S.	30364

Table 5: Peak Demand by Region

Our modeling framework assumes that at the baseline price, the demand for electricity in Wisconsin is at its forecast level. As prices rise, demand is reduced somewhat. The degree to which demand is reduced will depend upon the elasticity parameter of the demand curve. For our base-case simulation, we assume an elasticity of -0.1. This is consistent with historic econometric estimates of short-run electricity demand elasticity, but those estimates deal with response over longer periods of time than one hour. With a constant elasticity demand curve setting elasticity $\varepsilon = -0.1$ implies, for example, that a doubling in price will cause a 10% drop in demand. This most likely *overstates* the actual response in all electricity markets currently operating in the United States. It is important to bear in mind that because of how electricity has been historically priced, at least for the near term, the amount of price-responsiveness in aggregate demand is limited. Technologies that enable consumers to see and receive economic benefits from being responsive to hourly wholesale prices must be in place before there will be a significant amount of elasticity in aggregate wholesale electricity demand. Price-responsive (elastic) demand can be an effective check against the market power of suppliers. Below, our calculation of the sensitivity of the Cournot simulation results to the elasticity parameter provides a demonstration of this effect.

Given the elasticity of our demand curve, changes in energy prices will cause demand to change to some degree. We will also examine the natural variation in demand due to changing consumption patterns. We do this by calculating the Cournot equilibrium for a range of anchor demand quantities (*i.e.* the load level that would obtain at the assumed baseline price). Varying this anchor demand level also provides a straightforward and effective way of examining the potential impact of adding transmission capacity or new, competitive, generation resources. This is because this added capacity can be viewed as offsetting demand. Thus, for example, the level of market power seen at a demand of 11,000 MW assuming 1,000 MW of new capacity owned by a new entrant will be comparable to the level seen at 10,000 MW of demand without that new capacity.

3.3 Market Supply

We construct firm level cost functions by using plant level data on the capacities, heat rates, fuel and maintenance costs of each generation unit. We assume no forced outages in the units. The cost/capacity pairs of each unit are then combined to produce, for each firm, a step-function cost curve of total output.[21] Hydro generation does not make up a very large share of the capacity in the US MAPP and MAIN regions. Because we are estimating the extent of market power, which is usually a peak effect, we assume that all hydro units are operating at capacity (*i.e.* are not energy constrained) during these periods.

[21] This process is described in more detail in Borenstein and Bushnell (1999).

