Staff Report On Electric Industry Market Power
in
Michigan's Upper Peninsula

Prepared by the Staff of the Michigan Public Service Commission

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Executive Summary

The Michigan Legislature began the process of restructuring the State's electric industry with the enactment of 2000 PA 141.[1] An important policy goal of Act 141 is to introduce competition into the electric industry by offering Michigan ratepayers the opportunity to choose to purchase electric generation services from a competitive electric service provider. One purpose of the legislation was to promote reliable power at reasonable rates. The goal of promoting reasonable rates will not be realized, however, if one or a few suppliers can exercise market power and cause prices to increase unnecessarily. Act 141 requires the Commission to analyze and submit a report on the potential for market power in Michigan's Upper Peninsula (U.P.). This report fulfills that requirement. This report has been written by the Staff of the Michigan Public Service Commission, which is solely responsible for its contents.

Market Power

As used throughout this report, market power is defined as the ability of one or a few electricity providers to raise the price of electricity above the price that would exist in a competitive market for a significant period of time.

In order to measure market power, the study relies on market concentration ratios, sometimes called structural analysis, a model of strategic behavior, an analysis of transmission options, and a review of barriers to entry into the market by new suppliers. For this report, the Staff has performed its own analyses, has reviewed studies performed by others, and has reviewed comments from interested parties.

Structural Analysis

Section 10f of Act 141 includes a market concentration test that triggers required mitigation measures by an electric utility that fails the test. The Act 141 test requires several adjustments to each supplier's share of electric generation before the concentration ratio is calculated. The test establishes a threshold level of 30%, below which no remediation is required by the Act. According to Staff's calculations, presently none of the U.P. utilities exceeds the 30% threshold.

This study also examines the more widely used Herfindahl-Hirschman Index (HHI). This index is used by the Department of Justice Antitrust Division (DOJ), the Federal Trade Commission (FTC), and the Federal Energy Regulatory Commission (FERC) when these agencies review merger applications. The HHI is used to screen proposed mergers in order to identify those that are likely to create or enhance the exercise of market power.

Transmission and Barriers to Entry

As directed by the legislation, this report includes an analysis of transmission issues in the U.P. Transmission can play a vital role in mitigating market power created when one or a few firms own most of the generation in one region. With adequate transmission, electric generation providers can import power from other regions to compete with local generators. The report

[1] 2000 PA 141, the Michigan "Customer Choice and Electric Reliability Act", was signed into law by Governor Engler on June 3, 2000.

includes a description of transmission capacity into and through the U.P. and the effect of transmission constraints on competition and market power.

This report also reviews barriers to entry into the U.P. market through control of essential resources. Some of the most important resources include generation fuels, fuel delivery systems, and potential generation plant sites.

Behavioral Model

A model of strategic behavior is also used in the report to detect the ability of one or a few firms to profit from withholding electricity from the market in order to raise prices. In so doing, the model explicitly considers the effect of increasing prices on the demand for electricity and the likely reaction of other suppliers to the 'strategic" behavior of one or a few large firms.

The study also involves a review of similar models that have been used recently to analyze the potential for market power in the integrated Wisconsin Upper Michigan System (WUMS).

Conclusion

As noted previously, none of the U.P. utilities currently exceeds the remediation threshold identified in Act 141 for market power. Most commenters, however, articulated deficiencies in and disagreement with the Act 141 test .

The HHI analysis closely followed the methodology developed by the FERC. This index is widely used in the antitrust field and frequently cited in academic literature. The study made use of available capacity and uncommitted capacity to calculate the HHI concentration ratios. Markets for firm and non-firm power, for on-peak and off-peak power were analyzed for this report. The results reveal that the U.P. is a highly concentrated market with most capacity under the control of Wisconsin Energy Company (WEC). WEC has two subsidiaries that operate in the U.P., Wisconsin Electric Power (WEPCO) and Edison Sault Electric (EDSE). WEPCO owns the Presque Isle power plant, which represents approximately 50% of the U.P.'s capacity. Results of the behavioral model indicate that if price regulation were abandoned, WEC could indeed exercise market power. These results mirror the findings of a study prepared for the Public Service Commission of Wisconsin.

Transmission into and through the U.P. is constrained at various times throughout the year. This limits the ability of current transmission facilities to alleviate market power that may be exercised by an electric service provider. The newly incorporated American Transmission Company (ATC), however, is including the U.P. in its planning process. The ATC is a single purpose provider of transmission service and covers most of the U.P. None of the major transmission expansion projects inherited by the ATC from its contributing owners are currently scheduled for the U.P. However, ATC's planning process is just beginning and is expected to address U.P. transmission constraints. The ATC has also included a redispatch option in its open access tariff, which may facilitate use of the transmission system by new market participants.

Aside from the transmission issues, Staff is not aware of any significant barriers to entry into the U.P. market. Barriers to entry can result when one supplier controls one or more resources needed to efficiently produce electricity. These resources include fuel, fuel delivery systems, possible plant sites, and other inputs.

At the present time, it is difficult for WEC to exercise market power, since retail price regulation is exercised by the Michigan Public Service Commission, and wholesale by the

FERC. There is also currently an advantage to WEC's Michigan customers because of the Company's ownership of Michigan generation. This U.P. generation is used in conjunction with WEC's Wisconsin generation and loads to reduce costs below those that would be incurred if the U.P. and Wisconsin systems were operated separately. If prices are deregulated, however, the Company will likely have the ability and incentive to exercise market power.

Recommendations

Several recommendations have been provided by commenters to mitigate potential market power in the U.P. Some of these include requiring WEC to divest its Presque Isle power plant and relinquish its control of transmission capacity. The U.P. market, however, is not yet deregulated, and it is unclear how quickly customers may leave their regulated utilities when given the choice to do so. Therefore, it appears premature to require divestiture of the Presque Isle plant. For the time being, the best apparent strategy for avoiding market power in the U.P. is to increase transmission capacity into and through the area. It may also involve, as part of a comprehensive mitigation strategy, giving customers options that they need to manage any potential price manipulation.

Staff specifically recommends that WEC be required to file a market power mitigation plan with the Commission in eighteen months. The plan should include an assessment of the ATC's plans and its progress in implementing transmission expansion in the U.P., the efforts undertaken by WEC to encourage transmission expansion, and other steps taken by WEC to mitigate potential market power in the U.P.

I. INTRODUCTION

On June 3, 2000, Governor Engler signed into law PA 141 (Act 141) and PA 142 (Act 142). These two Acts amended 1939 PA 3, which establishes the power, authority, duties, and obligations of the Michigan Public Service Commission (Commission). With the enactment of Acts 141 and 142, the Michigan Legislature began restructuring Michigan's regulated electric utility industry into a competitive industry.

Until recently, the electric utility industry was composed primarily of vertically integrated utility companies providing generation, transmission, and distribution services. Electric utilities were usually awarded exclusive franchises to serve specific "service territories" on a cost-plus ratemaking basis. Nearly all of the states granted monopoly privileges to electric utilities in exchange for the utilities being subject to cost-of-service price regulation. Beginning in the early 1980's, attempts have been made by the federal government to encourage competition in the wholesale generation component of the industry. Within the past five years, states have also begun to introduce competition into the retail electric utility industry. Today, price regulation is still practiced by this Commission for retail service and by the FERC for wholesale service, although many wholesale suppliers can now charge market-based rates and Michigan retail customers are being given the option to select competitive electric generation suppliers. Act 141 will eventually allow most Michigan electric customers the opportunity to select a competitive supplier. [2]

As markets are opened to competition and customers are permitted to select suppliers, it is important that incumbent utilities not be permitted to take advantage of their existing assets and market positions to subvert competition. Numerous media reports cite allegations of market power leading to price manipulation in the newly deregulated California and New York markets. Without discussing the merits of these allegations, it should be noted that major market centers (Northeast, PJM, New York, and California) have implemented market monitoring programs as an integral component of their structures. If competition is to yield any benefits to consumers, it cannot be thwarted through the exercise of market power. Among the many provisions of Act 141 was the requirement for the Commission to prepare a market power report of Michigan's Upper Peninsula (U.P.). Act 141 in Section10f (6) states:

> "Within one year of the effective date of the amendatory act that added this section, the commission shall issue a report to the governor and the legislature that analyzes all aspects relating to market power in the Upper Peninsula of this state. The report shall include, but not be limited to, concentration of generating capacity, control of the transmission system, restrictions on the delivery of power,

[2] The Michigan Public Service Commission regulates investor owned utilities and member owned cooperative utilities. The investor owned and cooperative utilities are required by Act 141 to permit their customers to select alternative generation suppliers. The Commission's jurisdiction does not include municipally owned utilities. Section 10y of 2000 PA 141 covers municipal utility participation in the customer choice program. Staff is not aware of any municipals that have instituted such a program.

> ability of new suppliers to enter the market, and identification of any market power problems under the existing market power test."

As required by Act 141, the Commission opened Docket No. U-12533 to solicit public input. One public hearing on this matter was held in Escanaba on September 13, 2000, and another was held in Lansing on September 19, 2000. Verbal comments were received from the public, and written comments were scheduled for filing with the Commission by October 4, 2000. Formal written comments were received from Wisconsin Electric Company and Edison Sault Electric, the Upper Peninsula Transmission Dependent Utilities, the American Transmission Company LLC, Wisconsin Public Service Corporation and Upper Peninsula Power Company, the Michigan Municipal Electric Association, International Paper Company, Mead Paper Company, the Michigan Electric Cooperative Association, and the Michigan Chamber of Commerce. Public input on market power in the U.P. provided valuable information and insights and greatly assisted the Staff in the preparation of this report.

The purpose of this report is to analyze the market power issues identified in Section 10f (6) of Act 141, report conclusions based on that analysis, and make appropriate recommendations. An essential part of any market power study is a definition of the product market. For purposes of the market power test included in Act 141, the relevant market is for generation services in the entire U.P. The language of Act 141, however, permits a comprehensive approach to this study. Staff recognizes the existence of multiple product markets in the U.P. Adopting common practices for conducting this type of study, Staff examines the retail and wholesale markets, on-peak and off-peak, for firm and non-firm power.

In preparing this report, Staff also examined a market power report prepared for the Public Service Commission of Wisconsin (PSCW) by the economic consulting firm of Tabors Caramanis & Associates. The PSCW was required to conduct and submit a market power report to the Wisconsin Legislature in the year 2000. The report covered the Wisconsin Upper Michigan System (WUMS), which includes the U.P. of Michigan. Because of the highly integrated nature of WUMS, this report is relevant to examining market power in the U.P. Staff's review included comments made by WEC concerning the Wisconsin Commission's report. Staff also examined a report and study prepared by the Customer First Coalition of Wisconsin regarding market power in Wisconsin. Staff's review included the Federal Energy Regulatory Commission's (FERC) merger policy guidelines, and criteria for establishing market-based rates. Finally, Staff also incorporates by reference its Market Power report of June 5, 1998. The findings in this report reflect Staff's investigation into market power issues in the U.P. of Michigan.

Staff's analysis of the electric utility industry in Michigan's U.P. demonstrates that control of power generation service is highly concentrated, with WEC subsidiaries controlling most electric generation and transmission in the U.P. At this time, WEC is constrained from exercising market power by retail and wholesale price regulation exercised by this Commission and the Federal Energy Regulatory Commission (FERC) respectively. In the absence of this regulation, Staff concludes that WEC has the ability to exercise market power in the U.P. Until markets are deregulated, however, Staff finds that there are advantages to WEC's control of a major portion of the U.P.'s production capacity and does not recommend a major restructuring of the market at this time.

II. Upper Peninsula Industry Profile

U.P. electricity use in 1999, the latest complete year for which data has been compiled, was approximately 5.5 million Megawatt hours (MWh). This compares to the approximately 90 million MWh used in Michigan's Lower Peninsula in the same year. Total peak demand (non-coincidental) in that year is estimated to have been approximately 900 Megawatts (MW). For comparative purposes, the Lower Peninsula's coincidental demand was about 19,000 MW.

The electric utility industry in the U.P., serving over 190,000 customers, consists of five investor owned utilities, three electric cooperatives, nine municipal utilities, and several industrial facilities that have their own electric generators. A list of utilities and their annual sales is shown on page one of Appendix A. Wisconsin Electric Power (WEPCO) and Edison Sault Electric (EDSE) are both wholly-owned subsidiaries of WEC, with headquarters in Milwaukee. Wisconsin Public Service (WPS) and Upper Peninsula Power Company (UPPCO) are wholly-owned subsidiaries of WPS Resources, of Green Bay.

WEPCO, alone, accounted for over 50% of the U.P.'s electric energy sales in 1999. The WEC subsidiaries, WEPCO and EDSE, together made 64% of the 1999 sales. Figure 1 shows 1999 U.P. electricity sales by utility. Most of WEPCO's U.P. sales were to the Empire and Tilden mines. Of WEPCO's 1999 Michigan energy sales totaling 2,923,501 MWh, 74%, or about 2,170,970 MWh, were made to these two accounts. In fact, the two mines accounted for approximately 39% of the entire U.P.'s 1999 energy sales. The Empire and Tilden mines, because of their size and energy use patterns, have a significant impact on the U.P.'s electric load profile.

