FACTORS AFFECTING INDIANA ELECTRICITY PRICES IN COMPETITIVE MARKETS

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Chapter 1: Summary and Model Overview

Motivation

Large power companies have driven up electricity prices in California by throttling their generators up and down to create artificial shortages, according to dozens of interviews with regulators, lawyers and energy industry workers....The California Energy Commission calculates that an average of 14,990 megawatts of generating capacity, nearly a third of the state's total, was unavailable each day in April because of plant shutdowns, more than four times as much as a year ago....But an extensive investigation by The Chronicle has found that not only were generators shut down to boost prices but these "gaming" tactics contributed to the plants' deteriorating condition...."We suspected it," said Jim MacIntosh, the manager of grid operations for the ISO. "It was a sure factor in driving up prices." Such swings in unit output, he said, "would only make sense in a scenario when they're trying to game something. Otherwise, why would they do that? They're tearing their units up." (1)

The above quote provides an early warning for those policymakers entrusted with the responsibility of ensuring the proper functioning of the electricity generation, transmission, and distribution systems in the Midwest. It also should provide a wake-up call for those customers in such markets here in the Midwest -- in particular, present and future "poles and wires" distribution companies and others -- who will increasingly have to satisfy their power needs from the open wholesale electricity markets. It also underscores the importance of Indiana policymakers to having analytic tools that capture the effects of such behavior.

There is no evidence that such withholding has taken place in the past in Midwest markets, nor is this report predicting that withholding will take place. However, it must be recognized that in market situations when only a few competitors have power for sale, there is a strong economic incentive to withhold power, particularly when demanders have few options to avoid purchasing the electricity.

The New Modeling System

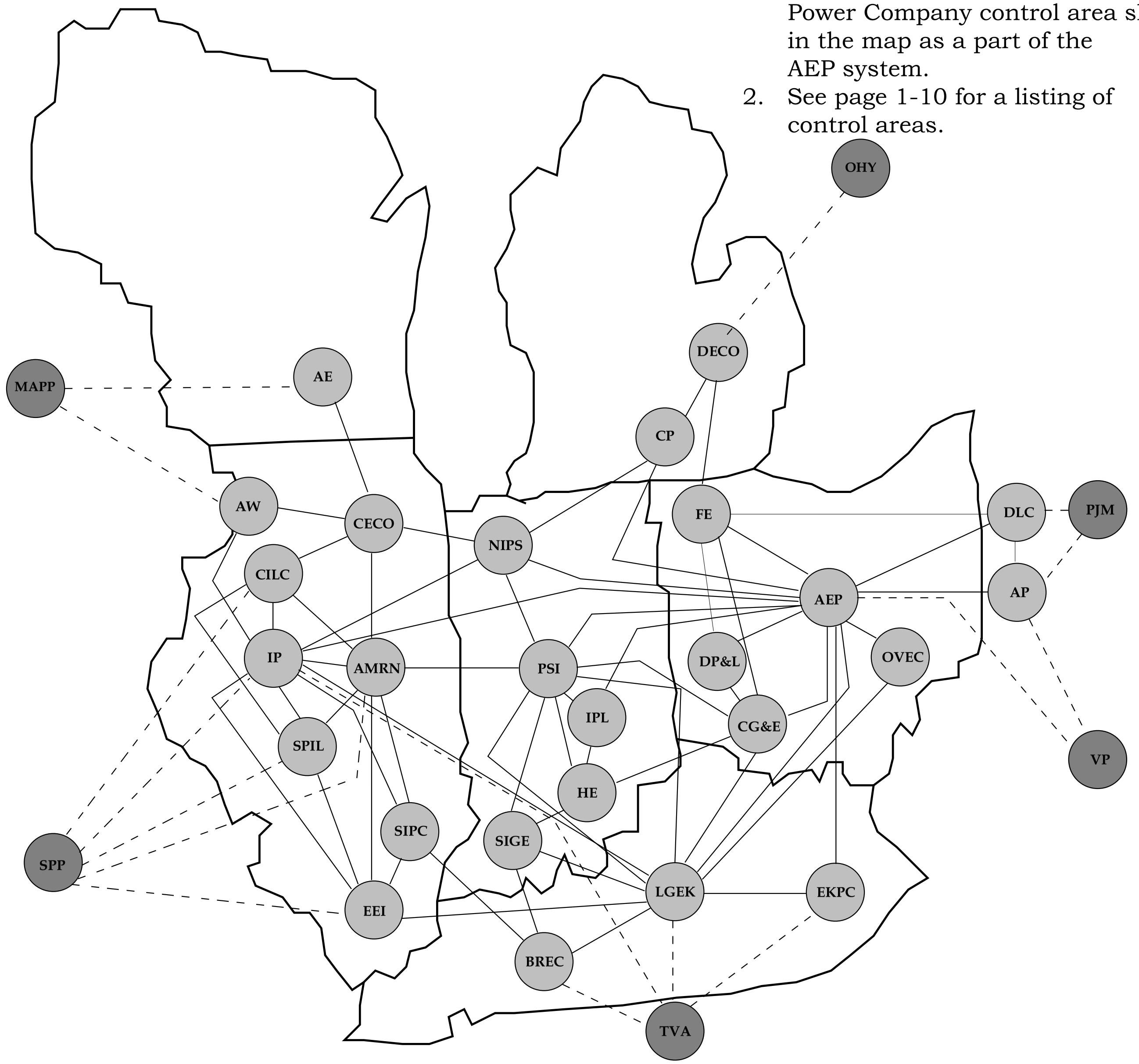
This report describes the results of a set of simulations of a typical hour of peak demand in 2003 using an improved price forecasting system for the Midwest. Developed by the State Utility Forecasting Group (SUFG) over the past two years, this new system can simulate the impact of generation withholding on electricity prices in Indiana and elsewhere in the Midwest. The system models expected wholesale electricity prices under various scenarios in each of 26 control areas* in the region as depicted in Figure 1-1.

It is important to recognize that the situation simulated does not require any further restructuring of the Midwest markets. In particular, since it simulates only the behavior of the supply side of the wholesale, not retail markets, the simulations are unaffected by any restructuring changes in electricity retail markets except as such changes might affect the amount of electricity used by customers in the control areas.

* In this report, the term control area refers to a geographic region with all generators and loads in the region located in the same place. These areas roughly correspond to traditional utility service territories.

Figure 1-1. Network Topology of the Model

Notes:
1. Indiana has six control areas counting the Indiana Michigan Power Company control area shown in the map as a part of the AEP system.
2. See page 1-10 for a listing of control areas.



The model structure assumes that the generation and transmission markets are operated in such a way that all utilities and independent power producers are able to sell power to all wholesale customers wherever it is economical and technically possible to do so.

Thus, it addresses an issue quite independent of the deregulation of retail markets, which would simply allow others besides local distribution companies to purchase electricity in such markets. The only change from present practices in the Midwest is that the forecasting system focuses on the likely pattern of wholesale power prices in Midwest markets if all power were to be bought and sold in such markets.

Currently, only a limited amount of power flows through wholesale markets; the bulk is generated and sold directly to native load customers by each local distribution company, with the price dictated by the regulatory compact.

In past reports (1996 and 1999), SUFG's regional forecasting system assumed that the wholesale markets functioned perfectly, in that electricity was free to flow to all markets, constrained only by the capacity of the transmission system and the physical laws that govern electricity flows. Further, once electricity arrived at the point of sale (the control areas), competition forced all hourly transactions to take place at the marginal cost of the most expensive unit dispatched to meet demand in that hour.

The following quotes are instructive in further describing this competitive scenario.

> *In a competitive market, sellers take price as given and expand production and sales as long as the cost of producing and delivering an additional unit is less than market price. Sellers behave in this way because they cannot profitably raise the market price by reducing the output they supply. A market is likely to be competitive if there are many sellers or if entry of new sellers is easy.* (2)

> *Prices at times rise above the variable cost of production of the most expensive plant serving a market even if no producer exercises market power. This can occur when demand exceeds maximum available supply at the bid price of the most expensive plant, and transmission constraints make it impossible to bring in more power from other regions. Prices will rise until they bring supply back into balance with demand.* (3)

Recent developments in California and elsewhere, where market clearing prices during peak periods have obviously departed from anything resembling their costs of production, have made it clear to SUFG and other analysts that continued use of the perfect competition assumption was no longer defensible.

This report, then, details recent improvements in, and experiments with, the SUFG regional price forecasting system, which now allows the analysis of the impact of purposeful withholding of output from the market similar to the type mentioned in the quote above. The new model maintains the capability of our previous system to forecast Indiana electricity prices with restructuring under a wide range of demand and supply scenarios.

Why should such market power be of interest to electricity stakeholders? The following quotes provide an answer.

> *Market power may be exercised by a single firm or by two or more firms acting simultaneously. Companies may exercise market power simultaneously without an agreement to limit competition, or they may reach an agreement to collude. Collision is tacit if the agreement is reached without overt communication or sharing of profits. A colluding company foregoes profitable opportunities to increase sales because it understands that, if it were to cheat on the agreement, other colluding companies would punish it by taking steps that would lower its profits.*

> *When an electric generator exercises market power, buyers pay higher prices for electric power. Consumption patterns are distorted (since) too little electricity is consumed. (Also,) costs of generation are increased for society because some efficient generating units belonging to the company (or companies) exercising market power are not used while less efficient units owned by others are used instead.* (4)
>
> *Electricity markets are dynamic and can change dramatically over the course of a few hours, creating opportunities to exercise market power even though the market may be competitive under most circumstances.* (5)

In addition to simulating the exercise of such market power and in order to provide some indication of the impact of such behavior relative to other factors, this report also simulates the price impact of three other factors expected to be major determinants of price in the Midwest areas:

- The amount of transmission congestion in the system.
- The amount of new generation capacity expected to come online in the near future.
- The amount of demand-side management expected in the near future.

All four factors are expected to play a significant role in determining Indiana ratepayer prices if the Midwest electricity markets continue to move to more open markets. This can be expected with or without deregulation at the retail level as the wholesale markets and regional transmission structures develop in the Midwest.

While the details of this environment will govern to a large extent which factors will dominate, enough is now known about the likely general structure of the emerging markets to be able to construct a preliminary model of the Midwest -- East Central Area Reliability Coordination Agreement (ECAR)/Mid-American Interconnected Network (MAIN) -- wholesale electricity market behavior. The modeling system, as yet, is not capable of producing a reliable forecast of the likely combined impact of these factors; however, it can be used to simulate the relative magnitude and direction of each of these four factors taken individually.

Summary of the Base Case

To start with, the base case simulation and the four variants described below all are carried out for a time period where use of the system is high, and thus represent a "worst case" scenario with regard to stress on the system. During off-peak periods, the system should be able to function efficiently, and neither the availability of sufficient transmission or generation capacity nor the problem of insufficient competition should significantly affect the price of electricity, which under these conditions should be near to the marginal cost of production.

The analysis starts with a projection of the pattern of electricity prices in Indiana for a typical peak period in 2003 given the following default assumptions:

- Price sensitive energy use and peak demand in each of the 26 control areas within ECAR/MAIN shown in Figure 1-2 will grow at 2 percent per year in the region.
- Transmission tie-line capacities in the regions are set at expected 2003 levels.*

* Also known as interties, tie-lines are the transmission lines that electrically connect two control areas. They are represented in Figure 1-1 by the lines connecting the circles. Where multiple tie-lines exist between a pair of control areas, they are represented by a single equivalent line.

- Only 33% of the total capacity (about 8000 MW) of each of the power plants announced to be online in 2003 will be available by 2003. This avoids having to guess which units would or would not be constructed in their entirety. This results in a more dispersed capacity pattern than is likely to be the case in the future as specific plants are cancelled in their entirety.

- Non-collusive withholding by the 25 investor-owned utilities (IOUs) and independent power producers (IPPs) is assumed. As will be explained later in this report, this present pattern of ownership results in small enough market shares for each as to create little incentive for any of the utilities to withhold significant amounts of generating capacity from the market.

Summary of the Results of the Four Scenarios

This initial analysis of the sensitivity of Indiana electricity prices to changes in these assumptions show that:

- While localized electricity transmission congestion may be a problem for particular planned generation additions, congestion at the regional (tie-line) level appears to be a problem for Indiana during peak demand periods only if overall transmission utilization rises well above current levels. Otherwise, only modest departures from the price pattern in our base case should be expected. This is a direct result of Indiana's favorable location in the middle of the highly connected ECAR/MAIN system. However, this conclusion must be provisional for now, and must await confirmation by an improved version of the model that includes as constraints additional physical laws that govern power flow patterns in such models and improved data on the transfer capabilities of ECAR/MAIN.

- As in the case of transmission congestion, only modest departures from the price pattern in our base case would be expected to take place if less than the 8000 MW assumed to come on line by 2003 in fact comes on line. The reason is this base case assumption results in sufficient additional capacity to meet growing demands, minimizing the ability of market participants to withhold output and thus artificially raise prices.

- As expected, supply reducting collusive behavior by a cartel of suppliers can present a problem unless regulators ensure that there will be sufficient competition among suppliers during peak hours at each control area of the ECAR/MAIN system.

- A far more likely problem that will result if too few competitors are present in the Midwest is the phenomenon of each firm independently withholding a part of its output in the hopes of driving up the price on its remaining sales. This behavior is hardly illegal, and is certainly to be expected when the number of competitors is small enough so each thinks it can have an influence on prices. This is true despite protests from customers about "price gouging," and departures from what might be considered a just and reasonable price. Preliminary results indicate that such non-collusive withholding can cause serious problems in Midwest markets during peak demand periods.

- Reductions in demand caused by demand-side management (DSM) and conservation can have a significant impact on prices in the ECAR/MAIN region during periods of peak demand. The ability of DSM to simultaneously capture the benefits of reduced congestion on the transmission system, the benefits of increased available supply, and the combined effect of these two factors to increase competition throughout the region are potent arguments for including DSM in any Midwest energy policy. The more options and incentives consumers have to alter their use of electricity through real time pricing, load curtailment, or other standard DSM measures, the less market power can be exercised by suppliers, making all consumers better off, both in terms of lower prices (working through the increase in demand elasticity associated with DSM) and lower likelihood of power shortages during peak periods.

It should be recognized that the best short-term response to the possibility of artificially induced price spikes in our wholesale markets is for policy makers to do everything possible to encourage and allow purchasers in such markets to have other options besides purchasing the electricity.

Model Overview

All of these results are based on a set of models recently created by the SUFG staff. These models simulate the behavior of ECAR/MAIN electricity markets as they move toward a more open and competitive environment, with or without retail deregulation, taking into account the absence of perfectly functioning markets.

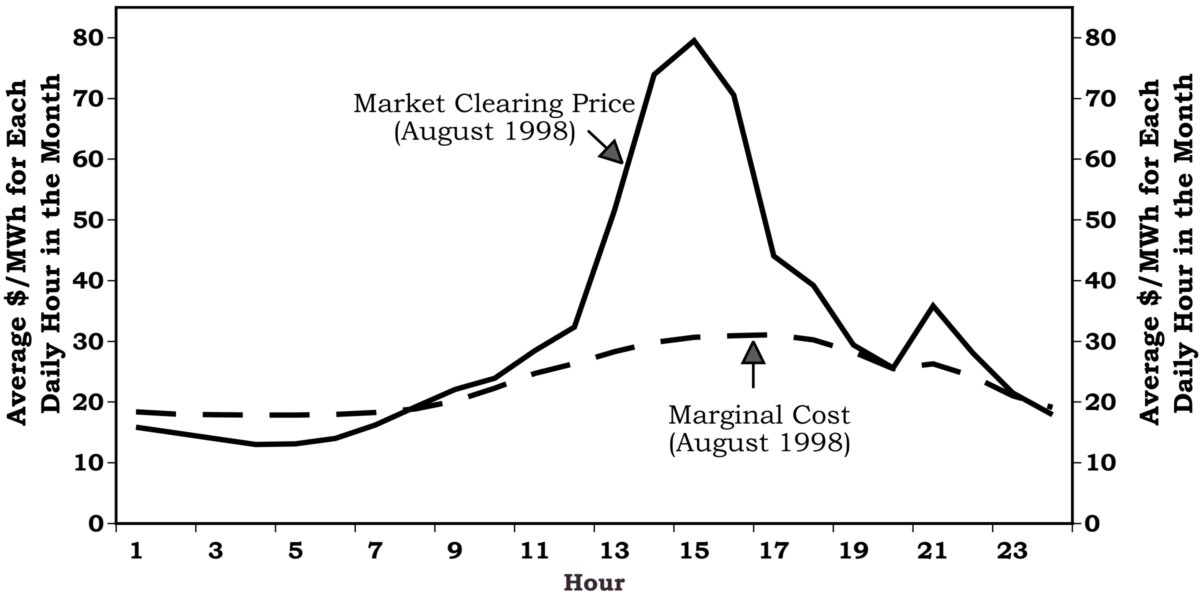
The models used in this study were developed to simulate the restructured wholesale markets in the Midwest based on observing the behavior of the restructured markets in the United States and around the world. In these restructured markets, such as California, Pennsylvania-Jersey-Maryland Power Pool (PJM), New York and New England, departures of prices from marginal cost most commonly occur during peak hours, and result in high prices during both the winter and summer peaks, but especially so during the summer peak. Figures 1-2 and 1-3 document this behavior for two markets -- the California Power Exchange (CAL-PX) and PJM -- for the month of August 1998. Note that during off-peak hours, prices approximate marginal costs while significant departures of price above marginal cost take place during peak periods. These peak hour price spikes are well documented in the literature, including the trade press and the websites maintained by the market operators in these restructured markets.

While such departures can be observed in perfectly functioning auction markets, they also can be an indication that competitors are adjusting their bids to maximize profits in a perfectly legal way -- no collusion, just each in a vacuum considering the reactions of its opponents to its strategic decisions.