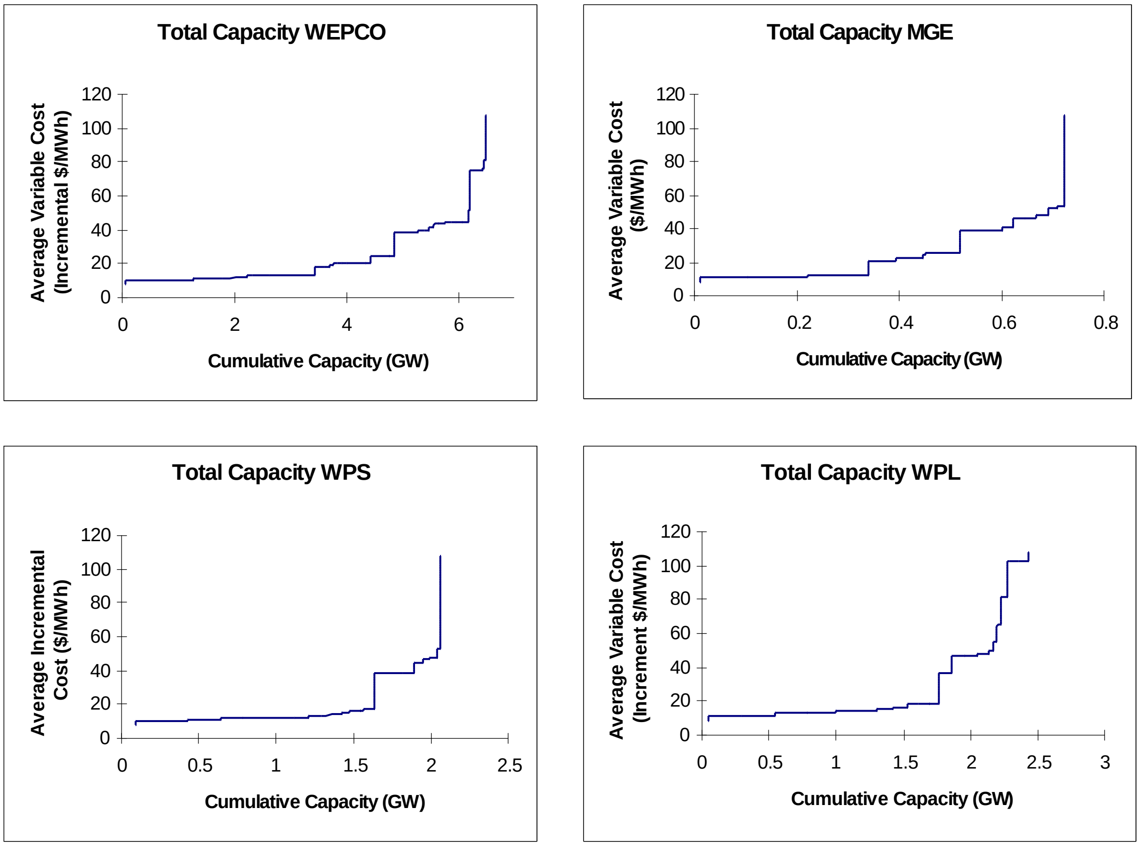

Figure 3: Cost Curves of Cournot Firms

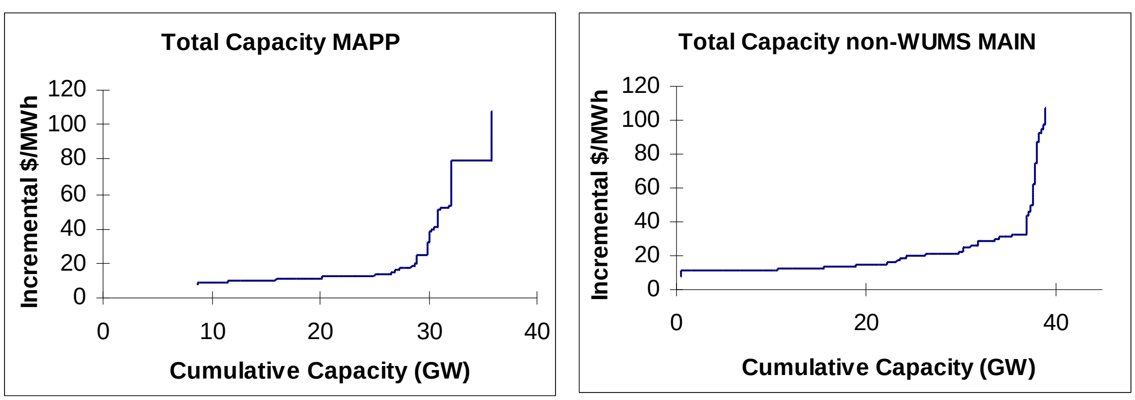

Figure 4: Cost Curves for WUMS Neighboring Regions

Most of the generation characteristics for generation within Wisconsin are taken from the Public Service Commission of Wisconsin (PSCW) 1994 Advance Plan 7 supporting documents. Information on generation additions made since 1994 are taken from PSCW Bulletin 46 and

FERC Form 1. The cost curves of the 4 largest WUMS producers, along with the aggregate cost-curves of the U.S. portion of MAPP and the non-WUMS MAIN regions are shown in Figures 3 and 4. Generation characteristics for units outside of Wisconsin are taken from the public work papers of a simulation performed for a recent Ohio proceeding to determine the transition costs of implementing that state's restructuring law. These data are drawn from output files of simulations using the generator data set of Henwood Energy Services.

3.4 Cournot Simulation Algorithm

In general, firms are divided into two categories: price-taking firms and strategic firms. Firms that, because they are very small, cannot credibly attempt to affect the market price under any normal demand conditions, are treated as price-takers. Some large firms, either because they are publicly or cooperatively owned, or are themselves large consumers of electricity, are also included in the price-taking group of firms. These firms are modeled as simply producing every unit of output they could for which their marginal cost is less than the market price. Larger deregulated generators that it appeared could affect the market price under some conditions are assumed to follow Cournot strategies. In the case of Alliant Energy, which owns WP&L along with other utilities outside WUMS, we assume only the generation assets in Wisconsin are deregulated. Other assets controlled by Alliant are assumed to be price-takers.