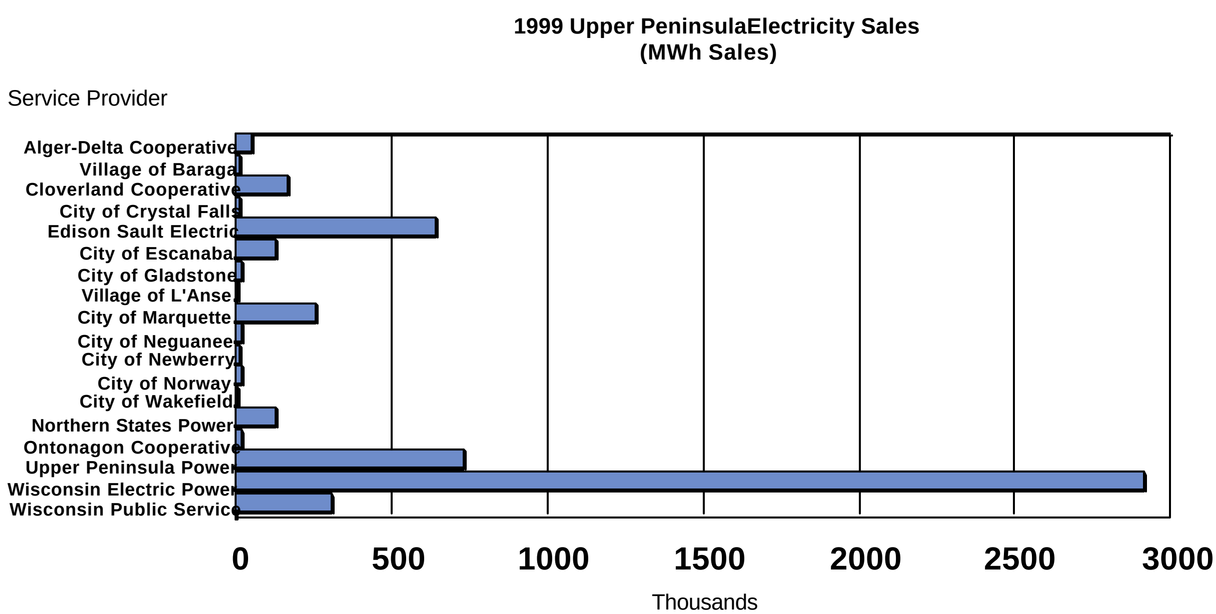

Figure 1

U.P. peak demand by month for 1999, with the mines' demands highlighted, is shown in figure 2. Generally, monthly peak demand data is "flatter" in the U.P. than in the Lower

Peninsula or the State. This is due to greater penetration of air conditioning load and hotter, more humid summer weather in the Lower Peninsula, which causes sharp summer peaks. The U.P. load profile is also influenced by the relatively large volume of sales accounted for by the high-load-factor mines. These high-load-factor loads have historically caused the U.P. to experience a relatively flat load curve, with a modest winter peak. In the last few years, however, air conditioning load has grown in the summer tending to give the U.P. both summer and winter peaks. Page two of Appendix A shows the 1999 monthly peaks by utility.

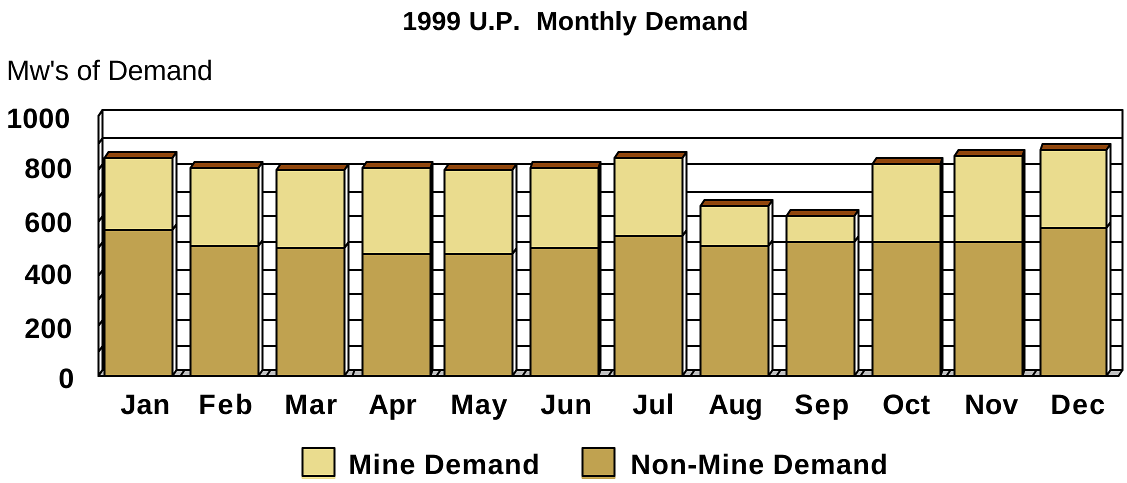

Figure 2

The U.P. power supply and transmission systems are essentially divided into two previously separated systems, the eastern side and the western side. The electrical transmission system has interface connections with three regions: the Mid-America Interconnected Network (MAIN), East Central Area Reliability (ECAR) region, and the Mid-America Power Pool (MAPP) – although the MAPP connection is for a small Northern States Power load in the far northwest section of the U.P. Despite the interconnections, transmission constraints limit the transmission of power into and across the U.P. Ownership of U.P. generating resources is shown in figure 3. As seen from that figure, WEPCO, on its own, controls 64% of the U.P.'s non-industrial owned generating capacity, and 72% when considered in conjunction with its sister company EDSE.

1999 Ownership of Generation Resources

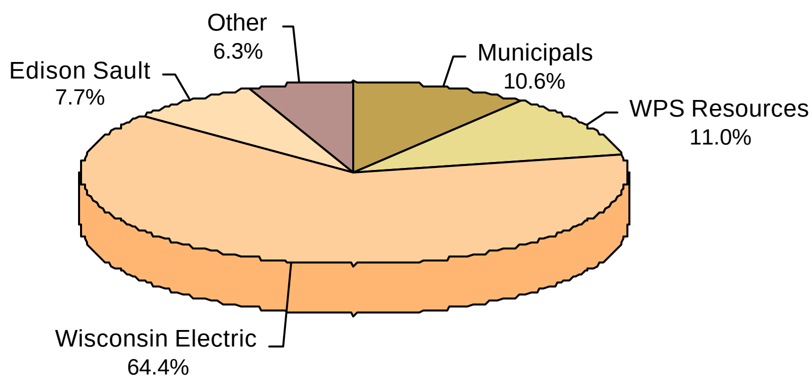

Figure 3

Pages three and four of attached Appendix A contain an inventory of generating and transmission resources by owner, fuel type, and capacity for summer and winter periods.[3] The U.P.'s largest single generating resource is the Presque Isle plant owned by WEPCO. The plant consists of nine coal fired units capable of producing 617 MW of electricity, in total. This plant, alone, represents nearly 50% of the U.P.'s generating capability. As seen on pages three and four of Appendix A, the U.P.'s largest category of generating capacity is comprised of coal-fired steam units. Although hydro electric generators are numerous, they account for only a modest portion of the U.P.'s (especially the western U.P.'s) generating capacity. The largest hydro facility in the western U.P. is WEPCO's Big Quinnesec station at 15 MW of capacity. Altogether, WEPCO owns about 79 MW of hydro capacity in Michigan's U.P.

WPS and UPPCO, both owned by WPS Resources Holding Company, collectively own about 100 MW of generating capacity located in the U.P. Many of these units, however, run at higher operating costs, so UPPCO relies on purchased power for about 86% of the energy needed to serve its customers.

The cities of Marquette and Escanaba have about 130 MW of hydroelectric, coal-fired and oil/gas generating capacity. Marquette and Escanaba are generally self-sufficient from a capacity and energy standpoint, although they do buy and sell non-firm energy as needs and opportunities arise.

In the eastern U.P., about 72 MW of generating capacity is provided by Cloverland, Edison Sault and the City of Newberry. EDSE owns and operates about 30 MW of hydroelectric generation and 4 MW of diesel generation. Along with Cloverland it shares the purchase of about 20 MW of hydroelectric generation from the U.S. Army Corps of Engineers. Hydroelectric generation provides about 40% of EDSE's total energy requirements. The exact amount of hydro capacity and energy can vary from year to year, depending on water flow in the St. Mary's river.

The second and third largest single sources of power in the U.P. are the transmission interconnections between the U.P. and Wisconsin and the U.P. and the Lower Peninsula,

[3] Summer and winter generating capability can be different for some electric generating units.

respectively. The U.P. has two significant interconnections with the remainder of the U.S. EDSE connects the eastern part of the U.P. to Consumers Energy in the Lower Peninsula at the McGulpin substation. The connection consists of two sets of 138 KV submarine cables, with both normally energized. Transformer capacity at the McGupin substation limits the interconnection to120 MW of capacity. The second interconnection is located at the Plains substation, previously owned by WEPCO. The substation, is now owned and operated by the American Transmission Company (ATC). The interconnection consists of one 345 KV and two 138 KV lines from Wisconsin. First contingency constraints limit transmission capacity to 220 MW of power from Wisconsin into the U.P. but permit 475 MW of power flow from the U.P. into Wisconsin.

Until April 2000, the eastern and western portions of the U.P. power grids were essentially two separate systems. The Central Upper Peninsula Transmission line (CUPT) was completed in that month. It now provides approximately 70 MW of transfer capacity between the eastern and western portions of the U.P. The CUPT line is a 138 KV circuit that terminates at EDSE's 69 KV system. The 69 KV system effectively limits east/west power flows to approximately 70 MW of firm transmission capacity. Even this limited capacity, however, is not available throughout the entire year because of parallel flows through the U.P.[4]

On January 1, 2001, ownership and control of the transmission assets of WEPCO, WPS, and EDSE were transferred to the American Transmission Company (ATC). UPPCO and Cloverland Electric Cooperative are also scheduled to transfer ownership of their transmission assets to the ATC. The ATC is a transmission company formed in response to incentives provided by Wisconsin legislation. The state of Wisconsin encouraged utilities to transfer control of their transmission assets to an independent company with the sole purpose of providing transmission services. Each utility transferring transmission assets to the ATC received a pro rata share of ownership in the ATC. Because of its relatively large size, WEC, through its subsidiaries, holds the largest single equity position in the ATC – about 46%. Interconnected U.P. utilities with transmission assets to transfer to the ATC have also been permitted to join the ATC. However, transmission dependent utilities in Michigan, with no transmission assets to transfer, have not been permitted to invest in the ATC.

Since WEPCO has transferred its assets to the ATC, the transmission tie between the western U.P. and Wisconsin is now owned by the ATC. However, due to the tariff adopted by FERC for the ATC, WEPCO is permitted to retain firm, year-round control of 175 MW of firm transmission capacity through the Plains substation by predesignation of network resources and loads. Some commenters would characterize the predesignation of resources and loads as equivalent to a rollover of firm-service capacity rights. The remaining 45 MW are controlled by WPS (40 MW) and the industrial companies (5 MW). The ATC tariff does include an option for redispatch that can, depending on the requested transaction, effectively expand transmission options into the U.P. Redispatch options are discussed on pages 19 and 21 of this report.

In addition, there are six industrial sites in the U.P that employ self-service power. These units, shown on pages three and four of Appendix A, do not generally participate in retail or wholesale markets.

The Western U.P. market is highly integrated with the eastern Wisconsin region. Load control is exercised by WEPCO for its U.P. load, for EDSE, and for Cloverland. WPS exercises load control for its U.P. load and for UPPCO.

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[4] Parallel flows consist of unscheduled flows over a transmission path and can limit the amount of firm or non-firm service to an amount less than the rated capacity of the transmission path.

III. Market Power

Market power is defined as the ability of a firm, or a group of firms, to profitably raise the market price of a product above the price that would prevail in a competitive market and maintain that higher price for a significant period of time. In a truly competitive market, no single firm or group of firms can determine market prices. Instead, competitive firms are "price takers" and must accept the market price, as determined by supply and demand, as a given. If the number of sellers in a market is small enough, however, one participant or a small group (acting in concert) may be able to influence prices by their decisions on how much of a commodity to produce. In the electric utility industry, a firm could exercise market power in either the generation, transmission, or distribution markets. Since transmission and distribution remain regulated, however, the market power issues of most direct interest to policymakers involve the electric generation market. Market power can significantly erode the consumer benefits that would be expected to result from the transition from regulated to competitive markets for electricity generation services.