The SUFG models assume that an independent third party would be entrusted to dispatch generators in the Midwest according to their supply bids and the relevant demand bids. As in the case in the PJM and New York power pool, regional market clearing prices are determined by a pool bidding system matching the supply and demand bids for every hour in each region -- in this case, in each control area. Bilateral contracting (buyers and sellers bypassing the power market and contracting between themselves for power) is not explicitly modeled, but prices for such contracts are assumed to be determined the same way as pool bidding. This assumption is reasonable for this analysis because the price of bilateral contracts seems to converge to pool prices in both the California and PJM markets. (6)

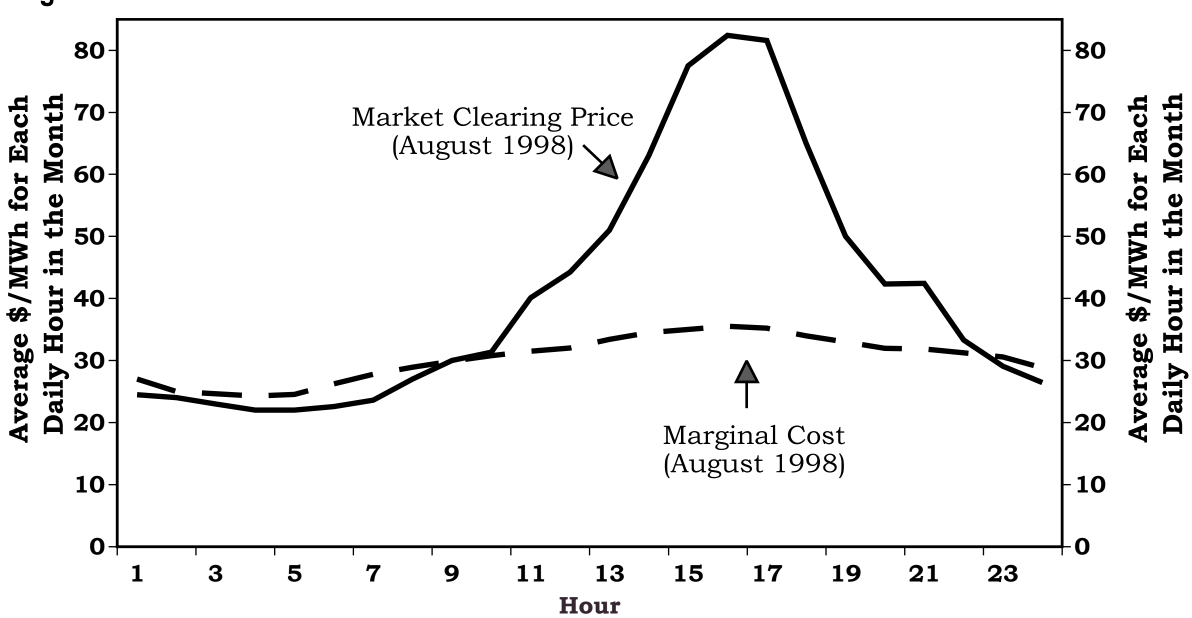
For this analysis, the models are used to simulate the behavior of the generation owners in the ECAR/MAIN region during the peak period of 2003 if all owners were allowed to compete for shares of ECAR/MAIN's 26 regional electric energy demands. The demand for electricity at each control area represents the total control area demand and is therefore an aggregate across all rate classes. 2003 peak demand functions for

Figure 1-2 PJM: Energy-Weighted Average Wholesale Market Clearing Price and Marginal Cost



Source: Sparrow, F.T., Yu, Z., Lusan, D. "Estimation of Conjectural Variations of Competitive Electricity Prices and Consumer Response, Proceeding of the American Power Conference, 1999.

Figure 1-3. CAL-PX: Energy-Weighted Average Wholesale Market Clearing Price and Marginal Cost



Source: Sparrow, F.T., Yu, Z., Lusan, D. "Estimation of Conjectural Variations of Competitive Electricity Prices and Consumer Response, Proceeding of the American Power Conference, 1999.

each of the 26 control areas in the model were obtained in the following way. First, the hour when regional demand peaked for 1998 (a normal year) was determined (July 20 at 6:00 p.m.); next the actual demand for that system peak hour was determined for each of the 26 control areas, as was the average price paid by the control area customers for electricity. A linear demand function was then fitted through this price/quantity point, using a national average peak demand elasticity estimate* of -0.05 developed by the Energy Information Administration (EIA). (7).

Finally, each of the 26 fittted 1998 peak demand functions were assumed to grow at 2 percent per year (without affecting the elasticity) to obtain the 26 estimated 2003 peak demand functions. Further details on the estimation procedure are described in Appendix C.

The important improvement in the modeling system is the recognition that competition will not necessarily result in all prices equal to marginal costs. Rather, each competitor will think it can influence the market price by withholding output from the market, opening up the possibility that if their market share is sufficiently large, this could raise the price on their remaining output so much as to more than offset the decline in profit caused by the power withheld. Competition is assumed to take place in an hourly power market for each control area in the region. All transactions within a control area take place at the market clearing price. All markets are subject to the physical generation and transmission capacity constraints of the system on the supply side of the markets and the price responsive behavior of electricity consumers on the demand side of the markets. All markets are also subject to the behavioral assumption that all generating owners will try to find that pattern of production to meet local and export demand that maximizes their profit.

It is important to recognize that such models predict hourly prices for each of the control areas in Figure 1-1, and that these prices can differ for a given hour due to differences in the supply/demand/transmission situation in these markets.

Figure 1-4 shows the base case price dispersion for the hour analyzed in this report. The horizontal axis represents the nodes; the vertical axis indicates the relative market clearing prices for these control areas, ordered from lowest to highest. As expected, some control areas have lower market clearing prices than others due to their proximity to low-cost generating units, the transmission capacity situation, the demand characteristics of the control areas, and finally, the model's assumption that competitors will take advantage of the physical and economic constraints on the system by withholding power from the markets, which magnifies the price differences even further.

It should be emphasized that the price dispersion observed in Figure 1-4 has little relation to

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* Demand elasticity is defined as the percent change in demand divided by the percent change in price that brought about the change in demand. Thus, if a 10 percent decrease in price resulted in a 20 percent increase in demand the elasticity would be 2.

It is usually measured at a particular price/quantity point on the demand cure, and can also be defined as the slope of the demand curve at that point times the price divided by the quantity. Economists prefer elasticity to the slope of the demand curve as a measure of demand responsiveness since the elasticity does not depend on the units in which price and quantity are measured.

The -0.05 assumption used in this study means demand is not at all responsive to price changes, e.g., consumers during peak hours have few options but to pay whatever price the suppliers are charging, which of course, increases suppier effective market power.

any historical price dispersion data observed in actual ECAR/MAIN nodal data. The price dispersion shown in Figure 1-4 is an extreme scenario in that it assumes no new transmission expansion by 2003, 2 percent demand growth per year until then, only one third of the new units announced comes online and most importantly, competitors take maximum advantage of these physical constraints by withholding the profit maximizing amount of power from the markets, magnifying these price differences.

The impact of the single assumption of the ability of suppliers to drive prices up by withholding, rather than simply bid all their output into the market, is enormous in explaining the price differences. If perfect competition were assumed (all transactions in each of the 26 areas taking place at the marginal cost of the most expensive unit dispatched to meet demand in each area) the price variance shown in Figure 1-2 would be dramatically reduced. Instead of the large spread between lowest and highest prices shown in Figure 1-2, less than a 10 percent spread between the lowest and highest prices observed in the ECAR/MAIN network would be observed.

Model Taxonomy

Models of electric market behavior differ regarding the nature of the profit maximization problem faced by generation owners.

At one extreme, it can be assumed that all generating units are either owned by a single monopoly or that multiple owners agree to act as a cartel, controlling total output to maximize total profit. Either way, the result is the same; consumer prices are increased and electricity output decreased until the monopolist's profits are maximized.

The monopoly case is extremely unlikely, given vigilant oversight by regulators, antitrust lawyers, consumer groups and others. However, it is useful to construct the upper limit on price that results in this case given what is known regarding the region's demand response to prices and the region's costs of generation, transmission and distribution. The monopoly model assumes that for every hour, the monopoly/cartel chooses a level of output that equates marginal revenue to marginal cost in order to maximize the profit of the monopoly/cartel. This behavior is controlled by the hourly demand and supply functions and the capacity of the transmission system to move electricity from source to destination.

At the other extreme, perfect competition is assumed, e.g., it is assumed that the ownership of the generating units is so diverse that no individual owner can control enough of the output in the market to influence the market clearing price. Consequently, they take the current market price as a given and the market clearing prices reflect the marginal costs of the most expensive units dispatched to meet demand in any hour.

In between these two limiting unrealistic cases lies the real world that SUFG is modeling — the world of competition between a limited number of competitors — not so many as to make each think they have no control over prices, but not so few that workable full monopoly power is an option. In such imperfectly competitive markets, each must consider its competitors' reactions to output and price decisions — the so-called "gaming" modeling system.

The withholding model used in this report is based on a simple premise that -- as apparently is the case in California according to the quote at the beginning of this report -- each competitor will consider the possibility of withholding a portion of its output from the market in order to drive prices up enough for the remainder of its output to more than make up the profit lost by the supply reductions.

The Geographical Topology of the Models

As illustrated in Figure 1-1, the models represent 25 generation utilities and a number of IPPs, who are competing for business at 26 control areas connected by about 100 equivalent transmission lines. Each control area contains the name of the *home* utility now serving the native load of the control area; dotted lines connect the system of neighboring regions: Mid-Continent Area Power Pool (MAPP), Southwest Power Pool (SPP), Tennessee Valley Authority (TVA), Virginia Power (VP), PJM, and Ontario Hydro (OHY). The home utilities for each of the control areas are:

AEP (American Electric Power)

AE (Alliant East) and AW (Alliant West)

AMRN (Ameren)

AP (Allegheny Power)

BREC (Big Rivers Electric Corporation)

CG&E (Cincinnati Gas & Electric Co.) and PSI (PSI Energy Inc.) of Cinergy

CECO (Commonwealth Edison Co.)

CILC (Central Illinois Light Co.)

CP (Consumers Energy)

DECO (Detroit Edison Co.)

DLC (Duquesne Light Co.)

DP&L (Dayton Power & Light Co.)

EEI (Electric Energy, Inc.)

EKPC (East Kentucky Power Coop.)

FE (First Energy)

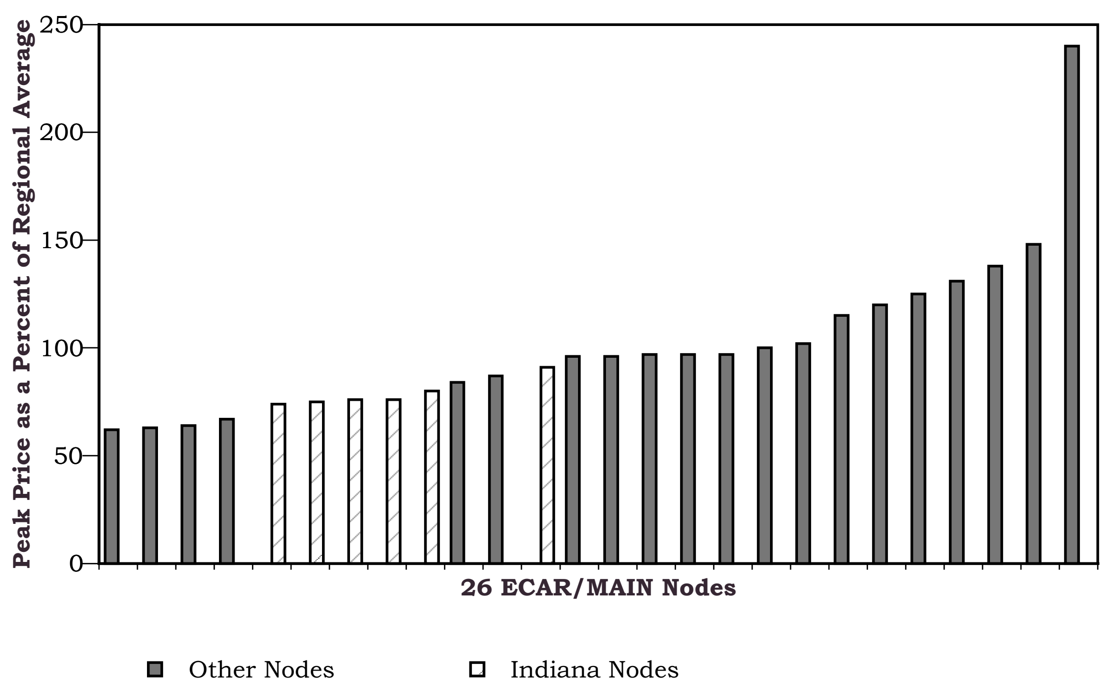
HE (Hoosier Energy Rural Electric Coop.)

IP (Illinois Power Co.)

IPL (Indianapolis Power & Light Co.)

LGEK (Louisville Gas & Electric Co. and

Figure 1-2. Peak Price Variation for ECAR/MAIN



Kentucky Utilities Co.)

NIPS (Northern Indiana Public Service Co.)

OVEC (Ohio Valley Electric Corp.)

SIGE (Southern Indiana Gas & Electric Co.)

SIPC (Southern Illinois Power Coop.)

SPIL (Springfield Illinois City Water, Light and Power).

Some companies are divided into two separate control areas due to weak transmission connections or because they do not perform joint dispatch. These control areas are Alliant East and Alliant West, PSI and CG&E. A few control areas in northwest MAIN are not included due to a lack of data, but will be included in future studies.

End Notes

1. "Power Juggling Ramped Up Price -- Insiders Say Manipulation Also Strained Equipment," Powermarketers online news, May 20, 2001.

2. Binz, R.J. and Frankena, M.W., "Addressing Market Power: The Next Step in Electric Restructuring," *Competitive Policy Institute*, p. 19.

3. Office of Economic, Electricity and Natural Gas Analysis, Office of Policy, U.S. Department of Energy, "Horizontal Market Power in Restructured Electricity Markets," , March 2000.

4. "Addressing Market Power: The Next Step in Electric Restructuring," op.cit., p 22-23.

5. "Horizontal Market Power in Restructured Electricity Markets," op.cit. p 22-23.

6. S.V. Vactor, "East vs. West: Comparing Electric Markets in California and PJM," *Public Utilities Fortnightly*, July 15, 2000, pp. 22-35.

7. Energy Information Administration, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Utilities, a Preliminary Analysis through 2015,* 1997.

Factors Affecting Indiana Electricity Prices in Competitive Markets

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Table of Contents

Table of Contents (Continued)

List of Figures

List of Tables

Foreword

In response to the changing nature of the electricity industry, the State Utility Forecasting Group (SUFG) has expanded its efforts to provide accurate, timely and useful input to decision makers in Indiana. While SUFG continues to maintain its traditional forecasting system, which predicts electricity prices and use as well as the need for new generating capacity under the present method of regulation, new models are being developed and updated that should be useful to the decision makers as they consider the pros and cons of various restructuring options.

This report is the latest of these efforts. In previous reports, SUFG has considered the likely impact on Indiana ratepayers of:

- a continued regulation scenario (SUFG's 1987, 1988, 1990, 1993, 1994, 1996 and 1999 forecasts) if regulation worked perfectly; and
- a switch to competition in the generation sector while maintaining the regulatory compact for distribution and transmission, assuming competition worked perfectly (1996, 1998 and 1999 forecasts):
  - if Indiana competes with the rest of the eastern interconnection (1996 forecast);
  - if Indiana exports and imports were set at 1997 levels (SUFG's 1998 interim report, pages 1-8 to 1-9); and,
  - if Indiana exports and imports are determined competitively, i.e., Indiana power would flow according to market forces (SUFG's 1999 report, pages 9-1 to 9-11).

This report moves the analysis one step closer to the real world by recognizing that markets are not likely to result in the economist's optimistic assumption that prices are equal to marginal costs. Rather, competition in the generation of electricity may very likely produce hourly prices well in excess of marginal cost.

This report is SUFG's first effort at forecasting the likely time pattern of electricity prices under more realistic conditions. It should be emphasized that this is a progress report towards the goal of developing a reliable forecasting methodology pursuant to SUFG's mandate to *develop and keep current a methodology for forecasting the probable future growth of the use of electricity within Indiana and within this region of the nation.* (Indiana Code 8-1-8.5, amended in 1985).

As in all first efforts, this report will be revised and improved upon as the methodologies employed are modified to reflect the latest advances in this developing area and new data become available. The information contained within should not be construed as advocating or reflecting any other organization's views or policy position. Further details regarding the forecast and methodology may be obtained from SUFG at:

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Chapter 2: The Results of the Analysis

The Impact of Congestion in the Tie Lines on Electricity Prices and Market Performance

To what extent will the capacity of the ECAR/MAIN transmission tie lines hinder the effective working of a more open market structure anticipated in the near future? Is the electricity transmission situation so tight here in the Midwest that any significant outages during peak demand periods will cause prices throughout the region to rise significantly? Or, is sufficient transmission capacity available to result in few, if any, price spikes due to transmission congestion and those limited to the small geographic areas directly impacted by line outages?

This analysis deals with the overall ability of the interconnected transmission system shown in Figure 1-1 to move electricity economically from one control area to another. The ability of the local transmission system to accommodate the addition of specific new generating units is not addressed here. The issue of local congestion is beyond the power of SUFG's current modeling system. Rather, the concern is the possibility of the ECAR/MAIN long-distance bulk transmission system being overwhelmed by the expected increase in the volume of economy sales between utilities as they search for maximum profit solutions in the more open markets.

Fortunately, the simulations indicate that in projected peak periods in 2003, the ECAR/MAIN transmission grid, with certain known exceptions, appears to be able to handle the increase without disastrous results, partly because it is highly interconnected (see Figure 1-1) and partly because of the current capacity situation. This is not to say there will be no problems with the transmission system — unintended power flows are the bad news that accompanies the good news of a highly interconnected system.

