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ANL-06/16

Evaluating the Potential Impact of Transmission Constraints on the Operation of a Competitive Electricity Market in Illinois

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Evaluating the Potential Impact of Transmission Constraints on the Operation of a Competitive Electricity Market in Illinois

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for
Illinois Commerce Commission

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EXECUTIVE SUMMARY

In Illinois, electricity restructuring is mandated by the Electric Service Customer Choice and Rate Relief Law of 1997. The law provides for a transition period up to January 1, 2007, in which the electric power system is to move toward a competitive market. Despite the current adequacy of the generation and transmission system in Illinois, there is concern that the uncertainties of electricity restructuring warrant a more detailed analysis to determine if there might be pitfalls that have not been identified under current conditions. The problems experienced elsewhere in the country emphasizes the need for an evaluation of how Illinois might fare under a restructured electricity market.

The Illinois Commerce Commission (ICC) commissioned this study to be undertaken as a joint effort by the University of Illinois at Urbana-Champaign and Argonne National Laboratory to evaluate the Illinois situation in the 2007 period when restructuring is scheduled to be fully implemented in the State. The purpose of this study is to make an initial determination if the transmission system in Illinois and the surrounding region would be able to support a competitive electricity market, would allow for effective competition to keep prices in check, and would allow for new market participants to effectively compete for market share. The study seeks to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power in one or more portions of the state and thereby create undue pressure on the prices charged to customers and/or inhibit new market participants from entering the market.

The term “market power” has many different definitions and there is no universal agreement on how to measure it. For the purposes of this study, the term is defined as the ability to raise prices and increase profitability by unilateral action. With this definition, the central question of this analysis becomes:

“Can a company, acting on its own, raise electricity prices and increase its profits?”

It should be noted that the intent of the study is not to predict whether or not such market power would be exercised by any company. Rather, it is designed to determine if a set of reasonably expected conditions could allow any company to do so. It should also be emphasized that this study is not intended to be a comprehensive evaluation of the electric power system in the State. Rather, it is intended to identify some issues that may impact the effective functioning of a competitive market.

Two analytical tools are used in this study: the PowerWorld® model and the Electricity Market Complex Adaptive Systems (EMCAS)© model. PowerWorld Simulator is an interactive power system package designed to simulate high voltage power system operation. EMCAS uses an agent-based modeling structure to simulate the operation of the different entities participating in the electricity market.

The analysis of the power system in Illinois in this study was based on a set of assumptions and input data. These assumptions and inputs were used to provide a straightforward set of conditions that could be used to determine how the power system might function. They were not intended to represent the predicted, most likely, or optimal set of conditions for the Illinois market. Rather, they were intended to test how the market might behave under a given configuration. The basic assumptions included the following:

- *A single market for electricity will be operating in the State and surrounding study area in the analysis year of 2007. A single independent system operator (ISO) will operate the entire transmission system in the State.*
- *A day-ahead market (DAM) for energy and ancillary services will operate in the State. The DAM will allow suppliers (i.e., generation companies, or GenCos in the terminology of the analytical models used here) and purchasers (i.e., demand companies, or DemCos) to bid for their participation in the market. No bilateral contracts are assumed to be in place. There will be no tariffs or price caps to limit charges to consumers.*
- *The configuration of the power system in Illinois in the analysis year was constructed from the 2003 summer case prepared by the North American Electric Reliability Council (NERC), which includes about 1,900 buses and 2,650 branches in Illinois. In addition to the in-state transmission configuration, the power transfers into and out of the State were accounted for in order to get an accurate picture of how the State's system would perform. PowerWorld used a larger portion of the eastern interconnection. EMCAS used a reduced out-of-state network with transmission capacity that allowed power to move into and out of the State.*
- *Load forecasts were based on data contained in Feferal Energy Regulatory Commission (FERC) Form 714.*
- *Generation capacity additions were taken from FERC, Energy Information Agency (EIA), and Illinois EPA sources. About 6 GW of new capacity represented a growth of about 14% from 2001 levels.*
- *Fuel price projections were based on regional forecasts produced by the EIA National Energy Modeling System (NEMS) model that are reported in its Annual Energy Outlook (AEO).*

The basic assumptions were grouped into two sets. The Case Study Assumptions provided a point of comparison for a single configuration and operating profile of the power system. The Conservative Assumptions were designed to verify that the results and conclusions were not distorted by the details of this single configuration. Under Conservative Assumptions forced outages and company-level unit commitment decisions were eliminated. Also, generation production cost included only fuel and variable operation and maintenance costs under Conservative Assumptions.

Using the basic assumptions and inputs, alternative cases were analyzed to determine how the Illinois market might function in the analysis year. The cases studied included the following:

Production Cost (PC)	*GenCo bids were based on unit production cost*
Physical Withholding (PW)	*GenCos withheld units from the market*
Economic Withholding (EW)	*GenCos increased prices above production cost*

The following observations can be made from what has been studied thus far under the assumptions applied:

Basic System Status

(a) The State has an adequate supply of generation capability to meet its needs and to export power to surrounding areas. It might even be argued that there is an excess of capacity given that the projected statewide generation reserve margin (in excess of 40%) is higher than what is generally used for system reliability planning. Further, some generators would not be dispatched at all under the conditions laid out in the PC case.

(b) The ownership of the generation capacity is concentrated in five companies: Exelon Nuclear, Midwest Generation, Ameren, Dynegy, and Dominion Energy. Together, they account for more than 77% of the generation capacity in the State. If they were to be dispatched under PC case market conditions, they would account for about 98% of the electricity generated in the State. Using any one of a number of measures of market competition, the State's generation capacity can be considered to be concentrated. With this degree of concentration and with much of this capacity in the form of low cost nuclear and coal units, it would be difficult for new generation companies to enter the deregulated market. In fact, many of the existing natural gas units, some of which are only a few years old, would have difficulty competing in this market.

(c) During the high load periods, which occurred about 5% of the time, electricity prices rose, since higher-cost generators had to be brought on-line to meet loads while maintaining the integrity and stability of the power grid. Even without any attempt to manipulate prices on the part of generation companies, prices were as much as 30% higher in high load periods.

(d) The transmission system in the State has areas that show evidence of congestion. Some transmission equipment was operated at its capacity limits for a significant number of hours in a year. The congested regions include the City of Chicago, the areas north and west of Chicago out to the Iowa border, a broad area stretching southwest of Chicago to Peoria and Springfield, and several smaller isolated areas in the southern part of the State. The effects of the transmission congestion were more prevalent during peak load periods, during which prices spread across the State. Price variations across the State due to transmission congestion were as much as 24% during these peak load periods.

(e) Using Conservative Assumptions, in which more generation capacity was assumed to be made available by the elimination of forced outages and company level unit commitment decisions, the results did not materially change. The generation market was still concentrated and transmission congestion was still evident. Price variations, though smaller in absolute magnitude, were equivalent in relative terms.

(f) Under a fully competitive market in the State using the market rules assumed here, some generation companies were pressed to maintain operating profitability. Only 6 out of 24 generation companies in the State were able to operate profitably. The dominance of the low cost nuclear and coal units made it difficult for others to compete. Under Conservative Assumptions, none of the generation companies, except Exelon Nuclear, was profitable. Exelon's operating profit was very small. For both the Case Study Assumptions and the Conservative Assumptions, the analysis period was only one year, and an assessment of long-term profitability that includes factors such as capital outlays was not included.

Market Power Potential

(g) If generation companies seek to raise market prices by physically withholding single units from service, the results here show that, for the most part, they would not likely benefit. Because of the abundance of generation in the State, there was almost always another unit that could be brought into service to replace one that was withheld. This is true even in light of the transmission congestion.

(h) In contrast, physically withholding multiple units that are strategically located in the transmission network, particularly during peak load conditions, can increase profitability. A single company using a strategy based on indicators of system reserve margin to identify times to withhold capacity and indicators of locational prices to identify which capacity to withhold could significantly increase its profitability. This type of strategic physical withholding could even create conditions where some load cannot be met and could result in very steep price increases. Exelon Nuclear, Midwest Generation, and Ameren all had market power (as defined here) when using this strategy. Dynegy and Dominion Energy did not.

(i) If the major generation companies sought to raise market prices by unilaterally increasing the price of their units (i.e., by economic withholding), the results would be mixed. Applying a price increase to all units for all hours increased profits for Exelon Nuclear and Midwest Generation, but at the expense of significant loss in generator dispatch since some of the higher cost units would be selected only sporadically by the market. The resulting dispatch schedule may not be technically practical for the companies' larger units. For Ameren, Dynegy, and Dominion Energy, the higher priced units would not be selected in the market and the price increase gained by other units would not be sufficient to recover the lost revenue. Profitability decreased.

(j) Alternatively, a more limited application of price increases that was restricted to peak hours only allowed Exelon Nuclear and Midwest Generation to significantly increase profits with only a small decrease in generator dispatch. Ameren, Dynegy, and Dominion did not see any profit increase by applying this strategy. The same was true under Conservative Assumptions except that Exelon would need very large price increases to increase its profitability. When using this strategy, Exelon Nuclear and Midwest Generation had market power according to the definition used here.

(k) By raising their prices, all generation companies could cause consumer costs to rise, some by as much as 250% in some parts of the State on a peak day. However, only Exelon Nuclear and Midwest Generation saw a significant increase in their operating profits by applying this strategy.

Overall, the answer to the basic question of the study, *"Can a company, acting on its own, raise electricity prices and increase its profits?"* is affirmative. There is a concentration in the generation market and evidence of transmission congestion, at least during high load periods. This will give rise to the ability of some companies to unilaterally raise prices and increase their profits. Consumer costs will increase, in some cases substantially. However, the situations under which this can be done are limited to a number of conditions, especially high load periods.

1 INTRODUCTION

1.1 BACKGROUND

In 1978, the Public Utility Regulatory Policies Act (PURPA) passed by Congress began the process of restructuring the electricity system in the U.S. away from regulated monopolies and toward competitive businesses. This process continued with the Energy Policy Act of 1992, which focused on providing opportunities for competition in the wholesale electricity market. Orders 888 and 889, issued by the Federal Energy Regulatory Commission (FERC) in 1996, provided for open access to the bulk power transmission system for all wholesale electricity producers and purchasers. However, the FERC recognized that open access at the retail level would also require legislative and/or regulatory action by the states.

Since the passage of these legislative and regulatory measures, a number of states have taken steps to restructure the electricity system in their jurisdictions and to provide access to retail customers to electricity providers other than their local electric utility. To date, 24 states have implemented some form of electricity restructuring legislation. Of these, 18, including Illinois, are actively engaged in implementing the process, five have delayed implementation, and one, California, has suspended implementation.[1]

While restructuring has proceeded relatively smoothly in some parts of the country, such as with the New York Independent System Operator (NYISO), and the Pennsylvania-New Jersey-Maryland (PJM) area, the serious problems experienced in California in 2000/2001 have demonstrated the need to better understand the operation of a restructured electricity market. The California experience showed how a set of conditions, such as the following, could combine to create a “perfect storm” in the electricity business:

- *Low investment in new generation capacity.* California’s load increased by 11% in the 1990s while generation capacity decreased by 2%.

- *Low hydropower conditions.* California depended on 7–11 GW of out-of-state generation capacity, much of which was hydropower-based and much of which experienced low water levels due to an extended period of dry weather.

- *Generation units out of service.* As much as 10 GW of generation capacity were out of operation, some during peak load periods.

- *Transmission limitations.* A major transmission line, Path 15, was significantly congested, thus inhibiting the transfer of power between northern and southern California.

- *Independent power producers’ reluctance to sell power.* Because of the precarious financial position of the utilities, independent producers feared not being paid for the power they provided.

[1] Energy Information Administration last update (Feb. 2003).

- *Shortcomings of the wholesale market design.* The California market rules prohibited the use of forward long-term contracts for the purchase of electricity; utilities were required to use the volatile spot market exclusively.

- *High natural gas prices.* The high prices for natural gas added to the cost of electricity.

- *Fixed retail prices.* With high wholesale prices and fixed retail prices, there was no price feedback to consumers. Companies were unable to recover their costs and accumulated significant debts. [2]

In addition to these extreme conditions, experience in other electricity markets in the U.S. and abroad has shown that it is possible for restructuring to function in such a way as to reduce or negate the benefits that should accrue from open competition.

In Illinois, electricity restructuring is mandated by the Electric Service Customer Choice and Rate Relief Law of 1997. [3] The law provides for a transition period up to January 1, 2007, in which the electric power system is to move toward a competitive market.

Under the historical structure of electric utility monopolies, Illinois has had an adequate level of generation and transmission capacity to meet demand. In a reliability assessment, [4] the North American Electric Reliability Council (NERC) indicated that the long-term generation capacity reserve margins for the MidAmerica Interconnected Network (MAIN), which encompasses most of Illinois and parts of Iowa, Minnesota, Missouri, and Wisconsin, is well within requirements. Further, it indicated that the "…bulk electric transmission system generally appears to have no major limitations and is expected to perform adequately over a wide range of system conditions." There were, however, some reported limitations on power transfers into Wisconsin and Iowa and heavy loadings on lines in the southern part of the MAIN area.

1.2 PURPOSE OF THE STUDY

Despite the current adequacy of the generation and transmission system in Illinois, there is concern that the uncertainties of electricity restructuring warrant a more detailed analysis to determine if there might be pitfalls that have not been identified under current conditions. The problems experienced elsewhere in the country emphasize the need for an evaluation of how Illinois might fare under a restructured electricity market.

The Illinois Commerce Commission (ICC) commissioned this study to be undertaken as a joint effort by the University of Illinois at Urbana-Champaign and Argonne National Laboratory to evaluate the Illinois situation in the 2007 period when restructuring is scheduled to be fully

[2] *Status of the California Electricity Situation*, Energy Information Administration (Aug 2002).
[3] Illinois Compiled Statutes, Utilities, Public Utilities Act, 220 ILCS 5.
[4] North American Electric Reliability Council, "Reliability Assessment 2002-2011, The Reliability of Bulk Electric Systems in North America (October 2002).

implemented in the State. The purpose of this study is to make an initial determination if the transmission system in Illinois and the surrounding region would be able to support a competitive electricity market, would allow for effective competition to keep prices in check, and would allow for new market participants to effectively compete for market share. The study seeks to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power in one or more portions of the State and thereby create undue pressure on the prices charged to customers and/or inhibit new market participants from entering the market.

The term "market power" has many different definitions, and there is no universal agreement on how to measure it. For the purposes of this study, the term is defined as the ability to raise prices and increase profitability by unilateral action. A more complete definition is provided later. With this definition, the central question of this analysis becomes:

"Can a company, acting on its own, raise electricity prices and increase its profits?"

It should be noted that the intent of the study is not to predict whether or not such market power would be exercised by any company. Rather, it is designed to determine if a set of reasonably expected conditions could allow any company to do so. It should also be emphasized that this study is not intended to be a comprehensive evaluation of the electric power system in the State. Rather, it is intended to identify some issues that may impact the effective functioning of a competitive market.

1.3 METHODOLOGY

Two analytical tools are used in this study: the PowerWorld® model and the Electricity Market Complex Adaptive Systems (EMCAS)© model.

1.3.1 PowerWorld Model

PowerWorld® Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses (i.e., transmission network connection points). Powerful visualization techniques are used on an interactive basis, resulting in an intuitive and easy-to-use graphical user interface (GUI). The GUI includes animated one-line diagrams with support for panning, zooming, and conditional display of objects.

One of the add-ons available with Simulator is the Security Constrained Optimal Power Flow (SCOPF). The advantage of having an SCOPF embedded into Simulator is that it is now possible to optimally dispatch the generation in an area or group of areas while *simultaneously* enforcing the transmission line and interface limits both for a baseline case and for a set of contingencies. Simulator SCOPF can then calculate the marginal price to supply electricity to a bus (also known as the locational marginal price), taking into account transmission system congestion. The advantage with Simulator is that these values are not just calculated; they can also be shown on a one-line diagram, on a contoured map, or exported to a spreadsheet. Simulator SCOPF was used to perform the detailed power flow analyses in this study.

More details on the PowerWorld model are given in Appendix A.

1.3.2 EMCAS Model

EMCAS uses an agent-based modeling structure to simulate the operation of the different entities participating in the electricity market. In this approach, an agent is modeled as an independent entity that makes decisions and takes actions using the limited and/or uncertain information available to it, similar to how organizations and individuals operate in the real world. Figure 1.3.2-1 shows the basic structure of EMCAS. EMCAS agents included in the simulation are:

- Consumers – the end users of electricity including residential, commercial, industrial and other customers.

- Generation Companies (GenCos) – companies that own and operate generators.

- Demand Companies (DemCos) – companies that are financially obligated to provide electricity to consumers. DemCos do not own any physical assets (e.g., distribution lines).

- Distribution Companies (DistCos) – companies that own and operate the distribution system. DistCos and DemCos are frequently under the same corporate parent. In the simulation, they are treated as individual entities.

- Transmission Companies (TransCos) – companies that own the transmission system.

- Independent System Operator (ISO) – the organization that operates the transmission system. This agent can be an Independent System Operator (ISO), a Regional Transmission Organization (RTO), or Independent Transmission Provider (ITP).

- Regulator – the organization that sets the market rules.

An important point in the use of this framework is that some of the agents may belong to the same corporate parent. For example, a company may have subsidiaries that include a GenCo, a DemCo, a DistCo, and a TransCo. In the study, these entities are tracked separately.

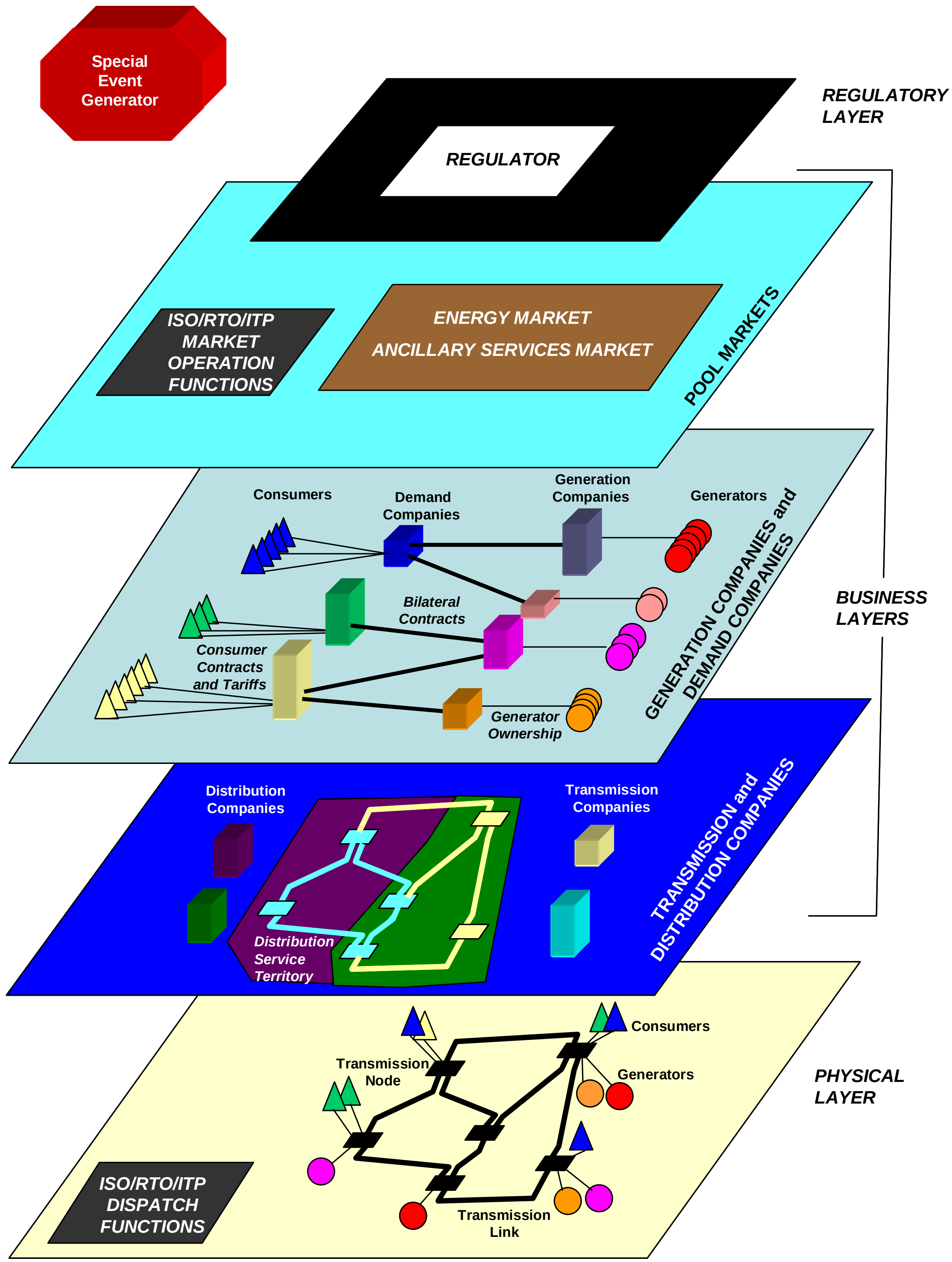

Figure 1.3.2-1 EMCAS Structure

The agents interact on several different layers. In the physical layer, the consumers use electricity, thus putting load on the power system. The ISO dispatches the available generators to meet that load while maintaining the constraints and limitations of the transmission system. In the business layers, pool markets are operated and bilateral contracts are executed to allow companies to buy and sell power under market conditions. Transmission and distribution costs are included as part of the business arrangements.

Figure 1.3.2-2 is a simplified schematic of the flow of the simulation in the EMCAS model. The basic procedure is as follows:

Day-Ahead Market

ISO. The simulation begins with the ISO projecting the system loads for the next day.

GenCo. Each GenCo receives this information and makes a projection of the next day's prices. The basic price projection scheme used here is to average the prices of the previous week for each hour, with corrections made for weekends. (Other price projection schemes were also implemented. These are described later.) This captures the general trend of recent prices and can be considered as a relatively conservative estimate of where prices might be. In addition, each GenCo makes an evaluation of the previous success or failure of bids that have been submitted into the market.

Each GenCo runs the company level unit commitment and resource allocation (CLUCRA) algorithm to determine which units can be expected to be profitable, given the projected prices for the next day. The CLUCRA algorithm considers fuel costs, operating and maintenance costs, and startup/shutdown costs in making this determination. The determination is based on evaluating the prices for each hour and the potential costs and revenue for the whole day. Details of CLUCRA algorithm are in Appendix B. Using the CLUCRA results, a decision is made to commit the unit to the next day's market or to shut it down to avoid expenses that cannot be recovered at the projected prices.

Each GenCo applies its business strategy to determine what price will be applied to the units that are being offered into the market. Bid prices can be for the entire capacity of the unit or can be for blocks or portions of capacity.

The bids (a quantity and a price) are submitted to the ISO.

DemCo. Each DemCo projects the loads that will be coming from the consumers it serves. As described earlier, the loads are assumed to be firm commitments and not on interruptible service. Load bids are submitted to the ISO.

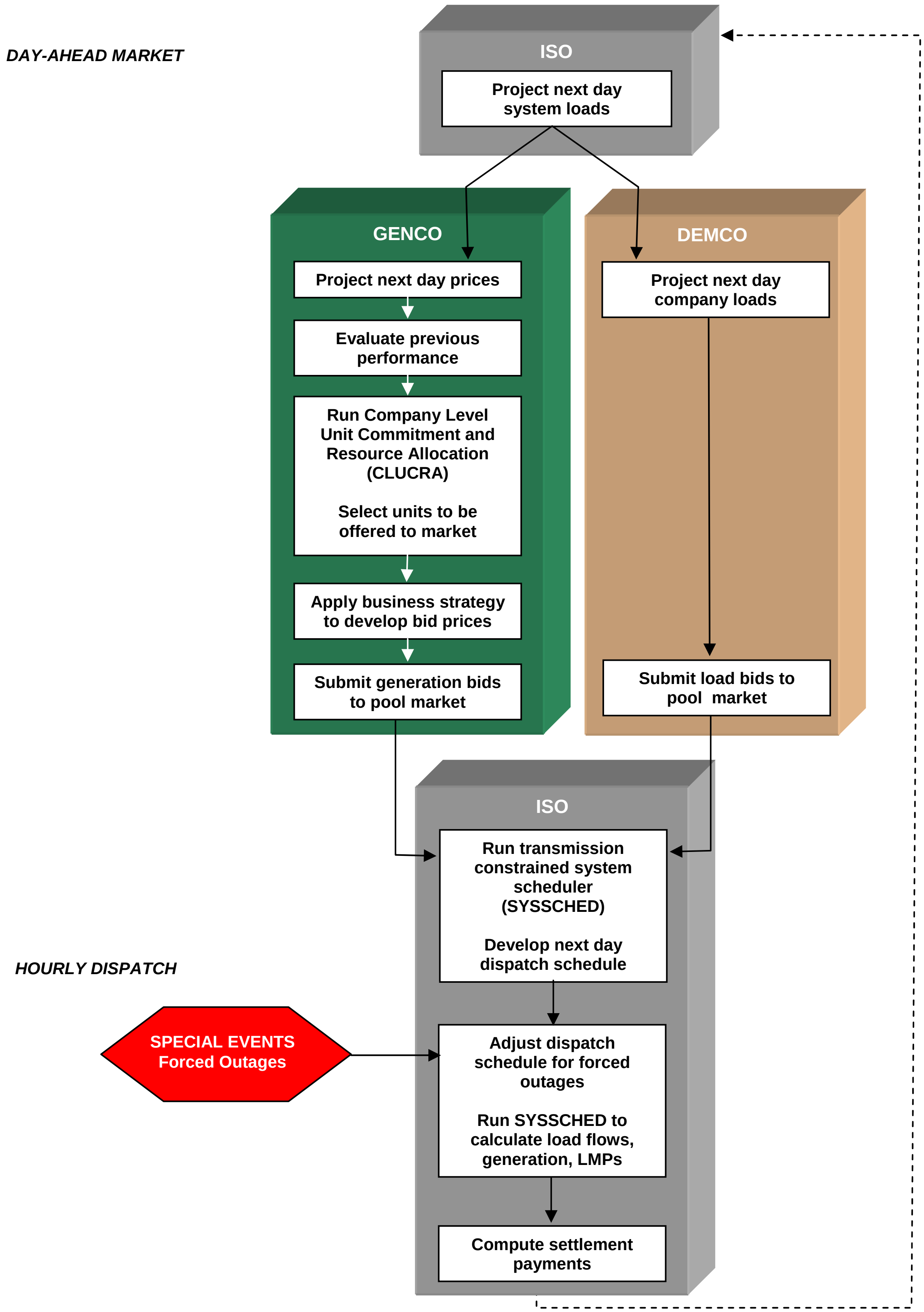

Figure 1.3.2-2 Schematic of EMCAS Simulation Sequence

ISO. With the generation and load bids, the ISO runs the transmission constrained system scheduler (SYSSCHED) algorithm. SYSSCHED is a DC optimal power flow (DCOPF) load flow calculation. It selects the lowest cost combination of units, based on the bid prices received from the GenCos, to meet the load bids received from the DemCos. The flow limits of the transmission system serve as constraints in the algorithm. SYSSCHED is used to develop the schedule of units that will be dispatched the next day.

In addition to determining the generators that will be scheduled to meet the projected load, ancillary service generators that provide spinning, non-spinning, and replacement reserve capacity are also selected.

Hourly Dispatch

Special Events. During the hourly dispatch portion of the simulation, special events are injected to represent conditions that are different than what was projected in the day-ahead market analysis. Generator forced outages are introduced at this point. Although it is possible to inject transmission line outages and load perturbations, these were not implemented here.

ISO. The ISO adjusts the availability of generators to account for the forced outages. The ISO runs the SYSSCHED DCOPF to dispatch the available generators, including those that are on standby to provide reserves, to meet the load. Generation rates, load flow, and locational marginal prices (LMPs) are calculated.

At the completion of the 24 hours of the dispatch day, the ISO calculates the revenues and costs associated with the day's operation.

The process then recycles to begin the simulation for the next day.

This basic sequence is used in all of the cases that are included in the analyses here. More details on the EMCAS model can be found in Appendix B.

1.3.3 Model Application

The PowerWorld and EMCAS models were used in tandem. EMCAS was used to calculate the behavior of the agents participating in the market. It focused on the manner in which the market participants make decisions and on how they adapt their behavior to market changes and to their own success or failure in the marketplace. PowerWorld was used to calculate the detailed operation of the physical power system. It provided a detailed look at generator dispatching, transmission loading, and contingency conditions for the various behavior patterns of the market participants. The use of both models provides the ability to look at the details of the market and the details of the physical power system in an integrated fashion. Appendix C provides a comparison of the EMCAS and PowerWorld load flow results and shows them to be in very good correlation.

1.3.4 Locational Marginal Prices

One of the primary focuses of this study is the locational differences in electricity prices under a fully restructured market. The locational marginal price (LMP), expressed in $/MWh, is defined as the cost of serving one additional MW of load at any point in the network.[5] The LMP has three components: (1) the marginal cost to produce the last MW of power, (2) a transmission congestion charge, and (3) the cost of marginal transmission losses. In situations where there is no transmission congestion, LMPs at all buses are similar, varying only by a relatively small amount to cover marginal transmission losses. An uncongested state only occurs when generating units can be dispatched according to an economic merit order without overloading transmission lines and violating security measures. The economic merit ordering of units or blocks of units is typically based on marginal production costs such that generators that are the least expensive to operate are dispatched first while the most expensive units are utilized only during times of the highest demand. However, the actual dispatch of units must often deviate from the economic merit order to keep the transmission system operating within a stable and secure state. This change in the order of dispatch of units when transmission congestion occurs leads to variations in LMPs across a region. In some cases, the variation in LMPs among network nodes can be significant.

In this study, the LMPs are calculated for each node in the network by the PowerWorld and EMCAS models. The algorithms used in the models, in effect, check each node in the transmission network to determine what the cost would be to provide a small increment of power to that node. Both models seek to dispatch the available generators such that the total cost of operating the system is minimized, subject to the transmission system's constraints and reliability standards.

1.3.5 Market Power

In a Notice of Proposed Rulemaking, the Federal Energy Regulatory Commission (FERC) defined "market power" as the "…ability to raise price above competitive levels." [6] Not included in the FERC definition is what constitutes a "competitive level" in an electricity market.

FERC has, at various times, considered several different measures of market power, including the following:

- *20% Benchmark.* A power supplier was considered to have the potential for market power if it had a 20% or more share of the market.

- *Limited Competing Supplier Test.* An evaluation is made of whether the total transmission capacity (TTC) in an area would allow competitors to provide power.

- *Supply Margin Assessment.* An evaluation is made of whether the power supplied from a specific seller is needed to meet peak day demand.

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[5] See *Power System Economics*, S. Stoft, IEEE Press, New Jersey (2002) for a description of LMPs.

[6] "Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design," paragraph 393, Docket No. RM01-12-000, Federal Energy Regulatory Commission (July 2002).

- *Delivered Price Test.* The ability of a supplier to provide power into a market with a price of no more than 5% of a reference price in the area is determined.

- *Residual Supply Index.* A determination is made of whether a particular demand can be met without any production from a specific seller.

Separate from the FERC approaches, the U.S. Department of Justice uses the Herfindahl-Hirschman Index (HHI) to estimate the level of concentration in a market and the potential for the exercise of market power. The HHI is the sum of the squares of the market shares, in percent, of each company in a market. HHI values between 1,000 and 1,800 are considered to be indicative of "moderately concentrated" markets. HHI values above 1,800 are considered to be indicative of "concentrated" markets. With this definition, concentrated markets can provide the opportunity for a company to exercise market power. While the HHI has been used to some degree in the electric power industry, it is recognized as not being the best measure of market power potential, since it does not capture the unique aspects of the power system. The inability to store the product (i.e., electricity) in anticipation of price changes, the interconnectedness of all the market participants, and the need to maintain overall system reliability are not captured by the HHI. Thus, market power behavior can theoretically be exercised in the electricity system even in markets with HHI values below 1,000.

As stated earlier, to date, there is no universal agreement on what constitutes a definitive measure of market power in the electric power industry. For the purposes of this study, the following are used to indicate the ability of a company to exercise market power:

Baseline price levels are the locational marginal prices (LMPs) when all potential suppliers in the market (i.e., all GenCos) offer their power at production cost.

Market power is the ability of a company to profitably increase prices (i.e., LMPs) above baseline price levels by its own actions, independent of what other companies do.

The application of these relatively simple definitions will be demonstrated in more detail in the sections giving results of the analyses.

1.3.6 Data Sources

Data for the analysis were drawn from several different sources as shown in Table 1.3.6-1. The information is primarily from publicly available sources. Therefore, the information used in this study does not necessarily reflect the actual conditions that currently exist in the electricity market or that will be experienced in the future. Although several companies provided some data modifications, business proprietary information such as fuel purchase contracts, actual generator performance, and corporate debt service were not utilized here. The results presented here must be viewed in the light of these limitations. Comparisons with current information on electricity prices, company profitability, and other such parameters must be made with the awareness of the data restrictions.

Table 1.3.6-1 Data Sources

Data	Primary Sources
Transmission Network Configuration	National Electric Reliability Council (NERC) – Summer 2003 Case
Generator Performance and Cost	• FERC Form 1 data (1994-2000) • EIA Form 860A – Annual Electric Generator Report – Utility • EIA Form 860B – Annual Electric Generator Report – Nonutility • EIA Form 861 – Annual Electric Power Industry Report • Argonne Power Plant Inventory (APPI database) • NERC's Electricity Supply & Demand (ES&D) database • EIA Electric Power Monthly • EIA Form 767 Steam-Electric Plant Operation and Design Report • EIA Form 906 – Power Plant Report • IL EPA – Electric Power Plant Construction Projects Since 1998 (Status as of June 22, 2001) • IL EPA – Electric Power Plant Construction Projects Since 1998 (Status as of June 13, 2002) • NERC Generation Availability Data Set (GADS) – Generating unit outage factors
Load	• FERC Form 714 - Hourly control area loads (aggregated among all power sinks) - Control area load growth projections • EIA's AEO 2003 with projections to 2025 - Default regional load growth rates (when Form 714 is not available) • Based on Power World Case – Bus-load distribution factors
Fuel Prices	• EIA's AEO 2003 with projections to 2025 – Regional electric utility fuel prices

1.3.7 Company and Ownership Convention

Since the passage of the Illinois restructuring law, the ownership of the various components of the electric power system in the State has changed considerably. The traditional vertically integrated electric utilities that owned and operated the generation, transmission, and distribution system as a single corporate entity have given way to a mix of company configurations. Some still own and operate the full spectrum of power system components. Some have subsidiaries under a corporate parent, each of which owns different components. Some are separate companies that own only generation equipment. Some own no physical electric power assets, but operate as intermediaries or brokers in the market.

The company ownership terminology that is employed in the analytical models is used throughout this document. It identifies each organizational unit as a separate agent (e.g., GenCos, DistCos, TransCo, DemCo) even though they may be part of the same corporate parent.

2 CURRENT STATUS OF THE POWER SYSTEM IN ILLINOIS

2.1 REGULATORY AND MARKET STRUCTURE

The Electric Service Customer Choice and Rate Relief Law of 1997 specifies how Illinois will transition to a restructured electricity market. Table 2.1-1 lists the key provisions that are relevant to this study.

In summary, by 2007 the Illinois power market is envisioned to have the following characteristics:

- All customers will have the choice of purchasing their electricity from any of the alternative suppliers willing to serve them.

- Electricity prices to customers, whether supplied by third party retailers or the incumbent utility, will ultimately be based on market conditions, whether those markets are concentrated or not and whether the prices are high or low.

- All electricity suppliers will have equal access to the transmission and distribution system to supply their customers.

- The transmission system will be operated by one or more Independent System Operators (ISOs), which will run the system in an equitable and efficient manner for all suppliers and customers.

This is, of course, a highly simplified description of the power system specified in the law. There are a number of requirements that must be met before this idealistic structure can be fully realized.

An important note is that the Illinois law does not specify the details of how the competitive market will be set up. Unlike the California law, which mandated certain actions by the electric utilities (e.g., the sale of their generators) and which dictated the structure of the market (e.g., reliance on a bidding market rather than bilateral contracts), the Illinois law leaves much of the market design open to later development.

In addition to the State regulatory requirements, the power system is subject to the federal requirements imposed by the Federal Energy Regulatory Commission (FERC). FERC has issued its proposed structure for the operation of competitive electricity markets. [7] This Standard Market Design (SMD) has undergone a significant amount of review and comment and has not yet been finalized. Because of serious objections raised by affected parties in some areas of the country, it appears unlikely that the SMD will be implemented in the proposed form.

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[7] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, Docket No. RM01-12-000, Federal Energy Regulatory Commission (July 2002).

Table 2.1-1 Summary of Related Provisions of Illinois Electricity Restructuring

Electricity Providers – The Law identifies two major types of electricity providers: *Electric utilities* – the public utilities that have franchises to sell electricity to retail customers within a service area. *Alternative retail electric suppliers* – entities other than electric utilities that offer electricity for sale to retail customers. Included are corporations, cooperatives, power marketers, aggregators, resellers, and others.
Electricity Services – Several types of electricity services are identified, including: *Tariffed services* – electricity service that is provided by an electric utility under rates that are regulated by the ICC. *Unbundled services* – portions of a tariffed service that electric utilities offer separately to their customers. *Competitive services* – electricity service that is available to a customer segment or to a geographic area and that can be provided by an entity other than an electric utility or utility affiliate. An electric utility may petition the ICC to declare a tariffed service to be a competitive service. In making its determination, the ICC must consider if there is adequate transmission capacity available to supply the customer segment or geographic area from providers other than the electric utility or its affiliates. When a service is declared to be competitive, the suppliers may charge market-based prices for it. *Contract services* – electricity service that is provided by mutual agreement between an electric utility and a retail customer. *Delivery services* – electricity transmission and distribution services. Delivery services are not expected to be declared competitive services.
Prices – The law identifies several types of pricing mechanisms: *Market based prices* – prices for electricity based on the cost of obtaining the service at wholesale through a competitive bidding or similar process. *Real-time prices* – prices for electricity that vary with time; typically hourly for non-residential customers, periodically during the day for residential customers. *Cost-based prices* – prices that are based on the cost of providing the service.
Customer Choice – The law provides for customer choice of electricity service. The dates when different customer classes were able to choose alternative suppliers are: *Large commercial and industrial customers* – October 1, 1999. *All other non-residential customers* – December 31, 2000. *Residential customers* – May 1, 2002. Transition charges may be imposed by electric utilities through 2006.
Asset Ownership – Electric utilities may sell, lease, or transfer assets (e.g., generators) to an affiliated entity (e.g., a subsidiary of its parent company) or unaffiliated entity (e.g., an entirely separate company). The ICC may adopt rules requiring functional separation between the generation service and delivery service components of an electric utility in order to ensure efficient competition for alternate suppliers.
Access to Transmission and Distribution Facilities – Electric utilities must allow alternative retail electric providers to interconnect to their transmission and distribution systems in order to supply customers.
Independent System Operator (ISO) – Every electric utility that owns transmission facilities must submit to FERC a plan for joining an ISO that will independently manage and control the transmission system. The ISO operating in Illinois may establish a competitive power exchange auction open to all suppliers.
Transition Period – The law sets the transition period in which the move from the traditional electric utilities providing tariffed services to a fully competitive market as 1997 to January 1, 2007. A number of rules and procedures are specified for the operation of the power system and the charges that may be levied during this period.

Note: In addition to these provisions, there are other elements of the law that do not affect this study and are not included in the table. Examples are how the transition period will be managed, consumer protection, protection of labor, nuclear decommissioning, and others.

2.2 ELECTRICITY DEMAND

Figure 2.2-1 shows the electricity demand growth in the State since 1990. Consumption has grown by about 20% over the period, with the largest increase coming in the commercial sector.

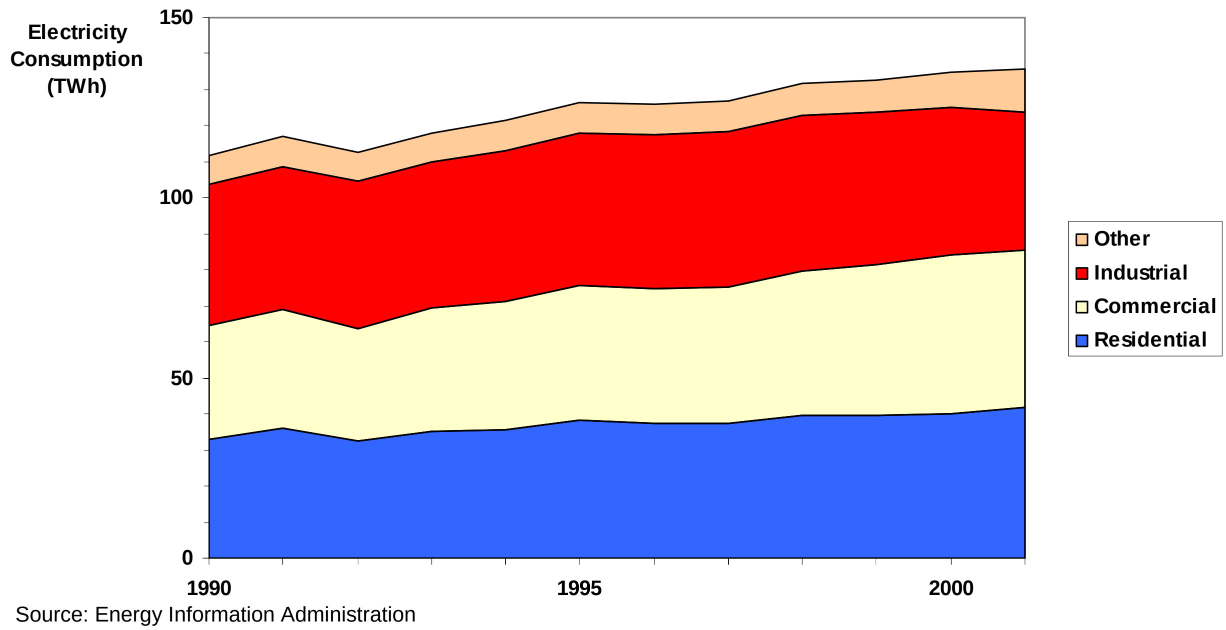


Figure 2.2-1 Electricity Demand Growth in Illinois

Figure 2.2-2 shows the service territories of the distribution companies (DistCos) operating in Illinois. Table 2.2-1 shows electricity sales and the number of consumers served for each. The figure and table show the major distribution companies in the State. There are a number of smaller, municipally-owned distribution companies that buy bulk power and operate their own systems. These are not included here.

The distribution companies are regulated monopolies in Illinois and are part of the electric utilities as defined in the restructuring law. They own and operate the distribution lines, substations, and other equipment. For the purposes of this study, they are distinguished from “Demand Companies,” which are discussed next. Distribution services are expected to remain tariffed delivery services, even after the completion of restructuring.

Table 2.2-2 lists the Demand Companies (DemCos) certified to sell electricity in Illinois. By convention for this study, DemCos are distinguished from DistCos in that they do not have a monopoly service territory and, in theory, can sell electricity to any consumer anywhere in the State. Some of these are affiliates of the electric utilities; some are registered as alternative retail electric suppliers (ARES). While some have been providing service to customers, some are only certified with the State but have not yet begun actual sales.

Table 2.2-3 shows the electricity sales by Illinois DemCos split between those that are electric utility affiliates and those that are alternative retail electricity suppliers. Table 2.2-4 shows the number of customers eligible to switch from the traditional bundled service from electric utilities to delivery services that are market based, along with statistics on those that have actually switched. To date, only a small number of consumers have switched supply plans. Large consumers, those with greater than 1 MW of load, have been much more active in exercising their supplier choice with about half choosing alternative plans.

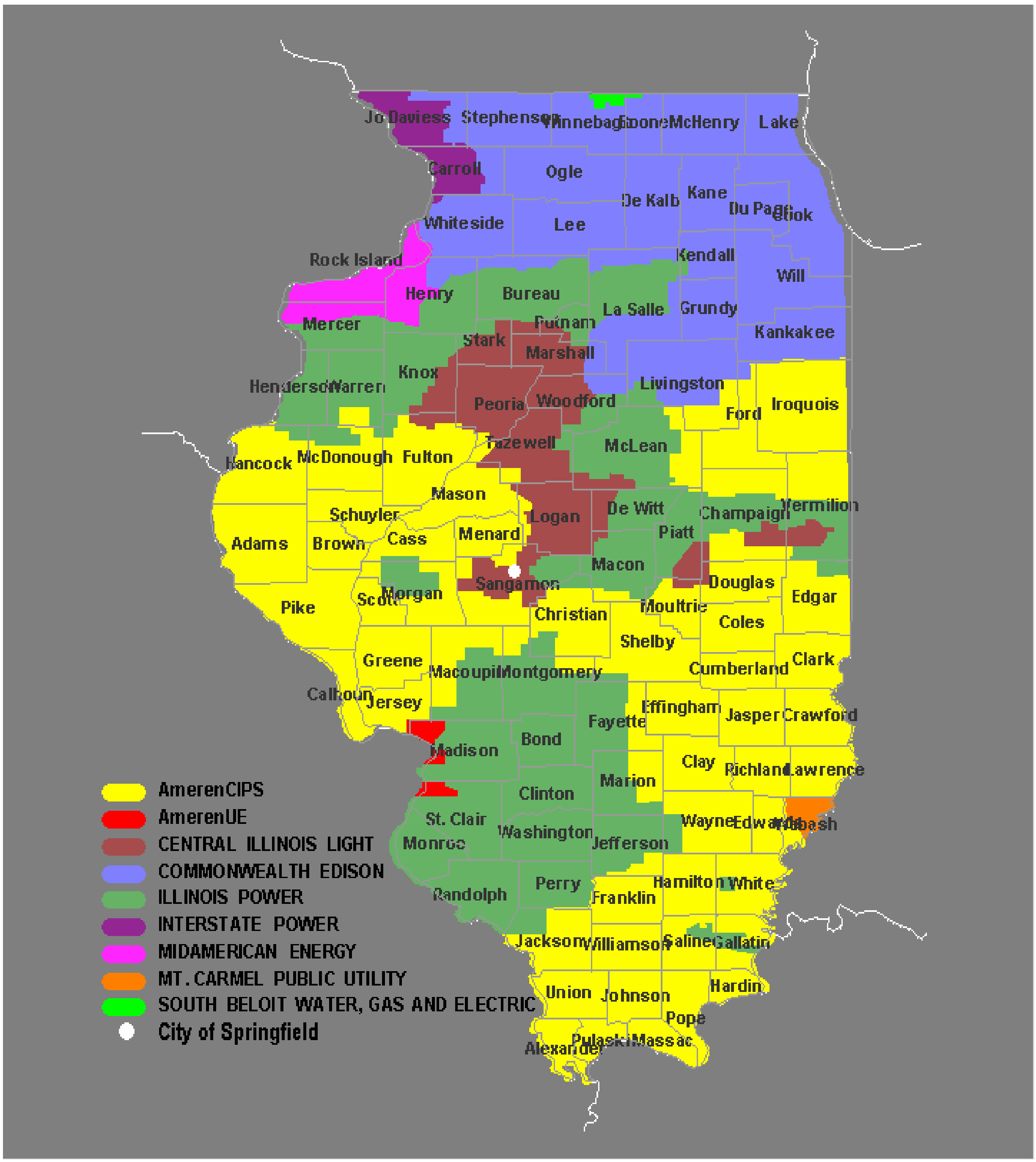


Figure 2.2-2 Distribution Company Service Territories

Table 2.2-1 Distribution Companies in Illinois

Distribution Company Name	Ownership	Total Sales in 2002 (TWh)	Number of Consumers in Service Territory (Thousands)
DistCo Ameren – CILCO	Private	6.1	203
DistCo Ameren – CIPS	Private	9.0	326
DistCo Ameren – UE (Illinois only)	Private	3.5	66
DistCo Ameren – EEI[a]	Private	NA	NA
DistCo Commonwealth Edison Co.	Private	87.1	3,590
DistCo Illinois Power Co.	Private	19.1	573
DistCo Alliant Energy (Interstate Power, South Beloit) [b]	Private	0.6	20
DistCo MidAmerican Energy Co. [c]	Private	1.9	84
DistCo Mt Carmel Public Utility Co.	Private	0.1	6
DistCo Springfield, City of	Municipal	0.2	68

[a] Ameren is a majority owner of Electric Energy, Inc.

[b] Alliant Energy operates primarily in Iowa and Wisconsin with small service territories (Interstate Power and South Beloit Water, Gas, and Electric) in Illinois.

[c] MidAmerican is owned by MidAmerican Energy, which operates primarily in Iowa with a small service territory in Illinois.

Source: Illinois Commerce Commission

Table 2.2-2 Demand Companies in Illinois

Demand Company Name	Ownership
Electric Utility Affiliates	
DemCo – Ameren	Private
Ameren – CILCO	
Ameren – CIPS	
Ameren – UE (Illinois portion)	
Ameren – Electric Energy Inc.	
DemCo – Commonwealth Edison Co.	Private
DemCo – Illinois Power Co.	Private
DemCo – Alliant Energy (Interstate Power Co, South Beloit)	Private
DemCo – MidAmerican Energy Co (Illinois portion)	Private
DemCo – Mt Carmel Public Utility Co.	Private
DemCo – City of Springfield	Municipal
DemCo – IMEA - Illinois Municipal Electric Agency	Municipal
DemCo – Soyland Power Coop Inc.	Cooperative
Alternative Retail Electric Suppliers	
DemCo – Constellation NewEnergy Inc.	Private
DemCo – Ameren Energy Marketing Co.	Private
DemCo – Blackhawk Energy Services, LLC	Private
DemCo – Dynegy Energy Services, Inc.	Private
DemCo – EnerStar Power Corp.	Private
DemCo – Exelon Energy Co.	Private
DemCo – Illinois Power Energy, Inc.	Private
DemCo – Peoples Energy Services Corp.	Private
DemCo – Sempra Energy Solutions	Private
DemCo – Sempra Energy Trading Corp.	Private
DemCo – WPS Energy Services, Inc.	Private

Source: Illinois Commerce Commission

Table 2.2-3 Sales by Electric Utilities and Alternative Retail Electricity Suppliers in 2002

Seller and Category of Service	Portion of Total Electricity Sales (%)
DemCos: Electric Utility Services	
Bundled Service	72.7
Contract Service	5.6
Power Purchase Option	9.3
DemCos: Alternative Retail Electricity Suppliers	
In-state, unregulated, retail utility sales outside utility's own territory.	5.0
Retail electric suppliers (affiliate and unaffiliated sales).	7.4
	100.0

Source: Illinois Commerce Commission

Table 2.2-4 Delivery Service Consumers in 2002

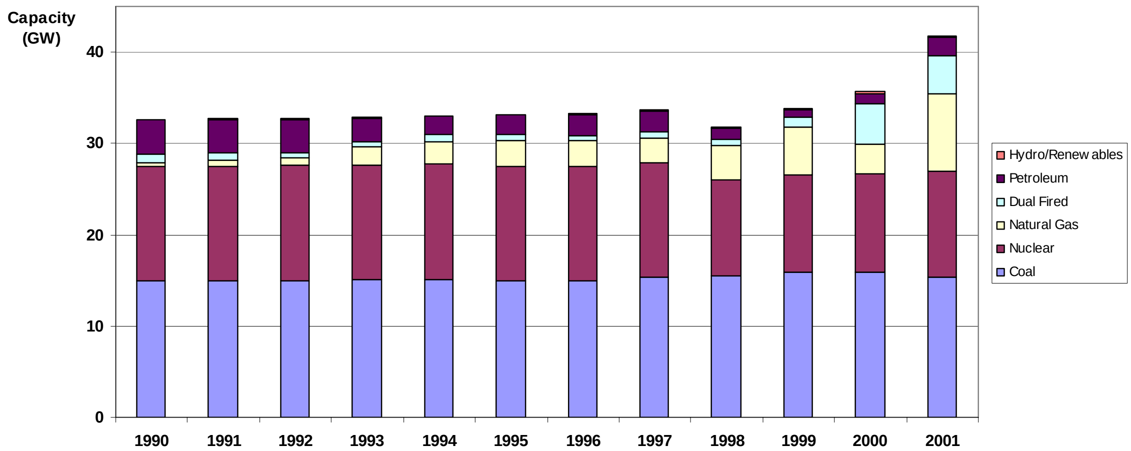
	Total Number of Customers	Number of Customers Eligible for Delivery Services		Number of Customers Switched to Delivery Services		Percentage of Customers Switched to Delivery Services (%)	
DemCo: Electric Utility Affiliates		Less than 1 MW	Greater than 1 MW	Less than 1 MW	Greater than 1 MW	Less than 1 MW	Greater than 1 MW
DemCo: AmerenCILCO	199,878	19,935	71	0	0	0.0	0.0
DemCo: AmerenCIPS	323,563	47,338	119	703	44	0.0	0.0
DemCo: AmerenUE	65,634	7,504	40	0	0	1.5	37.0
DemCo: Commonwealth Edison	3,526,553	328,038	1,846	20,465	1,101	6.2	59.6
DemCo: Illinois Power	567,485	65,986	218	990	61	1.5	28.0
DemCo: MidAmerican	83,087	1,392	28	0	0	0.0	0.0
Total		470,193	2,322	22,158	1,206	4.7	51.9

Source: Illinois Commerce Commission

2.3 GENERATION CAPACITY

Figure 2.3-1 shows the generation capacity located in the State since 1990. Capacity has grown by about 28% over the period. The dip in 1998 reflects the closing of the 2,000 MW Zion nuclear plant in 1998.

Table 2.3-1 shows the generation companies (GenCos) that are operating in the State. The GenCos are the corporate entities that own and operate generation equipment. Two companies, Midwest Generation and Exelon Nuclear, own more than half of the generation capacity in the State. Adding the next two largest companies, Dynergy Midwest Generation and Ameren, brings the total to about 77% of the State's generation capacity owned by four companies.



Sources: Energy Information Administration (1990-2000),
State of Illinois data (2001)

Figure 2.3-1 Historical Generation Capacity in Illinois

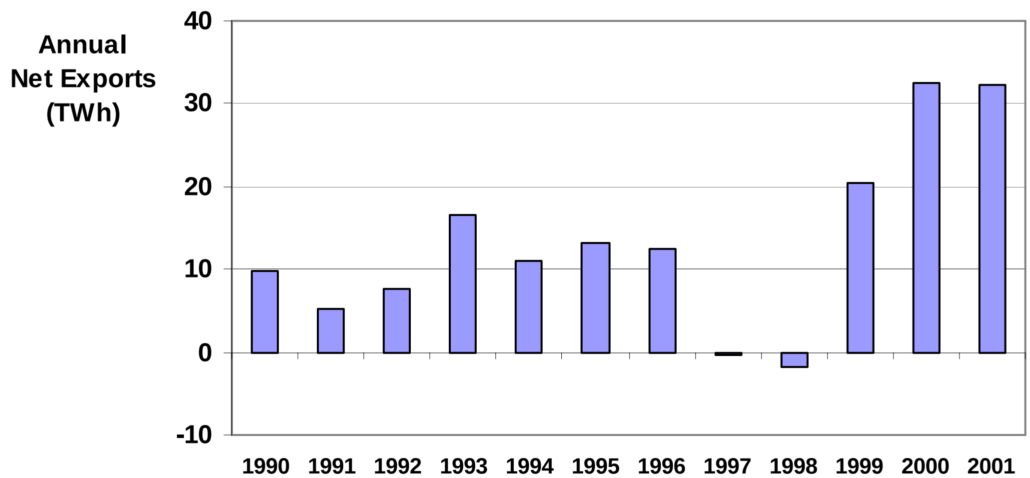
Table 2.3-1 Generation Capacity by Company in 2001

Generation Company	Coal	Oil	Natural Gas	Nuclear	Total Capacity (MW)	Portion of State Total (%)
GenCo – Allegheny Power	0	0	664	0	664	1.6%
GenCo – Ameren						
Ameren-CILCO	1,221	26	46	0	1,293	3.1%
Ameren-CIPS	2,944	213	300	0	3,457	8.3%
Ameren-EEI	1,100	193	0	0	1,293	3.1%
Ameren-UE	0	511	926	0	1,437	3.4%
GenCo – Aquila Energy	0	0	0	0	0	0.0%
GenCo – Calpine	0	0	174	0	174	0.4%
GenCo – Calumet Energy LLC	0	0	0	0	0	0.0%
City of Springfield	463	44	139	0	646	1.5%
GenCo – Constellation Power	0	0	125	0	125	0.3%
GenCo – Dominion Energy	1,933	0	852	0	2,785	6.7%
GenCo – Duke Energy	0	0	664	0	664	1.6%
GenCo – Dynegy Midwest Generation Inc.	3,369	245	491	0	4,105	9.8%
GenCo – Dynegy/NRG Energy	0	0	398	0	398	1.0%
GenCo – Exelon Generation	0	0	0	9,882	9,882	23.7%
GenCo – Exelon Nuclear/MidAmerican Energy	0	0	0	1,657	1,657	4.0%
GenCo – MidAmerican Energy Co	0	0	572	0	572	1.4%
GenCo – Midwest Generation LLC	6,509	770	3,476	0	10,755	25.8%
GenCo – NRG Energy	0	0	300	0	300	0.7%
GenCo – Power Energy Partners	0	0	0	0	0	0.0%
GenCo – PPL	0	0	0	0	0	0.0%
GenCo – Reliant Energy	0	0	1,108	0	1,108	2.7%
GenCo – Southern Illinois Power Coop.	272	0	0	0	272	0.7%
GenCo - Southwestern Electric Coop.	0	0	0	0	0	0.0%
GenCo – Soyland Power Coop Inc.	22	24	125	0	171	0.4%
Total Capacity In Illinois	**17,833**	**2,026**	**10,360**	**11,539**	**41,758**	**100.0%**
					HHI – based on company capacity	**1,498**
					HHI – based on coal capacity	**2,173**
					HHI – based on natural gas capacity	**1,562**

As shown on the table, calculating the Herfindahl-Hirschman Index (HHI) for this situation gives a value of 1,498, which implies a moderately concentrated market for generation capacity in the State. As discussed earlier, the HHI applied to generation ownership is not the best way to gauge the competitiveness of an electricity market, but it does provide a rough indicator of the degree of concentration in the market.

Another way to look at the HHI is to consider how the various types of generation capacity are distributed among the companies. Table 2.3-1 shows an HHI of 2,173 for the coal capacity and 1,562 for the natural gas capacity. These reflect concentration in the coal capacity and a moderate degree of concentration in the natural gas capacity, based on this index. The nuclear capacity is owned totally by Exelon Nuclear and its joint ownership with MidAmerican Energy.

With the exception of two years, 1997 and 1998, Illinois has been a net exporter of electricity, as shown on Figure 2.3-1. In the latest year of data reported, annual net exports have amounted to about 19% of the electricity generated in the State.



Source: Energy Information Administration

Figure 2.3-2 Annual Net Exports of Electricity

2.4 TRANSMISSION CAPACITY

Figure 2.4-1 shows the configuration of the major lines of the transmission system in Illinois and surrounding states. Transmission capacity is concentrated to provide service to the Chicago area in the northeastern part of the State and in the southwest, near St. Louis. There are several interties with transmission systems in surrounding states, the most significant with northwestern Indiana.

Table 2.4-1 shows the transmission companies in the State. Currently, transmission line ownership is in the hands of the electric utilities. There have been many discussions about selling the transmission facilities to an independent transmission provider or to other companies. This situation will likely not stabilize until the restructuring is complete.

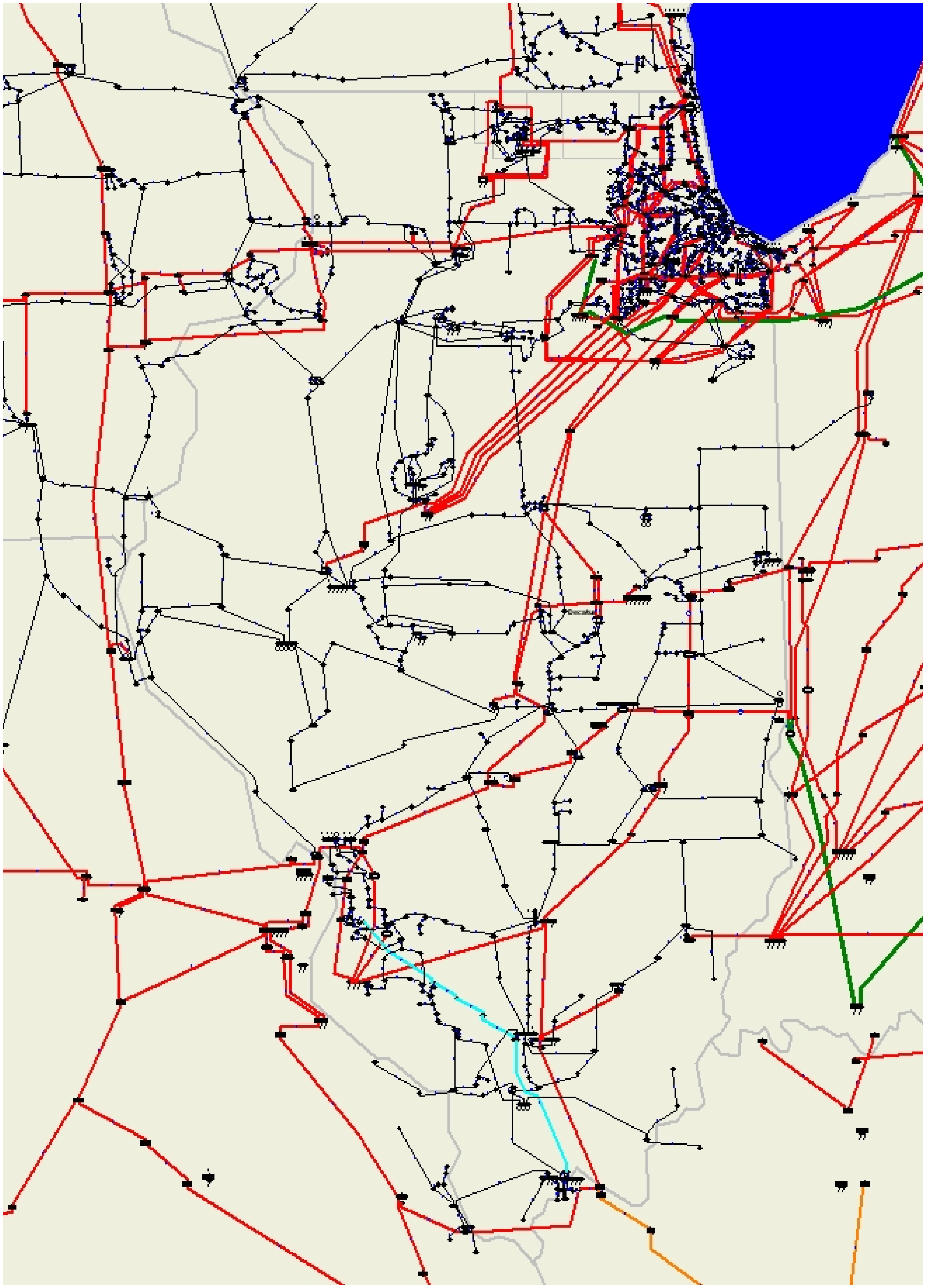


Figure 2.4-1 Detailed PowerWorld Simulator One-line Diagram of Illinois Transmission, along with High Voltage Transmission in Other States

Table 2.4-1 Transmission Companies in Illinois

Transmission Company Name	Ownership
TransCo – Ameren	Private
TransCo – Commonwealth Edison Co.	Private
TransCo – Illinois Power Co.	Private
TransCo – Alliant Energy	Private
TransCo – MidAmerican Energy Co.	Private
TransCo – Mt Carmel Public Utility Co.	Private
TransCo – Springfield, City of	Municipal

3 BASIC ASSUMPTIONS AND DATA INPUTS

The analysis of the power system in Illinois in this study is based on a set of assumptions and input data. These assumptions and inputs provide a set of conditions that can be used to determine how the power system might function. They are not intended to represent the predicted, most likely, or optimal set of conditions for the Illinois market. Rather, they are intended to test how the market might behave under a given configuration.

The basic assumptions are grouped into two sets as shown in Table 3-1. The details of each of the assumptions are provided in the following sections. The Case Study Assumptions provide a point of comparison for a single configuration and operating profile of the power system. The set of Conservative Assumptions is designed to verify that the results and conclusions are not distorted by the features of this single configuration. This will be explained in more detail later.