Staff's Market Power report of June 5, 1998 (p. 5-10) identified two types of market power, horizontal and vertical. Horizontal market power is exercised when a firm profitably drives up prices through its control of a single activity, such as electric generation, where it controls a significant share of the total capacity available to the market. The issue of horizontal market power is important in the U.P. electricity market because generation capacity and control of transmission resources is highly concentrated. This concentration could prevent new suppliers from entering the market, which would defeat the objectives of the competitive market initiatives included in P.A. 141.

Vertical market power is exercised when a firm involved in two related activities, such as electricity generation and transmission, uses its dominance in one area to raise prices and increase profits for the overall enterprise. Electricity markets have historically been structured as vertical monopolies with franchise territories. Within these franchise territories, electric utilities commonly own multiple generators. By controlling transmission in a geographic franchise territory, a utility could limit the import/export of power from/to other areas. This arrangement potentially allows one or a few generating plant owners to restrict output at one or more plants, which causes prices to rise for the power produced at all of their other units. Vertical market power may be easier to address because mechanisms have been adopted that limit a firm's operating discretion, such as independent operation of the transmission system on a non-discriminatory basis. In fact, the creation of the ATC with its open access tariff is a potentially important step in ameliorating vertical market power.

IV. Measurement of Market Power

In addition to the market power test prescribed in Act 141, there are two broad analytical measures of market power used extensively in anti-trust cases and found throughout economic literature. Also, anecdotal experience can yield insight into the existence of market power. The two analytical measures include industry concentration measures and strategic, or behavioral, models. Generally, concentration measures can be used to indicate the likelihood that market power exists, while strategic models can predict whether market power can be exercised.

Concentration measures, or ratios, have been developed and used by the Federal Trade Commission (FTC), the Department of Justice Antitrust Division (DOJ), and the Federal Energy Regulatory Commission (FERC). These measures are discussed widely in academic literature and used frequently as one gauge of market power. The principal concentration index used by the DOJ and FTC is the Herfindahl-Hirschmann Index (HHI). FERC has modified FTC and DOJ concentration measures to address the unique characteristics of the electric industry. FERC uses the modified HHI index as an important screening tool for determining whether proposed mergers between utilities are likely to result in the creation or enhancement of market power. A discussion of the HHI is also found on pages 34 to 39 of the Staff's June 1998 market power report. FERC also uses the percentage of generation ownership under a utility's control (a related concentration measure) when determining whether the utility should be allowed to sell wholesale energy at market prices instead of at cost-based regulated rates. The percentage ownership determination is the first step in calculating an HHI index number.

One important limitation of concentration measures is that even high concentration ratios do not mean that market power can actually be exercised. The existence of other potential suppliers and the elasticity of demand must also be considered in determining whether market power can actually be exercised. A firm cannot effectively exercise market power if customers can easily turn to alternative providers or curtail their demand significantly as prices rise. To account for these factors, many market power studies also use "strategic", or game based, models.

Strategic models are based on economic theory and widely observed behavior that predict the exercise or absence of market power in various markets. The most commonly employed formats include Bertrand, Cournot/Nash, and supply function equilibrium (SFE). These models are based on the assumption the utility companies are "profit maximizing" entities. The models are designed to predict whether the structure of the market permits one or a small number of firms, acting as profit maximizers, to exercise market power by raising prices above the competitive equilibrium price. That is, the models test for the ability of firms to withhold production, thereby increasing prices above the competitive price level in order to raise profits. This type of an analysis explicitly considers demand for the product and the availability of alternatives and yields information on whether this market power can actually be exercised.

Anecdotal experience can also yield insight into the exercise of market power. In Staff's review of comments from interested parties, it recounts the observations and concerns made by participants in the U.P. electricity markets.

V. Act 141, Section 10f Market Power Test

Act 141, Section 10f, describes a market power test to determine if and when a utility subject to this section of the act will be exempted from "capped" rates. The test separates Michigan into two markets, the Lower Peninsula and the Upper Peninsula. Section 10f states:

> "Sec. 10f. (1) If, after subtracting the average demand for each retail customer under contract that exceeds 15% of the utility's retail load in the relevant market, an electric utility has commercial control over more than 30% of the generating capacity available to serve a relevant market, the utility shall do one or more of the following with respect to any generation in excess of that required to serve its firm retail sales load, including a reasonable reserve margin:
> (a) Divest a portion of its generating capacity.

(b) Sell generating capacity under a contract with a non-retail purchaser for a term of at least 5 years.
(c) Transfer generating capacity to an independent brokering trustee for a term of at least 5 years in blocks of at least 500 megawatts, 24 hours a day.
(2) The total generating capacity available to serve the relevant market shall be determined by the commission and shall equal the sum of the firm available transmission capability into the relevant market and the aggregate generating capacity located within the relevant market, less 1 or more of the following:
(a) If a municipal utility does not permit its retail customers to select alternative electric suppliers, the generating capacity owned by a municipal utility necessary to serve the retail native load.
(b) Generating capacity dedicated to serving on-site load.
(c) The generating capacity of any multi-state electric supplier jurisdictionally assigned to customers of other states."

The results of the legislative test for the U.P. are shown on page five of Appendix A and indicate that none of the U.P. utilities exceeds the 30% generation threshold described in the Act. Staff's test relies on 1999 data, the latest complete set available, in performing this test. For purposes of the test, WEPCO and EDSE are treated collectively, since these two companies are affiliates. Likewise, WPS and UPPCO are treated collectively for the same reason. Two significant adjustments are necessary to the raw capacity data appearing on page three of Appendix A. As required by the Section 10f(1) test, Staff has included only 8% of WEPCO's U.P. generating capacity in the test. Staff's allocation of U.P. generating capacity makes use of the 75% demand, 25% energy allocator adopted by this Commission in numerous cases and is based on actual 1999 data. Likewise, as required by the Act, Staff has reduced the Company's available capacity by the average demand of customers constituting more that 15% of its retail load, in this case 248 MW for the Empire and Tilden mines. As a result of these adjustments, the highest measure of concentration, calculated according to the provisions of Act 141, is approximately 24%. This is below the 30% threshold established by the legislature for triggering market power remedies. Therefore, at this time, none of the utilities in the U.P. exceeds the test threshold, and it is not necessary for any of them to undertake the remedial action described in the Act.

<u>Discussion of Comments on PA 141 Market Power Test</u>

Comments filed on behalf of the Upper Peninsula Transmission Dependent Utilities (UPTDU) reach a different conclusion regarding this test. The Michigan Municipal Electric Association (MMEA) and the Michigan Electric Cooperative Association (MECA) also support UPTDU's assessment. According to UPTDU's calculation, WEPCO controls at least 47.1% of the generating resources in the U.P., after adjustments required by Act 141. The UPTDU concludes that this level is above the 30% market power threshold identified in Act 141. Two major differences between Staff's approach and that of the UPTDU occur in calculating the numerator of this ratio. According to UPTDU, the net amount of WEPCO's U.P. capacity that should be assigned to Wisconsin is 287.4 MW instead of 641 MW that Staff allocated to Wisconsin. Staff's analysis used a jurisdictional capacity allocation of approximately 92% to Wisconsin and 8% to Michigan. In its comments, the UPTDU argues that a 75% demand and

25% energy allocator based upon WEPCO's 1998 rate case filing (U-11837) should be used for this calculation. UPTDU takes the additional step of including WEPCO's Wisconsin-based generation that is allocated to Michigan customers into the numerator for the calculation. Staff does not believe that Act 141 permits the inclusion of this generation and, therefore, did not include it for purposes of conducting its test. The UPTDU's methodology caused WEPCO's Michigan allocated capacity to be 287.4 MW, compared to Staff's 55 MW.

The second major difference in calculating this ratio involves the amount of Empire and Tilden mines' capacities that should be removed from the numerator. According to the UPTDU, the average demand of large customers should be 157 MW instead of the 248 MW used by Staff. The 91 MW difference in the large customer adjustment used by Staff and UPTDU arises from Staff's use of 1999 actual average demands while UPTDU used 12 monthly coincidental demands from the 1998 MPSC Case No. U-11837.

The UPTDU concludes that WEPCO is in a clear position to control the generating market in the Western U.P. because of the concentration of generating resources that it possesses. The UPTDU members assert that a competitive market cannot develop in the U.P unless remedial action is taken by the State of Michigan, including the Commission where appropriate, to mitigate WEPCO's control of both generating resources and transmission access.

International Paper Company (IP) states it is vitally concerned with electric restructuring in Michigan and encourages the development of a competitive market. In IP's opinion, WEPCO has market power in the U.P. regardless of the calculation set forth in Act 141. Recent merger activity by WEC, WEPCO's parent, has increased IP's concern over vertical market power. According to IP, WEC's plan to add significant generating capacity and restructure the generation portion of its current utility business should be evaluated for its impact on market power. IP also argues that the adjustments required by Act 141 are fallacious. Although Act 141 requires the allocation of most of WEPCO's U.P. generation to Wisconsin, IP notes that in reality energy would flow to Wisconsin only when it is not needed to serve U.P. load. IP urges that meaningful mitigation measures be established for the U.P. market.

WPS and its affiliated utility, UPPCO, state that regardless of the results of the Act 141 calculation, electric generation in the U.P. is highly concentrated. They contend that because of generation and transmission constraints, the U.P will incur restrictions on delivery of power from generation suppliers other than the existing suppliers located in the U.P. WPS and UPPCO state this situation creates an impediment for new generation suppliers to enter the market. The WPS Resources Companies also state that there appears to be no available firm transmission capacity out of the U.P. Thus, they say not only would any new suppliers have to compete with lower cost existing U.P. generation, but there is also very limited potential for any new U.P. suppliers to sell energy into markets outside the U.P. Regarding the market power test in Act 141, they believe that it does not follow traditional approaches. However, the Companies recognize that Act 141 has provided reasonable market protection by requiring that all utility generation needed to serve native load customers will remain under the MPSC's cost-based regulation. Therefore this generation can not be used to extract monopoly rents in the U.P.'s capacity constrained market. The WPS Resources Companies conclude that before FERC and MPSC cost based regulatory controls over utility regulation are relaxed or eliminated, market power must first be eliminated through generation divestiture, the emergence of new non-affiliated generation suppliers, and the expansion of transmission capacity into and out of the U.P.

WEPCO argues that those who contend the Act 141 test is flawed incorrectly assert that majority ownership equates to market power. WEPCO states that it is a multi-state company that operates its generation resources as an integrated system to serve customers' loads irrespective of which state the generation is located in. Total generation costs are jurisdictionally allocated to each state for rate-making purposes on the basis that reflects each state's share of WEPCO's total generation requirements. WEPCO argues that its generation capacity is fully committed to satisfy its Wisconsin and Michigan peak load obligations. The Company also argues that although the U.P. exports generation capacity to Wisconsin to meet summer peak demand, the U.P. is a net importer of energy from Wisconsin. The WEC Companies state that this represents a unique and mutually beneficial relationship and results in a lower-cost blended generation benefiting U.P. customers. According to WEPCO, divestiture of its U.P generation would disrupt the ability of Michigan customers to benefit from lower cost Wisconsin generation and deprive Wisconsin customers of generating capacity upon which they depend. According to WEPCO, the sale of the Presque Isle Power Plant to another owner would only transfer any market power concern from WEPCO to a new owner. According to the Company, Act 141 fairly recognizes that one customer, Cleveland Cliffs, Inc. (CCI), is the largest customer in the U.P. and accounts for nearly 50% of the generation capacity owned by WEPCO. It also recognizes that capacity committed to load at regulated or contractual prices is not available to manipulate market prices. WEPCO concludes that it is necessary to distinguish between the appearance of market power and the actual ability to exercise market power.

Staff Conclusions on Public Comments

Having reviewed the comments, Staff recognizes that most parties would be uncomfortable with the Act 141 test as the sole measure for market power. The unadjusted generation and transmission concentration ratio for the WEC companies of 65%, found on page three of Appendix A, demonstrates a highly concentrated market. Nevertheless, Staff is convinced by its application of the test that no utility in the U.P. triggers the statutory remediation threshold of 30%, after the test's required adjustments are made. This contradiction demonstrates an important limitation of the Section 10f(1) test. For example, despite controlling two-thirds of the generation and transmission import capacity into the U.P., WEC (WEPCO and EDSE) is allocated only 24% of the capacity under the PA 141 test. The largest single plant in the U.P. is the coal fired Presque Isle plant owned by WEPCO. The plant has a capacity of 617 MW and represents approximately 50% of both the generation capacity in the U.P. and transmission capacity into the U.P. The test requirements in PA 141, however, result in only 70 MW allocated to the U.P., an amount that UPTDU points out is insufficient to serve WEPCO's U.P. load requirements.

Section 10f(6) requires the Commission to "analyze all aspects relating to market power in the Upper Peninsula (U.P.) of this state". The analysis is required to "include, but not be limited to, concentration of generating capacity" (Section 10f(6)). Staff interprets this charge to mean that its analysis should not stop with the Section 10(f)1 test. Instead, Staff recognizes that in terms of measuring the concentration of generating capacity, the 10f(1) test has some important limitations. The 10f(1) test does not adequately predict the amount of capacity actually available to serve the U.P. market.