SUFG's simulations testing the impact of varying transmission capacity on ECAR/MAIN prices during a typical peak hour in 2003 are consistent with the conclusions reached this spring in the ECAR capacity reports for the summer 2001. They report that assuming curtailment of interruptible and direct control loads (about 3500 MW) and scheduled net purchases (about 2000 MW), the region's capacity margin would be above 14 percent. (1) Further, ECAR reports that of the 10 most limiting transmission facilities, only three are within Indiana. (2)

While the system was deemed adequate for the 2001 peak season, this does not automatically mean that ECAR subscribes to the transmission system being adequate in 2003. It does suggest that as of this year there were no significant problems anticipated in the near future.

The results of SUFG's transmission congestion simulations are presented in Figure 2-1, which shows the price sensitivity of the Midwest markets to assumed changes in the availability of transmission capacity. The horizontal axis plots assumed percent changes in the tie line capacity of the ECAR/MAIN transmission system; the vertical axis shows the percent response of Indiana's peak price to these changes.

The analysis was conducted by setting the capacity of all transmission lines in the model at the indicated levels, e.g., a 10 percent decrease means reducing all line capacities by 10 percent, running the simulation, and observing the percent change in price relative to the base case described earlier.

The cause and effect in these simulations is straightforward and instructive. The cause — lower transmission capacity between nodes in an electricity network — means less trading between high cost and low cost nodes, which in turn means less substitution of low-cost imported generation for higher cost native generation, increasing both the average price and the regional price dispersion shown in Figure 1-2. However, this is not the only causal relationship. Lower transmission capacity means more market power for local generators, which when exercised, boosts prices even further. To put it another way, adequate transmission capacity has two quite separate benefits:

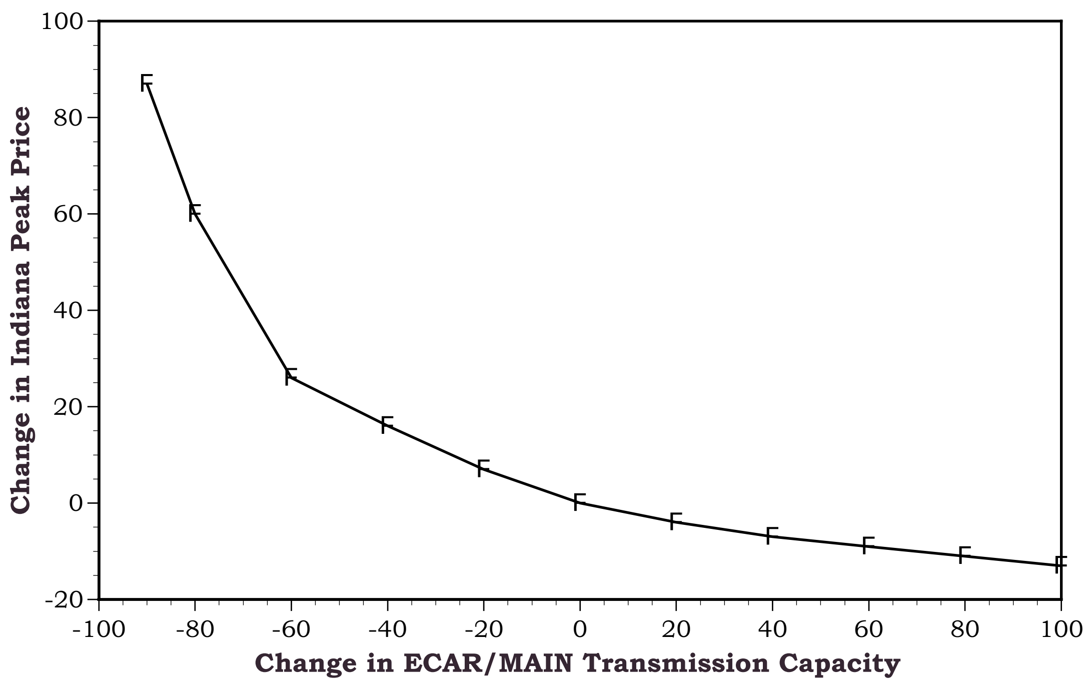
1. It allows cost reducing import substitution, which benefits importer and exporter alike.

2. It reduces local market power, reducing the size of the markups over cost the locals can charge.

What is of interest in the simulations is the relative insensitivity of electricity prices in Indiana to fairly significant decreases in available transmission capacity. This analysis demonstrated that electricity prices were not affected significantly by a small decrease in transmission capacity. The simulations showed that a 10% uniform decrease in all line transmission capacity resulted in only a 3.5% increase in price.

This result does not necessarily hold for all locations in the ECAR/MAIN region. Those regions that are more transmission capacity constrained than the Indiana control areas can be expected to see greater price increases than those shown here for Indiana under the same transmission capacity reduction scenarios. The point is that Indiana can expect to benefit from its central location in the well connected transmission line structure that characterizes the ECAR/MAIN region. If this analysis were to be carried out for other states/regions within ECAR/MAIN, the result could be quite different. As Figure 2-1 indi-

Figure 2-1. Sensitivity of Indiana Peak Price to ECAR/MAIN Transmission Intertie Capacity



cates, it takes reductions in the order of 33 percent or more before really significant average peak price increases develop in Indiana.

However, several assumptions result in the diagram understating the impact of reductions in available transmission tie line capacity.

First, by assuming that 33 percent of each of the approximately 24,000 MW total of announced capacity additions will be built amounts to a much more dispersed generation pattern than will in fact develop. What will happen is some plants will be built in their entirety while others will be canceled altogether. This 100 percent or nothing construction decision will put more strain on the transmission system than the situation SUFG is assuming.

Second, the analysis makes the optimistic assumption that the reduction in effective transmission capacity is spread evenly over all the lines in the ECAR/MAIN system. If all the reduction were to take place in selected Indiana congestion points, the price impact could be much greater.

Third, the present model does not include a representation of the physical laws that govern the pattern of power flow in electrical system -- the so-called "power flow" equations. Leaving these out understates congestion in electricity networks as pointed out later in "The Next Steps" section. SUFG plants to remedy this problem in the near future.

Finally, the model's transmission data are mostly taken from the Open Access Sametime Information System (OASIS), a system much criticized in recent years. As better data becomes available on transfer capability, they will be included in SUFG's system. Until then, any transmission congestion conclusions should be considered provisional.

To summarize, the tie line transmission congestion simulations SUFG ran confirmed the general conclusions reached in the most recent ECAR summer assessment study.

However, this result needs to be used with caution since it was created with the following assumptions:

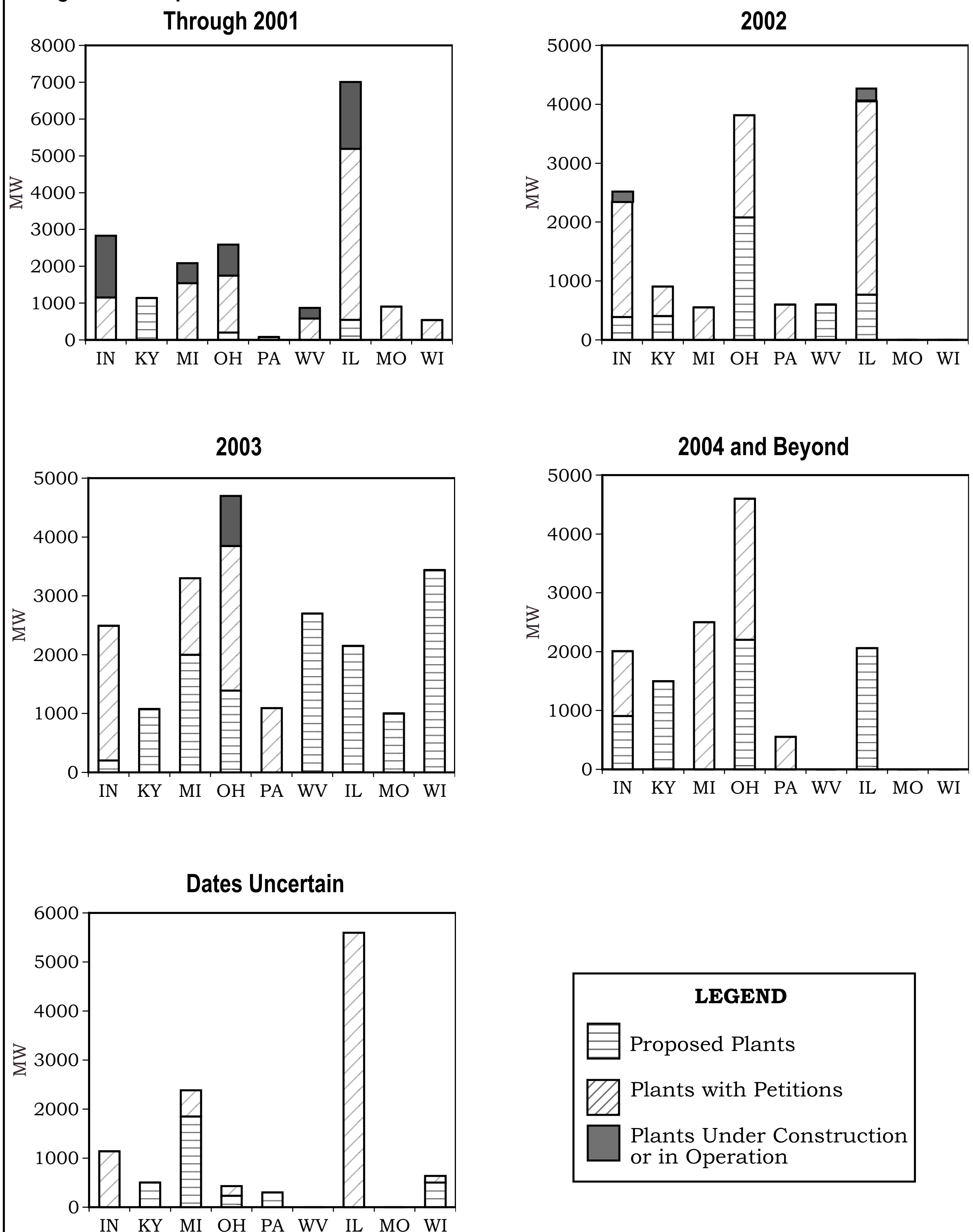
- Congestion within control areas will not be a problem, e.g., when new plants are built, expansion of the local grid to serve the capacity will also take place.
- The base case new generating capacity is assumed to be added in a dispersed manner.
- The change in tie line capacity is also uniformly distributed on all lines in the region.

Thus, while the conclusion that there is enough transmission capacity in our region to handle the expected volume of trade in 2003 without transmission congestion causing significant price increases is important, it does not rule out localized congestion problems taking place. Such eventualities should be anticipated and be planned for by a far more localized and detailed model than the SUFG modeling system.

The Impact of Limited Additional New Construction on Electricity Prices and Market Performance

Figure 2-2 and the maps in Appendix D give SUFG's latest (April 2001) count of the number of plants (141) and total MW (77,334) proposed for construction in the ECAR/MAIN region. If all the proposed plants were to come on line, the 77,334 MW would represent a 40 percent increase in the current ECAR/MAIN capacity of 165,000 MW. Clearly, not all of these plants will be completed since they would represent enough addi-

Figure 2-2. SUFG Estimates of Anticipated New Generating Capacity in ECAR/MAIN Region as of April 2001



tional capacity to satisfy the region's expected 2 percent growth in demand for the next 17 years (without considering additional reserve margin and retirement).

Figure 2-2 breaks down the 77,334 MW total into three categories.

1. Those under construction or in operation (6,412 MW).
2. Those approved or under review by various agencies (41,528 MW).
3. Those still in the planning process (29,394 MW).

The figure also shows that in total over 32,000 MW of these categories are expected to come online by 2003.

Furthermore, the number and capacity of new plants are constantly changing as new plants are announced and others are canceled. For all analyses in this study, the new capacity database was frozen at about 24,000 MW in 2003.

SUFG adopted as its base case for the simulations the assumption that approximately 8000 MW of new capacity -- about one third of the 2003 total at the time the analysis were performed -- would be producing electricity in the ECAR/MAIN region by 2003.

In many cases, the specific type of unit -- simple cycle combustion turbine (CT) or combined cycle (CC) -- was unavailable for announced new plants. In these instances, SUFG assigned a type based on information such as construction time, plant size, or cost. This results in a mix of 84 percent CT and 16 percent CC units through 2003. Since the more complex CC units take longer to build, many of the announced CC plants are scheduled to start operation after 2003 and are not included in these analyses. Other studies of new plant types indicate the CC portion to be around 40 percent through 2005.

Similarly, specific data on the specific fuel and operating costs of the new capacity were not available. SUFG developed operating costs for the plants using the SUFG fuel price forecast and typical plant efficiency and maintenance cost data for the plant type. This results in a variable production cost of approximately 3.2 cents/kWh for CTs and 2.1 cents/kWh for CCs.

The results are shown in Figure 2-3 with the base case of 33 percent built resulting in the base case price. As expected, if more than 33 percent is actually built, prices will drop as the pressure of the additional supply drives prices down throughout the region: conversely, if less than one-third is actually producing, prices will be higher.

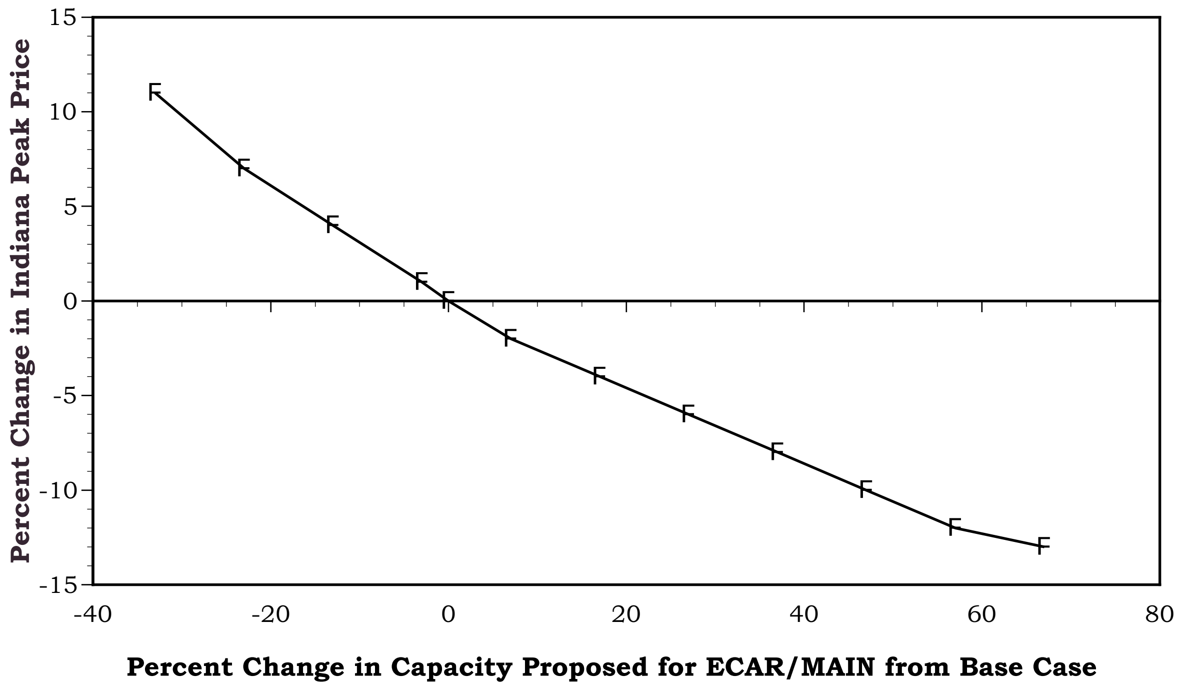
For this analysis, the percent increases were simply applied directly to the MW capacities at each of the known locations of the new units shown on the maps and the model was run with all other base case assumptions maintained.

It is somewhat surprising and counterintuitive to see how unresponsive electricity prices are to changes in the amount of merchant plant capacity built in the Midwest. The reasons are as instructive as they are unexpected and serve as an example of the usefulness of this type of analysis for policy makers.

The basic reason is the nearly identical operating cost estimates for gas-fired plants to be built here in the Midwest compared to the mix of nuclear and coal-fired plants with significantly differing operating costs that make up the bulk of existing capacity in the ECAR/MAIN region. New capacity additions with similar capital and operating costs result in flat spots (in fact two flat spots -- one for CT, one for CC) on the supply curves which determine market clearing prices. These flat spots in turn mean changes in supply can have little impact on equilibrium price given that enough capacity is added.

Figures 2-4a and 2-4b illustrate the result of a number of CTs with identical operating costs be-

Figure 2-3. Sensitivity of Indiana Peak Price to Merchant Generating Capacity



ing added to a control area's merit ordered dispatch function. In Figure 2-4a, a reduction in supply of ΔS results in a price increase of ΔP. In 2-4b, the same ΔS reduction after new plants with identical costs in the amount of ΔQ added to the supply curve means that the reduction leaves prices unchanged at $\overline{P}$.

The Impact of Market Power by Cartels and Non-collusive Withholding by Competitors on Electricity Prices and Market Performance

The previous two sets of simulations involve altering the ECAR/MAIN physical system parameters. The first set traced the consequence of varying the transfer capability of the transmission system while the second traced the consequences of changes in the amount of new capacity. The impact of these changes was estimated with the base case assumptions regarding the competitive nature of the Midwest power markets, i.e., no exercise of collusive monopoly power, and there is a limited amount of non-collusive withholding by market suppliers.