Table 3-1 Basic Assumptions

Item	Case Study Assumptions	Conservative Assumptions
Illinois Market Configuration	Single independent system operator	Same
	Day-ahead energy market using pay-locational-marginal-price settlement rule	Same
	Day-ahead ancillary services market	Same
	No bilateral contracts	Same
	No consumer tariffs	Same
Agent Profiles	GenCos: apply company-level unit commitment and add prorated fixed operating and maintenance costs into bid price	No company-level unit commitment No fixed operating and maintenance cost added
	Consumers: no price response	Same
	DemCos: apply flat markup to costs	Same
	DistCos: apply fixed distribution use charge	Same
	TransCos: apply fixed transmission use charge and also receive transmission congestion payment	Same
Transmission Network	Detailed representation in-state	Same
	Simplified representation out-of-state	Same
Load	Projections based on FERC information	Same
Generation	Capacity expansion based on announced construction plans	Same
Outages	Planned, maintenance, and forced outages included	No maintenance or forced outages
Fuel Prices	Developed from EIA forecasts	Same

The analyses were carried out for various time periods in a single year. The year 2007 was chosen as the analysis year, as it represented the time when all of the transition activities specified in the Illinois restructuring law are to be completed. It should be emphasized that the results are not intended to be a prediction of what will happen in Illinois in 2007. For this reason, the results are referred to as "analysis year results." In fact, any other year after restructuring is completed could have been used as the analysis year. All of the cost results are presented in 2002 dollars.

A point needs to be emphasized with respect to the comparison of these results to current experience. As was discussed in the earlier section on data sources, there were limits on the information available for the study, the most significant being the need to avoid business proprietary information. In addition to this limitation, the simplifying assumptions used to create the simulation model that approximates the operation of the Illinois market, which are discussed below, will limit how closely the results can match historical experience. While it is appropriate to see how well the model results match actual experience, it should not be expected that there will be a complete correlation. The data limitations and the modeling simplifications prohibit this. For this reason, these results must be viewed as an initial point of comparison against for other studies and analyses. In traditional modeling terms, these results should be viewed as "descriptive" and not as "predictive."

3.1 ILLINOIS MARKET CONFIGURATION

The configuration of the electricity market in Illinois was not explicitly specified as part of the restructuring law. Companies have had a great deal of freedom in how they structure themselves during the transition period. The Federal Energy Regulatory Commission (FERC) issued several versions of a proposed rulemaking to establish a standard market design (SMD), which was recommended for electricity markets across the country. These designs have received numerous positive and negative comments and are still undergoing review and revision. Lacking a State-imposed design or a federal design, there is a great deal of uncertainty regarding how the Illinois electricity market will take form. For the purposes of this study, the following assumptions were used as the market rules in operation in Illinois in the analysis year.

Single Independent System Operator

It is assumed that a single market for electricity will be operating in the State in the analysis year. That is, all of the companies in Illinois that buy or sell electricity will do so in the same marketplace. This is a significant simplifying assumption that avoids consideration of how multiple markets operating in the State might deal with their interfaces, the "seams" issue in the terminology of the FERC SMD. Given that the actual structure of the Illinois market is not yet established, the single market assumption is a reasonable approach to use here.

The single ISO assumption has the effect of simplifying the operation of the State's electricity market in the model simulation. The market operating and settlement rules are the same across the State; there are no cross-ISO charges imposed for moving power across jurisdictional lines; the system reliability standards are uniform across the State, and all market participants operate under uniform procedures. Clearly, if more than one ISO were to function in the State, the market operation could be much more complex. Companies could participate in multiple markets if they chose, market rules might be different, and the payment procedures for power flows across ISO lines could be complex. While the modeling framework could be set up to simulate multiple ISOs, the current uncertainty in the Illinois market does not warrant adding this complexity at this time.

Another consideration in the assumption of a single ISO in the State is the effect on out-of-state market participants. In this study, companies outside Illinois can participate in the same marketplace as Illinois companies and can be either buyers or sellers of electricity. In the simulation, the Illinois ISO administers the single market in which both in-state and out-of-state companies participate. There are no charges for power flows across State borders or for the wheeling of power from one out-of-state point to another out-of-state point on lines that run through the State. In essence, the simulation considers a market that is larger than just the State borders. However, for this study, out-of-state companies are represented in a simplified fashion, which will be described in more detail later. They do, however, play a role in the Illinois electricity market in that they can purchase electricity from Illinois producers or can sell electricity to Illinois users. The physical limits of the transmission tie lines between Illinois and surrounding states are explicitly included in the analysis.

Consistent with the assumption of a single market, it is assumed that the single independent system operator (ISO) operates the entire transmission system in the State. This ISO has the responsibility for scheduling, dispatching, and reliability of the transmission system.

The Illinois restructuring law does not mandate that there be only one ISO operating in the State, but it does require all electric utilities to join an ISO or RTO. Again, given the uncertainties as to how this will develop, it is assumed here that only one ISO will operate the transmission system in the State.

Day-Ahead Market

It is assumed that a day-ahead market (DAM) for energy and ancillary services will operate in the State. The DAM will allow suppliers (i.e., GenCos in the terminology of the analytical models used here) and purchasers (i.e., DemCos) to bid for their participation in the market. The bidding will be administered by the ISO and will allow market participants to offer to buy and sell electricity at unregulated prices.

There are several different approaches that have been used in pool markets in the U.S. and abroad to pay for electricity that is bought and sold. One of the approaches used in the earliest electricity markets is the pay-market-clearing-price (PMCP) rule. In this approach, generation and demand bids are accepted in the DAM by the ISO based on bid price and on the physical limitations of the transmission system. All pool market purchases and sales in a given hour are settled at the price of the most expensive generator accepted by the market in that hour. This single price is referred to as the market clearing price (MCP). In effect, it is the marginal cost of providing power to the market. All GenCos whose bids are accepted are paid the MCP independently of what their actual bid was. All DemCos pay the MCP for the electricity they buy.

One shortcoming of the PMCP rule is that it does not have any explicit locational effects. That is, all GenCos (and DemCos) participating in the market are paid (or pay) the same MCP, independent of where they are in the transmission network. A modification to the PMCP rule has been introduced in virtually all operating markets in the U.S. and abroad and is included here. Since transmission system congestion can preclude the use of the lowest-cost generators and since this congestion may be experienced in parts of the power system but not everywhere, the marginal cost of providing power may be different at different points in the system. The pay-locational-marginal-price (PLMP) rule focuses on determining the marginal cost of providing power at each individual point of the power network and includes the effects of transmission congestion explicitly.[8] There is not a single MCP but rather a separate price at each node of the transmission network. In the PowerWorld and EMCAS models used for this study, the LMP is calculated using an optimization routine that, in effect, tests each node of the network to determine what the cost would be to provide an additional unit of power at that point. It determines the shadow price at each network node. When there is no congestion in the transmission network, the LMPs are identical at each node. When there is congestion, the marginal cost of providing power at one node is different than at another node, and the LMPs vary across the network.

There are several different ways the PLMP rule can be applied when calculating settlement payments to market participants. The rules most commonly used in currently functioning markets are used here. GenCos whose units are dispatched are paid the LMP at the network node (i.e., bus) where each unit is connected. DemCos pay a load-weighted average price for the zone in which their consumers are located, where a zone is a collection of nodes (i.e., buses) in a geographical area. (The zones used in this study are described later.) Zonal pricing for demand, instead of bus-level pricing, is used in current electricity markets as a way of reducing the administrative burden of maintaining prices for thousands of buses on an hourly basis. There is some debate as to whether zonal or bus-level pricing for demand is the best way to operate a market. Since zonal pricing is used in most markets, it has been selected for use here.

One aspect of the PLMP rule is not immediately obvious. When the payments to GenCos and the payments by DemCos are netted out, the sum is generally not zero when there is transmission congestion. This is true whether zonal or bus-level pricing is used. This is a result of the fact that congestion creates LMPs that can vary widely throughout the network in a nonlinear way. In the EMCAS simulation, the difference in payment to GenCos and payment from DemCos is distributed to the transmission company as a congestion payment, as discussed later.

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[8] For a more detailed description of locational effects, see *Power System Economics*, S. Stoft, IEEE Press, New Jersey (2002) for a description of LMPs. Good introductory material on locational pricing can also be found at the Web sites of currently operating markets including: www.nyiso.com, www.iso-ne.com, and www.pjm.com.

One alternative to the PMCP rule or the PLMP rule is the pay-as-bid (PAB) rule. In this approach, all GenCos are paid only their bid price if they are selected. There are few electricity markets worldwide that are employing this method.

Ancillary Services

As part of the day-ahead market, the need for reserve capacity to deal with generator outages is included. These ancillary services include regulation reserve, spinning and non-spinning reserve, and replacement capacity. A simplified approach is used here. In the simulation, after the day-ahead market procedure is completed and the dispatch schedule is established, additional capacity is selected to provide for ancillary services. This capacity is taken from the units that have been bid into the day-ahead market but not selected. The amount of additional ancillary service capacity that is needed is determined as the fraction above the projected load, which is determined by the ISO from the demand bids that have been received. In these analyses, the ancillary services requirement is assumed to be 5% above projected load. The units that are selected to provide ancillary services are paid their bid price, regardless of whether or not they are actually dispatched. This is referred to as a capacity payment.

One limitation of this simplified approach is that the capacity selected to provide ancillary services in the day-ahead market may or may not be in the appropriate position in the transmission network to actually deliver the needed service during actual dispatch. Since the location of forced outages during the next day that would require the use of ancillary services is unknown, it could be that the selected units are not able to deliver the service due to transmission congestion. To account for this condition, an additional step is applied in the simulation during the hourly dispatch. Should ancillary services be required (e.g., due to a forced outage of a generator), the available units that were not selected in the day-ahead market (including those that were selected for only a portion of their available capacity) are evaluated to determine their ability to provide the service at lowest cost to the system. Any unit that is dispatched to provide ancillary services is paid for its generation in the in the same fashion as any other generator that was scheduled for dispatch. This is in addition to any capacity payment that is received.

The costs of ancillary services capacity payments are charged to the demand companies purchasing electricity from the market and are prorated based on their load. The costs of generation payments show up in the price that demand companies pay for energy, that is, in the LMP.

It is recognized that this is a simplification of the ancillary services market, but it does provide the ability to account for these costs in an approximate way.

Bilateral Contracts

Bilateral contracts between suppliers (GenCos) and purchasers (DemCos) establish a price for the injection of power at a point in the transmission system and its withdrawal at another point. These bilateral contracts can be short-term (e.g., day-ahead) or longer-term (e.g., week-, month-, or year-ahead). In these analyses, no bilateral contracts are assumed to be in place.

Consumer Tariffs

It is assumed here that all consumers (residential, commercial, industrial) pay the market-based price for electricity, which is based on the LMP. There are no tariffs or price caps to limit charges to consumers.

3.2 AGENT PROFILES

In the analysis, each of the market participants is characterized by its preferences and business strategies. The following assumptions are used here:

Consumers

Consumers are assumed to have no response to electricity prices. That is, they will neither increase nor decrease demand based on prices. It should be noted that the lack of consumer price response is a significant assumption. These conditions can have the effect of allowing electricity prices to rise indefinitely under several circumstances. If there are no competing suppliers that offer lower prices and/or if all suppliers raise prices in unison and/or there are no price caps, consumer prices can rise without limit. There is considerable research that has been done to determine consumer response to electricity prices. In general, it has been determined that residential customers have a much smaller response to electricity prices than do large industrial or commercial customers. A recent study of the California electricity crisis [9] estimated that consumers in San Diego, where retail prices were allowed to fluctuate along with wholesale prices, showed a 5% reduction in demand when prices increased by 100%. It also showed that consumer response to price reflected reaction to their most recent electricity bill (usually monthly) rather than to prevailing daily prices.

The assumption of no consumer response to prices is used here to determine the effect of competition among suppliers in the absence of any consumer reaction.

Generation Companies

Generation companies (GenCos) participate in the market by offering to supply electricity at given location (i.e., injection bus) at a given price. All GenCos are treated as unregulated entities that can offer their capacity to the market at any price they chose. They are not guaranteed any rate of return, nor is there any guarantee that their units will be dispatched. The single ISO operating the market makes decisions on which units will be scheduled for dispatch based on the need to meet load and the limitations of the transmission system.

In the simulations that use the Case Study Assumptions, GenCos utilize a company-level unit commitment algorithm (i.e., the CLUCRA algorithm mentioned earlier) to make an initial decision on the hours (if any) that a unit is offered into the day-ahead market. The CLUCRA algorithm also projects the most profitable operating level for each unit and determines if a unit

[9] Bushnell, James B., and Erin T. Mansur, *Consumption Under Noisy Price Signals: A Study of Electricity Retail Rate Deregulation in San Diego*, University of California Energy Institute, Berkeley, CA (July 2003).

will be able to recover its costs if it is scheduled for dispatch. These costs include expenditures for fuel, variable operating and maintenance, and unit startup/shutdown. It also takes into account minimum downtime between unit startups. If the market prices are expected to be too low and the unit will lose money if it is operated, the GenCo will not offer it for service. Unit commitment decisions are currently made in virtually all power systems, including those that are not deregulated. It provides the GenCo the opportunity to take units out of service that cannot recover their costs. A more detailed description of how the company-level unit commitment analysis (the CLUCRA algorithm) operates in EMCAS is given in Appendix B. To test the effect of the unit commitment analysis on the results, simulations using the Conservative Assumptions bypass this step for each GenCo, and each offers all of its capacity into the market, whether or not it is expected to recover costs. This has the effect of making more generation capacity available to the market. It does, however, imply that a GenCo is willing to accept economic losses on the operation of some of its capacity.

Beyond the unit commitment analysis, GenCos are free to use any one of a number of strategies to determine how much capacity they will offer in the market and what price will be asked. A number of different strategies are tested here.

Demand Companies

In this analysis, all of the demand served by DemCos is assumed to be firm load and is not interruptible based on market price. There is no strategic behavior on the part of DemCos. Any unserved energy (i.e., load not met) is due only to the unavailability of generation and/or transmission capacity (e.g., a forced outage of a generator in a critical location) and not to any market considerations. Since there is no strategic behavior, it is assumed that all DemCos will charge consumers a flat markup of their costs to purchase electricity. This is assumed to be 10% and is applied only to the cost of energy, not to the cost of transmission or distribution services.

As with the assumption of no consumer price response, this assumption has implications for the results, although less so. Recall that there are no bilateral contracts and all DemCos (and GenCos) participate in the market only through the pool. Under these conditions, the only manner in which DemCos could respond to high prices would be to shed load using, for example, interruptible service contracts or incentive payments to consumers that reduce load. These options are generally limited to large customers and are not included here.

Distribution Companies

In the simulation, DistCos are assumed to be simply collectors of revenue for the use of their distribution lines. A distribution use charge (DUC), which is a flat fee measured in $/MWh, is levied on all consumers. There is no strategic business behavior associated with DistCo operation.

The DUC is assumed to be 18 $/MWh,[10] which is an approximation of the rates currently posted by companies in Illinois offering unbundled service for different classes of service.

Transmission Company

It is assumed here that there is a single TransCo that owns the system. It does not employ any strategic business behavior. Instead, it is a collector of revenue for the use of its lines. This assumption is made here because of the uncertainty in who will own various parts of the transmission system in the analysis year. Since the TransCo does not engage in any strategic behavior, this assumption does not affect results in any significant way.

TransCo revenue comes in two forms: a transmission use charge (TUC) and a Transmission Congestion Payment (TCP). The TUC is a flat fee, measured in $/MWh, that is based on the energy withdrawn, and is charged, by convention here, to the DemCos withdrawing the energy. (The DemCos will pass this charge on to their consumers without any markup.) The TUC is assumed to be 3 $/MWh, which is an approximation of the rates currently used by different transmission owners when pricing their services in the wholesale market.[11]

The TCP is based on the differences in LMPs in the network and is calculated for every line in the network. In an uncongested situation without transmission losses, the LMPs are the same throughout the system and there is no TCP. With congestion, the LMP is different at different nodes in the network. As discussed earlier, the market configuration employed here uses the PLMP rule to settle payments to market participants. GenCos are paid the LMP at the buses that their generators are attached to. DemCos pay the load-weighted average LMP of the zones that their consumers are located in. When transmission congestion is present, with resulting variations in LMPs, the net of payments by DemCos and payments to GenCos is generally non-zero. In the simulation, this difference is the TCP that is paid to the TransCo.

The calculation of the TCP, as the difference in LMPs when there is congestion, is done with consideration of the direction of the power flow at any hour. By convention, the TCP on each line is calculated as the LMP at the receiving point minus the LMP at the originating point multiplied by the flow. This convention can sometimes lead to a negative value of the TCP for a line or set of lines.

In some operating electricity markets, there is a transmission rights market in which GenCos and DemCos can purchase transmission options, called firm transmission rights (FTRs), as a hedge. In these types of markets, the TCP would be allocated among the holders of these rights and the TransCo(s). Should the TCP have a negative value, the holders of the FTRs would be required to reimburse the TransCo for this amount. In the current simulation, there is no

[10] The distribution use charges for the companies operating in Illinois are posted on their individual Web sites and are on file with the Illinois Commerce Commission. The rates vary from 10 $/MWh to 21 $/MWh and depend on customer service class. The value of 18 $/MWh is used here as an average value and represents what is charged to the largest number of customers.

[11] The value used for TUC is estimated from rates posted by the Midwest System Operator (MISO). The MISO rate is calculated annually base on filings with FERC and EIA. Converted to a $/MWh basis, the rates range from 2.4 $/MWh to 5.5 $/MWh, with an average of 3 $/MWh.

transmission rights market and the TCP (either positive or negative) is assumed to be allocated solely to the TransCo.

Independent System Operator

The single ISO handles the scheduling and dispatching of the entire system operating in the State. It also handles the settlement of charges and payments in the pool market, including both energy and ancillary services. In operating the transmission system, the ISO uses a transmission-constrained dispatch procedure (the SYSSCHED DCOPF described earlier). This procedure seeks to dispatch the lowest-cost generators at each hour subject to maintaining the physical limits of transmission lines. In some cases, lower-cost generators cannot be utilized, as they would result in unacceptable overloads on transmission lines. Higher-cost generators must be dispatched to avoid these conditions. It is this situation that results in LMPs being different in different locations.

In selecting the lowest-cost generators, the ISO relies on the bid prices supplied by the GenCos. The "lowest cost" generator is, in actuality, the "lowest priced" generator. In the simulation, the ISO does not attempt to adjust bid prices submitted by GenCos.

3.3 TRANSMISSION NETWORK CONFIGURATION

The configuration of the power system in Illinois in the analysis year was constructed from the 2003 summer case prepared by the North American Electric Reliability Council (NERC). Data on load growth, generator additions and retirements, and transmission system changes were added to bring the system up to what might be expected in the analysis year of 2007. The NERC case, which covers the entire eastern interconnection of the U.S., includes about 1,900 buses and 2,650 branches in Illinois. All of the analyses with both PowerWorld and EMCAS were done using this detailed transmission configuration for the State.

For the EMCAS analysis, the buses in Illinois were grouped into zones. These zones serve several purposes. First, they are used to divide larger regions of the State, that are based on traditional utility control areas, into smaller areas that may see different price effects due to different levels of transmission congestion. The selection of the buses that are included in each zone was done using a preliminary analysis of load flows using PowerWorld. Buses that were geographically close and had similar LMPs, thus indicating minimal congestion among them, were included in the same zone.

Second, the zones provide the market areas that are used in determining prices to be charged to DemCos. As discussed previously, DemCos participating in the market pay the load-weighted average of the bus LMPs for the zones that their consumers are located in. This zonal pricing is used in most of the currently operating electricity markets in the U.S., which is why it is used here as well.

In addition to the in-state transmission configuration, the power transfers into and out of the State must be accounted for in order to get an accurate picture of how the State's system performs. PowerWorld uses a larger portion of the eastern interconnection. EMCAS uses a reduced out-of-state network with transmission capacity that allows power to move into and out of the State. All of the tie lines between Illinois and surrounding States were identified and aggregated into a small set of interconnection points. The interconnection points covered an area including Indiana, Michigan, and parts of Ohio in the east, Tennessee in the south, parts of Missouri served by Ameren and AECI utilities in the southwest, Iowa and parts of Minnesota in the west, and Wisconsin in the north. The in-state zones and the out-of-state interconnection points are shown on Table 3.3-1 and Figure 3.3-1. The zone and interconnection point names reflect the current owners of the primary lines. Figure 3.3-2 shows the zones that have major transmission links between them. The links on this figure represent the ability to move power between zones at 138 kV or higher voltages and, in most cases, represent the availability of multiple transmission lines operating between the zones. Table 3.3-2 shows the capacities of the tie lines between Illinois and out-of-state zones.

The use of this simplified representation of the out-of-state network in EMCAS has implications for the results. In terms of the ability to transfer power into or out of the State, the representation is a good approximation, since the individual tie lines and their capacities are represented explicitly. This allows the physical limits of power flows between in-state and out-of-state nodes to be represented. In terms of which out-of-state suppliers will contribute to meeting the State's load and which out-of-state loads will be met by in-state suppliers, the representation used here does not address these details. Further, the representation used here is not intended to capture power transfers among out-of-state suppliers with any high degree of accuracy. Nor is it intended to provide details of power wheeling that crosses the State from one out-of-state supplier to an out-of-state load. Despite these limitations, this simplified representation can be expected to give reasonable results for the in-state market participants.

Table 3.3-1 In-State Zones and Out-of-State Connection Points

In-State Zones	Current Ownership of Buses in Zone
AMRN – A, B, C, D, E	Ameren [a]
CILC	Ameren
EEI	Ameren
CWLP	City Water and Light (Springfield)
IP – A, B, C, D	Illinois Power
NI – A, B, C, D, E, F, G	Commonwealth Edison [b]
SIPC	Southern Illinois Power Cooperative
Out-Of-State Connection Points	**Current Ownership of Principal Tie Lines**
AEP	American Electric Power
AMRN-OUT	Ameren – outside Illinois
ALTE	Alliant Energy – East
ALTW	Alliant Energy – West
BREC	Big Rivers Electric Corp.
CIN	Cinergy Corporation
DOE	Department of Energy
MEC	MidAmerican Energy Company
NIPS	Northern Indiana Public Service
TVA	Tennessee Valley Authority
WEC	Wisconsin Energy Corporation

[a] Buses owned by Mt Carmel Public Utility are included in the AMRN-B zone. Buses in Illinois owned by MidAmerican Energy are included in the NI-A zone.
[b] Buses in Illinois owned by Alliant Energy (Interstate Power and South Beloit) are treated as part of the out-of-state zone.

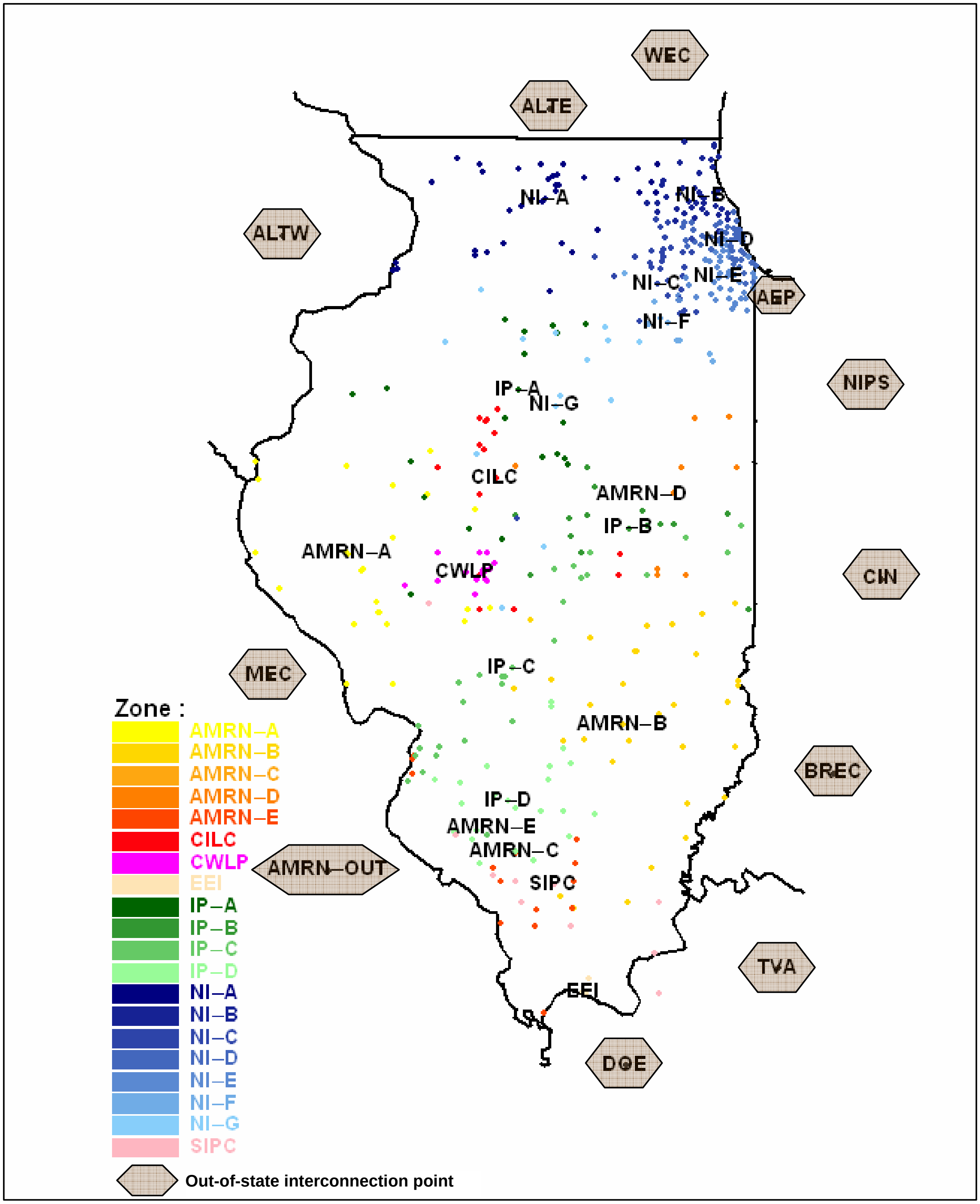

Figure 3.3-1 In-State Zones and Out-of-State Interconnection Points

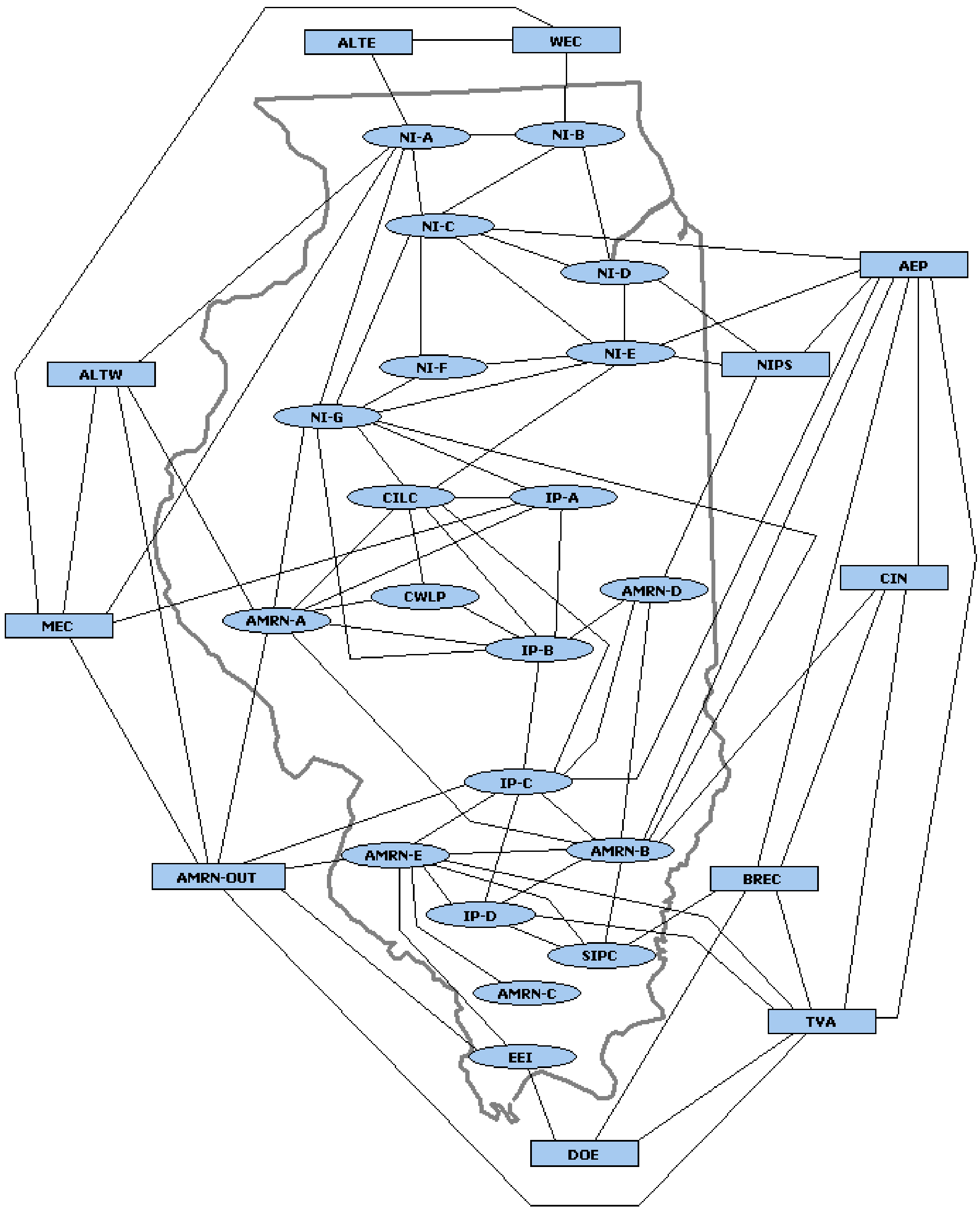

Figure 3.3-2 Zone Power Transfer Links

Table 3.3-2 Transmission Line Limits between In-State and Out-of-State Zones

In-State Zone	Out-of-State Connection Point	Transmission Capacity Based on Thermal Line Limits (MW)
AMRN-A	ALTW	295
AMRN-A	AMRN-OUT	460
AMRN-B	AEP	1,332
AMRN-B	CIN	1,505
AMRN-D	NIPS	227
AMRN-E	AMRN-OUT	4,187
AMRN-E	AMRN-OUT	495
AMRN-E	TVA	949
EEI	AMRN-OUT	221
EEI	DOE	1,752
IP-A	MEC	200
IP-C	AEP	937
IP-C	AMRN-OUT	372
IP-D	TVA	1,195
NI-A	ALTE	1,325
NI-A	ALTW	1,157
NI-A	MEC	6,195
NI-B	WEC	2,505
NI-C	AEP	3,975
NI-D	NIPS	1,755
NI-E	AEP	1,957
NI-E	NIPS	4,671
SIPC	BREC	259

Note: The sum of the thermal line limits does not reflect the transmission capacity into and out of the State, which is significantly less. The actual capacity is a function of the power flows in the whole system at any point in time and is considered in both the EMCAS and PowerWorld simulations.

In order to provide a more accurate representation of the power flows outside of the State, PowerWorld used a significantly larger network configuration than was used in EMCAS. Since the focus area of this study was the U.S. Midwest in general and Illinois in particular, the original 42,700 bus, 6800 generator, 57,000 line/transformer NERC case modeled was equivalenced to one with 12,925 buses, 1790 generators, and 17,647 lines and transformers. The explicitly retained portion of the system roughly covers the region bounded by Minnesota, Missouri, Tennessee, Ohio, and Michigan. The total generation capacity was reduced from about 780 GW in the original NERC case to about 216 GW. While the reduced case had only about one quarter the generation capacity of the original case, it still contained four times the total Illinois generation capacity (171 GW out-of-state and 45 GW in-state). Hence, the reduced case provided a sufficiently large generation and load market. The breakdown of the 12,925 buses by NERC region was 2,207 in SERC, 4,052 in ECAR, 1,929 in MAPP, and 4,737 in MAIN (1,847 in-state and 2,919 out-of-state). During the study, the limits on all in-state transmission lines were enforced. Limits were only enforced for out-of-state lines for voltages above 200 kV.

The PowerWorld representation provides much more detail on the out-of-state network, but it too is limited in representing the full extent of the power grid. It represents the system in the states immediately adjacent to Illinois but does not include the parts of the eastern interconnection beyond these areas. The large eastern markets (e.g., PJM, NYISO) and southeastern markets, which could have an impact on the behavior of the Illinois market, are not represented here.

3.4 LOAD

Table 3.4-1 shows projected seasonal peaks and total load that were used for this analysis. This load profile is based on data contained in FERC Form 714 that contains total control area loads for all hours of an historical year. This form also contains 10-year forecasts of seasonal peak loads and total annual loads. To project hourly loads for a control area, historic hourly loads are scaled such that the total annual load and both summer and winter peaks match the Form 714 projection. This method produces results that exactly match the annual load factor predicted by the reporting control areas.

Hourly loads at a bus are based on a bus distribution factor (BDF) that indicates the portion of the total control area load that is assigned to that specific bus. The BDFs remain constant throughout the simulation year and are based on PowerWorld input data for a peak load day. A BDF is multiplied by the hourly control area load to obtain the hourly bus load; that is, the FERC Form 714 data that were scaled to the projection year. This methodology assumed that the relative load contribution that a bus makes to the control area total is constant throughout the year.

The load forecasting method used here addresses the need to develop projections of hourly load patterns in order to run the PowerWorld and EMCAS simulations. Clearly, it is not possible to develop an accurate representation of how loads will vary by hour at each bus in the network for a period several years in the future. The method used here provides a load profile that is tied to a number of key reference points that make it reasonable for use in this analysis. First, the peak, seasonal, and annual loads are tied to the FERC Form 714 projections. These may or may not be accurate in forecasting years into the future, but they represent a common point that is used by many organizations studying load growth. Second, the BDFs used to distribute load to individual buses are taken from historical data. Using them with the assumption that they are constant throughout the year cannot be expected to be entirely accurate, but lacking detailed bus-by-bus load data for an entire year, it is a reasonable assumption. The use of actual load profile data for the analysis year would change the results to the extent that the data deviated from the profiles used here.

Figure 3.4-1 shows the assumed load for the State for the 8,760 hours of the analysis year. The load shows the typical seasonal variation for a northern U.S. State. Peak loads are seen in the summer months – June, July, August – as air conditioning use increases. Some unusually warm days in the spring and fall also show up on this data. During the rest of the year, the load follows a pattern that varies within a smaller range. April and October are the months with the lowest loads. Daily and weekly variations in load are evident from the data.

Figure 3.4-2 shows the peak load by zone for the analysis year. The load data also shows the wide variation between the northern part of the State and downstate. Northern Illinois accounts for more than 70% of the statewide peak load. It also shows a much larger seasonal variation due to the more extensive use of air conditioning in the summer along with the higher population density. The downstate areas show much less variability in load with a flatter load profile.

Table 3.4-1 Load Forecasts for 2007

Control Area	Summer Peak (MW)	Summer Loads (MWh)	Winter Peak (MW)	Winter Loads (MWh)	Annual Load (MWh)	Annual Load Factor (Frac.)
Central Illinois Light Company (CILCO)	1,272	3,585,804	956	3,248,826	6,834,629	0.6134
Commonwealth Edison (ComEd)	24,200	54,652,572	16,300	50,597,428	105,250,000	0.4965
Electric Energy Inc. (EEI)	900	603,800	1,194	2,538,119	3,141,919	0.3004
Illinois Power Company (IP)	3,333	9,009,642	2,446	8,165,738	17,175,379	0.5883
Southern Illinois Power Co-operative (SIPC)	270	663,146	272	704,341	1,367,487	0.5739
Springfield Il. City Water Light & Power (CWLP)	502	1,132,894	346	1,001,106	2,134,000	0.4853
Associated Electric Power Coop.	4,066	9,427,934	3,646	9,638,734	19,066,668	0.5353
Madison Gas and Electric Company	829	1,918,063	548	1,738,919	3,656,982	0.5036
Dairyland Power Cooperative	877	2,429,482	804	2,356,518	4,786,000	0.6230
Indianapolis Power & Light Co.	3,390	8,351,066	2,741	7,960,934	16,312,000	0.5493
AEP-East System	21,217	63,701,767	21,062	65,091,997	128,793,763	0.6929
Hoosier Energy	1,246	2,943,619	1,254	3,086,454	6,030,073	0.5525
Tennessee Valley Authority	34,110	94,016,640	33,509	89,074,360	183,091,000	0.6127
Mid-American Energy	4,345	10,558,673	3,005	9,753,545	20,312,218	0.5337
Alliant West	3,555	10,761,793	2,695	10,364,724	21,126,517	0.6784
Alliant East	2,908	7,228,927	2,547	6,900,751	14,129,678	0.5547
AMEREN	10,967	27,280,332	8,592	24,987,668	52,268,000	0.5441
Cinergy	11,740	32,148,313	9,687	30,434,975	62,583,288	0.6085
Consumers Power	9,501	24,471,445	7,264	23,039,555	47,511,000	0.5708
Northern Indiana Public Service Corp.	3,172	9,331,131	2,571	8,697,869	18,029,000	0.6488
Wisconsin Electric Power Company	6,800	17,821,877	5,096	17,107,123	34,929,000	0.5864
Wisconsin Public Service Corp.	2,429	6,972,091	2,036	6,780,663	13,752,755	0.6463
Big Rivers Electric Corp.	1,502	4,146,879	1,433	4,459,158	8,606,037	0.6539
Northern States Power	8,587	23,495,460	7,329	22,411,956	45,907,416	0.6103
Louisville Gas and Kentucky Utilities	7,587	18,243,760	6,325	16,702,240	34,946,000	0.5258
Dayton Power and Light	3,285	9,136,039	2,855	8,560,954	17,696,993	0.6150
Southern Indiana Gas and Electric	1,376	3,536,046	1,001	3,134,954	6,671,000	0.5534
Total	**173,967**	**457,569,194**	**147,513**	**438,539,609**	**896,108,802**	**0.5880**

Source: NERC, Energy Information Administration

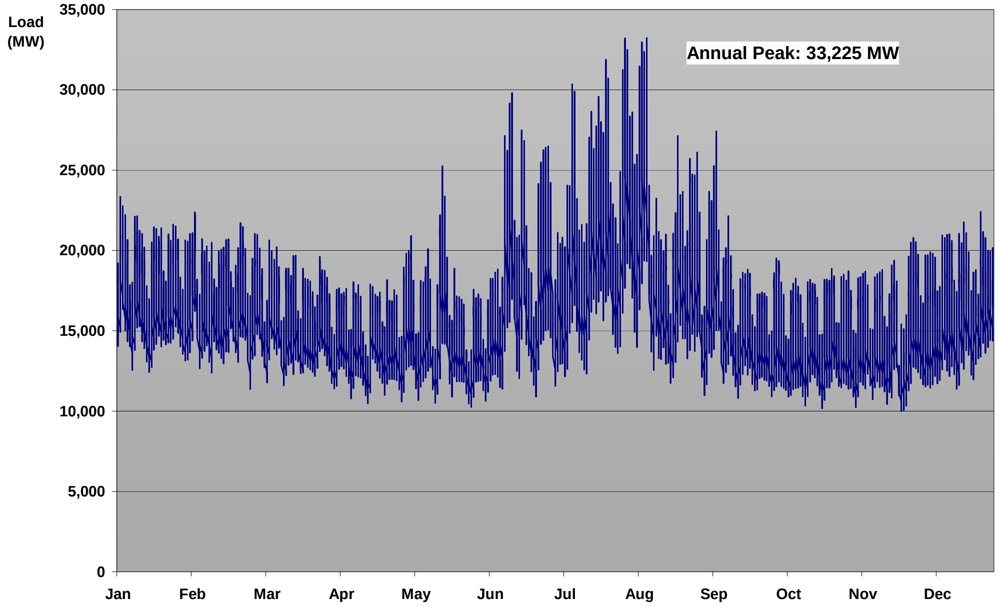

Figure 3.4-1 Statewide Hourly Load for the Analysis Year

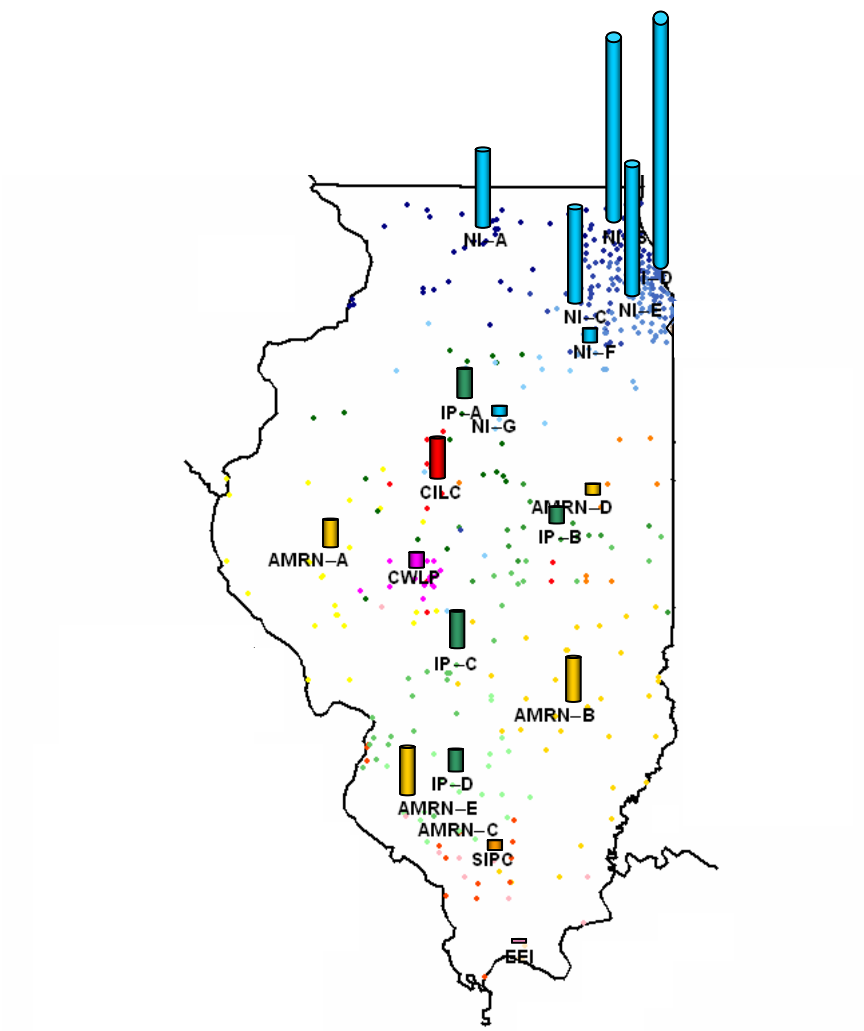

Figure 3.4-2 Peak Load by Zone for the Analysis Year

3.5 GENERATION CAPACITY

Table 3.5-1 summarizes the generation capacity assumed to be operating in the State in the analysis year. Detailed unit-by-unit information was taken from FERC, EIA, and Illinois EPA sources, as discussed earlier. The total increase of about 6 GW from capacity in 2001 represents a growth of about 14%. Since the load growth in this period is projected to be much smaller, the statewide generation reserve margin will grow to be about 43%. Whether this large reserve margin will actually be realized is open to question.

Table 3.5-1 also shows the generation ownership in the analysis year. The HHI based on installed capacity drops somewhat from its current value of 1,498 to 1,123, which still indicates a moderately concentrated market based on the Department of Justice guidelines. The HHI for coal capacity is essentially the same as in 2001. For natural gas capacity, the HHI drops from 1,562 in 2001 to 783 in the analysis year. The natural gas capacity additions by a number of different companies have moved this into the range that indicates a market that is not considered as concentrated by this index.

In the simulations using the Case Study Assumptions, it was assumed that for each hour of the year, some capacity would not be available, due to scheduled outages and forced outages. Scheduled outages include what are termed “planned outages” that involve the removal of a unit from service to perform work during a prearranged time period. This period is determined well in advance, and tasks such as annual overhauls, testing, and component inspections are conducted. Scheduled outages also include “maintenance outages.” A maintenance outage is the removal of a unit from service to perform work on a specific problematic component. This work need not be done immediately and can be deferred to a more convenient time, usually within about a week. Both planned and maintenance outages may be extended in time if the work takes longer to complete than originally scheduled. A “forced outage” is the result of a component failure. It must be fixed within a short period of time (usually within less than a week, if not immediately). All outages used in this study are based on information contained in the Generation Availability Data System (GADS). [12]

The analysis assigns planned outage lengths to individual units based on the type of fuel that the unit burns and the prime mover (i.e., steam, gas turbine, combined cycle, etc.). Planned outages are scheduled at the beginning of the year and are coordinated among all generation companies such that the highest hourly reserve margin (not including unplanned outages) during the year is at the lowest possible level. Planned outages are therefore scheduled to occur during low-load periods when reserve margins are at a peak. The simulation schedules planned outages sequentially, one unit at a time, in a pre-specified order. For this analysis, units are ordered according to average production costs in terms of $/MWh such that less expensive units are scheduled first and those with the highest costs are scheduled last.

[12] *Generating Availability Report*, North American Reliability Council, New Jersey (2002).

Table 3.5-1 Analysis Year Generation Capacity by Company

		Capacity Additions/ Retirements		Analysis Year Capacity					
Generation Company	2001 Capacity (MW)	(MW)	Type	Coal	Oil	Natural Gas	Nuclear	Total Capacity (MW)	Portion of State Total (%)
GenCo – Allegheny Power	664	0		0	0	664	0	664	1.4%
GenCo – Ameren									
Ameren-CILCO	1,293	0		1,221	26	46	0	1,293	2.7%
Ameren-CIPS	3,457	-304	Coal	2,640	210	500	0	3,350	7.1%
		-3	Oil						
		200	Gas						
Ameren-EEI	1,293	-193	Oil	1,100	0	318	0	1,418	3.0%
		318	Gas						
Ameren-UE	1,437	-474	Oil	0	37	1,526	0	1,563	3.3%
		600	Gas						
GenCo – Aquila Energy	0	770	Gas	0	0	770	0	770	1.6%
GenCo – Calpine	174	480	Gas	0	0	654	0	654	1.4%
GenCo – Calumet Energy LLC	0	305	Gas	0	0	305	0	305	0.6%
GenCo – City of Springfield	646	0		463	44	139	0	646	1.4%
GenCo – Constellation Power	125	871	Gas	0	0	996	0	996	2.1%
GenCo – Dominion Energy	2,785	688	Gas	1,933	0	1,540	0	3,473	7.3%
GenCo – Duke Energy	664	0		0	0	664	0	664	1.4%
GenCo – Dynegy Midwest Gener.	4,105	0		3,369	245	491	0	4,105	8.6%
GenCo – Dynegy/NRG Energy	398	0		0	0	398	0	398	0.8%
GenCo – Exelon Generation	9,882	328	Gas	0	0	328	9,882	10,210	21.5%
GenCo – Exelon Nucl/MidAmer	1,657	0		0	0	0	1,657	1,657	3.5%
GenCo – MidAmerican Energy Co.	572	0		0	0	572	0	572	1.2%
GenCo – Midwest Generation LLC	10,755	-371	Coal	6,138	770	2,415	0	9,323	19.6%
		-1,061	Gas						
GenCo – NRG Energy	300	2,357	Gas	0	0	2,657	0	2,657	5.6%
GenCo – Power Energy Partners	0	356	Gas	0	0	356	0	356	0.7%
GenCo – PPL	0	450	Gas	0	0	450	0	450	0.9%
GenCo – Reliant Energy	1,108	194	Gas	0	0	1,302	0	1,302	2.7%
GenCo – Southern Ill Power Coop.	272	166	Gas	272	0	166	0	438	0.9%
GenCo – Southwestern Elec. Coop.	0	71	Gas	0	0	71	0	71	0.1%
GenCo – Soyland Power Coop. Inc.	171	0		22	24	125	0	171	0.4%
TOTAL CAPACITY IN ILLINOIS	**41,758**	**5,748**		**17,158**	**1,356**	**17,453**	**11,539**	**47,506**	**100.0%**
								HHI – based on total company capacity	**1,123**
								HHI – based on coal capacity	**2,130**
								HHI – based on natural gas capacity	**783**

The planned outage algorithm first computes reserve margins for each hour of the year under the assumption that all units are always available for service. The unit with the lowest average production cost is then taken off-line for a continuous planned outage length that is consistent with the average downtime for units of that specific type. The planned outage period is selected such that it maintains the minimum reserve margin. After recomputing hourly reserve margins, the planned outage period for the unit with the next lowest production cost is determined. All units are scheduled for maintenance sequentially using the same rule. The end result is to "valley fill" the low-load period with maintenance, thus reducing variability in hourly reserve margins among seasons of the year.

Maintenance outages typically range in length from a few hours to a few days. The work can be deferred beyond the end of the next weekend, but must be scheduled before the next planned outage period. In the simulation, component problems that result in this type of outage occur at random. The maintenance outage algorithm schedules the down period within one month of a randomly drawn problem event. The duration of the maintenance period is consistent with the work that must be performed on the failing component as indicated by GADS statistics.

Forced outages occur at random as the result of component failures. Outage durations range from a few hours to several days as a function of the cause of the failure. Consistent with GADS statistics, the forced outage algorithm determines the number of outages, by cause, that the entire fleet of units will encounter. The algorithm also determines the approximate number of hours that each unit is forced out of service based on GADS cumulative frequency distributions. This methodology results in a pattern of outages in which there is diversity among units in terms of the number of hours that each are out of service during a given year. A Monte Carlo simulation approach was used to generate a set of forced outage patterns from which the one used here was selected.

Using a specific forced outage scenario, as employed here, implies that a strict interpretation of results should be confined to the outage scenario chosen. However, it is felt that this approach will deliver results that are more representative of actual system performance than the alternative approach of using derated capacity, even when the results are extrapolated to conditions other than the specific outage scenario chosen.

To verify that the results and conclusions are not skewed by the specific maintenance and forced outage scenario selected, simulations were run using the Conservative Assumptions in which the planned outages were included but maintenance and forced outages were not. This removes the outages that are random in nature while including those that can be reasonably predicted. This assumption results in more generation capacity being available than would ordinarily be expected at any given time, but it does provide a point of comparison under conservative conditions.

Figure 3.5-1 shows the capacity that is assumed to be on-line in the analysis under Case Study Assumptions. Planned maintenance outages are greatest in the spring and fall periods and are minimal during peak load periods. Forced outages are random throughout the year. It can be seen from the figure that, on a statewide basis, there is always adequate generation capacity to meet the load. Statewide, the hourly generation reserve margin never falls below 22%, even with scheduled and forced outages.

Figure 3.5-2 shows the capacity available under Conservative Assumptions in which the maintenance and forced outages are eliminated. Note that during the high-load summer months, all of the capacity in the State is assumed to be available for operation. Although the probability that these conditions will be seen in practice is very small, they are used in this analysis to test the ability of a company to exercise market power under a very optimistic state of the power system. If the exercise of market power can be seen under these conditions, the loss of available capacity due to outages would only exacerbate the situation. An alternative way to study this issue would have been to investigate a range of outage scenarios; however, the large number of possible combinations makes this impractical.

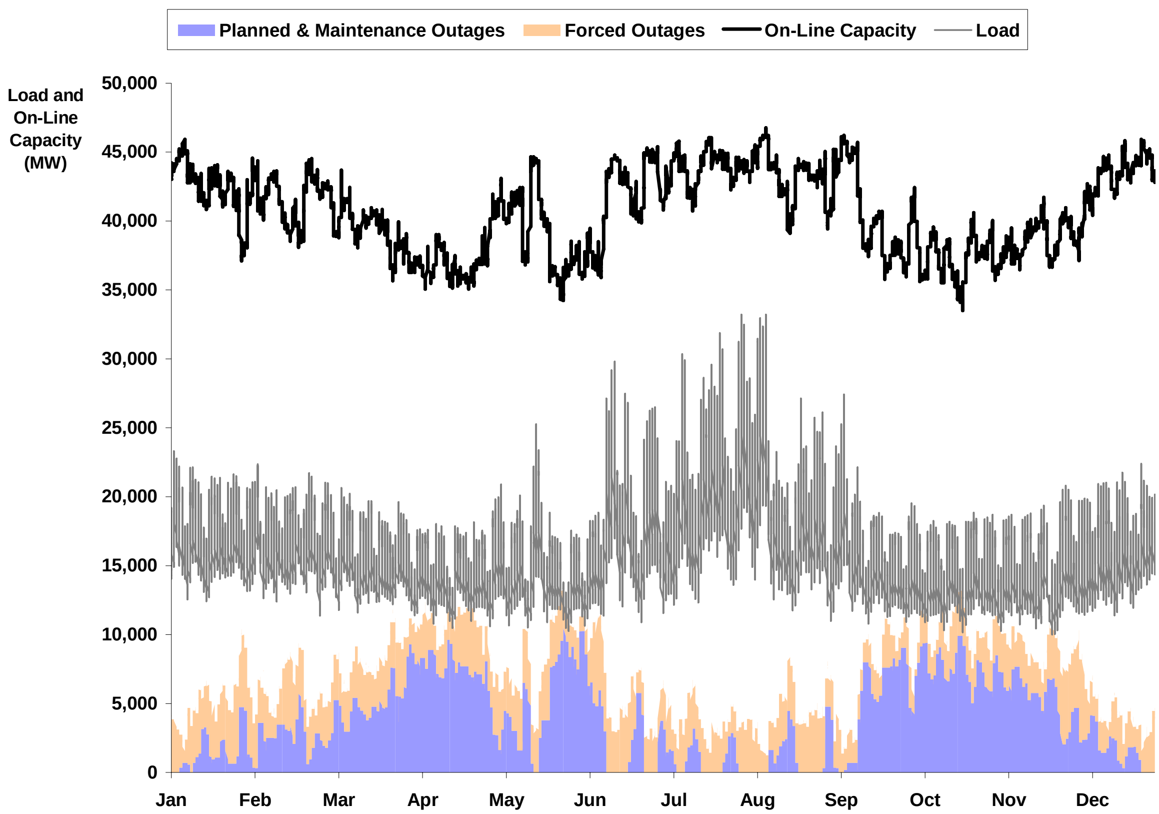

Figure 3.5-1 Analysis Year Available Generation Capacity (Case Study Assumptions)

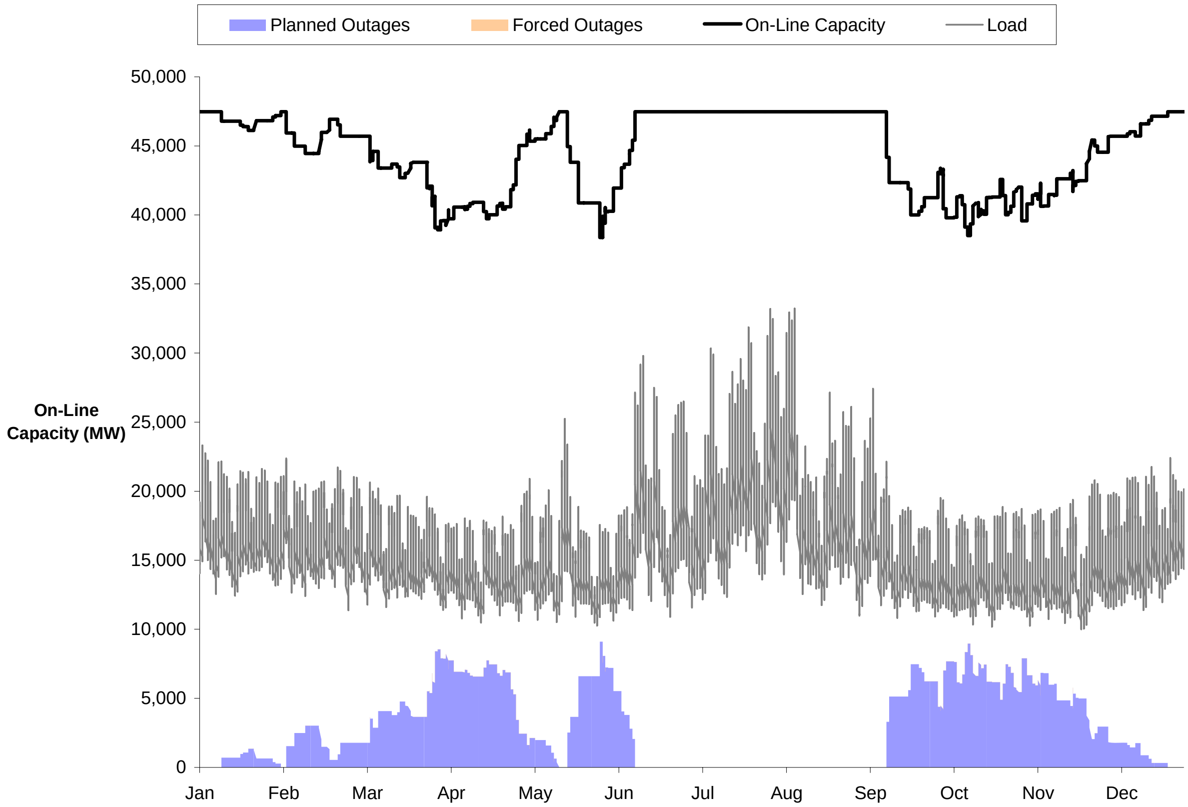

Figure 3.5-2 Analysis Year Available Generation Capacity (Conservative Assumptions)

3.6 FUEL PRICES

Fuel price projections are based on regional forecasts produced by the Energy Information Agency's (EIA) National Energy Modeling System (NEMS) model that are reported in its Annual Energy Outlook (AEO).[13] NEMS prices are based on supply and energy demand simulations. The model accounts for numerous factors that impact domestic fuel prices. These include macroeconomic growth, energy intensity, domestic and international energy production, sectoral energy demands, and environmental considerations.

Fuel prices delivered to the electric sector are projected regionally in the AEO. The East North Central Region, which includes Illinois, also includes Wisconsin, Michigan, Indiana, and Ohio. Load control areas in Iowa and Missouri are in the West North Central Region, and TVA is in the South Atlantic Region. AEO utility fuel price forecasts for the three regions developed in late 2002 by EIA are shown in Tables 3.6-1 through 3.6-3. Prices are projected for distillate fuel oil, residual fuel oil, natural gas, and steam coal. Each unit in the power plant inventory is assigned a fuel price in the forecast year based on its location and primary fuel type. Note that fuel prices increase slightly in 2003 but return to lower levels in 2004. After 2004, prices are nearly constant through 2007.

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[13] *Annual Energy Outlook with Projections*, AEO, 2003, National Energy Modeling System Run aeo2003.d110502c, Energy Information Administration, Washington, DC.

Table 3.6-1 Electric Generator Fuel Prices for the East North Central Census Division

Fuel Type	Fuel Price ($ / million Btu)							
Year	2000	2001	2002	2003	2004	2005	2006	2007
Jet Fuel	7.07	6.14	5.74	6.16	5.82	5.58	5.36	5.36
Distillate Fuel	6.56	5.94	5.53	5.95	5.14	4.95	4.86	4.87
Residual Fuel	3.50	4.41	4.15	4.46	4.04	3.91	3.95	3.97
Natural Gas	3.54	4.20	2.78	3.12	2.96	2.90	2.83	2.89
Steam Coal	1.21	1.24	1.20	1.20	1.19	1.21	1.19	1.18
Petroleum Products	3.93	4.71	5.34	5.84	5.13	4.94	4.85	4.85
Fossil Fuel Average	1.33	1.41	1.36	1.39	1.38	1.39	1.37	1.36

Table 3.6-2 Electric Generator Fuel Prices for the West North Central Census Division

Fuel Type	Fuel Price ($ / million Btu)							
Year	2000	2001	2002	2003	2004	2005	2006	2007
Jet Fuel	7.28	6.39	6.07	6.49	6.22	5.98	5.77	5.76
Distillate Fuel	6.67	6.18	5.57	5.99	5.22	5.03	4.94	4.95
Residual Fuel	4.50	4.13	3.34	3.63	3.06	2.93	2.96	2.98
Natural Gas	4.37	4.26	3.25	3.45	3.31	3.25	3.21	3.22
Steam Coal	0.86	0.92	0.87	0.88	0.88	0.90	0.89	0.89
Petroleum Products	6.00	5.22	5.47	5.98	5.18	4.99	4.91	4.89
Fossil Fuel Average	1.02	1.05	0.97	0.99	0.97	0.96	0.96	0.94

Table 3.6-3 Electric Generator Fuel Prices for the South Atlantic Census Division

Fuel Type	Fuel Price ($ / million Btu)							
Year	2000	2001	2002	2003	2004	2005	2006	2007
Jet Fuel	7.32	6.40	5.98	6.40	6.10	5.88	5.66	5.65
Distillate Fuel	6.70	6.07	5.37	5.80	4.98	4.80	4.72	4.72
Residual Fuel	4.43	5.33	3.85	4.13	3.89	3.77	3.79	3.81
Natural Gas	4.54	4.64	3.40	3.85	3.63	3.54	3.48	3.56
Steam Coal	1.45	1.47	1.47	1.47	1.46	1.45	1.44	1.43
Petroleum Products	4.58	5.41	4.06	4.50	4.24	4.15	4.15	4.16
Fossil Fuel Average	2.02	2.18	1.74	1.78	1.76	1.73	1.72	1.71

Note for Tables 3.2.6-1,2,3: Includes combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Jet fuel price is for units using a kerosene-type jet fuel. Price includes federal and State taxes while excluding county and local taxes.
Source: www.eia.doe.gov/oiaf/aeo/supplement/sup_t2t3.pdf (Model run November 2002)

3.7 OUT-OF-STATE LOAD AND GENERATION

For the simplified representation of the out-of-state power system described earlier, the loads and generation were represented by simple supply and demand curves. The total generation capacity of the reduced network was 216 GW serving the total system peak load of about 172 GW. While generating units within Illinois were represented in the EMCAS model with their individual characteristics, the out-of-state generation capacity was aggregated by interconnection point and modeled with their respective cumulative supply curves. The supply curves for out-of-state generators were constructed on the basis of their variable production costs. Under Case Study Assumptions, the effects of outages are accounted for by derating the units (i.e., reducing their available capacity by their average outage rates) and adjusting the out-of-state supply curves accordingly. This simplified approach is required, since there was insufficient information to allow for a unit-specific outage scenario, such as was developed for the in-state units. It allows for an approximation of how outages can affect available capacity. For simulations using the Conservative Assumptions, the derating of out-of-state units is maintained using only planned and maintenance outage rates. Forced outages were eliminated for consistency with the in-state representation.

A similar simplified approach has been applied for the modeling of out-of-state loads that were also aggregated by interconnection point. The details of these out-of-state supply and demand curves are given in Appendix D.

This simplified representation of out-of-state load and generation in EMCAS can be expected to have some impacts on the results. The spatial distribution of loads and generation at the out-of-state nodes does not capture the details of how power might be distributed in the out-of-state areas. As a result, the ability of in-state generation to meet out-of-state loads may be overestimated, since transmission limitations in the out-of-state areas are not considered. All load is assumed to be at the few out-of-state nodes that are included, and the only limitations on their being met by in-state suppliers are the capacity limits on the interties. Capacity limits on any strictly out-of-state lines are not considered. In an analogous fashion, the ability of out-of-state generation to meet in-state loads may also be overestimated, since some of that generation may experience local transmission congestion that is not represented in the simplified structure.

The use of the PowerWorld model overcomes some of these issues, since it is configured to represent much more of the eastern interconnection in detail. By including transmission details in a wider area surrounding the State, the effects of the simplification are reduced. In the PowerWorld model, all out-of-state generation and loads in the retained portion of the system were represented in detail. Table 3.7-1 contains a breakdown of the out-of-state generation capacity and peak load by control area and fuel type. Although this addresses some of the problems of representing out-of-state conditions, it too is a simplification in that areas beyond those shown here are not represented.