VI. Alternative Measures of Market Concentration

Competitive markets are characterized by many producers and sellers, each holding a small segment of the entire market. If the number of producers declines, and each remaining producer acquires a greater share of the market, the degree of competition will likewise decline. If this occurs, it becomes easier for each remaining producer to exercise market power. Therefore, the degree of market concentration is considered an important determinant of whether a market is competitive and an indication of whether market power can be exercised by one or a small number of firms. As another measure of market power, Staff has examined the market concentration measures used by the Department of Justice (DOJ) and Federal Trade Commission (FTC). These measures are widely used in studies of market concentration and anti-trust reviews. They also form the basis of the Federal Energy Regulatory Commission (FERC) analysis of market power. The concentration measure most widely relied upon is the Herfindahl-Hirschmann Index (HHI). The single producer index or other indexes are also cited in market power studies.

The HHI, a widely used concentration measure, determines market concentration by computing the sum of the squared market shares of each competitor. The DOJ, FTC, and FERC use the HHI as a primary screening tool to identify whether, following a merger, a market is likely to have enough competitors to be workably competitive.[5] The maximum value of the HHI is 10,000 and occurs in a perfect monopoly, with one firm supplying the entire market. In a perfectly competitive market, there are many firms with each accounting for a small portion of the market. Therefore, one would expect to find a comparatively small HHI value in a competitive market. For example, 100 firms, each possessing 1% of the market, would produce an HHI of 100. Normally, a proposed merger that would result in a market with an HHI of less than 1,000 is not considered to pose adverse competitive effects. Proposed mergers that result in a market with an HHI between 1,000 and 1,800 and result in a change in the HHI value of 100 or more are considered to have potentially significant competitive concerns. If a proposed merger results in an HHI value greater than 1,800, and the change in HHI is greater than 50, the merger likely would raise significant competitive concerns. Mergers producing an HHI greater than 1,800 and increasing the HHI by more than 100, are considered likely to create or enhance market power. When reviewing a merger, the Federal agencies also consider other factors such as efficiency gains, whether the assets would exit the market in the absence of the proposed merger, and other extenuating circumstances that would materially influence the competitive outcome of the proposed merger. Nevertheless, the Agencies use the HHI as an important measure of market concentration and an indication of the likely effects of that concentration on competition in the market being considered in the merger. Staff does not use the HHI index for assessing the desirability of a merger in this report, but instead as an important measure of concentration in the existing market structure.

It must be stressed that no single indicator of market power should be accepted blindly. The amount of concentration in U.P. markets that exists today evolved under a rate-regulated, exclusive franchise system. Looking at the current concentration ratio is similar to looking at a history of the market. This may not be indicative of what the market would look like under full competition. Other factors such as the availability and closeness of substitutes for a good or service, impediments to or ease of entry of potential competitors into the market, and the

[5] See the FERC web site at www.ferc.fed.us/electric/mergers/mrgrpag.htm. for a description of this methodology.

responsiveness of demand to changes in prices are important determinants of whether market power can be exercised by a firm.

All market power studies must begin by identifying the market being analyzed. This usually involves a geographical region as well as product definitions. For purposes of this report, Act 141 defines the geographical market as the U.P. of Michigan, which conforms conveniently to the transmission constraints that limit power flows into and out of the region. Product definitions in the electric industry are generally based upon demand conditions in the market and reliability of the product. To account for demand intensity, Staff has analyzed on-peak and off-peak conditions in the U.P. and to account for reliability, Staff has examined firm and non-firm power markets.

Most tests required by and submitted to the FERC are short-run tests, and the tests that Staff has conducted for this report follow that format.[6] In order to demonstrate that a firm does not possess long-run generation dominance, or market power, the FERC requires an applicant to show that it does not control essential inputs or transmission in a market. The transmission criteria can usually be satisfied by submitting an open access transmission tariff. In order to show the lack of dominance of a major input, the applicant is usually required to show that it does not control fuel, fuel transportation into a market, likely plant sites, etc. Aside from transmission, discussed later, Staff is not aware of any participants controlling any other of these essential inputs in the U.P. market. Therefore, Staff has concentrated on the short-run markets in analyzing concentration measures in the U.P.

Beginning on page six of the Appendix A, HHI values are computed for various power markets in the U.P. The procedure used to calculate the values closely follows the methodology adopted by the FERC for measuring capacity. This includes assigning generation and transmission capacity to those entities that own or control this capacity, deducting firm sales to other entities, and adding any firm purchases. The FERC procedure calculates the total capacity available to each market supplier. If markets were fully deregulated, this would represent a crucial measure of market concentration. However, absent full deregulation, each utility maintains an obligation to serve its full service (tariff) customers, and this obligation must be deducted from each utility's total transmission and generation capacity. The amount of capacity necessary to satisfy this obligation varies as demand from the utility's customers varies throughout the year. This produces different markets; markets for on-peak, off-peak, firm, and non-firm power. When a company's native load obligation is deducted from its total capacity, the result is the firm's available, or uncommitted, capacity. Staff has calculated HHI indices for each of these markets, using each participant's uncommitted capacity and the winter period to examine peak demand conditions.

Using uncommitted capacity, Staff calculates the U.P. market concentration based on current native load obligations, including a 15% reserve margin, and assuming that a small or modest number of customers seek alternative suppliers (retail or wholesale). Beginning with on-peak firm power requirements, Staff used data from 1999 for the peak month of December. On Appendix A, page six, the on-peak firm HHI index is estimated to be 7,333. Off-peak firm and on-peak non-firm are calculated to be 6,185 and 6,583 respectively. Finally, off-peak non-firm is calculated to be 2,657.

On page ten of Appendix A, Staff calculates concentration ratios for two markets based on the assumption of full deregulation with no obligation to serve. This represents the full competition scenario and is based upon available capacity. Since WEPCO is contracted to supply power to

[6] The short-run is the period of time necessary to build new generation facilities.

the mines, full deregulation would not likely affect this obligation. To account for WEPCO's contractual load obligation, this capacity was deducted from WEPCO's available generation in calculating the concentration ratios. Staff has also assumed that capacity controlled by municipal electric utilities in the U.P. is available to serve this market (i.e.the municipal markets are also open for customer choice). The calculated HHI indices are 5,007 for winter firm and 2,229 for winter non-firm energy.

While Staff has used the traditional winter peak in its analysis, results using the summer peak may or may not be significantly different under the assumption of continued regulation and obligation to serve. Focusing on the U.P. market alone would produce equivalent HHI results for the summer period. However, considering demands in Wisconsin could alter these results substantially. The state of Wisconsin typically experiences a summer peak that is the result of high demand for air conditioning. During this peak, substantial amounts of Presque Isle power plant's capacity is transmitted to WEPCO's Wisconsin-based native load. During these times, it is unavailable to sell into the U.P. market. This causes a sharp decline in the capacity available in the U.P. market, changes the resulting HHI indexes, and rearranges the possibilities for market power to be exercised. During the summer peak period, due to Wisconsin native load obligations, WEPCO's concentration of generation declines dramatically. Its summer off-peak concentration ratio, however, would remain quite high.

All of these results indicate that retail and wholesale markets in the U.P. are highly concentrated. Staff's Market Power paper of June 1998 also concluded that the U.P. market for power was highly concentrated. Without detailing the various markets or identifying the control of transmission rights, the Staff estimated the U.P. to have an HHI of about 4400. The concentration ratios do not mean that market power now exists or will inevitably be exercised in the U.P. if regulation is relaxed. Instead, they imply a highly concentrated market where the existence and exercise of market power is much more likely, compared to less concentrated markets.

Discussion of Comments Regarding Market Concentration Measures

The Customers First! Coalition market power report, issued October 23, 2000, calculated the HHI for Wisconsin-Upper Michigan (WUMS) region, a much larger region than the U.P. alone. The Coalition calculated an HHI in the WUMS region by assuming the existence of 1600 firms in Wisconsin each importing 1 MW of electricity. This assumption produced a WUMS HHI of approximately 2700. Assuming fewer importing firms, which would be more realistic, the calculated HHI index would increase. The resulting HHI figure was driven by the large share of capacity controlled by WEPCO in the WUMS region. When the generation capacities were augmented by the transmission capacity controlled by WEPCO the HHI was calculated to be 2639. In either case, the calculated HHI indexes for the WUMS region were well above the 1800 level considered to be indicative of significant market power concerns by DOJ and FERC.

Finally, the Tabors Caramanis and Associates market power study of November 2, 2000, performed on behalf of the Wisconsin Public Service Commission, calculated HHI values between 1800 and 3000 for all geographic and product markets in the WUMS region. The WUMS region includes eastern Wisconsin and the U.P. of Michigan, transmission interconnections with the Mid-American Power Pool, and interconnections to the south with Commonwealth Edison. The HHI for the winter off-peak market in the WEPCO region was calculated to be approximately 2250, based on the economic capacity test, and 2550 based on the available economic capacity test. The study emphasized that the HHI is a structural analysis that only provides an indication of market concentration; it does not provide a direct indication of the ability of any market participation to manipulate prices through the exercise of market power.

VII. Transmission

Section 10f of Act 141 explicitly requires an analysis of transmission issues in the U.P. A review of Appendix A, page 10, makes clear the important role played by transmission in reducing electricity industry concentration measures. On page 10, a significant difference is shown in the HHI concentration measures for firm and non-firm markets, 5,007 and 2,229 respectively. This difference arises because WEPCO owns most of the generation and controls most of the firm (year-round) transmission into the U.P. from Wisconsin. Therefore, the Company has a tight grip on the market for firm power. However, when firm transmission is not scheduled, the transmission plant is available for non-firm transmission service into the U.P. Assuming that all transmission capacity is available at certain times throughout the year, this capacity would be available for use by other service providers in the U.P. The reduction in the HHI concentration index from firm to non-firm power indicates the important role that transmission can play in alleviating market concentration and offering competition a chance to materialize.

The ATC's proposed rate schedule offers the advantage of a single transmission rate, differentiated by location, over most of the U.P. and eastern Wisconsin. This non-pancaked rate should increase the potential for competition. Non-pancaked rates mean that as power is transmitted through different control areas, additional transmission rates are not added to the transmission cost. Instead, one transmission rate is paid for transmission service over all control areas within the ATC. The value of this potential, however, is clouded by the current control of transmission rights into and out of the U.P. Until recently, the 220 MW of import capacity has been reserved on a firm basis, making non-firm transmission the only option for new transactions. On the eastern side of the U.P., 120 MW of capacity exists across the straits of Mackinaw, but is limited by EDSE's 69 KV system to 70 MW for transmission to the west of the straits region.

The ATC open access transmission tariff does provide for another transmission option known as redispatch. This option provides a financial method of increasing transmission capacity. During normal operations, a control area "dispatches" production plant based on "incremental cost". The control area will normally order the lowest running cost plants within the control area to produce power first, and, as demand increases, it will then "dispatch" the next higher running cost plants. By this method, running costs of an electric system are minimized. As load on an electric grid grows, however, congestion is created at various points along the grid making it difficult or impossible to "dispatch" the lowest running cost plants. Some generating plants may have higher running costs than other plants, but because of their locations they can alleviate transmission congestion when they operate. Therefore, as demand grows and the normal low cost dispatch protocol results in transmission congestions, the system is redispatched. Higher cost but strategically located plants may be required to operate ahead of lower running cost facilities, thereby alleviating transmission constraints. Because of its location, a redispatched plant can alleviate a transmission constraint and allow a transmission transaction to occur that would not be possible under normal dispatch protocols. Since dispatch protocols normally result in the least cost operations of an electric system, redispatch results in higher operating costs. In the U.P. this situation usually occurs when lower cost Wisconsin plants are normally dispatched ahead of the Presque Isle plant until the transmission capacity into the U.P. becomes congested. When this occurs, a redispatch option would cause the higher cost units at Presque Isle to begin operating, thereby displacing some of the power being produced by lower cost Wisconsin plants.