Cournot Firms	Price-taking firms
MGE, WEPCO, WPS, WP&L	UPPCo, municipals and cooperatives, WPPI, all other WUMS producers, all MAPP and non-WUMS MAIN producers

Several utilities in Wisconsin have proposed the formation of a Nuclear Management Company that would be responsible for the operation and maintenance of nuclear plants in Wisconsin. It is our understanding that under the terms of this proposal, the parent utility would still receive all revenues associated with production from their respective ownership shares of these facilities. Therefore, ownership shares of the nuclear plants were still considered to be part of the generation portfolio of the Cournot players.

The presence of price taking fringe firms implies that the Cournot players will compete over a residual demand curve, *i.e.* the market level demand *minus* the output level of the fringe firms. Therefore, Cournot firms account for the fact that if they increase price, by restricting output, the level of fringe supply will increase. Therefore, Cournot firms face the following demand curve:

$$D_r(P) = D(P) - \sum_{i=1}^{F} \mathrm{Min}(S_i^f(P), TR_i) \qquad \textbf{(4)}$$

where $D(P)$ is the market demand function, $S_i^f(P)$ represents the fringe supply curve for fringe firm i and TR_i represents the transmission constraint faced by the ith fringe firm and F is the total number of fringe firms Thus the supply capability of the fringe can be constrained by transmission limits. The function, $D_r(P)$ is the resulting residual demand curve faced by Cournot players in their respective markets.

To compute the Cournot equilibria, we use the above definition and construct the residual demand curve faced by the Cournot players for a wide range of market demand levels. For each anchor demand level, we calculate the Cournot equilibrium.[22]

Price caps

Every restructured electricity market in the world operates under some form of explicit or implicit cap on energy prices. Because of the high levels of market power likely in the WUMS region, certain firms would often be able to set prices at whatever the capped level will be. The level of price-cap assumed will therefore play are large role in overall price levels. For the purposes of this simulation, we assume that prices are capped at $1,000/MWh (including the $32/MWh T&D charge, the level used in eastern markets such as PJM, the New York ISO, and ISO-New England.

Multiple Equilibria

Once one accounts for the presence of a price taking fringe the residual demand contains flat regions. This results from the fact that each plant is assumed to have a constant marginal cost up to capacity, causing the fringe supply curve to have flat regions. As a result, the demand curve faced by any one firm will also have flat regions and those flat regions will be associated with discontinuities in the marginal revenue curve that the firm faces. For a given firm, this can result in multiple local profit maxima. This in itself is not a problem because our grid-search method assures that the output derived is a firm's global profit maximum. However, this can also lead to multiple equilibria because small changes in the output of other firms can cause a given firm to make relatively large jumps in its own optimal output.[23]

It is important to keep in mind that the reported results represent one of potentially several equilibria. In demand ranges where the capacity of the fringe is exhausted (for WUMS this means every firm but WEPCO, WP&L, WPS and MGE) at the Cournot equilibrium there will not be multiple equilibria. This is likely to be most of the time for the WUMS region. However, it is almost certain that the equilibrium with higher prices is the most profitable for each strategic firm. In a repeated market such as this one, it is reasonable to expect that firms would move towards the most profitable equilibrium point. Wherever possible we therefore report the prices from the highest priced equilibrium, when multiple equilibria exist.

4. Cournot Simulation Results

[22] See Borenstein and Bushnell (1999) for more details regarding the search algorithm.

[23] It should be noted that the multiple equilibria problem in the Cournot analysis is different from the one that occurs with a supply function analysis. It appears here because we attempt to model explicitly the discontinuities in fringe firm cost functions, and there are a countable number of equilibria. In SF analysis there is a continuous range of equilibria.

We simulated the current market structure with the 4 largest WUMS utilities acting as Cournot firms and all other firms acting as price-takers. Transmission into the WUMS region was set at the capacities shown in Table 1, and demand elasticity was assumed to be –0.1. We examined demand ranging from 6,000 MW to 12,000 MW for the WUMS region.