Table 3.7-1 Out-of-State Generation and Load Modeled in PowerWorld

Control Area	Load (MW)	Generation Capacity by Fuel Type (MW)				
		Coal	Nuclear	Gas	Hydro/ Pumped.	Other or Unknown
AECI (SERC)	4415	2412	0	1614	58	249
TVA (SERC)	30435	16256	5902	7363	6581	560
DOE (SERC0	500	0	0	0	0	0
AEP (ECAR)	23094	21300	2060	6455	731	292
OVEC (ECAR)	2251	2251	0	0	0	0
HE (ECAR)	1250	1250	0	240	0	50
CIN (ECAR)	11775	10171	0	1831	75	1220
DPL (ECAR)	3437	3305	0	1410	0	0
SIGE (ECAR)	1647	1647	0	309	0	135
LGEE (ECAR)	7314	5928	0	796	71	1259
BREC (ECAR)	1558	1709	0	0	0	65
IPL (ECAR)	2971	2664	0	742	0	100
NIPS (ECAR)	3244	2684	0	890	0	375
CONS (ECAR)	9407	3372	774	5887	1872	1999
Other (ECAR)	0	0	0	1776	0	0
ALTW (MAIN)	3454	2100	590	499	0	1049
AMRN-NonIL	7639	5672	1194	1050	808	371
ALTE (MAIN)	2505	2034	0	1136	26	264
WEC (MAIN)	6792	3640	1012	1032	143	868
WPS (MAIN)	2486	1019	500	432	131	414
Other (MAIN)	1157	251	0	244	30	348
NSP (MAPP)	9367	4110	1716	1059	254	1883
MEC (MAPP)	4802	3799	0	1700	0	450
Other (MAPP)	939	1257	0	84	21	60
Total	**142,439**	**98,831**	**13,748**	**36,549**	**10,801**	**12,011**

3.8 SYSTEM CONTINGENCIES

Secure power system operation requires that the system be operated with no limit violations and also with no violations under a specified set of contingent conditions. In this study, the impacts of 1,360 different contingencies were considered. This was done using PowerWorld Simulator's security constrained optimal power flow (SCOPF). While many of the contingencies consisted of single line or transformers outages, others considered multiple device outages (with the most complex having 18 different actions). Table 3.8-1 shows a breakdown of the contingencies by company. During the study, contingent line flows were enforced using the power flow case "B" limit set (as indicated by the Illinois utilities).

Table 3.8-1 Contingencies by Company

Company	Number of Contingencies
Ameren	266
Central Illinois Light Company (CILCO)	38
Commonwealth Edison (ComEd)	450
ECAR (Total)	196
Electric Energy Inc. (EEI)	35
Illinois Power	120
MAIN (other)	129
MAPP (Total)	86
SERC (Total)	10
Southern Illinois Power Co-operative (SIPC)	12
Springfield City Water Light & Power (CWLP)	18

4. ANALYSIS OF ALTERNATIVE CASES

Using the basic assumptions and inputs described in the previous section, alternative cases were analyzed to determine how the Illinois market might function in the analysis year. Table 4-1 lists the cases that have been studied here.

Table 4-1 Alternative Cases Analyzed

Section Number – Case	Description
4.1 Production Cost (PC)	**GenCo bids are based on unit production cost.**
4.2 Physical Withholding (PW)	**GenCos withhold units from the market.**
4.2.1 Single Unit (PW-SU)	Individual units are withheld.
4.2.2 Multiple Unit (PW-MU)	Multiple units are withheld.
4.2.3 Profitability Criteria (PW-PR)	Units withheld based on profitability.
4.2.4 System Reserve Criteria (PW-SR)	Units withheld based on system reserve.
4.2.5 Companywide (PW-CW)	All of a company's units are withheld.
4.3 Economic Withholding (EW)	**GenCos increase prices above production cost.**
4.3.1 Single Unit (EW-SU)	Prices are increased on individual units.
4.3.2 Companywide (EW-CW)	Prices are increased for all of a company's units.

In evaluating each of these cases, the focus is on addressing the primary question of the study: "*Can a company, acting on its own, raise electricity prices and increase its profits?*" The production cost case represents the simplest of the strategies in that all generation companies base their market participation on the production cost of their units. This case is used as the benchmark against which the other cases are compared.

The selection of the other cases was based on developing insight into how the market would respond to the application of various company strategies. The intent here is not to identify any particular strategy as being more or less likely to be employed or more or less desirable than any other. Rather, the case selection was designed to test a number of strategies that have been seen in various forms in other operating electricity markets. These can be viewed as a series of "electronic experiments" designed to improve the understanding of the market.

In testing the various strategies, some were applied in a very simple fashion in order to develop perspective on how they might influence the market. These simple cases were used to identify the effect of one specific element of a business strategy. By using this approach, the understanding of the market behavior is built up in a step-by-step manner in order to better understand the complex and highly nonlinear nature of the electricity market.

Some of the cases were run under both the Case Study Assumptions and under the Conservative Assumptions. This was designed to verify that the use of company-level unit commitment, the inclusion of fixed operating and maintenance costs in bid prices, and the consideration of outages were not skewing the results.

None of the business strategies tested can be said to represent the full complexity of how decisions are made in an electricity market. Rather, the cases tested here should be viewed as indicators of how a specific business decision might affect the market and consumers.

4.1 PRODUCTION COST CASE

The production cost (PC) case assumed that all GenCos participated in the market using production cost-based pricing. In this analysis, the term “production cost” is defined to include the following:

- Fuel cost – the cost of fuel required to generate electricity – depends on the price of the fuel itself (measured in $/Btu) and on the efficiency of the generator, which is referred to as the unit’s heat rate and which is measured in Btu/kWh. The fuel cost is the fuel price divided by the heat rate.

- Variable Operation and Maintenance (VOM) – these costs relate to consumables that are needed to generate electricity and include water, chemicals, and other materials that are consumed in proportion to the amount of electricity generated.

Under the Case Study Assumptions, the following was also added to production cost:

- Fixed Operation and Maintenance (FOM) – these costs are independent of the actual number of hours of operation or the amount of electricity generated. They include items such as operating labor and annual maintenance charges. The FOM costs are expressed in units of $/kW-month. These costs are converted to a per-kWh basis by using an average unit capacity factor.

Under the Conservative Assumptions, FOM was not included in production cost.

All of these cost elements vary with the type and efficiency of the unit. The analysis uses specific values for each individual unit included in the simulation. These values were taken from the data sources identified in Section 2. Table 4.1-1 shows the range of values for each unit type included in the analysis.

There are ways to define production cost other than what is used here. In some analyses, the production cost is defined only as the fuel and VOM cost (i.e, as in the Conservative Assumptions), which represents the short-term marginal cost of production. While this method is widely used, it is not a sustainable approach to market bidding over any extended period (i.e., months). A company that receives reimbursement of only the fuel and VOM costs of a unit will not be able to cover the FOM costs. This lack of adequate return will eventually force the company to cease operating the unit. As this analysis is done over a longer time period, it was decided to include the FOM as part of what is termed the production cost when applying the Case Study Assumptions. Deleting it under the Conservative Assumptions provides an indication of the magnitude of its impact.

The amortization of capital costs was not included here as part of what is termed production cost. These costs are generally considered in analyses that span longer time periods (i.e., several years) than what is addressed here. It can be argued that the amortization of capital should be included in market bidding in the same manner as the FOM costs. A company that does not receive enough return to cover its capital amortization costs will likewise be forced to cease operation after some period of time. In addition to the analysis being limited to one year, there was insufficient data available on capital amortization to allow it to be used in this study. Hence it was not considered here.

Table 4.1-1 PC Case – Range of Generator Cost Parameters

Generating Unit Type	Unit Sizes (MW)	Fuel Cost ($/MMBtu)	Variable Operating and Maintenance Cost ($/MWh)	Total Variable Operating Cost [a] ($/MWh)	Fixed Operating and Maintenance Cost ($/kW-m)	Shutdown & Startup Cost [b] ($1,000 per cycle)
Nuclear	828–1,225	0.43–0.47	3.0–8.0	8.3–13.1	1.3–4.0	56.9–87.2
Bituminous Coal (<100 MW)	22–81	1.18	2.0–6.4	16.2–24.1	0.5–4.0	1.6–5.9
Bituminous Coal (>100 MW)	109–635	1.18	0.9–4.5	13.0–18.6	0.5–1.9	7.0–45.6
Sub-bituminous Coal	120–893	1.18	0.9–4.5	12.8–16.9	1.0–2.0	7.2–47.6
Oil-Fired Steam Units	46–210	3.97	1.6–3.0	47.5–48.5	0.5–0.7	2.2–10.2
Natural Gas-Fired Steam Units	50–545	2.89	0.6–0.9	41.1–50.0	0.4–0.8	7.5–67.2
Natural Gas-Fired Combined Cycle	250–300	2.89	0.5	20.8–24.6	1.2	17.8–21.1
Natural Gas-Fired Gas Turbines	10–172	2.89	0.0-4.4	25.8–71.2	0.0–4.8	0.0–0.4
Gas Turbines (Diesel-Fired)	13–57	4.87	0.0–3.0	45.0–93.0	0.0–0.5	0.0–0.2
Jet Engines	22–38	5.36	0.0–1.6	80.7–129.3	0.0–0.4	0.0–0.3

[a] Includes fuel cost calculated from unit heat rate and variable operating and maintenance cost.
[b] For cold start.

In the PC case, the bids that GenCos offer for the sale of electricity were based entirely on the production costs of the generators (with and without FOM under Case Study and Conservative Assumptions, respectively). No strategic bidding, designed to take advantage of market conditions, was employed by any company. Results of the PC case were used as a point of comparison for the other cases.

4.1.1 Day-Ahead Market Results

In the day-ahead market, DemCos and GenCos submitted bids to buy and sell electricity for each hour of the next day. The bids were used by the ISO to construct supply and demand curves. In the PC case, the demand bids from the DemCos were assumed to represent firm loads (i.e., not interruptible) and were, therefore, not price-sensitive. In contrast, the supply bids from the GenCos had price variations (i.e., as a result of variations in the production cost of different units) and were ranked accordingly. The supply and demand bids were then run through the transmission-constrained dispatch analysis (i.e., the SYSSCHED algorithm) that selected the least cost dispatching schedule subject to the physical constraints of the transmission system.

Figure 4.1.1-1 shows the results of the day-ahead market bidding for typical hours that represent low load, intermediate load, and peak load. Included in the figure are all of the in-state and out-of-state companies, so that the figure is illustrative of the entire market. In all three conditions, the demand is shown as a vertical line representing the non-price-responsive nature of the demand. The supply curve shows two lines: one that represents the bids that were submitted, and one that represents the bids that were selected after the transmission constrained dispatch analysis was applied. The difference between the two lines represents the need to utilize higher cost generators due to congestion in the transmission network.

In the low-load hour, the two supply curves are virtually identical, indicating that it was possible to use the least cost generation, since transmission congestion did not occur. In the intermediate-load hour, there were signs of transmission congestion. Some of the lower-cost units had to be bypassed, and more expensive units were scheduled for dispatch. In peak-load hours, transmission congestion often developed, and it was necessary to dispatch some units out of the economic merit order. When this occurs, generators with relatively low bids remain idle while generators with more expensive bids are put into operation. These high-priced bids were accepted, since power injection into the grid at the unit's specific interconnection point (i.e., bus) served loads, often locally, without overloading transmission lines. On the other hand, accepting the lower-cost bid would have resulted in the violation of transmission system line limitations and/or security safeguards. This dispatch of units out of bid merit order led to LMP differences across the system.

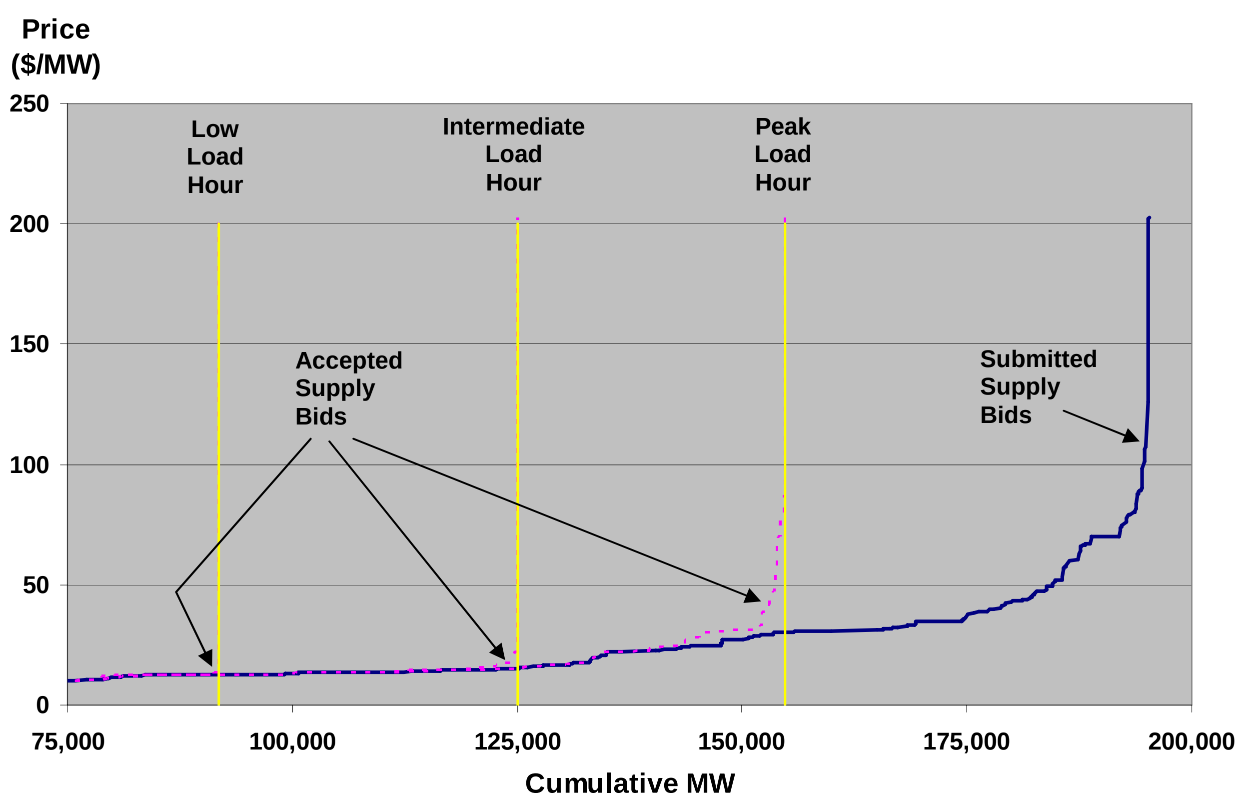


Figure 4.1.1-1 Typical Day-Ahead Market Supply/Demand Curves

4.1.2 Transmission System Loading

Case Study Assumptions

The components of the transmission system that are operated at their maximum capacity limits represent transmission congestion that can force the dispatching of generators out of the economic merit order, thus leading to higher electricity costs. Table 4.1.2-1 shows the components of the transmission network that were congested and the number of hours in the year this occurred. Figure 4.1.2-1 shows the location of these components.

It should be noted that these results do not consider any modifications to the transmission network topology that might be used by an ISO to relieve congestion (e.g., opening or closing circuits). The network topology used here, which was based on the National Electric Reliability Council (NERC) 2003 summer case as previously described, was static. It should also be noted that this set of constraints did not include consideration of the system contingencies discussed earlier. This basic analysis considered only the capacity limits of the equipment. Including contingencies would place more constraints on the transmission system. If limitations in the transmission system can be exploited by companies under these less constraining operating rules (i.e., without contingencies), it can be safely extrapolated that a higher degree of market power could be exercised when contingencies are considered. A more detailed transmission analysis that includes consideration of the contingencies is included in the PowerWorld analysis in Appendixes E and F.

The table shows that there were 65 transmission components that experienced capacity limits sometime during the year. A total of 22 are operated at their capacity limits for more 1% of the hours in a year. Nine were at capacity for more than 10% of the time, and 5 more than 20% of the time. These represented significant bottlenecks that can affect the movement of power. The following observations can be made from these results:

- *NI-A Zone.* The 345 kV Cordova line, which is a bus coupling, was operated at maximum capacity for over 2,300 hours per year. This is near the Quad Cities nuclear plant. The Dixon-Mendota 138-kV line was also at capacity for extended periods. These capacity limits affected power flows in the northwest portion of the State as well as interconnections with Iowa.

- *NI-B Zone.* There were only a few hours when lines in this zone were at capacity limits. As will be seen later, this does not necessarily mean that this zone is immune from the impacts of congestion.

- *NI-C Zone.* The 138-kV Crest Hill line was at its limit over 200 hours per year. This had an effect on the southwest portion of the Commonwealth Edison territory near Joliet.

- *NI-D Zone.* Several lines in this zone were loaded to capacity for extended periods. These limits had a significant effect on the flow of power through the central part of the City of Chicago.[14]

- *NI-E Zone.* The 345-kV line from Frankfort to Gooding Grove, just south of Chicago and east of Joliet, is at capacity for over 600 hours. This affects the movement of power into Chicago as well as to the surrounding areas.

- *NI-F Zone.* There are no lines at their capacity limits in this zone.

- *NI-G Zone.* The 138-kV Mazon-Oglesby line is operated at its maximum capacity for the majority of hours in the year.

- *IP-A Zone.* The capacity limits on the lines in this zone are reached less than 1% of the hours of the year.

- *IP-B Zone.* The 138-kV Kickapoo line is at capacity more than 300 hours per year. This is in the vicinity of the highly loaded Holland-Mason line described below.

- *IP-C Zone.* The 138-kV Sidney line (east central part of the State) and Gillespie line (northeast of St. Louis) are at capacity more than 100 hours per year.

- *AMRN-A Zone.* The lines loaded to capacity in this zone are at there limits for only a few hours per year.

- *AMRN-B Zone.* The Holland transformer is at capacity more than 2,200 hours per year. Also, the Coffeen-Pana 345-kV line, which is in the same vicinity, is at capacity almost 200 hours per year.

- *AMRN-D Zone.* The Gibson and Rantoul-Sidney 138-kV lines are at capacity for extended periods. These affect the area southeast of St. Louis.

- *AMRN-E Zone.* The Pinckneyville transformers are loaded to capacity over 1,000 hours per year. These limits affect the southern part of the State.

- *CILC Zone.* The Mason to Holland and Mason to Tazewell 138-kV lines are at capacity over 2,000 hours per year. These significant capacity limits affect power flows in the Peoria region.

- *EEI Zone.* The Joppa 161-kV line is at capacity almost 400 hours per year. This affects the southernmost portion of the State.

[14] A number of improvements to the transmission system serving downtown Chicago have been implemented recently. These were not part of the 2003 NERC summer case used here. Also, there are a number of phase shifters used by Commonwealth Edison to manage power flow in the area. They are considered in an approximate way in the EMCAS simulation and in more detail in the PowerWorld simulation, as discussed in Appendixes E and F.

- *SIPC Zone*. The Baldwin-Campbell 138-kV line is operated at capacity more than 300 hours per year. This affects power flows southeast of St. Louis.

Conservative Assumptions

Table 4.1.2-2 shows the equipment operated at capacity limits using the Conservative Assumptions. For the most part, the same transmission equipment that was operated at capacity for extended periods under the Case Study Assumptions was also stressed under the Conservative Assumptions. Fifty components were operated at capacity limits at some point in the year, 19 for more than 1% of the time, 11 for more than 10%, and 2 for more than 20%. This indicates that the transmission limits constrained the operation of the power system even under these conservative assumptions.

Table 4.1.2-1 PC Case (Case Study Assumptions) Equipment Loadings

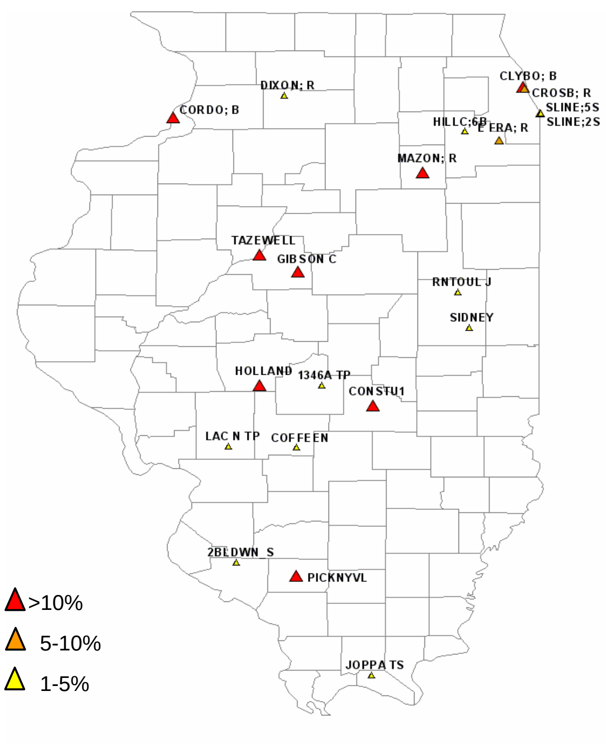
ID	Bus		Zone		Equipment			Hours Per Year Operated at Capacity
	From	To	From	To				
NI-A								
36284_37616	CORDO; B	CORDO;	NI-A	NI-A	345	kV	Line	2,329
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line	172
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line	39
36773_37076	GARDE;	H71 ;BT	NI-A	NI-A	138	kV	Line	11
36284_36362	CORDO; B	NELSO; B	NI-A	NI-A	345	kV	Line	1
NI-B								
37231_37371	SILVE; R	WILSO; R	NI-B	NI-B	138	kV	Line	11
36389_36067	SILVE; R	SILVE;3M	NI-B	NI-B	138	/345	Transformer	7
36067_37231	SILVE;3M	SILVE; R	NI-B	NI-B	138	/138	Transformer	7
NI-C								
36844_37362	HILLC;6B	WILL ;BT	NI-C	NI-E	138	kV	Line	272
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line	8
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line	8
NI-D								
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line	3,208
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line	508
36649_36691	CROSB; R	DIVER; R	NI-D	NI-D	138	kV	Line	448
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line	275
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer	12
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer	12
36294_36025	CRAWF; B	CRAWF;4M	NI-D	NI-D	138	/345	Transformer	3
36025_36640	CRAWF;4M	CRAWF; B	NI-D	NI-D	138	/138	Transformer	3
NI-E								
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line	608
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line	49
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line	23
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line	15
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer	10
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345	Transformer	10

Table 4.1.2-1 PC Case (Case Study Assumptions) Equipment Loadings

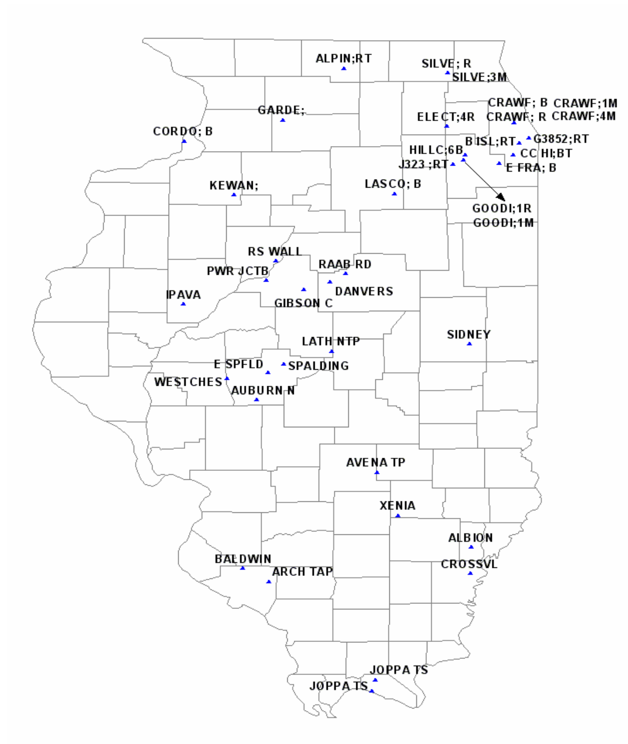
ID	Bus From	Bus To	Zone From	Zone To	Equipment			Hours Per Year Operated at Capacity
36451_36881	J323 ;RT	JO 9; R	NI-E	NI-E	138	kV	Line	3
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line	1
36308_36334	E FRA; B	GOODI;3B	NI-E	NI-E	345	kV	Line	1
NI-G								
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line	5,337
36891_37135	KEWAN;	POWER;	NI-G	NI-G	138	kV	Line	36
36922_36968	LASCO; B	MAZON; B	NI-G	NI-G	138	kV	Line	9
IP-A								
32411_37135	PWR JCTB	POWER;	IP-A	NI-G	138	kV	Line	43
32344_32379	RAAB RD	WASH ST	IP-A	IP-A	138	kV	Line	2
32344_32380	RAAB RD	ELPASO T	IP-A	IP-A	138	kV	Line	2
32343_32375	DANVERS	LILLY	IP-A	IP-A	138	kV	Line	1
IP-B								
32410_33159	1346A TP	KICKAPOO	IP-B	CILC	138	kV	Line	320
32358_32410	LATH NTP	1346A TP	IP-B	IP-B	138	kV	Line	16
IP-C								
32388_32405	SIDNEY	MIRA TAP	IP-C	IP-B	138	kV	Line	176
32291_32298	LAC N TP	GILSP TP	IP-C	IP-C	138	kV	Line	109
32388_32387	SIDNEY	SIDNEY	IP-C	IP-C	345	/138	Transformer	9
IP-D								
32285_32320	ARCH TAP	STEELVIL	IP-D	IP-D	138	kV	Line	82
32274_32327	BALDWIN	MT VRNON	IP-D	IP-D	345	kV	Line	2
AMRN-A								
30055_33315	AUBURN N	CHATHAM	AMRN-A	CWLP	138	kV	Line	24
30788_30789	IPAVA	IPAVA	AMRN-A	AMRN-A	138	/345	Transformer	1
AMRN-B								
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer	2,241
30395_31445	COFFEEN	PANA	AMRN-B	AMRN-B	345	kV	Line	191
30010_30439	ALBION	CROSSVL	AMRN-B	AMRN-B	138	kV	Line	47
30439_31351	CROSSVL	NORRIS	AMRN-B	AMRN-B	138	kV	Line	30
30072_31568	AVENA TP	RAMSEY	AMRN-B	AMRN-B	138	kV	Line	24
31993_32327	XENIA	MT VRNON	AMRN-B	IP-D	345	kV	Line	8
AMRN-D								
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line	1,227
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line	432
30614_32348	GIBSON C	BROKAW	AMRN-D	IP-B	138	kV	Line	12
AMRN-E								
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer	2,246
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer	1,468
30825_33394	JOPPA TS	JOPPA TS	AMRN-E	EEI	161	/345	Transformer	75
CILC								
33157_33175	HOLLAND	MASON	CILC	CILC	138	kV	Line	2,749
33141_33175	TAZEWELL	MASON	CILC	CILC	138	kV	Line	2,263
33002_33139	RS WALL	RSW EAST	CILC	CILC	138	/69	Transformer	11
33158_33307	E SPFLD	EASTDALE	CILC	CWLP	138	kV	Line	4

Table 4.1.2-1 PC Case (Case Study Assumptions) Equipment Loadings

ID	Bus From	Bus To	Zone From	Zone To	Equipment			Hours Per Year Operated at Capacity
EEI								
33394_33396	JOPPA TS	JOPTAPY	EEI	EEI	161	kV	Line	380
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line	49
SIPC								
33370_33373	2BLDWN_S	2CMPBL_S	SIPC	SIPC	69	kV	Line	303
CWLP								
33314_33315	SPALDING	CHATHAM	CWLP	CWLP	138	kV	Line	9
33312_33313	WESTCHES	WESTCHES	CWLP	CWLP	138	/69	Transformer	4



(a) Loaded to capacity limit equal to or more than 1% of the time



(b) Loaded to capacity limit up to 1% of the time

Note: For clarity, only one terminus (the From Bus) of each line is shown in each figure. Geographic locations are approximate.

Figure 4.1.2-1 PC Case (Case Study Assumptions) Transmission Components Operated at Maximum Capacity

Table 4.1.2-2 PC Case (Conservative Assumptions) Equipment Loadings

	Bus		Zone					Hours Per Year Operated at Capacity
ID	From	To	From	To	Equipment			
NI-A								
36284_37616	CORDO; B	CORDO;	NI-A	NI-A	345	kV	Line	4,482
36773_37076	GARDE;	H71 ;BT	NI-A	NI-A	138	kV	Line	665
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line	648
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line	44
36284_36362	CORDO; B	NELSO; B	NI-A	NI-A	345	kV	Line	34
37039_37171	NELSO; R	R FAL; R	NI-A	NI-A	138	kV	Line	7
NI-C								
36844_37362	HILLC;6B	WILL ;BT	NI-C	NI-E	138	kV	Line	986
36310_36362	ELECT; B	NELSO; B	NI-C	NI-A	345	kV	Line	149
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line	10
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line	2
NI-D								
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line	2,070
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line	610
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line	312
36649_36691	CROSB; R	DIVER; R	NI-D	NI-D	138	kV	Line	19
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer	12
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer	12
NI-E								
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line	1,400
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line	60
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line	30
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line	16
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345	Transformer	11
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer	11
NI-G								
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line	1,102
36891_37135	KEWAN;	POWER;	NI-G	NI-G	138	kV	Line	5
IP-A								
32411_37135	PWR JCTB	POWER;	IP-A	NI-G	138	kV	Line	5
IP-B								
32410_33159	1346A TP	KICKAPOO	IP-B	CILC	138	kV	Line	1,263
IP-C								
32388_32405	SIDNEY	MIRA TAP	IP-C	IP-B	138	kV	Line	958
32388_32387	SIDNEY	SIDNEY	IP-C	IP-C	345	/138	Transformer	63
AMRN-A								
30055_33315	AUBURN N	CHATHAM	AMRN-A	CWLP	138	kV	Line	50
31015_31559	MARBHD N	QUINCY S	AMRN-A	AMRN-A	138	kV	Line	1
30789_30990	IPAVA	MACOMB W	AMRN-A	AMRN-A	138	kV	Line	1
AMRN-B								
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer	1,351
30010_30439	ALBION	CROSSVL	AMRN-B	AMRN-B	138	kV	Line	250

Table 4.1.2-2 PC Case (Conservative Assumptions) Equipment Loadings

	Bus		Zone		Equipment			Hours Per Year Operated at Capacity
ID	From	To	From	To				
30439_31351	CROSSVL	NORRIS	AMRN-B	AMRN-B	138	kV	Line	168
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line	11
31993_32327	XENIA	MT VRNON	AMRN-B	IP-D	345	kV	Line	2
30395_31445	COFFEEN	PANA	AMRN-B	AMRN-B	345	kV	Line	1
30072_31568	AVENA TP	RAMSEY	AMRN-B	AMRN-B	138	kV	Line	1
AMRN-D								
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line	1,514
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line	33
AMRN-E								
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer	24
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer	24
30825_33394	JOPPA TS	JOPPA TS	AMRN-E	EEI	161	/345	Transformer	19
CILC								
33157_33175	HOLLAND	MASON	CILC	CILC	138	kV	Line	1,583
33141_33175	TAZEWELL	MASON	CILC	CILC	138	kV	Line	897
EEI								
33394_33396	JOPPA TS	JOPTAPY	EEI	EEI	161	kV	Line	869
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line	29
33392_33396	JOPPA S	JOPTAPY	EEI	EEI	161	kV	Line	7
CWLP								
33314_33315	SPALDING	CHATHAM	CWLP	CWLP	138	kV	Line	14
33312_33313	WESTCHES	WESTCHES	CWLP	CWLP	138	/69	Transformer	10

4.1.3 Locational Marginal Prices

While transmission capacity limits, shown in the previous section under both the Case Study and Conservative Assumptions, identify the points in the transmission system that are congested, they do not by themselves define the scope and magnitude of the situation, nor do they indicate how any company might exert market power by utilizing these limits. What is more significant than the limits themselves is how these limits affect prices at various points in the network (i.e., locational marginal prices [LMPs]). The price effects of the congestion may be evident in the vicinity of these heavily loaded components or they may be seen in much wider areas.

In identifying a particular bus in the network as possibly being affected by transmission congestion, the following indicators can be used:

- LMPs higher than surrounding areas, and
- Higher LMPs persisting for an extended period.

Under PC case conditions, in which there is no strategic bidding by GenCos (i.e., all are bidding production cost), these LMP indicators can provide an identification of where transmission congestion has its most significant price impacts. Figure 4.1.3-1 shows the criteria used to group the LMP indicators, for those buses that have either load or generators, into categories that might indicate the impacts of transmission congestion. The criteria can be interpreted by the following examples:

- If the LMP at the bus was always below 30 $/MWh, then it was coded blue.
- If the LMP was between 30 and 35 $/MWh for more than 80 hours per month (or 876 hours per year), the bus was coded yellow.
- If the LMP was between 35 and 45 $/MWh and if this was maintained for more than 8 hours per month (or 88 hours per year), it was coded yellow; if it was more than 80 hours per month (or 876 hours per year), it was coded orange.
- If the LMP was between 45 and 60 $/MWh, it was coded yellow; if this was maintained for more than 8 hours per month (or 88 hours per year), it was coded orange; if it was more than 80 hours per month (or 876 hours per year), it was coded red.
- If the LMP was over 60 $/MWh, it was coded orange; if this persisted for more than 40 hours per month (or 438 hours per year), it was coded red.

The LMP values and the hours of exceedance were chosen based on frequency distributions of LMPs seen under these conditions. These levels appear to be reasonable indicators of increasing prices due to increased load and transmission congestion.

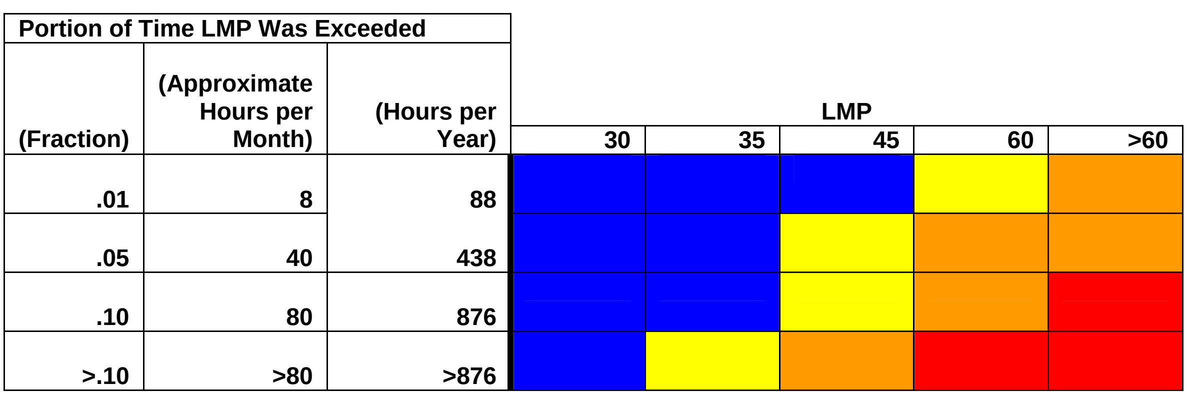


Figure 4.1.3-1 Criteria Used for Coding LMPs

Case Study Assumptions

Figure 4.1.3-2 shows the application of these criteria to the hourly LMPs calculated during each month of the simulation. Figure 4.1.3-3 shows the application on an annual basis.

The monthly results show that for about six months out of the year – January through March and October through December – the LMPs around the State were relatively constant. There was little transmission congestion and almost all the buses were coded blue. As the load increased in the warmer months – June, July, and August – much of the State showed an increase in LMPs. That most of the LMPs were in the same range (i.e., yellow), indicates that all paid higher prices as more expensive generation had to be dispatched to meet the increasing load. This was not the result of transmission congestion. It is the variations in color (i.e., into orange and red) that indicate the effects of transmission congestion, which caused price disparities across the State.

Comparing the locations of the buses showing higher than average LMPs (i.e., coded orange and red) to the locations of the capacity-loaded components of the transmission system shown in the previous section shows a degree of correlation. The following observations can be made:

- Buses in the City of Chicago were affected most by the limits on a number of transmission components. Higher LMPs were evident through the peak-load months. The impact of the capacity limits of the transmission equipment identified earlier (i.e., in the NI-D zone) are evident.

- Buses in the area north of Chicago and west out to the Iowa border also had higher LMPs than the rest of the State. The capacity limits on the nearby transmission components (i.e., in the NI-A and NI-D zones) caused higher prices, starting in June and continuing through September.

- A broad area stretching southwest of Chicago to Peoria and south to Springfield saw higher LMPs, but only during peak-load months. Transmission congestion did not impact these areas significantly in lower-load months.

- Smaller pockets of high LMPs were seen in the Sidney, Crossville, Joppa, and Pinckneyville areas due to the limits on local transmission components identified earlier.

As the load decreased through the fall and early winter, the situation returned to the condition where most of the State had LMPs in the blue range.

Table 4.1.3-1 shows the maximum monthly values of the LMPs for both the load and generator buses. Individual buses reached very high values. This reflects the value of generation at each bus as determined by the ISO's transmission-constrained scheduling algorithm (i.e., the SYSSCHED process described in Section 1.3).

It should be reemphasized that under PC case conditions there was no strategic bidding and GenCos priced their power at production costs. By this assumption, no market power was being exercised. Strategic bidding could be expected to amplify price differences between areas.

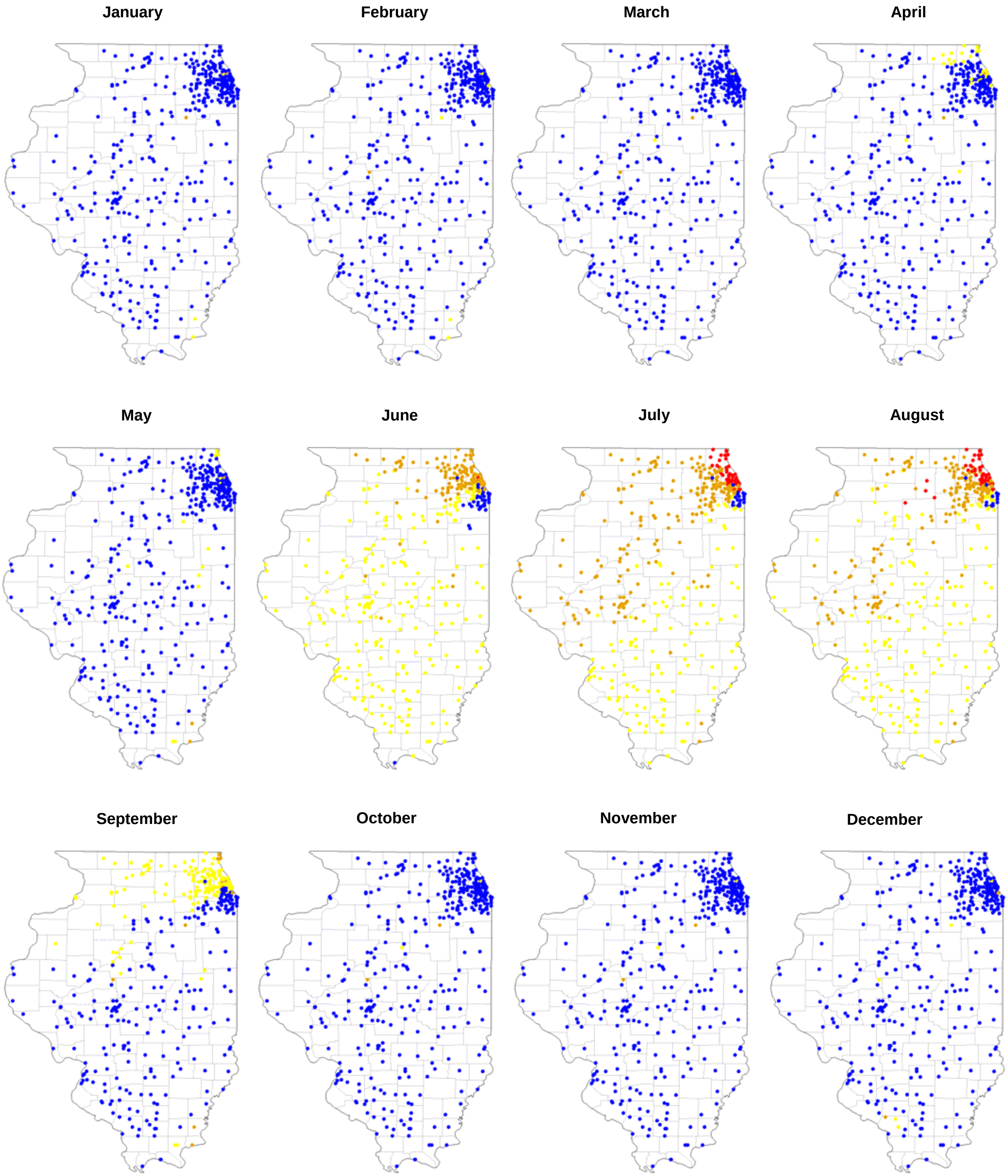


Figure 4.1.3-2 PC Case (Case Study Assumptions) Potential Load Pocket Identification Based on Monthly Data

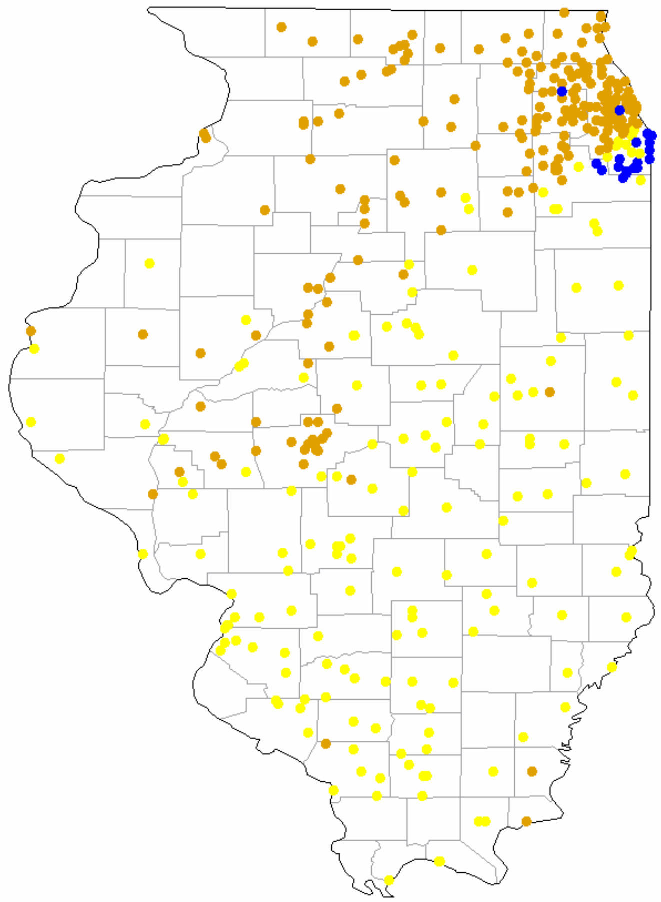


Figure 4.1.3-3 PC Case (Case Study Assumptions) Potential Load Pocket Identification Based on Annual Data

Table 4.1.3-1 PC Case (Case Study Assumptions) – Monthly Maximum LMPs at Generator and Load Buses

		Zone						
Month		**NI-A**	**NI-B**	**NI-C**	**NI-D**	**NI-E**	**NI-F**	**NI-G**
Jan	**Max LMP**	**33.28**	**55.58**	**33.45**	**98.80**	**31.99**	**30.37**	**45.96**
	Bus No.	36976	36684	36942	36624	36940	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	WILMI;	MAZON; R
Feb	**Max LMP**	**30.76**	**44.27**	**32.01**	**71.11**	**30.83**	**30.51**	**45.27**
	Bus No.	36976	36684	36695	36624	36745	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	DRESD; R	CLYBO; B	F CIT; R	WILMI;	MAZON; R
Mar	**Max LMP**	**32.28**	**50.13**	**32.41**	**84.73**	**31.24**	**30.83**	**46.97**
	Bus No.	36976	36684	36942	36624	36940	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	WILMI;	MAZON; R
Apr	**Max LMP**	**33.02**	**57.47**	**34.75**	**104.84**	**31.62**	**32.54**	**52.28**
	Bus No.	36976	36684	36695	36624	36940	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	DRESD; R	CLYBO; B	LISLE; B	WILMI;	MAZON; R
May	**Max LMP**	**37.61**	**75.99**	**37.89**	**150.31**	**35.33**	**32.18**	**49.54**
	Bus No.	36976	36684	36942	36624	36940	37659	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	KENDA;3C	MAZON; R
Jun	**Max LMP**	**380.92**	**173.26**	**234.22**	**381.76**	**58.69**	**49.11**	**61.41**
	Bus No.	36981	36684	37211	36624	36940	37659	36969
	Bus Name	MENDO;	DEVON;0B	SANDW; R	CLYBO; B	LISLE; B	KENDA;3C	MAZON; R
Jul	**Max LMP**	**319.17**	**1,879.92**	**199.07**	**602.30**	**130.25**	**78.15**	**102.81**
	Bus No.	36981	37371	37211	37317	36745	37659	37550
	Bus Name	MENDO;	WILSO; R	SANDW; R	WASHI; R	F CIT; R	KENDA;3C	POWER;6U
Aug	**Max LMP**	**781.79**	**311.33**	**465.72**	**715.51**	**97.97**	**70.01**	**63.40**
	Bus No.	36981	36684	37211	36624	36745	37659	36969
	Bus Name	MENDO;	DEVON;0B	SANDW; R	CLYBO; B	F CIT; R	KENDA;3C	MAZON; R
Sep	**Max LMP**	**49.02**	**114.78**	**49.54**	**241.76**	**44.90**	**39.49**	**51.28**
	Bus No.	36976	36684	36942	36624	36940	37659	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	KENDA;3C	MAZON; R
Oct	**Max LMP**	**31.20**	**48.84**	**33.99**	**82.87**	**30.30**	**32.04**	**50.22**
	Bus No.	36976	36684	36695	36624	36940	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	DRESD; R	CLYBO; B	LISLE; B	WILMI;	MAZON; R
Nov	**Max LMP**	**35.09**	**62.97**	**35.29**	**117.03**	**33.45**	**31.24**	**45.28**
	Bus No.	36976	36684	36942	36624	36940	37659	36969
	Bus Name	MCHEN; B	DEVON;0B	LOMBA; B	CLYBO; B	LISLE; B	KENDA;3C	MAZON; R
Dec	**Max LMP**	**32.42**	**54.00**	**32.73**	**95.85**	**34.91**	**31.09**	**47.33**
	Bus No.	36976	36684	36695	36624	36745	37369	36969
	Bus Name	MCHEN; B	DEVON;0B	DRESD; R	CLYBO; B	F CIT; R	WILMI;	MAZON; R

Color Coding

- LMP < 35 \$/MWh
- 35 \$/MWh ≤ LMP < 45 \$/MWh
- 45 \$/MWh ≤ LMP < 60 \$/MWh
- LMP ≥ 60 \$/MWh

Table 4.1.3-1 PC Case (Case Study Assumptions) – Monthly Maximum LMPs at Generator and Load Buses (Cont'd)

		Zone					
Month		**IP-A**	**IP-B**	**IP-C**	**IP-D**		**CWLP**
Jan	**Max LMP**	**30.52**	**29.76**	**29.79**	**28.87**		**29.59**
	Bus No.	32603	32273	32616	32675		33305
	Bus Name	EGAL #1	VERMILON	W TILTON	BLUFF CY		INTERSTA
Feb	**Max LMP**	**29.73**	**30.67**	**29.75**	**30.83**		**29.20**
	Bus No.	32615	32397	32660	32285		33315
	Bus Name	NORMAL E	MAHOMET	PORTR RD	ARCH TAP		CHATHAM
Mar	**Max LMP**	**30.10**	**29.69**	**29.69**	**29.50**		**29.67**
	Bus No.	32603	32273	32616	32675		33305
	Bus Name	EGAL #1	VERMILON	W TILTON	BLUFF CY		INTERSTA
Apr	**Max LMP**	**29.90**	**29.28**	**29.20**	**29.11**		**29.33**
	Bus No.	32603	32361	32362	32664		33306
	Bus Name	EGAL #1	ILLOP TP	N DEC W	EBELV 1		EASTDALE
May	**Max LMP**	**33.20**	**55.44**	**32.45**	**32.60**		**32.00**
	Bus No.	32603	32403	32651	32285		33315
	Bus Name	EGAL #1	PERKNSRD	SHRAM CY	ARCH TAP		CHATHAM
Jun	**Max LMP**	**43.74**	**91.97**	**40.05**	**38.19**		**40.20**
	Bus No.	32603	32403	32370	32675		33305
	Bus Name	EGAL #1	PERKNSRD	CATERPIL	BLUFF CY		INTERSTA
Jul	**Max LMP**	**71.65**	**86.09**	**49.79**	**48.06**		**84.08**
	Bus No.	32409	32403	32362	32664		33302
	Bus Name	ELKHART	PERKNSRD	N DEC W	EBELV 1		DALLMAN
Aug	**Max LMP**	**50.71**	**63.92**	**51.06**	**46.71**		**51.50**
	Bus No.	32409	32403	32370	32512		33305
	Bus Name	ELKHART	PERKNSRD	CATERPIL	HOOKDALE		INTERSTA
Sep	**Max LMP**	**39.92**	**48.13**	**35.99**	**38.48**		**36.66**
	Bus No.	32603	32403	32362	32675		33306
	Bus Name	EGAL #1	PERKNSRD	N DEC W	BLUFF CY		EASTDALE
Oct	**Max LMP**	**29.33**	**28.80**	**28.78**	**28.75**		**28.83**
	Bus No.	32603	32361	32304	32664		33306
	Bus Name	EGAL #1	ILLOP TP	AM STEEL	EBELV 1		EASTDALE
Nov	**Max LMP**	**38.44**	**30.52**	**30.55**	**30.49**		**30.60**
	Bus No.	32344	32361	32304	32664		33306
	Bus Name	RAAB RD	ILLOP TP	AM STEEL	EBELV 1		EASTDALE
Dec	**Max LMP**	**31.69**	**32.64**	**30.95**	**29.52**		**30.50**
	Bus No.	32615	32397	32370	32512		33305
	Bus Name	NORMAL E	MAHOMET	CATERPIL	HOOKDALE		INTERSTA

Color Coding

- LMP < 35 \$/MWh
- 35 \$/MWh ≤ LMP < 45 \$/MWh
- 45 \$/MWh ≤ LMP < 60 \$/MWh
- LMP ≥ 60 \$/MWh

Table 4.1.3-1 PC Case (Case Study Assumptions) – Monthly Maximum LMPs at Generator and Load Buses (Cont'd)

		Zone							
Month		AMRN-A	AMRN-B	AMRN-C	AMRN-D	AMRN-E	CILC	EEI	SIPC
Jan	Max LMP	30.12	29.36	28.71	29.88	30.86	29.95	29.54	73.43
	Bus No.	30018	30931	31503	31958	31383	33084	33484	33356
	Bus Name	AMOCO	LAWRNCVL	PICKVL 3	WATSEKA	ORDILL	TAZEWELL	JOPPA #4	2GALTN_S
Feb	Max LMP	29.65	31.60	30.23	39.37	32.40	62.46	30.79	59.86
	Bus No.	31115	30431	31501	31576	31383	33175	33484	33356
	Bus Name	MEPPEN	CRAB ORH	PICKVL 1	RANTOUL	ORDILL	MASON	JOPPA #4	2GALTN_S
Mar	Max LMP	29.84	29.63	29.40	29.71	29.67	77.70	29.66	30.05
	Bus No.	30018	31256	31501	31958	30004	33175	33484	33352
	Bus Name	AMOCO	MOWEAQUA	PICKVL 1	WATSEKA	ADM N AM	MASON	JOPPA #4	5RNSHW_S
Apr	Max LMP	29.67	29.15	29.06	48.60	29.19	29.54	28.99	29.51
	Bus No.	30018	31256	31501	31576	30004	33137	33485	33352
	Bus Name	AMOCO	MOWEAQUA	PICKVL 1	RANTOUL	ADM N AM	EDWARDS3	JOPPA #5	5RNSHW_S
May	Max LMP	33.04	33.39	32.21	48.14	33.32	43.63	32.62	69.43
	Bus No.	30018	31332	31501	31576	31383	33175	33484	33356
	Bus Name	AMOCO	NEWTON 1	PICKVL 1	RANTOUL	ORDILL	MASON	JOPPA #4	2GALTN_S
Jun	Max LMP	42.69	39.51	37.42	49.52	40.06	108.64	36.63	56.21
	Bus No.	30018	31256	31502	31576	30004	33175	33484	33356
	Bus Name	AMOCO	MOWEAQUA	PICKVL 2	RANTOUL	ADM N AM	MASON	JOPPA #4	2GALTN_S
Jul	Max LMP	76.37	51.06	47.34	49.87	49.60	386.30	46.63	67.90
	Bus No.	30022	30439	31501	31576	30004	33159	33484	33356
	Bus Name	AMOS AM	CROSSVL	PICKVL 1	RANTOUL	ADM N AM	KICKAPOO	JOPPA #4	2GALTN_S
Aug	Max LMP	51.88	49.77	45.61	48.78	51.09	62.19	45.38	79.02
	Bus No.	30789	31256	31501	31576	30004	33175	33484	33356
	Bus Name	IPAVA	MOWEAQUA	PICKVL 1	RANTOUL	ADM N AM	MASON	JOPPA #4	2GALTN_S
Sep	Max LMP	38.70	42.97	34.34	49.94	35.92	110.64	35.07	80.02
	Bus No.	30018	30073	31502	31576	30004	33175	33484	33356
	Bus Name	AMOCO	AVENA	PICKVL 2	RANTOUL	ADM N AM	MASON	JOPPA #4	2GALTN_S
Oct	Max LMP	29.18	28.71	28.72	28.69	28.79	62.56	28.70	39.67
	Bus No.	30018	31807	31501	30613	31211	33175	33484	33373
	Bus Name	AMOCO	TAYLR NE	PICKVL 1	GIBSN G2	MISS	MASON	JOPPA #4	2CMPBL_S
Nov	Max LMP	31.50	30.39	30.40	37.49	30.57	78.78	30.29	73.98
	Bus No.	30018	31807	31501	31576	31211	33175	33484	33373
	Bus Name	AMOCO	TAYLR NE	PICKVL 1	RANTOUL	MISS	MASON	JOPPA #4	2CMPBL_S
Dec	Max LMP	30.59	30.26	29.42	43.04	30.97	57.25	29.37	74.91
	Bus No.	31054	31256	31501	31576	30004	33175	33484	33373
	Bus Name	MASON CY	MOWEAQUA	PICKVL 1	RANTOUL	ADM N AM	MASON	JOPPA #4	2CMPBL_S

Color Coding

- LMP < 35 \$/MWh (blue)
- 35 \$/MWh ≤ LMP < 45 \$/MWh (yellow)
- 45 \$/MWh ≤ LMP < 60 \$/MWh (orange)
- LMP ≥ 60 \$/MWh (red)

Conservative Assumptions

Figures 4.1.3-4 and 4.1.3-5 show the results of using the Conservative Assumptions. These show the impact of transmission congestion in the Chicago area and the northern part of the State in July and August as in the Case Study Assumptions. For the other areas, the figures might be viewed as indicating that there is little effect of transmission congestion. However, as will be discussed later, the overall level of LMPs under Conservative Assumptions was significantly lower than under Case Study Assumptions. Thus, the color coding scheme used for the Case Study Assumptions (Figure 4.1.3-1) tends to understate the relative magnitude of variations in LMPs. Figure 4.1.3-6 shows a modified color coding scheme adjusted to reflect the lower overall prices under Conservative Assumptions. Figure 4.1.3-7 shows the annual LMP results with this modified scheme. These results show that the effects of transmission congestion under Conservative Assumptions are generally consistent with what was seen under Case Study Assumptions. The higher LMPs did not extend as far to the south and central parts of the State because of the increased generation available, but the rest of the State showed patterns very similar to those under the Case Study Assumptions.

4.1.4 Zonal Locational Marginal Prices

The previous section focused on the effects of transmission congestion on LMPs at specific buses in the network. This section focuses on the effects of the congestion on zonal LMPs, which have a direct relation to the prices consumers will pay for electricity.

LMPs were calculated for all buses in the network as part of the simulation. One set of buses had generators connected to them. The LMPs at these buses were used to determine the reimbursement to GenCos for the dispatch of their generators. Another set of buses had consumer load attached to them. These buses were grouped into the zones identified earlier. The load-weighted average LMPs for the buses in each zone were used to determine consumer payments. The LMPs for a third set of buses, which had neither generators nor loads attached, were included in the simulation calculations but are not displayed here, since they do not affect either GenCo revenues or consumer payments.

Case Study Assumptions

Figure 4.1.4-1 shows the monthly maximum and minimum values of the load-weighted LMP in each zone for the analysis year. It should be noted that the LMPs shown on the figure are load-weighted zonal averages, which are used to determine consumer charges. Individual nodes in the transmission network show even greater variation than what is shown as the zonal average.

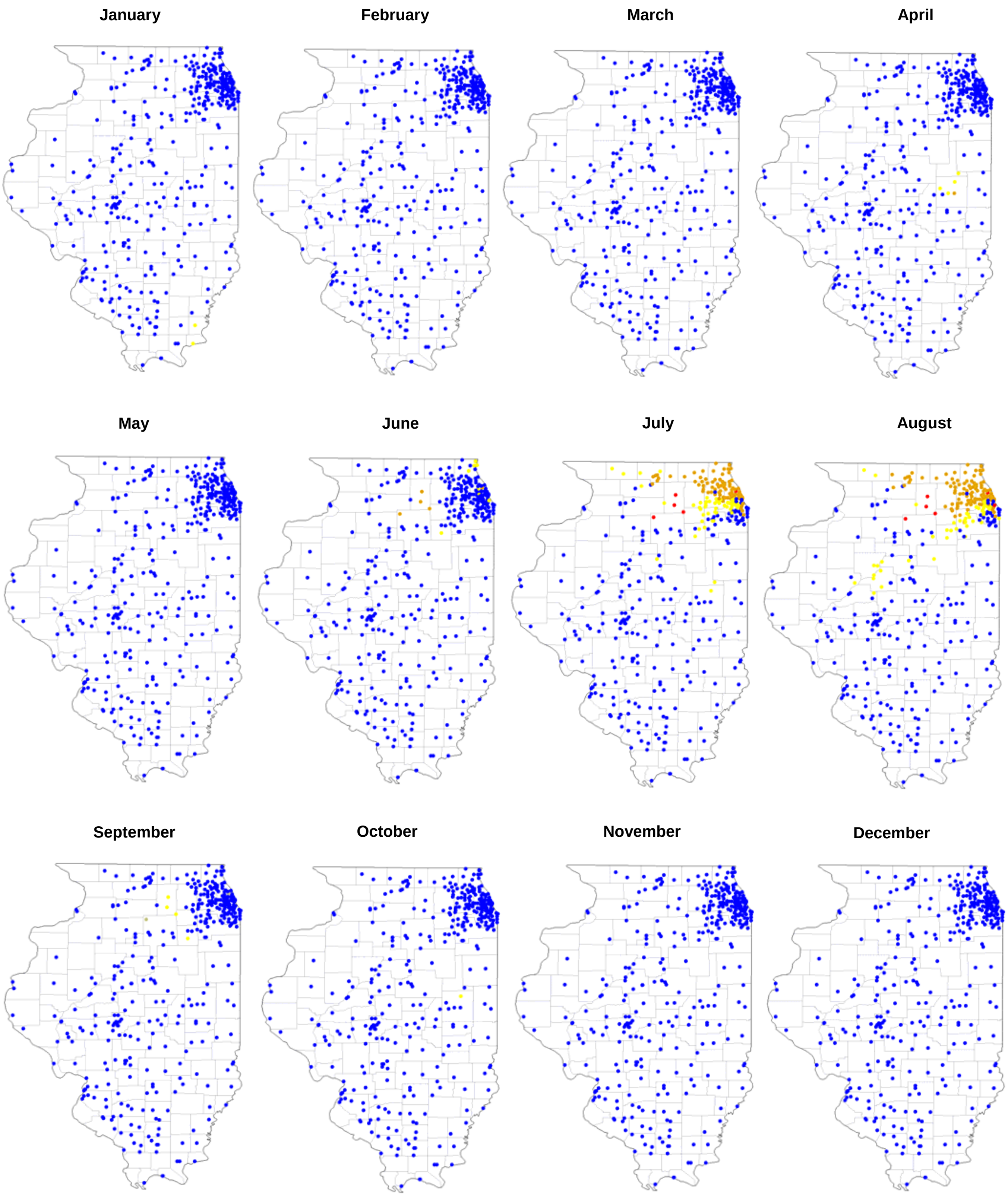


Figure 4.1.3-4 PC Case (Conservative Assumptions) Potential Load Pocket Identification Based on Monthly Data

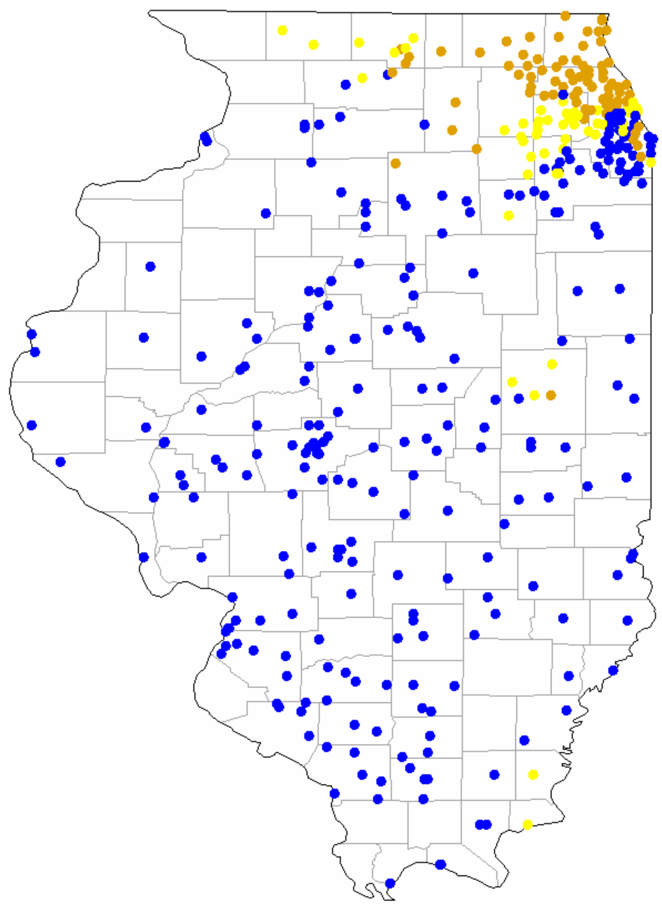


Figure 4.1.3-5 PC Case (Conservative Assumptions) Potential Load Pocket Identification Based on Annual Data

Portion of Time LMP Is Exceeded							
			LMP				
(Fraction)	(Approximate Hours per Month)	(Hours per Year)	20	25	30	50	
.01	8	88					
.05	40	438					
.10	80	876					
>.10	>80	>876					

Figure 4.1.3-6 Criteria Used for Coding LMPs – Modified for Conservative Assumptions

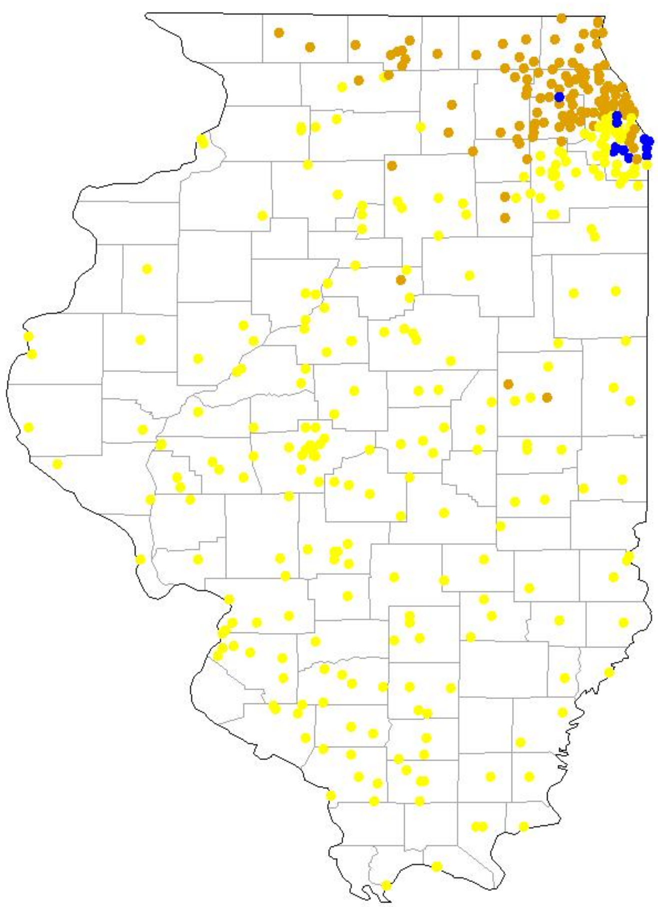


Figure 4.1.3-7 PC Case (Conservative Assumptions) Potential Load Pocket Identification Based on Annual Data – Modified Color Code Categories

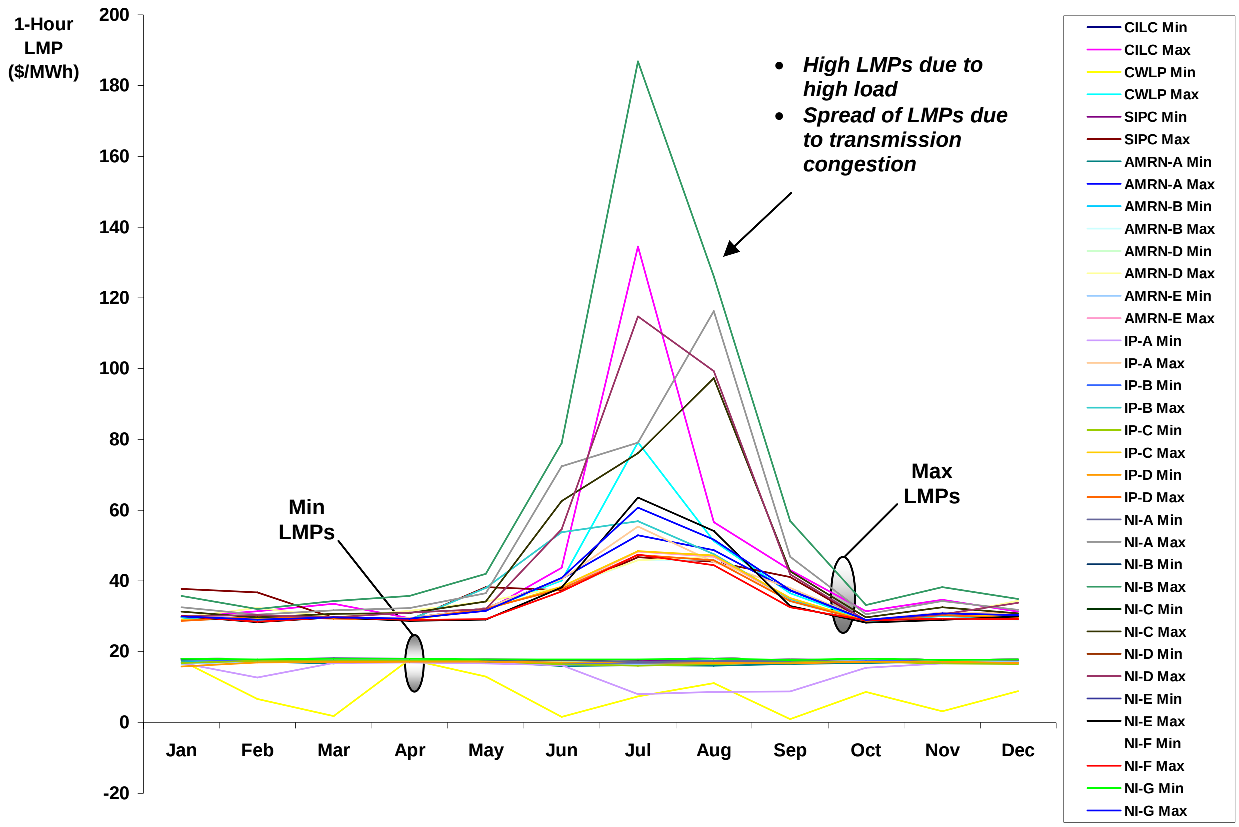


Figure 4.1.4-1 PC Case (Case Study Assumptions) Variation in Monthly Maximum and Minimum Load-Weighted Zonal LMPs

The variation in the zonal LMPs shows several distinct features:

LMPs increased in high load periods. As seen in the figure, LMPs increased across the State during high-load periods as more expensive generators were brought on-line to meet the load. This is seen as an increase in the maximum LMP in all zones in the June, July, August, and September periods. Even in the PC case, where there was no attempt to exercise market power by any company, the zonal LMPs were almost 10 times higher in high-load periods than they were during low-load periods.