One benefit of the ATC redispatch option for network customers is that the added cost of redispatching a unit is spread over all the network customers on a load ratio basis. Therefore, a network customer seeking a transmission transaction requiring redispatch is not solely responsible for the cost of exercising this option. Firm point-to-point customers, however, are solely responsible for the cost of redispatch, if needed. Since the option results in out of merit plant operations, which causes production costs to be higher than they otherwise would have been, these costs are added to a firm point-to-point customer's transmission costs. The redispatch cost is computed as the difference between the incremental cost of the low cost unit that is backed-down and the high cost unit that is ramped-up by the redispatch order. The predominant flow of power across the Wisconsin/Michigan border causing a constrained transmission is from south to north during the cooler months, as low cost Wisconsin plants are dispatched to meet U.P. loads ahead of higher cost U.P. units. The availability and cost of using the redispatch option depends on the specific transmission transaction being proposed including the amount of capacity requested, location of the generating unit, and the time schedule associated with the transaction. Nevertheless, redispatch would normally require using higher cost U.P. units that could raise the cost of a transmission transaction. For example, the average unit fuel costs for each Presque Isle unit is shown below:

1999 Presque Isle Fuel Cost (Cents/KWh) by Unit

Unit 1	2.588
Unit 2	1.916
Unit 3	1.631
Unit 4	1.631
Unit 5	1.614
Unit 7	1.293
Unit 8	1.239
Unit 9	1.255

Since typical transmission congestion occurs on south to north power flows, one plausible scenario to alleviate the constraint is to redispatch Presque Isle, increasing its output. Since the Presque Isle plant is designated as a must run unit over a large portion of the WUMS load curve, the most efficient units are frequently already in service. Therefore, less efficient units must be relied upon in the case of a redispatch request. This could easily cause the transmission costs for a firm point to point customer to increase significantly, causing some transactions to be impractical.

The future value of ATC's redispatch option also depends on whether and how much generation is added in the U.P. or existing generation is retired in the coming years. Load growth or plant closings would also materially affect the value of redispatch. Operations at the Empire and Tilden mines are among the most important considerations. As noted previously, these mines represent a large portion of the U.P. load. If operations at the mines were curtailed, for example, an important U.P. load center would drop, freeing up capacity at Presque Isle for redispatch (assuming that WEPCO maintained the existing Presque Isle units in operating condition).

Another major consideration regarding redispatch is the status of the industrial generating facilities located throughout the U.P. For example, the industrial generators, mostly paper mills, operate approximately 155 MW of capacity in the U.P. If one or more of these industrial sites closed its generating facility while continuing to operate its mill, the options for redispatch would be reduced.

Discussion of Filed Comments Regarding Transmission

The UPTDU has expressed concerns over certain aspects of the ATC's plans. According to the UPTDU, the ATC will perpetuate the U.P.'s isolation by phasing in a single rate over a five-year period, but not integrating WPS and UPPCO's rates. Rates for WEPCO and EDSE, however, will be integrated. UPTDU claims that the Wisconsin companies and EDSE are in a position to bear higher transmission rates proposed by ATC because of their ownership of ATC, and, thus, their participation in the ATC profits. Non-transmission owning U.P. municipal or cooperative utilities have not been allowed to join the ATC. The UPTDU believes that these U.P. transmission customers will have to pay higher rates, but will not be permitted to share in the ATC profits.

UPTDU also asserts that ATC's proposed tariff contains costs that unduly raise transmission rates. The UPTDU members state that the definition of transmission assets, as incorporating all 69 KV facilities and above, unfairly requires their members to pay for the distribution costs of ATC members. These factors, in the UPTDU's opinion, help create and enhance market power at the expense of its members. The UPTDU does not think that the formation of the ATC will, in itself, alter the transmission constraints in the Western U.P or resolve problems caused by WEPCO's domination of the available transmission capacity at the constrained U.P.-Wisconsin interface. According to the UPTDU, WEPCO is in the position to prevent the export of any excess U.P. generation capacity to Wisconsin and beyond. The UPTDU members argue that a competitive electricity market cannot develop in the U.P. unless action is taken by the MPSC to mitigate the effects of WEPCO's purported monopoly. In their opinion, both expansion of the transmission interface between the U.P. and Wisconsin and divestiture of WEPCO's generating facilities are necessary in order to develop a competitive market.

VIII. Ability of New Suppliers to Enter the U.P. Market

One factor acting to restrain the exercise of market power is the potential entrance of new competitors into a market. Higher prices and profits act as an incentive to increase the supply of a product by encouraging such entry. Act 141 recognizes this restraining value by requiring a review of the ability of new suppliers to enter the U.P. market. While a number of barriers to entry into the electricity markets are sometimes cited in the literature, two are of particular concern. These are scale economies and control of a essential input or delivery system.

Economies of scale exist when the unit cost of production declines as the scale of production increases. Scale economies can exist in industries that require significant capital investment and are assumed to exist in electricity generation industry up to a certain generator size. As the size of a generator increases, up to a limit, the unit cost per KWh produced declines. Firms producing a homogenous product, like electricity, are at a disadvantage if their plants are relatively small compared to larger, more efficient, generators in the market. Staff does not estimate at what point economies of scale begin to disappear, only that this pattern is a widely observed in the industry. In the U.P., a supplier who could build only a small plant, because of market size, could not easily compete with the larger suppliers throughout most of the year. This barrier could exist in the U.P. since the market for potential entrants is limited by the relatively small U.P. market and by transmission constraints, especially into the Wisconsin and the Lower Peninsula markets from the U.P.

The second barrier can occur if one participant controls a essential input, like natural gas or coal delivery, or a vital distribution system, like the transmission system. This has been discussed previously, and Staff again notes that at this time it is unaware of any issues related to control over fuel supply or other inputs required by the industry. Transmission, however, is another matter.

Discussion of Filed Comments on Barriers to Entry

The ATC claims that one of the generic benefits of ATC formation is that it will improve the ability of new suppliers to enter the market. That is because, as a single purpose transmission company, ATC will face no conflict of interest in responding to requests for new generation interconnections to its system. ATC commits to ensuring that transmission facilities necessary to connect new generation to the system are licensed and constructed. Also, by virtue of ATC's redispatch policy, suppliers utilizing generation resources south of the Wisconsin-U.P. constraint will have the opportunity to contract with customers in the U.P. In addition, on January 1, 2002, pursuant to Act 141, any retail customer may access unbundled transmission service through any electric utility or licensed Alternative Supplier. The advantage of network customer status includes equal footing with other long-term existing network customers of transmission service in the U.P. The ATC contends that its transmission tariff can help eliminate barriers to choice and competition that may exist in the U.P.

WPS and UPPCO comment that there is limited ability for new generation suppliers to enter the U.P. generation market. Current generation alternatives are most likely to be natural gas or oil fired combustion turbines and/or combined cycle generation units, which may not be able to compete with excess base load generation. They also point out that if there is no available excess firm transmission capacity out of the U.P., new suppliers have a very limited potential to sell capacity from units located in the U.P. to markets with higher prices outside the U.P. WPS further comments that the ATC's proposed redispatch, as a solution to constrained transmission into the U.P., may not work because it relies on the existence of excess generation located in the U.P. to provide the needed redispatch. This is especially problematical during peak load periods, when generation is fully utilized. WEPCO has stated that all of its U.P. generation is committed to obligation-to-serve customers or contract customers in Michigan and Wisconsin. If WEPCO does not have excess generation in the U.P., options for redispatch are limited or not available. The Wisconsin generation market is also constrained. Therefore, imports from Wisconsin or states beyond to serve U.P. customers are severely limited or non-existent. In the opinion of WPS, the lack of options makes it unlikely that new generation suppliers will enter the U.P. generation market.

According to the UPTDU, WEPCO is in a position to undercut potential competitors thereby making a new generating unit in the Western U.P. uneconomical. Thus, WPS and the UPTDU consumer-owned utilities are in the unenviable position of having to install smaller, less economical generating units to meet their future load growth requirements. Potential independent power producers are also deterred from installing new generation in the Western U.P. In the UPTDU's opinion, divestiture of WEPCO's generation facilities will be required to initiate a competitive market in the Western U.P.

Staff believes that the ATC represents a favorable development for constraining the exercise of market power in the U.P. The ATC's open access transmission tariff offers one potential opportunity for removing entry barriers into the market. In order to realize this potential, upgrades to transmission in the U.P. must be made and/or redispatch must prove to be a viable option. Staff is particularly concerned regarding the viability of redispatch as an option for serving firm point-to-point transmission customers.

IX. Other Measures of Market Power

Pivotal Supplier Index

The Customers First! Coalition used the Pivotal Supplier Index (PSI) in addition to the HHI concentration measure in its study of market power in Wisconsin. This study is of interest because the WUMS system examined in the study included the U.P. of Michigan. Also, if the Wisconsin market suffers from market power, the existence of additional firm transmission options would be of limited use since Michigan customers would have to contend with market power being exercised within the state of Wisconsin. The PSI calculates the frequency that some quantity of production from a given supplier is necessary to serve market demand. 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 amount of the market demand. In so doing, it indicates whether production from the firm being studied is necessary to satisfy the remaining market demand. If the capacity is necessary, then the firm being studied could withhold its production from the market and insufficient substitutes would be available to replace that production. The PSI essentially detects, indirectly, the ability of a firm to exercise market power. According to the Customer First study, the PSI calculation reinforces the HHI findings that WEPCO is the dominant supplier to the WUMS region. The shortcoming of the PSI, much like the HHI, is that, while it indicates the likely presence of market power, it does not provide a determination that market power is actually being exercised or can be exercised.

Strategic Models

Concentration models have been used to screen markets for the likelihood of market power. They provide a good indication of which markets are likely to be vulnerable to the exercise of market power by one or a few firms. Strategic models go the next step and examine whether a firm can actually exercise market power, given a market's structure. In Appendix B, Staff has used a strategic model to determine whether the exercise of market power would be profitable in the U.P. and what the resulting prices differences would be under varying demand elasticities between a fully competitive market and one controlled by a strategic firm. These estimates are based upon the U.P. electric market's current participants, structure, and assuming that WEC would seek to maximize profits by exercising market power if given the opportunity. The model explicitly recognizes the importance of demand responses to changes in prices by analyzing various demand elasticities. It also explicitly considers the alternatives available to U.P. customers from other existing generators.

Staff's analysis recognizes that demand elasticity plays an important role in determining the degree to which a market participant can take advantage of market power. Staff has examined elasticities of -.25, -.5 and -.8, but believes that demand is very inelastic, especially in the short-run. The plausible range of elasticity is near the bottom of the range that Staff has examined. For example, the U.S. Department of Energy uses a demand elasticity of -0.25 in its studies.

Given the heavy concentration of generation and transmission in one company, WEC, Staff's model indicates that the exercise of market power would be profitable for WEC and would result in prices higher than those that would exist in a competitive market over a large range of likely demand elasticities.

Strategic, or behavioral, models were also used in the Customers First! Coalition and Tabors Caramanis & Associates market power studies in Wisconsin. These simulation models likewise analyzed the strategic behavior by generating firms and/or retail suppliers in various types of power markets, under different market structures and modeling assumptions. The simulation modeling of strategic behavior, in both studies, indicated significant market power in the WUMS market.

The Tabors Caramanis & Associates study, performed on behalf of the PSCW, used the Price-Cost Margin Index (PCMI), which measures the actual ability of a market participant to exercise market power by identifying the extent to which prices would exceed the levels expected to occur in a perfectly competitive market. The Tabors study assumed that price regulation would end and that the entire region's retail electric industry would become deregulated. The study forecasted the PCMI in the WUMS region for the period 2001-2007 and found that the PCMI was above the competitive market price threshold level continually over this period. The Tabors firm forecast that the price impact of market power in the WUMS region would be significant during the entire study period of 2001-2007, if all market participants were to be deregulated. Again, the results of this strategic simulation study reinforce the findings arising from the Tabors' market concentration analysis.

X. Market Power Findings in Wisconsin

Throughout this report, Staff has recounted the results of market power studies conducted in Wisconsin. These include the report conducted for the PSCW. The Wisconsin Public Service Commission employed the economic consulting firm of Tabors, Caramanis and Associates to conduct a study on the potential for horizontal market power in Wisconsin. The study also analyzed the likely impact of market power on the creation of an effective competitive market for electricity in Wisconsin. The region covered by the Tabors study included the U.P. of Michigan and the eastern portion of Wisconsin. The study concluded that: (1) the potential exists for the exercise of market power in the WUMS system; (2) that WEPCO has the largest market share in the geographic market; (3) under the current ownership structure a workable competitive retail electricity market can only be achieved by WEPCO divesting its generation assets, by requiring owners of existing generation to commit a significant portion of their capacity to fixed price contracts, and by expanding transmission capacity into WUMS.

The Wisconsin Public Service Commission issued its report to the Wisconsin Legislature on market power in December, 2000. According to the PSCW, the results of the Tabor's report should not be surprising given the degree of concentration of power plant ownership in Wisconsin and the existence of transmission constraints. The Commission also noted that the issues surrounding restructuring are very complex and that complete and immediate wholesale and retail deregulation may not be in the public interest. Therefore, the Wisconsin Commission did not recommend generating plant divestiture for the time being. The Wisconsin Commission has indicated that it will explore the Tabors study's suggestion involving contracts between generators and customers and study the expansion of the transmission system. The PSCW agreed to focus on taking steps to assure that the requisite infrastructure would be in place to maintain continued electric reliability and low electric rates in the state.