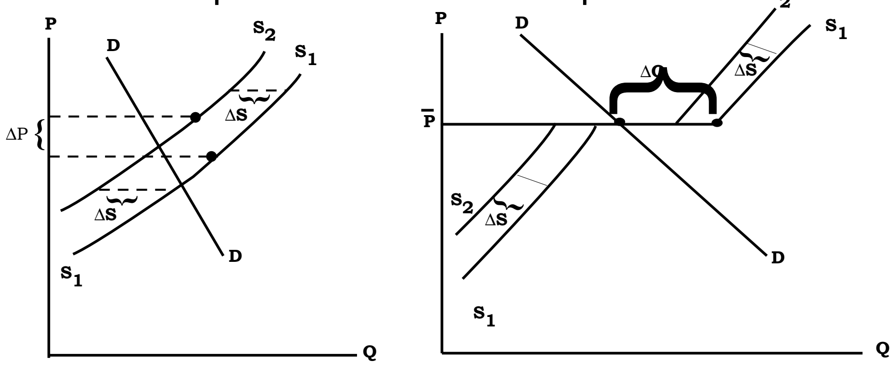
SUFG's regional output withholding model explicitly includes the impact of transmission limits and wheeling costs in measuring market power and imperfection when there is a limited number of competitors.

In this set of simulations the physical characteristics of the generation and transmission system are maintained at their base case levels, and the pricing consequences of differing assumptions regarding the nature of competition are explored. Figure 2-5 summarizes the SUFG simulations, all done for the peak hour in the study period year.

Figure 2-4. Price Impact of Adding Generating Plants with Identical Operating Costs

Figure 2-4a. Price Impact without "Flat Spot"

Figure 2-4b. Price Impact with "Flat Spot"



The Base Case (28 Suppliers)

In the base case, it is assumed that each of the 28 corporate suppliers in the ECAR/MAIN region acts independently, each choosing that level of production that maximizes its own profit. While withholding is present in this solution, its impact is mitigated by the large number of competitors and consequently small market shares, which reduces the amount of withholding each would choose. (Still the price is well above the marginal cost of the most expensive unit dispatched during the peak hour.) This base case is represented by the point on the figure corresponding to 28 competitors and a 0 percent deviation from the base price. The results of all the other less competitive scenarios will be compared to the prices prevailing in this base case by measuring on the vertical axis the percentage increase observed as the number of competitors is reduced.

The Monopoly Case

What would happen if one monopolist or a single cartel of all the players, were to control the production of power in the ECAR/MAIN region?

Prices skyrocket in the monopoly case shown in Figure 2-5. This should come as no surprise. Disastrous results arise as the monopolist reduces output until it could increase profits no more by further reductions. The results of the simulation show that the profit maximizing price would be about 5.5 times that expected in the base case.

As unlikely as this case is, it does serve as a warning to policy makers that without careful attention to ensuring sufficient competition in the region, bad things can happen to electricity prices.

The Consolidation of Producers Case (Variable Number of Suppliers)

A far more likely outcome of the exercise of market power is the situation where through consolidations or other corporate agreements, the 28 producers were reduced to a far fewer number of players, who, while they don't collude to reduce output and drive up prices, do independently withhold a portion of their output in expectation of increased profits. In this simulation, no price caps are assumed.

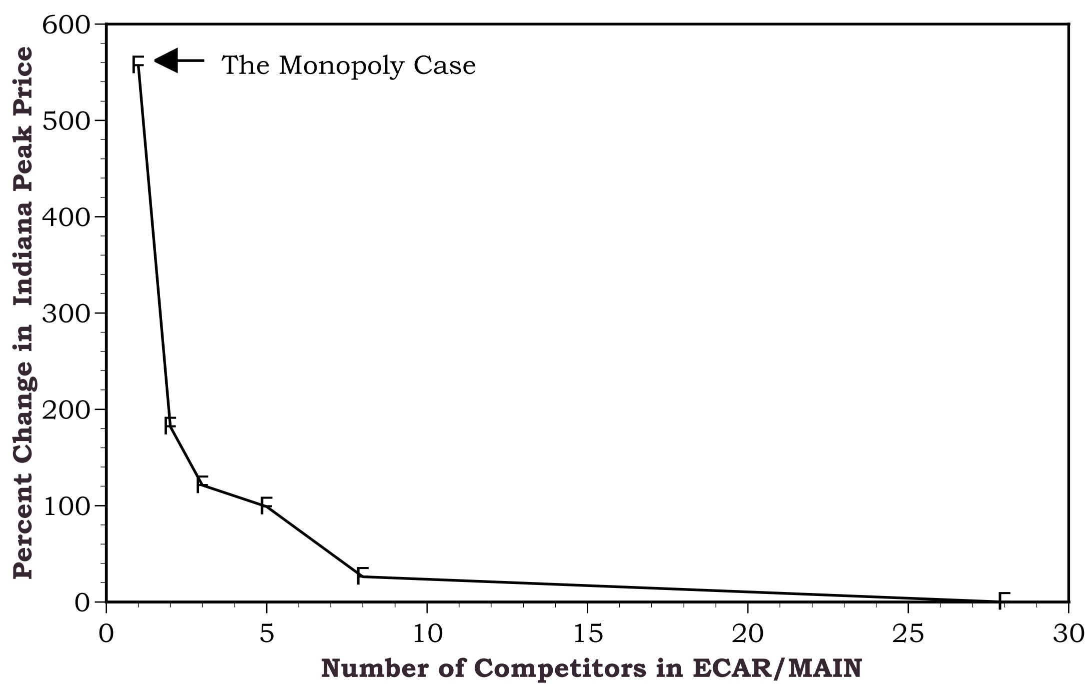
Figure 2-5 shows the dangers of reducing the number of competitors. On the horizontal axis are the number of competitors in the ECAR/MAIN region; on the vertical axis is the percent change in Indiana electricity price from the base case of 28 companies.

What the figure shows is that while a reduction in the number of competitors from the base case of 28 to 8 -- a near 75% reduction -- increases the average price only about 20%, a 100% increase takes place if the number decreases to 5, and an increase of almost 200% increase takes place if there are only two competitors.

Of course, the results are a direct result of the assumptions regarding how the competitors' calculate the optimal (profit maximizing) amount of product to withhold from the market. Other assumptions might lead to quite different results; if, for instance it is assumed that the dominant local utility in each control area acted as the price leader, and the other competitors simply followed. Further, the response of almost all withholding models depends on estimates of the elasticity of demand in each control area. Demand elasticity is a measure of how sensitive price is to reductions in the amount supplied -- highly elastic demand functions mean large reductions in the amount supplied produce small increases in price, a situation where many substitutes for the good exist. Conversely, low demand elasticities mean large price increases arise from small quantity decreases, a situation that arises when there are few substitutes for the product. As was explained earlier in this report and in Appendix C, the simulations assume a very low peak demand price elasticity of 0.05 -- the EIA's estimate of the elasticity during peak periods. Different estimates of demand elasticity will produce different results.

Finally, the results may be dependent on the initial price and quantity that the competitors choose to start their calculations regarding the

Figure 2-5. Sensitivity of Indiana Peak Price to Number of Competitors



optimal amount to withhold. While the SUFG staff has yet to encounter this situation, the staff has not been able to rule it out completely.

If this is the case -- that the starting point and path to the solution determines the solution -- then policy makers must take special care as the Midwest shifts from restricted to more open competition in wholesale markets to make sure that the transition groundrules for consolidation of producers lead to the most competitive (lowest price) solution possible under the circumstances.

In summary, the point of the exercise is not to condemn all consolidations outright. Undoubtedly, some are going to result in cost reductions that can be passed on to consumers. The point is that with consolidations resulting in fewer competitors at each control area, the likelihood that perfectly legal withholding will take place increases with each consolidation.

The Impact of Conservation and Demand Reduction on Electricity Prices and Market Performance

A recent study released by the Environmental Law & Policy Center (3) combined with the California experience has once again moved energy conservation and DSM back into the public spotlight. What role can such demand-side measures be expected to play in the Midwest as we move to a more competitive environment?

It is important that policy makers recognize the triple benefit of peak demand reducing DSM measures. Generally, DSM reduces the need not only for new generating stations and new transmission lines, but also can increase effective competition. (Exceptions exist to the rule that reductions in demand always result in less line congestion.) The excess supply created by DSM means more competition as owners are forced to offer electricity at prices that approach their marginal costs.

Thus, the simulations testing the impact on Indiana prices of reductions in peak demand should indicate a price sensitivity greater than the sum of the transmission congestion simulation and the supply curtailment simulation taken together.

Figure 2-6 shows the results of the simulation when demands are reduced uniformly by the indicated percentages. As predicted, reductions in peak demand caused by DSM results in larger percent price changes for a given percent change alone than either transmission capacity or additional generating units. However, the magnitude of the difference is surprising. The larger than expected decrease in price associated with reductions in demand is due to the added effect on prices of the increasingly competitive environment.

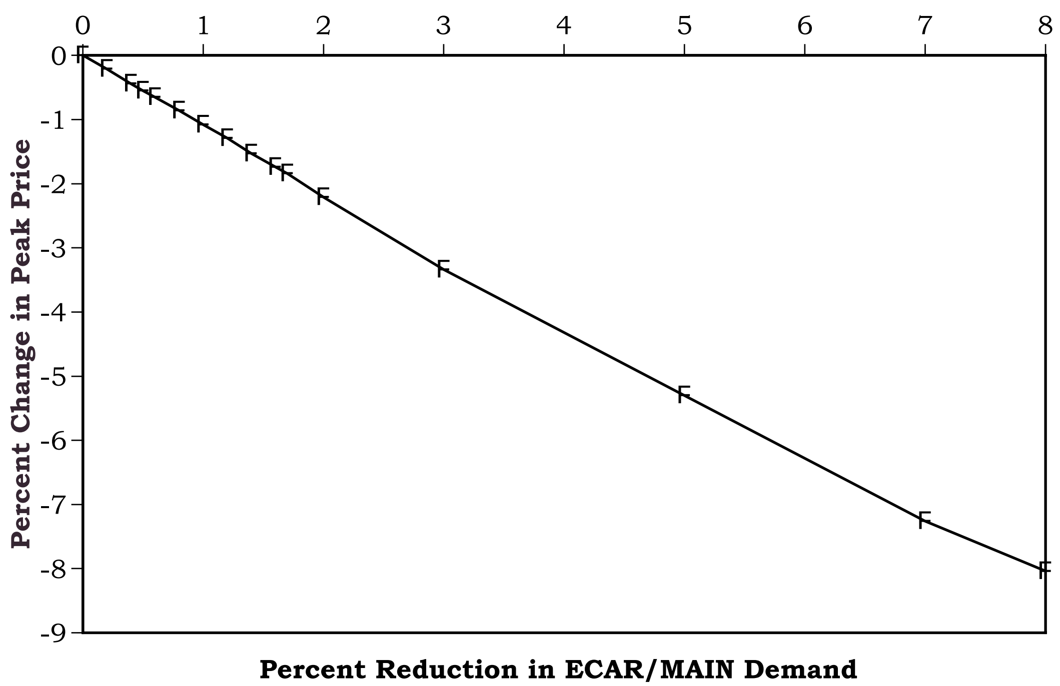
Thus, demand reduction combines the consumer price benefits of increased generation and transmission capacity with the benefits of increased competition. This is the advantage of DSM; it should not be overlooked when DSM measures are being considered by utilities and regulators.

The Next Steps

While the modeling system in its present form can be used to trace out the consequences of changes in each of the four factors described, its real usefulness will be to trace the consequences of combinations of these factors. This is because the combined effect may definitely not be the sum of the individual effects since in some instances the factors will offset one another (e.g., generally more congestion will result from more generating units coming on line) while others tend to reinforce one another (e.g., adding transmission capacity reduces congestion and increases effective competition).

Unfortunately, both computational and data problems make the current modeling system inadequate to the challenge of forecasting the net effects of the factors taken together.

Figure 2-6. Sensitivity of Indiana Peak Price to ECAR/MAIN Demand Reduction



Structural Problems

While the present model structure is a vast improvement over SUFG's previous modeling system, it still has its problems.

- **The Power Flow Equations**. Currently, the withholding model does not take into account the power flow equations that govern how electricity distributes itself among the lines in the ECAR/MAIN network. While other SUFG models contain these equations and adding them to this model is not difficult mathematically, solving the augmented model in a reasonable computational time has not yet been achieved. The omission of the power flow equations generally results in the model understating the amount of congestion in the system.

- **Capacity Expansion of the Transmission Lines**. While the model provides for additions to generating capacity, it does not allow for optimal expansion of the transmission system. This is not a problem in short-run (approximately three years) projections, but optimized transmission capacity expansion needs to be added if the model is to produce believable long-run forecasts.

- **Allocation of Power Losses**. Since the model keeps track of electricity flows by companies owning the generators and the cost of electricity delivered by each company plays a major role in determining market shares in withholding models, some method must be found to allocate power losses on common lines among those companies using the lines.

If a linear loss function were used, there would be no problem since all power flows would be burdened with the same percent loss. The problem arises when non-linear loss functions are used. Using the marginal line loss as a basis for charging all users will overstate the total cost of line loss to all users. This is hardly a new problem. Economists and others use two criteria -- fairness (equity) and efficiency -- to judge the various allocation methods. Almost inevitably the criteria collide: e.g., efficient solutions (no over/under use in the short run and correct price signals for long-run capacity adjustments) almost always are inequitable and vice versa.

The economists' solution usually takes the form of a two-part pricing scheme -- that portion of the price recovered as a function of use is set to send the correct price signal to producers and consumers, and a fixed charge is assessed users in proportion to their use to make the solution equitable. This is in much the same way that costs are recovered from large industrial customers -- a kWh energy charge which reflects the out-of-pocket costs of the generation of electricity -- a function of use and a kW capacity charge which reflects the utility cost of the peak demand by the customer the utility must be prepared to meet.

SUFG is working on an improved method of allocating such line losses, but the effort is still in a preliminary stage.

- **Reserve Margins**. Currently, the model uses capacity derates based on expected outage rates to capture the impacts of reserve requirements. This process involves reducing the capacity of each generator based on how often the generator might be expected to be unavailable, thereby providing a proxy for the reserve generation usually needed when a plant shuts down. A more sophisticated method, such as the simulation of an ancillary service market for reserves, may be needed.

- **Buyer Response to Market Price**. Buyers at each node respond to the market price charged by sellers by adjusting demand up or down depending on the formulation of the demand function. The model currently assumes that demand "D" is a linear function of price "P," e.g., D = a-bP where a and b are parameters.

  While this function has certain desirable properties (e.g., the demand elasticity increases with increases in price, setting a limit on profitable price increases by suppliers), it is too simplistic for most purposes. A method needs to be found to further individualize the demand functions for each of the area loads in the model to better reflect known differences in regional demand response to changes in electricity prices. At a minimum, the area responses need to differ depending on the industrial, residential and commercial mix in each control area.

Data Problems

Analysis of each of the four factors depends on data sets that need improvement and verification.

- **Tie Line Congestion**. Data from Federal Energy Regulatory Commission (FERC) filings and OASIS plus SUFG knowledge of the transmission system has been used to construct an equivalent simplified transmission network using standard network reduction techniques. As potential bottlenecks in the system are identified, the data describing these lines needs to be confirmed. Current OASIS transfer capabilities may be unuseable as proxies for future capabilities.

- **New Generation Additions**. While SUFG has a comparatively good database of new plants on line, under construction, approved and proposed, the data is always in flux as the various projects work their way through the system. To improve this critical data set, SUFG hopes to promote a joint Indiana Utility Regulatory Commission (IURC)/SUFG effort to form a consortium of Midwest energy and environmental regulatory agencies to share state databases. This should improve the quality and timeliness of the new capacity construction databases for all participants. Finally, a way needs to be found to predict new construction based on a long-term optimal generation/transmission construction model. Until this is done, the model time horizon is limited to short-term (less than five years) use.

- **Estimates of Demand Elasticity**. The key here is to improve the model's estimates of demand elasticity since it can be shown that the magnitude of these elasticities are a major determinant in selecting the price mark up of electricity over the marginal cost by a monopolist.

- **Ownership of Supply Assets**. In addition to improved estimates of demand elasticity, better data are needed on likely consolidations, purchases and sales of generating units in the region since the impact of withholding on price is determined primarily by the number of competitors in each control area.

End Notes

1. East Central Area Reliability Coordination Agreement, *2001 Summer Assessment of Load and Capacity,* 01-GRP-33, April 2001.

2. East Central Area Reliability Coordination Agreement, *2001 Summer Assessment of Transmission System Performance*, 01-TSPP-3, May 2001.

3. Environmental Law & Policy Center, *Executive Summary: Repowering the Midwest, The Clean Energy Development Plan for the Heartland,* 2001.

Chapter 3: Modeling Strategic Behavior

Maximizing Profit

For illustration purposes, suppose a single company controls all generating units capable of supplying power to a group of control areas. The monopoly knows the operating costs of its generating units, which are located in the various control areas. The monopolist also knows the losses and wheeling charges associated with the transmission lines connecting the control areas as well as the responses of buyers to changes in the price charged. The monopolist's task is to choose the pattern of generation, transmission, and prices charged for each control area that maximizes its profit, subject to the constraints:

(a) that generation in each control area plus imports from other control areas (adjusted for line loss) less exports to other control areas equals demand in the control area, and

(b) that the capacity constraints limiting generation and transmission be respected.

If there is no congestion in the transmission system, the pattern that produces maximum profit occurs when the differences in marginal revenue between any two connected control areas is equal to the value of line losses and wheeling charges connecting the control areas. Otherwise, an adjustment in the pattern can be made that will increase the overall profit.

Now, suppose two firms, A and B, each owning a portion of the generating units in the control areas, are competing to meet the demands in each of the control areas. Both firms recognize that the price in a control area will be determined by the total amount of supply offered by firms A and B in that control area. The generation costs of units owned by firms A and B are assumed independent of one another for each control area.

The demand/supply balance at each control area must be satisfied, e.g., firm A's plus B's production at each control area plus A's and B's imports from generators owned by A and B in other control areas (adjusted for line loss) must equal the power demanded at the control area plus exports of power from A's and B's units in the control area to other control areas. In addition, each supplier must respect the capacities of its own generators and the joint flows on the lines connecting control areas cannot exceed the line capacity. If it were not for the joint dependence of the price on the sum of output offered by each and the transmission costs and constraints, the problem would simply be two separate monopolists' problems.