LMPs varied across zones as a result of transmission congestion. During high load periods, the LMPs spread across the zones in the State. Were the LMPs to rise and fall together at the same rate, the indication would have been that there was no significant transmission congestion as all areas would have had nearly the same price at all times. However, as was described earlier, there were a number of points in the transmission system where equipment was loaded to capacity and constrained the movement of power. This caused the LMPs to vary across the zones. This was most evident in the June, July, August, September periods when the spread in the LMPs across the zones became significant. The transmission congestion described earlier forced the price higher in some areas than in others. The variation across the State results in LMPs in the northern part of the State reaching almost five times higher than elsewhere.

Transmission congestion created higher LMPs even during non-peak hours. The figure shows several times where the LMPs became higher or lower across the State even in the lower-load months. This was the result of the scheduled and forced outage scenario used in the PC case using Case Study Assumptions, where some generators in these zones were assumed to be out of service. In these areas, this loss of generation capacity could not be readily made up by other, less expensive units due to transmission limits. More expensive units had to be brought on-line to meet the load.

To gain a more detailed look at the occurrence of higher LMPs, Table 4.1.4-1 shows the statistical variation in the zonal LMPs, and Figure 4.1.4-2 shows a frequency distribution of load-weighted LMPs in each zone. In most areas of the State, the LMPs were in the range of 20-28 $/MWh for 90% of the time over the course of a year. As shown on the expanded scale, about 5% of the time the higher loads caused LMPs to rise together due to a small amount of transmission congestion. For about 1% of the time (about 88 hours per year), the increasing transmission congestion caused LMPs to rise considerably and to vary significantly from zone to zone. LMPs across the State rose above 100 $/MWh, as shown in the table. This distribution shows that, in general, the hours where high LMPs would be experienced are relatively few under PC case conditions; however, during these hours, the LMPs can be significantly higher and can show wide variability across the State.

Table 4.1.4-1 PC Case (Case Study Assumptions) – Statistical Variation in LMPs

	Load-Weighted Locational Marginal Price ($/MWh)		
Zone	**Mean**	**Median**	**Maximum**
NI-A	21.7	19.0	116.3
NI-B	22.4	19.2	186.9
NI-C	21.6	19.2	97.4
NI-D	21.5	19.2	114.8
NI-E	21.0	19.2	63.6
NI-F	21.0	19.3	47.5
NI-G	21.2	19.1	60.7
IP-A	20.0	18.4	55.5
IP-B	20.7	18.8	56.9
IP-C	20.5	18.6	48.4
IP-D	20.4	18.6	47.4
AMRN-A	20.6	18.7	52.9
AMRN-B	20.5	18.7	46.0
AMRN-D	20.7	18.8	46.9
AMRN-E	20.5	18.6	48.3
CILC	21.3	19.2	134.5
SIPC	20.8	18.8	46.7
CWLP	20.3	18.4	79.2

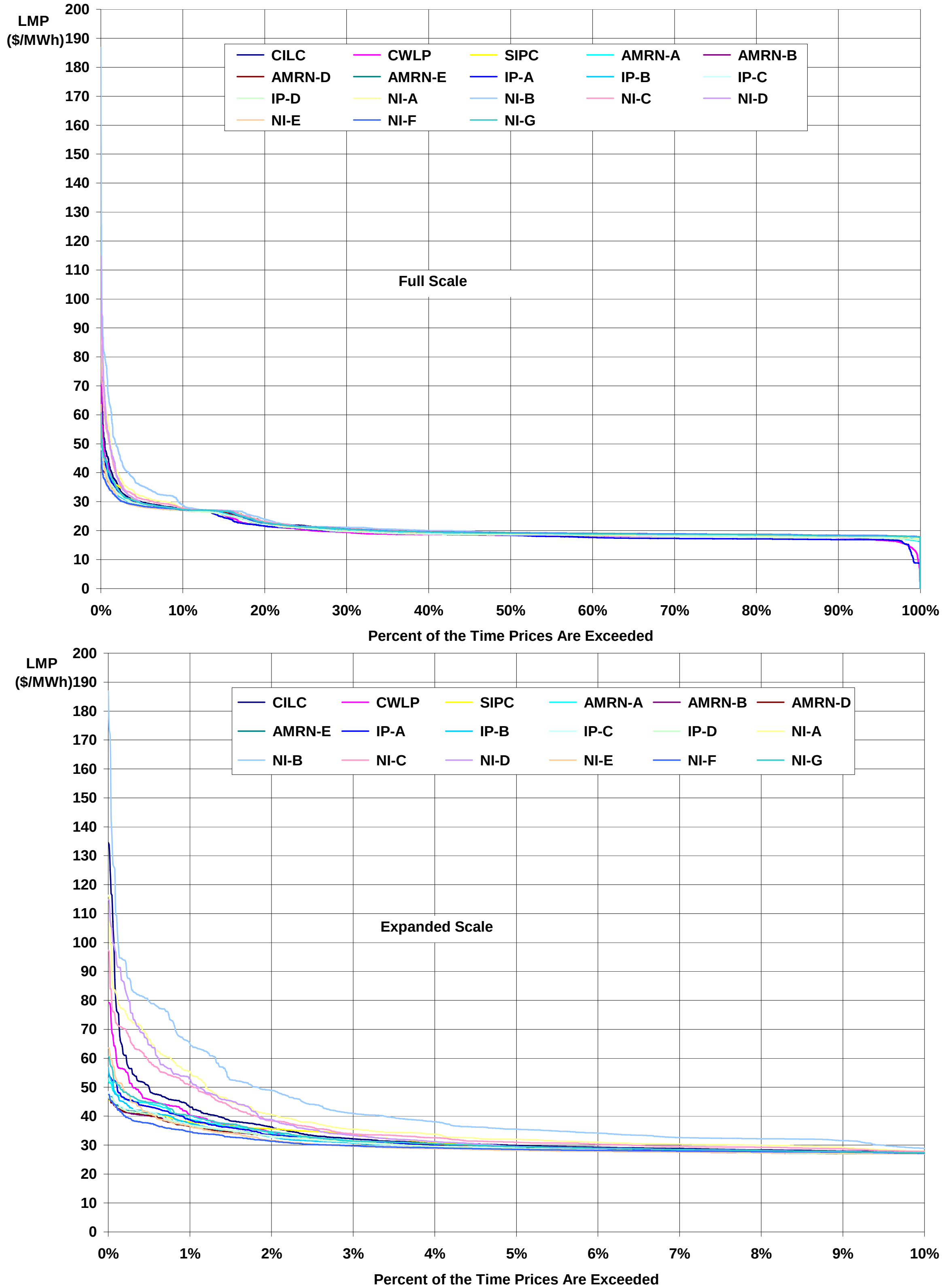


Figure 4.1.4-2 PC Case (Case Study Assumptions) Frequency Distribution of Load-Weighted LMPs by Zone

Figure 4.1.4-3 shows the hourly load-weighted average LMPs by zone for two months of the analysis year: April, which was a low-load month, and July, which was a high-load month. As a point of reference, the statewide load for each month is also shown. The results show the variation in LMP that follow hourly and weekly variations in load.

During low-load periods, the LMPs were relatively uniform throughout the State. The LMPs in northern Illinois average about 10-15% higher. Under low-load conditions, the transmission congestion (i.e., caused by components operated at their capacity limits) was not a major issue. Even with the forced outages and the congestion in the PC case, there was ample generation and transmission capacity to keep LMPs relatively low and geographically constant. During high-load periods, the LMPs increased in both magnitude and variability.

The transmission congestion results discussed in the previous section can be compared with the LMP results, and the following observations can be made:

- The NI zones all showed the effects of transmission congestion with LMPs that were measurably higher than elsewhere in the State. It can be seen that the effects of the congestion extended well beyond the immediate vicinity of the heavily loaded equipment. For example, in the area north of Chicago (i.e., the NI-B zone) there were only a few system components loaded to capacity for a few hours per year. Nevertheless, it had the highest mean value of LMP and the highest maximum value. Congestion in the adjacent NI-A zone (northwest portion of the State) and NI-D zone (Chicago) affected prices in this zone.

- The IP, AMRN, and SIPC zones had the lowest LMPs in the State. In the case of AMRN, this was true even though some equipment was consistently heavily loaded (e.g., Holland transformer, Gibson 138-kV line, Pickneyville transformers). Since the congestion had a smaller effect on prices, these zones were less likely to be impacted by market power effects, since there were other relatively low-cost generation options that could supply the load.

- The CILC zone had high LMPs resulting from congestion on the Holland-Mason-Tazewell lines. The LMPs were in the same range as the NI zones. This zone could be open to the exercise of market power because of these limits and their impact on prices.

- The CWLP zone showed some congestion effects that were intermediate to the other zones and for fewer hours.

- The NI and CILC zones could be considered the most vulnerable to the exercise of market power due to transmission congestion.

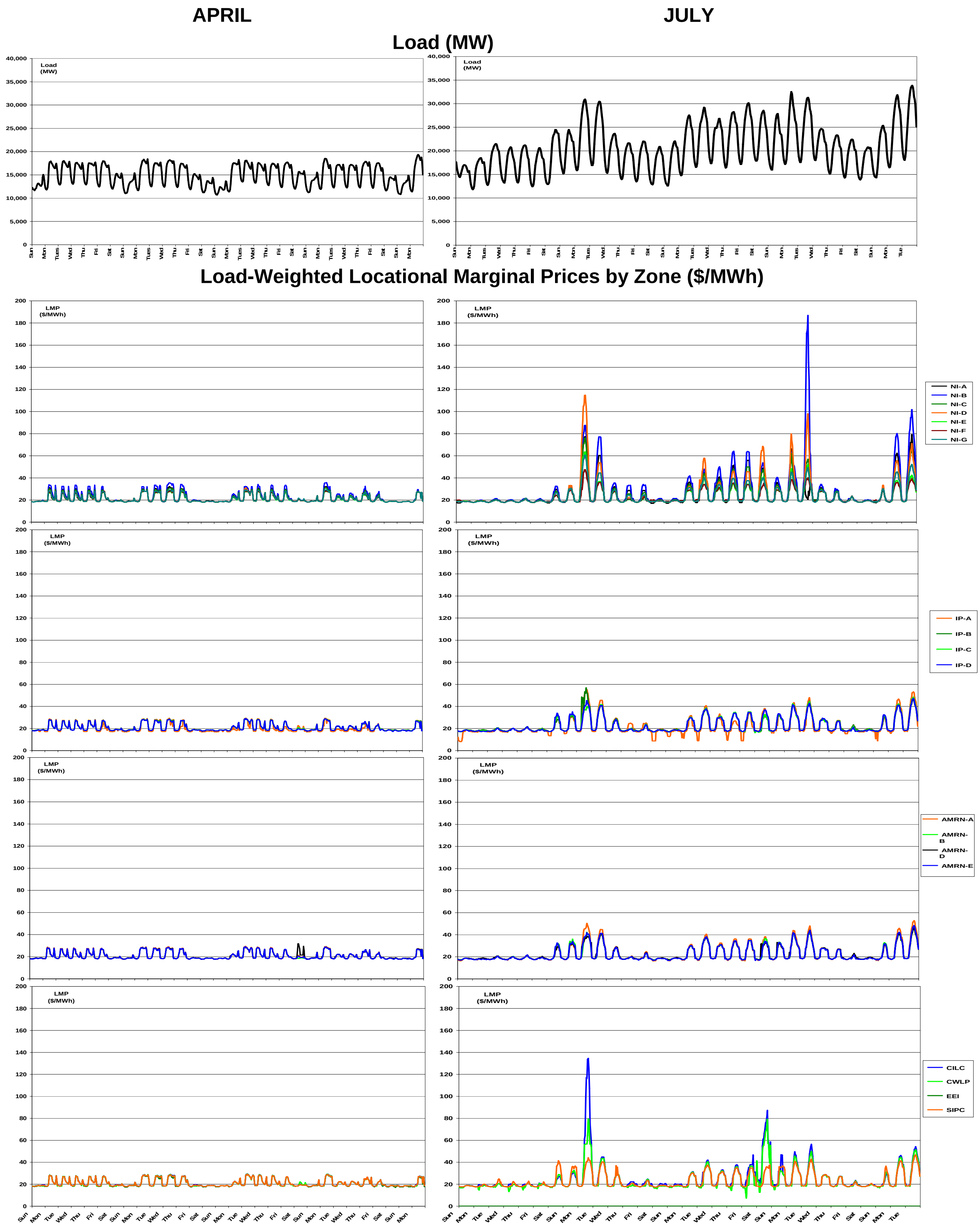


Figure 4.1.4-3 PC Case (Case Study Assumptions) Load-Weighted Zone LMPs for April and July

Conservative Assumptions

Figures 4.1.4-4 and 4.1.4-5 show the effect on LMPs of using the Conservative Assumptions. The elimination of FOM from production cost, the elimination of forced outages, and the dropping of the company-level unit commitment process resulted in the LMPs statewide being measurably lower under these assumptions than under the Case Study Assumptions. Under Case Study Assumptions, the LMPs tended to average about 20-28 $/MWh during most hours and peak at about 190 $/MWh. Under Conservative Assumptions, they averaged about 13-16 $/MWh for most hours with a peak at 80 $/MWh. This result is expected, since the Conservative Assumptions make more capacity available and that capacity is bid into the market at lower prices (i.e., without the FOM added).

Despite these lower prices, the pattern of increasing LMPs during peak months and an increase in the spread of prices due to transmission congestion remained, even under Conservative Assumptions. Having the additional generation capacity available using these assumptions did not completely eliminate the effects of transmission congestion. Prices in the northern part of the State were still more than double those elsewhere due to this congestion.

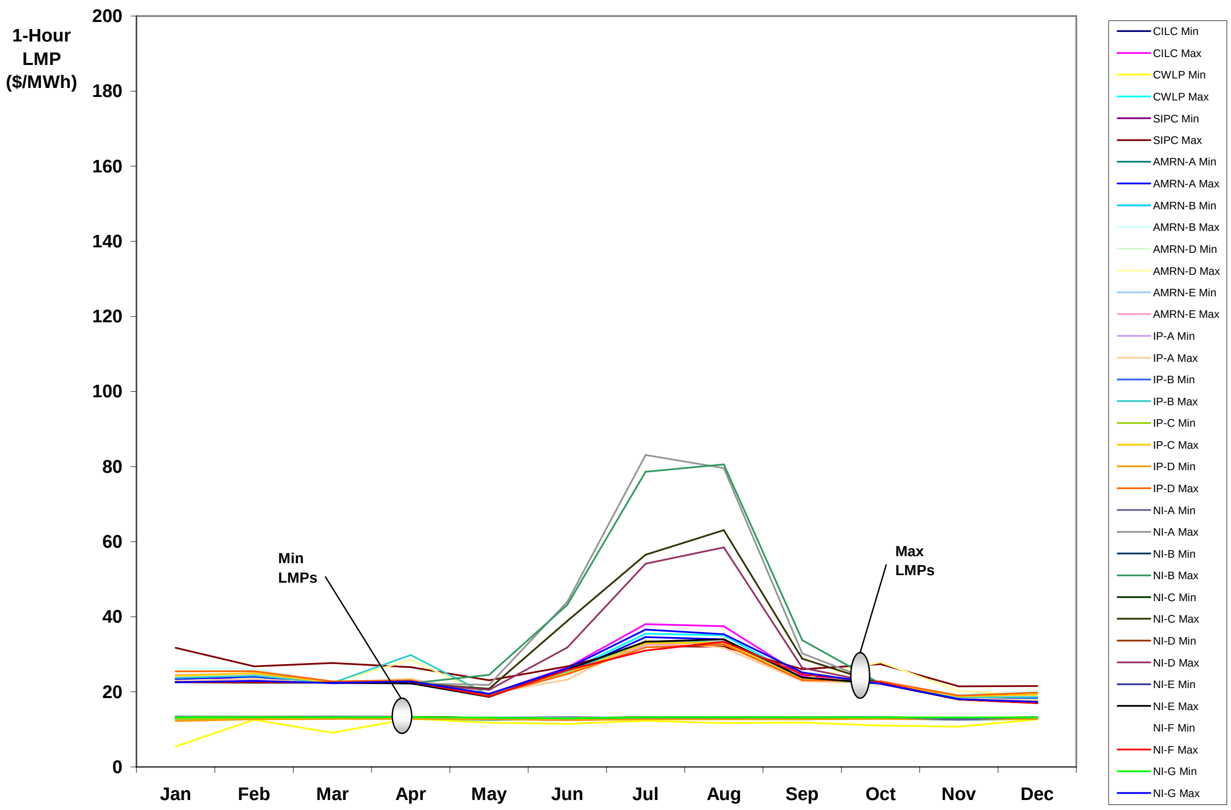
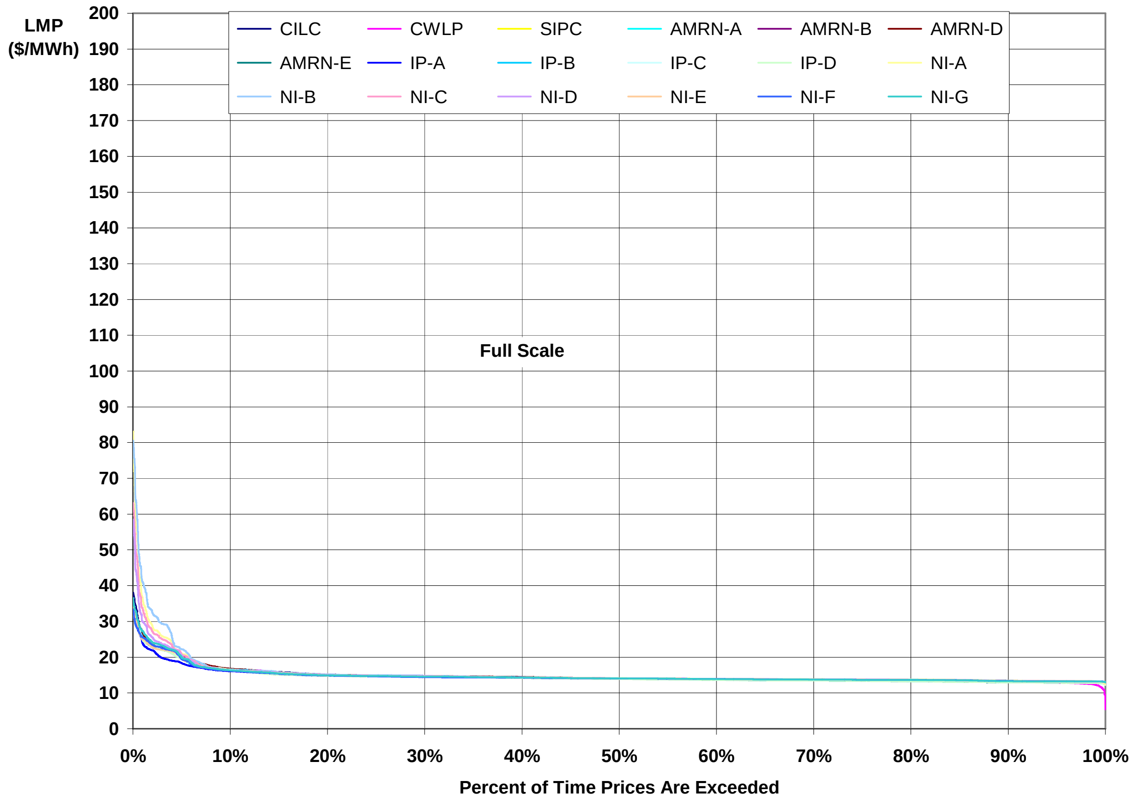


Figure 4.1.4-4 PC Case (Conservative Assumptions) Variation in Monthly Maximum and Minimum Load-Weighted LMPs



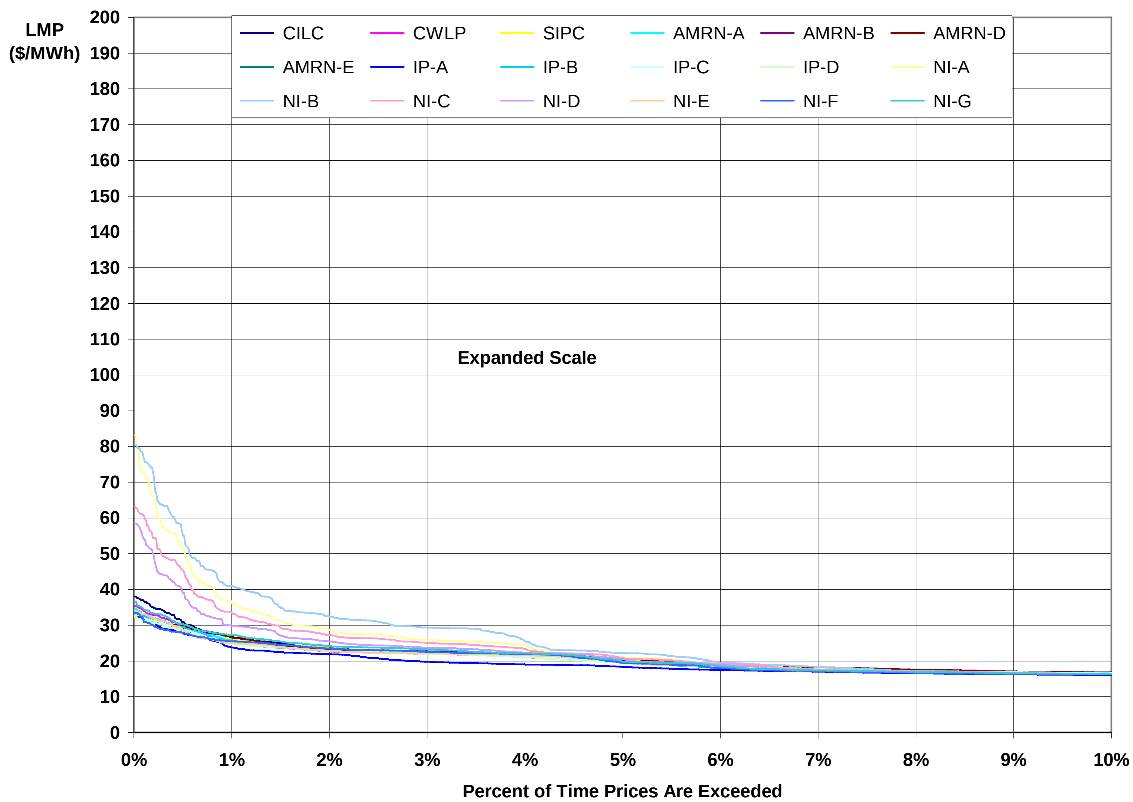


Figure 4.1.4-5 PC Case (Conservative Assumptions) Frequency Distribution of Load-Weighted LMPs by Zone

4.1.5 Generation Dispatch

Case Study Assumptions

Figure 4.1.5-1 shows the simulation results for the dispatching of generation to meet load for each hour of the year. The figure shows the generation from in-state sources only. Throughout the year there was more than enough generation to meet the in-state load, as well as enough to make the State a net exporter under PC case conditions using the Case Study Assumptions. At any hour and at any of the interties with surrounding systems, the power flow may be either into or out of the State, as Illinois companies will import power if it is economically competitive. On an annual basis, the State exported about 6% of its electricity generation, which is somewhat lower than historical values (19% in 2001, as discussed earlier). The GenCos in the State remained competitive with out-of-state suppliers.

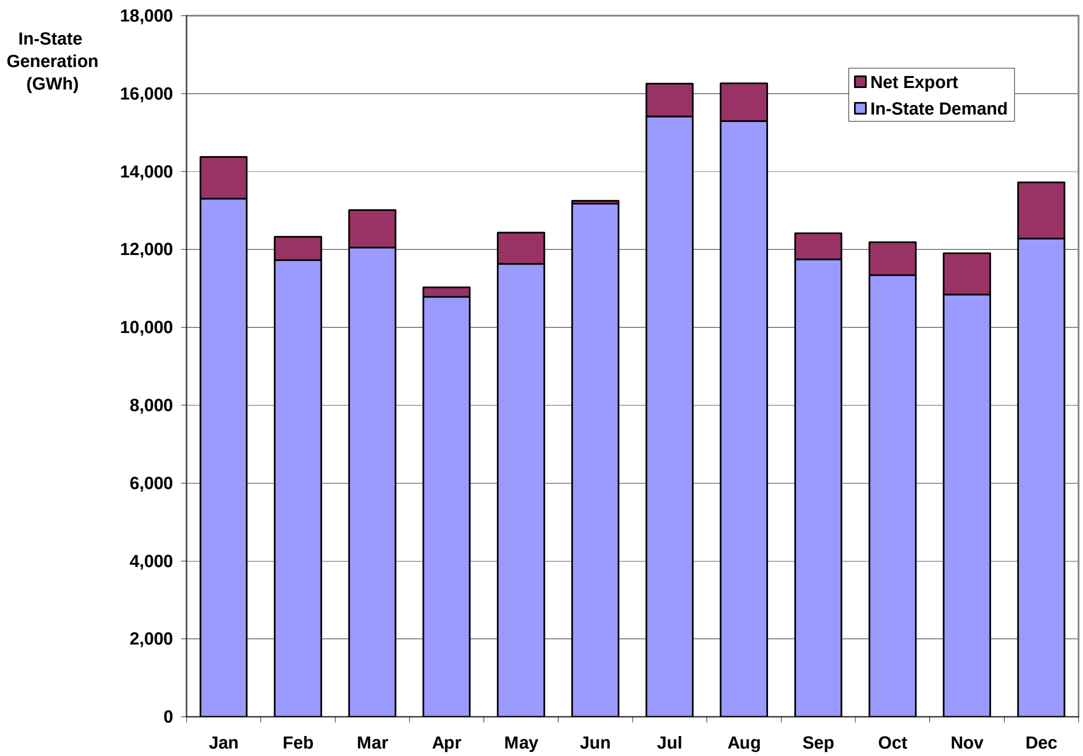


Figure 4.1.5-1 PC Case (Case Study Assumptions) In-State Generation and Exports

Figure 4.1.5-2 shows the distribution of the generation throughout the State over the year. In the simulation about 60% of the State's generation came from facilities located in the northern part of the State. Figure 4.1.5-3 shows the generation by fuel type throughout the year. Nuclear and coal units dominated the supply in the State. Only about 2% was from natural gas or other sources. This is especially significant since much of the new generation capacity that has been installed in the State in the last decade has been natural-gas-fired. All of the new capacity assumed to be installed up through the analysis year was also gas-fired. The results indicate only a limited use of the gas-fired units, even with the relatively low natural gas prices used for the

PC case analysis. This pattern is consistent with historical data. The Energy Information Administration reported that in 2001 only 1.1% of the electricity generated in the State was from natural gas.[15] The large increase in gas-fired capacity did not alter that under PC case conditions.

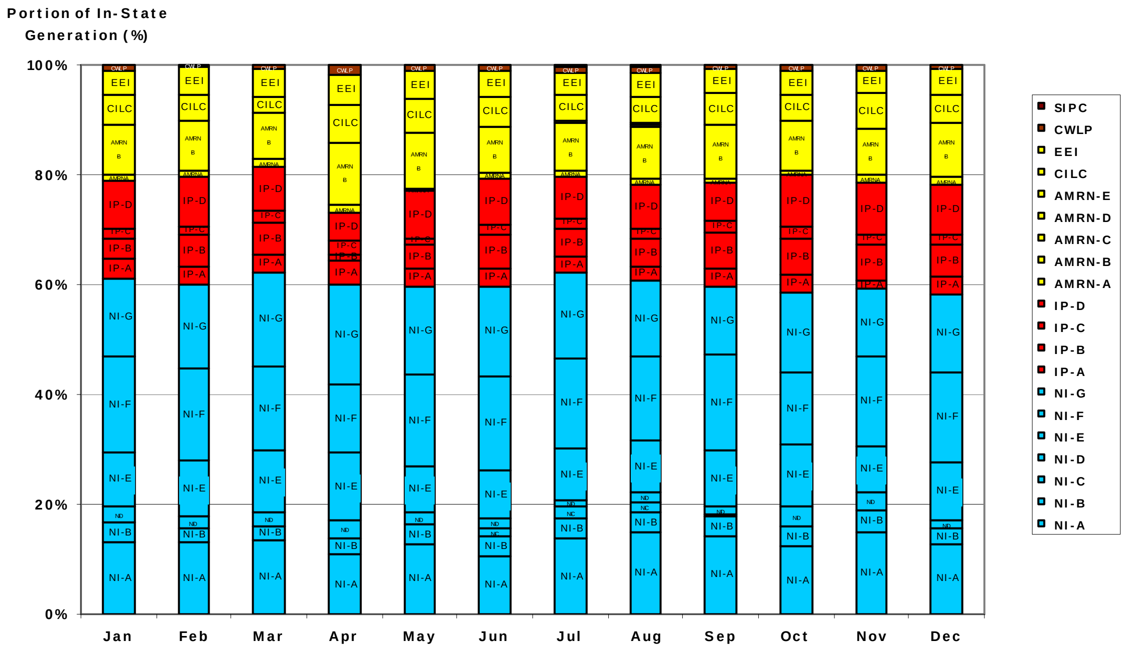


Figure 4.1.5-2 PC Case (Case Study Assumptions) In-State Generation by Zone

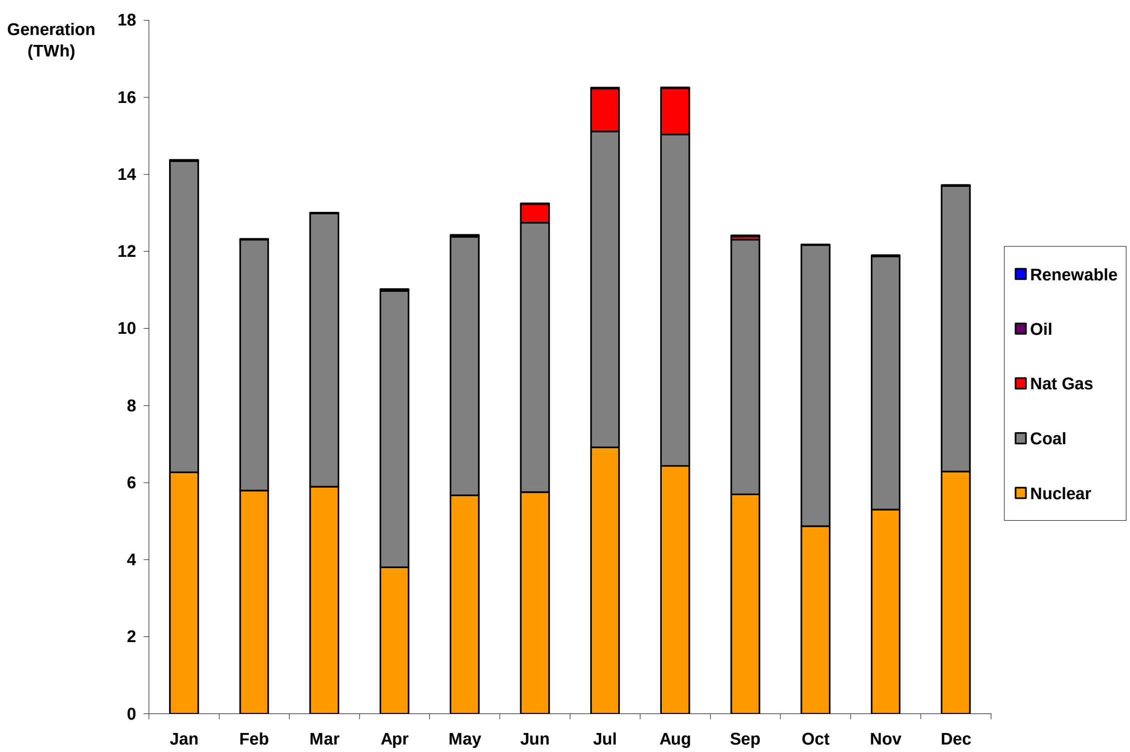


Figure 4.1.5-3 PC Case (Case Study Assumptions) In-State Generation by Fuel Type

[15] See http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls.

Conservative Assumptions

Figure 4.1.5-4 shows the results of the PC case when the Conservative Assumptions were used. While the general pattern of in-state generation is similar to that under the Case Study Assumptions, the level of generation by in-state GenCos was reduced and the State was a net importer of electricity. Under these assumptions, the State imported about 15% of its electricity on an annual basis.

Under Conservative Assumptions, the exclusion of forced outages made more generation capacity available from both in-state and out-of-state suppliers. Likewise, the elimination of the FOM as part of the production cost, lowered the cost of both in-state and out-of-state suppliers. The results show that out-of-state suppliers were more economically competitive under the Conservative Assumptions and captured a higher market share of the generation. As noted earlier, the State has historically been a net exporter of electricity. The results based on using the Conservative Assumptions deviate from this historical pattern.

Figure 4.1.5-5 shows the generation by fuel type for the PC case using the Conservative Assumptions. The pattern is similar to that under the Case Study Assumptions; that is, nuclear and coal dominated the generation, with natural gas providing only a small portion during peak months. Gas provided only about 1% of the annual generation under these assumptions.

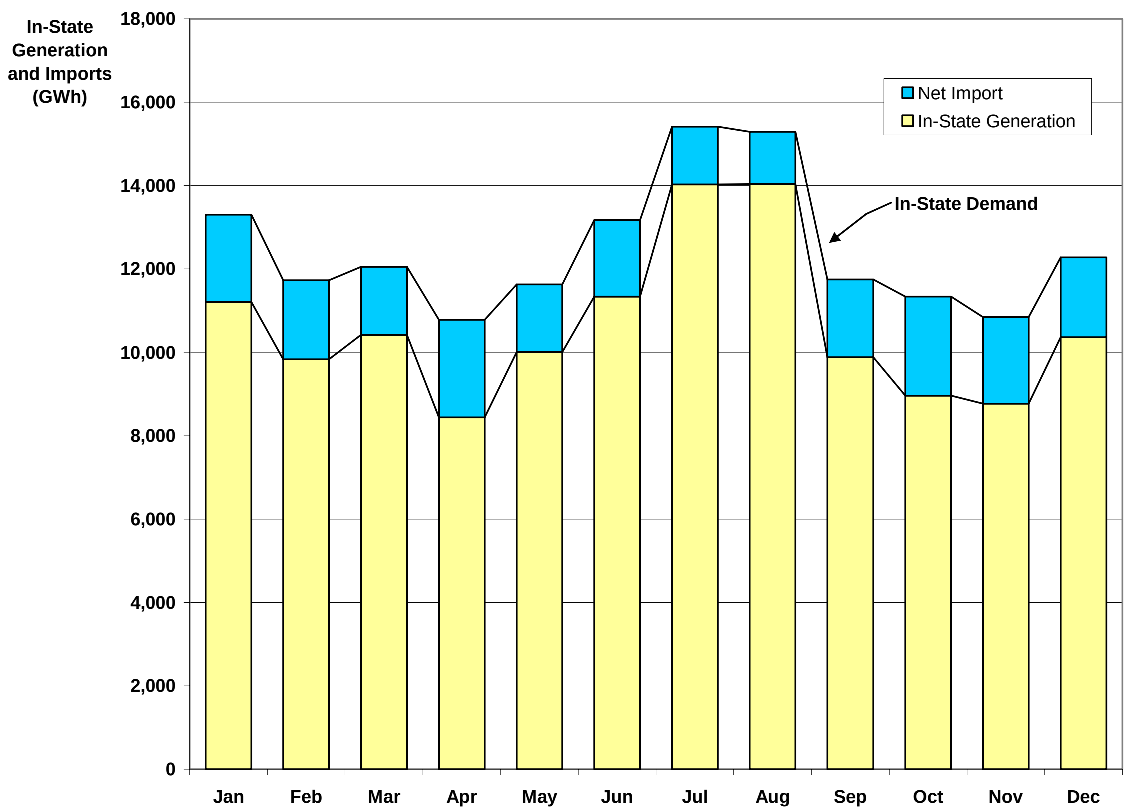


Figure 4.1.5.-4 PC Case (Conservative Assumptions) In-State Generation and Imports

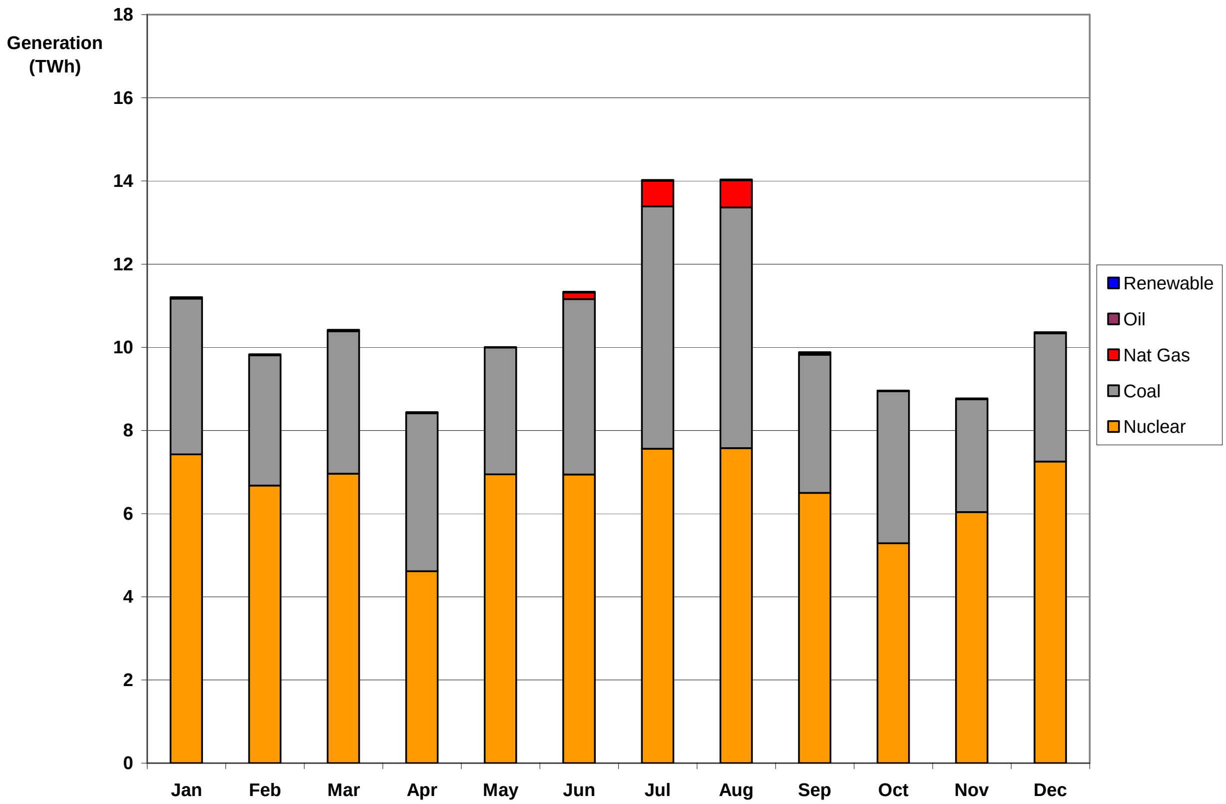


Figure 4.1.5-5 PC Case (Conservative Assumptions) In-State Generation by Fuel Type

4.1.6 Agent Results

The PC case results for each of the agents that are participants in the electricity market are discussed in the next sections.

Generation Companies – Case Study Assumptions

Figure 4.1.6.-1 shows the monthly generation in the analysis year for each company operating in Illinois. Figure 4.1.6-2 shows the market share of each company based on annual generation. Table 4.1.6-1 shows the HHI computed on this same basis. The figures and the table illustrate the concentration in the State generation market under PC case conditions. Exelon Nuclear captured 43% of the annual generation in the State. Four other companies, Ameren, Dominion Energy, Dynergy Midwest Generation, and Midwest Generation LLC, accounted for most of the balance. The five companies together accounted for about 97% of the State generation in the PC case.

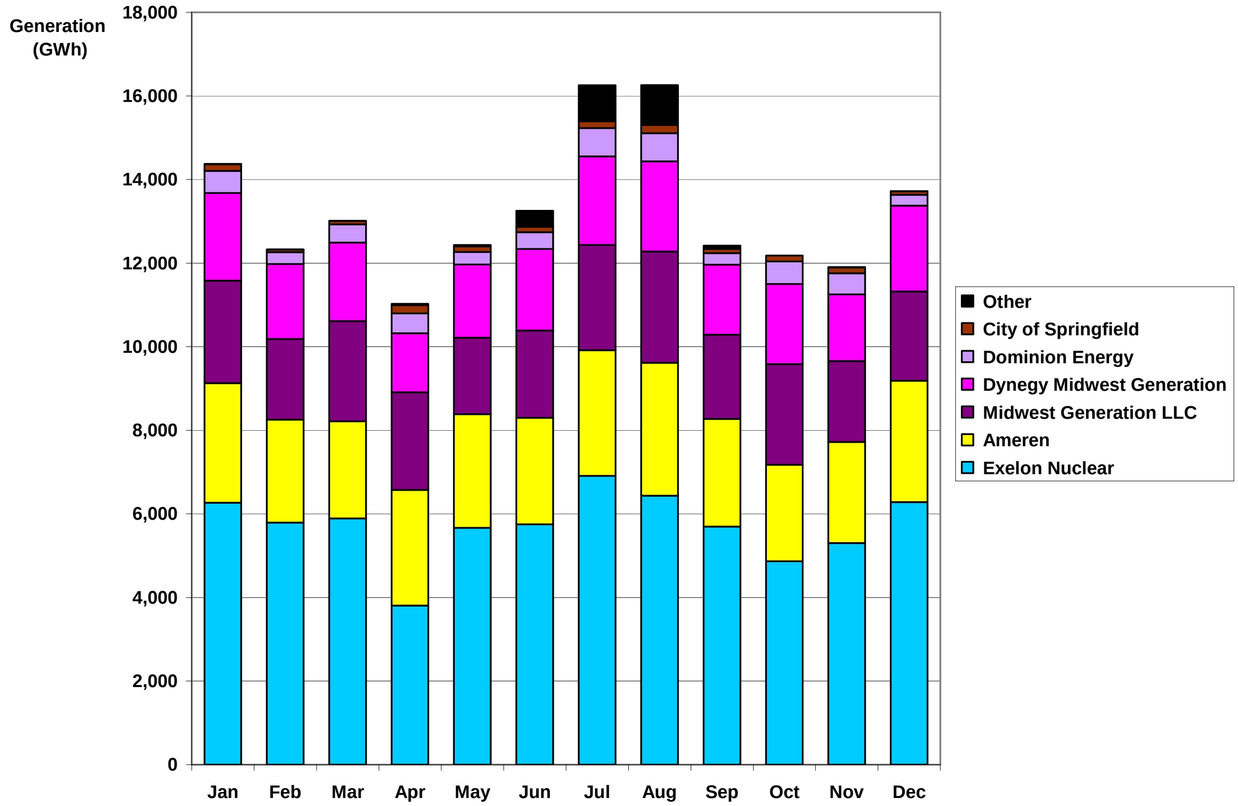


Figure 4.1.6-1 PC Case (Case Study Assumptions) Generation by Company

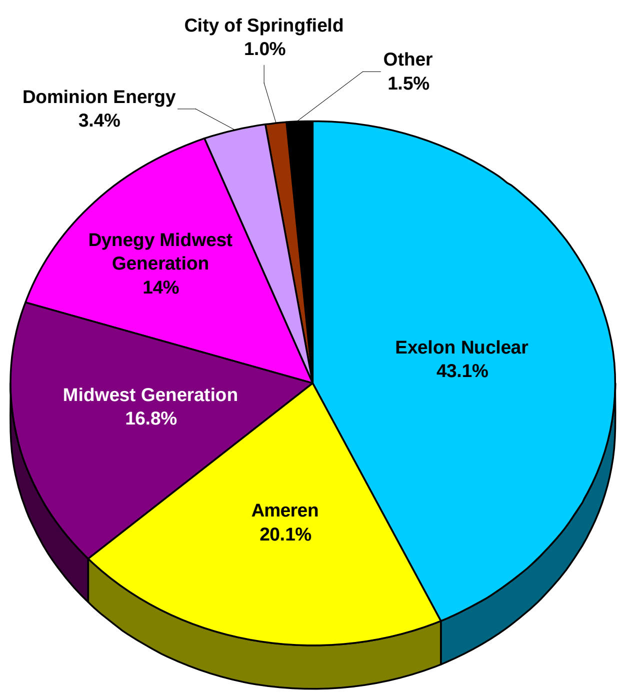


Figure 4.1.6-2 PC Case (Case Study Assumptions) GenCo Market Share of Annual GWh of Generation

Table 4.1.6-1 PC Case (Case Study Assumptions) Generation Company Market Share

	Annual Generation (GWh)						
Generation Company	**Nuclear**	**Coal**	**Natural Gas**	**Oil**	**Other**	**Total**	**Market Share of Annual GWh of Generation**
GenCo – Exelon Nuclear	66,313					66,313	41.7%
GenCo – Ameren		31,567	255	1	244	32,066	20.1%
GenCo – Midwest Generation LLC		26,665	23	5		26,693	16.8%
GenCo – Dynegy Midwest Generation		22,360				22,402	14.1%
GenCo – Dominion Energy		4,955	414			5,369	3.4%
GenCo – Exelon Nuc/Midamer Energy	2,362					2,362	1.5%
GenCo – City of Springfield		1,581	2			1,583	1.0%
GenCo – NRG Energy			741			741	0.5%
GenCo – Reliant Energy			379			379	0.2%
GenCo – Calpine			290			290	0.2%
GenCo – Constellation Power			191			191	0.1%
GenCo – Duke Energy			174			174	0.1%
GenCo – Southern Illinois Power Coop.		110	28			138	0.1%
GenCo – Dynegy/NRG Energy			116			116	0.1%
GenCo – MidAmerican Energy Co.			112			112	0.1%
GenCo – Allegheny Power			80			80	0.1%
GenCo – Aquila Energy			52			52	0.0%
GenCo – PPL			47			47	0.0%
GenCo – Power Energy Partners			30			30	0.0%
GenCo – Soyland Power Coop Inc.		6	12			18	0.0%
GenCo – Calumet Energy LLC							0.0%
GenCo – Southwestern Electric Coop.							0.0%
Total	**68,675**	**87,243**	**2,986**	**6**	**244**	**159,154**	**100.0%**
HHI – based on total generation							**2,636**
HHI – based on coal-fired generation							**2,936**
HHI – based on natural-gas-fired generation							**1,257**

In evaluating the market power potential of the generation companies, some of the various indices mentioned earlier were considered. The HHI base on total generation was in excess of 2,600, which indicates a highly concentrated market for electricity generation. The FERC 20% benchmark test shows that both Exelon Nuclear and Ameren had the 20% market share, with Midwest Generation and Dynegy a little lower. Applying the FERC residual supply index approach, the State's peak load could not be met if all of the capacity from any of the top market share holders were not available. Thus, by several measures, the generation market in the State can be considered to be concentrated.

Looking at the HHI based on fuel type shows that the coal-fired generation was highly concentrated. Three companies, Ameren, Midwest Generation, and Dynegy, accounted for 92% of the generation produced by coal plants. For nuclear generation, the market belonged entirely to Exelon Nuclear and its joint ownership venture with MidAmerican. For natural gas units, the HHI indicated a moderately concentrated market with the annual generation spread among a number of companies. The implication is that all of the State's low-cost generation in the form of nuclear and coal units, which had dominant market share when production cost bidding was used, is concentrated in the ownership of a few companies. Even the higher-cost natural gas units showed a moderate degree of concentration in such a market.

It should be recalled that in this study the generation market, in which the GenCos competed and in which the various indices of market power were computed, includes the entire State of Illinois. All suppliers could offer to meet any demand in the State with the choice subject to the price competitiveness and transmission limits. Out-of-state markets (both load and supply) were represented in simplified form, but out-of-state suppliers competed on the same basis as in-state suppliers, subject to the limits of the transmission system interties. On this basis, the determination of a statewide value of the various market power indices (e.g., HHI, 20% benchmark, residual supply index) is the clearest indicator of market concentration.

Figure 4.1.6-3 shows the company annual generation normalized to the installed capacity; that is, the annual generation was computed as a fraction of the total possible generation if all the company's units were operated at full capacity. Note that the annual generation includes time when units are out of service for planned, maintenance, and forced outages. Only the Exelon, Dynegy, and Ameren units were operated at high capacity factors in the PC case using Case Study Assumptions. Some other companies' units were operated in the range of 15-30% capacity factors while many of the others were at less than 10%. Company units that were operated at low capacity factors, or were not operated at all in the PC case, either were utilized only for peaking purpose for a limited number of hours, were not economically competitive in the market, or were located on the transmission grid where they could not be dispatched at a greater rate due to transmission limits.

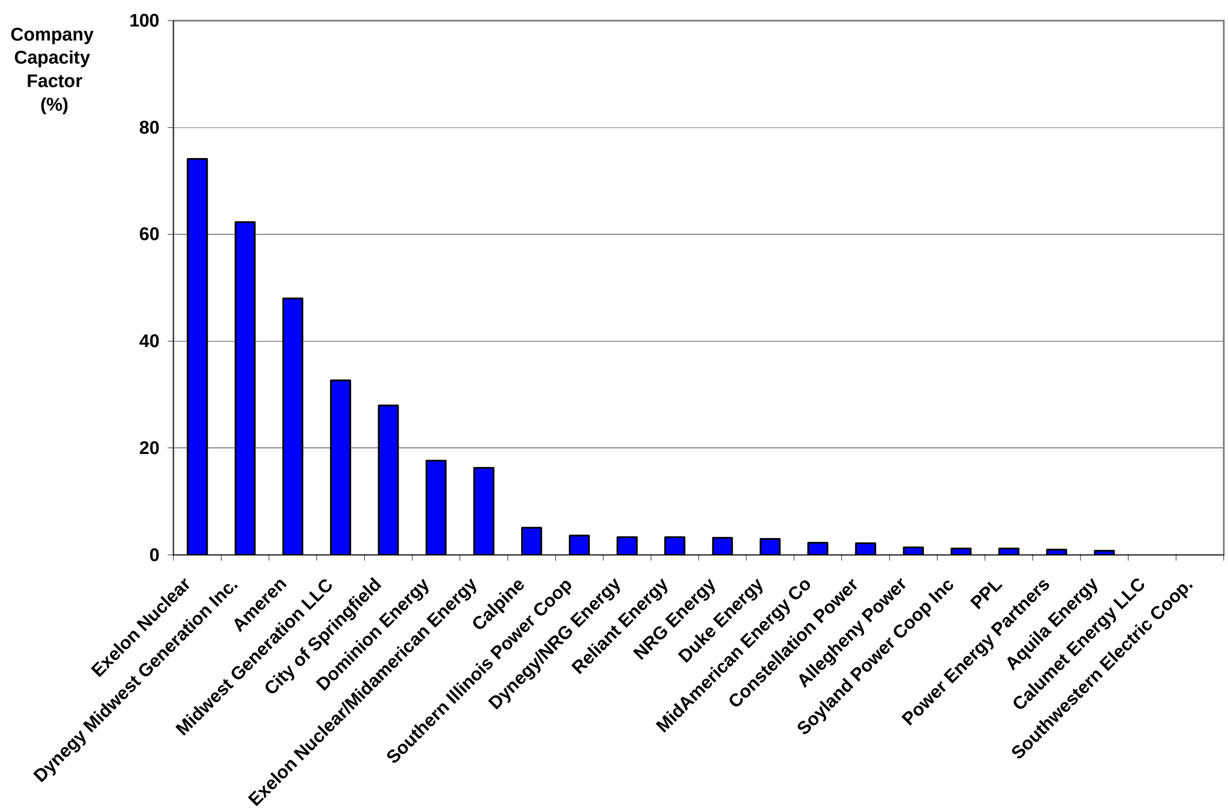


Figure 4.1.6-3 PC Case (Case Study Assumptions) Generation Company Capacity Factors

Figure 4.1.6-4 shows the operating revenues and costs for each of the GenCos. Table 4.1.6-2 shows the annual operating profit margin. Note that this profit margin is not a complete financial accounting of each company. Revenues are only from the sale of electricity and do not consider other revenue streams such as fees for engineering services provided to other companies; sales of equipment, facilities, or real estate; or returns on other company investments. Costs include only production costs. The cost of amortizing capital investments is not included here. Therefore, the profit margins shown in the table must be viewed as strictly based on generator operating parameters. Table 4.1.6-3 shows the company annual average revenue and cost rates per MWh generated. These rates were calculated based on the total generation that each company provided in the PC case. The very large values of cost rates and large negative values of operating profit rates result from the very small amount of generation that each of these companies provided in the PC case.

Table 4.1.6-4 shows the cost by type of unit. The nuclear and coal units were significantly cheaper by the production cost measure, with or without the inclusion of the fixed operating and maintenance costs. The natural gas units had high production costs per MWh generated, since their capacity factors were low and their fixed operation and maintenance costs were spread over a smaller level of generation.

Under PC case conditions, the companies with significant market share showed an operating profit, some very substantial. All of the others showed operating losses. For some of the companies showing losses, their generators were not being dispatched under PC case market conditions. Their generators were too expensive to compete effectively, even when all companies were bidding only production costs into the electricity market. For other companies, even if their generators were being dispatched, their utilization rates were too low for them to recover their fixed operating costs. In either case, this is not a sustainable position for these companies over an extended period of time. It can be noted that many of the companies that were identified as planning the construction of new generating capacity do not show operating profitability in the PC case.

If the amortization of capital costs were included in the cost figures, the profit margins would be different for each company. Those with large margins might not, in fact, have seen these large profits when capital cost amortization was included. Those with smaller margins might actually have been unprofitable. Those that already were experiencing negative margins would have been in an even weaker situation. Data on capital amortization and other debt service requirements of the GenCos were not available for this study.

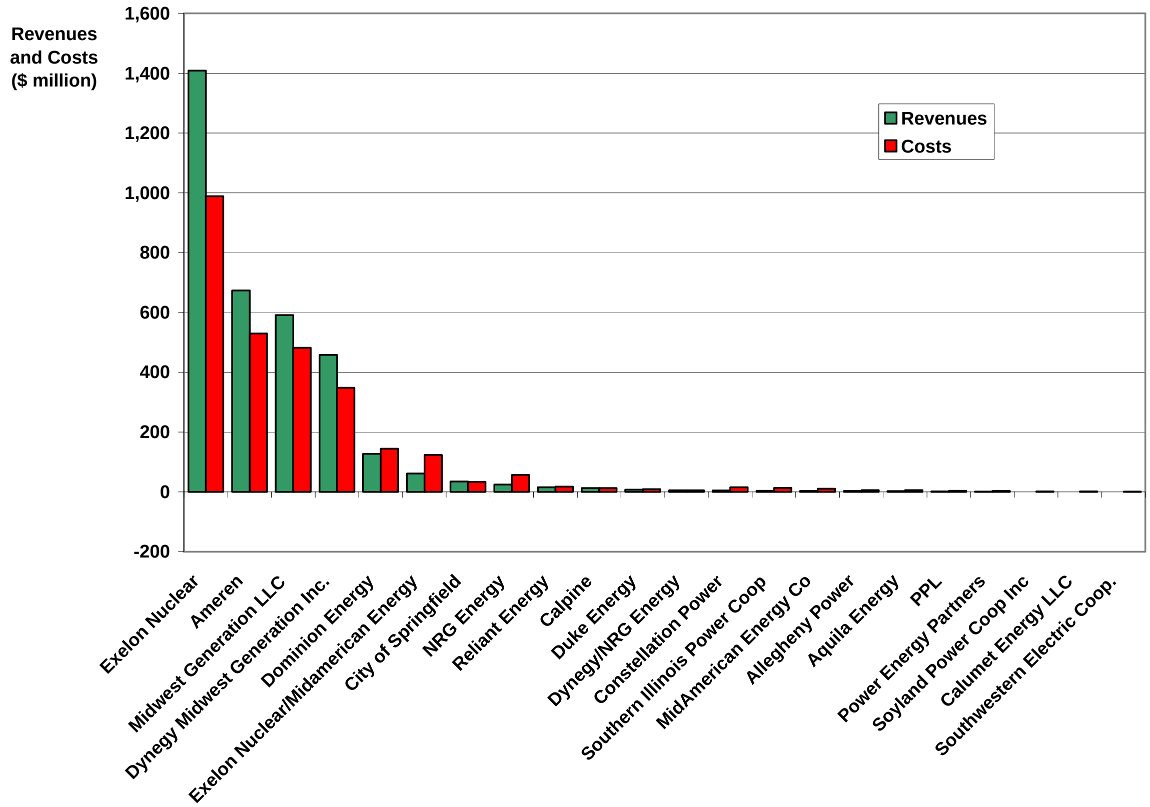


Figure 4.1.6-4 PC Case (Case Study Assumptions) Generation Company Revenues and Costs

Table 4.1.6-2 PC Case (Case Study Assumptions) Generation Company Revenues, Costs, and Operating Profitability

Generation Company	Revenues ($ Million)	Costs ($ Million)	Operating Profit Margin [a]
GenCo – Exelon Nuclear	1,408.6	988.5	42.5%
GenCo – Ameren	673.9	529.3	27.3%
GenCo – Midwest Generation LLC	591.1	482.0	22.6%
GenCo – Dynegy Midwest Generation Inc.	458.4	348.1	31.7%
GenCo – Dominion Energy	127.6	144.1	-11.4%
GenCo – Exelon Nuclear/Midamerican Energy	61.4	124.2	-50.5%
GenCo – City of Springfield	34.7	33.7	3.0%
GenCo – NRG Energy	24.7	56.3	-56.2%
GenCo – Reliant Energy	15.6	18.1	-13.6%
GenCo – Calpine	12.5	13.0	-3.7%
GenCo – Duke Energy	7.4	9.0	-18.3%
GenCo – Dynegy/NRG Energy	5.4	5.7	-4.5%
GenCo – Constellation Power	4.9	15.5	-68.3%
GenCo – Southern Illinois Power Coop.	4.0	13.3	-69.9%
GenCo – MidAmerican Energy Co.	3.3	10.4	-67.9%
GenCo – Allegheny Power	3.1	6.3	-50.1%
GenCo – Aquila Energy	2.2	6.2	-65.4%
GenCo – PPL	1.7	4.1	-57.3%
GenCo – Power Energy Partners	1.1	3.0	-61.7%
GenCo – Soyland Power Coop Inc.	0.7	1.6	-59.7%
GenCo – Calumet Energy LLC	0.0	1.8	-99.8%
GenCo – Southwestern Electric Coop.	0.0	1.1	-100.0%
Total	**3,442.4**	**2,815.2**	**22.3%**

[a] Revenues are from only the sale of electricity. Costs include only fuel, fixed and variable operation and maintenance costs, and startup/shutdown costs. The operating profit shown here is not a complete financial compilation.

Table 4.1.6-3 PC Case (Case Study Assumptions) Generation Company Revenue and Cost Rates

	Company Annual Average Based on PC Case Generation		
Generation Company	PC Case Revenue Rate[a] ($/MWh Generated)	PC Case Cost Rate[b] ($/MWh Generated)	PC Case Operating Profit Rate ($/MWh Generated)
Exelon Nuclear	21.2	14.9	6.3
Ameren	21.0	16.5	4.5
Midwest Generation LLC	22.1	18.1	4.1
Dynegy Midwest Generation Inc.	20.5	15.5	4.9
Dominion Energy	23.8	26.8	-3.1
Exelon Nuclear/Midamerican Energy	26.0	52.6	-26.6
City of Springfield	21.9	21.3	0.6
NRG Energy	33.3	76.0	-42.7
Reliant Energy	41.3	47.8	-6.5
Calpine	43.1	44.8	-1.7
Duke Energy	42.6	52.1	-9.5
Dynegy/NRG Energy	46.7	48.9	-2.2
Constellation Power	25.8	81.5	-55.7
Southern Illinois Power Coop.	29.1	96.6	-67.5
MidAmerican Energy Co.	29.8	92.7	-62.9
Allegheny Power	38.9	78.0	-39.1
Aquila Energy	42.0	121.2	-79.2
PPL	37.3	87.4	-50.0
Power Energy Partners	37.5	98.1	-60.5
Soyland Power Coop Inc.	37.1	92.0	-54.9
Calumet Energy LLC	29.9	15,724.4	-15,694.5
Southwestern Electric Coop.	Not dispatched	Not dispatched	Not dispatched

[a]The revenue rate is calculated by dividing the total revenue received by the company by the total generation in the PC case.
[b] The cost rate is calculated by dividing the total costs of the company's units in the PC case (including fuel, variable and fixed operating and maintenance, and startup/shutdown costs) by the total generation in the PC case. Large values of the cost rate (and large negative values of the operating profit rate) are due to the small amount of generation in the PC case.