XI. Conclusions and Recommendations

Staff's analysis, together with those performed for Wisconsin, demonstrates that generation and transmission capacity in the U.P. is highly concentrated in most markets and during most of the year. It further identifies WEC (parent of WEPCO and EDSE) as controlling, by far, the greatest percentage of generation and transmission capacity. At this time, this Commission and FERC exercise price regulation in the retail and wholesale markets of the U.P., making the exercise of market power difficult. As long as the WEC companies are required to use their facilities to serve Michigan and Wisconsin load, Staff believes their ability to "game" the U.P. markets is minimal, and occurs predominately in the wholesale market. Nevertheless, WEC's WEPCO subsidiary is relatively so large and possesses such a large percentage of U.P. generation and transmission, that even accounting for these obligations, the U.P. markets are highly concentrated throughout most of the year. If markets are assumed to be fully deregulated, without an obligation to serve, it is very clear that the WEC subsidiaries would dominate the U.P. markets in terms of generation and transmission and would have the ability and incentive to exercise market power.

Act 141's goal is to ensure continued electric system reliability and reasonable electricity rates in the state while implementing electric industry restructuring. Considering the degree of generation and transmission capacity concentration held by the WEC subsidiaries in the U.P. of Michigan, the potential for the exercise of market power exists within the U.P. and could ultimately undermine the objectives of Act 141. This is true for retail and wholesale markets, on and off-peak.

One solution proposed by some commenters to the concentration of capacity held by the WEC subsidiaries is the divestiture of the Presque Isle plant. Until a wider scale deregulation plan is implemented for the U.P. or customers begin leaving utilities, this would be premature. There are advantages to Michigan customers in having WEPCO continue to own and operate the Presque Isle plant at this time. The current ownership encourages more efficient operation, and scale economies can be enjoyed in operating the plant. Also, replacing one owner with another would not do much to alleviate the market concentration that Staff has observed in the U.P. Finally, much of the cost of the plant's capacity is allocated to WEPCO's Wisconsin customers, and Wisconsin has not indicated an intention to encourage customer choice, to deregulate, or otherwise restructure its electric industry at this time.

Staff believes that one of the best measures for assisting the development of a competitive market in the U.P. is to expand transmission capacity. This can be done by physically expanding the interconnections in the western U.P., and potentially through exercise of the redispatch option in the ATC tariff. Staff also recommends the examination of options to increase the ability of moving lower peninsula power into the western U.P. One limitation on power flow through the U.P. occurs when 138 KV transmission lines from the Western U.P. and the Lower Peninsula connect to the 69 KV lines near Manistique and the Hiawatha substation. This limits east-west power flows to about 70 MW. Construction of a 138 KV system the full length of the U.P. could increase transmission from the Lower Peninsula to the Western U.P. to approximately 120 MW. Parallel flows over the U.P. grid would likely impair this capability periodically throughout the year, but this potential bears further study.

Staff's analysis of the U.P. market also demonstrates the greater vulnerability of the market to price manipulation during the shoulder to peak periods. This is especially true for demand elasticities that Staff believes characterize the market today. One way to combat market power is to increase the elasticity of demand. Demand elasticities may be increased by providing customers with options that allow them to "manage" their demands. Two such options include load management and distributed generation. These options could assist an expansion of transmission capacity as part of a comprehensive strategy for mitigating potential market power.

Major transmission projects that the ATC has inherited from its contributing owners do not include an expansion of capacity into, through, or out-of the U.P. Staff notes, however, that the ATC is a new firm which is just beginning its planning process. The ATC has indicated that it will pursue system improvement plans aimed at improving the transfer capability into and out-of the U.P., and Staff expects that its transmission recommendations will be addressed in the ATC's planning process. Staff strongly recommends that the ATC move expeditiously to complete its planning process and implement transmission upgrades in the U.P. Therefore, the prudent course of action would be to give the ATC sufficient time to complete its current project planning process and implement transmission upgrades. This would also allow Staff to assess whether transmission upgrades and the ATC redispatch option can play a significant role in countering potential market power in the U.P. Staff recommends continued monitoring of the U.P. electricity markets to determine if market power is being exercised as markets are restructured, with especially close monitoring of transmission improvements in the U.P. to determine if they assist in opening the U.P. markets. Given Staff's concern with WEC's prominent role in the U.P.'s electricity supply, Staff further recommends that the Company be required to submit a market power mitigation filing to the Commission in eighteen months. This filing should include a plan detailing market power mitigation measures that WEC has taken, is in the process of taking, and will likely implement in the near future to mitigate its market power. Staff believes that this market mitigation plan should be made available for public comment. After public comments are filed, a Staff report should be prepared, according to the following schedule. Staff recommends that sixty days be provided for interested parties to present comments to the Company's filing, with the Staff report being due 120 days after the close of the comment period.

On behalf of the Commission, the Staff wishes to thank the many parties for the information and comments that they have provided in docket U-12533 and in the preparation of this report.

XII. Comments On Staff's Draft Report

On March 30, Staff provided a draft of its U.P. Market Power report to parties that had previously participated in the Commission's U-12533 docket by submitting written comments. The Staff solicited comments on its draft report in order to provide a complete review of this complex issue, including the positions of participants in the U.P. Comments were received from the American Transmission Company, International Paper, the Upper Peninsula Transmission Dependent Utilities, WEC, and WPS Resources/UPPCO. Generally, the comments were supportive of the Staff's study, although one challenged the Staff's methodology in undertaking the mandatory PA 141 test.

American Transmission Company

The ATC provided comments to clarify the transmission capacity rights of network customers. The ATC points out that network customers designate network resources and loads. They also state that the transmission provider (ATC) must determine if the customer's designated resources can actually be used to meet its load requirements, given other loads and resources on the system. This determination is made under various load scenarios (example peak, shoulder, off-peak, etc.). If the use of the designated sources to satisfy the loads is feasible, the designation is approved. According to ATC, this permits the transmission customer to schedule and use the transmission system, but does not allocate a specific amount of transmission capacity to the transmission customer. In the case of the U.P., the ATC would maintain that 175 MW of transmission capacity through the Plains substation should not be allocated to WEPCO. Instead, the ATC would contend that WEPCO has network resources in Wisconsin that have been approved to meet its load in the U.P. of Michigan. According to ATC, the fact that they have been approved to meet the U.P. load by using the transmission facilities that link Wisconsin to the U.P. power grid does not mean that WEPCO has specific rights to a specific amount of transfer capability at the interface.

As noted by ATC in its comments, the issue of participants' rights to transmission capacity is unresolved. Staff expects that some U.P. market participants would view rights to transmission capacity differently from ATC. Even assuming ATC's interpretation, WEPCO would retain pre-designated resources and loads which essentially "grandfather" in the Company's use of the constrained transmission facilities. This would effectively preclude a potential competitor from using the transmission facilities, whether or not specific rights existed for specific capacity, during critical times of the year. As a result, an effective capacity of 175 MW on the transmission system is available to WEPCO but no one else on a firm basis throughout the entire year.

The preceding discussion leads Staff to conclude that the allocation of transmission capacity for the various market power tests that have been conducted for this report remains appropriate and accurate. In fact, ATC comes to a similar conclusion on page 3 of its comments:

> "The impact of the discussion above may not be too significant in an environment where few things are changing. So long as the discussion in the draft report on redispatch (pp. 14-16) were kept in mind, the assignment of numerical values to network rights could serve as an effective shorthand for conducting the mathematical analyses represented in the report."

ATC does contend, however that if retail competition takes hold in the U.P. and WEPCO loses significant load, transmission will effectively be freed up into the U.P. Staff agrees that if this were to occur then transmission capacity for the various market power tests may have to be reallocated.

In its comments, the ATC recognizes " the need for additional transfer capability into and out of the UP". It also states that it is pursuing a system improvement plan that includes needed improvements in the U.P. ATC anticipates issuing its first ten year plan this summer. In addition to system improvements, ATC touts its ability to break down entry barriers into the U.P. market and its operational independence as advantages that it offers in support of competition.

International Paper

In its comments, International Paper agreed with the analysis and conclusions reached by the Staff in its draft report. It further expressed concerns regarding the mitigation measures that WEPCO might propose in the mitigation filing recommended by Staff. International Paper states that customer benefits envisioned by PA 141 cannot be realized unless a competitive market develops. It concludes by stating "We trust that the MPSC will ensure that adequate mitigation actually takes place as required to allow a competitive market to develop."

Upper Peninsula Transmission Dependent Utilities

While generally supportive of the Staff findings, the UPTDU took issue with the methodology used by the Staff for performing the mandatory 2000 Act 141 market power test. These issues are discussed on pages 9 to 11 of the Staff's report. According to the UPTDU, its methodology demonstrates that WEPCO does not pass the Legislative test as defined in Act 141.

The UPTDU also provided comments on the redispatch option offered by the ATC open access tariff. According to UPTDU, the option is not designed to increase the actual transmission capacity across the constrained interface, but is an operational strategy to alleviate constraints. The UPTDU states that any entity constructing a power plant in the U.P. could only offer interruptible power to potential customers in Wisconsin since the bulk of the transmission capacity is controlled by WEPCO. A potential supplier desiring to build a plant in northern Wisconsin would face a similar problem in serving U.P. customers. Because of the constrained interface between Wisconsin and Michigan, only interruptible power could be sold in the U.P. Therefore, the UPTDU concludes that even with the redispatch option, WEPCO would control the market for firm power and energy.

The UPTDU also took issue with the Staff's inclusion of municipal capacity for the HHI tests. According to UPTDU comments it is unlikely that the municipals would participate in the fully competitive market. Staff notes, however, that for purposes of wholesale market power tests, this capacity is usually included. Staff would also note that removing the municipal capacity from the HHI calculation serves to increase the resulting HHI numbers.

Finally, UPTDU states while Staff's analysis confirms the dominant position occupied by WEPCO, the Staff fails to provide adequate mitigation measures. UPTDU recommends divestiture of WEPCO generating capacity to a sufficient number of purchasers to prevent price control and construction of additional transmission capacity into and out-of the U.P. Without these mitigation measures, UPTDU asserts that no meaningful competition will occur in the U.P.

Wisconsin Energy (Wisconsin Electric and Edison Sault)

WEPCO and EDSE state that the Staff's analysis is an accurate depiction of current conditions in the U.P. electricity markets. They agree with Staff that so long as prices remain regulated by the Commission and by the FERC, market power is difficult to exercise. They further state that by recommending a mitigation filing, Staff understates the value of cost-based regulation in mitigating market power.

WEPCO and EDSE also caution against tying market power issues too closely to development of a competitive market. The companies state that ownership of a large share of generation will not subvert a competitive market envisioned by Act 141. Instead, WEPCO and EDSE believe that continued ownership of its generating capacity will offer price stability until a competitive market develops. The companies cite new transmission capacity, redispatch, and potential new generators as sources of potential capacity to support a competitive market.

Finally, WEPCO and EDSE suggest that Staff modify its recommendations to require the companies to file periodic reports on the broader issue of developing a competitive market in the U.P., instead of a market power mitigation plan. This would include changes in price regulation and the amount of generation committed to serve contract and native load customers, as well as market power issues. It also suggests similar reports from ATC regarding transmission improvements and the performance of redispatch. The companies state that if circumstances change so that Staff's concern regarding market power is heightened, the companies will work collaboratively with Staff to develop appropriate mitigation measures.

<u>WPS Resources (Wisconsin Public Service and Upper Peninsula Power)</u>

WPS Resources believes the Staff has fairly and accurately assessed market power issues in the U.P. and it substantially agrees with the Staff's conclusions. It also reaffirmed its positions, conclusions, and recommendations as articulated in its October 4, 2000 comments filed with the Commission.

Appendix A

Upper Peninsula Market Power Report

Prepared By The Staff Of The Michigan Public Service Commission

June 5, 2001

1999 Upper Peninsula Electric Energy Suppliers, Energy Sales and Customers

Service Provider	KWh Sales (Thousands)	Percentage Of U.P. Sales	Total Customers	Service Territory
Alger-Delta Cooperative	52,931	1.0%	9,167	Alger, Delta,Marquette, Menominee, Schoolcraft
Village of Baraga	18,061	0.3%	710	Baraga
Cloverland Cooperative	176,492	3.2%	16,993	Chippewa, Luce, Mackinac, Schoolcraft
City of Crystal Falls	16,902	0.3%	1,636	Crystal Falls
Edison Sault Electric	646,408	11.6%	21,469	Manistique, Sault Ste Marie, St. Ignace
City of Escanaba	136,278	2.4%	7,475	Escanaba
City of Gladstone	26,701	0.5%	2,692	Gladstone
Village of L'Anse	13,393	0.2%	1,091	L'Anse
City of Marquette	262,441	4.7%	14,943	Marquette
City of Neguanee	22,586	0.4%	2,264	Negaunee
City of Newberry	16,848	0.3%	1,454	Newberry
City of Norway	27,914	0.5%	2,154	Norway
City of Wakefield	12,888	0.2%	1,107	Wakefield
Northern States Power	137,989	2.5%	9,270	Bessemer, Ironwood
Ontonagon Cooperative	24,521	0.4%	4,282	Baraga, Houghtoh, Keweenaw, Ontonagon
Upper Peninsula Power	738,872	13.3%	62,709	Northwestern Upper Peninsula
Wisconsin Electric Power	2,923,501	52.5%	25,467	Western Upper Peninsula
Wisconsin Public Service	315,341	5.7%	8,694	Mellen, Menominee
Total	5,570,067	100.0%	193,577	

Source: U.S. Department of Energy, Energy Information Administration, and the 1999 Edition of Electrical World
Electric Power Producers and Distributors Directory.