Under the current market structure, Cournot equilibrium prices reach the $1,000/MWh price cap at all load levels in the WUMS region. Market clearing prices for all three regions are shown in Table 6. These results show that the prospects for competition are even worse than that shown by the pivotal bidding analysis, which identified monopoly market conditions for load levels above 7,700 MW. The Cournot analysis implies that even at lower demand levels, competition between the firms with available capacity at those levels is not sufficient to keep prices below capped levels. Unlike most electricity markets that we have studied where market power is a problem mainly during high demand periods, these results indicate that the Wisconsin market under its current structure would have severe market power problems nearly all the time.

WUMS Demand at $22/MWh	WUMS Perfect Comp. Price ($/MWh)	WUMS Cournot Price ($/MWh)	non-WUMS MAIN Demand MW	non-WUMS MAIN Price ($/MWh)	MAPP Demand MW	MAPP Price ($/MWh)
6000	13.38	967.98	19766	15.12	16562	10.51
6500	13.55	967.98	21372	15.39	17851	11.00
7000	13.64	967.98	22977	16.40	19139	11.12
7500	14.27	967.98	24583	19.85	20428	12.01
8000	15.98	967.98	26188	20.56	21716	12.09
8500	18.33	967.98	27794	20.93	23005	12.57
9000	20.20	967.98	29399	21.39	24293	12.81
9500	20.93	967.98	31005	25.46	25582	13.44
10000	23.98	967.98	32610	28.73	26870	15.13
10500	30.31	967.98	34216	30.79	28159	17.31
11000	36.83	967.98	35821	32.59	29447	25.14
11500	39.76	967.98	37427	48.89	30736	40.44
12000	49.41	967.98	39032	115.87	32024	78.61

Table 6: Base Case Cournot Outcomes

4.1 Alternative Scenarios

Based upon our analysis, the current market structure will not produce workable competition. We therefore examined several alternatives for increasing the competitiveness of the market. These include expanding transmission capacity into the WUMS region, divestiture, and increasing demand elasticity. In addition to these three changes, we can also obtain a rough estimate of the impact of new entry of competitive generation capacity into the WUMS region by treating that capacity as negative demand. In other words the extent to which prices are raised above marginal cost at a demand level of 9,000 MW without any new generation will be roughly comparable to the results at demand level of 10,000 MW with 1,000 MW of new generation.

Divestiture of WEPCO portfolio

As described above, the size of the WEPCO generation portfolio combined with the limited import capacity into WUMS means that the owner of this portfolio is a pivotal supplier for the WUMS region for a large percentage of the time. Given the relative inelasticity of demand, this means that to maximize profits, the owner of such a portfolio could be expected to raise prices to capped levels for the demand levels examined above. One natural first step in trying to implement a more competitive market structure would therefore be to divide this dominant portfolio into multiple smaller portfolios. In order to examine the effect of such a move, we simulated the market under the same assumptions as for the base case except that the WEPCO portfolio was divided into 3 identical pieces of just under 2,000 MW each. This meant that the WUMS market featured 6 Cournot firms. One firm (MGE) had 721 MW and the other five were roughly the same size with around 2,000 MW each. This market structure at first glance is more concentrated than that of California, where the 10 large firms control the bulk of California ISO capacity. There are also other important differences that limit the competitiveness of this hypothetical WUMS market relative to California. There is considerable 'fringe' capacity (*i.e.* capacity owned by firms that are individually relatively small) within the California ISO system and, most importantly, much more transmission capacity relative to demand into California than into WUMS. There is approximately 8,000 MW of transmission capacity available at the Oregon-California border and 12,000 MW available between California and the desert southwest, although simultaneous import levels can be quite a bit lower. There is sufficient transmission capacity to serve nearly half of California's peak-load. Wisconsin, by comparison, can only meet about 10% of its peak load with imports.