Table 4.1.6-4 PC Case (Case Study Assumptions) – Generation Cost by Unit Type

		Costs ($million)						
Type	Generation (GWh)	Fuel	Variable O/M	Fixed O/M	Startup/ Shutdown	Total Cost	Effective Operating Cost[a] ($/MWh)	Effective Production Cost[b] ($/MWh)
Nuclear	68,675	327.9	380.8	381.2	21.0	1,110.8	10.3	16.2
Coal	87,243	1,012.7	159.7	246.4	58.0	1,476.9	13.4	16.9
Natural Gas	2,986	80.3	0.7	135.8	5.6	222.4	27.1	74.5
Oil	6	0.5	0.0	5.0	0.0	5.4	79.5	945.1
Hydro	244	-	-	-	-	-	-	-
Total	**159,154**	**1,421.4**	**541.2**	**768.4**	**84.6**	**2,815.6**		

[a] Based on fuel and variable O/M only.
[b] Based on total cost.

Generation Companies – Conservative Assumptions

Figure 4.1.6-5 shows the GenCo market share using the Conservative Assumptions. Exelon Nuclear's share of the in-state generation market increased to more than 60% while the shares of the other companies decreased proportionally. Recall that under the Conservative Assumptions, the State became a net importer of electricity as out-of-state companies were more competitive. Under these assumptions, Exelon Nuclear was able to maintain a competitive position while the other companies lost market share to out-of-state suppliers. This is the result of the fuel cost advantage of the nuclear units. Under the Conservative Assumptions, the production cost (excluding FOM) dropped considerably for the nuclear units and less so for the coal units. The natural gas units, whose production cost also dropped substantially under Conservative Assumptions, were still more than twice as expensive as the in-state nuclear and coal units. Under the Conservative Assumptions, the HHI based on generation increased to 3,797 (from 2,636 using the Case Study Assumptions), thus indicating an increase in market concentration for the in-state companies.

Figure 4.1.6-6 shows the operating revenues and costs of each of the in-state GenCos under Conservative Assumptions. Table 4.1.6-5 shows the annual operating profit margin under these conditions. With the exception of Exelon Nuclear, all companies were not profitable. Exelon Nuclear's operating profits dropped considerably. These changes came from the loss of market share to out-of-state suppliers and the lower market prices resulting from the exclusion of FOM in the production cost.

It is interesting to note that while the use of the Conservative Assumptions made more generation capacity available and would be expected to increase competition among suppliers, in fact the opposite was seen. Market concentration among in-state suppliers actually increased as market share was lost to out-of-state suppliers. Further, the Conservative Assumptions led to an unsustainable financial position for all GenCos, as all except one were unprofitable. The one profit level was very small.

Demand Companies – Case Study Assumptions

Under PC case assumptions, all DemCos offered their consumers the same purchase terms: the market price of electricity plus a 10% markup. Hence, there was no incentive for consumers to switch to alternative suppliers, and all were supplied by the same DemCo they had prior to restructuring. Figure 4.1.6-7 shows the load that was served by each DemCo in the PC case. Figure 4.1.6-8 shows the market share of each DemCo based on annual load served in the State. With these results, the HHI was computed to be 5,417, which indicates a highly concentrated market for DemCos. Using the FERC 20% benchmark shows that, as a demand company, Commonwealth Edison exceeded the benchmark level. The Ameren companies were at about 15%. Overall, three companies account for more than 98% of electricity sales to consumers. Recall that in the PC case assumptions, all the DemCos' load was considered to be firm load and not price-sensitive. Further, under the provisions of a fully restructured market, any DemCo licensed to operate in the State will be able to sell electricity to any consumer in the State.

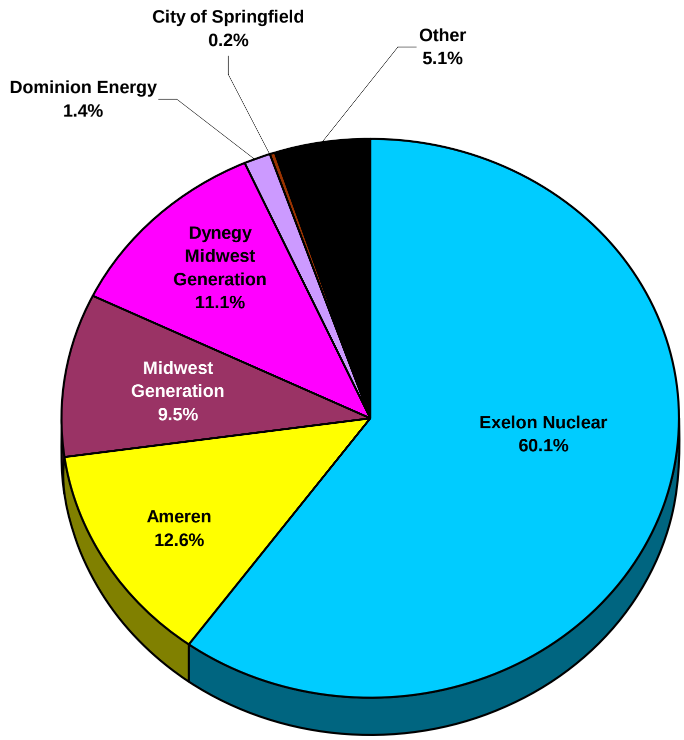


Figure 4.1.6.-5 PC Case (Conservative Assumptions) GenCo Market Share of Annual GWh of Generation

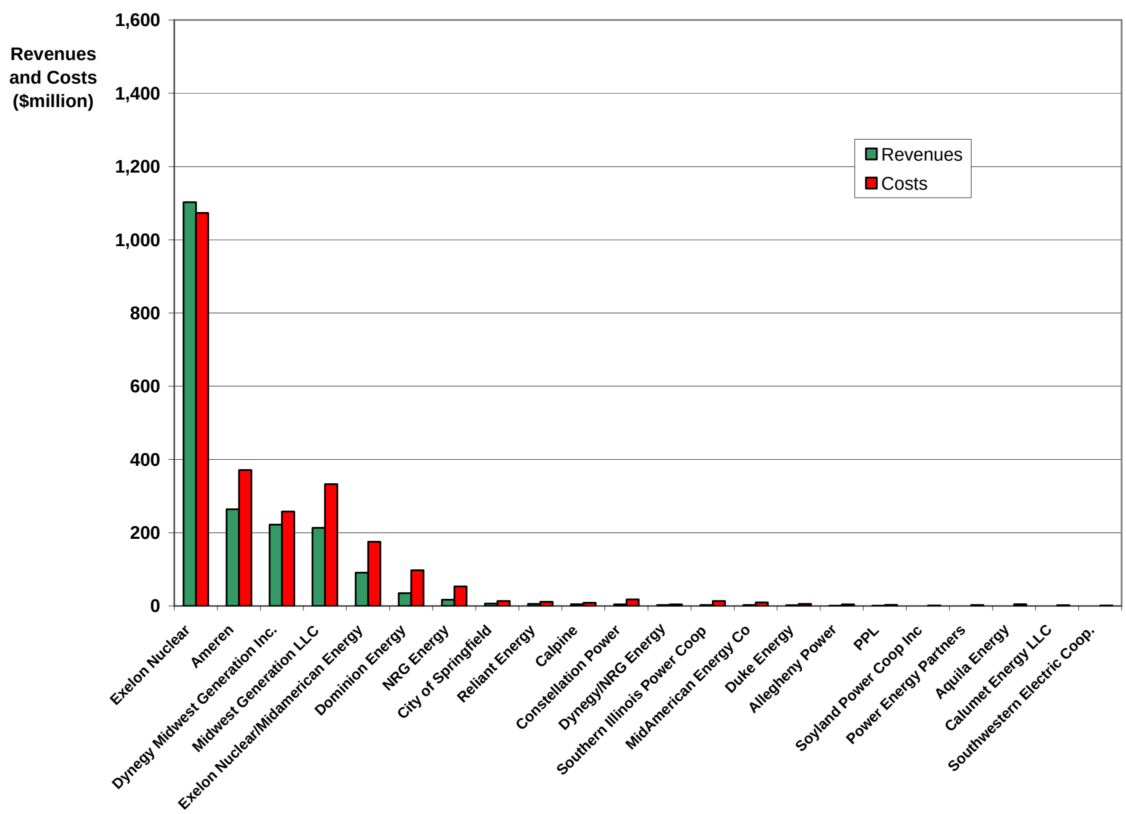


Figure 4.1.6-6 PC Case (Conservative Assumptions) Generation Company Revenues and Costs

Table 4.1.6-5 PC Case (Conservative Assumptions) Generation Company Revenues, Costs, and Operating Profitability

Generation Company	Revenues ($ Million)	Costs ($ Million)	Operating Profit Margin [a]
GenCo – Exelon Nuclear	1,102.7	1,073.5	2.7%
GenCo – Ameren	263.7	370.9	-28.9%
GenCo – Dynegy Midwest Generation Inc.	222.0	258.1	-14.0%
GenCo – Midwest Generation LLC	212.8	332.4	-36.0%
GenCo – Exelon Nuclear/Midamerican Energy	91.0	175.3	-48.1%
GenCo – Dominion Energy	34.4	97.5	-64.7%
GenCo – NRG Energy	16.8	53.5	-68.7%
GenCo – City of Springfield	6.4	13.1	-50.8%
GenCo – Reliant Energy	5.6	11.6	-52.2%
GenCo – Calpine	5.0	8.6	-41.3%
GenCo – Constellation Power	4.4	18.2	-75.6%
GenCo – Dynegy/NRG Energy	2.3	4.0	-41.8%
GenCo – Southern Illinois Power Coop.	2.2	13.0	-82.8%
GenCo – MidAmerican Energy Co.	2.2	9.9	-77.9%
GenCo – Duke Energy	1.6	5.3	-69.5%
GenCo – Allegheny Power	0.5	4.4	-88.2%
GenCo – PPL	0.3	3.0	-88.4%
GenCo – Soyland Power Coop Inc.	0.3	1.5	-81.3%
GenCo – Power Energy Partners	0.1	2.2	-96.2%
GenCo – Aquila Energy	0.0	4.5	-99.4%
GenCo – Calumet Energy LLC	0.0	1.8	-100.0%
GenCo – Southwestern Electric Coop.	0.0	1.1	-100.0%
Total	**1,974.4**	**2,463.2**	**-19.8%**

[a] Revenues are from only the sale of electricity. Costs include only fuel, variable operation and maintenance costs, and startup/shutdown costs. The operating profit shown here is not a complete financial compilation.

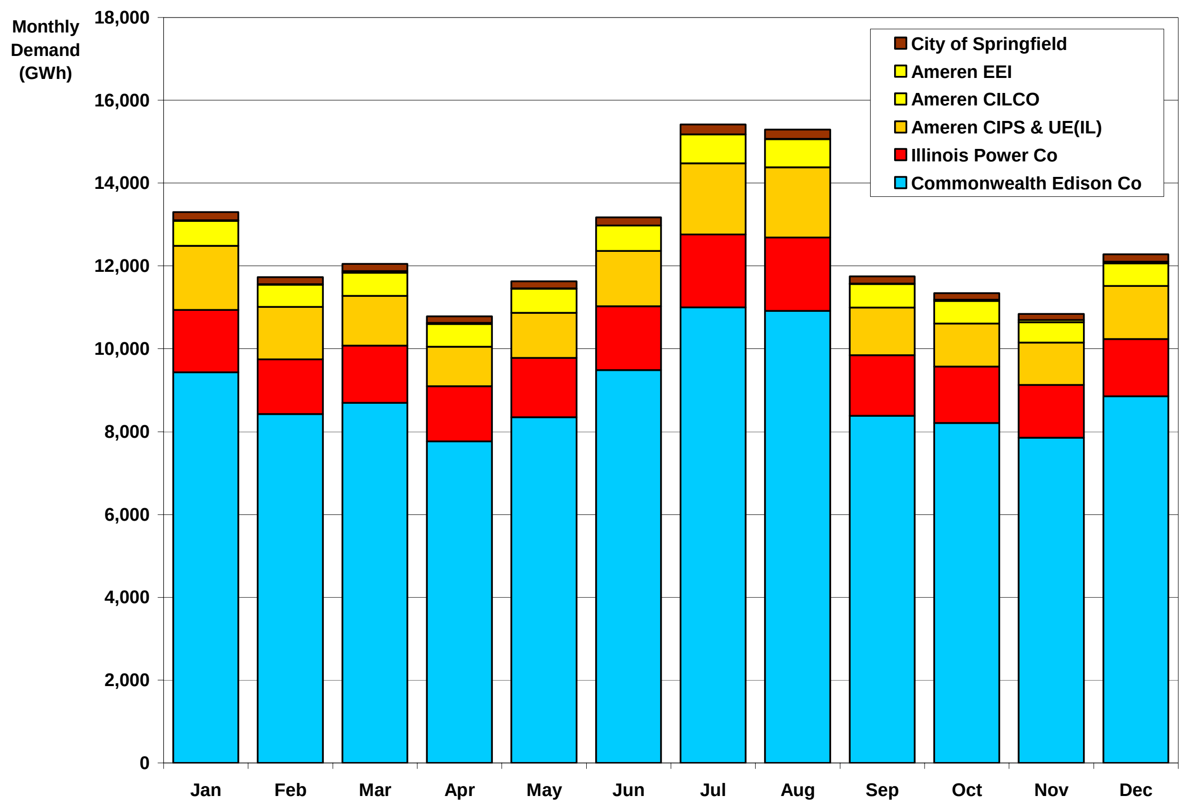


Figure 4.1.6-7 PC Case (Case Study Assumptions) Load Served by Demand Company

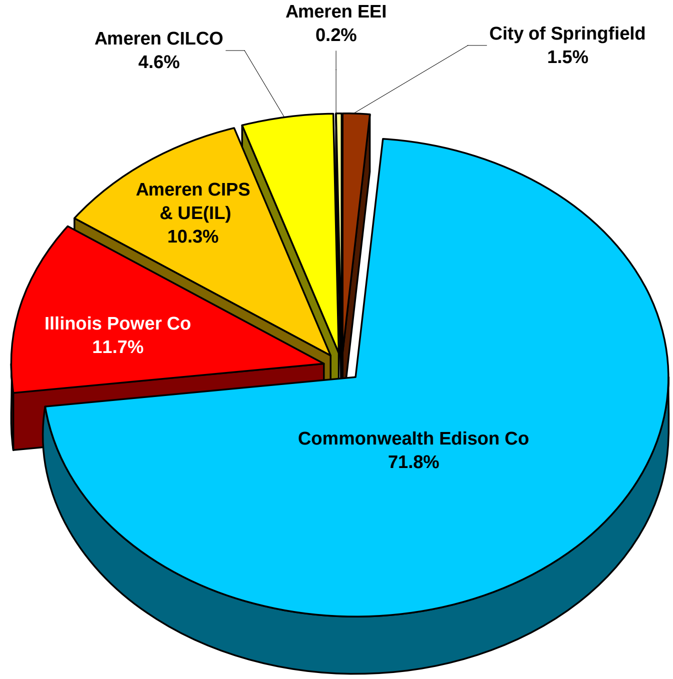


Figure 4.1.6-8 PC Case (Case Study Assumptions) Demand Company Market Share

Figure 4.1.6-9 shows the monthly revenues for the DemCos in the PC case. The revenues include payments received from consumers and payments for energy, transmission, and distribution services. By convention, the DemCos collected all of these from consumers and passed the transmission and distribution charges to the respective companies with no markup. A DemCo markup was applied only to the energy charges. Table 4.1.6-6 shows the annual revenues and costs. The costs include the pass-through payments made to TransCos and DistCos as well as the energy costs. Since there were no bilateral contracts in operation in the PC case, all of the energy costs arose from purchases from the pool energy market.

In the PC case, all of the DemCos are profitable by the assumption that they charged their consumers a markup of their cost of electricity purchases. As a point of comparison, in the recent electricity problems in California, the companies that are the equivalent of what is referred to here as a DemCo were not able to pass through their cost of electricity purchases to consumers because of tariff restrictions. This led to bankruptcy filings.

Demand Companies – Conservative Assumptions

Using the Conservative Assumptions, the load served and customer distribution among DemCos was unchanged from the Case Study Assumptions. The DemCo revenues and costs were reduced as a result of the reduction in energy charges, as shown in Table 4.1.6-7. The operating profit margin was reduced as a result of the reduction in energy costs, while transmission and distribution costs were unchanged.

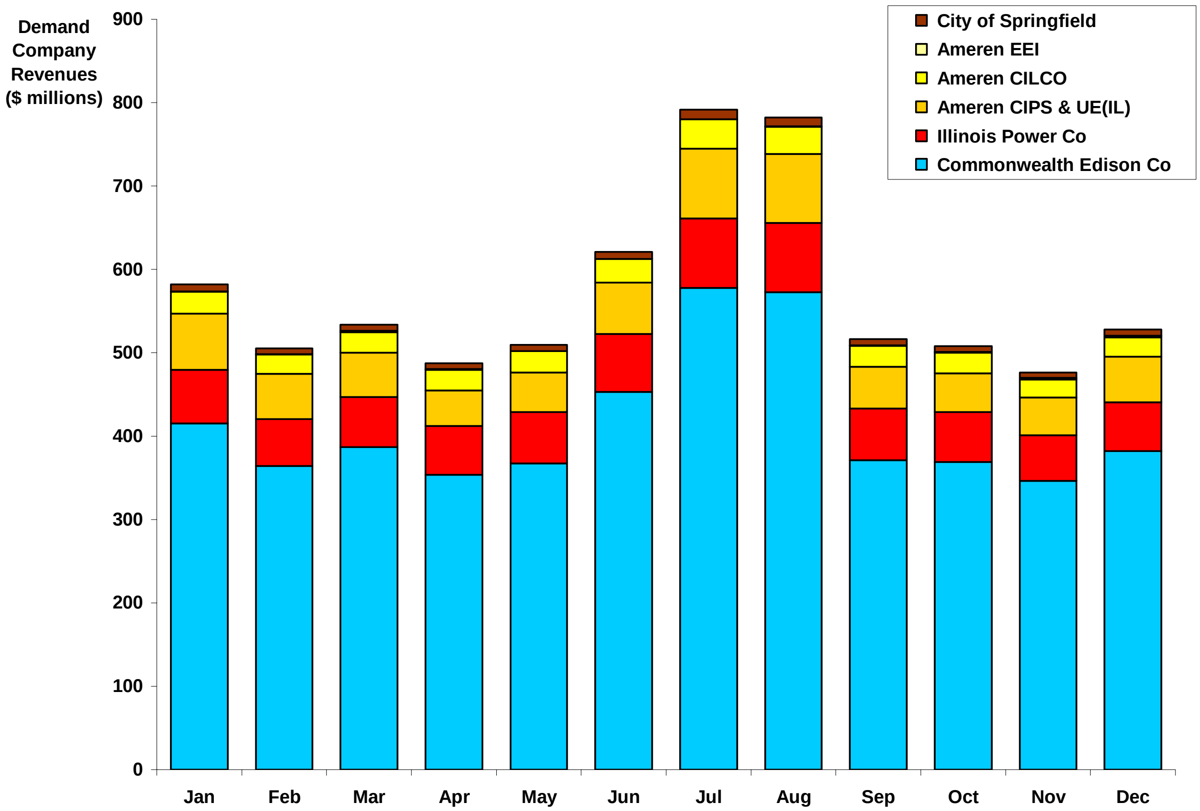


Figure 4.1.6-9 PC Case (Case Study Assumptions) Demand Company Revenues

Table 4.1.6-6 PC Case (Case Study Assumptions) Demand Company Annual Revenues and Costs

Demand Company	Revenues[a] ($Million)	Costs[b] ($ Million)	Operating Profit Margin (%)
DemCo Commonwealth Edison	4,959.3	4,715.1	5.2
DemCo Illinois Power	772.8	736.3	5.0
DemCo Ameren			
Ameren CIPS,UE(IL)	688.0	655.0	5.0
Ameren CILCO	315.0	299.8	5.1
Ameren EEI	10.4	10.0	5.0
DemCo City of Springfield	96.8	92.2	5.1
Total	**6,842.2**	**6,508.4**	**5.1**

[a] Revenues are payments received from consumers and include charges for energy, transmission, and distribution services. No markup is applied to the transmission and distribution charges by the DemCo.
[b] Costs include the pass through of the transmission and distribution payments received from consumers.

Table 4.1.6-7 PC Case (Conservative Assumptions) Demand Company Annual Revenues and Costs

Demand Company	Revenues[a] ($Million)	Costs[b] ($ Million)	Operating Profit Margin (%)
DemCo Commonwealth Edison	4,131.3	3,961.9	4.3
DemCo Illinois Power	657.9	631.7	4.1
DemCo Ameren			
Ameren CIPS,UE(IL)	581.1	557.7	4.2
Ameren CILCO	263.9	253.3	4.2
Ameren EEI	8.9	8.5	4.0
DemCo City of Springfield	82.3	79.0	4.2
Total	5,725.4	5,492.1	4.2

[a] Revenues are payments received from consumers and include charges for energy, transmission, and distribution services. No markup is applied to the transmission and distribution charges by the DemCo.
[b] Costs include the pass through of the transmission and distribution payments received from consumers.

Distribution Companies

Figure 4.1.6-10 shows the monthly revenue received by DistCos. Table 4.1.6-8 summarizes these results over the year. Recall that the DistCos charged a fixed rate of 18 $/MWh for the use of their facilities and did not engage in any strategic market behavior.

Applying the Conservative Assumptions did not change the distribution charges.

Transmission Company – Case Study Assumptions

Figure 4.1.6-11 shows the monthly revenues of the single TransCo assumed in the PC case. Table 4.1.6-9 summarizes the results over the year. The revenues include the transmission use charge (TUC), which is a fixed fee of 3 $/MWh, and the transmission congestion payment (TCP), which results from the difference in LMPs, as described previously. During lower load periods, the transmission use charge made up almost all the revenues, since there was little congestion during these periods. In January, the TCP was actually negative because of the directional convention used in computing it, as was described earlier. In a market where transmission rights were sold, this would imply a reimbursement by the holders of these rights to the transmission company. The transmission rights market was not included in this simulation. During high load periods the transmission congestion payment made up almost one-half of the revenue.

Transmission Company – Conservative Assumptions

Use of the Conservative Assumptions did not change the TUC but did reduce the TCP, due to the lower LMPs around the system. This is shown in Table 4.1.6-10.

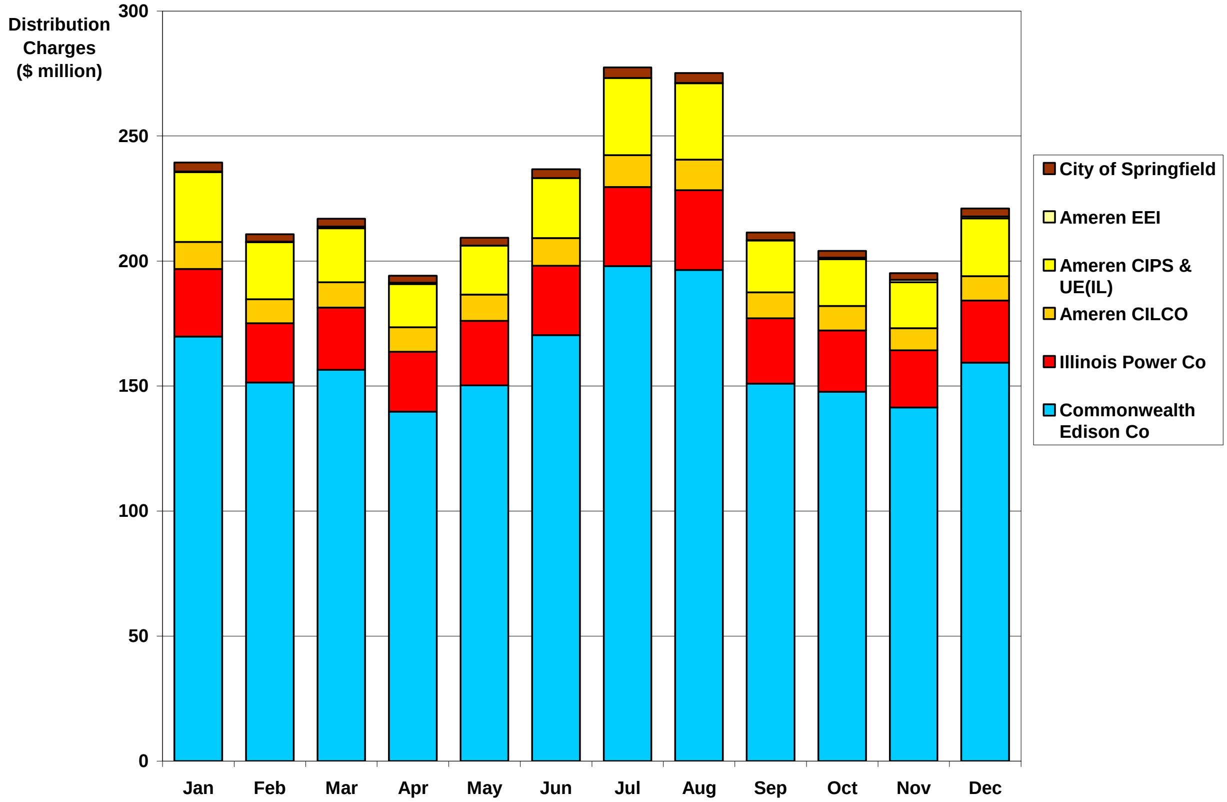


Figure 4.1.6-10 PC Case Distribution Company Revenues

Table 4.1.6-8 PC Case (Case Study and Conservative Assumptions) Distribution Company Annual Revenues

Distribution Company	Revenues ($Million)
DistCo – Commonwealth Edison Co.	1,931.9
DistCo – Illinois Power Co.	315.3
DistCo – Ameren - CIPS & UE(IL)	275.6
DistCo – Ameren - CILCO	125.5
DistCo – Ameren - EEI	4.4
DistCo – City of Springfield	39.2
Total	**2,691.7**

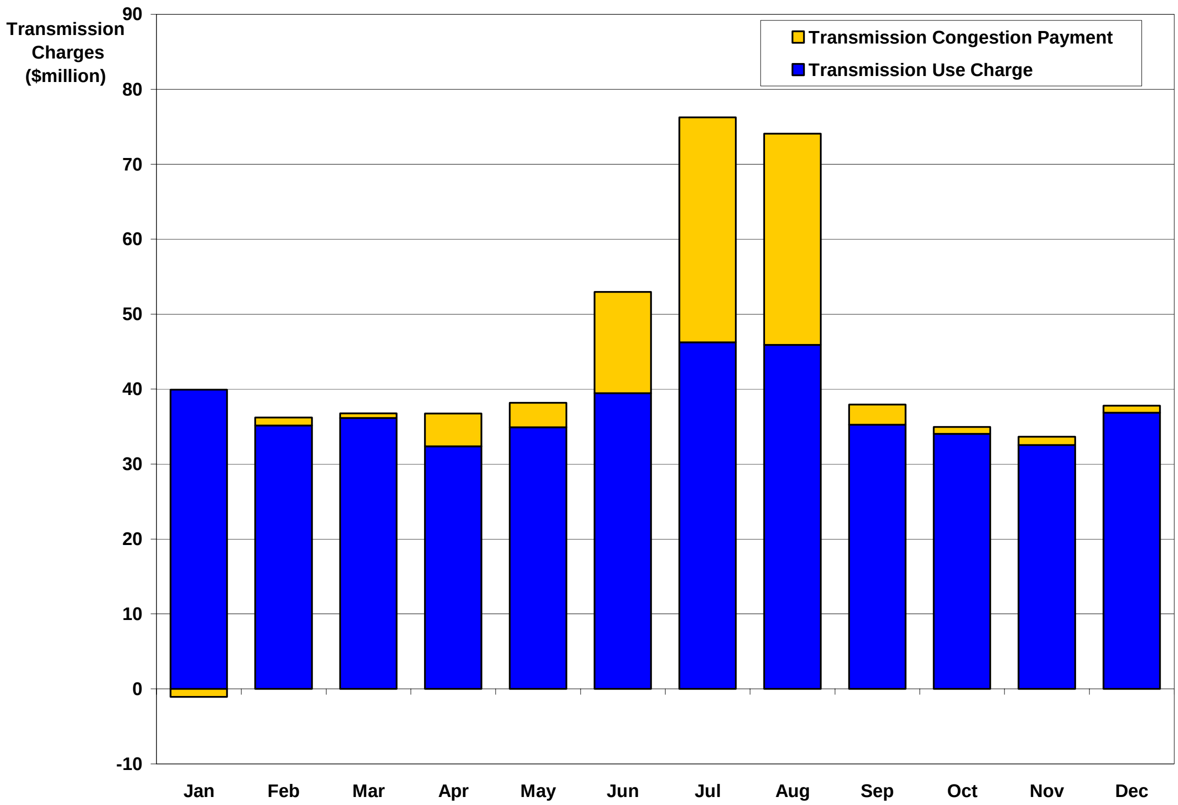


Figure 4.1.6-11 PC Case (Case Study Assumptions) Transmission Company Revenue

Table 4.1.6-9 PC Case (Case Study Assumptions) Transmission Company Annual Revenue

Transmission Company	Revenue ($Million)
TransCo Transmission Use Charge	448.6
TransCo Transmission Congestion Payment	85.7
TOTAL	**534.3**

Table 4.1.6-10 PC Case (Conservative Assumptions) Transmission Company Annual Revenue

Transmission Company	Revenue ($Million)
TransCo Transmission Use Charge	448.6
TransCo Transmission Congestion Payment	64.8
TOTAL	**513.4**

Consumers – Case Study Assumptions

Figure 4.1.6-12 shows the monthly costs paid by consumers for electricity in the PC case. The consumer costs include payments for energy, transmission services, and distribution services. Energy and distribution charges made up more than 90% of the costs. The transmission costs shown here are the TUCs. They made up a relatively small portion of the total. The transmission costs shown in the figure do not include the TCPs since, for consumers, these are reflected in the LMPs that are used to determine their energy costs and are, therefore, included in that part of the figure. Consumer costs were highest in the peak load months of June, July, and August, which together accounted for about 30% of the annual costs.

Figure 4.1.6-13 shows the distribution of consumer costs by zone. About 70% of the consumer costs were incurred in the NI zones, where the same portion of the State's load is concentrated.

Figure 4.1.6-14 shows the monthly variation in consumer price for electricity. The actual price varied by hour through the analysis year. Shown is the load-weighted average by zone for each month. The prices in the NI zones were consistently higher throughout the year than elsewhere in the State due to transmission limits. The IP, AMRN, and SIPC zones showed consistently lower consumer prices. For the CILC and CWLP zones, prices showed more volatility than elsewhere. These results derive from the variation in zonal LMPs due to transmission congestion, as was discussed in Section 4.1.4. Consumers paid the LMP of the zone they are located in, plus the transmission and distribution charges. Thus, the transmission limits can be seen to have a direct impact on consumer prices. Higher production costs resulted, since units must be redispacthed to relieve congestion. Congestion charges also added to consumer costs.

During the lower-load months, the prices were closer together throughout the State. During the peak months of June, July, and August the prices increased, as did their spread. There was about a 9% spread in prices in January. This increased to about 19% in August. These results also follow the variation in zonal LMPs discussed earlier.

Table 4.1.6-11 shows the annual consumer costs by zone along with the annual average electricity price. The variation in annual average electricity price across the State resulted in a 12% difference between the highest and lowest values under PC case conditions. This is a relatively modest variability given the wide range of loads across the State. The implication is that under PC case conditions, transmission congestion can create a spread in consumer costs in peak-load months (about 19% from Figure 4.1.6-14), but the annual average variation is smaller (5% from Table 4.1.6-11), since the energy portion of the consumer bill, which is most affected by the transmission congestion, is on the order of half the total.

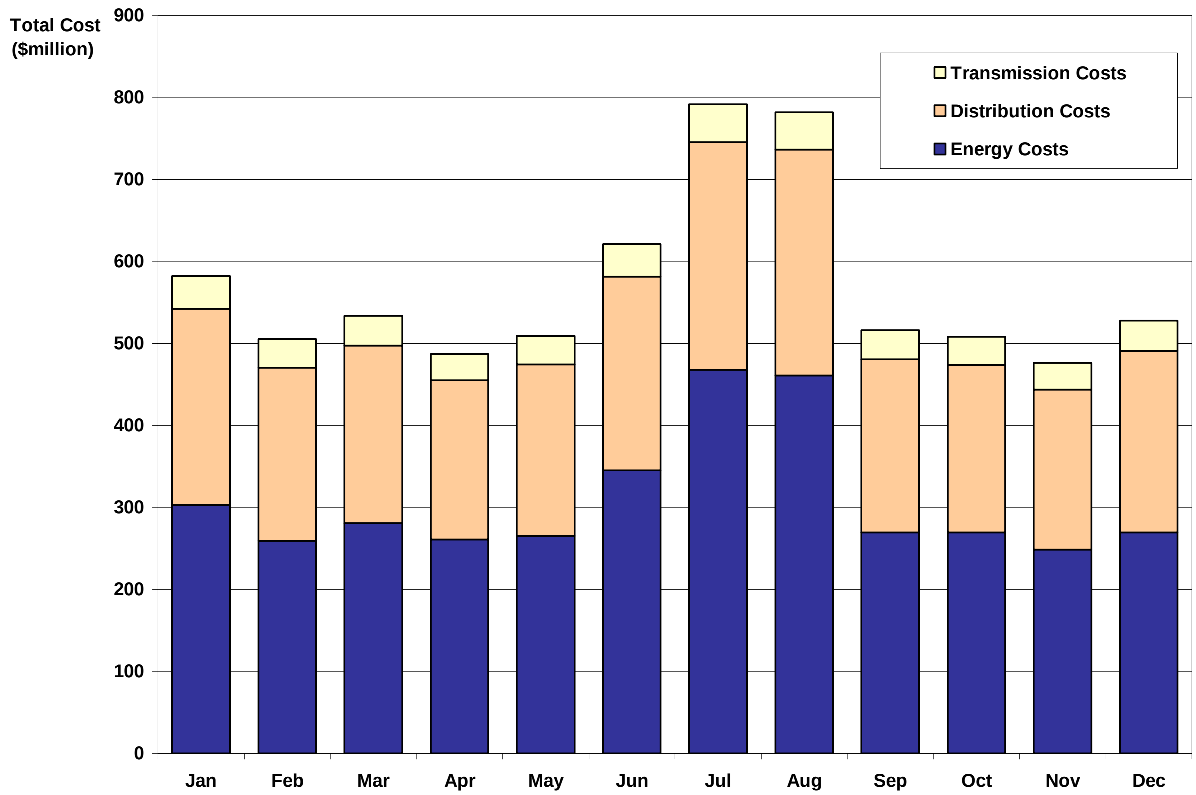


Figure 4.1.6-12 PC Case (Case Study Assumptions) Consumer Costs

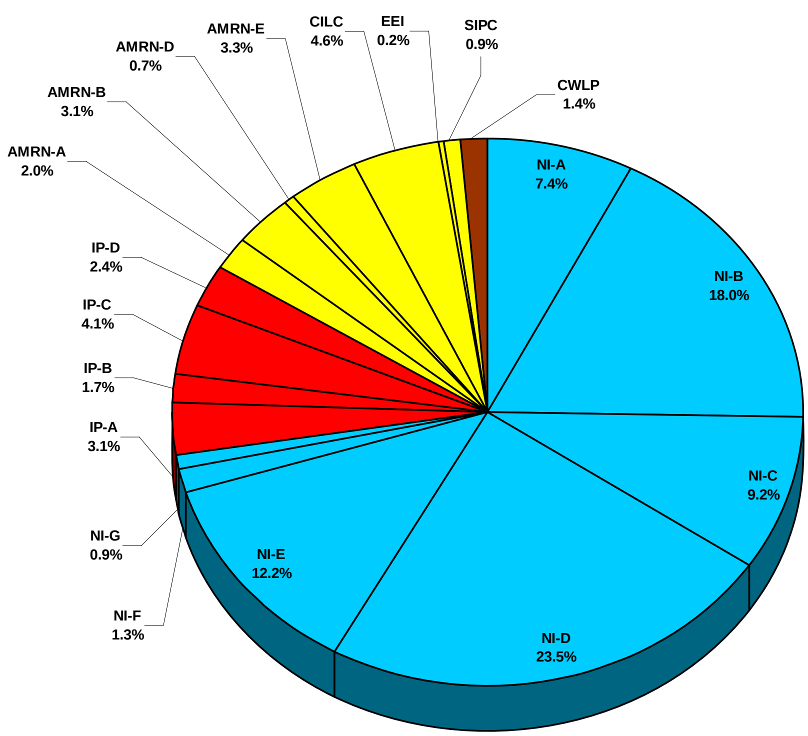


Figure 4.1.6-13 PC Case (Case Study Assumptions) Consumer Cost Distribution by Zone

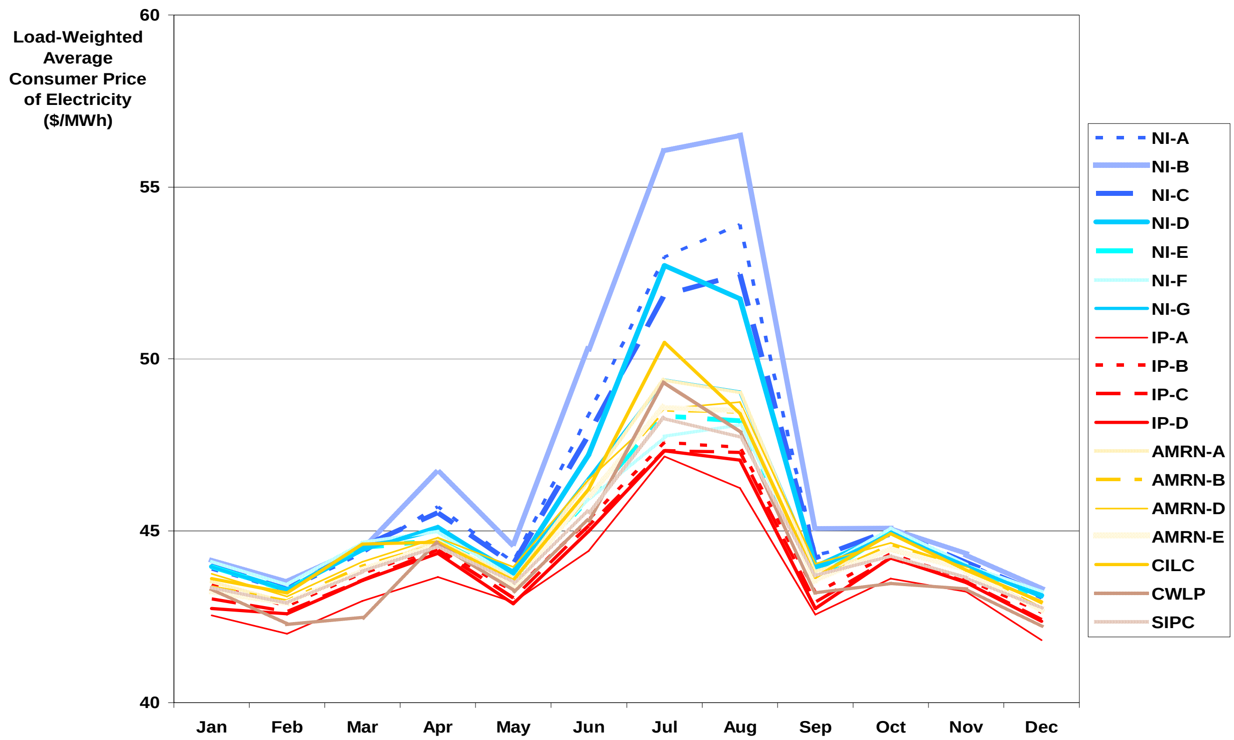


Figure 4.1.6-14 PC Case (Case Study Assumptions) Consumer Price of Electricity

Table 4.1.6-11 PC Case (Case Study Assumptions) Consumer Costs by Zone

Zone	Demand (TWh)	Energy Costs [a] ($million)	Transmission Use Charges [b] ($million)	Distribution Use Charges [c] ($million)	Total Consumer Cost ($million)	Average Cost of Electricity [d] ($/MWh)
NI-A	10.9	277.2	32.7	196.3	506.2	46.4
NI-B	25.9	685.8	77.8	466.7	1,230.3	47.4
NI-C	13.6	341.9	40.8	244.9	627.6	46.1
NI-D	35.0	874.0	104.9	629.4	1,608.3	46.0
NI-E	18.6	446.7	55.8	335.0	837.6	45.0
NI-F	2.0	48.1	6.0	36.1	90.2	45.0
NI-G	1.3	31.7	3.9	23.5	59.0	45.3
NI Total	**107.3**	**2,705.4**	**321.9**	**1,931.9**	**4,959.3**	**46.2**
IP-A	4.8	109.1	14.4	86.4	209.9	43.7
IP-B	2.7	63.0	8.1	48.3	119.4	44.5
IP-C	6.3	146.5	18.9	113.3	278.7	44.3
IP-D	3.7	86.4	11.2	67.2	164.8	44.2
IP Total	**17.5**	**405.0**	**52.5**	**315.3**	**772.8**	**44.2**
AMRN-A	3.0	71.5	8.9	53.3	133.7	45.1
AMRN-B	4.8	113.9	14.3	85.7	213.9	44.9
AMRN-D	1.1	26.7	3.3	19.9	49.9	45.2
AMRN-E	5.1	121.5	15.3	91.6	228.4	44.9
AMRN Total	**14.0**	**333.7**	**41.7**	**250.3**	**625.9**	**44.7**
CILC	7.0	168.6	20.9	125.5	315.0	45.2
EEI	0.2	5.4	0.7	4.4	10.4	43.1
SIPC	1.4	32.9	4.2	25.1	62.1	44.6
CWLP	2.2	51.1	6.5	39.2	96.8	44.5
Total	**149.5**	**3,702.0**	**448.6**	**2,691.7**	**6,842.3**	**45.8**

[a] Includes cost of energy purchased from DemCo serving the consumer. This cost includes DemCo markup on energy sales.
[b] Includes transmission use charge. By convention, this is paid by consumers to the DemCo, but there is no markup added. Transmission congestion charges are calculated on each line in the transmission network as the difference in LMPs. Therefore, consumers experience transmission congestion charges as part of their energy charge.
[c] Includes distribution use charges. By convention, this is paid by consumers to the DemCo, but there is no markup added.
[d] Demand-weighted average.

Consumers – Conservative Assumptions

Figure 4.1.6-15 shows the monthly consumer price for electricity under Conservative Assumptions. Table 4.1.6-12 shows the annual consumer costs by zone. During the low-load months, prices are very close across the State. During the peak-load months, the prices increase and spread apart as before. Overall, the consumer prices and costs are lower under the Conservative Assumptions, since more generation capacity is offered into the market at lower prices. Nevertheless, the effect of transmission congestion remains, as demonstrated by the spread in prices during the peak load months. The degree of spread during these months is only slightly smaller than under the Case Study Assumptions (17% instead of 20%). On an annual basis, the degree of spread is essentially unchanged from the Case Study Assumptions.

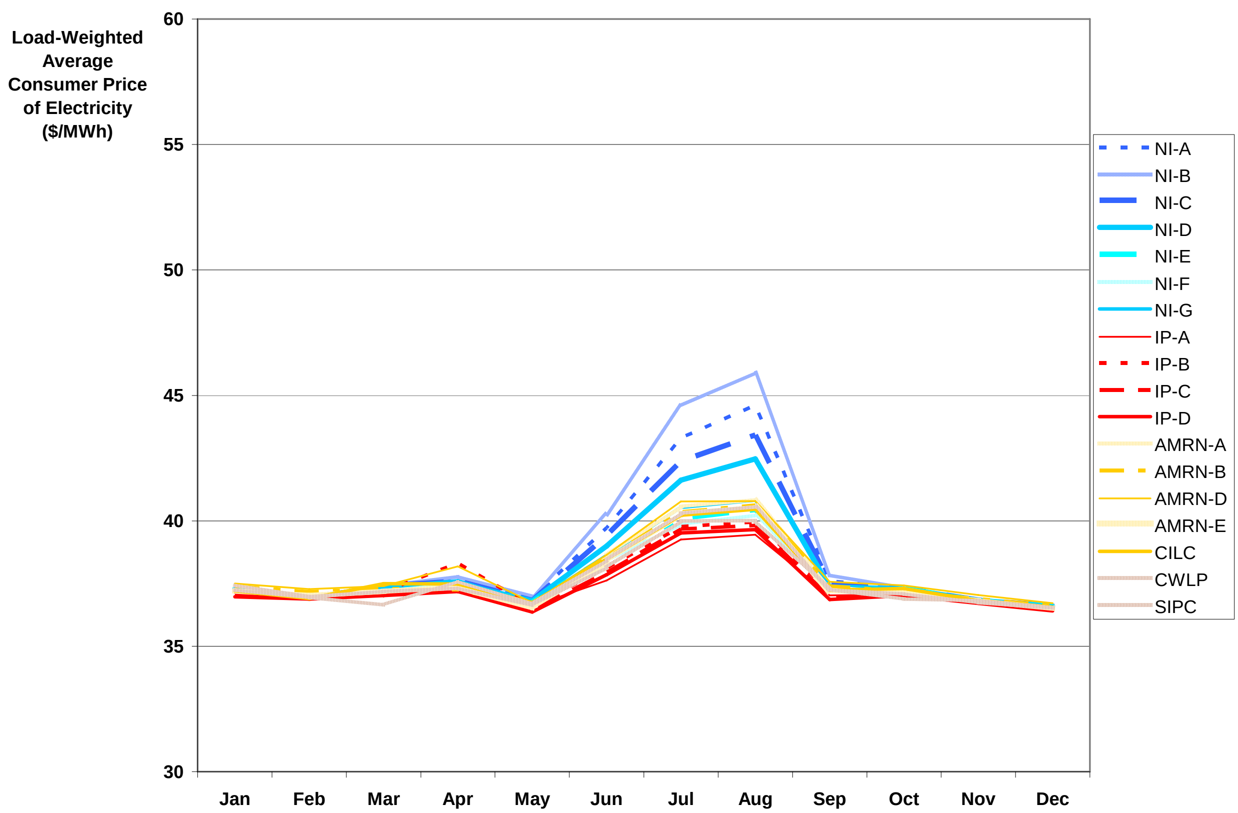


Figure 4.1.6-15 PC Case (Conservative Assumptions) Consumer Price of Electricity

Table 4.1.6-12 PC Case (Conservative Assumptions) Consumer Costs by Zone

Zone	Demand (TWh)	Energy Costs [a] ($million)	Transmission Use Charges [b] ($million)	Distribution Use Charges [c] ($million)	Total Consumer Cost ($million)	Average Cost of Electricity [d] ($/MWh)
NI-A	10.9	194.1	32.7	196.3	423.1	38.8
NI-B	25.9	470.1	77.8	466.7	1014.6	39.2
NI-C	13.6	238.4	40.8	244.9	524.1	38.5
NI-D	35.0	604.4	104.9	629.4	1338.7	38.2
NI-E	18.6	313.9	55.8	335.0	704.7	37.9
NI-F	2.0	33.7	6.0	36.1	75.8	37.9
NI-G	1.3	22.1	3.9	23.5	49.5	38.1
NI Total	**107.3**	**1,876.7**	**321.9**	**1,931.9**	**4,130.5**	**38.5**
IP-A	4.8	79.2	14.4	86.4	180	37.5
IP-B	2.7	45.0	8.1	48.3	101.4	37.6
IP-C	6.3	104.3	18.9	113.3	236.5	37.5
IP-D	3.7	61.5	11.2	67.2	139.9	37.8
IP Total	**17.5**	**290.0**	**52.5**	**315.3**	**657.8**	**37.6**
AMRN-A	3.0	50.3	8.9	53.3	112.5	37.5
AMRN-B	4.8	80.9	14.3	85.7	180.9	37.7
AMRN-D	1.1	19.0	3.3	19.9	42.2	38.4
AMRN-E	5.1	85.9	15.3	91.6	192.8	37.8
AMRN Total	**14.0**	**236.2**	**41.7**	**250.3**	**528.2**	**37.7**
CILC	7.0	117.5	20.9	125.5	263.9	37.7
EEI	0.2	3.8	0.7	4.4	8.9	37.1
SIPC	1.4	23.3	4.2	25.1	52.6	37.6
CWLP	2.2	36.6	6.5	39.2	82.3	37.4
TOTAL	**149.5**	**2,584.1**	**448.6**	**2,691.7**	**5,724.4**	**38.3**

[a] Includes cost of energy purchased from DemCo serving the consumer. This cost includes DemCo markup on energy sales.
[b] Includes transmission use charge. By convention, this is paid by consumers to the DemCo, but there is no markup added. Transmission congestion charges are calculated on each line in the transmission network as the difference in LMPs. Therefore, consumers experience transmission congestion charges as part of their energy charge.
[c] Includes distribution use charges. By convention, this is paid by consumers to the DemCo, but there is no markup added.
[d] Demand-weighted average.

Agent Summary – Case Study Assumptions

Figure 4.1.6-16 summarizes the PC case revenue and cost flows. It should be emphasized that these flows represent operational considerations only and do not include items such as amortization of capital investments, taxes, fees, and other such financial parameters. As such, this is not intended to represent a complete financial accounting of the electricity system in the State.

Consumers ultimately paid for all the services received from the power system. By convention here, it was assumed here that consumer payments were all sent to the demand companies that were their suppliers. In the PC case, there were no bilateral contracts; hence demand companies purchased all of their electricity from the day-ahead pool market, which was administered by the independent system operator (ISO). Also by convention here, the ISO handled the settlement payments to all market participants. Generation companies received payment for the energy sold into the day-ahead market. The single transmission company received transmission use charges, which were based on a fixed charge rate per MWh, and transmission congestion charges, which were calculated based on the differences in LMPs. Distribution companies received distribution service charges, which were based on a fixed charge rate per MWh. Generation companies, the single transmission company, and the distribution companies all had costs associated with the operation of their equipment. Only the generation costs (i.e., fuel, operating and maintenance) were estimated here.

The results show that under PC case conditions, consumers in the State would pay $6.84 billion for electricity in the analysis year. The cost of electricity generation was the largest component of consumer costs at $3.44 billion per year. Distribution costs were the next largest at $2.69 billion per year. Since the distribution system is the most equipment- and labor-intensive part of any electric power system, it is not surprising that these costs made up such a large portion of the total cost. Transmission use costs were a much smaller portion of the total at $0.45 billion. In the PC case, transmission congestion charges added $0.09 billion or about 1.3% to the total cost and were less than the transmission use charges.

Out-of-state purchases and sales of electricity netted out to $0.16 billion inflow to State companies over the year. These are wholesale energy costs, since the out-of-state analysis did not include transmission and distribution charges.

Also shown on the figure are the annual average electricity prices. Consumers across the State paid an average of 45.8 $/MWh (4.58 ¢/kWh). GenCos earned 3.91 $/MWh in operating profit, which included profits from out-of-state sales. DemCos earned 2.30 $/MWh.

Agent Summary – Conservative Assumptions

Figure 4.1.6-17 shows the revenue and cost flows under Conservative Assumptions. In general, the revenues and costs decreased with the lower generation costs. The most significant changes are that the GenCos had a negative operating profit over the year, and the net from wholesale out-of-state purchases and sales shows the result of the State being a net importer of electricity under these conditions.

Comparison with Historical Data

Table 4.1.6-13 shows a comparison of some of the PC case results to historical data for the year 2002. These results are comparable only in the broadest of terms for several reasons. First, as was described earlier, the cost accounting included here represents only operating expenses and revenues. Under PC case conditions, companies used only production costs (i.e., fuel and operating and maintenance costs) to formulate their bids into the electricity market. Cost components such as capital amortization, fees, taxes, and other such items were not included. In current practice, these items are factored into the rate base and result in higher prices. A more detailed cost accounting, which was not possible here, would likely bring the prices in the simulation closer to historical patterns. Second, the electricity market that is represented in the PC case is significantly different than what is currently in place. In the PC case, all companies compete in the day-ahead pool market to provide electricity to any point in the State, subject to the limitations of the transmission system. This has the effect of making more capacity available throughout the State, thus lowering prices.

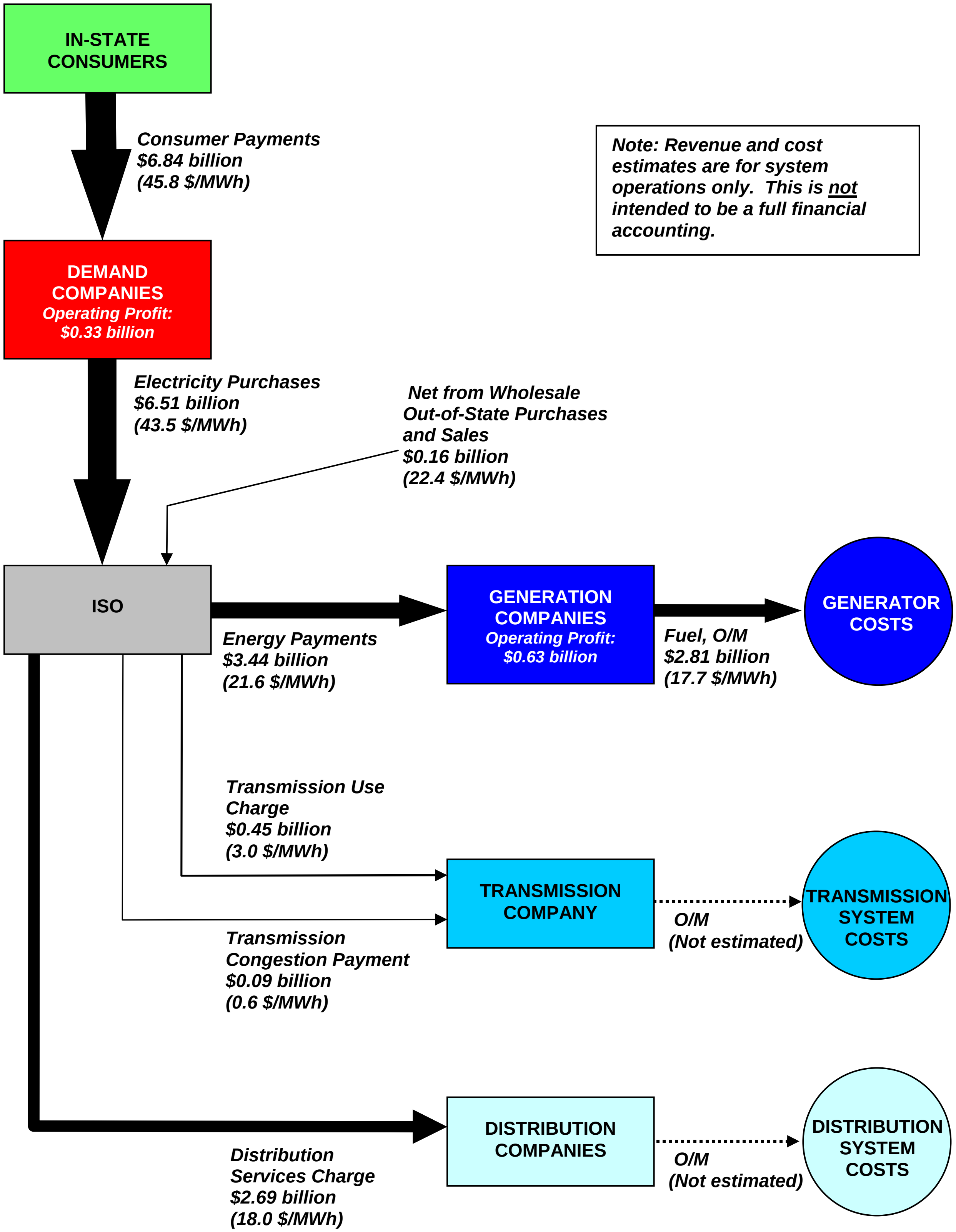


Figure 4.1.6-16 PC Case (Case Study Assumptions) Revenue and Cost Flow

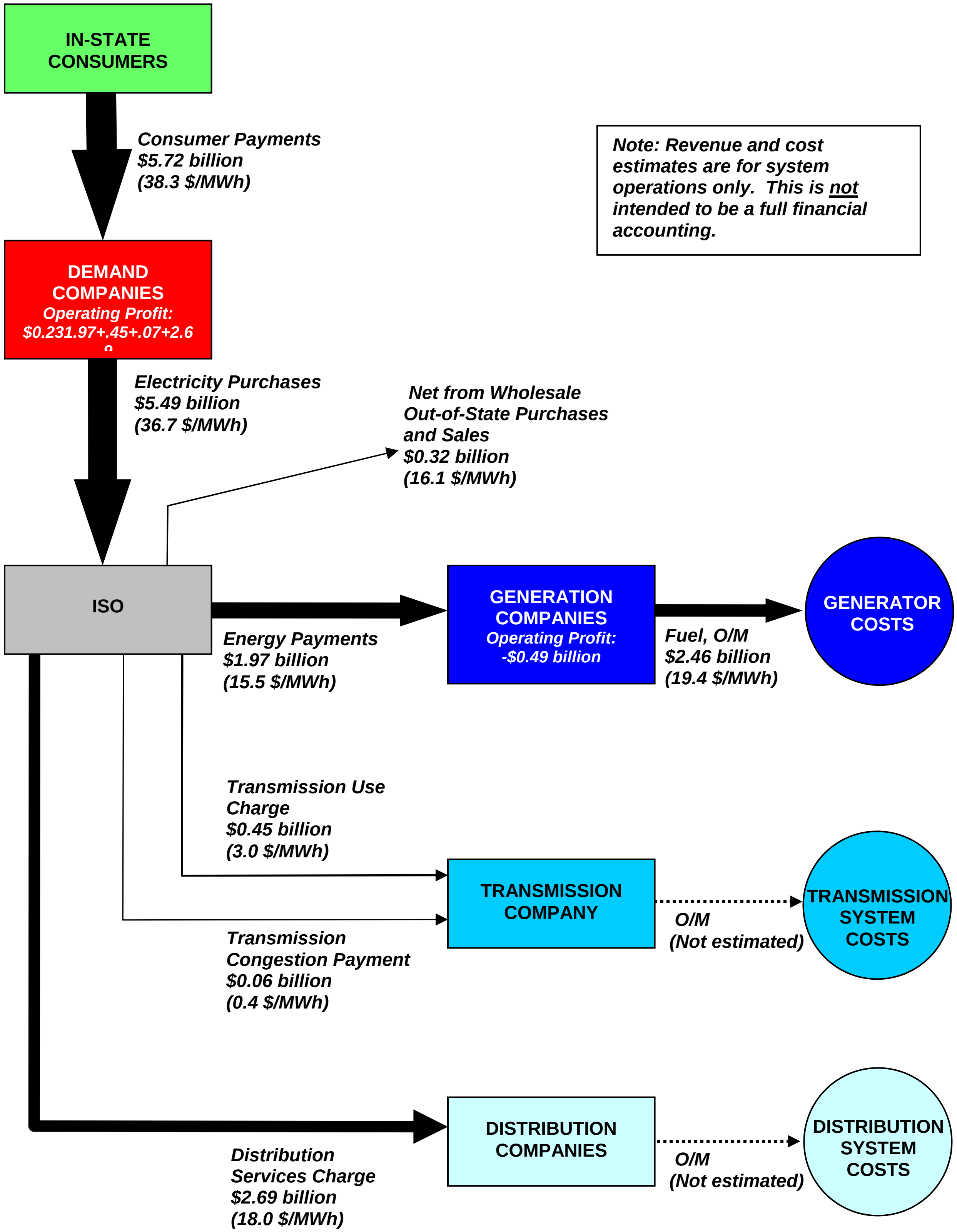


Figure 4.1.6-17 PC Case (Conservative Assumptions) Revenue and Cost Flow

Table 4.1.6-13 Comparison of 2002 Historical Data with PC Case Results

		PC Case Analysis Year Approximately Comparable Result	
	2002 Historical Data [a]	Case Study Assumptions	Conservative Assumptions
Sales of Electricity to Ultimate Customers	127.3 TWh	149.6 TWh	149.6 TWh
Revenues from Sales of Electricity to Ultimate Customers	$8.07 billion	$6.84 billion	$5.72 billion
Revenue Rate from Sales of Electricity to Ultimate Customers	6.34 ¢/kWh	4.58 ¢/kWh	3.83 ¢/kWh

[a] Source: Illinois Commerce Commission

4.1.7 Production Cost Case Summary

The following summary observations can be made from the PC case results:

- The PC case results showed a concentration of market share for both GenCos and DemCos and the existence of transmission congestion during high-load periods, even when none of companies was engaging in strategic market behavior to increase profits. This is an indication that the potential for market power exists. The use of the Conservative Assumptions, which resulted in more generation capacity being available, did not change this situation. In fact, the concentration in the in-state generation market increased under these assumptions as out-of-state suppliers gained a higher market share at the expense of some of the in-state suppliers.

- Under PC case conditions, across most of the State there was adequate generation capacity available and relatively little transmission congestion during low-load periods. With some exceptions, the LMPs in each zone were close to each other and varied by a relatively small amount as the load increased and decreased. In the high-load periods, all areas of the State experienced an increase in the magnitude of electricity prices. The magnitude of the increase was due to the need to bring more expensive generators on-line to serve the load. In the high-load periods, some areas of the State showed evidence of transmission congestion. Not only did the magnitude of the LMPs increase, but the variation from each other increased significantly. It is the difference in LMPs between zones that is the indicator of transmission limitations. Application of the Conservative Assumptions reduced the magnitude of the price increase, and the spread of price increases across the State, since more capacity was made available at lower bid prices. However, the effect of transmission congestion was still noticeable. Prices in the northern part of the State were more than double those elsewhere due to this congestion.

- Under PC case conditions, the cost of electricity to consumers was about $6.84 billion per year. Of that, approximately $0.33 billion went as operating profit to demand companies that served as electricity suppliers; $3.44 billion to generation companies, which spent about $2.81 billion operating their equipment; $2.69 billion to distribution companies; and $0.54 billion to the transmission company. Transmission congestion accounted for about 1.3% of the total costs on an annual basis. About $0.16 billion was received from electricity sales to out-of-state consumers. (The actual cost of electricity to consumers in 2002 was $8.07 billion. This is not directly comparable to PC case results since the analysis done here did not account for all of the costs incurred by companies that would likely be passed on to consumers.) Use of the Conservative Assumptions generally lowered all these values. The most significant impact of these assumptions was that the sum of the operating profits of the in-state GenCos became negative (-$0.49 billion instead of +$0.63 billion) and the net of out-of-state purchases and sales was negative, as the State was a net importer of electricity under these assumptions.

- The prices that consumers paid for electricity under competitive market conditions in the PC case varied by region and time. The annual average price of electricity across the State was 4.58 ¢/kWh. Payments for energy, transmission, distribution, and demand company services amounted to 2.2 ¢/kWh, 0.4 ¢/kWh, 1.8 ¢/kWh, and 0.2 ¢/kWh, respectively. For much of the year, the prices throughout the State were close. During peak-load months, the rates in some parts of the State were as much as 19% higher. On an annual average basis, the variation across the State was about 5%. Use of the Conservative Assumptions lowered the annual average price paid by consumers to 3.83 ¢/kWh. The variation across the State remained essentially the same.

- Under PC case market conditions, Illinois exported a portion of its electricity throughout the year. On an annual basis, the net export amounted to about 6% of the total generation. State installed capacity was in excess of the peak demand, and the exports can be attributed to the economic competitiveness of power generated in the State. Under Conservative Assumptions, the State is a net importer of electricity (approximately 15%). The dropping of the forced outages, company-level unit commitment, and fixed operating and maintenance costs from both the in-state and out-of-state suppliers resulted in the out-of-state suppliers being more economically competitive. They gained market share under these conditions.

- Virtually all of the in-state generation was provided by nuclear and coal units. On an annual basis, only about 2% of the generation in the State was from natural gas or other fuels under PC case conditions. This was true despite the recent large capacity additions of gas-fired units and the relatively low natural gas prices assumed for the PC case. Use of the Conservative Assumptions did not alter this.

- On an annual basis, the effects of transmission congestion were seen in the northern part of the State with the highest potential in the Chicago metropolitan area. The area north of Chicago and west to the Iowa border also saw significant impacts. Additional impacts were seen in a broad area stretching southwest of Chicago to Peoria and south to Springfield. Smaller pockets of high LMPs were seen in the Sidney, Crossville, Joppa, and Pinckneyville areas. Under Conservative Assumptions, a similar pattern was observed, but was less pronounced.