Each firm wishes to maximize its own profits, which equal the sum over all control areas of its revenues (the price received in the control area, a function of the sum of the MWh offered for sale by the two competitors in the control area, times the amount offered by the firm) less its expenses (the sum over all control areas of its generating and wheeling costs).

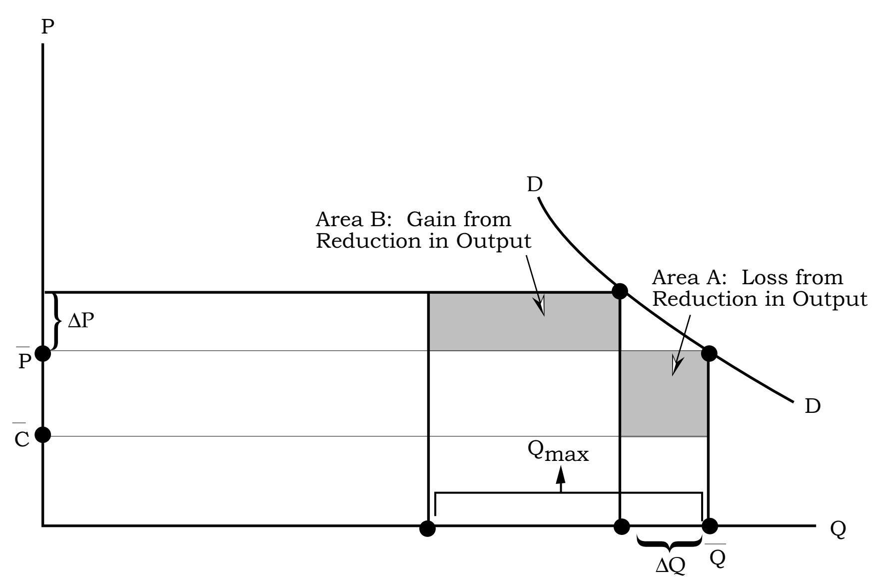
Assuming, as before, that there is no congestion in the transmission network, the problem reduces to how each will go about maximizing its own profit. Each firm recognizes that its own profit is dependent on the other's decisions through the price function in each control area since the more a competitor offers for sale, the lower the revenue per unit received by both firms.

Economists have proposed many ways of dealing with this interdependency. The approach taken is to recognize that each of the competitors must think strategically in deciding how much to offer in a control area. By thinking strategically, economists mean that each firm must anticipate the other competitor's response in making its own decision of how much output to offer. In pricing strategies between two rival companies, each firm must account for the others' price response when charging its own price. If a firm increases its price, will the competition follow suit, keep prices the same, or lower them? Firms competing in control areas where the price is determined by what both offer face a similar question. If a firm offers more, will the competitor increase its offer, keep it the same, or reduce it? No illegal activity is taking place here; there is no collusion between the firms.

Perhaps the simplest assumption one can make is that a competitor will not respond to a change in the others' output decision, but instead will continue to offer the same quantity for sale in the control area. This assumption, the *Cournot Assumption*, named after the French economist who first described this behavior in the 18th century, is the assumption used in the current SUFG model of imperfect competition. This approach allows SUFG to construct a model of the price and output consequences of a large set of firms competing in many spatially separated control areas, not just two firms competing in many such control areas.

The behavior of a single firm in this situation can be understood by considering Figure 3-1. The figure plots "Q," the demand for electricity in a given hour as a function of the price, "P." This function is represented by the curve "D-D" on the figure. Also plotted is a single representative competitor's estimate of the total amount of all competitors' output expected to be bid into the

Figure 3-1. The Decision to Withhold Output



Q_{max} = Maximum output the competitor could supply

$\overline{Q}$ = Amount the competitor thinks all would supply including own supply

$\overline{P}$ = Market price the competitor thinks associated with c

ΔQ = Amount competitor is thinking of withholding

ΔP = Price increase the competitor thinks will take place if competitor withholds ΔQ

market, "$\overline{Q}$," and "Q_{max}," that portion of $\overline{Q}$ that could be supplied by the competitor if the representative competitor supplies all that was available from its generating units.

If the competitor supplied Q_{max}, then the hourly market would clear at $\overline{P}$ and the competitor's profit would be $(\overline{P}-\overline{C})Q_{max}$, assuming $\overline{C}$ is the constant marginal cost of production for the competitor's generating units. Now suppose the competitor decided to withhold a small portion, say ΔQ, of output from the market, what would be the impact on the competitor's profit?

Area A, $(\Delta Q)(\overline{P}-\overline{C})$, is the lost profit on the small reduction -- the cost to the competitor of withholding output. Area B, $(\Delta P)(Q_{max}-\Delta Q)$, is the gain associated with withholding output -- the price increase times the production remaining after the reduction. If area B is bigger than area A, withholding output will increase the competitor's profits; otherwise, profits will decrease.

Finding the solution to a problem with many firms competing at many demand control areas, with each firm assuming all other competitors do not change their behavior in the face of a change in output offered, is tedious and time consuming. However, it is not difficult to understand conceptually since the principle is the same as that described in the simple case described above.

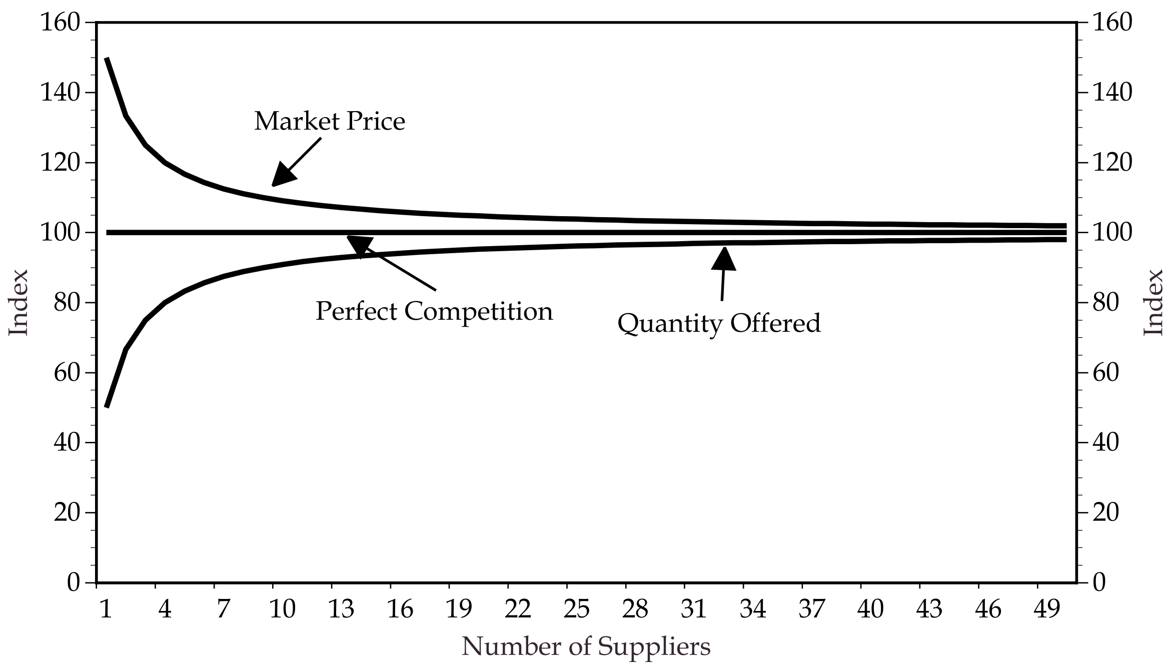
The equilibrium conditions that must hold in these control areas are a complicated extension of the equilibrium conditions for the monopolist. That is, each competitor's pattern of generation and transmission of its electricity must be such that each has no incentive to change the output offered to any control area. Each firm must find the allocation of its resources that equates the difference in its marginal profit in any pair of control areas to the value of the wheeling charge and the line loss on the connection between the two control areas, where the marginal profit is calculated using the Cournot assumption. In this case all firms in the control area are in this position rather than a single monopoly firm and all firms make their calculations based on the behavioral assumptions that no firm will respond to any change in output with a counter-change in strategy.

The impact of the Cournot assumption on the average price can be shown by considering a vastly simplified network. This network has no line losses, wheeling charges or transmission capacity limits, has identical linear total cost functions for all generation and has identical linear demand functions. This network is identical to one where all generation and loads are located at a single point and is commonly called a point model. With these assumptions and some algebraic manipulation (see next section), it is possible to derive the relationships depicted in Figure 3-2.

Figure 3-2 illustrates the relationship between the expected aggregate control area price and quantity offered and the number of firms competing in the control area. In the figure, both the control area price and the quantity offered are expressed as indices relative to the corresponding perfect competition values, where the perfect competition values are assigned an index value of 100. The key relationships observed are that both the expected aggregate control area price and the quantity offered in the control area rapidly approach the values expected with perfect competition as the number of firms in the control area increases given that each firm has the same marginal cost and capacity in the area. The symmetry observed in Figure 3-2 is an artifact of the slope assumed for the linear demand functions. Alternative slope assumptions result in a monopoly control area price higher or lower than that shown in the figure, but the relationship depicted still holds. From the figure, it is obvious that control area prices decline and control area supply increases with the number of firms supplying the control area.

The rate at which both the quantity offered and the control area price approach the perfect competition line as the number of competitors in-

Figure 3-2. Relationship of Market Price and Quantity Offered to Number of Suppliers



crease is a function of the assumed linear demand function (see next section). Under a different set of assumptions either trajectory could lie closer to, or farther from, the perfect competition line.

Given that the model has 28 competitors and each uses the Cournot assumption regarding its opponent's response to changes in its output decisions, one would, on the basis of Figure 3-1, expect to find an equilibrium price *close* to the marginal cost price expected if the control areas were competitive.

This is not necessarily the case. Losses and wheeling charges are not zero and transmission capacity is finite. They impede the free flow of electricity between control areas and push the results in the direction of the monopolist solution. In the limit, as line loss/wheeling charges increase, the aggregate output and price values approach those of the monopolistic case described above while holding the number of competitors' constant.

Further, all demand functions and cost functions are not identical. Differences in cost and demand functions can be exploited by players in a game, again driving the output and price decisions of the case towards that expected if a monopoly were to exist.

This is about as far as one can go in predicting the outcome of the imperfectly competitive control area case in such a simple model. The equilibrium price and output decisions predicted by such a model must be bounded by the perfectly competitive and monopoly cases. Beyond that, the trade off between a large number of players (forcing the price/output equilibrium to resemble perfect competition) and the presence of line losses/wheeling charges (forcing the price/output equilibrium to resemble the monopoly case) can only be settled by computing the price/output decisions for the case at hand — 25 utilities plus a number of IPPs competing in 26 control control areas.

A Mathematical Comparison of the Monopoly, Oligopoly and Competitive Models

Consider the situation where n firms compete for an aggregate control area using the gaming strategy of Cournot and each firm has an identical total cost function. For simplicity, assume:

$P(Q)=a-bQ$ (Control area demand)

$TC_i(q_i)=cq_i$ (Total cost for firm i)

where a, b, and c are constants.

In Appendix A the profit maximizing conditions for the Cournot version of oligopoly are derived as:

$$P + q_i \frac{\partial P}{\partial q_i} - MC(q_i) = 0 \quad \text{for} \quad i = 1, n$$

Since all firms in this example have identical cost functions, each firm's marginal cost is the same ($Mc(q_i)=c$) and each firm will produce an identical amount ($q_i=Q/n$). Substituting values yields a-bQ+Q/n*(-b)-c=0 and solving for Q yields:

$$Q = \frac{n(a-c)}{(n+1)b}$$

Substituting for Q in the control area demand function,

$$P = a - b\left[\frac{n}{n+1}\ \frac{(a-c)}{b}\right]$$

and simplifying results in $P = \frac{a}{n+1} + \frac{nc}{n+1}$.

Now consider two special cases -- that of a single firm (monopoly) and that of many firms (perfect competition). In the monopoly case n=1 and in the perfect competition case n approaches infinity and the equilibrium control area quantities and control area prices are those shown in Tables 3-1 and 3-2. By inspection of the tables, it is obvious that supply increases and price decreases as the number of firms increase.

The relation of this result to the logic of Figure 3-1 is straightforward. The larger the number of competitors, the smaller each control area share will be, which means Q_{max} in Figure 3-1 becomes smaller, which means area B becomes smaller, which means smaller gains associated with withholding, which means a decrease in the amount each will withhold, which means a smaller increase in price above that expected with perfect competition.

Table 3-1. Aggregate Output Expected

Monopoly	n Player Game	Perfect Competition
$\frac{a-c}{2b}$	$\frac{n(a-c)}{(n+1)b}$	$\frac{a-c}{b}$

Table 3-2. Aggregate Price Expected

Monopoly	n Player Game	Perfect Competition
$\frac{a+c}{2}$	$\frac{a}{(n+1)} + \frac{nc}{(n+1)}$	c

Appendix A: Mathematical Models of Imperfect Competition for a Non-spatial Market

This appendix describes various economic models that result in market prices above marginal cost. (1) These models are collectively referred to as models of imperfect competition, or gaming models, and share the common assumption that market suppliers are able to manipulate market supply and thereby, market price. This assumption is in stark contrast to that of the traditional perfect competition assumption that no market supplier is able to influence market price, which is the marginal cost of production of the most expensive unit dispatched to meet demand.

In the perfect competition model, it is possible for market prices to exceed marginal cost due to abnormally high demand and/or production outages that result in demand exceeding supply. The models described in this appendix pertain to purposeful withholding of supply, not short-run imbalance of supply and demand.

Imperfect competition describes a spectrum of market outcomes lying between the polar extremes of perfect competition and the unregulated monopoly. Figure A-1 shows relative prices under different market assumptions.

In a perfectly competitive market, prices equal marginal cost P_C, and in the long run, production (Q_C) occurs at the minimum industry average cost. This market results in maximum social welfare. The monopoly market on the other extreme is one where there is only one producer. The profit maximizing output of the monopoly is point M in Figure A-1, the output level at which marginal revenue equals marginal cost. The corresponding price, P_M, is the highest of all and provides an upper bound on the possible price outcomes in the markets.

The general formulation of the imperfectly competitive model is as follows. Each firm's decision problem is to maximize its own profits (Π), given a market price

$$P = P(Q) = P(q_1 + q_2 + \ldots + q_n)$$

and the firm's total costs $TC_i(q_i)$. That is

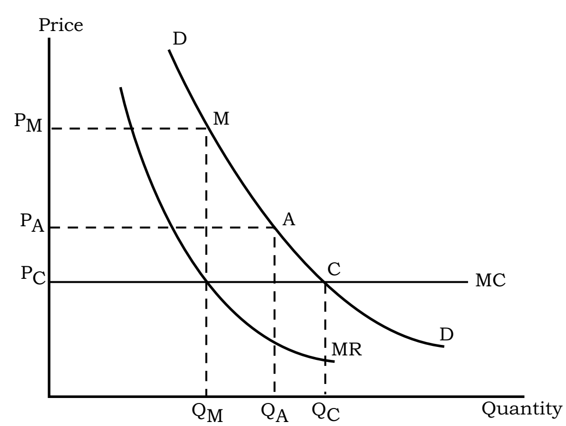
$$\Pi_i = P(Q)q_i - TC_i(q_i)$$

$$= P(q_1 + q_2 + \ldots + q_n)q_i - TC_i(q_i)$$

where i = 1,2,...n refers to individual firms and non-subscripted terms refer to the market.

The models of imperfect competition result from postulating how firms make this profit maximizing output choice. In economic terms, the central question concerns how one firm assumes other firms react to its decisions. A major concern for economic modelers is how to capture these strategic considerations in some sort of tractable analytical model. A popular approach, and the one used in the model in this report, relies on

Figure A-1. Alternative Solutions to the Imperfectly Competitive Model



Source: Nicholson 1995 Figure 21.1

the tools of game theory to examine strategic choices in a simplified setting. According to game theory, a market is said to have achieved a Nash equilibrium if, given the equilibrium price and quantity, no market participant has any incentive to change its behavior. Models in common use, arranged in decreasing order of popularity in literature, include:

1. The Cournot model, which assumes that firm i treats other firms' output as fixed in its decision ($\partial q_j / \partial q_i = 0$ for all j not equal to i).

2. The Price-Leadership (Stackelberg) model, which assumes there is one dominant producer and a fringe of quasi-competitive producers.

3. The Quasi-competitive (Bertrand) model, which assumes that firms behave as price takers.

4. The Cartel model, which assumes firms can collude in choosing industry output.

5. The Conjectural Variations model, which assumes that firm j's output will respond to variations in firm i's output ($\partial q_j / \partial q_i \neq 0$).

Market equilibrium can occur at many points on the demand curve. In Figure A-1, the quasi-competitive equilibrium occurs at point C, the cartel equilibrium at point M, and the Cournot equilibrium at point A. All other equilibria occur between points M and C, depending on the specific assumptions about firms' strategic interrelationships.

Cournot Model

Cournot assumed that each firm recognizes that its own decisions about its output q_i affect price, but that its output decisions do not affect the output of other firms. That is, each firm recognizes that $(\partial P / \partial q_i \neq 0)$ but assumes $(\partial q_j / \partial q_i = 0)$ for all j not equal to i. Using these assumptions, the first order conditions for a profit maximum can be derived as follows:

$$\Pi_i = P(Q)q_i - TC_i(q_i)$$

$$\frac{\partial \Pi_i}{\partial q_i} = P + q_i \frac{\partial P}{\partial q_i} - MC_i(q_i) = 0$$

The firm assumes that changes in its output level q_i affect its profits only through their direct effect on the market price. The above equation together with the market clearing demand equation

$$P = P(Q) = P(q_i + q_2 + \ldots + q_n),$$

will permit an equilibrium solution for the production levels $(q_1, q_2, \ldots, q_n)$.

Note that the market price from the profit maximizing condition

$$P = MC_i(q_i) - q_i \frac{\partial P}{\partial q_i}$$

is greater than the marginal cost since the term $\frac{\partial P}{\partial q_i}$ is negative.