WUMS Demand at $22/MWh	WUMS Perfect Comp price ($/MWh)	WUMS Cournot Price ($/MWh)	Non-WUMS MAIN Demand MW	non-WUMS MAIN Price ($/MWh)	MAPP Demand	MAPP price ($/MWh)
6000	13.38	515.42	19766	15.12	16562	10.51
6500	13.55	802.86	21371.5	15.39	17850.5	11.00
7000	13.64	967.98	22977	16.40	19139	11.12
7500	14.27	967.98	24582.5	19.85	20427.5	12.01
8000	15.98	967.98	26188	20.56	21716	12.09
8500	18.33	967.98	27793.5	20.93	23004.5	12.57
9000	20.20	967.98	29399	21.39	24293	12.81
9500	20.93	967.98	31004.5	25.46	25581.5	13.44
10000	23.98	967.98	32610	28.73	26870	15.13
10500	30.31	967.98	34215.5	30.79	28158.5	17.31
11000	36.86	967.98	35821	32.59	29447	25.14
11500	39.76	967.98	37426.5	48.89	30735.5	40.44
12000	49.68	967.98	39032	115.87	32024	78.61

Table 7: Divestiture of WEPCO into 3 identical firms

The results of the Cournot simulation of this hypothetical divestiture demonstrate the limits of such a policy. As shown in Table 7, except for the low demand periods of 6,000 and 6,500 MW anchor demand levels, prices again hit the price cap of $1,000/MWh. This indicates that more extensive divestiture, in combination with transmission and demand side enhancements would be necessary to create a competitive market structure inside of WUMS.

Transmission Expansion

Transmission limits into WUMS are a key contributor to the lack of competition in the Cournot simulations. We therefore examined the impact of considerably expanding the import capabilities into WUMS. We examined a market in which the MAPP-WUMS import capability was increased from 1,100 MW to 3,600 MW and the Illinois – WUMS capability was expanded from 500 to 1,100 MW. The results from this simulation are shown in Table 8. It is important to note that these hypothetical grid expansions exceed the levels currently under consideration. The goal of current planning studies is to achieve a simultaneous import capacity into WUMS of 3,000 MW in total.[24]

WUMS Demand at $22/MWh	WUMS Perfect Comp price ($/MWh)	WUMS Cournot Price ($/MWh)	Non-WUMS MAIN Demand MW	non-WUMS MAIN Price ($/MWh)	MAPP Demand	MAPP price ($/MWh)
6000	11.46	14.88	19266	14.89	19062	11.12
6500	11.57	15.35	20878	15.14	20351	11.88
7000	12.01	15.86	22477	15.87	21639	12.09
7500	12.49	19.15	24083	19.16	22928	12.57
8000	13.30	20.54	25688	20.55	24216	12.81
8500	13.44	79.10	28794	21.04	25505	13.44
9000	13.64	146.68	30399	25.44	26793	15.13
9500	15.89	197.66	32005	28.73	28082	17.31
10000	18.02	263.77	33610	30.31	29370	25.14
10500	22.19	351.73	35216	31.61	30659	40.44
11000	31.61	478.55	36821	32.93	31947	53.62
11500	39.76	686.26	38427	92.60	33236	78.61
12000	49.41	967.98	39630	967.99	34524	78.61

Table 8: Transmission Expansion

The transmission expansion significantly lowers both the perfectly competitive and Cournot equilibrium WUMS prices. Although there is less market power being exercised within WUMS in this scenario, the impact of that market power on the exporting regions of MAPP and non-WUMS MAIN is greater. Because the extra transmission capacity raises exports from both MAPP and non-WUMS MAIN, prices at the higher demand levels in both these regions rise relative to the Cournot base case.

Increasing Demand Elasticity

As a final alternative for enhancing competition, we examined the impact of an increase in the elasticity of demand from –0.1 to –0.4. As shown in Table 9, increasing demand elasticity has by far the largest impact on lowering Cournot equilibrium prices.

[24] These targets are taken from the Wisconsin Interface Reliability Enhancement Study (WIRES) report to the Wisconsin Reliability Assessment Organization (WRAO) of August 1998.

WUMS Demand at $22/MWh	WUMS Perfect Comp price ($/MWh)	WUMS Cournot Price ($/MWh)	Non-WUMS MAIN Demand MW	non-WUMS MAIN Price ($/MWh)	MAPP Demand	MAPP price ($/MWh)
6000	13.54	36.89	19766	15.12	16562	10.51
6500	13.56	36.89	21372	15.39	17851	11.00
7000	13.79	45.74	22977	16.40	19139	11.12
7500	15.19	53.99	24583	19.85	20428	12.01
8000	17.12	58.05	26188	20.56	21716	12.09
8500	18.58	58.39	27794	20.93	23005	12.57
9000	20.20	58.39	29399	21.39	24293	12.81
9500	20.70	58.39	31005	25.46	25582	13.44
10000	23.98	58.39	32610	28.73	26870	15.13
10500	25.49	69.25	34216	30.79	28159	17.31
11000	31.01	69.25	35821	32.59	29447	25.14
11500	38.72	79.10	37427	48.89	30736	40.44
12000	43.21	93.71	38532	115.87	32024	78.61