- Under PC case conditions, including the assumptions about fuel prices, forced outages, and production cost bidding, the generation market was highly concentrated with five generation companies together accounting for 98% of the generation sales. The use of the Conservative Assumptions concentrated this even further, since some of the in-state suppliers could not compete well with out-of-state suppliers under these conditions. One company, Exelon Nuclear, accounted for more than 60% of the generation under these conditions.

- With generation companies bidding into the market at production costs, not all showed an operating profit over the year. The electricity prices on this basis were not high enough to allow all companies to recover their fixed operating costs. Including capital amortization would have exacerbated this situation. Of the 24 companies that own generators in the State, only five showed an operating profit in the PC case. Four of the six are large companies that are currently major participants in the electric power system in the State. Under Conservative Assumptions, all companies except one did not show any operating profit. The one company that did show an operating profit, Exelon Nuclear, had only a very small return. The lower market prices that resulted from these assumptions made it impossible for companies to recover fixed costs. The sustainability of this situation would worsen if capital expenditures were factored into the analysis.

- Under PC case assumptions, in which there was no switching by consumers from one demand company to an alternative supplier, the sale of electricity to consumers was highly concentrated, with three demand companies accounting for more than 98% of sales. The same was true under Conservative Assumptions.

Overall, the PC Case results, under both Case Study and Conservative Assumptions, demonstrated the potential for market power, as defined earlier, to be exerted. Transmission congestion was evident, and there was a concentration in the generation market. The extent to which this market power could be exerted was evaluated in the additional cases that are reported in the following sections.

4.2 PHYSICAL WITHHOLDING CASES

Generation companies participating in a competitive electricity market may elect to take capacity off-line in order to improve their business position. There are two basic conditions under which this physical withholding can be profitable for a generation company:

- *Low prices inhibit cost recovery.* In this situation, a company may determine that the expected market price is too low to operate a unit (or units) profitably. Under these circumstances, the market price may be so low that it is not possible to recover the cost of fuel to run the unit. A generation company can decide that it is cheaper not to run the unit and to wait until prices rise to a level that would allow at least the recovery of fuel and other operating costs.

- *Withholding capacity increases profitability of other units.* In this situation, a company with a portfolio of generators may decide to take one or more units off-line in an effort to cause the LMPs around the system to increase, thus increasing the profit on all its other operating units.

Withholding capacity during periods of low prices is a routine situation and may not indicate an attempt to exercise market power. In fact, all generation companies practice this by shutting down their most expensive-to-operate units during low-load conditions. In the PC case under Case Study Assumptions, the EMCAS model employs a company-level unit commitment algorithm (i.e., the CLUCRA algorithm discussed earlier) that simulates this decision-making in the day-ahead market. That is, generation companies project the day-ahead market prices and take units off-line that are not expected to be able to operate at a profit. Hence, withholding capacity can occur even when such action has no material impact on prices, but is merely a response to the expectation of low prices in the market. (Under the Conservative Assumptions, this CLUCRA algorithm is not used.)

There are many ways for a GenCo to implement a physical withholding strategy with the intent of exercising market power. To identify what approaches might yield attractive results, several tests were done with the EMCAS model. Simulations were carried out in which one unit at a time was taken off-line, several units were taken off-line, and all the units owned by a company were taken off-line. Clearly these are not fundamental business strategies that would be employed on a regular or continuing basis by a GenCo. Nevertheless, these simple cases provide insight into what effects might be expected by implementing these approaches.

4.2.1 Physical Withholding – Single Unit Cases

Case Study Assumptions

The intentional withholding of capacity in an attempt to increase market prices has been a significant issue in all of the operating electricity markets. All markets have installed monitoring mechanisms that, in one form or another, require generation companies to justify taking units out of service, particularly during peak-load periods. To obtain a preliminary indication of the viability of physical withholding to increase profits, a series of simulation runs was conducted in which units were taken off-line one at a time and the resultant impacts on LMPs and company profitability were calculated. For these Physical Withholding – Single Unit (PW-SU) cases, the peak-load day of the analysis year was used in the simulation, as it represented the period during which much of the available capacity needed to be utilized to meet demand. Withholding a unit on this day would have the highest probability of increasing prices throughout the systeml, and thus offer a GenCo the potential for increased profitability (i.e., would meet the definition of market power used here).

The effect that withholding a unit has on market prices depends on three considerations:

- *Unit capacity* – In general, although not always, the larger a unit is, the more it will affect market prices if it is withheld.

- *Unit location on the transmission network* – Units that are in areas of transmission congestion will have a larger impact on the market if the transmission system cannot allow replacement capacity to be utilized. In some cases, withholding a relatively small unit may have a substantial market impact, including creating load curtailments due to transmission congestion.

- *Availability of replacement capacity* – The availability (or unavailability) of replacement capacity, and its price, will determine how the market will respond to physical withholding.

In the PC case, a total of 180 units were scheduled for dispatch on the peak-load day of the analysis year. For the PW-SU cases, single units were assumed to be taken out of service, one at a time, in the day-ahead market. To meet demand, other available units were selected and scheduled for dispatch in the SYSSCHED algorithm used by the ISO simulation in the model (see Section 1.3). All GenCos, including the one withholding a unit, maintained their PC case pricing strategy of bidding available capacity at production cost.

Three conditions were imposed on this analysis. First, of the 180 units scheduled for dispatch, a number were of approximately the same size and were located at the same point in the transmission network. Since withholding a unit of the same size at the same location would produce the same market impact, it was necessary to analyze only 62 unique units for the effects of physical withholding.

Second, withholding units could create conditions where the total load could not be served due to transmission congestion. In practice, transmission system operators might be able to avoid this situation by changing the configuration of the network (e.g., closing breakers that are normally open), allowing lines to overload for a short period of time, or making other adjustments. For this analysis, the original network configuration was preserved. In the simulation, if the day-ahead market showed the need for load curtailment due to withholding, the load was reduced and all available capacity, subject to transmission limits, was scheduled for dispatch.

Third, the biggest impact from physical withholding can be expected on the peak-load day. In the analysis year, this was a day in August. Units that were withheld were assumed to be taken out of service for the entire day. Additional cases were run to determine the effect of withholding units on a low-load day and on a day when a significant number of units were off-line for maintenance.

Table 4.2.1-1 shows the results of the PW-SU case for the peak-load day. The change in company daily profits includes the loss of revenue from the unit being withheld plus the increase in revenue from the higher market prices that are paid to the company's units that continue to operate. The change in other GenCo profits reflects the change in market price that they will experience.

Only 5 of the 62 units tested showed a positive impact of physical withholding on their owners' daily operating profits for the peak-load day. The positive impact was primarily a result of where these units were on the transmission grid rather than on their size.

The table also shows that withholding other units of the same or larger capacity provided no benefit to company profitability. It is the transmission limit that resulted in the positive profit impact.

Withholding any of the other units, one at a time, either had no impact or decreased company daily profits. In these cases, the loss of revenue from the unit being withheld was not offset by the higher market prices for the units still operating.

The results also show that withholding any unit increased the daily operating profit of all other GenCos in almost all cases, due to the higher market prices that all received. The implication is that the withholding of a single unit by any one GenCo might not only decrease its own operating profits, but might serve to increase the operating profit of its competitors, since the decrease in supply raises prices for all.

One of the withheld units, Crawford 8 owned by Midwest Generation, showed very large increases in daily operating profit for the company. This was the result of a load curtailment, which yielded very high prices. While in practice this curtailment might be eliminated by reconfiguring the network and/or allowing transmission line overloads, which were not considered here, the results show that this unit could have a significant impact if it were taken off-line on a peak-load day.

Figure 4.2.1-1 shows the effect of the PW-SU cases on load-weighted zonal LMPs. There was very little effect except for a few units.

Figure 4.2.1-2 shows the distribution of changes in daily operating profits as a function of the capacity of the unit withheld. It demonstrates that an increase in the size of the unit withheld, even on a peak-load day, did not result in increased company profitability. In fact, the opposite was true. The location of the unit on the network was much more important. This is not an unexpected result, given the large amount of generation available in the State.

Table 4.2.1-1 PW-SU Cases (Case Study Assumptions) – Impact on Peak-Load Day GenCo Profits

			GenCo Peak Day Operating Profit[b] ($1000)		Other GenCos Peak Day Operating Profit[b] ($1000)		
Unit Being Withheld [a]	Owner	Capacity Withheld (MW)	PC Case	Change by Withholding	PC Case	Change by Withholding)	Load Curtailed (MW)
Crawford 8	Midwest Generation LLC	319	2,418	8,611	9,599	6,891	56.24
Will County 4	Midwest Generation LLC	510	2,418	99	9,599	757	-
Gibson City 1	Ameren	117	1,730	4	10,288	8	-
University Park North 4	PPL	35.25	8	1	12,010	(9)	-
University Park 1	Constellation Power	62.04	34	0	11,983	2	-
Sterling Ave(1-2) (Northwest)	Ameren	30	1,730	(0)	10,288	3	-
Pinckneyville 3	Ameren	39.5	1,730	(2)	10,288	3	-
Crawford 7G	Midwest Generation LLC	106.5	2,418	(2)	9,599	(0)	-
Raccoon Creek En. Ctr. 1	Aquila Energy	75.2	23	(3)	11,994	3	-
Shelby Energy Center 2	Reliant Energy	41.36	334	(3)	11,683	3	-
Lincoln Energy Center 8	Allegheny Power	78.02	31	(3)	11,987	6	-
Venice (new GT 2-3)	Ameren	48	1,730	(3)	10,288	3	-
Goose Creek En. Center 1	Aquila Energy	70.5	23	(4)	11,994	9	-
Pinckneyville (5-6)	Ameren	79	1,730	(4)	10,288	3	-
Equistar Morris (cogen) 1	Calpine	39	237	(5)	11,780	5	-
Kinmundy 2	Ameren	117	1,730	(5)	10,288	2	-
Powerton 5	Midwest Generation LLC	769	2,418	(5)	9,599	638	-
Crete Energy Park 4	Power Energy Partners	83.66	19	(6)	11,998	(2)	-
Pearl Station 1	Soyland Power Coop Inc.	22	8	(6)	12,009	3	-
Joppa MEPI 2	Ameren	67.68	1,730	(6)	10,288	3	-
Electric Junct (5-12)	Midwest Generation LLC	115.8	2,418	(11)	9,599	4	-
Lakeside (1-2)	City of Springfield	76	121	(12)	11,897	32	-
Lee County 8	Duke Energy	78.02	77	(14)	11,940	7	-
Hennepin 2	Dynegy Midwest Gen Inc.	215	1,062	(18)	10,955	58	-
Hutsonville 4	Ameren	77	1,730	(21)	10,288	14	-
Elwood Energy 2	Dominion Energy	159.8	602	(24)	11,415	72	-
Grand Tower CC 1	Ameren	240	1,730	(24)	10,288	44	-
Nelson (Lee County 1)	NRG Energy	274.56	511	(25)	11,506	44	-
Vermilion 2	Dynegy Midwest Gen Inc.	102	1,062	(27)	10,955	33	-
Elwood Energy III 9	Dominion Energy	161.68	602	(28)	11,415	39	-
Cordova Energy 1	MidAmerican Energy Co.	240	52	(32)	11,966	63	-
Elgin Energy Center 1-2	Ameren	234	1,730	(34)	10,288	101	-
Marion 4	Southern Ill Power Coop.	170	26	(39)	11,991	50	-
Rocky Road 1	Dynegy/NRG Energy	113.74	137	(41)	11,880	69	-
Rockford Energy Center 1	NRG Energy	147	511	(47)	11,506	83	-
Meredosia 3	Ameren	245	1,730	(56)	10,288	47	-
Holland Energy 2	Constellation Power	288	34	(57)	11,983	65	-
Joppa Steam 5	Ameren	169	1,730	(57)	10,288	48	-
Dallman 3	City of Springfield	192	121	(58)	11,897	63	-
Kendall County 4	NRG Energy	240	511	(59)	11,506	100	-
Kendall County 1	NRG Energy	240	511	(60)	11,506	120	-
Aurora (DuPage Co 3)	Reliant Energy	159.8	334	(65)	11,683	112	-
Aurora (DuPage Co 5-10)	Reliant Energy	253.8	334	(67)	11,683	129	-
Zion Energy Center 1	Calpine	150.4	237	(69)	11,780	90	-
Wood River 5	Dynegy Midwest Gen Inc.	372	1,062	(97)	10,955	129	-
Coffeen 1	Ameren	360	1,730	(97)	10,288	102	-
Duck Creek	Ameren	366	1,730	(133)	10,288	200	-
E D Edwards 3	Ameren	361	1,730	(147)	10,288	194	-
Havana 6	Dynegy Midwest Gen Inc.	428	1,062	(148)	10,955	138	-
Kincaid 2	Dominion Energy	579	602	(177)	11,415	176	-
Coffeen 2	Ameren	615	1,730	(178)	10,288	182	-
Newton 2	Ameren	610	1,730	(197)	10,288	150	-
Joliet 29_7	Midwest Generation LLC	518	2,418	(209)	9,599	240	-
Quad Cities 1	Exelon Nuclear/Midamer	855	261	(212)	11,756	183	-
Baldwin 3	Dynegy Midwest Gen Inc.	595	1,062	(221)	10,955	171	-
Waukegan 8	Midwest Generation LLC	361	2,418	(234)	9,599	318	-
Dresden 3	Exelon Nuclear	850	4,335	(317)	7,683	465	-
LaSalle 1	Exelon Nuclear	1,128	4,335	(346)	7,683	328	-
Clinton	Exelon Nuclear	930	4,335	(351)	7,683	408	-
Braidwood 2	Exelon Nuclear	1,179	4,335	(386)	7,683	217	-
Byron 1	Exelon Nuclear	1,195	4,335	(458)	7,683	937	-

[a] Each unit is withheld one at a time with all other units operating.
[b] All GenCos use production cost bidding for their operating units.

Unit Being WithHold	Capacity Withheld (MW)	Peak Hour Zonal LMP ($/MWh) NI-A	NI-B	NI-C	NI-D	NI-E	NI-F	NI-G	IP-A	IP-B	IP-C	IP-D	AMRN-A	AMRN-B	AMRN-D	AMRN-E	CILC	CWLP	SIPC
NONE	**0**	**87.2**	**92.7**	**77.6**	**99.3**	**54.1**	**43.7**	**47.7**	**42.6**	**42.0**	**42.5**	**41.6**	**45.2**	**41.2**	**41.5**	**42.2**	**52.2**	**46.3**	**41.1**
Crawford 8	319	114.4	123.9	97.8	265.1	72.6	48.7	47.8	40.3	41.7	42.2	41.7	44.3	41.4	41.3	42.1	50.8	45.0	41.5
Will County 4	510	98.9	128.5	109.3	147.5	69.4	45.7	47.1	43.3	43.5	43.9	42.9	48.1	42.7	42.9	43.6	60.5	49.6	42.5
Gibson City 1	117	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
University Park North 4	35.25	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
University Park 1	62.04	87.3	92.7	77.7	99.3	54.1	44.0	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Sterling Ave(1-2) (Northwest)	30	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Pinckneyville 3	39.5	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Crawford 7G	106.5	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Raccoon Creek En. Ctr. 1	75.2	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Shelby Energy Center 2	41.36	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Lincoln Energy Center 8	78.02	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Venice (new GT 2-3)	48	86.8	92.7	77.3	99.3	54.1	43.8	47.7	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Goose Creek En. Center 1	70.5	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Pinckneyville (5-6)	79	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Equistar Morris (cogen) 1	39	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Kinmundy 2	117	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Powerton 5	769	90.7	91.7	82.2	96.2	55.5	43.7	51.6	43.8	43.2	42.7	42.9	43.8	42.6	43.3	43.0	66.6	26.9	42.8
Crete Energy Park 4	83.66	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Pearl Station 1	22	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Joppa MEPI 2	67.68	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Electric Junct (5-12)	115.8	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Lakeside (1-2)	76	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Lee County 8	78.02	86.7	92.7	77.2	99.4	54.1	43.8	47.7	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Hennepin 2	215	86.8	92.7	77.3	99.3	54.1	43.9	47.8	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Hutsonville 4	77	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Elwood Energy 2	159.8	88.4	92.5	78.9	98.5	54.4	43.9	49.0	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Grand Tower CC 1	240	86.8	92.7	77.3	99.3	54.1	43.8	47.7	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Nelson (Lee County 1)	274.56	85.7	92.6	76.3	99.4	54.0	43.8	47.8	43.3	41.8	42.5	41.6	45.6	41.1	41.4	42.3	52.1	46.2	41.2
Vermilion 2	102	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Elwood Energy III 9	161.68	87.2	92.7	77.6	99.3	54.1	43.7	47.6	42.6	42.0	42.5	41.5	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Cordova Energy 1	240	86.4	92.6	77.0	99.4	54.1	43.8	47.7	42.9	41.9	42.5	41.6	45.4	41.2	41.4	42.2	52.1	46.2	41.1
Elgin Energy Center 1-2	234	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Marion 4	170	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Rocky Road 1	113.74	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Rockford Energy Center 1	147	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Meredosia 3	245	86.8	92.7	77.3	99.3	54.1	43.8	47.7	42.8	42.0	42.5	41.6	45.3	41.2	41.5	42.2	52.1	46.2	41.1
Holland Energy 2	288	88.0	92.5	78.5	98.7	54.3	43.7	48.5	43.4	43.1	43.5	42.4	46.1	42.2	42.6	43.2	53.2	47.4	42.0
Joppa Steam 5	169	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Dallman 3	192	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Kendall County 4	240	88.3	92.5	78.8	98.5	54.4	43.6	48.8	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Kendall County 1	240	87.2	92.7	77.6	99.3	54.1	43.7	47.6	42.6	42.0	42.5	41.5	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Aurora (DuPage Co 3)	159.8	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Aurora (DuPage Co 5-10)	253.8	87.3	92.7	77.7	99.3	54.1	43.9	47.8	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Zion Energy Center 1	150.4	87.2	92.7	77.6	99.3	54.1	43.7	47.7	42.6	42.0	42.5	41.6	45.2	41.2	41.5	42.2	52.2	46.3	41.1
Wood River 5	372	87.8	92.4	78.4	98.6	54.3	43.7	48.8	43.8	43.4	43.8	42.7	46.5	42.4	42.9	43.5	53.5	47.7	42.2
Coffeen 1	360	88.3	92.5	78.9	98.5	54.4	43.7	48.9	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Duck Creek	366	88.3	92.5	78.8	98.5	54.4	43.6	48.8	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
E D Edwards 3	361	88.3	92.5	78.9	98.5	54.4	43.6	48.8	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.8	47.7	42.3
Havana 6	428	87.7	92.4	78.4	98.6	54.3	43.7	48.8	43.8	43.4	43.7	42.7	46.5	42.4	42.8	43.4	53.6	47.8	42.2
Kincaid 2	579	88.4	92.5	78.9	98.5	54.4	43.9	49.0	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Coffeen 2	615	88.3	92.5	78.9	98.5	54.4	43.7	48.9	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Newton 2	610	88.3	92.5	78.9	98.5	54.4	43.7	48.9	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Joliet 29_7	518	88.2	92.5	78.7	98.5	54.4	43.6	48.8	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Quad Cities 1	855	83.3	92.3	74.5	99.5	53.8	43.8	48.4	44.7	41.9	42.9	42.0	46.4	41.4	41.4	42.7	52.2	46.5	41.5
Baldwin 3	595	88.3	92.5	78.9	98.5	54.4	43.7	48.9	43.7	43.6	43.9	42.8	46.5	42.6	43.0	43.6	53.7	47.9	42.3
Waukegan 8	361	98.1	104.1	83.5	107.5	56.2	45.0	47.9	42.3	41.9	42.4	41.5	45.4	41.2	41.4	42.1	53.3	46.4	41.1
Dresden 3	850	91.5	92.3	81.8	97.5	54.8	43.9	50.2	43.9	45.4	45.3	44.0	47.4	44.0	44.7	44.9	55.4	49.6	43.5
LaSalle 1	1128	88.2	92.8	78.2	99.0	53.3	45.3	48.8	43.3	43.4	43.7	42.9	45.9	42.7	43.0	43.4	52.5	47.0	42.5
Clinton	930	90.6	92.3	81.1	97.7	54.7	43.9	50.0	44.1	45.1	45.1	43.8	47.4	43.8	44.3	44.7	55.1	49.4	43.3
Braidwood 2	1179	88.0	92.6	78.1	98.9	53.3	45.4	48.7	43.3	43.4	43.7	42.9	45.9	42.7	43.0	43.4	52.4	47.0	42.5
Byron 1	1195	110.5	119.7	95.2	118.3	59.5	48.7	50.8	42.8	43.3	43.8	42.8	47.0	42.5	42.8	43.5	56.3	48.3	42.4

Change in LMP	< 5%	5-10%	10-20%	>20%

Figure 4.2.1-1 PW-SU Cases (Case Study Assumptions) – Effect on Zonal LMP

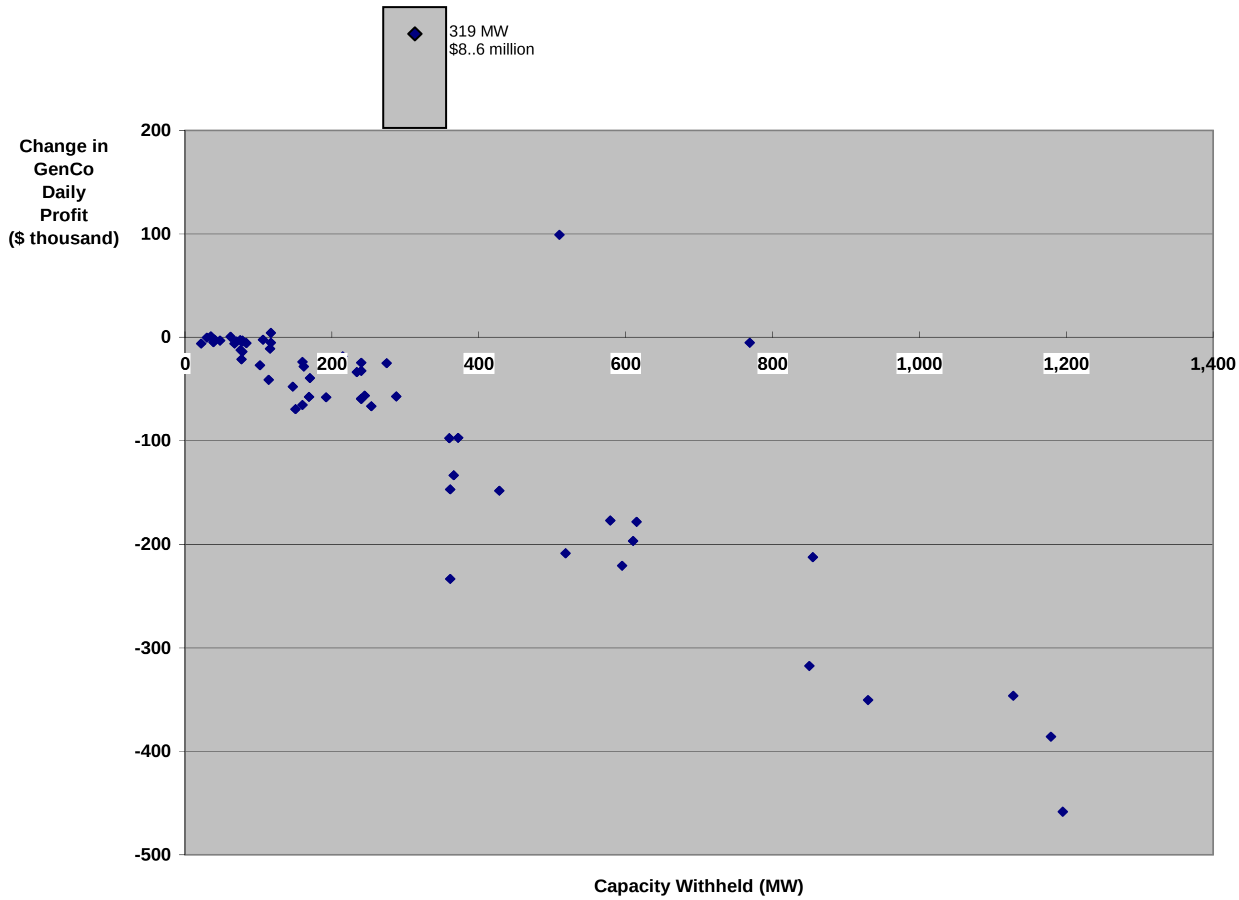


Figure 4.2.1-2 PW-SU Cases (Case Study Assumptions) – Relationship of Capacity Withheld to Daily Operating Profit

Figure 4.2.1-3 shows the location of the units that were withheld in the PW-SU cases. The color coding indicates the magnitude of the change in daily operating profitability on the peak-load day. It is evident that withholding a single unit in the northeast part of the State from among those serving the Chicago metropolitan area was the only condition that offered the potential for an increase in company profits. This is not surprising, given the transmission constraints described in Section 4.1.2. Withholding a unit, even a large capacity one, elsewhere in the State provided little or no benefit to the owners. This is true even given the transmission limits seen elsewhere in the State. The implication is that there is adequate transmission capacity to deal with the loss of individual units. A company seeking to exert market power with this strategy would need to do more than take a single unit out of service.

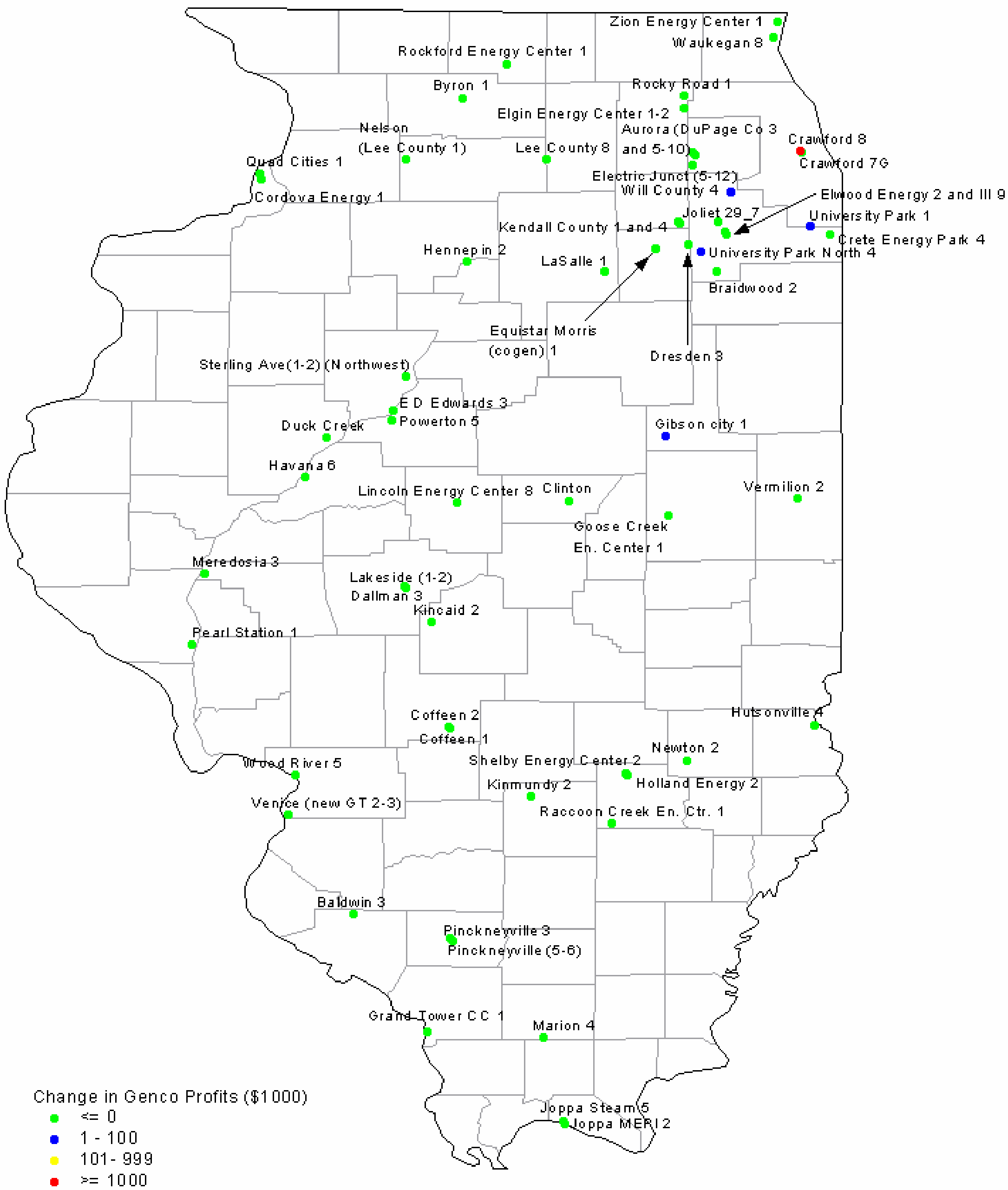


Figure 4.2.1-3 PW-SU Cases Effect of Location of Units Withheld on Company Operating Profitability

Table 4.2.1-2 shows the effect of physical withholding on low load days. One day in the analysis year when the load was low and planned maintenance outages were few was evaluated. Another day when load was low but a number of units were out on planned maintenance was also evaluated. The units showing positive impacts on the peak day were withheld on these days. In both cases the effect on company daily operating profit was not attractive.

Table 4.2.1-2 PW-SU Cases (Case Study Assumptions) – Impact on GenCo Profits on Low Load Days

			Change in GenCo Operating Profit ($1,000)	
Unit Being Withheld	Owner	Capacity Withheld (MW)	Low Load Day with Limited Maintenance Outages	Low Load Day with Extensive Maintenance Outages
Crawford 8	Midwest Generation LLC	319	1	(1)
Will County 4	Midwest Generation LLC	510	(62)	(50)
Gibson City 1	Ameren	117	(3)	0
University Park North 4	PPL	35.25	0	0
University Park 1	Constellation Power	62.04	0	0

Conservative Assumptions

An additional set of physical withholding runs was made to determine if the specific conditions used in the Case Study Assumptions were generating skewed results. Table 4.2.1-3 shows the impact of withholding single units under the Conservative Assumptions where there were no forced outages, no company-level unit commitment algorithm, and fixed operating and maintenance costs were eliminated from the production cost bidding.

Only the 5 units that showed an increase in company profitability were tested. Of these, only one, Crawford 8, showed the ability of its owner to increase company profitability by withholding it. The increase was much smaller than under Case Study Assumptions since there was no load curtailment. For all the other units, the company withholding it lost operating profit.

Thus, under both Case Study and Conservative Assumptions, withholding a single unit is not an effective strategy for a GenCo seeking to exercise market power.

Table 4.2.1-3 PW-SU Cases (Conservative Assumptions) – Impact on Peak Load Day GenCo Profits

			GenCo Peak Day Operating Profit[b] ($1,000)		Other GenCos Peak Day Operating Profit[b] ($1,000)		
Unit Being Withheld [a]	Owner	Capacity Withheld (MW)	PC Case	Change by With-holding	PC Case	Change by With-holding)	Load Cur-tailed (MW)
Crawford 8	Midwest Generation LLC	319	1,134	146	3,952	(137)	0
Will County 4	Midwest Generation LLC	510	1,134	(109)	3,952	(28)	0
Gibson City 1	Ameren	117	631	(0)	4,455	(0)	0
University Park North 4	PPL	35.25	(6)	(0)	5,092	(0)	0
University Park 1	Constellation Power	62.04	(41)	(0)	5,127	(0)	0

[a] Each unit is withheld one at a time with all other units operating.
[b] All GenCos use production cost bidding for their operating units.

4.2.2 Physical Withholding – Multiple Units

The previous results indicated that the withholding of a single unit, even on a peak day, would not offer much incentive to a GenCo seeking to increase profitability. The next step was to investigate the possible effects of multiple units being withheld. There are many possible combinations of multiple units that could have been tested. For the initial set of tests, units that were strategically located and might result in increased profits by their withholding were identified by an inspection of the PC case results. Because of the very large number of possible combinations, only a few illustrative cases were evaluated in this manner. A broader approach was carried out in subsequent cases.

Table 4.2.2-1 shows the results for the Physical Withholding – Multiple Unit (PW-MU) cases. The conditions that produced an increase in the peak-day operating profits were only those that resulted in the need for load curtailments. Other combinations produced no benefit to the company.

Table 4.2.2-1 PW-MU Cases (Case Study Assumptions) – Impact on Peak Load Day GenCo Profits

			GenCo Peak Day Operating Profit[b] ($1000)		Other GenCos Peak Day Operating Profit[b] ($1000)		
Units Being Withheld [a]	Owner	Capacity Withheld (MW)	PC Case	Change by With-holding	PC Case	Change by With-holding)	Load Cur-tailed (MW)
Crawford 8, Will County 4	Midwest Generation LLC	829	2,418	16,817	9,599	24,549	99
Crawford 8, Waukegan 8	Midwest Generation LLC	680	2,418	9,998	9,599	6,137	54
Crawford 7Y, 7G, 8	Midwest Generation LLC	532	2,418	9,596	9,599	8,155	30
Byron 1,2	Exelon Nuclear	2,370	4,335	9,443	7,683	43,398	69
Waukegan 7, 8	Midwest Generation LLC	689	2,418	5,540	9,599	11,074	81
Will County 4, Joliet 29_7	Midwest Generation LLC	1028	2,418	5,096	9,599	14,200	22
Will County 4, Waukegan 8	Midwest Generation LLC	871	2,418	4,656	9,599	14,389	35
Byron1, Clinton	Exelon Nuclear	2125	4,335	724	7,683	5,808	1
Havana 6, Hennepin 2	Dynegy Midwest Gen Inc.	643	1,062	(191)	10,955	187	-
DuckCreek, E.D.Edwards 3	Ameren	727	1,730	(283)	10,288	828	-
Baldwin 3, Wood River 5	Dynegy Midwest Gen Inc.	967	1,062	(331)	10,955	274	-

[a] Each group of units withheld with all other units operating.
[b] All GenCos use production cost bidding for their operating units.

4.2.3 Physical Withholding – Profitability Criteria

The number of combinations of multiple units to withhold was too large to lend itself to an assessment of all of the possibilities. Instead, a screen was needed to identify which units were likely candidates for withholding. The one tested here involved identifying the units that had the smallest profit potential for a GenCo and withholding them from the market. Table 4.2.3-1 summarizes the procedure used to implement this Physical Withholding – Profitability Criteria (PW-PR) case. An initial determination was made of the expected profitability of each unit during each hour of the next day using projected prices at each node of the network. In the PC case, a unit with a positive projected profit would be considered to be available to the market.

In the PW-PR case, the profitability criterion was increased. A profit margin of 150% was selected as an arbitrary starting point for use here. That is, for a unit to be made available to the market, it must be projected to show a profit of 50% over its cost of operation. Units that did not show this rate of return in any hour were considered to be withdrawn for that hour.

When this initial screening of unit profitability was made, the available units were run through the CLUCRA algorithm to develop their optimal dispatch schedule. For those units that were identified as being withheld for selected hours because they failed the profitability criterion, their dispatch schedule was adjusted to reflect minimum downtimes and startup/shutdown costs. The resulting dispatch schedule was what the GenCo offered to the market for the next day. These units were bid into the market at production cost.

Table 4.2.3-1 Physical Withholding – Profitability Criteria Decision Rules

Description	Computational Procedure
GenCos project next day prices. The next day prices are projected by averaging the previous week's prices.	$LMP_{n\,h\,d+1}$ = Average $[LMP_{n\,h\,d}]_{d,d-5}$ *with adjustments for weekends*
GenCos apply the Physical Withholding – Profitability Criteria strategy to identify units to be withheld. If the expected hourly operating profit, including the profitability criteria, is positive, the unit will be made available for that hour and run through the unit commitment algorithm.	*Expected Hourly Profit* $_{g\,h\,d+1}$ $= (LMP_{n\,h\,d+1} - \alpha \times \text{Production Cost}_g) \times \text{Unit Size}_g$ $[\alpha=1.50]$ *If Expected Hourly Profit* $_{g\,h\,d+1} \geq 0$ *Unit will be offered to the market for that hour*
If the expected hourly operating profit, including the profitability criteria, is negative, the unit will be withheld for that hour.	*If Expected Hourly Profit* $_{g\,h\,d+1} < 0$ *Unit is withheld from the market for that hour*
GenCos run the unit commitment algorithm. With the projected prices for the next day and with the identification of which units will be withheld for selected hours, the CLUCRA unit commitment algorithm is run to determine which units will be offered into the market over the day. Those units that have been identified as withheld for selected hours will have their schedules adjusted to account for minimum downtime. Startup and shutdown costs will be included as part of the unit commitment.	CLUCRA $(LMP_{n\,d+1}) \rightarrow$ *Unit commitment with units withheld*
GenCos apply production cost bidding for units that are offered to the market.	
	d = day *h= hour* *n=network node* *g=generator*

Table 4.2.3-2 shows the units that were withheld from the market on the peak day by using the PW-PR screen and their effect on company profitability. Note that some units were withheld for several hours and others were withheld for the entire day. Similar to the single unit withholding results, there was little or no profit benefit to the companies by applying this type of physical withholding. The loss in revenue from withholding the units was not made up by the increase in market prices.

Table 4.2.3-2 PW-PR Case (Case Study Assumptions) – Impact on Peak Load Day GenCo Profits

				GenCo Peak Day Operating Profit[b] ($1000)	
Owner	Units Being Withheld by Application of the 150% Profit Margin Screen [a]	Capacity Withheld (MW)	Hours Withheld	PC Case	Change by With-holding
Allegheny Power	-			31	1
Ameren	Meredosia 4 Grand Tower CC 1 Grand Tower CC 2	200 240 240	1 to 24 1, 24 1, 24	1,730	4
Aquila Energy	-			23	0
Calpine	-			237	-2
Calumet Energy LLC	-			-5	0
City of Springfield	-			121	3
Constellation Power	Holland Energy 1 Holland Energy 2	288 288	1 to 24 1	34	-1
Dominion Energy	State Line 3 State Line 4	197 318	1 to 24 1 to 24	602	6
Duke Energy	-			77	-1
Dynegy Midwest Generation Inc.	Havana (1-5) Hennepin 1 Wood River 1 Wood River 2 Wood River 3	238 74 46.3 46.3 46.3	1 to 24 1 to 6 1 to 24 1 to 24 1 to 24	1,062	9
Dynegy/NRG Energy	-			137	0
Exelon Nuclear	-			4,335	3
Exelon Nuclear/Midamerican Energy	-			261	-6
MidAmerican Energy Co.	Cordova Energy 1 Cordova Energy 2	240 240	1, 24 1, 24	52	0
Midwest Generation LLC	Collins 1 Collins 2 Collins 3 Crawford 7G Fisk 19	554 554 530 106.5 326	1 to 24 1 to 24 1 to 24 9 to 24 8 to 24	2,418	68
NRG Energy	Kendall County 1 Kendall County 2 Kendall County 3 Kendall County 4 Nelson (Lee County 1) Nelson (Lee County 2) Nelson (Lee County 3) Nelson (Lee County 4) Rockford Energy Center 3	240 240 240 240 274.56 274.56 274.56 274.56 147	1, 24 1, 24 1, 24 1, 24 1, 24 1, 24 1, 24 1, 24 1 to 10, 23, 24	511	-1
Power Energy Partners	-			19	2
PPL	-			8	0
Reliant Energy	-			334	0
Southern Illinois Power Coop.	Marion 1 Marion 2 Marion 3	34 34 34	1 to 24 1 to 24 1 to 24	26	4
Southwestern Electric Coop.	-			-3	0
Soyland Power Coop Inc.	Pearl Station 1	22	1,2,24	8	0

Additional cases were run with changes in the profitability criterion, both higher and lower. The same pattern of limited impact on company profitability was observed. It can be concluded that the profitability criterion does not provide an adequate identification of units that could be withheld to increase overall company profitability.

4.2.4 Physical Withholding – System Reserve Criteria

Another screen was used in an attempt to identify units that a company might consider for physical withholding. This was based on using the system reserve – the generating capacity that is available in excess of the load. Table 4.2.4-1 summarizes the decision rules for this approach.

Table 4.2.4-1 Physical Withholding – System Reserve Criteria Decision Rules

Description	Computational Procedure
GenCos project next day prices. The next day's price for each hour at each node of the network is projected as inversely proportional to the system reserve. That is, as the reserve margin decreases, prices are projected to increase proportionally. This is a simple projection approach but captures the anticipated effects of high demands on the system on prices.	*System Reserve (SR)* $= (\text{Available Capacity}_{h\ d+1}\ /\ \text{Load}_{h\ d+1}\ -\ 1)$ $LMP_{n\ h\ d+1} = LMP_{n\ h\ d}\ (SR_{h\ d} / SR_{h\ d+1})$
GenCos apply the Physical Withholding – System Reserve Criteria strategy to adjust the unit commitment. If the system reserve margin is expected to be lower than a trigger point, units are considered for withholding. Units are rank-ordered by the projected price (LMP) from highest to lowest. Capacity to be withheld is that which will bring the SR down by a target amount. Units are withheld up to a specified portion of the company's total capacity. If the system reserve margin is expected to be higher than the trigger point, no units are withheld.	*If* $SR_{h\ d+1} \leq \theta$ [θ=55%] *Unit ranking: Highest LMP, second highest, …* *Target reduction in system reserve by withholding =* σ [σ=5%] *Capacity Withheld* $= \sum_{\sigma}$ *Units in rank order* *where Capacity Withheld* $\leq \delta$ *x Company Capacity* [δ=25%] *If* $SR_{h\ d+1} > \theta$ *No withholding*
GenCos run the unit commitment algorithm. With the projected prices for the next day and with the identification of which units will be withheld for selected hours, the CLUCRA unit commitment algorithm is run to determine which units will be offered into the market over the day. Those units that have been identified as withheld for selected hours will have their schedules adjusted to account for minimum downtime. Startup and shutdown costs will be included as part of the unit commitment.	*CLUCRA* $(LMP_{n\ d+1}) \rightarrow$ *Unit commitment with units withheld*
GenCos apply production cost bidding for units that are offered to the market.	
	d = day *h= hour* *n=network node* *g=generator*

Case Study Assumptions

In the Physical Withholding – System Reserve Criteria (PW-SR) case, the GenCo strategy was based on identifying when the system reserve was expected to be low and then withholding capacity in an attempt to drive up prices. It recognized the fact, as was shown previously, that during periods of high system reserve (i.e., low loads, high available generation) there was ample capacity for competitors to take up the slack from any units that were withheld from service. By identifying times when the system reserve was low, a company could pinpoint those hours when withholding a unit would have the biggest impact. Based on a number of experiments with the EMCAS model, a system reserve of 55% was selected as the trigger point for companies to implement this strategy. During periods when the system reserve was higher, there was no benefit to withholding. From the load and available capacity projections, the system reserve was projected to be below 55% for 108 hours during the analysis year. (Under Conservative Assumptions, it was below 55% for 48 hours during the analysis year.)

With the projected system reserve for the next day, GenCos projected the next day's prices. Instead of using the average of the previous week's prices, as was done in earlier cases, a more forward-looking approach was used in an attempt to take better advantage of expected high price conditions. The next day's prices were projected to be inversely proportional to the system reserve. These projections were then used in the unit commitment algorithm (i.e., the CLUCRA described in Section 1.3) to develop an initial listing of units to be offered into the next day's market.

If the system reserve was expected to be at or below the trigger point, the GenCos considered withholding units to increase prices. Their portfolio of units was rank-ordered by the LMP of the bus they were connected to. Generators at buses with the highest LMPs were ranked first, as they would likely have the biggest impact on prices if they were taken out of service. The amount of capacity to be withheld was that which would bring the system reserve lower by a target amount. For these cases, the target amount was chosen to be 5%. This value was selected after experimenting with a number of possible values. Much larger values were shown to generate withholding that was too extensive. Much smaller values restricted the withholding to being inconsequential.

With the target amount of capacity to be withheld when the trigger point was reached, GenCos proceeded through the rank-ordered list and withheld enough capacity to meet the target. A limit was placed on the total amount of a company's capacity that would be withheld. In these cases, the limit was set at 25% of the total company capacity. This was done to avoid extreme conditions that were not practical and not of interest.

Cases in which individual companies applied the PW-SR strategy one at a time were studied. Also studied was a case in which all companies pursued the strategy at the same time. Table 4.2.4-2 shows the effects on GenCo peak day profitability when the Case Study Assumptions were used. In all cases, the application of this strategy led to the need for load curtailments. This strategy enabled companies to not only identify how much capacity could be withheld to affect the system reserve, but also where that withholding would have the biggest effects. There were clear profit benefits to the companies by using this method to withhold capacity. For the largest three companies, peak day profits increased between 100% (Ameren) to 668% (Midwest Generation) if each were to apply the strategy by itself. If all companies applied the strategy at the same time, the company profitability would increase by more than 17 times. In addition to benefits to the companies employing the strategy, there were significant benefits to other GenCos as well, as shown on the table. Figure 4.2.4-1 shows the location of the units withheld by the application of the PW-SR strategy. They are all in areas affected by the transmission congestion discussed in Section 4.1.2.

Table 4.2.4-2 PW-SR Case (Case Study Assumptions) – Impact on GenCo Peak Day Profits

			GenCo Peak Day Operating Profit ($1,000)		Other GenCo Peak Day Operating Profit ($1,000)		
GenCo Applying PW-SR Strategy	**Units Withheld**	**Capacity Withheld (MW)**	**PC Case**	**Change by With-holding**	**PC Case**	**Change by With-holding**	**Load Cur-tailed (MW)**
Exelon Nuclear	Byron 1	1,195	4,140	9,487	7,033	42,091	70
	Byron 2	1,175					
Midwest Generation LLC	Joliet 29_7	518	2,037	13,602	9,136	40,926	208
	Joliet 29_8	518					
	Crawford 7Y	107					
	Waukegan 6	100					
	Waukegan 7	328					
	Waukegan 8	361					
Ameren	E D Edwards 1	117	1,647	1,728	9,526	1,544	55
	E D Edwards 2	262					
	E D Edwards 3	361					
	Duck Creek	366					
	Coffeen 1	360					
	Meredosia 3	245					
Dynegy Midwest Generation Inc.	None	0	1,037	-	10,136	-	-
Dominion Energy	None	0	527	-	10,646	-	-
All Companies							1,089
Exelon Nuclear	Byron 1	1,195	4,140	40,628	7,033	222,556	
	Byron 2	1,175					
Midwest Generation LLC	Joliet 29_7	518	2,037	81,047	9,136	182,138	
	Joliet 29_8	518					
	Crawford 7Y	107					
	Waukegan 6	100					
	Waukegan 7	328					
	Waukegan 8	361					
Ameren	E D Edwards 1	117	1,647	14,977	9,526	248,207	
	E D Edwards 2	262					
	E D Edwards 3	361					
	Duck Creek	366					
	Coffeen 1	360					
	Meredosia 3	245					

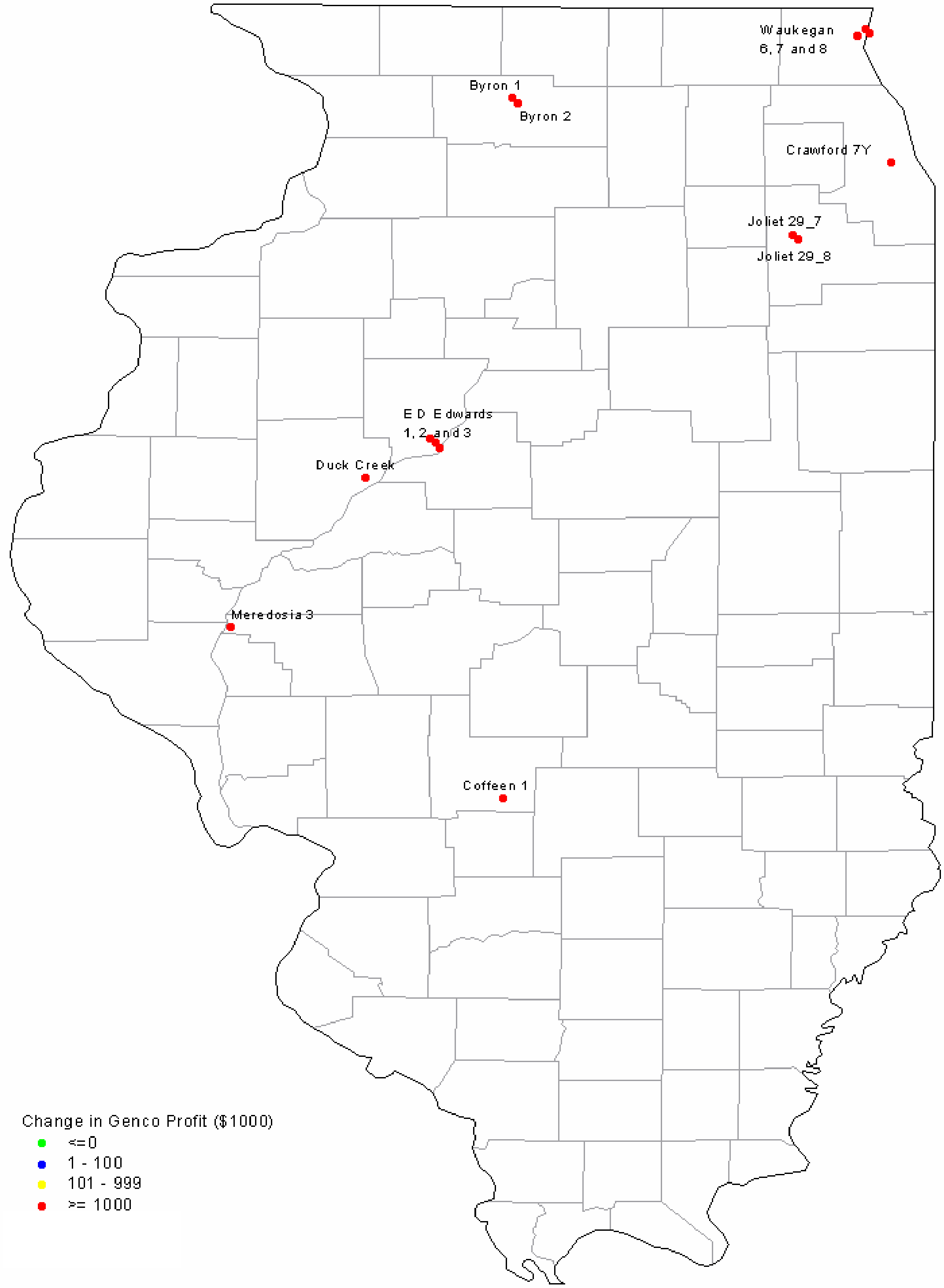


Figure 4.2.4-1 PW-SR Cases (Case Study Assumptions) – Effect of Location of Units Withheld on Company Operating Profitability

Figure 4.2.4-2 shows the effect of the PW-SR strategy on the daily maximum zonal LMPs. Recall that in this strategy, only production cost bidding was used by the companies. There was no strategic price bidding by any company. In some cases, the LMP increases were substantial. With all companies applying the strategy, the LMPs reached into the thousands. This is a clear indication of the limitations of the transmission system to allow the capacity that was available to replace the withdrawn capacity. The result was load curtailments and very high prices.

Company Withholding	None	Exelon	Midwest Generation	Ameren	Dynegy	Dominion	All
Capacity Withheld (MW)	0	2370	1932	1711	0	0	6013
Zone	Maximum Zonal LMP ($/MWh)						
NI-A	87.2	108.0	170.0	91.9	83.7	83.7	3,664.9
NI-B	92.7	140.5	932.7	116.3	94.2	94.2	4,341.8
NI-C	77.6	89.4	171.6	82.3	71.5	71.5	2,901.1
NI-D	99.3	87.9	310.5	81.2	65.9	65.9	4,184.9
NI-E	54.1	50.8	120.4	46.5	41.8	41.8	1,907.7
NI-F	43.7	44.8	78.2	42.4	38.4	38.4	653.9
NI-G	47.7	54.9	83.5	45.0	45.2	45.2	1,309.7
IP-A	43.2	51.1	44.4	44.4	44.4	44.4	649.8
IP-B	42.1	43.4	44.4	41.3	41.8	41.8	131.2
IP-C	42.6	44.1	45.0	42.0	42.2	42.2	42.0
IP-D	41.6	42.9	43.9	41.3	41.3	41.3	41.2
AMRN-A	45.3	48.8	54.0	44.5	44.5	44.5	400.8
AMRN-B	41.2	43.7	45.5	40.7	41.0	41.0	40.7
AMRN-D	41.6	42.6	43.8	40.9	41.3	41.3	45.7
AMRN-E	42.3	43.3	44.0	41.9	42.0	42.0	41.9
CILC	52.2	55.8	128.3	3840.6	47.8	47.8	5,987.9
SIPC	41.1	41.8	42.6	41.3	41.2	41.2	41.2
CWLP	46.3	49.3	51.8	44.0	44.7	44.7	109.3

Change in LMP	< 5%	5-10%	10-20%	>20%

Figure 4.2.4-2 PW-SR Cases (Case Study Assumptions) – Impact on Zonal LMP

Table 4.2.4-3 shows the effect on consumer costs. The increases were substantial, ranging from a 100% increase for the case where Ameren applied the PW-SR strategy to a 550% increase if Midwest Generation applied the strategy. If all companies applied the strategy, consumer peak day costs increased by almost a factor of 20. These results are consistent with the transmission congestion effects described in the PC case. The NI zones saw the biggest impacts from an attempt to exercise market power, in this case by using physical withholding. The IP, AMRN, and SIPC zones were impacted to a smaller degree. The CILC zone showed some vulnerability to this market power strategy.

Table 4.2.4-3 PW-SR Cases (Case Study Assumptions) – Impact on Peak Day Consumer Costs

		Company Applying PW-SR Strategy					
Zone	PC Case Peak Day Consumer Costs ($1,000)	Exelon Nuclear	Midwest Generation LLC	Ameren	Dynegy	Dominion Energy	All
		Change in Consumer Costs ($1,000)					
NI-A	3,615	16,709	17,344	176	0	0	82,653
NI-B	9,361	49,560	93,901	1,014	0	0	242,376
NI-C	4,171	14,866	20,199	190	0	0	75,414
NI-D	10,136	40,081	79,345	1,019	0	0	223,983
NI-E	4,532	7,446	14,521	223	0	0	49,423
NI-F	482	645	612	12	0	0	2,115
NI-G	331	453	342	(19)	0	0	3,161
IP-A	973	200	121	(186)	0	0	5,129
IP-B	559	90	50	(16)	0	0	(133)
IP-C	1,316	198	137	(29)	0	0	(1,362)
IP-D	776	61	54	(3)	0	0	(72)
AMRN-A	780	360	538	(3)	0	0	2,389
AMRN-B	1,224	166	122	(10)	0	0	(317)
AMRN-D	284	40	20	(6)	0	0	(67)
AMRN-E	1,319	205	152	(20)	0	0	(721)
CILC	1,436	2,321	4,200	43,122	0	0	49,511
SIPC	267	3	3	0	0	0	(9)
CWLP	525	(36)	(56)	(89)	0	0	163
Total	**42,087**	**133,367**	**231,606**	**45,377**	**0**	**0**	**733,637**

It should be noted that there are several parameters that affect the results of this strategy: the system reserve trigger point (chosen as 55% here), the system reserve reduction target (chosen as 5% here), and the maximum portion of company capacity to be withheld (chosen as 25% here). The values chosen here for these parameters are not intended to imply that these are the best or most realistic. Rather, they represent levels that provide insight into how this strategy might function. Sensitivity studies over a wide range of these values would be appropriate for further analysis.

Conservative Assumptions

Table 4.2.4-4 shows the effect of the application of this strategy under the Conservative Assumptions. With one exception, the results are the same as for the Case Study Assumptions, but the profit increases were more modest, since the prices were lower under these assumptions. Also, because of the larger amount of generation available due to the absence of forced outages and the company-level unit commitment under the Conservative Assumptions, there was less load curtailment. The exception is the application of this strategy by Exelon Nuclear. For this company, it did not increase profitability, as there was adequate generation and transmission capacity to replace the units withheld. There was no need for load curtailment in this case.

Table 4.2.4-4 PW-SR Case (Conservative Assumptions) – Impact on GenCo Peak Day Profits

			GenCo Peak Day Operating Profit ($1,000)		Other GenCo Peak Day Operating Profit ($1,000)		
GenCo Applying PW-SR Strategy	**Units Withheld**	**Capacity Withheld (MW)**	**PC Case**	**Change by With-holding**	**PC Case**	**Change by With-holding**	**Load Cur-tailed (MW)**
Exelon Nuclear	Byron 1	1,195	2,478	(675)	2,608	814	-
	Byron 2	1,175					
Midwest Generation LLC	Joliet 29_7	518	1,134	1,829	3,952	5,501	44
	Joliet 29_8	518					
	Crawford 7Y	107					
	Waukegan 6	100					
	Waukegan 7	328					
	Waukegan 8	361					
Ameren	E D Edwards 1	117	631	1,507	4,455	749	60
	E D Edwards 2	262					
	E D Edwards 3	361					
	Duck Creek	366					
	Coffeen 1	360					
	Meredosia 3	245					
	Meredosia 4	200					
Dynegy Midwest Generation Inc.	None	0	425	-	4,661	-	-
Dominion Energy	None	0	114	-	4,971	-	-
All Companies							253
Exelon Nuclear	Byron 1	1,195	2,478	13,359	2,608	61,205	
	Byron 2	1,175					
Midwest Generation LLC	Joliet 29_7	518	1,134	25,076	3,952	49,487	
	Joliet 29_8	518					
	Crawford 7Y	107					
	Waukegan 6	100					
	Waukegan 7	328					
	Waukegan 8	361					
Ameren	E D Edwards 1	117	631	3,567	4,455	70,997	
	E D Edwards 2	262					
	E D Edwards 3	361					
	Duck Creek	366					
	Coffeen 1	360					
	Meredosia 3	245					
	Meredosia 4	200					

4.2.5 Physical Withholding – Companywide

An extreme case of physical withholding would be for a company to pull all of its capacity out of service. Obviously, this would not improve the company's profitability; nevertheless, some of the indicators used by FERC to determine if a company has market power (e.g., the supply margin assessment, the residual supply index) are based on determining if load can be met without any contribution from the company being evaluated. With the concentration of capacity in a few companies, such as is the case in Illinois, this strategy could be expected to result in significant amounts of unserved energy. Table 4.2.5-1 shows the results of the Physical Withholding – Companywide (PW-CW) case. The amount of load that would need to be curtailed if each company took all of its capacity out of service is shown along with the zonal LMP effect.

Table 4.2.5-1 PW-CW Case – Load Curtailments and Zonal Price Effects

Generation Company	Capacity Withheld (MW)	Load Curtailed during Peak Hour of Peak Day (MW)	Maximum Zonal LMP during Peak Day		Load Curtailed during Off-Peak Hours of Peak Day (MW)
			($/MWh)	Zone	
Exelon Nuclear	9,947	1,237	5,051	NI-B	0
Midwest Generation	8,063	1,867	6,307	NI-D	0
Ameren	6,815	106	1,775	NI-A	0
Dynegy	3,812	0	96	NI-D	0
Dominion Energy	3,121	0	130	NI-D	0
City of Springfield	610	28	7,342	CWLP	0

The results show that Exelon Nuclear, Midwest Generation, Ameren, and the City of Springfield have market power using these criteria. In the case of Exelon Nuclear and Midwest Generation, the amount of load that would have to be curtailed was extensive and would likely have resulted in emergency conditions. In the case of Ameren and the City of Springfield, the amount of curtailment was small enough that it might have been managed with changes to the network configuration, which were not considered here. Nevertheless, the impact on zonal LMPs was substantial.

4.2.6 Physical Withholding Summary

The following summary observations can be made with respect to physical withholding strategies*:*

- Physically withholding individual units increased company operating profits only when applied to a few selected units. This was true for both the Case Study Assumptions and the Conservative Assumptions. For most units, withholding it from service on peak days resulted in a decrease in company operating profit. For a very few units that were critical to meeting load during peak hours, withholding it from service could create a situation where the demand could not be met without some change to the transmission network configuration. Unserved energy could result in large increases in prices and company profitability. However, this situation is generally avoided by companies seeking to maintain good customer relations.

- Withholding multiple units provided an increase in company profitability. However, this appeared to result only in cases where there was the need for load curtailment associated with the withholding.

- Unit profit margin did not serve as a good screen for a company to identify combinations of units for withholding. The change in profitability by the application of this screen was small.

- System reserve did appear to be a good screen for identifying units to withhold. If it was used, units could be withheld that provided a significant increase in company peak day profitability. Very high LMPs and very high increases in consumer costs also resulted from the application of this approach. Under Conservative Assumptions, the same was generally true except that the increases in profits were more modest. The exception to this result was Exelon Nuclear, for whom the application of this strategy did not increase profitability.

- The same zones that experienced high LMPs due to transmission congestion under PC case conditions were shown to be the most impacted by the application of a physical withholding strategy; i.e., the NI zones. The IP, AMRN, and SIPC zones were less impacted. The CILC zone showed a degree of vulnerability.

- Using the criteria of determining if load could be met without any contribution from a company indicated that Exelon Nuclear, Midwest Generation, Ameren, and the City of Springfield had market power. Load could not be met if all their units were taken out of service. Dynegy and Dominion Energy did not have market power, according to this measure.

4.3 ECONOMIC WITHHOLDING CASES

Economic withholding strategies in a competitive electricity market differ from physical withholding strategies in that the generation capacity is not taken off-line. Rather, it is made available to the market, but at increased prices. Analogous to physical withholding, the effect that economic withholding has on market prices depends on the size of the unit that has its price increased, the unit's location in the transmission network, and the availability of other capacity at lower prices.

4.3.1 Economic Withholding – Single Unit

To determine how economic withholding might affect the Illinois market, EMCAS simulation runs were conducted in which single units were assumed to have their bid prices increased. For the initial runs, attention was focused on the units that demonstrated a positive impact on company profitability in the physical withholding case described in the previous section. For these individual units, the price at which capacity was bid into the market was increased in multiples between 1.25 and 10 times above the unit's production cost. Two cases were run for each unit. In the first, the unit's bid price was increased for the entire peak-load day. In the second, the price increases were applied only during five peak-load hours. Table 4.3.1-1 shows the results of these simulations.

Table 4.3.1-1 Economic Single Unit Withholding (Case Study Assumptions) – Impact on Peak Load Day GenCo Profits

Unit Being Withheld	Owner	Capacity With Increased Bid Prices (MW)	PC Case Peak Day Operating Profit ($1000)	Hours that Prices Are Increased	Change in Company Peak Day Operating Profit With Increase in Bid Price Over Production Cost ($1000)					
					1.25	1.5	1.75	2.0	5.0	10.0
Crawford 8	Midwest Generation LLC	319	2,418	All Hours	-9.8	4.5	13.2	4.3	22.0	39.6
				Peak Hours	0.0	0.0	0.0	0.0	-58.5	5.5
Will County 4	Midwest Generation LLC	510	2,418	All Hours	-17.0	-46.7	-55.5	-65.9	-178.2	-189.9
				Peak Hours	0.0	0.0	0.0	0.0	-44.3	-74.7
Gibson City 1	Ameren	117	1,730	All Hours	4.3	4.3	4.3	4.3	4.3	4.3
				Peak Hours	1.9	1.9	1.9	1.9	1.9	1.9
University Park North 4	PPL	35.25	8	All Hours	0.4	0.8	0.8	0.9	0.8	0.9
				Peak Hours	-0.1	0.0	0.0	0.0	0.0	0.0
University Park 1	Constellation Power	62.04	34	All Hours	0.4	0.4	0.4	0.4	0.4	0.4
				Peak Hours	0.3	0.2	0.2	0.3	0.2	0.2

Economic withholding of single units had a very small impact on company peak day profitability. In some cases, the effect was negative, since the price increase reduced the unit's competitiveness in the market and its dispatch schedule was reduced. In all cases, the profitability increase was below, or at best equal to, what was experienced by simply physically withholding the unit. The implication is that single unit economic withholding resulted in the unit being dispatched less. There was adequate generation and transmission capacity available to allow other units to meet the load.

4.3.2 Economic Withholding – Companywide Withholding

A broader case of an economic withholding strategy is for a GenCo to increase the bid prices on all units in its portfolio. To determine the effectiveness of this strategy, EMCAS simulation runs were conducted in which the bid prices of all units for a selected GenCo were increased in multiples above production cost for the peak-load day. All other GenCos were assumed to maintain their bid prices at production cost. The results for each company are documented in the following sections. It should be restated that these simulations are not intended to imply that any company would employ this type of strategy. Rather, they are designed to identify what might be possible under the market configuration used in the simulation.