Quasi-Competitive (Bertrand) Model

As in the case under perfect competition, each firm in a quasi-competitive model is assumed to be a price taker. In this case the first order condition for profit maximization is that

$$\frac{\partial \Pi_i}{\partial q_i} = P - \frac{\partial TC_i(q_i)}{\partial q_i} = 0$$

or $P = MC_i(q_i)$

Even though n, the number of firms, may be small, the assumption of price-taking behavior results in a competitive outcome.

Cartel Model

The Cartel model assumes that firms as a group recognize that they can affect the market price. It also assumes that they manage to coordinate their decisions. In this case the cartel acts like a multi-plant monopoly and chooses the total market output ($q_1 + q_2 + \ldots + q_n$) so as to maximize the total monopoly profits.

$$\sum_{i=1}^{n} \Pi_i = P(Q)Q - \sum_{i=1}^{n} TC_i(q_i) = P(q_1 + \ldots q_n)(q_1 + \ldots q_n) - \sum_{i=1}^{n} TC_i(q_i)$$

The first order conditions for maximum total profit, $\sum_{i=1}^{n} \Pi_i$, are

$$\frac{\partial \sum_{i=1}^{n} \Pi_i}{\partial q_i} = P + (q_1 + \ldots + q_n)\frac{\partial P}{\partial q_i} - MC_i(q_i) = 0$$
$$= MR(Q) - MC_i(q_i) = 0$$

This equation holds because the total revenue depends on the sum of all cartel members' output levels, and the marginal revenue is the same no matter whose output level is changed. Because this coordinated plan requires a specific output level for each firm, the plan will also dictate how monopoly profits earned by the cartel are to be shared. In aggregate these profits will be as large as possible.

Conjectural Variations Model

This is the most general among the models of imperfect competition. It takes into account the strategic interactions between firms. When it is no longer assumed that $\partial q_j / \partial q_i = 0$ for all $j \neq i$, each firm's profit-maximizing decision is

$$\Pi_i = P(Q)q_i - TC_i(q_i)$$

$$\frac{\partial \Pi_i}{\partial q_i} = P + qi\frac{\partial P}{\partial q_i} - MC_i(q_i) = 0$$

or

$$P + q_i\frac{\partial P}{\partial q_i} + \sum_{j \neq i}\frac{\partial P}{\partial q_j}\frac{\partial q_j}{\partial q_i} - MC_i(q_i) = 0$$

The firm must not only be concerned with how its own output affects market price directly but also with how variations in its output will affect market price indirectly through its effect on the other firms' output decisions. Because the value of $\partial q_j / \partial q_i$ will be speculative (conjecture), models based on various assumptions about its value are termed "conjectural variations" models.

There is no generally accepted theory of the type of equilibrium that is likely to emerge from the responses given by the conjectural variation equations given above. Some specific assumptions about specific market situations result in such models as Stackelberg price-leadership model described below and the others described above.

Price Leadership (Stackelberg) Model

The price leadership model describes a situation where there is one dominant firm and a fringe of quasi-competitive suppliers. Assuming the leader is firm 1, a mathematical representation of this market would include a price-taking reaction

$$P = MC_i(q_i)$$

for i=2,3,…,n, the quasi-competitive fringe, with only firm 1 requiring a complex reaction function of the type

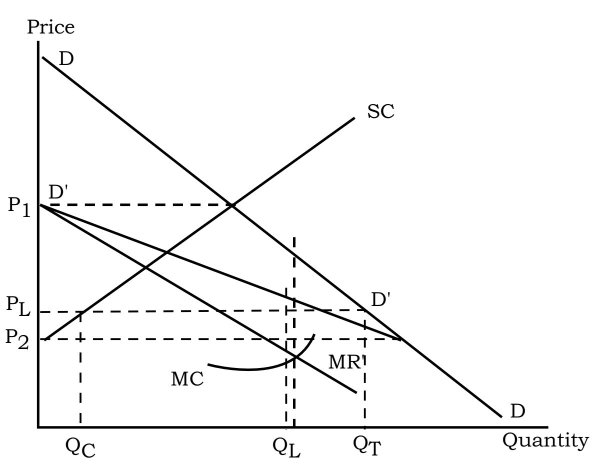
$$\frac{\partial \Pi_i}{\partial q_i} = P + q_i\left[\frac{\partial P}{\partial q_i} + \sum_{j \neq 1} \frac{\partial P}{\partial q_j} \cdot \frac{\partial qj}{\partial q_i}\right] - MC_i(q_i) = 0$$

The model assumes for whatever reason (avoid antitrust action?) the dominant firm allows the competitive fringe to offer to the market its supply, that supply dictated by the fringe firms' marginal cost functions. The dominant firm, knowing this quantity response to price by the fringe firms, then chooses the quantity it offers so as to maximize its monopoly profit from the residual market. A graphical analysis of such a market is given in Figure A-2.

The demand curve, DD, in Figure A-2 represents the total market demand curve. The supply curve, SC, represents the supply decisions of the competitive fringe. Using these two curves, the demand curve (D'D') facing the industry leader is derived as follows:

- If the dominant firm chooses to produce nothing, then the market clears at price P_1; the entire output is produced by the competitive fringe.

Figure A-2. Model of Price-Leadership Behavior



Source: Nicholson 1995 Figure 21.2

- For prices below P_2 the leader has the market to itself since the fringe is not willing to supply anything.
- Between P_2 and P_1 the demand curve the leader faces, D'D', is constructed by subtracting what the competitive fringe will supply from the total market demand.
- Given demand curve, D'D', the leader can construct its marginal revenue curve (MR') and then refer to its own marginal cost curve, MC', to determine the profit-maximizing output level Q_L.
- The market price then will be P_L.
- Given price P_L, the competitive fringe will produce Q_c, and the total industry output will be $Q_T(=Q_c+Q_L)$.

End Notes

1. Most of the material presented in this appendix is summarized from the excellent treatment of the subject in Walter Nicholson’s book on Microeconomic Theory. A reader desiring a more detailed treatment of the subject is referred to this book. (Nicholson, W., *Microeconomic Theory -- Basic Principles and Extensions*, 6th edition, The Dreyden Press, 1995.)

Appendix B: Mathematical Statement of SUFG's Models

The Spatial Gaming Model: Literature Study

There have been a limited number of studies on spatial Cournot gaming for electricity markets. One class of such studies is purely transportation network based. (1-3) The second class of such studies uses DC power flow equations to represent the spatial nature of the problem.(4-9) However, the studies with DC power flow constraints present largely expository models, none of which have actually solved with more than a few producers and demand nodes. This is largely due to the difficult computational burden, which SUFG has also encountered. Given the computational complexity of DC-flow constrained models, SUFG has chosen to settle for the standard transportation constraints in its current gaming model. Experiments on smaller systems show that the absence of DC-flow constraints does not significantly degrade the quality of the solution.

In the spatial gaming models, the Cournot strategy is used to simulate the producers' gaming behavior. That is, in making its production decision, a firm recognizes that its output will affect the market price, but assumes that its competitors' output will remain constant. Each producer's profit maximization problem is decoupled from the multi-player model through the use of the augmented Lagrangean function technique. A set of the Karush-Kuhn-Tucker (KKT) necessary conditions is then derived considering the Cournot strategy. The Nash-Cournot equilibrium is obtained by solving these KKT conditions. This can be done by using one of the Mixed Complementarity Problem (MCP) solvers [see General Algebraic Modeling System (GAMS), A User's Manual. GAMS Corporation]. (10)

The Spatial Gaming Model: Mathematical Statement

At the core of the SUFG spatial gaming model is a one-hour real power model. It does not include reactive power and other ancillary services. To obtain the results for a year or more, this hourly model is run for the required hours with the corresponding demands. Another important assumption in this model is that there is no arbitrage. This being the case, non-cost based price differences can exist between nodes.

The mathematical statement of the problem is as follows.

Let:

- F(i,j,s) = Power flow from i to j for company s
- PG(i,g,s) = Power generated at location i by plant g owned by company s
- P(i) = Price paid by consumers at i
- Q(i,s) = Sales by company s at i
- $\overline{c(i,g,s)}$ = Cost/kWh for plant g at i owned by s, a parameter
- $\overline{wh(i,j)}$ = Wheeling charge/kWh for flow from i to j, a parameter; the same for all companies.

Then:

$$\underbrace{\max\{\pi(1),\ldots,\pi(s),\ldots,\pi(s_m)\}}_{\text{the vector valued objective function}}$$

$$\pi(s) = \sum_i \overbrace{P(i)Q(i,s)}^{\text{Sales Revenues}} - \sum_i \sum_g \overbrace{PG(i,g,s)\overline{c}(i,g,s)}^{\text{Production Cost}}$$
$$- \underbrace{\sum_i \sum_j F(i,j,s)\overline{wh}(i,j)}_{\text{Wheeling Charges}}$$

such that:

(1) $$P(i) = \overline{a}_i - \overline{b}_i\left(\sum_s Q(i,s)\right)$$ (Linear demand functions for each region i)

(2) $$\underbrace{Q(i,s)}_{\text{Sales by s at i}} = \underbrace{\sum_g PG(i,g,s)}_{\text{Generation at i by s}} - \underbrace{\sum_j F(i,j,s) + \sum_j F(j,i,s)}_{\text{Net imports to i by s}}$$

(Sales at i by s equal generation at i by s less exports from i to j by s plus imports from j to i by s)

(3) $$\overbrace{\sum_s F(i,j,s) - \sum_s F(j,i,s)}^{\text{Net flows from i to j}} \leq \overline{F\max(i,j)}$$ (Link capacity constraints)

(4) $$\overline{P\min(i,g,s)} \leq PG(i,g,s) \leq \overline{P\max(i,g,s)}$$ (Generation capacity constraints)

(5) All variables greater than or equal to 0.

Solution

Let L(s) be the partial LaGrange function of the model form firm s created by adding constraints (2) and (3) set to 0 and multipled by their Lagrange multipliers to the objective function. Solving the following system of equations will give solutions to the gaming model.

(1) $\dfrac{\partial L(s)}{\partial PG(i,g,s)} \leq 0$, assuming $\dfrac{a\pi(k)}{\partial PG(i,g,s)} = 0 \ \forall k \neq s$, e.g., $\dfrac{\Delta PG(i,g,k)}{\Delta PG(i,g,s)} = 0 \ \forall k \neq s$, the Cournot assumption

(2) $\dfrac{\partial L(s)}{\partial F(i,j,s)} \leq 0$, assuming $\dfrac{\partial \pi(k)}{\partial F(i,j,s)} = 0 \ \forall k \neq s$, e.g., $\dfrac{\Delta F(i,j,k)}{\Delta F(i,j,s)} = 0 \ \forall k \neq s$, the Cournot

assumption.

(3) $$\frac{\partial L(s)}{\partial PG(i,g,s)} \quad PG(i,g,s) \;=\; 0, \;\; \forall \;\; i,g,s$$

(4) $$\frac{\partial L(s)}{\partial F(i,j,s)} F(i,j,s) \;=\; 0, \;\; \forall \;\; i,j,s$$

End Notes

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2. Jing-Yuan W and Smeers Y, "Spatial Oligopolistic Electricity Models With Cournot Generators and Regulated Transmission Prices," *Operations Research*, Vol. 47, No. 1, February 1999. pp. 102-112.

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4. Hogan WW, "A Market Power Model with Strategic Interaction in Electricity Networks," *The Energy Journal*, Vol. 18, No. 4, 1997, 107 - 141.

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6. Hobbs BF, Metzler CB, Pang JS, "Strategic Gaming Analysis for Electric Power Systems: An MPEC Approach," forthcoming *IEEE Trans. on Power Systems.*

7. Berry CA, Hobbs BF, Meroney WA, O'Neill RP, Stewart WR Jr., "Understanding How Market Power Can Arise in Network Competition: A Game Theoretic Approach," *Utility Policy*, 8 (1999) 139 -158.

8. Yu Z, "A Strategic Coalition Gaming Model with Spatial Formulation for Electricity markets," IEEE PES letters, *IEEE Power Engineering Review*, February 2001, V. 21, No. 2

9. Yu Z, Sparrow FT, et al, "A Spatial Gaming Model with Side-payment for Deregulated Electricity Markets," under review, *IEEE Trans. on Power Systems*.

10. GAMS -- The Solver Manuals. GAMS Development Corporation, 1996.

Appendix C: Data Sources

The majority of the data used in the imperfect competition models were obtained from the websites of the Federal Energy Regulatory Commission (FERC) and the Energy Information Agency (EIA). In some cases supplemental data or assumptions were necessary to complete certain data requirements.

Demand Data

For most control areas included in the model, hourly control area load was available for 1998 in FERC Form 714 filings. For those control areas for which Form 714 data was unavailable, annual peak demand and energy data were obtained from FERC Form 1, EIA Form 861, or company sources. These annual data were used in conjunction with an actual hourly control area load data set to estimate hourly load. The following procedure was employed to produce these estimates:

$$L_i' = A' + (L_i - A)\left(\frac{P' - A'}{P - A}\right)$$

where:

L_i' = Estimated Load for hour i
A' = Estimated average load
P' = Estimated peak load
L_i = Observed load for hour i
A = Observed average load
P = Observed peak load.

The resulting hourly load estimates contain the correct peak demand and energy. When choosing which observed hourly load data set to use in estimating an unavailable set, SUFG looked at summer versus winter peak load and summer and winter load factors.

Generation Data

The generation data comes from two primary sources: EIA Form 860 and FERC Form 1. Form 860 contains unit specific data on capacity, heat rates, and fuel types while the FERC Form 1 contains plant level data on operation and maintenance costs and fuel cost data by fuel type. For units brought on line after 1998, the last year of Form 860 available when the data set was constructed, SUFG has used generic cost and efficiency estimates. Almost all of these recent additions are simple-cycle gas-fired combustion turbines. The installation dates and types of these units were obtained from NERC, ECAR and MAIN reports and company sources.

Transmission Data

Physical characteristics of transmission lines connecting control areas were derived from FERC Form 715 data. Capacities and wheeling costs are based on recent OASIS postings.

Table C-1. Data Sources

Category and Description	Units	Source
Generating Unit Data		
Unit ID		1994-1998 EIA Form 860
Plant Code		1994-1998 EIA Form 860
Utility or Other Firm ID		1994-1998 EIA Form 860
Heat Rate	Btu/kWh	1994-1998 EIA Form 860
Fuel Type		1994-1998 EIA Form 860
Summer Capability	kW	1994-1998 EIA Form 860
Winter Capability	kW	1994-1998 EIA Form 860
Fuel Cost Data		
Utility or Other Firm ID		1994-1998 FERC Form 1
Plant Code		1994-1998 FERC Form 1
Fuel Type		1994-1998 FERC Form 1
Cost		1994-1998 FERC Form 1
O&M Cost Data		
Variable O&M Data	$/kWh	1994-1998 FERC Form 1
Fixed O&M Costs	$/kW	1994-1998 FERC Form 1
Hourly Load Data		
8760 Control Area Load		1998 FERC Form 714 & Other Sources and Estimates
Transmission Data		
Resistance and Reactance		1995 FERC Form 715
Capacity	kW	1995 FERC Form 715 & OASIS
Tariffs	$/MW	OASIS

Appendix D: Capacity Additions Database

Data are obtained from trade publications, such as Megawatt Daily and Electric Utility Week. In addition, contact has been made with many of the utilities and IPPs to verify the announcements. Utility, IPP, state regulatory and environmental agency websites were also used as a supplemental data source and for verification purposes.

Proposed merchant plants for Indiana are depicted in Figure D-1 as of March 2001. Twenty-three plants have been proposed and are in some stage of development. If all plants are built and put into commercial operation, Indiana would have additional capacity totaling 11,480 MW; however, this is not likely. The plants can be broken down into the following categories for Indiana:

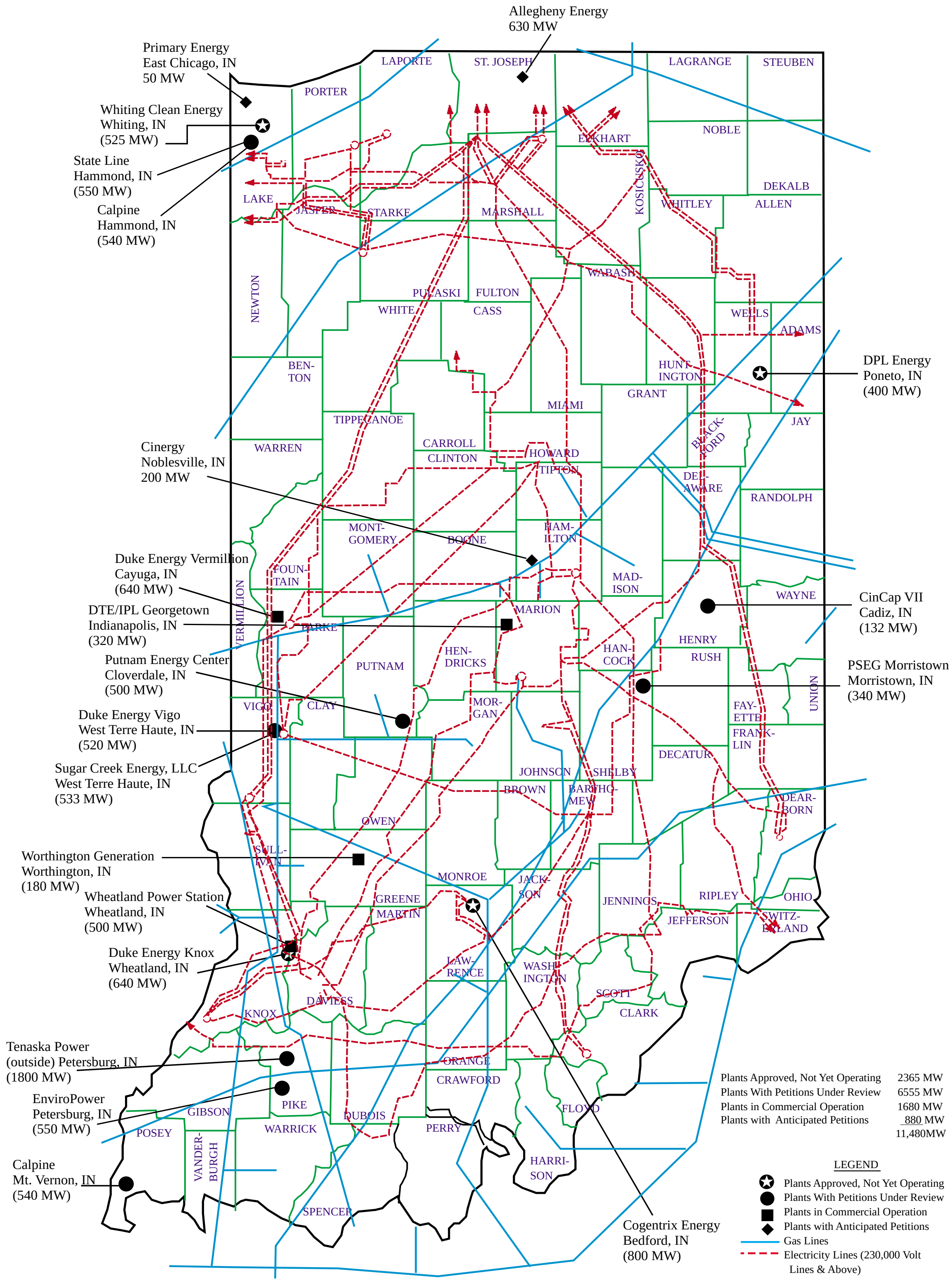
- Five plants (1,680 MW) are in commercial operation.
- Four plants (2,365 MW) have had petitions approved.
- Eleven plants (6,555 MW) have petitions under review.
- Three plants (880 MW) have been proposed.