1999 Upper Peninsula Monthly Maximum Demands
(MW's of Demand)

Company	January	February	March	April	May	June	July	August	September	October	November	December
Municipals:												
Crystal Falls	3	3	3	3	3	3	3	3	3	3	3	3
Escanaba	25	22	22	22	22	24	26	25	24	21	22	24
Gladstone	6	4	5	5	5	5	6	6	5	5	5	6
Marquette	51	44	43	40	40	49	52	49	50	45	47	50
Newberry	3	3	3	3	3	3	3	3	3	3	3	3
Norway												6
Cooperatives:												
Alger-Delta	12	10	10	9	9	10	11	11	10	10	11	12
Cloverland	38	35	32	29	31	30	33	32	32	34	34	38
Ontonogan 1998	5	4	4	4	4	4	5	5	5	5	6	6
Investor Owned Utilities:												
Edison Sault Electric	138	125	120	112	121	115	124	118	118	128	126	137
Wisconin Electric Power	386	390	393	432	411	414	409	249	212	403	435	411
Upper Peninsula Power	147	137	133	123	120	123	136	126	135	138	137	149
Iron River District	8	8	7	7	7	7	8	7	7	7	7	9
Wisconsin Public Service	25	22	22	20	20	22	26	24	24	21	23	26
Total	848	808	797	809	796	809	842	657	629	823	859	880
Empire & Tilden Mines	280	292	294	335	319	307	298	148	101	305	332	297
WEPCO less mines	106	98	99	97	92	107	111	101	111	98	103	114

Source: Annual P-521 reports to the Commission, and the 1999 Edition of Electrical World Electric Power Producers and Distributors Directory.

Ownership of Upper Peninsula
Generation and Transmission Capacity for Year Ended 1999
(Summer MW Capacity)

Utility Owned Units	Units	Name Plate Mw Rating	Net Summer Generating Capability	Type	Company Total	Company Percentage
Cloverland Electric Cooperative						
Drafter	1-5	9	8	IC		
Detour	6&7	6	5	IC	13	0.9%
City of Crystal Falls	1-3	1	1	HY	1	0.1%
City of Escanaba	1-2	23	26	ST	26	1.8%
City of Marquette						
Russell	1	1	1	HY		
Plant Four	GTI	24	23	GT		
Plant Two	1	3	3	HY		
Shiras	1-3	78	78	ST	104	7.0%
Newberry Water & Light	1-4	6	5	IC	5	0.3%
City of Norway	1-4	6	5	HY	5	0.3%
Northern States Power						
Superior Falls	1&2	1	2	HY	2	0.1%
Edison Sault Electric						
Hydros	6-80	42	29	HY		
Manistique	1&2	5	5	IC		
Transmission*		70	70			
Wisconsin Electric Power						
Big Quinnesec 61	4&5	4	0	HY		
Big Quinnesec 92	1&2	16	15	HY		
Brule	1-3	5	5	HY		
Chalkhill	1-3	8	7	HY		
Hemlock	1	3	1	HY		
Kingsford	1-3	7	6	HY		
Lower Paint	1	0	0	HY		
Michigamme	1&2	10	9	HY		
Peavy Fall	1&2	12	15	HY		
Presque Isle	1-9	625	617	ST		
Sturgeon	1	1	0	HY		
Twin Falls	1-5	6	7	HY		
Way	1	2	1	HY		
White Rapids	1-3	8	7	HY		
Transmission*		175	175			
Wisconsin Energy Total		998	971		971	65.1%
Upper Peninsula Power						
Autrain	1-2	1	1	HY		
Cataract	1	2	2	HY		
Gladstone	1	23	24	GT		
Hoist	1-3	4	4	HY		
Warden	1	19	18	ST		
McClure	1&2	8	9	HY		
Portage	1	23	24	GT		
Prickett	1-2	2	2	HY		
Victoria	1-2	12	12	HY		
Wisconsin Public Service Corp						
Grand Rapids	1-5	8	4	HY		
Transmission*		40	40			
WPL Resources Total		141	139		139	9.3%
Additional Transmission from Lower Peninsula		50	50		50	3.4%
Sub-Total		1346	1315		1315	88.2%
Non-Utility Owned Units						
Cellu Tissue/Menominee	2	3	2	ST	2	0.2%
Champion/ Quinnesec	1	28	26	ST	26	1.7%
Kimberly Clark/Munising	387	6	6	ST	6	0.4%
Mead Paper	7-9	103	101	ST	101	6.8%
NEW Hydro/Menominee	4,5,8, &9	2	2	HY	2	0.1%
Stone Container	1	15	13	COL	13	0.9%
Firm Transmission*		5	5		5	0.3%
U.S. Army Corps of Engineers		18	20	HY	20	1.3%
Sub-Total		180	175		175	11.8%
Total		1526	1490		1490	100.0%

COL- Closed Loop Biomass
IC - Internal Combustion
GT- Gas Turbine
HY - Hydro
ST - Steam

*Transmission assets are owned by the American Transmission Company.

Source: U.S. Department of Energy, Energy Information Agency, and Annual Reports to the Commission

Ownership of Upper Peninsula
Generation and Transmission Capacity for Year Ended 1999
(Winter Capacity)

ity Owned Units	Units	Name Plate Mw Rating	Net Winter Generating Capability	Type	Company Total	Company Percentage
Cloverland Electric Cooperative						
Drafter	1-5	9	8	IC		
Detour	6&7	6	5	IC	13	0.8%
City of Crystal Falls	1-3	1	1	HY	1	0.1%
City of Escanaba	1-2	23	26	ST	26	1.8%
City of Marquette						
Russell	1	1	1	HY		
Plant Four	GTI	24	24	GT		
Plant Two	1	3	3	HY		
Shiras	1-3	75	78	ST	105	7.0%
Newberry Water & Light	1-4	6	5	IC	5	0.3%
City of Norway	1-4	6	5	HY	5	0.3%
Northern States Power						
Superior Falls	1&2	1	1	HY	1	0.1%
Edison Sault Electric						
Hydros	6-80	42	29	HY		
Manistique	1&2	5	5	IC		
Transmission*		70	70			
Wisconsin Electric Power						
Big Quinnesec 61	4&5	0	0	HY		
Big Quinnesec 92	1&2	16	16	HY		
Brule	1-3	5	4	HY		
Chalkhill	1-3	8	7	HY		
Hemlock	1	3	2	HY		
Kingsford	1-3	7	6	HY		
Lower Paint	1	0	0	HY		
Michigamme	1&2	10	9	HY		
Peavy Fall	1&2	12	15	HY		
Presque Isle	1-9	625	617	ST		
Sturgeon	1	1	0	HY		
Twin Falls	1-5	6	7	HY		
Way	1	2	1	HY		
White Rapids	1-3	8	7	HY		
Transmission*		175	175			
Wisconsin Energy Total		994	971		971	64.8%
Upper Peninsula Power						
Autrain	1-2	1	1	HY		
Cataract	1	2	2	HY		
Gladstone	1	23	28	GT		
Hoist	1-3	4	4	HY		
Warden	1	19	18	ST		
McClure	1&2	8	9	HY		
Portage	1	23	28	GT		
Prickett	1-2	2	2	HY		
Victoria	1-2	12	12	HY		
Wisconsin Public Service Corp						
Grand Rapids	1-5	8	4	HY		
Transmission		40	40			
WPL Resources Total*		141	147		147	9.8%
Additional Transmission from Lower		50	50		50	3.3%
Sub-Total		1339	1324		1324	88.3%
Jtility Owned Units						
Cellu Tissue/Menominee	2	3	2	ST	2	0.2%
Champion/ Quinnesec	1	28	26	ST	26	1.7%
Kimberly Clark/Munising	387	6	6	ST	6	0.4%
Mead Paper	7-9	103	101	ST	101	6.8%
NEW Hydro/Menominee	4,5,8, &9	2	2	HY	2	0.1%
Stone Container	1	15	13	COL	13	0.9%
Firm Transmission*		5	5		5	0.3%
U.S. Army Corps of Engineers		18	20	HY	20	1.3%
Sub-Total		180	175		175	11.7%
Total		1519	1499		1499	100.0%

COL- Closed Loop Biomass
IC - Internal Combustion
GT- Gas Turbine
HY - Hydro
ST - Steam

*Transmission assets are owned by the American Transmission Company.

Source: U.S. Department of Energy, Energy Information Administration and P-521 Reports to the Commission

PA 141 Upper Peninsula Market Power Test
(MW Capacity)

Generation Source	Net Summer Capability	Adjustments	Included Generation	Percentage Control
Cloverland Electric Cooperative	18	0	18	
Municipals				
Crystal Falls	1	1	0	
Escanaba	26	26	0	
Marquette	66	66	0	
Newberry	5	5	0	
Norway	5	5	0	
Investor Owned Utilities				
Wisconsin Public Service				
Generation	4	0	4	
Transmission	40	0	40	
Upper Peninsula Power	96	0	96	
WPS ResourcesTotal	139	0	139	**23.4%**
Wisconsin Electric Power				
U.P. Generation Allocated to Michigan	692	637	55	
Marquette & USCE Purchase	53	0	53	
Transmission	175	0	175	
Less Cleveland Cliffs		248	248	
Edison Sault Electric				
Generation	34	0	34	
Transmission	70	0	70	
Wiconsin Electric Total	1023	885	138	**23.2%**
Northern States Power	2	0	2	
Industrials				
Cellu Tissue/Menominee	2	2	0	
Champion/ Quinnesec	26	26	0	
Kimberly Clark/Munising	6	6	0	
Mead Paper	101	101	0	
NEW Hydro/Menominee	2	2	0	
Stone Container	13	13	0	
Transmission	5	5	0	
Additional Transmission Capacity from Lower Peninsula	50		50	
Total Capacity Included in Test	1490	895	595	

Upper Peninsula Electric Industry
Market Power Test
Market for On-Peak Firm Energy
(FERC HHI Methodology)

Description	Winter Demand	Winter Capacity	Purchases	Committed Power Sales	Available Capacity	Percentage
Municipals*						
Crystal Falls	3	1	2		0	0
Escanaba	28	26	10		9	2
Marquette	58	105		38	10	2
Newberry	4	5	3		4	1
Norway	7	5	2		0	0
Cooperatives						
Cloverland	44	13	23	3	0	0
Investor Owned Utilities						
Edison Sault Electric	158	34	99	7	0	
Wisconsin Electric	473	692	38	25	232	
Transmission		175			175	
Wisconsin Energy Total	630	901	137	32	407	85
Wisconsin Public Service	30	4				
Upper Peninsula Power	182	103	40	47		
Transmission		40				
WPS Resources Total	212	147	40	47	0	0
U.S. Army Corps of Engineers		20		20	0	0
Lower Peninsula		50			50	10
Total	986	1272			479	100
HHI Index						**7333**

Upper Peninsula Electric Industry
Market Power Test
Market for Off-Peak Firm Energy
(FERC HHI Methodology)

Description	May Demand	Winter Capacity	Purchases	Committed Power Sales	Available Capacity	Percentage
Municipals*						
Crystal Falls	2	1			0	0
Escanaba	18	26	10		18	3
Marquette	35	105		38	33	5
Newberry	2	5	3		6	1
Norway	4	5			1	0
Cooperatives						
Cloverland^	23	13	23	3	9	1
Investor Owned Utilities						
Edison Sault Electric	85	34	99	7	41	
Wisconsin Electric	384	692	38		346	
Transmission		175			175	
Wisconsin Energy Total	469	901	137	7	562	78
Wisconsin Public Service	41	4			0	
Upper Peninsula Power	97	103	40	47	0	
Transmission		40			40	
WPS Resources Total	138	147	40	47	2	0
U.S. Army Corps of Engineers		20		20	0	0
Lower Peninsula		50			50	7
Total	691	1272			719	95
HHI Index						**6185**

* Demand estimated

Upper Peninsula Electric Industry
Market Power Test
Market for On-Peak Non-Firm Energy
(FERC HHI Methodology)