Exelon Nuclear

Case Study Assumptions

Figure 4.3.2-1 shows the results of companywide economic withholding as applied to the Exelon Nuclear portfolio of generators. The company's operating profits and generation level for the peak day are shown as a function of the amount that the price was increased above production cost. In the simulations, all units in the company's portfolio had their market bid prices increased at the same rate for the entire day. Figure 4.3.2-2 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested.

The results showed that for price increases up to about five times production cost, the company lost both generation (i.e., was dispatched less) and daily operating profit in the market. Up to this point, there was less expensive generation and adequate transmission capacity available to meet the load, both from in-state and out-of-state sources. As shown on Figure 4.3.2-2, during peak hours about 6,000 MW of the company's generating capacity was needed to meet the load. For this portion of capacity, prices could be increased considerably and still be accepted in the market. This is shown by the flattening of the generation curve in Figure 4.3.2-1. The Dresden, Byron, and LaSalle plants were the units that were still dispatched, even at the higher prices. Transmission limits kept cheaper capacity from displacing these higher-priced units. There is, however, a technical limit that keeps this from being a practical result. Under the market rules employed here, GenCos that have units that must run to stay within their technical performance limits must adjust their bid prices so as to ensure that their units are dispatched. Since Exelon's units are all nuclear plants, they are not readily cycled to match the dispatch schedule that would result from this pricing scheme.

These results also showed that Exelon Nuclear would not be able to increase the prices of its nuclear generators significantly for the entire day without running the risk that they would be outbid in the market during lower-load hours and thus have a dispatch schedule that would not be technically feasible. An alternative strategy would be to increase prices only during peak hours. Figure 4.3.2-3 shows these results. Prices were increased only during the period from 2 pm to 6 pm, when the load was the greatest. This was a far more attractive strategy from the company's perspective. The company's generation level was reduced only a small amount even as prices increased significantly. Even a twenty-fold price increase did not measurably change the company's generation level. In fact, prices could conceivably be raised even higher, since the generation level flattened out. This is in the absence of any consumer price response and/or regulatory controls..

At the twenty-fold increase above production cost, the company's capacity-weighted average bid price was about 315 $/MWh, which is considerably more expensive than other available capacity. The Exelon price increases caused an adjustment to the loading of the transmission system as the transmission-constrained dispatch (i.e., the SYSCHED algorithm in EMCAS) sought to replace the now-more-expensive Exelon units. However, cheaper generation was not able to displace these units because of transmission limitations. Table 4.3.2-1 shows the transmission components that were operated at their capacity limits at the twenty-fold price increase level. The location of these components was shown on Figure 4.1.2-1. An additional component, the Moweaqua line, also reached its capacity limit. Some lines (shown in normal print) remained at their capacity limits, as was seen in the PC case. Some lines (shown in bold) that were not congested under PC case conditions became congested as the system attempted to displace the expensive Exelon units. These newly congested lines were all outside the NI zones as the system sought to bring in power from elsewhere. Other lines (shown shaded) actually experienced a relaxation of congestion as the system adjusted to the price increases. This relaxation, however, did not allow for enough additional lower-cost-power to be dispatched to keep prices from rising.

This pricing strategy impacted the cost of electricity for consumers. Figure 4.3.2-4 shows the impact of the price increments on zonal LMPs. Figure 4.3.2-5 shows the impact on consumer costs. The results show that the company strategy had a significant impact. As was seen in the PC case discussion of transmission loading, the NI zones were the most impacted by the price increases. The transmission limits in these areas did not allow cheaper power to be brought in. In effect, the company could set prices at any level. Again, this should not be interpreted as an indication that the company would, in practice, exercise this market power.

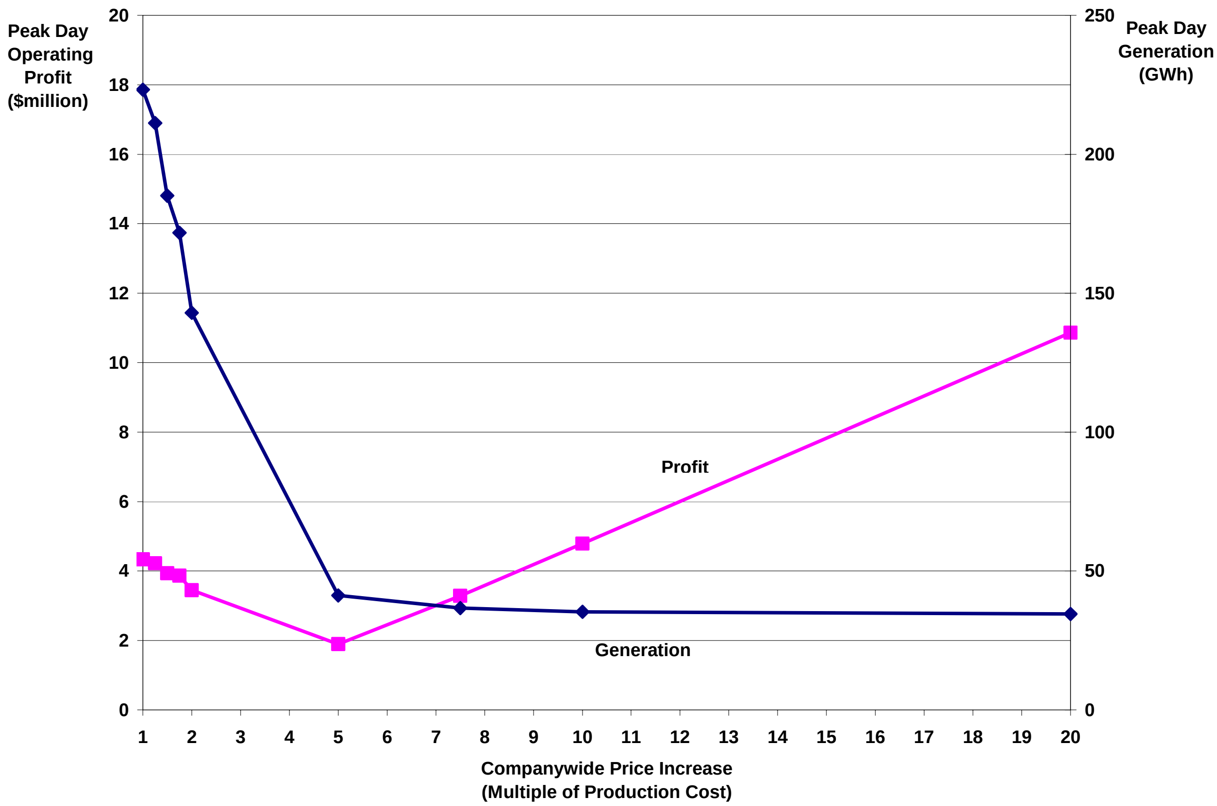


Figure 4.3.2-1 Exelon Nuclear Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

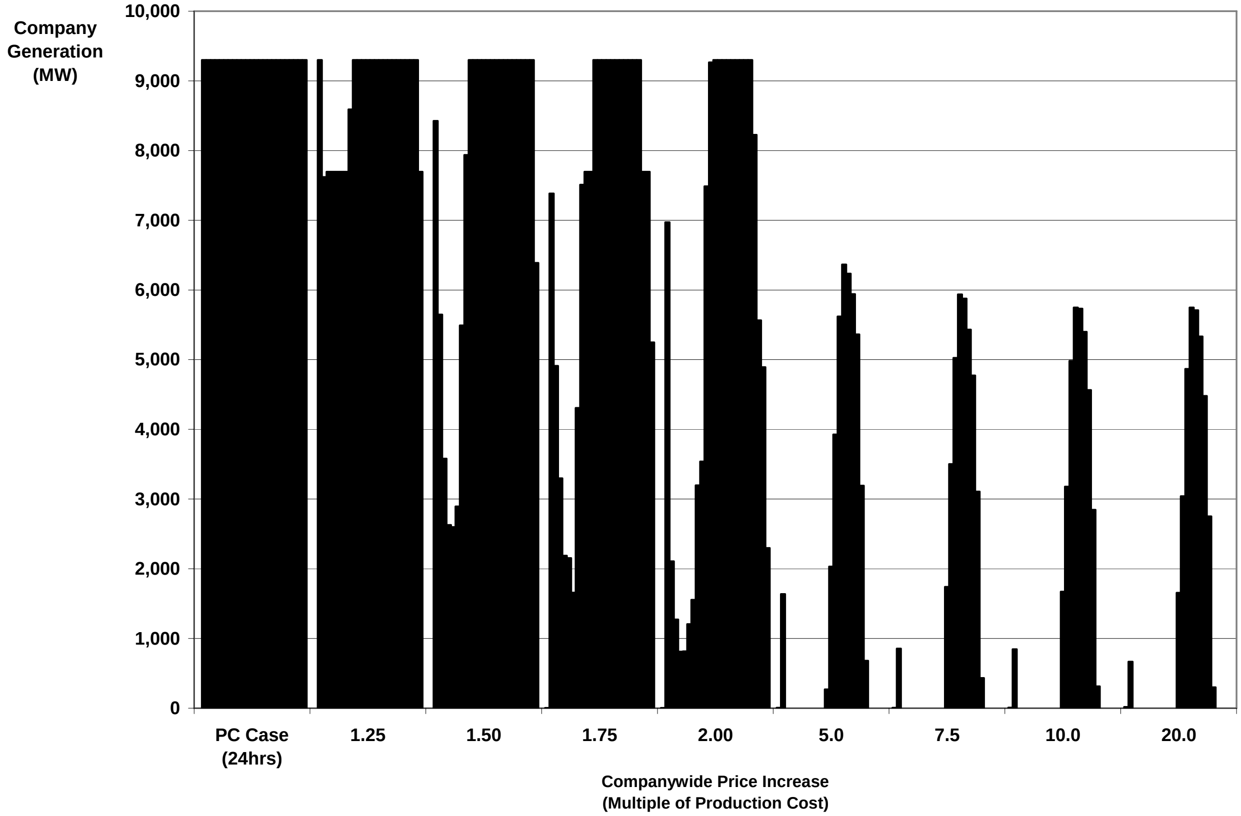


Figure 4.3.2-2 Exelon Nuclear Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

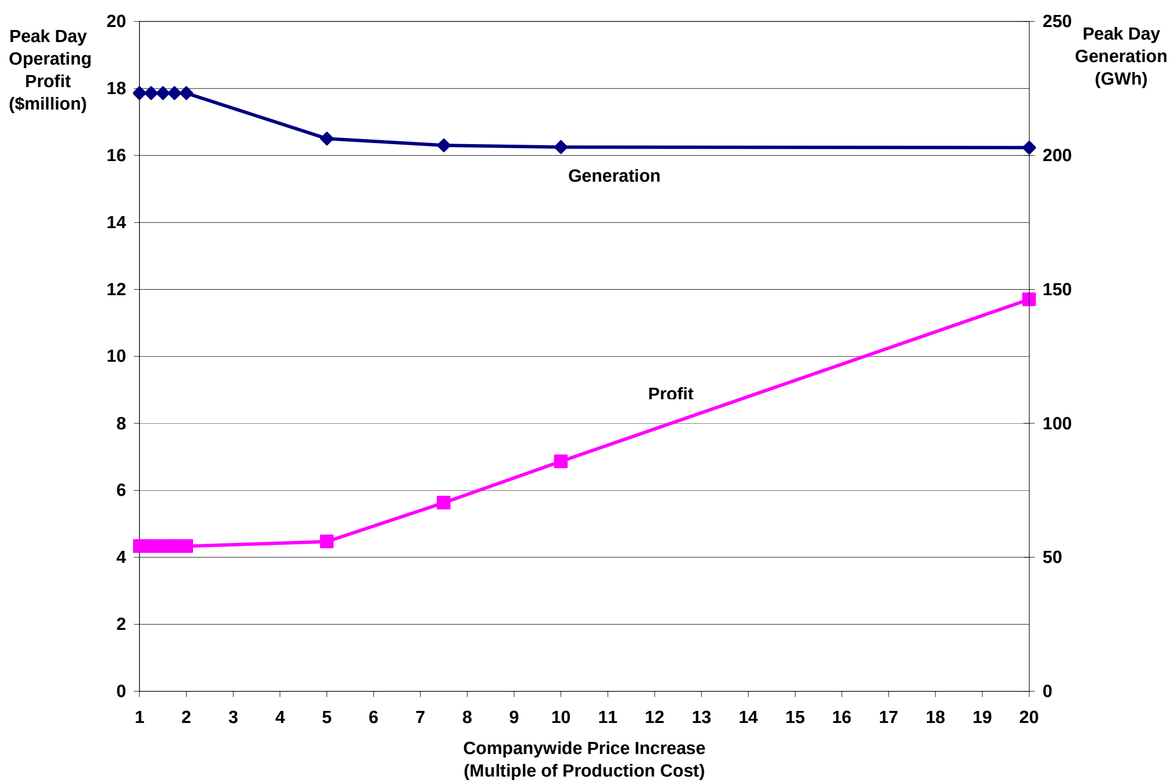


Figure 4.3.2-3 Exelon Nuclear Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-1 Transmission Components at Capacity Limits under Exelon Nuclear 20-Fold Peak Hour Price Increase (Case Study Assumptions)

ID	Bus From	Bus To	Zone From	Zone To	Equipment		
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-C							
32355_32369	**PANA IP**	**MOWEAQ T**	**IP-C**	**IP-C**	**138**	**kV**	**Line**
32368_32369	**RT 51 TP**	**MOWEAQ T**	**IP-C**	**IP-C**	**138**	**kV**	**Line**
AMRN-B							
30395_31445	**COFFEEN**	**PANA**	**AMRN-B**	**AMRN-B**	**345**	**kV**	**Line**
30439_31351	**CROSSVL**	**NORRIS**	**AMRN-B**	**AMRN-B**	**138**	**kV**	**Line**
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer
CILC							
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

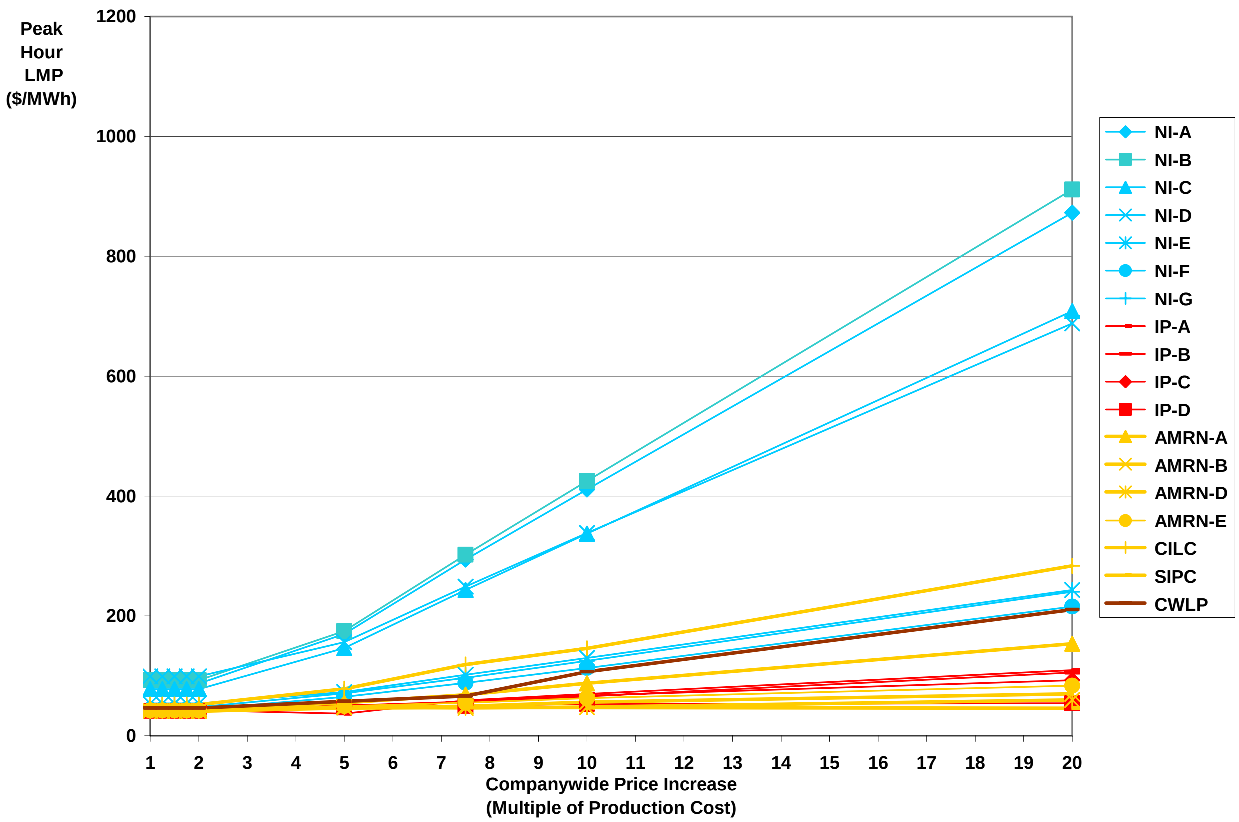


Figure 4.3.2-4 Exelon Nuclear Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

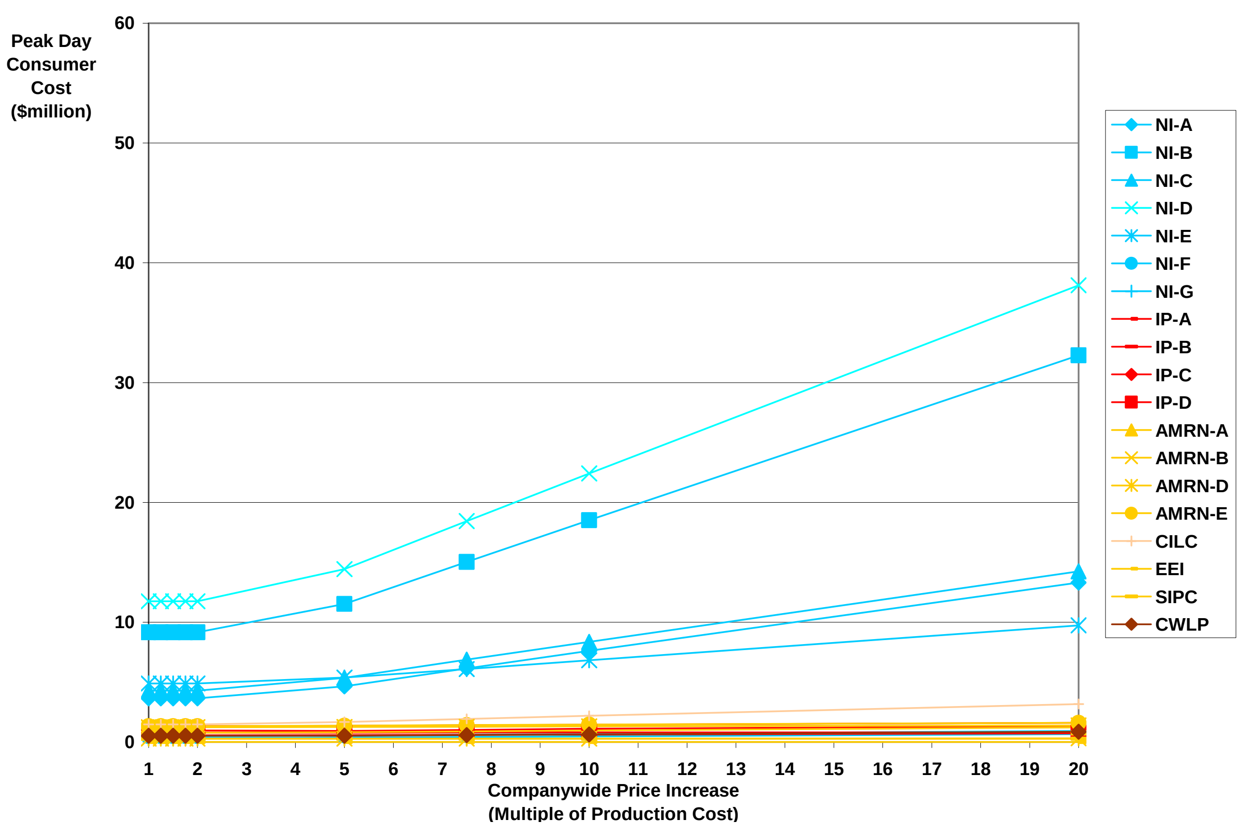


Figure 4.3.2-5 Exelon Nuclear Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-6 shows the effect of the Exelon peak hour price increases using the Conservative Assumptions. Comparing this to Figure 4.3.2-3 shows a somewhat different pattern under these conditions. First, the level of generation by the company is reduced when prices are increased and levels off in the same way it did under the Case Study Assumptions. The company's generation capacity remained competitive, even at 20 times production cost. Recall from the PC cases that the out-of-state suppliers gained market share at the expense of in-state suppliers when moving from Case Study Assumptions to Conservative Assumptions. The results here show that Exelon could still maintain its level of generation at elevated prices under Conservative Assumptions. The limits in the transmission system prevented any other generators from displacing the nuclear units.

The second observation in this result is that the company's profitability did not improve as a result of applying these price increases. Profitability dropped for the initial price increases and grew only slowly after that. This is a result of the much lower market prices seen under the Conservative Assumptions. It takes a much higher price increase to offset even the small amount of generation lost from the price increase. Nevertheless, the trend of the profitability curve indicates that a continuing price increase would, in fact, increase company profitabilty, which is consistent with the trend in the Case Study Assumptions.

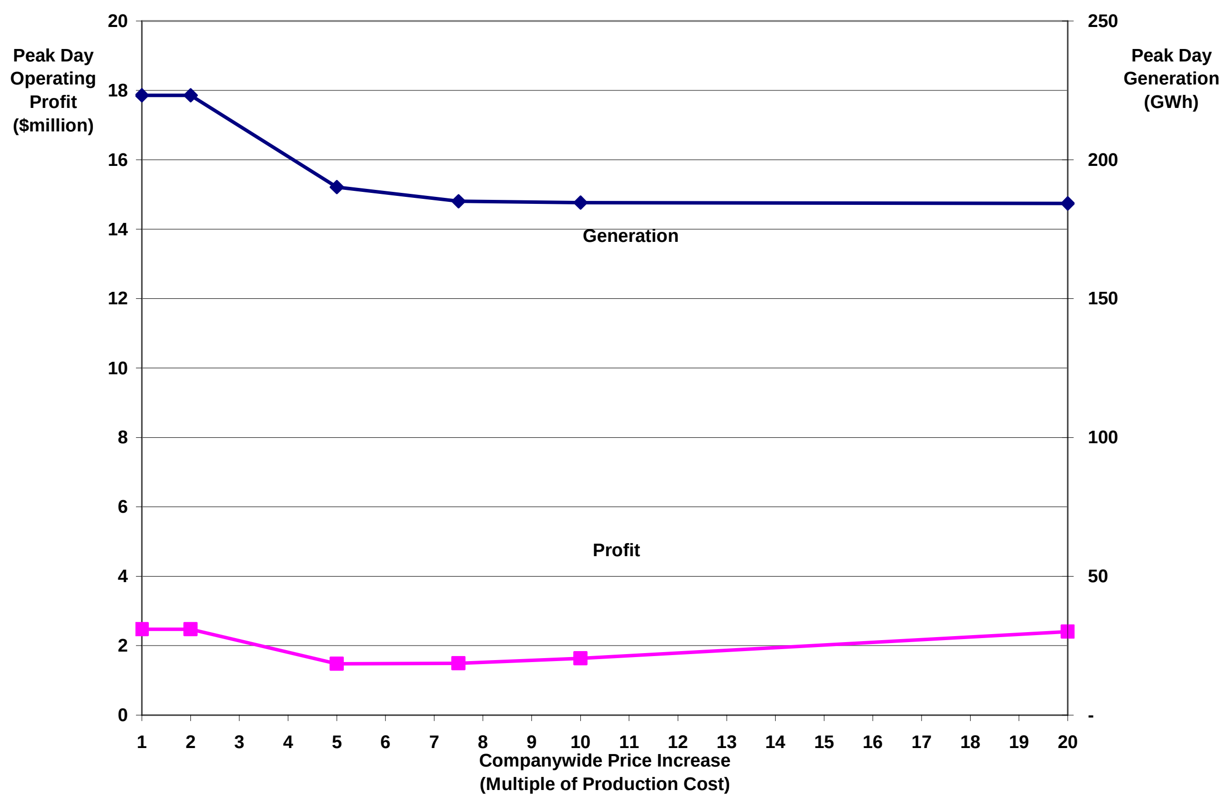


Figure 4.3.2-6 Exelon Nuclear Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-2 shows the transmission components that were at capacity limits at the twenty-fold price increase level under Conservative Assumptions. There was a similar change in the transmission loading as some lines remained at their capacity limits (normal print), some began to experience congestion (bold print), and some saw a relaxation of congestion (shaded print). As was seen in the PC case conditions, the additional generation capacity available under Conservative Assumptions did not eliminate the impacts of transmission congestion. In fact, the additional capacity resulted in more transmission components operating at their limits as the system sought to replace the higher-priced Exelon generation.

Table 4.3.2-2 Transmission Components at Capacity Limits under Exelon Nuclear 20-Fold Peak Hour Price Increase (Conservative Assumptions)

ID	Bus From	Bus To	Zone From	Zone To	Equipment		
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
36867_37387	**JEFFE; R**	**KINGS; R**	**NI-D**	**NI-D**	**138**	**kV**	**Line**
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line
36271_36415	**B ISL;RT**	**WILTO; R**	**NI-E**	**NI-C**	**345**	**kV**	**Line**
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
36891_37135	**KEWAN;**	**POWER;**	**NI-G**	**NI-G**	**138**	**kV**	**Line**
IP-A							
32411_37135	**PWR JCTB**	**POWER;**	**IP-A**	**NI-G**	**138**	**kV**	**Line**
IP-C							
32355_32369	**PANA IP**	**MOWEAQ T**	**IP-C**	**IP-C**	**138**	**kV**	**Line**
32368_32369	**RT 51 TP**	**MOWEAQ T**	**IP-C**	**IP-C**	**138**	**kV**	**Line**
32388_32405	**SIDNEY**	**MIRA TAP**	**IP-C**	**IP-B**	**138**	**kV**	**Line**
AMRN-B							
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line
30395_31445	**COFFEEN**	**PANA**	**AMRN-B**	**AMRN-B**	**345**	**kV**	**Line**
30439_31351	**CROSSVL**	**NORRIS**	**AMRN-B**	**AMRN-B**	**138**	**kV**	**Line**

Table 4.3.2-2 Transmission Components at Capacity Limits under Exelon Nuclear 20-Fold Peak Hour Price Increase (Conservative Assumptions)

ID	Bus From	Bus To	Zone From	Zone To	Equipment	
AMRN-D						
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138 kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138 kV**	**Line**
AMRN-E						
31500_31505	**PICKNYVL**	**PICKVL 5**	**AMRN-E**	**AMRN-E**	**13.8 /230**	**Transformer**
31500_31506	**PICKNYVL**	**PICKVL 6**	**AMRN-E**	**AMRN-E**	**13.8 /230**	**Transformer**
CILC						
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138 kV**	**Line**
EEI						
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161 kV	Line

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Midwest Generation LLC

Case Study Assumptions

Figure 4.3.2-7 shows the results of companywide economic withholding as applied to the Midwest Generation portfolio of generators. Figure 4.3.2-8 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested. For these simulation runs, the prices were increased for all of the company's units at the same rate for the entire peak day.

The results show that for price increases up to about five times production costs, the company lost generation in the market as cheaper units displaced its higher-priced ones. However, company daily operating profit increased slightly as the higher prices brought in more revenue for those units that were dispatched. As shown in Figure 4.3.2-8, during peak hours about 4,000 MW of the company's generating capacity was needed to meet the peak load. Prices on this capacity could be increased significantly without further loss of generation to competitors and with increasing company profitability. The Crawford, Joliet, Powerton, Waukegan, Will Co., and Fisk plants were dispatched, at least partially, even with the higher prices. Unlike the case for Exelon Nuclear, this dispatch schedule may be able to be accommodated by the company's generating units. Some of the fossil-fueled units have the ability to adjust to follow the load much more readily than the nuclear units. Nevertheless, this may not be a desirable operating schedule because of the extra wear on equipment that is cycled on and off, particularly the larger coal-fired units.

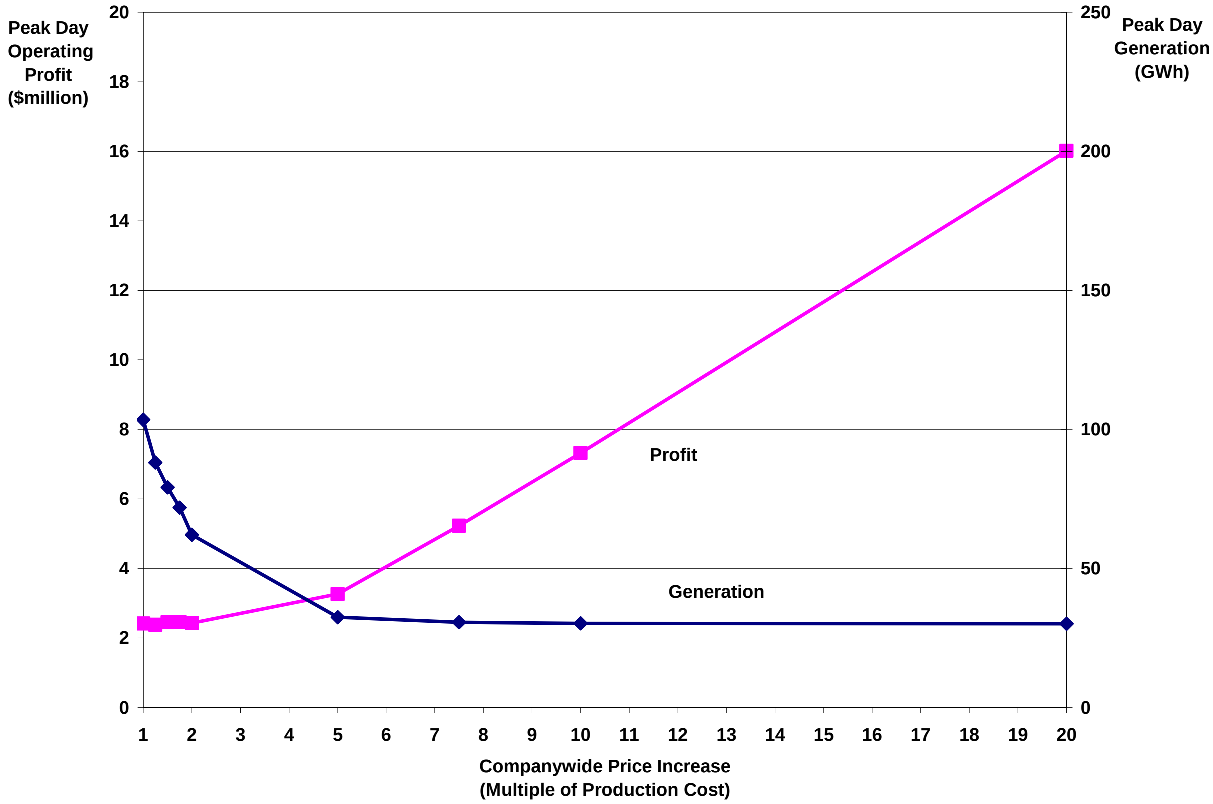


Figure 4.3.2-7 Midwest Generation Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

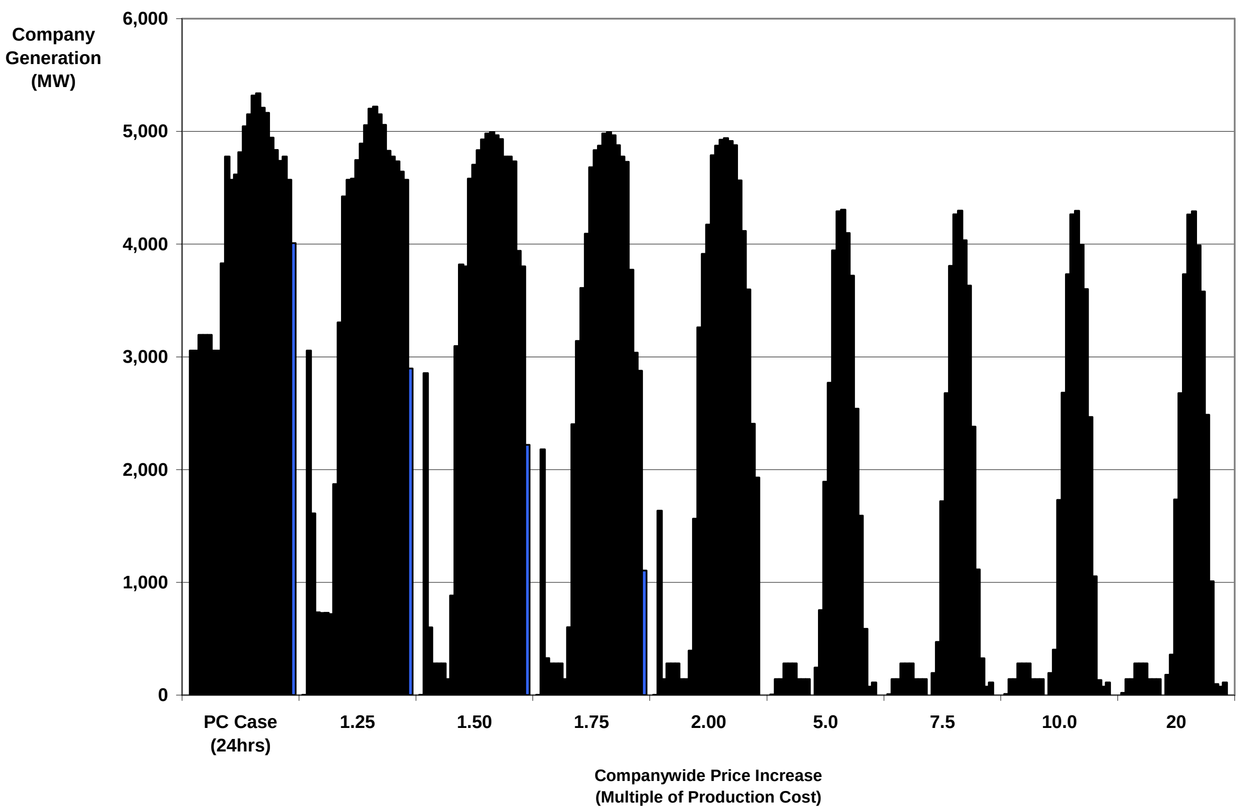


Figure 4.3.2-8 Midwest Generation Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

Figure 4.3.2-9 shows the results of price increases applied only during peak hours. This was a more attractive strategy from the company's perspective. There was very little loss in generation to competitors at any level of price increase. The twenty-fold price increase put the capacity-weighted average of the company's generation at about 630 $/MWh, or about twice the Exelon Nuclear average price at its twenty-fold increase. The company's generation was still accepted by the market at these very high prices because of transmission constraints that prohibited cheaper power from being utilized. Table 4.3.2-3 shows the transmission components that were at capacity limits under the twenty-fold price increase. This list is similar to what was seen for the Exelon Nuclear price increases. The differences in line loadings result from the locations on the transmission network of the Midwest Generation plants relative to the Exelon Nuclear plants. Note that there was no relaxation of congestion anywhere in the system under these conditions.

Figure 4.3.2-10 shows the impact of the price increments on zonal LMPs. Figure 4.3.2-11 shows the impact on consumer costs. The results are similar to those for Exelon Nuclear. The company had a significant impact, particularly in the NI zones, because of the transmission limits. There was also an impact in the CILC zone, which was affected by transmission constraints. As before, this should not be interpreted as an indication that the company would, in practice, exercise this market power. It only indicates that this could be a profitable strategy.

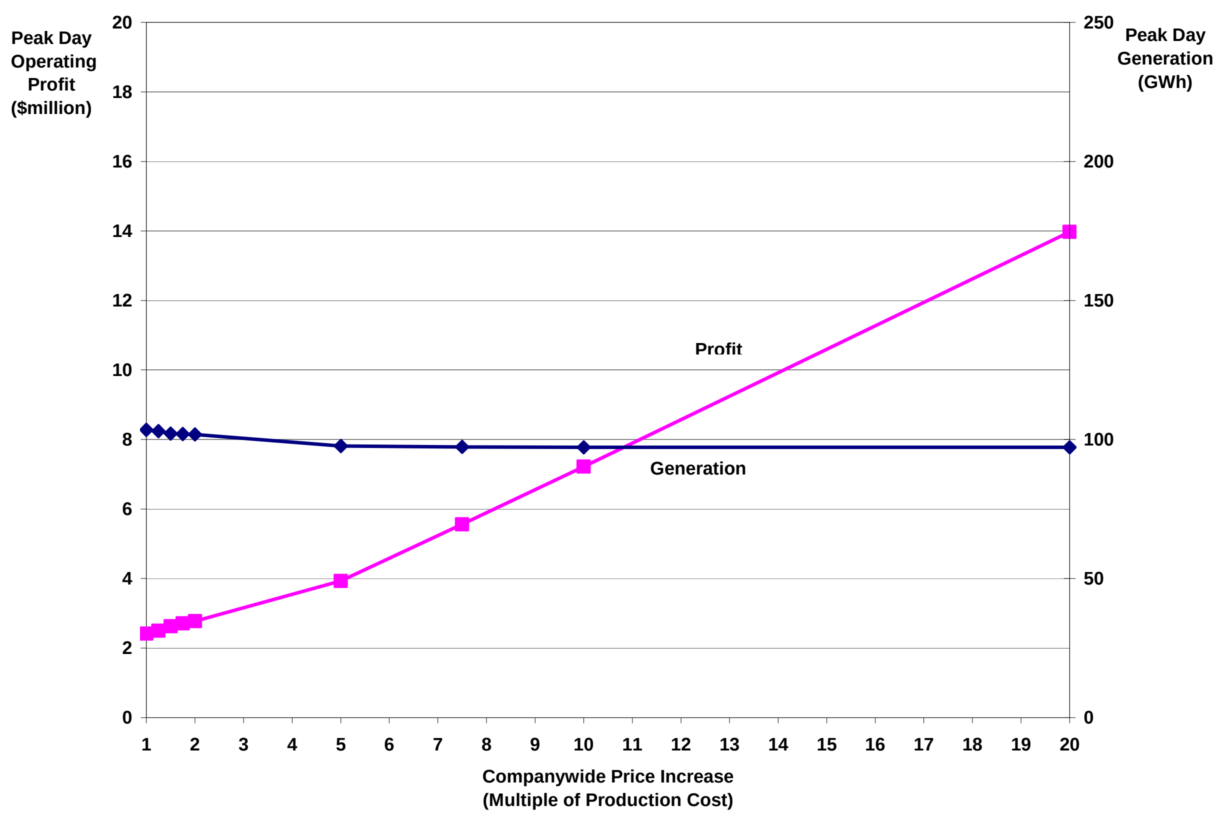


Figure 4.3.2-9 Midwest Generation Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-3 Transmission Components at Capacity Limits under Midwest Generation 20-Fold Price Increase (Case Study Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36766_37372	**FRONT; B**	**WOLFS; B**	**NI-C**	**NI-C**	**138**	**kV**	**Line**
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36295_36022	**CRAWF; R**	**CRAWF;1M**	**NI-D**	**NI-D**	**138**	**/345**	**Transformer**
36022_36641	**CRAWF;1M**	**CRAWF; R**	**NI-D**	**NI-D**	**138**	**/138**	**Transformer**
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36271_36415	**B ISL;RT**	**WILTO; R**	**NI-E**	**NI-C**	**345**	**kV**	**Line**
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-B							
32410_33159	**1346A TP**	**KICKAPOO**	**IP-B**	**CILC**	**138**	**kV**	**Line**
32358_32410	**LATH NTP**	**1346A TP**	**IP-B**	**IP-B**	**138**	**kV**	**Line**
AMRN-A							
30055_33315	**AUBURN N**	**CHATHAM**	**AMRN-A**	**CWLP**	**138**	**kV**	**Line**
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer
CILC							
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**
CWLP							
33314_33315	**SPALDING**	**CHATHAM**	**CWLP**	**CWLP**	**138**	**kV**	**Line**

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

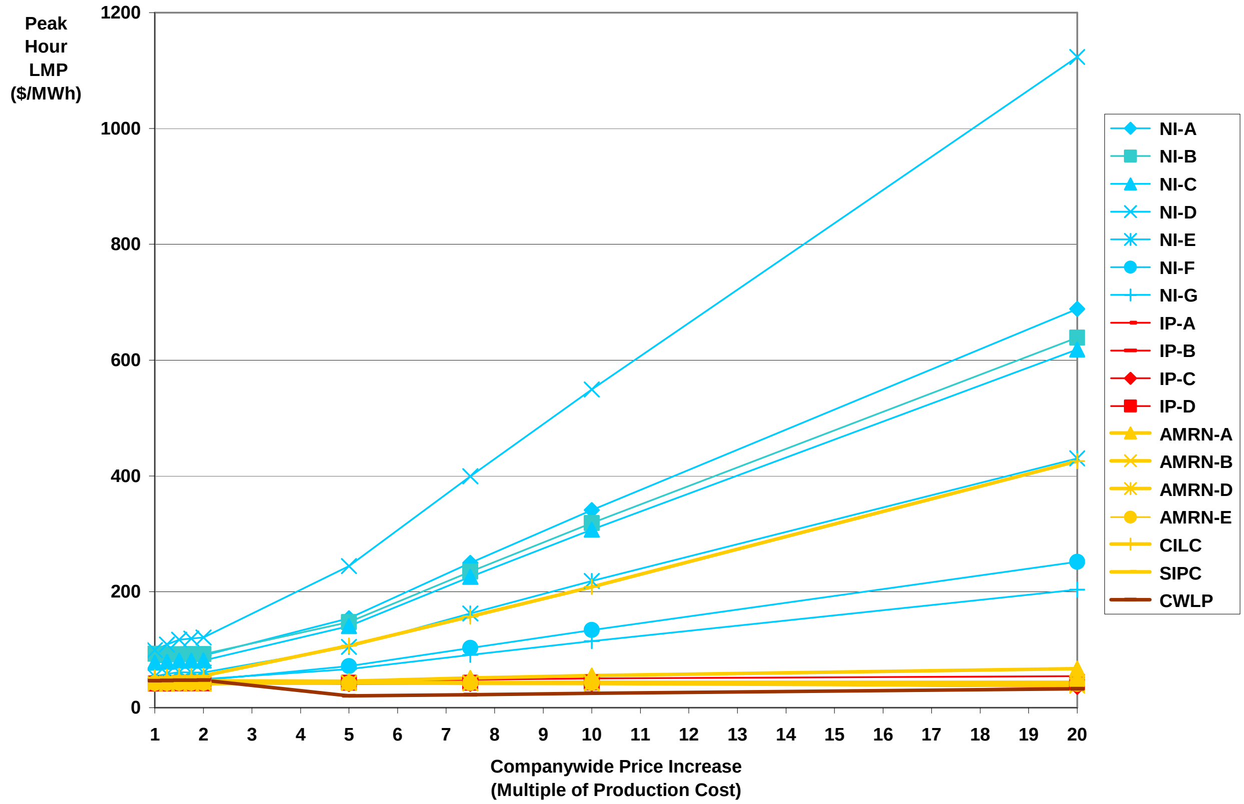


Figure 4.3.2-10 Midwest Generation Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

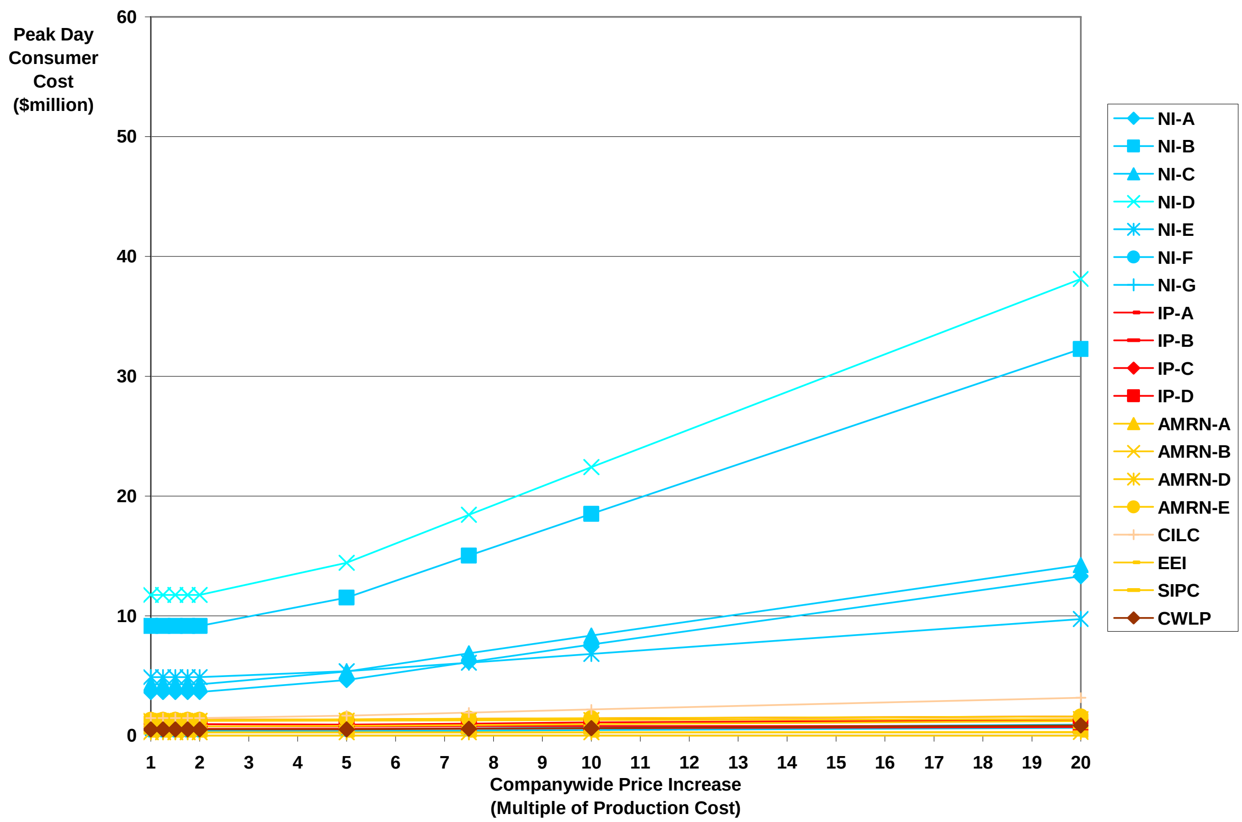


Figure 4.3.2-11 Midwest Generation Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-12 shows the company's generation and operating profit under Conservative Assumptions. The pattern is very similar to the results from the Case Study Assumptions. That is, there was very little loss of generation, even at large price increases. There was a continuing increase in operating profits with continued price increases. As in the Exelon Nuclear case, the rate of profitability increase was slower than under Case Study Assumptions due to the lower overall market prices under these conditions. Table 4.3.2-4 shows the transmission components at their operating limits. It is again similar to what was seen for Exelon Nuclear.

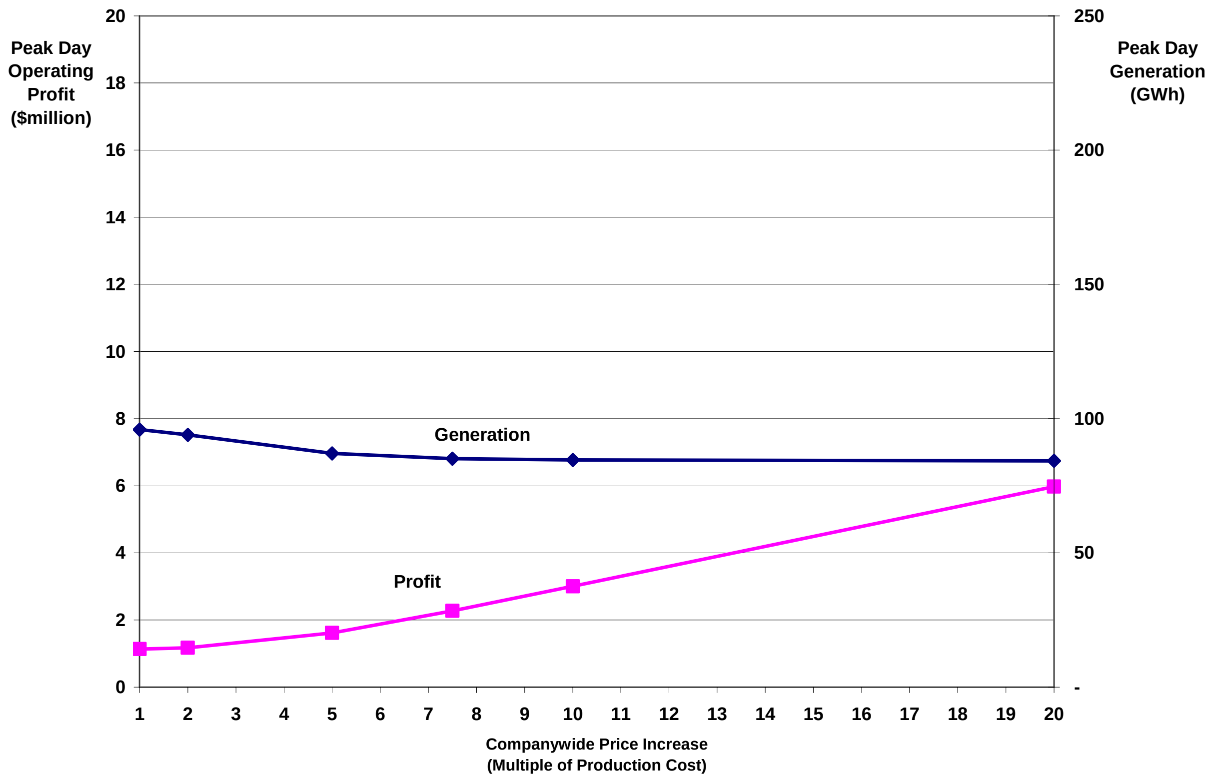


Figure 4.3.2-12 Midwest Generation Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-4 Transmission Components at Capacity Limits under Midwest Generation 20-Fold Price Increase (Conservative Assumptions)

ID	Bus From	Bus To	Zone From	Zone To	Equipment		
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36766_37372	**FRONT; B**	**WOLFS; B**	**NI-C**	**NI-C**	**138**	**kV**	**Line**
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-B							
32410_33159	**1346A TP**	**KICKAPOO**	**IP-B**	**CILC**	**138**	**kV**	**Line**
32358_32410	**LATH NTP**	**1346A TP**	**IP-B**	**IP-B**	**138**	**kV**	**Line**
IP-C							
32388_32405	**SIDNEY**	**MIRA TAP**	**IP-C**	**IP-B**	**138**	**kV**	**Line**
AMRN-A							
30055_33315	**AUBURN N**	**CHATHAM**	**AMRN-A**	**CWLP**	**138**	**kV**	**Line**
AMRN-B							
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line
AMRN-D							
30614_30615	**GIBSON C**	**GIBSONCP**	**AMRN-D**	**AMRN-D**	**138**	**kV**	**Line**
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
CILC							
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**
EEI							
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line
CWLP							
33314_33315	**SPALDING**	**CHATHAM**	**CWLP**	**CWLP**	**138**	**kV**	**Line**

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Ameren

Case Study Assumptions

Figure 4.3.2-13 shows the results of companywide economic withholding as applied to the Ameren portfolio of generators. Figure 4.3.2-14 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested. For these simulation runs, the prices were increased for all of the company's units at the same rate for the entire peak day.

The results show that the company lost both generation and profitability using this strategy. Even at large increases in prices, the profitability did not return to the PC case level. Competitors, both in-state and out-of-state, were able to supplant the company's higher-priced units. As shown in Figure 4.3.2-14, during peak hours about 500 MW of the company's capacity was needed to meet the peak load, even with high prices.

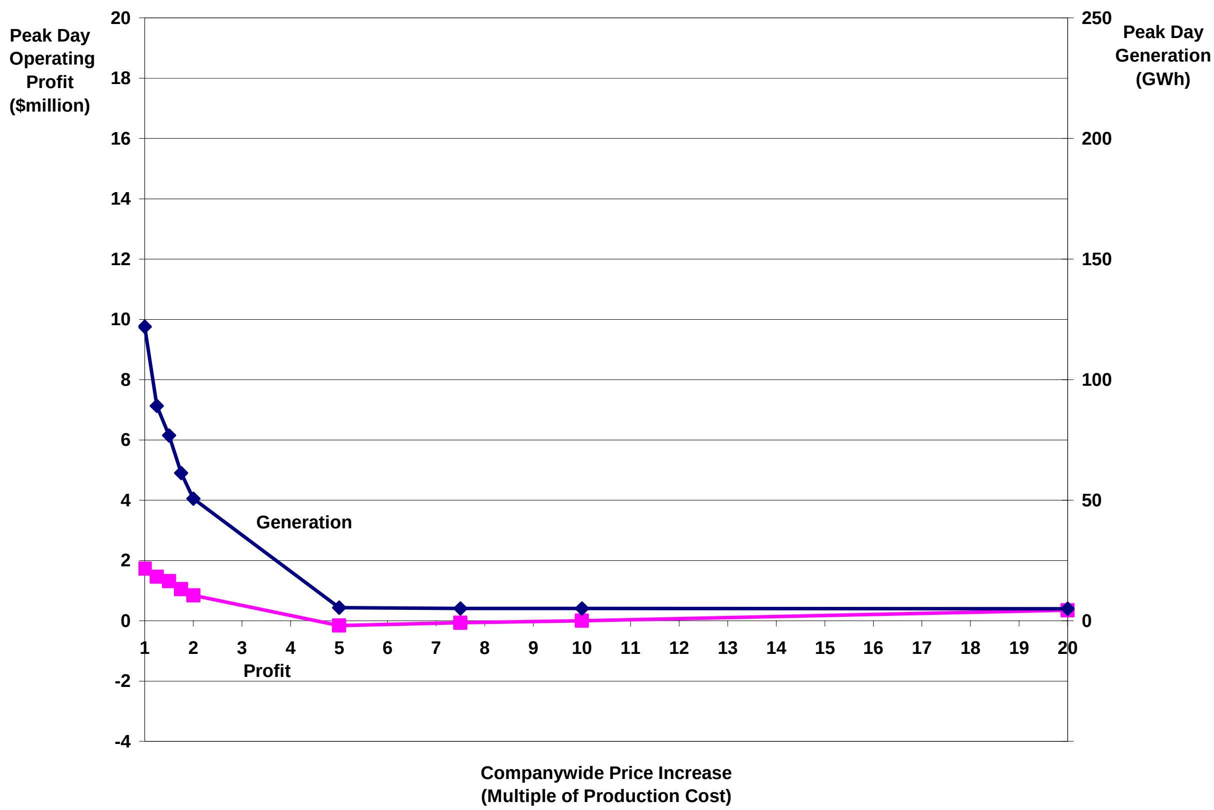


Figure 4.3.2-13 Ameren Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

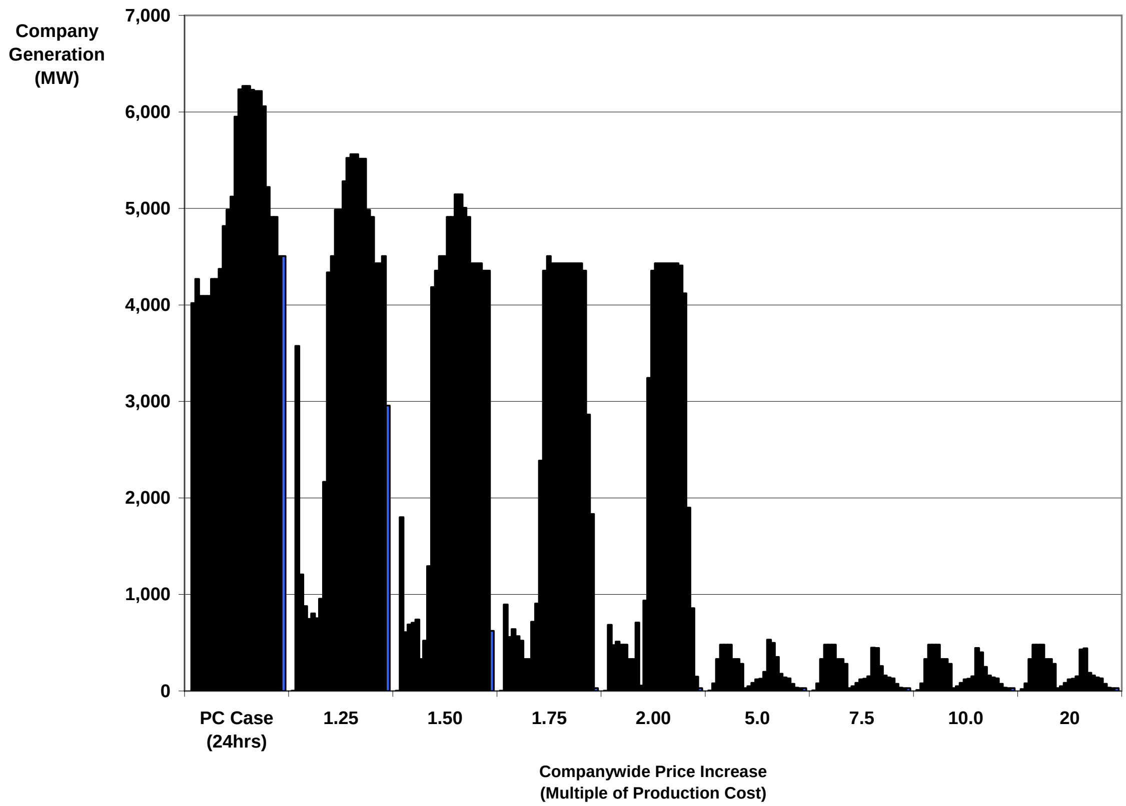


Figure 4.3.2-14 Ameren Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

Figure 4.3.2-15 shows the results of price increases applied only during peak hours. This strategy did not offer any benefit to the company even after a significant increase. (At a twenty-fold price increase, the capacity-weighted average of the company's generation was about 470 $/MWh.) The reason for this small impact is that the company's units were not as critical to meeting system loads as were those of Exelon Nuclear and Midwest Generation. Only the E.D. Ewards and Elgin Energy Center units continued to be dispatched at these high prices. There was ample generation and transmission capacity available to displace the company's units when their prices were increased. Table 4.3.2-5 shows the transmission components that were at capacity limits under the twenty-fold price increase. Several components experienced congestion as the system was redispatched to replace the more expensive Ameren units, but this did not result in any profit increases for the company.

Figure 4.3.2-16 shows the effect on zonal LMPs. Figure 4.3.2-17 shows the effect on consumer costs. Note that while the price increases by the company did not provide increased profitability, they did have a significant impact on the system across parts of the State. As in the Exelon and Midwest Generation results, the NI zones and the CILC zone were most affected because of their transmission constraints. The Ameren price increase did not create any new congestion within the NI zones; nevertheless, the congestion created elsewhere caused significant impacts there.

In effect, if the company increased its prices, the primary beneficiaries would be other companies. As the company increased prices on its units, it allowed other companies' units, which would not have been dispatched under PC case conditions, to be selected. These units, although cheaper than the Ameren units whose prices had been increased, were still more expensive than those that were used in the PC case. Thus all companies benefited from the higher price in the market.