In the ECAR/MAIN regions, 141 plants have been announced. If all the plants were built, this would increase capacity in the ECAR/MAIN regions by almost 78,000 MW. Figures D-2 through D-9 illustrate the proposed new capacity by state in the ECAR/MAIN regions. Table D-1 is a breakdown by state of the proposed capacity additions.

Table D-1. Anticipated Capacity for ECAR/MAIN

State	MWs
ECAR	
Indiana	11,480
Kentucky	5,125
Michigan	10,818
Ohio	16,427
Pennsylvania	1,140
West Virginia	4,543
ECAR Subtotal	49,533
MAIN	
Illinois	21,367
Missouri	1,900
Wisconsin	4,534
MAIN Subtotal	27,801
TOTAL	**77,334**

Figure D-1. Indiana Anticipated Capacity

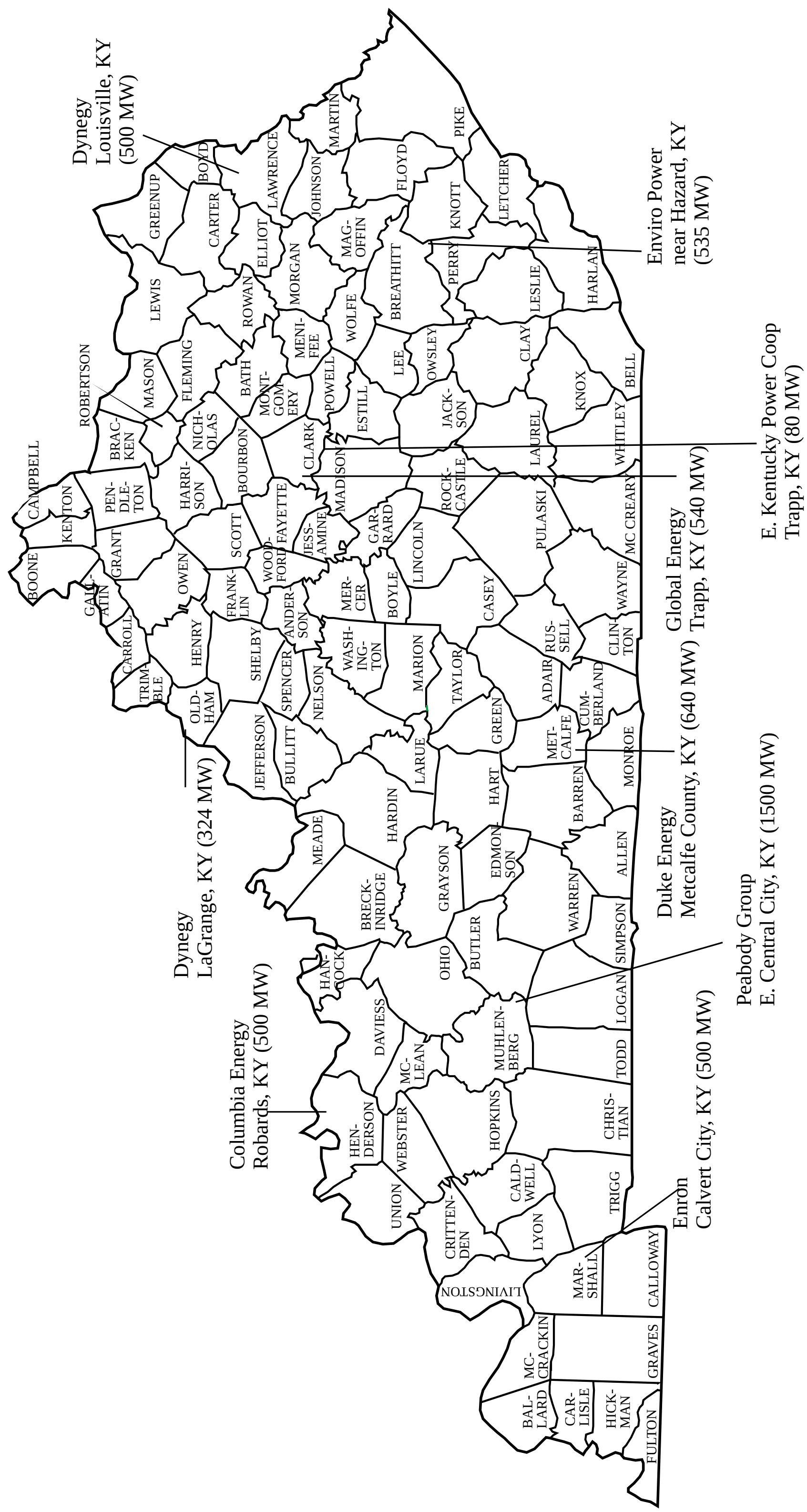


Plants Approved, Not Yet Operating	2365 MW
Plants With Petitions Under Review	6555 MW
Plants in Commercial Operation	1680 MW
Plants with Anticipated Petitions	880 MW
	11,480MW

LEGEND

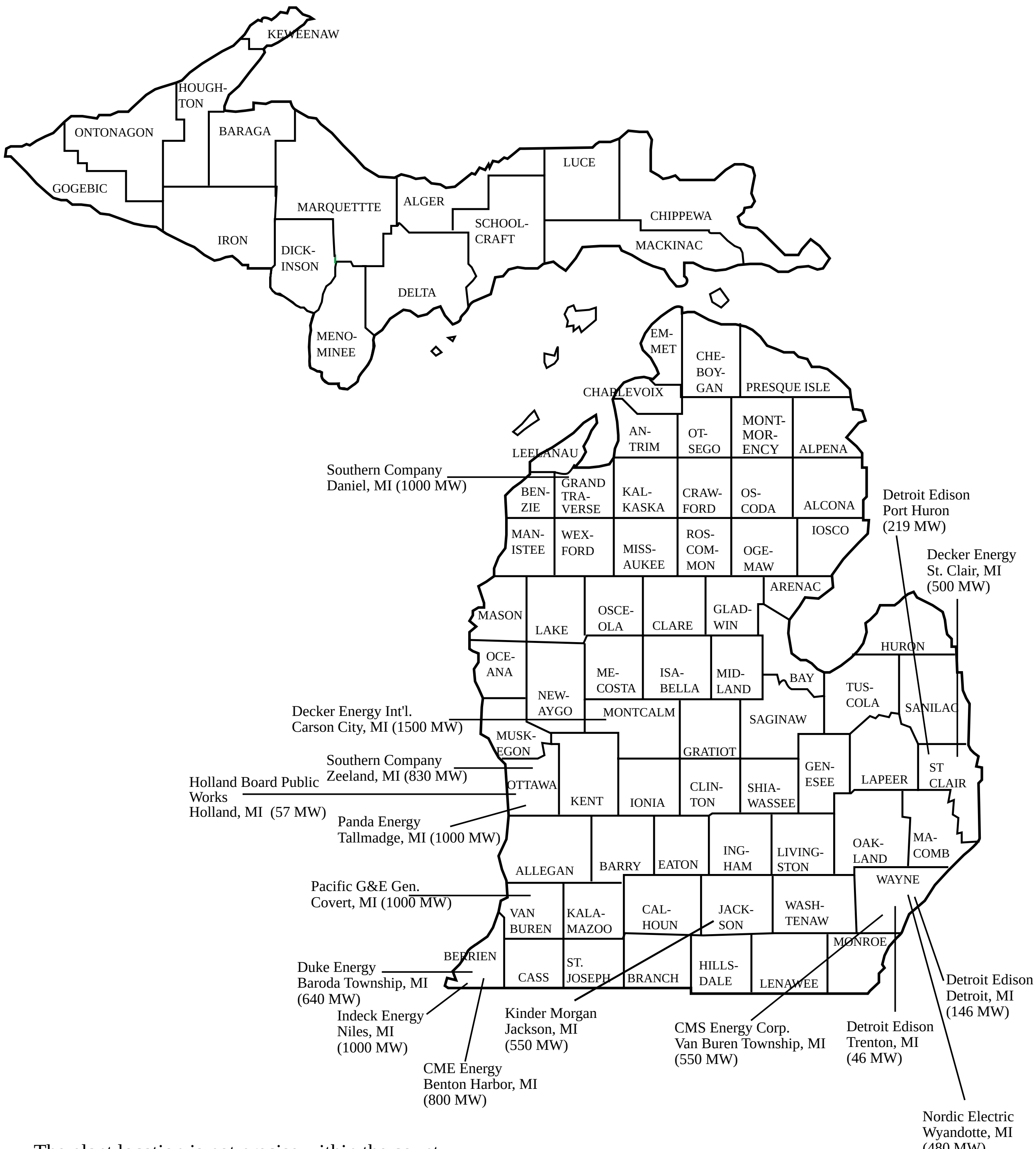
- Plants Approved, Not Yet Operating
- Plants With Petitions Under Review
- Plants in Commercial Operation
- Plants with Anticipated Petitions
- Gas Lines
- Electricity Lines (230,000 Volt Lines & Above)

Figure D-2. Kentucky Anticipated Capacity



The plant location is not precise within the county.

Figure D-3. Michigan Anticipated Capacity



The plant location is not precise within the county.

Figure D-4. Ohio Anticipated Capacity

The plant location is not precise within the county.

Figure D-5. Pennsylvania Anticipated Capacity

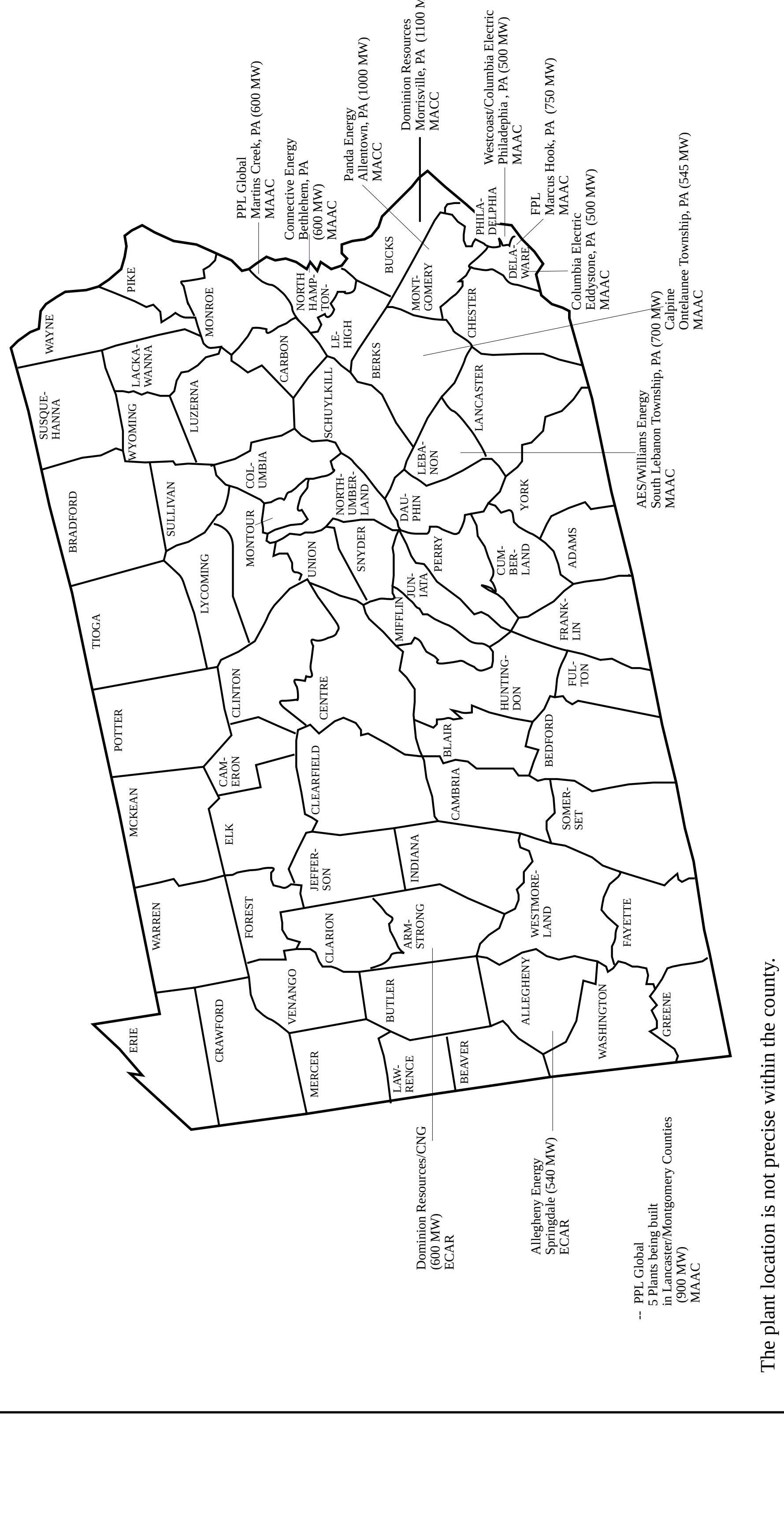
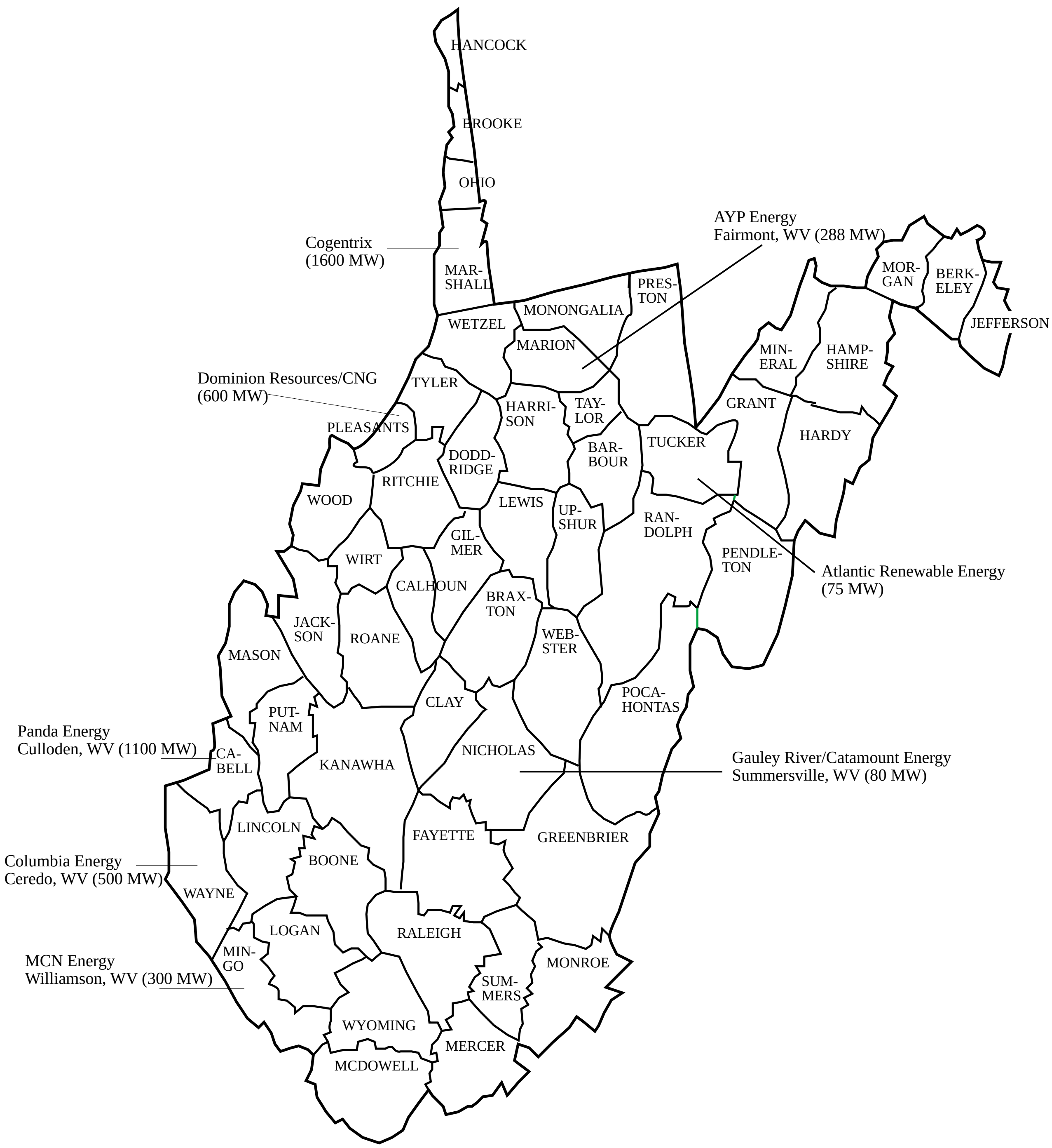
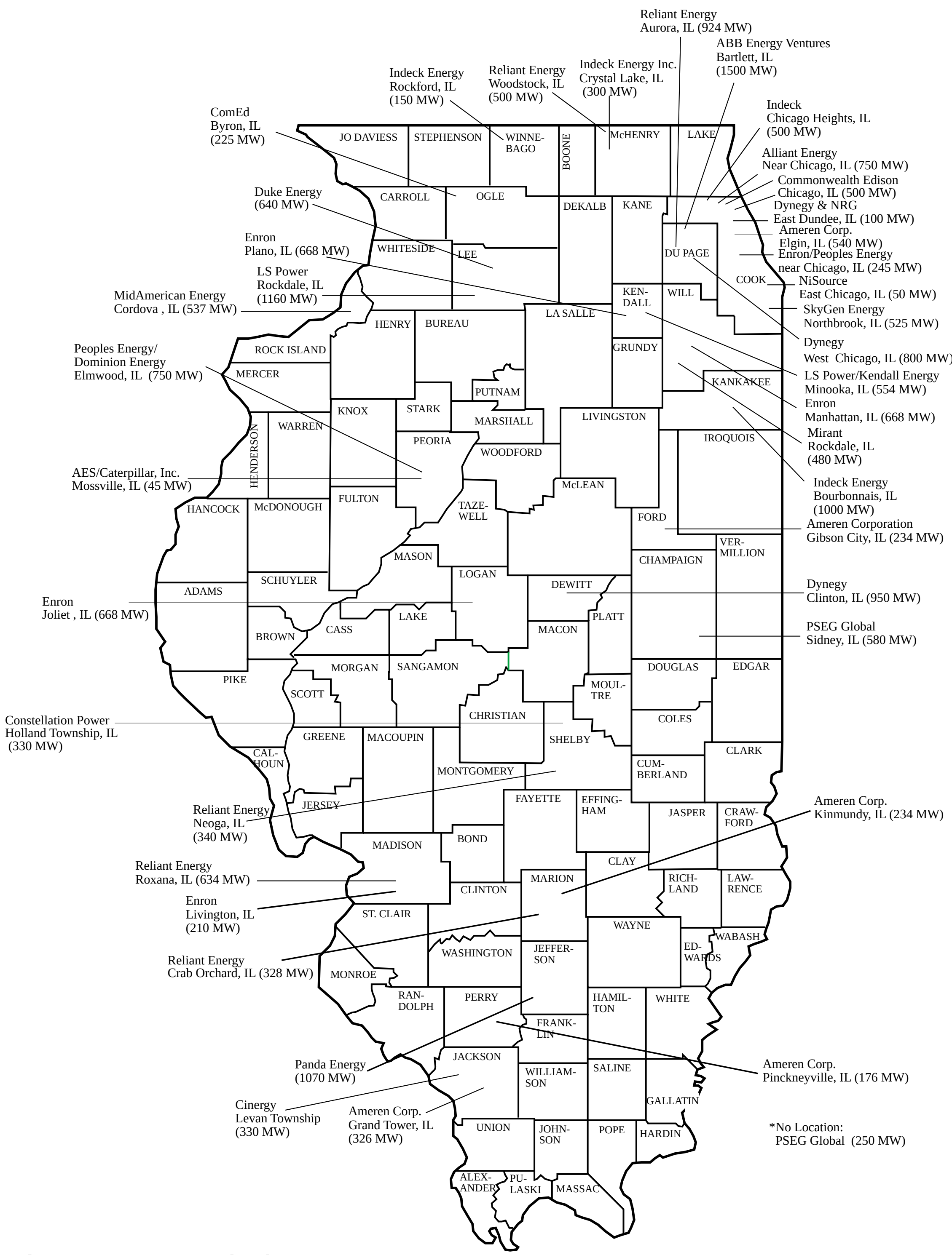