Table 9: Elasticity –0.4

Clearly, creating price-responsive demand can yield huge benefits in terms of mitigating market power. In order to place these results in context, however, it is useful to consider just how much demand reduction would be implied by an elasticity of –0.4. Figure 5 shows the WUMS anchor demand levels relative to the Cournot equilibrium demand levels for the –0.4 elasticity scenario.

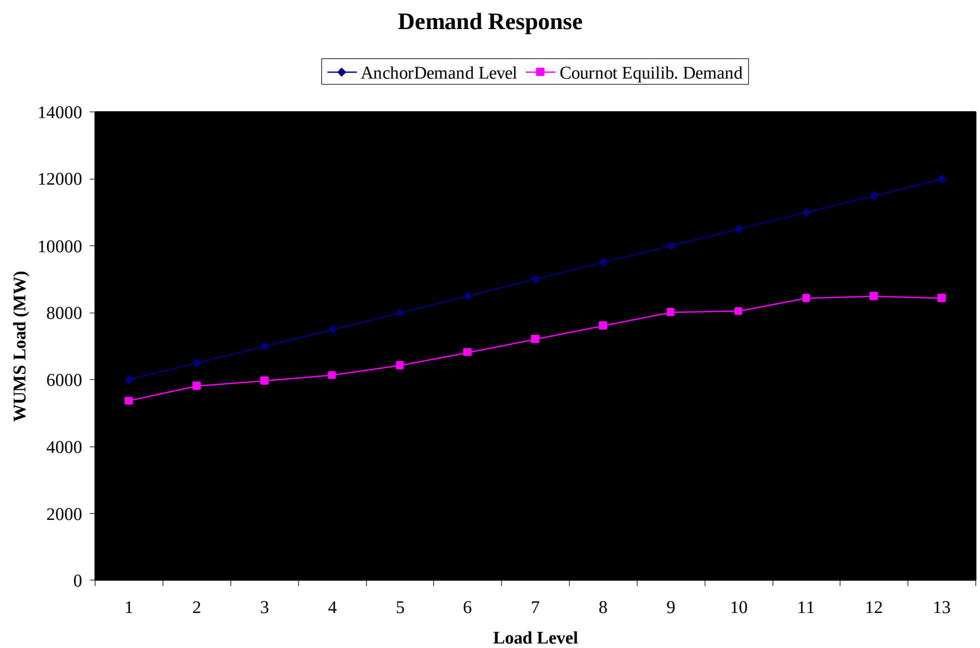

Figure 5: Demand Response with Elasticity = -0.4

With the price rising from the anchor demand level of $22/MWh to the Cournot equilibrium level of $93/MWh, peak demand is reduced by just under 4,000 MW. This is nearly 1/3 of total demand. By comparison, the current amount of interruptible load and direct load control in WUMS is around 900 MW. This level of demand-responsiveness on an hourly level is extremely unrealistic given the current state of metering, energy storage, and other price-responsiveness technologies available even in the current competitive wholesale markets in California, PJM, New York and New England. Even if such technologies were in place, it is extremely unlikely that they would produce anything approaching the demand response implied by a -0.4 elasticity.

5. Conclusions

In this paper, we have described several methods for estimating the potential for the exercise of market power in a restructured Wisconsin electricity market. These include a traditional concentration analysis using the HHI, a pivotal bidding analysis, and an oligopoly simulation that assumes four firms within the WUMS region adopt Cournot behavior. The results of all of these analyses indicate that under the current market structure, unregulated profit-maximizing suppliers in the WUMS region would be able to raise prices significantly above competitive levels.

The sources of this potential market power include the high concentration of capacity ownership within WUMS, the limited transmission capacity available for imports into WUMS, and the relatively tight reserve margins within the WUMS region. These factors compound with other aspects of electricity markets, notably the inelasticity of demand and the lack of economic storage, to create an environment in which firms may readily exercise market power.