Description	Winter Demand	Winter Capacity	Purchases	Committed Power Sales	Available Capacity	Percentage
Municipals*						
Crystal Falls	3	1	2		0	0
Escanaba	30	26	10		6	1
Marquette	60	105		38	8	2
Newberry	3	5	3		4	1
Norway	3	5	2		0	0
Cooperatives						
Cloverland	44	13	23	3	0	0
Investor Owned Utilities						
Edison Sault Electric	159	33	99	7	0	
Wisconsin Electric	500	686	38	25	199	
Transmission		175			175	
Wisconsin Energy Total	659	894	137	32	340	79
Wisconsin Public Service	30	4				
Upper Peninsula Power	182	103	40	47	0	
Transmission		0		0	0	
WPS Resources Total	212	107	40	47	0	0
U.S. Army Corps of Engineers		20		20	0	0
Lower Peninsula		70			70	16
Wisconsin Transmission						215
Total	1014	1246			429	315
HHI Index						**6583**

Upper Peninsula Electric Industry
Market Power Test
Market for Off-Peak Non-Firm Energy
(FERC HHI Methodology)

Description	May Demand	Winter Capacity	Purchases	Committed Power Sales	Available Capacity	Percentage
Municipals*						
Crystal Falls	2	1			0	0
Escanaba	18	26	10		18	3
Marquette	35	105		38	33	5
Newberry	2	5	3		6	1
Norway	4	5			1	0
Cooperatives						
Cloverland^	23	13	23	3	9	1
Investor Owned Utilities						
Edison Sault Electric	85	33	59	7	0	
Wisconsin Electric	384	679	38		334	
Transmission		0		0	0	
Wisconsin Energy Total	469	712	97	7	334	49
Wisconsin Public Service	41	4				
Upper Peninsula Power	97	103	40	47		
Transmission		0		0		
WPS Resources Total	138	107	40	47	0	0
U.S. Army Corps of Engineers		20		20	0	0
Lower Peninsula		110			110	16
Wisconsin Transmission		175			175	
Total	691	1279			686	74
HHI Index						**2657**

* Demand estimated

Upper Peninsula Electric Industry
Market Power Test
Fully Competitive Wholesale and Retail Markets
(FERC HHI Methodology)

Description	----------Firm Energy---------- Winter MW Capacity	Percentage	------Non-Firm Energy------ Winter MW Capacity	Percentage
Municipals*				
Crystal Falls	1	0.1%	1	0.1%
Escanaba	26	2.5%	26	2.5%
Marquette	105	9.9%	105	9.9%
Newberry	5	0.4%	5	0.4%
Norway	5	0.4%	5	0.4%
Cooperatives				
Cloverland	13	1.2%	13	1.2%
Investor Owned Utilities				
Edison Sault Electric	33	3.1%	33	3.1%
Wisconsin Electric	411	38.8%	411	38.8%
Transmission	245	23.1%	0	0.0%
Wisconsin Energy Total	689	65.0%	444	41.9%
Wisconsin Public Service	4	0.4%	4	0.4%
Upper Peninsula Power	103	9.7%	103	9.7%
Transmission	40	3.8%	0	0.0%
WPS Resources Total	147	13.9%	107	10.1%
U.S. Army Corps of Engineers	20	1.9%	20	1.9%
Additional Firm Transmission	50	4.7%	50	4.7%
Non-Firm Transmission			285	26.9%
Total	1061	100.0%	1061	100.0%
HHI Index		**5007**		**2229**

Appendix B

Upper Peninsula Market Power Report

Prepared By The Staff Of The Michigan Public Service Commission

June 5, 2001

APPENDIX B

Behavioral Model[1]

In order to simulate the effect that a high concentration of generation and transmission capacity could have on U.P. market prices, Staff has modeled the outcome of a market for electricity under two scenarios. In one scenario, Staff has assumed that the market is fully competitive and that no price regulation is exercised by the State or the Federal Government. This is not currently the case. If prices remain regulated, there is little need for a market power analysis, since presumably price regulation and obligation to serve will act as a surrogate for competition and constrain the exercise of any market power. If this is not the case, one must use a frame of reference to gauge the likely effects of market concentration. That reference is usually taken to be a competitive market. Competitive markets typically serve as a reference point because they yield efficient outcomes, that is they maximize the value of production given society's resources. Other market models fail to produce this efficient outcome.

Staff's analysis begins with the results one would expect with a competitive market. In this competitive model, prices are driven to marginal cost. As long as the marginal cost of production is less than or equal to the market price, the owner of a generating unit will operate and sell into the market. As generators compete based upon their marginal costs, prices eventually move to equal the marginal cost of the last unit called into service to satisfy market demand. This is consistent with short-run profit maximization in competitive markets, and would exist in a market with many producers and sellers of electricity

The second scenario recognizes Wisconsin Energy Company's (WEC) generation and transmission dominance in the U.P. market. It also assumes that full customer choice has been implemented in the U.P. and that price regulation for generation services no longer exists. In this scenario, Staff assumes that all other generators in the U.P. belong to a "fringe" of producers. These generators, whether municipal or private are small enough relative to the market and WEC to be "price-takers". The fringe generators cannot influence the market price because of their relatively small sizes and, instead, take the market price as given. WEC, on the other hand, is assumed to be a "strategic" player. It is so large relative to the other firms in the market that it can influence the market price by its decisions regarding production of electricity; it can cause price to rise by withholding electricity production or cause it to fall by increasing production. As a strategic player, WEC is assumed to vary its production of electricity and change the market price in a manner that maximizes the Company's profits. WEC's behavior is modeled to assume that it takes the output of the fringe firms as a given and then seeks to

[1] The development of the model used in this report draws on the work of Severin Borenstein, James Busnell, and Christopher R. Knittel in "Market Power in Electricity Markets: Beyond Concentration Measures", February 1999. The Borenstein, Busnell, and Knittel paper was part of a working series of papers for the Program on Workable Energy Regulation of the University of California Energy Institute. California Energy Institute papers can be viewed at http://www-path.eecs.berkeley.edu/ucei/

maximize its profits given the remainder of the market demand. This follows a Cournot format, representing a market that is not competitive.

Analysis of market concentration through a simulation requires a demand curve. The demand curve associates various quantities demanded by consumers with market prices for the product. For this analysis, Staff makes use of a constant elasticity of demand model that is "anchored" to various demand levels associated with current U.P. prices. The anchor demand levels represent various intensities of demand including near peak, and shoulder demands. The general form of the market demand curve takes the form:

$$Q_m = D(P) = kP^{-\varepsilon}$$

The strategic firm, WEC, takes as given the likely output of the fringe generators. Therefore, its demand curve will appear as:

$$Q_W = kP^{-\varepsilon} - Q_f$$

Where Q_f represents the output of the fringe firms, Q_m represents the market demand, P represents market price, k is the anchor quantity used to represent the various levels of demand, and ε represents the elasticity of demand.

One of the critical components of any market simulation is the elasticity of demand for a firm's product. Elasticity of demand is a measure of how responsive market demand for a product is to changes in its price. Generally, the elasticity is dependent on the availability of alternatives to the service or product, the importance of the product to the consumer, and amount of time available for consumers to respond to price changes. Products with high elasticity of demand generally have close substitutes, and this limits the ability of any producer to raise price above its cost. Consumers of products with high price elasticity will respond quickly, reducing the quantity of product purchased substantially if price rises. On the other hand, if price declines, consumers of these products will increase purchases substantially as the product is now more attractive relative to its close substitutes. The opposite is true for products that have a low elasticity of demand, or are inelastic. For these products, demand is not particularly responsive to price changes. This is a characterization of goods for which there is no close substitute.

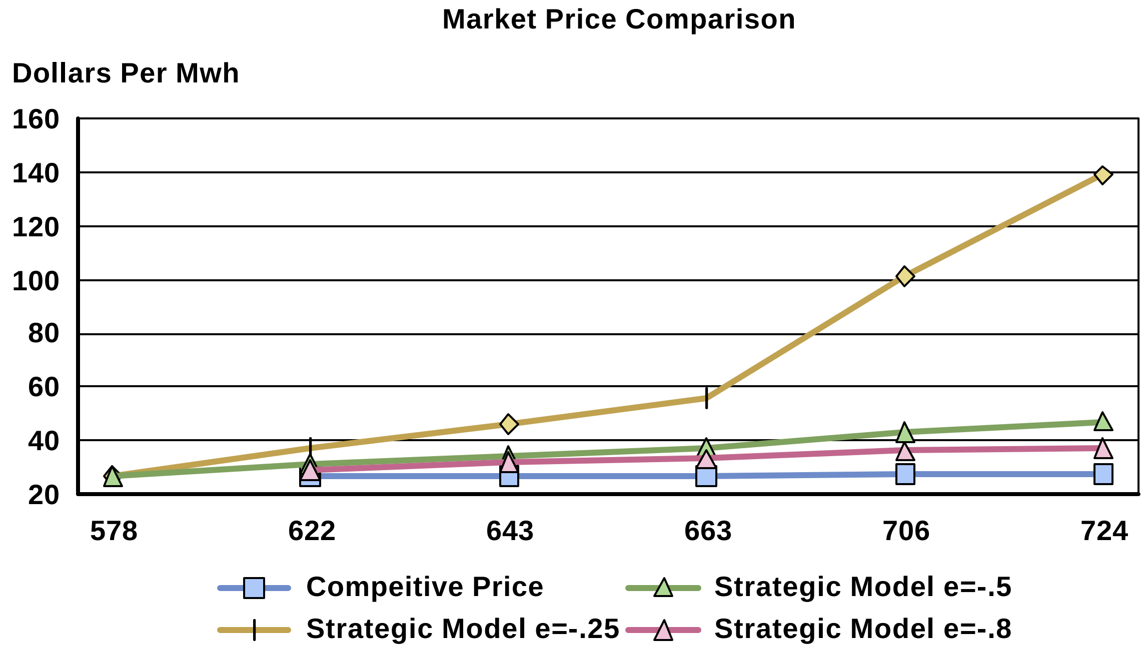
The objective of this analysis is not to calculate the precise outcome of U.P. markets if price deregulation ceased and customers were required to select a non-regulated provider. Instead, Staff estimates the price differences that would be produced under various assumptions of demand elasticity between a fully competitive market and one characterized by a single, large strategic competitor, i.e. a firm capable of exercising market power. It is easier to arrive at a plausible range for price elasticity in assessing market power than to rely only on a point price estimate, assuming a future deregulated market. If the plausible range shows a pattern of significantly different prices between the competitive model and the strategic model, Staff deduces the likelihood that market power would be exercised in such a market.

Staff calculated marginal cost data from P-521 reports to the Commission or directly from generators. The marginal production costs are composed of fuel, plus one-half the O&M costs for each unit. The marginal costs used are shown below:

Production Unit	MW Capacity	Estimated Marginal Cost $/MWH	Cumulative Capacity
Hydro	116.1	6.20	
Presque Isle #7,#8, & #9	234.9	22.81	351.0
Presque Isle #5 & #6	160.2	27.54	511.2
Presque Isle #3 & #4	104.4	27.84	615.6
Presque Isle #2	33.3	32.39	648.9
Shiraz Unit #3	39.6	36.00	688.5
Transmission/Lower Peninsula	70.0	40.00	758.5
Transmission/Wisconsin	40.0	40.00	798.5
Shiraz Unit #2	18.9	41.00	817.4
Escanaba	23.7	41.30	841.1
Presque Isle #1	22.5	42.71	863.6
Shiraz #1	11.2	45.00	874.8
Peaking Units	99.8	80.00	974.6
Total	974.6		

In Staff's examination of the U.P. markets, it has used price elasticities of -0.25, -0.5, and -0.8. Actual price elasticities are frequently estimated to be in the lower portion of this range, sometimes as low as -0.1. Currently, the U.S. Department of Energy uses a price elasticity for electricity of -0.25.

The next chart displays estimated prices in the U.P. market under fully competitive conditions and under the alternative scenario of WEC as a strategic firm exercising market power.



Competitive prices are assumed to follow marginal production costs. Prices for the strategic scenario are calculated assuming one dominant service provider seeking to maximize profits. From the chart, it is clear that prices from the strategic scenario are consistently above competitive prices after the U.P. load reaches about 578 MW's. This is the level represented by hydros and Presque Isle must-run requirements assuming WUMS at 80% peak, and "base load" municipal units. Staff assumes that participants have little discretion in dispatching hydro units. The lower the elasticity of demand, the greater the disparity of prices between the two models. Also note that as load presses on available generation, prices rise steadily under the strategic model. This indicates that as load moves through the shoulder period and into peak the ability to exercise market power is increased substantially.

If one were to assume increased transmission capacity into the U.P. and also assumed that Wisconsin markets were competitive, the range over which market power could be exercised would be reduced. The range would be constrained toward the on-peak loads, a common finding of strategic market analysis in the electric utility industry. Staff believes that the change in the range over which market power could be exercised would depend on how much additional transmission capacity was assumed to become available and how competitive Wisconsin markets were assumed to be.

Staff also notes that demand elasticity also plays a large role in determining how much prices in a non-competitive market will deviate from the prices that would be produced by a competitive market. Again, the results of Staff's model conform to those produced by other strategic models, and indicate that the more elastic is the demand for a product, the more constrained is the strategic players ability to raise prices above the competitive level.

Michigan's Upper Peninsula
Major Electricity Industry Assets