Figure D-6. West Virginia Anticipated Capacity



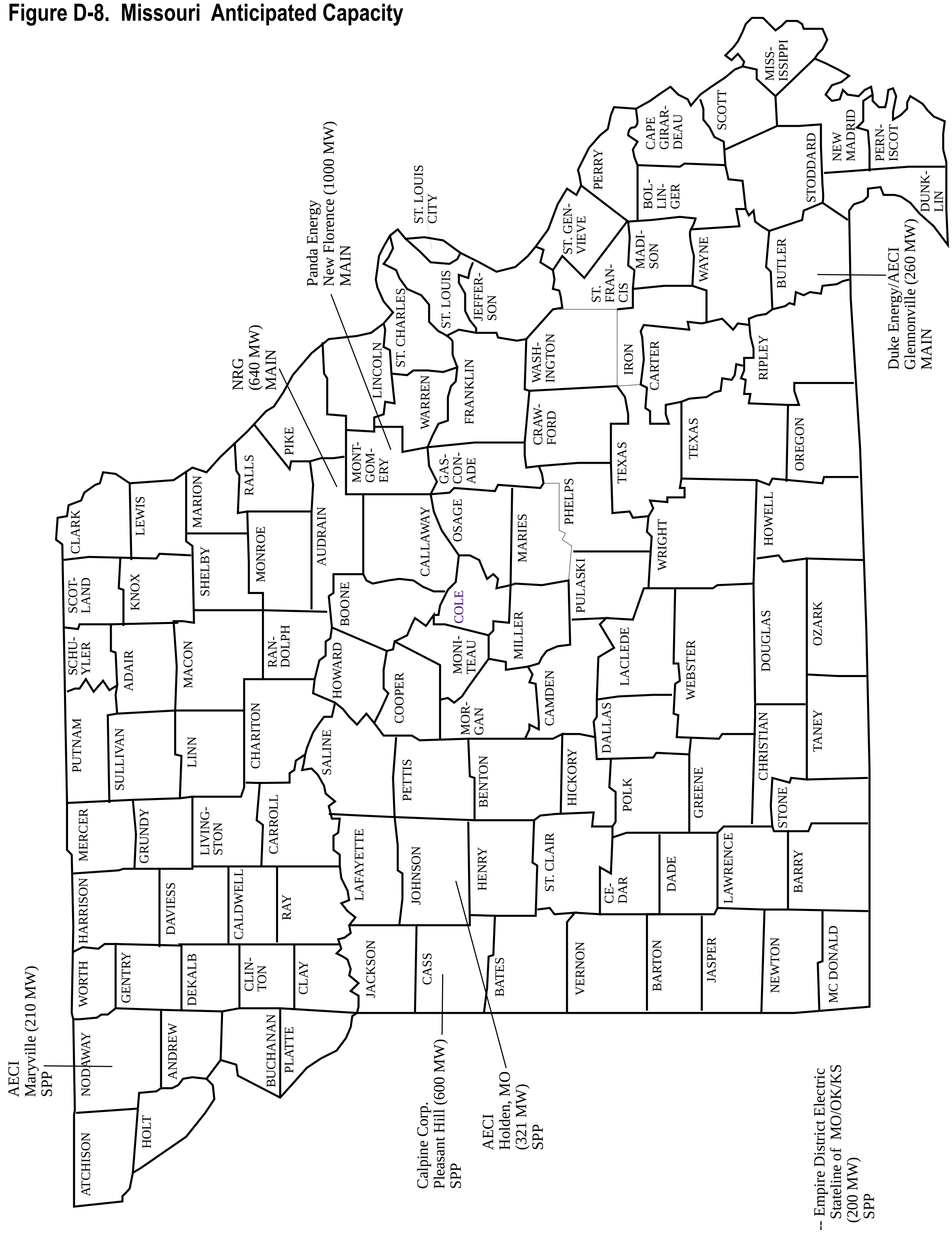
The plant location is not precise within the county.

Figure D-7. Illinois Anticipated Capacity



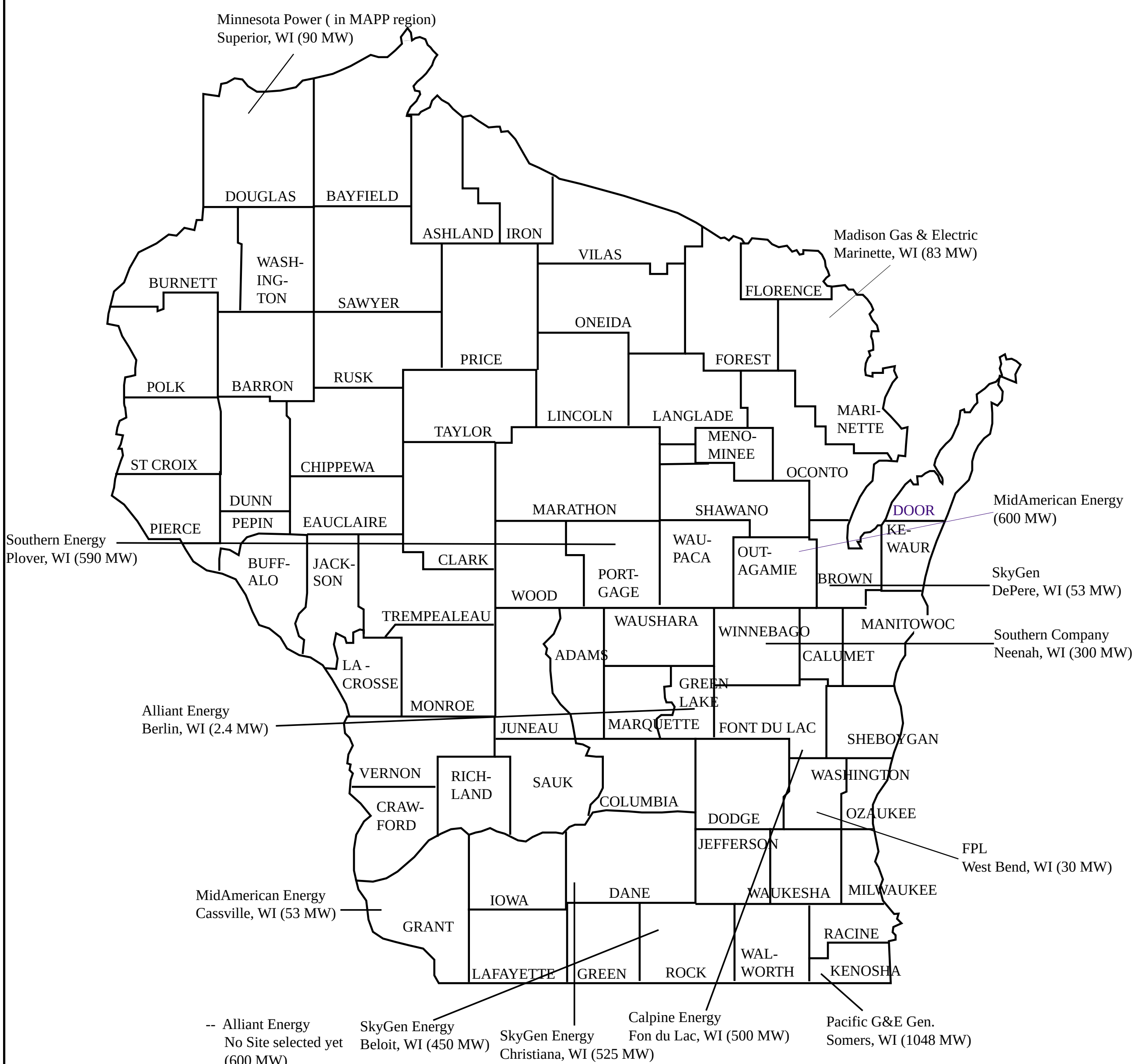
The plant location is not precise within the county.

Figure D-8. Missouri Anticipated Capacity



The plant location is not precise within the county.

Figure D-9. Wisconsin Anticipated Capacity



. The plant location is not precise within the county.

Glossary of Terms

Ancillary Services Services or tariff provisions related to generation and delivery of electric power other than simple generation, transmission or distribution. Ancillary services related to transmission services include: energy losses; energy imbalances; scheduling and dispatching; load following; system protection; and reactive power. Ancillary services related to energy markets include regulation, spinning reserves, non-spinning reserves and replacement reserve.

Base Case A specific set of model assumptions. The impact of individual assumptions are determined by varying one of them and comparing the results to the base case.

Bidding Systems A set of rules for soliciting and evaluating competing bids as a means of choosing suppliers and establishing rates for purchases of power or other resources.

Bilateral Contract A contract that is limited exclusively to two parties that trade with each other. This type of arrangement can be distinguished from a tariff system whereby a seller establishes a uniform contract or offer of services that generally is available to essentially all qualified parties.

Control Area In this report, the term control area refers to a geographic region with all generators and loads in the region as if they were located in the same place. These areas roughly correspond to traditional utility service territories.

Demand Elasticity The percent change in demand divided by the percent change in price that brought about the change in demand.

Demand Bids See *Bidding Systems.*

Deregulation The removal of government regulatory controls from the electricity industry.

Federal Energy Regulatory Commission (FERC) An independent agency created within the Department of Energy, FERC is vested with broad regulatory authority. Virtually every facet of electric and natural gas production, transmission and sales conducted by private investor-owned utilities, corporations or public marketing agencies was placed under the commission through either direct or indirect jurisdiction if any aspect of their operations were conducted in interstate commerce.

Gaming An opportunistic behavior by either the producers or the consumers or both to artificially influence the production, consumption and prices of a market. This term is often used against the term of perfect competition in economics such that market price, quantity and the revenues of the different producers are manipulated and are away from the perfect market outcome.

Gaming Models Mathematical models for simulating different market gaming strategies.

Imperfect Competition Prevails in a market whenever individual sellers have some degree of control over the price.

Independent Power Producers Non- utility owned generation (NUG).

Independent System Operator An entity independent of generation owners and consumers who oversee operations of regulated transmission facilities.

Joint Dispatch Two or more utilities which jointly share and operate their generating units to meet demand at a minimum cost.

Locational Pool Bidding An offer to supply electric energy at a specific geographic point within a larger regional area or pool.

Marginal Cost The change in total costs associated with a unit change in quantity supplied (i.e., demand or energy). Sometimes called incremental cost and is the increase in cost that results from producing one extra unit of output.

Market Clearing Price The matching of the last price per unit of product a specific seller is willing to sell with the last price per unit of product the purchaser is willing to buy. It is the price at which the market reaches an equilibrium; that is, the quantity supplied and the quantity demanded are equal.

Nash Equilibrium A theoretical situation where no producers can make himself better off by changing the quantity supplied to the market.

Non-Cooperative Gaming A form of imperfect competition where producers manipulate supply in order to maximize profits without knowledge of competitors' strategies.

North American Electric Reliability Council (NERC) A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of ten regional reliability councils and encompasses essentially all of the contiguous United States, Canada and Mexico.

Off-Peak Energy supplied during periods of relatively low system demand.

Peak Demand Energy supplied during periods of relatively high system demand.

Perfect Competition In a perfect competitive market, many firms sell a standardized product, buyers are fully informed about the prices of the standardized product offered by these competitive firms, and each firm has only a small market share of total supply and takes the price of the product as beyond its control.

Power Pools Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Spot Price The price of a commodity or service is established by the market for short-term transactions. This price can change with each transaction and reflects the continually changing balances between supply and demand.

Summer Peak Demand The greatest load on an electric system during any prescribed demand interval in the summer (or cooling) season, usually between June 1 and September 30 (north of the equator).

Supply Bids See *Bidding Systems.*

Transmission System That portion of a utility plant used for the purpose of transmitting electric energy in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of the transmission plant.

Winter Peak Demand The greatest load on an electric system during any prescribed demand interval in the winter (or heating) season, usually between December 1 of a calendar year and March 31 of the next calendar year.

List of Acronyms

AE	Alliant East
AEP	American Electric Power
AMRN	Ameren
AP	Allegheny Power
AW	Alliant West
BREC	Big Rivers Electric Corporation
CAL-PX	California Power Exchange
CECO	Commonwealth Edison Co.
CG&E	Cincinnati Gas & Electric Co.
CILC	Central Illinois Light Co.
CP	Consumers Energy
DECO	Detroit Edison Co.
DLC	Duquesne Light Co.
DP&L	Dayton Power & Light Co.
ECAR	East Central Area Reliability Coordination Agreement
EEI	Electric Energy, Inc.
EIA	Energy Information Administration
EKPC	East Kentucky Power Coop.
FE	First Energy
FERC	Federal Energy Regulatory Commission
GAMS	General Algebraic Modeling System
HE	Hoosier Energy Rural Electric Coop.
IP	Illinois Power Co.
IPL	Indianapolis Power & Light Co.
IPP	Independent power producers
IURC	Indiana Utility Regulatory Commission
KKT	Karush-Kuhn-Tucker
LGEK	Louisville Gas & Electric Co.and Kentucky Utilities Co.
MAIN	Mid-American Interconnected Network
MAPP	Mid-Continent Area Power Pool
MCP	Mixed Complementarity Problem
MILES	Mixed Inequality and Non-Linear Equation Solver
NEPOOL	New England Power Pool
NIPS	Northern Indiana Public Service Co.
OASIS	Open Access Same-Time Information System
OVEC	Ohio Valley Electric Corp.
PJM	Pennsylvania-Jersey-Maryland Power Pool
PSI	PSI Energy Inc. of Cinergy
SIGE	Southern Indiana Gas & Electric Co.
SIPC	Southern Illinois Power Coop.
SPIL	Springfield Illinois City Water, Light and Power
SPP	Southwest Power Pool
SUFG	State Utility Forecasting Group
TVA	Tennessee Valley Authority
VP	Virginia Power