We do not examine the potential for 'local' market power -- that is market power possessed by specific generation units due to their location within the network. Because of network reliability concerns, the production of certain generation units is required, and there are no competitive substitutes for this production. The problem of must-run generation and local market power is one that afflicts every electricity market to some degree, and it should be an additional concern beyond the potential market power that we identify in this study.

We examine several alternatives for increasing the competitiveness of the WUMS market, including asset divestiture and transmission expansion. Our results indicate that neither of these measures are, by themselves, sufficient for creating a robustly competitive market. Given the current distribution of plant ownership, the lack of available transmission capacity and the lack of price-responsive demand, the costs of market power would almost certainly exceed any benefits that could be produced by a policy of restructuring. The costs of attempting to mitigate such market power by restricting bidding behavior or other forms of indirect regulation would also probably exceed the benefits of a restructuring initiative similar to those implemented in other states. Extensive changes to the distribution of ownership, combined with a considerable expansion of transmission capacity and the price-responsiveness of demand, could produce a reasonably competitive market at the wholesale level with a minimum of regulatory intervention. However, the results of this study indicate that the current market structure in Wisconsin is very far away from reaching the levels that policy makers could reasonably find workably competitive.

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Appendix

Table 10: WUMS generation capacities and costs

Unit Name	Owner	Capacity (MW)	Var. Cost ($/MWh)
Hydro CMarq	Cmarq	4	0.00
Plant 4 GT 1 1	Cmarq	23	69.26
Shiras 1	Cmarq	13	25.25
Shiras 2	Cmarq	19	24.62
Shiras 3	Cmarq	44	18.88
Hydro CWPC	CWPC	12	0.00
Hydro Gresh	Gresh	1	0.00
Hydro KAUK	Kauk	22	0.00
West Marinett 33	Marshfield	34	36.90
Blount St 1&2B	MGE	6	24.99
Blount St 3&11B	MGE	27	25.49
Blount St 5&6B	MGE	38	25.49
Blount St 6	MGE	53	20.93
Blount St 7	MGE	52	22.19
Blount St 7B	MGE	23	40.94
Columbia 1	MGE	118	11.91
Columbia 2	MGE	118	11.66
Fitchburg GT 1	MGE	21	46.56
Fitchburg GT 2	MGE	23	46.05
Kewaunee 1	MGE	94	11.40
Nine Springs 1	MGE	14	53.07
Rosiere	MGE	11	0.00
Sycamore 1	MGE	17	52.03
Sycamore 2	MGE	23	48.35
West Marinette 34	MGE	83	38.72
Custer	Manitowoc	25	38.70
Manitowoc 2	Manitowoc	5	30.00
Manitowoc 5	Manitowoc	22	21.56
Manitowoc 6	Manitowoc	32	21.42
Manitowoc C3	Manitowoc	20	29.58
Manitowoc Di C1	Manitowoc	11	45.75
Hydro Oconto	Oconto	1	0.00
Fort Howard 1	Other	12	15.89
Landfill Gas 1	Other	3	11.98
Milwaukee Cou NA	Other	11	16.05
MMSD 1	Other	12	38.72

Unit Name	Owner	Capacity (MW)	Var. Cost ($/MWh)
Winnebago Land 1	other	2	15.07
Gladstone 1	UPPC	13	24.43
Gladstone 1	UPPC	13	24.43
Gladstone 1	UPPC	27	79.11
Hydro UPP	UPPC	30	0.00
John H Warden 1	UPPC	18	42.07
Portage 1	UPPC	25	87.69
Concord GT 1	WEPCO	105	39.35
Concord GT 2	WEPCO	105	39.48
Concord GT 3	WEPCO	106	43.90
Concord GT 4	WEPCO	105	43.21
Edgewater 4	WEPCO	87	13.27
Germantown 5	WEPCO	85	38.72
Germantown GT 1	WEPCO	64	75.12
Germantown GT 2	WEPCO	64	75.12
Germantown GT 3	WEPCO	54	74.94
Germantown GT 4	WEPCO	64	75.12
Germantown Inlet Coolers	WEPCO	50	38.72
Hydro WEP	WEPCO	69	0.00
Neenaha	WEPCO	300	38.72
Paris 1	WEPCO	104	44.47
Paris 2	WEPCO	106	44.71
Paris 3	WEPCO	104	44.60
Paris 4	WEPCO	104	45.05
Pleasant Prair 1	WEPCO	603	9.75
Pleasant Prair 2	WEPCO	603	9.71
Point Beach 1	WEPCO	496	11.57
Point Beach 2	WEPCO	456	11.68
Point Beach 5	WEPCO	23	75.71
Port Washingto 1	WEPCO	80	20.38
Port Washingto 2	WEPCO	83	20.20
Port Washingto 3	WEPCO	84	23.92
Port Washingto 4	WEPCO	80	24.42
Port Washingto 6	WEPCO	23	81.58
Presque Isle 1	WEPCO	25	41.26

Unit Name	Owner	Capacity (MW)	Var. Cost ($/MWh)
Presque Isle 2	WEPCO	37	41.39
Presque Isle 3	WEPCO	58	19.11
Presque Isle 4	WEPCO	58	18.28
Presque Isle 5	WEPCO	87	18.33
Presque Isle 6	WEPCO	90	18.14
Presque Isle 7	WEPCO	85	19.83
Presque Isle 8	WEPCO	85	19.93
Presque Isle 9	WEPCO	88	20.68
South Oak Cree 5	WEPCO	262	13.54
South Oak Cree 6	WEPCO	265	13.56
South Oak Cree 7	WEPCO	298	13.38
South Oak Cree 8	WEPCO	313	13.55
South Oak Cree 9	WEPCO	25	51.90
Valley 1	WEPCO	64	20.38
Valley 2	WEPCO	62	20.38
Valley 3	WEPCO	70	20.38
Valley 4	WEPCO	70	20.38
Whitewater Cog 1	WEPCO	245	23.98
Wash Isle C7	WIEC	3	62.20
Blackhawk 3	WPL	28	49.68
Blackhawk 4	WPL	30	54.54
Columbia 1	WPL	247	11.46
Columbia 2	WPL	247	11.23
Edgewater 3	WPL	76	18.58
Edgewater 4	WPL	238	13.30
Edgewater 5	WPL	306	14.27
Hydro CastleR & Pent	WPL	13	0.00
Hydro WPL	WPL	39	0.00
Kewaunee 1	WPL	216	13.64
Nelson Dewey 1	WPL	110	15.85
Nelson Dewey 2	WPL	113	15.19
Rock River 1	WPL	82	17.94
Rock River 2	WPL	83	18.02
Rock River 3	WPL	32	64.58
Rock River 4	WPL	18	102.32
Rock River 5	WPL	68	102.59

Unit Name	Owner	Capacity (MW)	Var. Cost ($/MWh)
Rock River 6	WPL	71	102.42
Sheepskin 1	WPL	44	81.27
South Fond Du 1	WPL	92	46.35
South Fond Du 2	WPL	93	47.76
South Fond Du 3	WPL	90	46.66
South Fond Du 4	WPL	95	36.86
Hydro WPPI	WPPI	13	0.00
Kaukauna G&D 1	WPPI	7	59.48
Kaukauna G&D GT1	WPPI	18	58.40
Menasha 3	WPPI	9	32.99
Menasha 4	WPPI	15	29.34
Columbia 1	WPS	170	10.47
Columbia 2	WPS	170	10.48
DePere Phase I	WPS	179	38.70
Eagle River 1	WPS	4	52.54
Edgewater 5	WPS	130	13.79
Hydro CastleR & Pent	WPS	13	0.00
Hydro WPS	WPS	65	0.00
Kewaunee 1	WPS	217	11.40
Pulliam 3	WPS	28	16.66
Pulliam 5	WPS	50	15.69
Pulliam 6	WPS	70	16.85
Pulliam 7	WPS	86	12.21
Pulliam 8	WPS	141	11.85
West Marinett 31	WPS	43	47.55
West Marinett 32	WPS	43	46.71
West Marinett 33	WPS	72	38.78
Weston 1	WPS	68	15.98
Weston 2	WPS	85	13.64
Weston 3	WPS	337	12.09
Weston 31	WPS	23	53.09
Weston 32	WPS	62	45.06
Lincoln	WPS	9	0.00
Hydro CastleR & Pent	WRPC	13	0.00