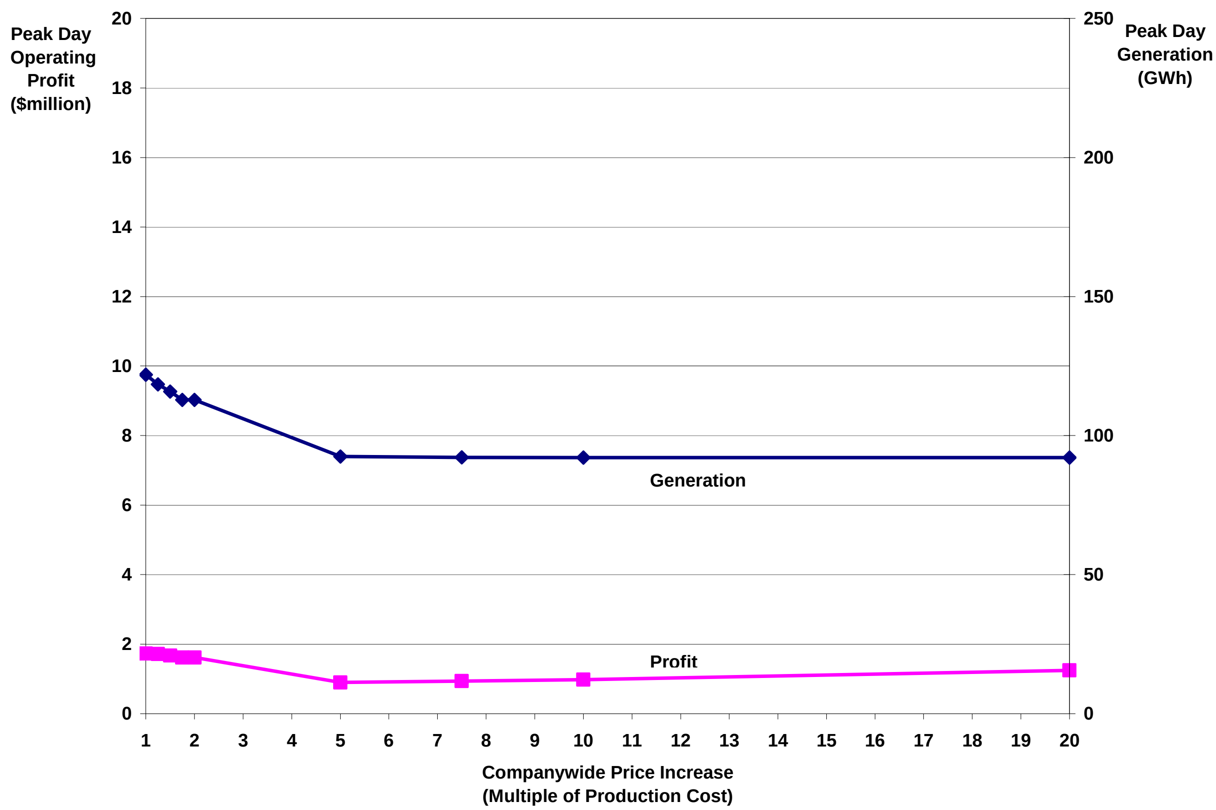


Figure 4.3.2-15 Ameren Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-5 Transmission Components at Capacity Limits under Ameren 20-Fold Price Increase (Case Study Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-B							
32358_32410	**LATH NTP**	**1346A TP**	**IP-B**	**IP-B**	**138**	**kV**	**Line**
32410_33159	**1346A TP**	**KICKAPOO**	**IP-B**	**CILC**	**138**	**kV**	**Line**
AMRN-A							
30055_33315	**AUBURN N**	**CHATHAM**	**AMRN-A**	**CWLP**	**138**	**kV**	**Line**
AMRN-B							
30439_31351	**CROSSVL**	**NORRIS**	**AMRN-B**	**AMRN-B**	**138**	**kV**	**Line**
31350_31351	**NORRIS**	**NORRIS**	**AMRN-B**	**AMRN-B**	**138**	**/345**	**Transformer**
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer
CILC							
33002_33139	**RS WALL**	**RSW EAST**	**CILC**	**CILC**	**138**	**/69**	**Transformer**
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**	**138**	**kV**	**Line**

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

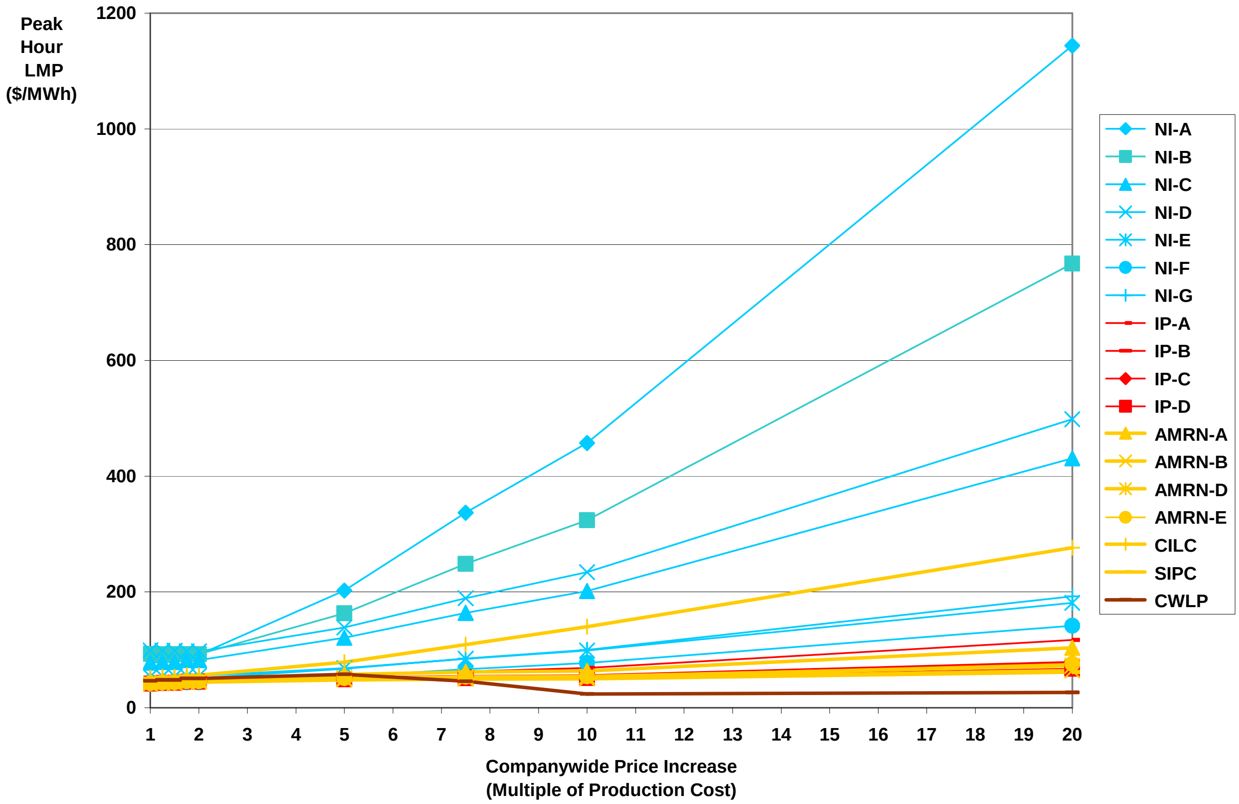


Figure 4.3.2-16 Ameren Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

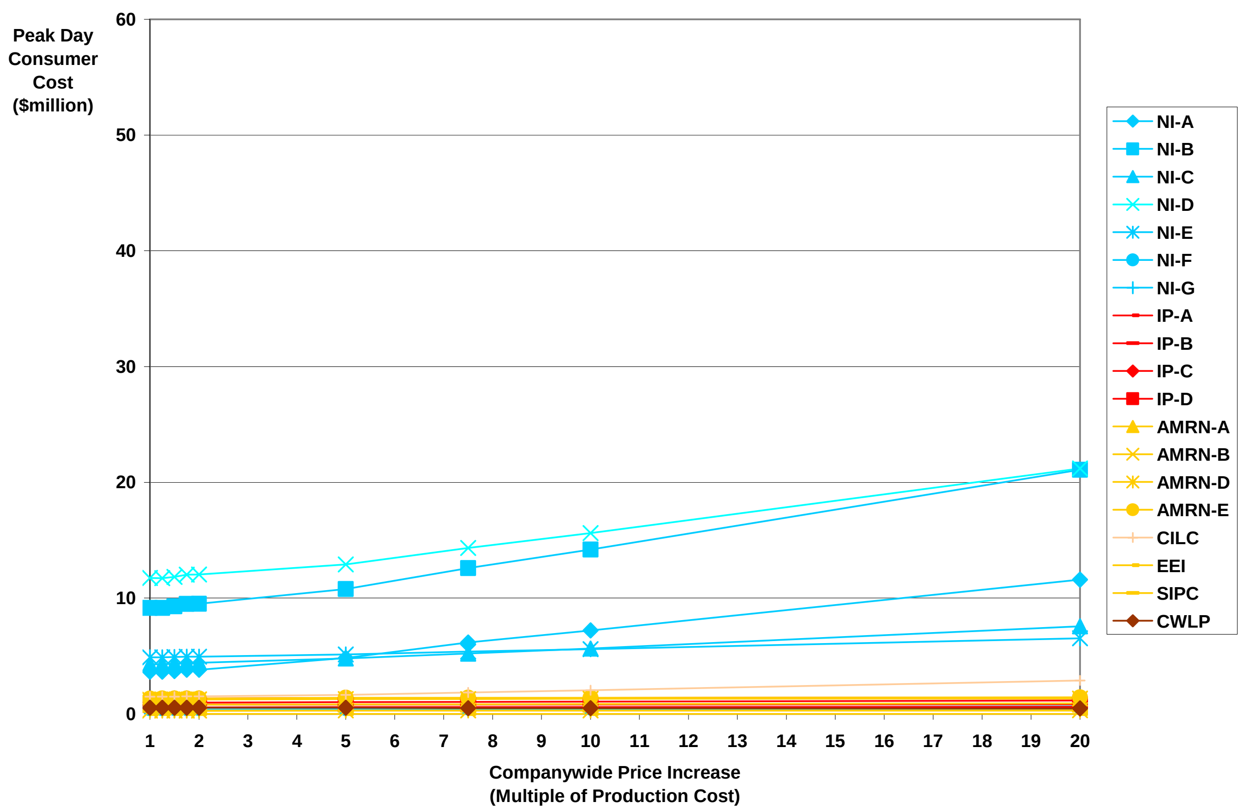


Figure 4.3.2-17 Ameren Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-18 shows the effect on company generation and operating profits under Conservative Assumptions. The result was essentially the same as under Case Study Assumptions. That is, there was no profit benefit to the company from unilateral price increases. Table 4.3.2-6 shows the transmission components that were at their capacity limits. Some components experienced additional congestion, but, as before, this did not result in any profit increases for the company.

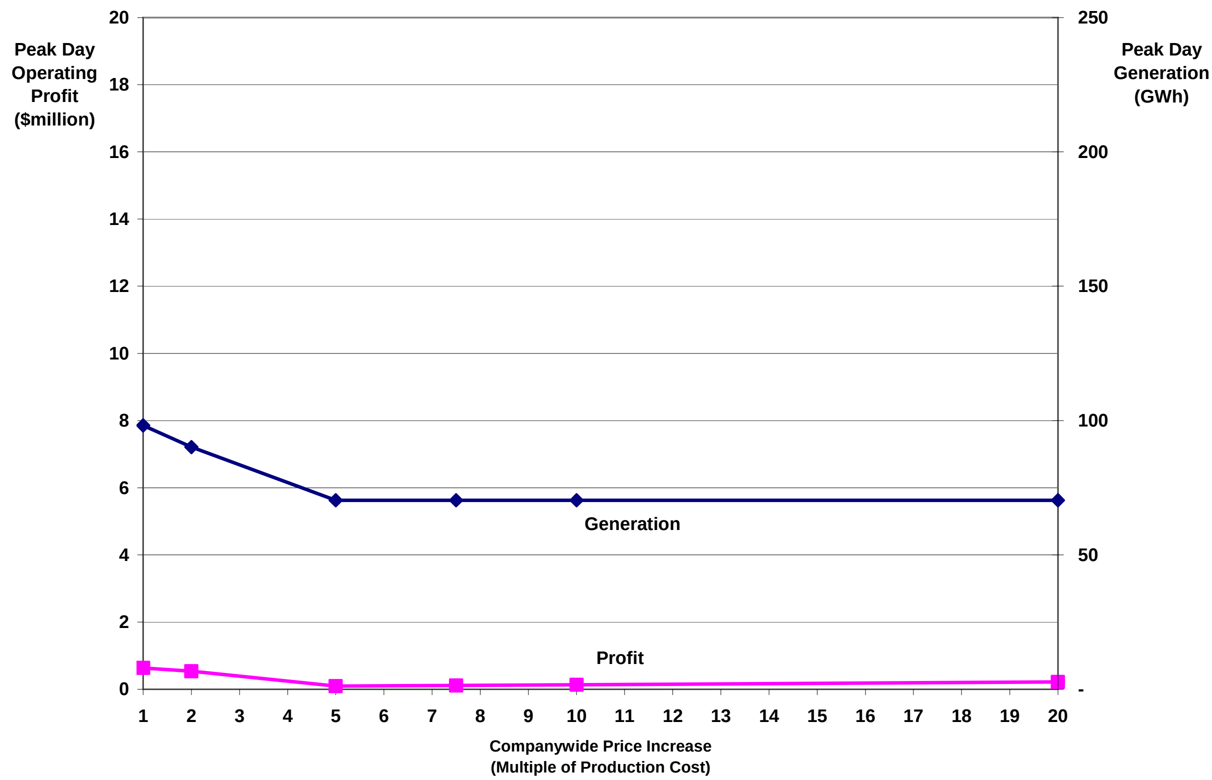


Figure 4.3.2-18 Ameren Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-6 Transmission Components at Capacity Limits under Ameren 20-Fold Price Increase (Conservative Assumptions)

ID	Bus From	Bus To	Zone From	Zone To	Equipment	
NI-A						
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138 kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138 kV	Line
NI-C						
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345 kV	Line
NI-D						
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138 kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138 kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138 kV	Line
36867_37387	**JEFFE; R**	**KINGS; R**	**NI-D**	**NI-D**		
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138 /345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138 /138	Transformer
NI-E						
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138 /345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138 /138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345 kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138 kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345 kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138 kV	Line
NI-G						
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138 kV	Line
IP-B						
32410_33159	**1346A TP**	**KICKAPOO**	**IP-B**	**CILC**		
AMRN-B						
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18 /345	Transformer
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138 kV	Line
AMRN-D						
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138 kV	Line
AMRN-E						
31023_33351	**MARION S**	**5MRN_PLN**	**AMRN-E**	**SIPC**		
CILC						
33002_33139	**RS WALL**	**RSW EAST**	**CILC**	**CILC**		
33157_33175	**HOLLAND**	**MASON**	**CILC**	**CILC**		
EEI						
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161 kV	Line

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Dynegy

Case Study Assumptions

Figure 4.3.2-19 shows the results of companywide economic withholding as applied to the Dynegy portfolio of generators. Figure 4.3.2-20 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested. For these simulation runs, the prices were increased for all of the company's units at the same rate for the entire peak day.

The results show that the company lost both generation and profits at any price increase. At increase multiples of five or more, the company's units were not dispatched and operating profit became negative as fixed costs could not be recovered. Cheaper units replaced almost all of the company's capacity, even during peak-load periods. At the twenty-fold price increase, the company's capacity-weighted average bid price was about 470 $/MWh.

Figure 4.3.2-21 shows the results of price increases applied only during peak hours. The situation was not much better for the company. A smaller drop in generation was seen, but profitability was still below PC case levels. Table 4.3.2-7 shows the transmission components that were at their capacity limits under the twenty-fold price increase. There was little change from the PC case conditions.

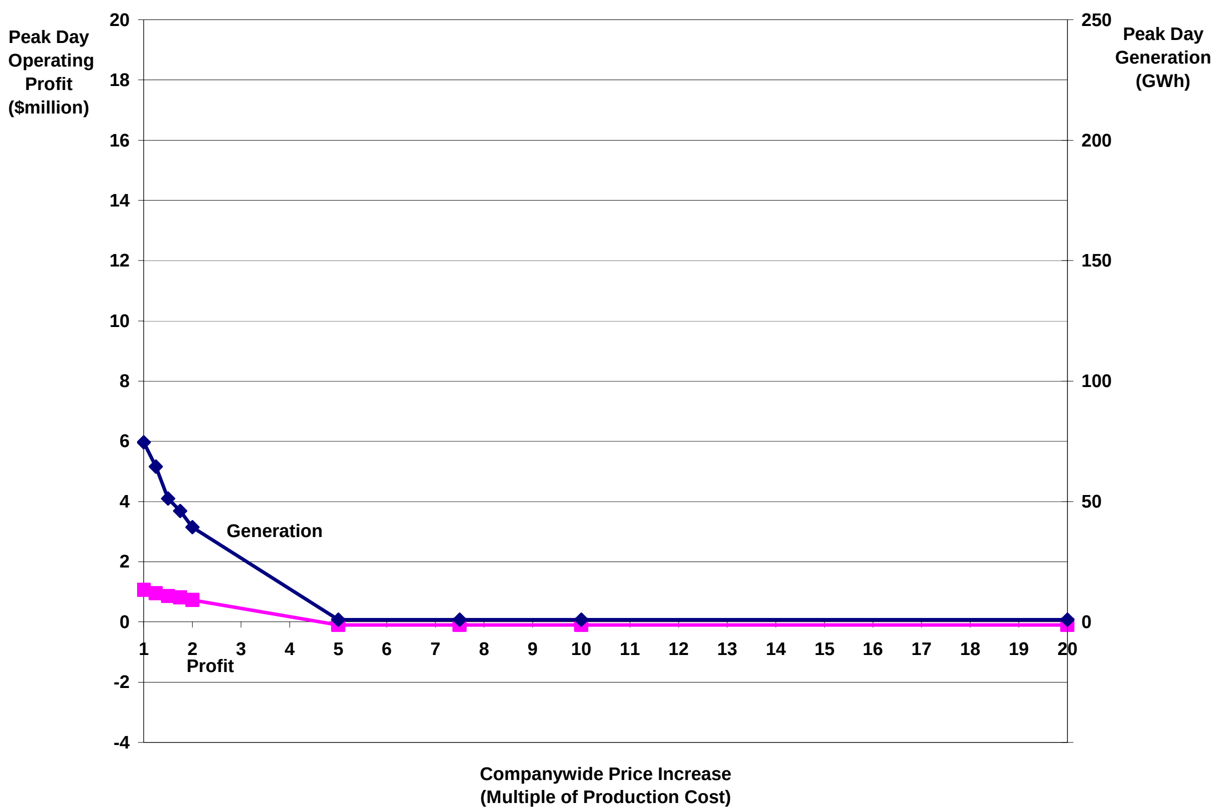


Figure 4.3.2-19 Dynegy Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

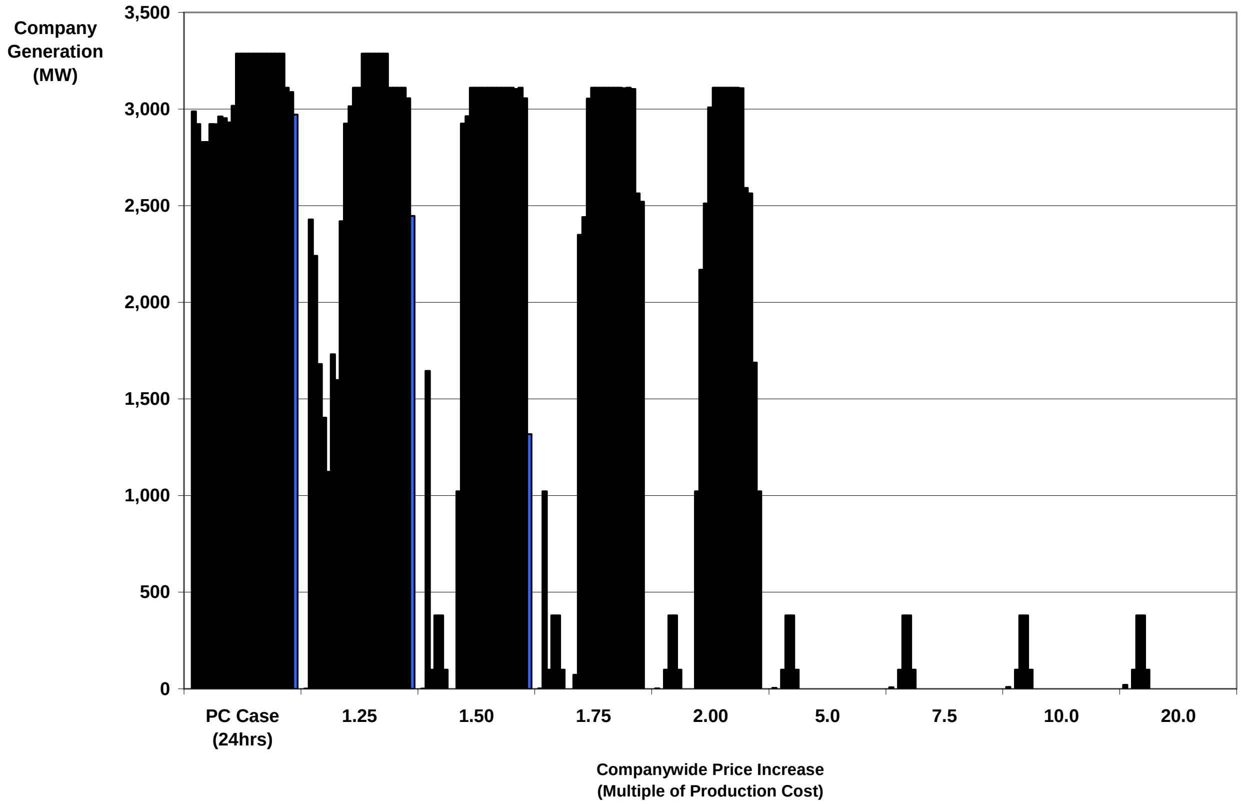


Figure 4.3.2-20 Dynegy Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

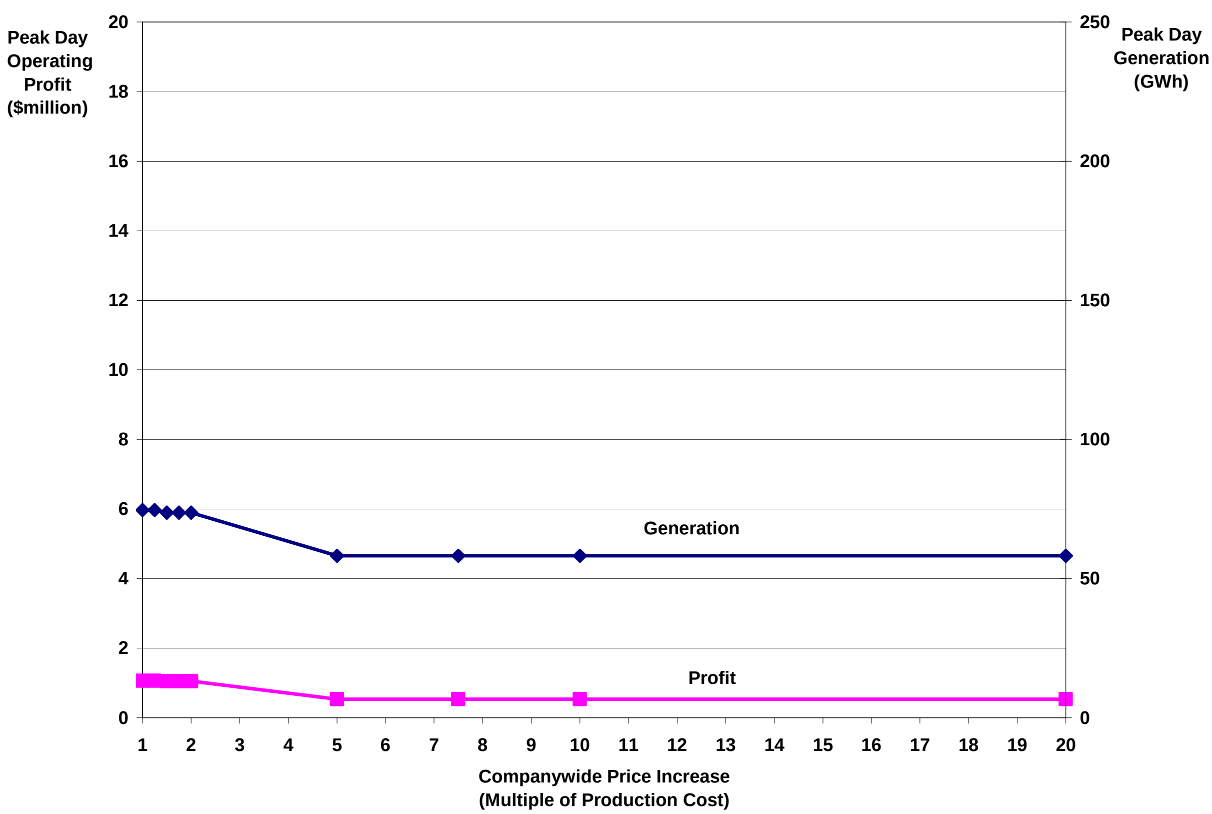


Figure 4.3.2-21 Dynegy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-7 Transmission Components at Capacity Limits under Dynegy 20-Fold Price Increase (Case Study Assumptions)

ID	Bus From	Bus To	Zone From	Zone To	Equipment		
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36310_36356	**ELECT; B**	**LOMBA; B**	**NI-C**	**NI-C**	**345**	**kV**	**Line**
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line
36702_36754	**E FRA; B**	**FFORT; B**	**NI-E**	**NI-E**	**138**	**kV**	**Line**
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

Figure 4.3.2-22 shows the effect on zonal LMPs. Figure 4.3.2-23 shows the effect on consumer costs. The company’s price increases had very little effect on either LMPs or consumer costs. There was adequate generation and transmission capacity available to displace the company’s units when their prices were increased. On this basis, there is no indication of the ability to exercise market power.

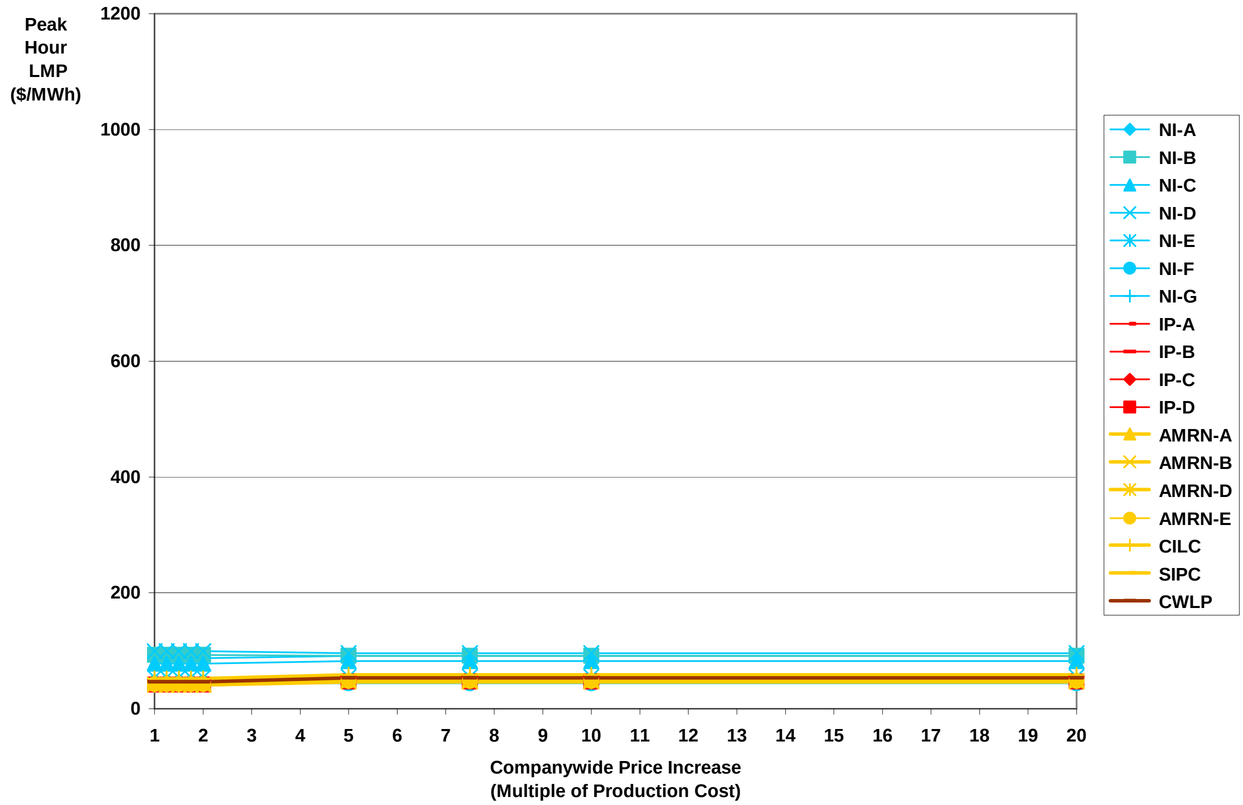


Figure 4.3.2-22 Dynegy Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

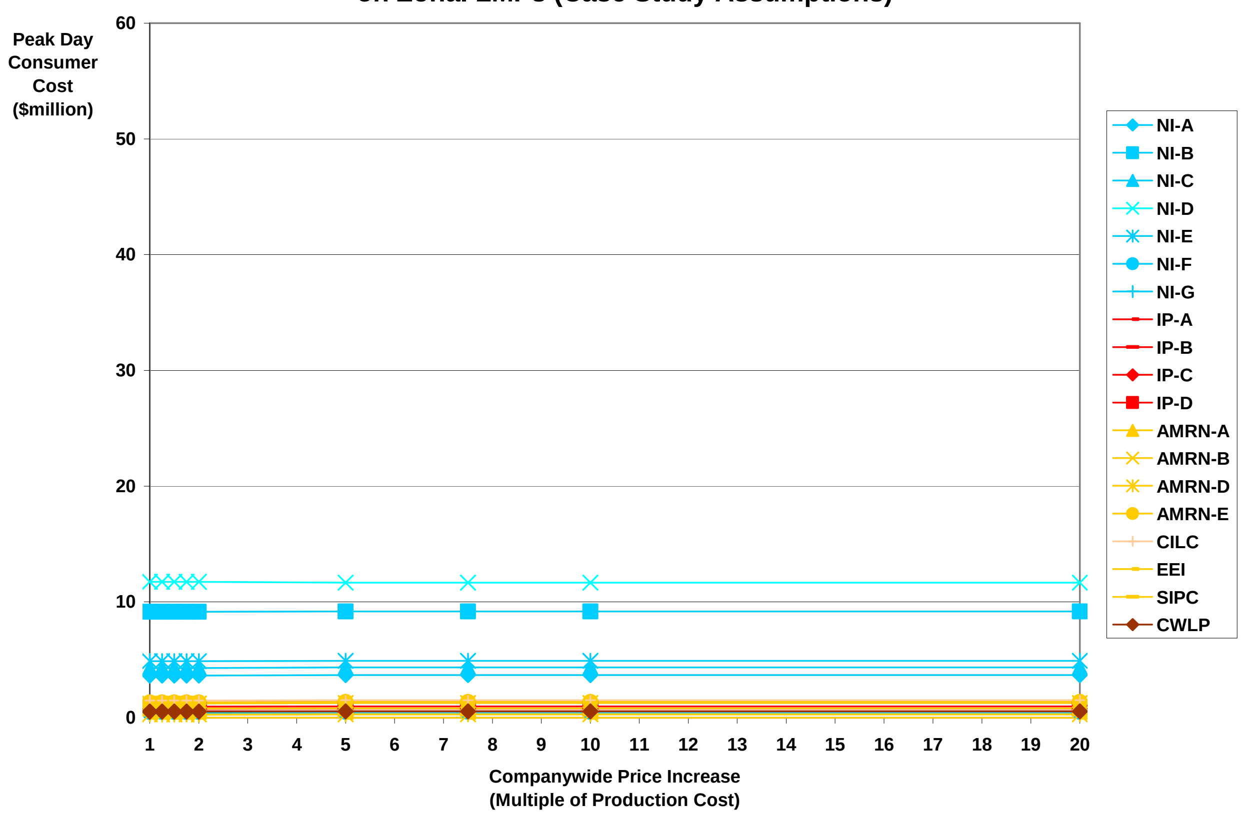


Figure 4.3.2-23 Dynegy Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-24 shows the generation and operating profit under Conservative Assumptions. The pattern was the same as for the Case Study Assumptions. Table 4.3.2-8 shows the transmission components at capacity limits. There was a change in the transmission loading, with some components experiencing increased congestion and some seeing a relaxation of congestion. However, this did not affect company profitability.

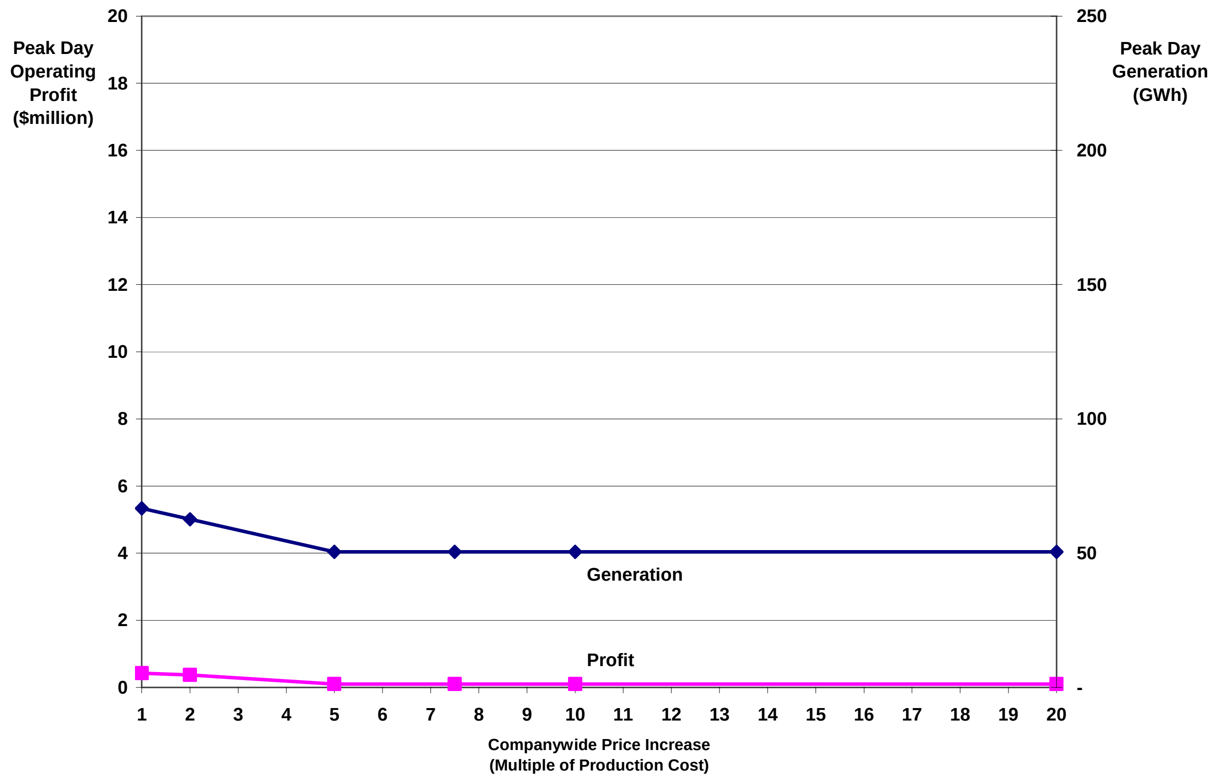


Figure 4.3.2-24 Dynegy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-8 Transmission Components at Capacity Limits under Dynegy 20-Fold Price Increase (Conservative Assumptions)

ID	Bus		Zone		Equipment		
	From	To	From	To			
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138	/345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138	/138	Transformer
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
IP-C							
32388_32405	**SIDNEY**	**MIRA TAP**	**IP-C**	**IP-B**	**138**	**kV**	**Line**
IP-D							
32293_32320	**CAMBL TP**	**STEELVIL**	**IP-D**	**IP-D**	**138**	**kV**	**Line**
AMRN-B							
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18	/345	Transformer
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138	kV	Line
AMRN-D							
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138	kV	Line
30614_30615	**GIBSON C**	**GIBSONCP**	**AMRN-D**	**AMRN-D**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	**PICKNYVL**	**PICKVL 5**	**AMRN-E**	**AMRN-C**	**13.8**	**/230**	**Transformer**
31500_31506	**PICKNYVL**	**PICKVL 6**	**AMRN-E**	**AMRN-C**	**13.8**	**/230**	**Transformer**
EEI							
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161	kV	Line

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Dominion Energy

Case Study Assumptions

Figure 4.3.2-25 shows the results of companywide economic withholding as applied to the Dominion Energy portfolio of generators. Figure 4.3.2-26 shows the dispatch of the company's generators over the 24 hours of the peak day for each of the price multiples tested. For these simulation runs, the prices were increased for all of the company's units at the same rate for the entire peak day.

The results show that the company lost both generation and profitability using this strategy, even at twenty-fold price increases. At this level, the company's capacity-weighted average bid price was about 485 $/MWh. Some of the company's capacity was needed during peak hours, but this became less attractive at higher prices. There was capacity available to replace units that were priced very high.

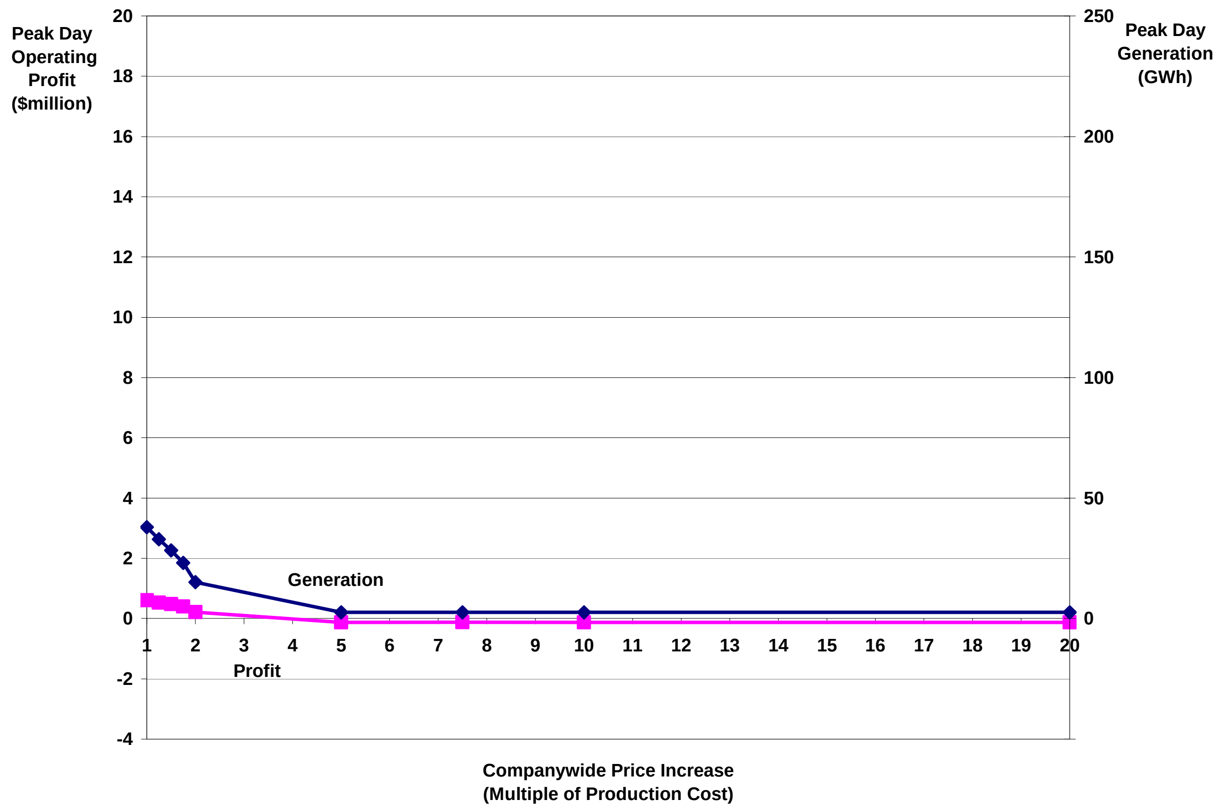


Figure 4.3.2-25 Dominion Energy Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)

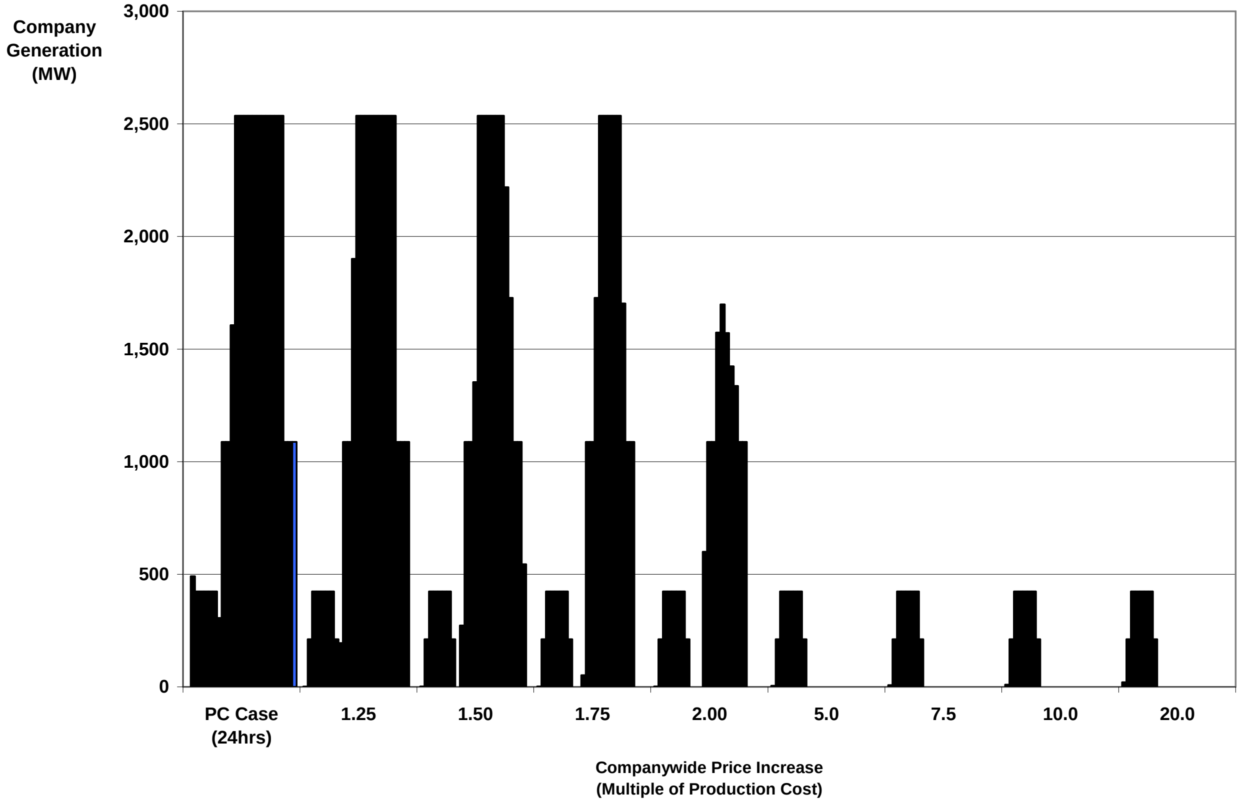


Figure 4.3.2-26 Dominion Energy Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)

Figure 4.3.2-27 shows the results of price increases applied only during peak hours. There was not much improvement for the company in this strategy. Profitability was increased only slightly at the high price increases, but was still below PC case levels. As was seen earlier, there was adequate generation and transmission capacity available to displace the company's units when their prices were increased. Table 4.3.2-9 shows the transmission components that were at capacity limits under these conditions. There were some changes in the transmission congestion, but this did not enable the company to increase its profitability. On this basis, there was no indication of the company's ability to exercise market power.

Figure 4.3.2-28 shows the effect on zonal LMPs. Figure 4.3.2-29 shows the effect on consumer costs. While the price increases by the company did not provide much in the way of increased profitability, they did have some impact on the system across parts of the State, particularly in the NI zones. In effect, if the company increased its prices, the primary beneficiaries would be other companies.

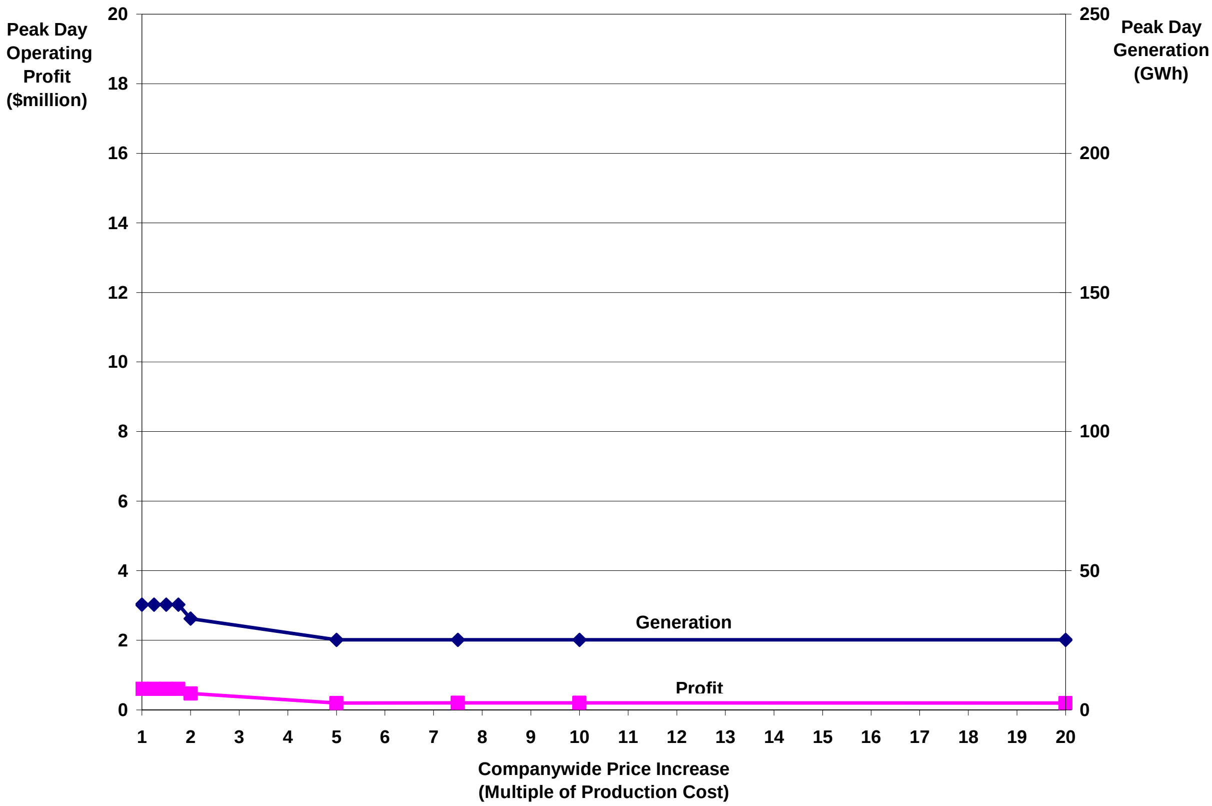


Figure 4.3.2-27 Dominion Energy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)

Table 4.3.2-9 Transmission Components at Capacity Limits under Dominion Energy 20-Fold Price Increase (Case Study Assumptions)

ID	Bus From	Bus To	Zone From	Zone To	Equipment		
NI-A							
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138	kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138	kV	Line
NI-C							
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345	kV	Line
36844_36880	HILLC;6B	JO 9; B	NI-C	NI-E	138	kV	Line
NI-D							
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138	kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138	kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138	kV	Line
NI-E							
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138	/345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138	/138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345	kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138	kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345	kV	Line
36628_37002	CC HI;BT	MOKEN;BT	NI-E	NI-E	138	kV	Line
NI-G							
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138	kV	Line
AMRN-B							
30395_31445	**COFFEEN**	**PANA**	**AMRN-B**	**AMRN-B**	**345**	**kV**	**Line**
AMRN-D							
30614_30615	GIBSON C	GIBSONCP	AMRN-D	AMRN-D	138	kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138**	**kV**	**Line**
AMRN-E							
31500_31505	PICKNYVL	PICKVL 5	AMRN-E	AMRN-E	13.8	/230	Transformer
31500_31506	PICKNYVL	PICKVL 6	AMRN-E	AMRN-E	13.8	/230	Transformer

Note:
Normal row indicates component at capacity under PC case conditions and under these conditions.
Shaded row indicates component at capacity under PC case conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case conditions.

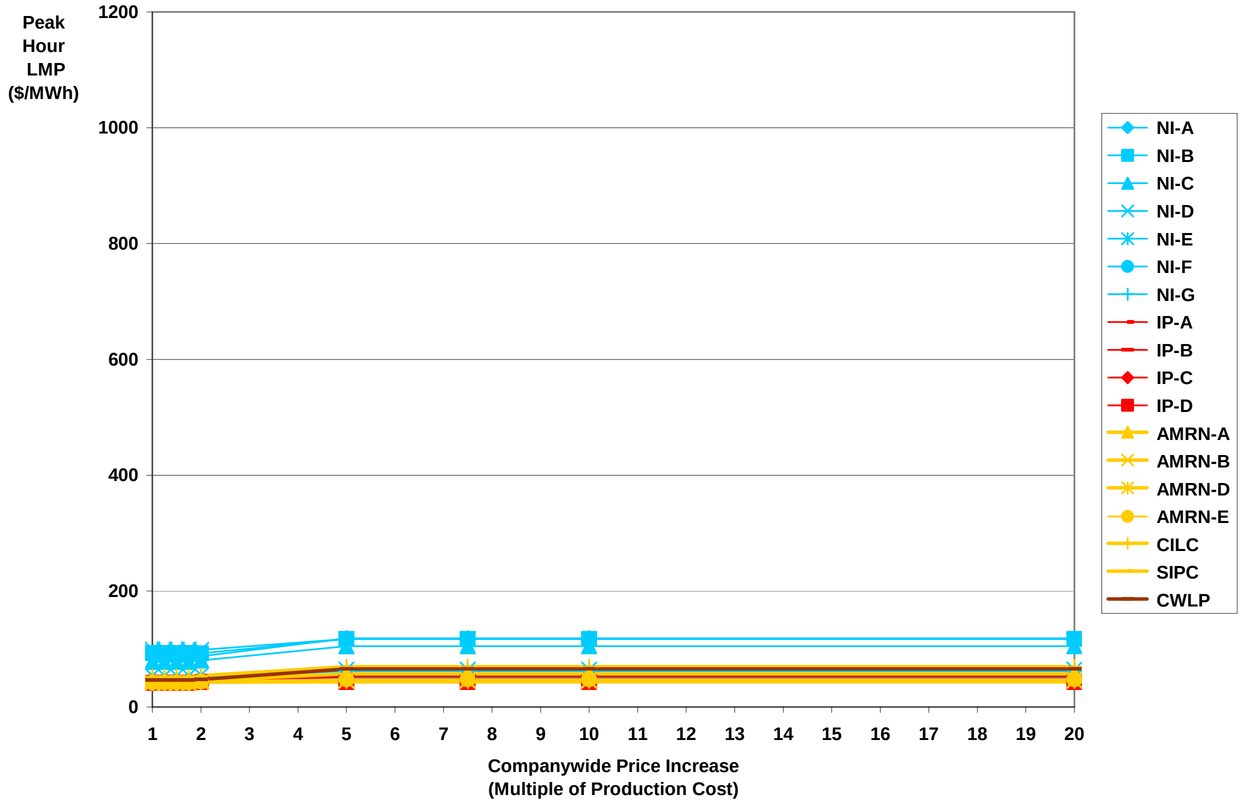


Figure 4.3.2-28 Dominion Energy Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)

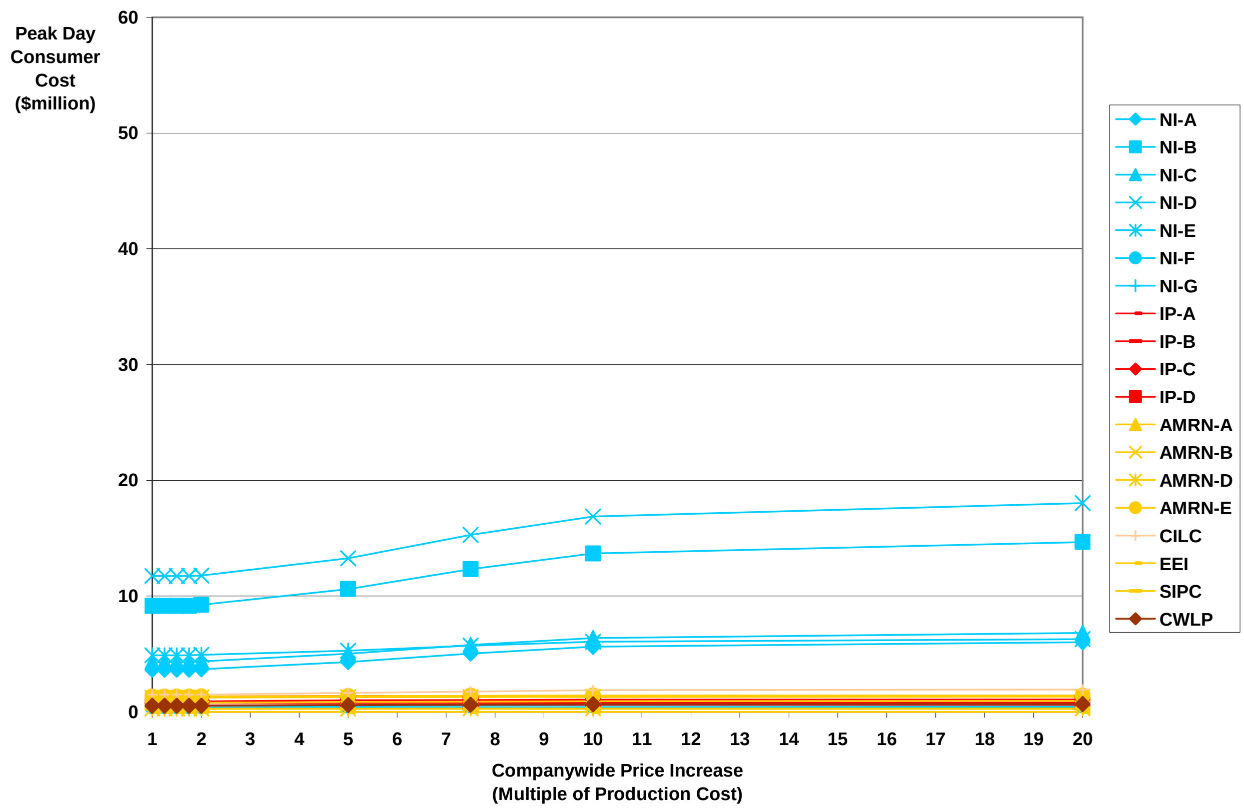


Figure 4.3.2-29 Dominion Energy Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)

Conservative Assumptions

Figure 4.3.2-30 shows the generation and operating profit under Conservative Assumptions. The result was essentially the same as for Case Study Assumptions. Table 4.3.2-10 shows the transmission components at capacity limits. As before, company profitability did improve as a result of the changes in congestion.

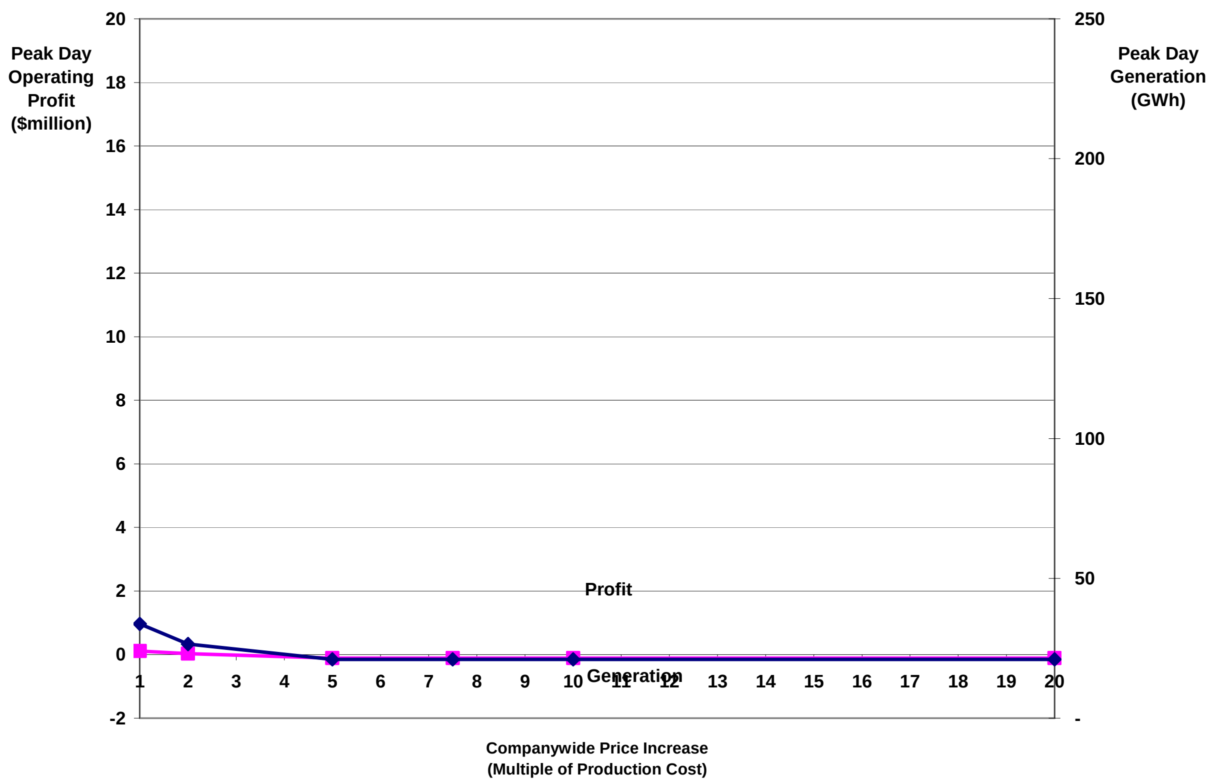


Figure 4.3.2-30 Dominion Energy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)

Table 4.3.2-10 Transmission Components at Capacity Limits under Dominion Energy 20-Fold Price Increase (Conservative Assumptions)

ID	Bus From	Bus To	Zone From	Zone To	Equipment	
NI-A						
36457_36599	ALPIN;RT	CHERR; R	NI-A	NI-A	138 kV	Line
36689_36982	DIXON; R	MENDO; T	NI-A	NI-A	138 kV	Line
NI-C						
36311_36349	ELECT;4R	ELECT;3R	NI-C	NI-C	345 kV	Line
NI-D						
36624_36648	CLYBO; B	CROSB; B	NI-D	NI-D	138 kV	Line
37260_37316	SLINE;2S	WASHI; B	NI-D	NI-D	138 kV	Line
37261_37317	SLINE;5S	WASHI; R	NI-D	NI-D	138 kV	Line
36867_37387	**JEFFE; R**	**KINGS; R**	**NI-D**	**NI-D**		
36295_36022	CRAWF; R	CRAWF;1M	NI-D	NI-D	138 /345	Transformer
36022_36641	CRAWF;1M	CRAWF; R	NI-D	NI-D	138 /138	Transformer
NI-E						
36337_36093	GOODI;1R	GOODI;1M	NI-E	NI-E	138 /345 kV	Transformer
36093_36791	GOODI;1M	GOODI; R	NI-E	NI-E	138 /138	Transformer
36309_36337	E FRA; R	GOODI;1R	NI-E	NI-E	345 kV	Line
36499_36559	G3852;RT	B ISL;1R	NI-E	NI-E	138 kV	Line
36271_36273	B ISL;RT	B ISL; R	NI-E	NI-E	345 kV	Line
36702_36754	E FRA; B	FFORT; B	NI-E	NI-E	138 kV	Line
NI-G						
36969_37085	MAZON; R	OGLES; T	NI-G	NI-G	138 kV	Line
AMRN-B						
30729_31991	CONSTU1	HOLLAND	AMRN-B	AMRN-B	18 /345	Transformer
30395_31445	**COFFEEN**	**PANA**	**AMRN-B**	**AMRN-B**	**345 kV**	**Line**
30431_31026	CRAB ORH	MARIONSA	AMRN-B	AMRN-E	138 kV	Line
AMRN-D						
31618_31739	RNTOUL J	SIDNYCPS	AMRN-D	AMRN-D	138 kV	Line
30614_32348	**GIBSON C**	**BROKAW**	**AMRN-D**	**IP-B**	**138 kV**	**Line**
EEI						
33394_33478	JOPPA TS	JOPPA GT	EEI	EEI	161 kV	Line

Note:
Normal row indicates component at capacity under PC case (Conservative Assumptions) conditions and under these conditions.
Shaded row indicates component at capacity under PC case (Conservative Assumptions) conditions but not under these conditions.
Bold row indicates component at capacity under these conditions but not under PC case (Conservative Assumptions) conditions.

Company Comparison

Case Study Assumptions

The previous sections have focused on the effects of economic withholding from the perspective of individual companies. To compare the results across companies requires an adjustment in the measurement scales used to display results. Previously, the multiplier that each company applied to the production cost of its units was used as the metric. However, each company has a different portfolio of units, each with a different production cost. The unit production costs range from very low for nuclear and large coal units, to very high for gas turbine peaking units. Applying companywide multipliers to bid prices amplified the wide range of production costs. Figure 4.3.2-31 shows the range of unit production costs for each company along with a capacity-weighted average. It is evident that, for example, a doubling of prices by one company can create a very different set of market bids than a doubling of prices by another company. For the cross-company comparisons, the capacity-weighted average price was used as the metric in place of the companywide price multiplier.

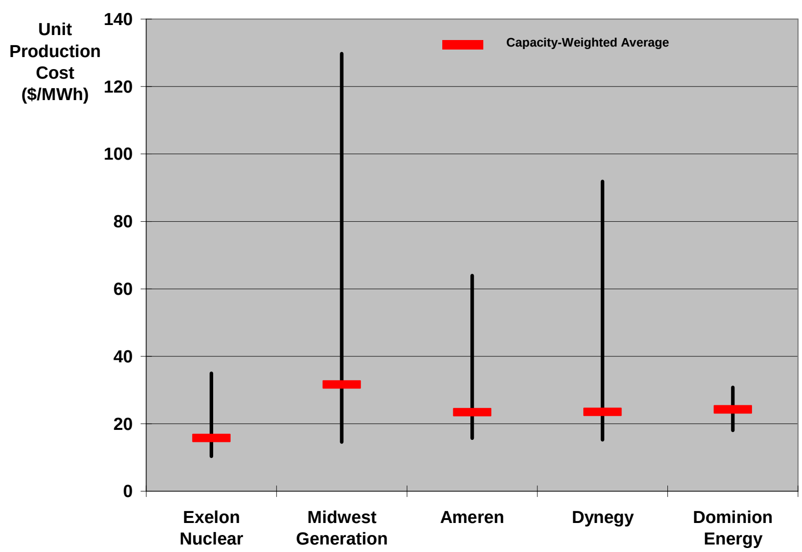


Figure 4.3.2-31 Range of Unit Production Costs and Capacity-Weighted Average

Figure 4.3.2-32 shows the effect that price increases, to the same capacity-weighted average for each company, had on consumer prices in each zone. All companies, with the exception of Dynegy, had the ability to impact consumer costs in the northeastern part of the State (i.e., the NI zones). A price increase to a companywide average of 300 $/MWh caused consumer costs to rise between 50% and 250%, depending on which company was implementing the increase. Some of the companies operating in one part of the State had the ability to create consumer price increases in other parts of the State, as shown on the figure. Some parts of the State (i.e., the IP and AMRN zones) were relatively insensitive to the price increases from any company. Consumers in these areas did not experience any significant cost increases even at the high price levels. All these results reflect the transmission limits discussed earlier.

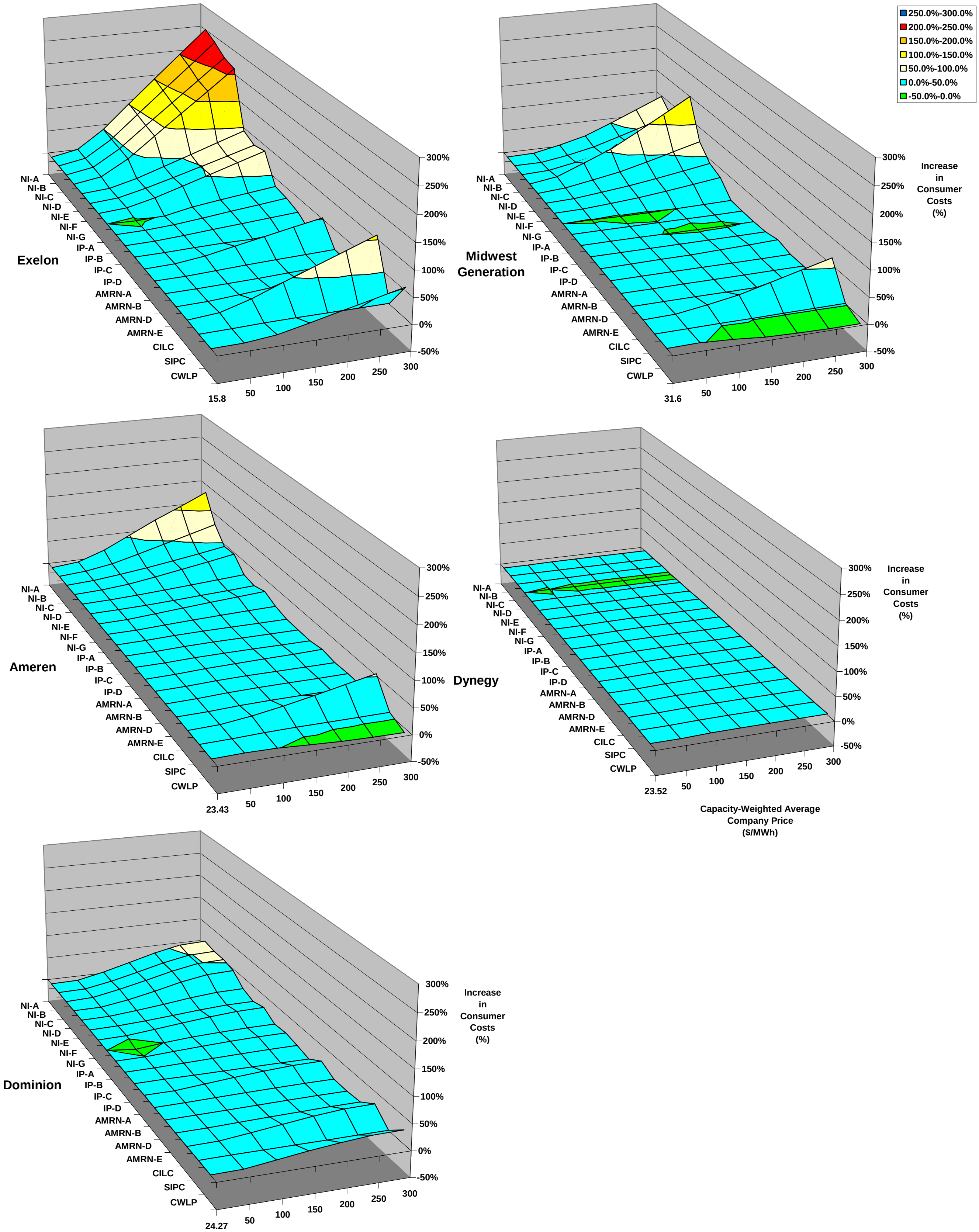


Figure 4.3.2-32 Effect of Companywide Price Increases during Peak Hours on Consumer Costs (Case Study Assumptions)

These results stem from the integrated operation of the electricity market as assumed in the simulation. Because the market was operated by a single ISO rather than by individual companies, any generator in any part of the State could be used to meet load in any other part of the State, subject to the limits of the transmission system. Thus, price increases by any one company had the potential to ripple across the State and affect the entire market. This was especially true for the companies that had large units located at critical points in the transmission network such as Exelon Nuclear, Midwest Generation, and Ameren. By raising their prices, they affected most of the market.

The parts of the State that are not significantly affected by these price increases had adequate lower-cost generation combined with transmission capacity to bring the cheaper power into the area. These areas were effectively insulated from price increases by the large GenCos. In an analogous fashion, the fact that price increases by Dynegy did not have the ability to affect much of the market indicates that their units are not as strategically located as those of other companies. At higher prices, their units were readily displaced by others.

Conservative Assumptions

Figure 4.3.2-33 shows the range of production costs and capacity-weighted average under the Conservative Assumptions. The difference from the previous figure is that fixed operating and maintenance costs have been excluded. The company comparison was repeated using these values of production cost. Figure 4.3.2-34 shows the effect of company price increases on consumer costs.

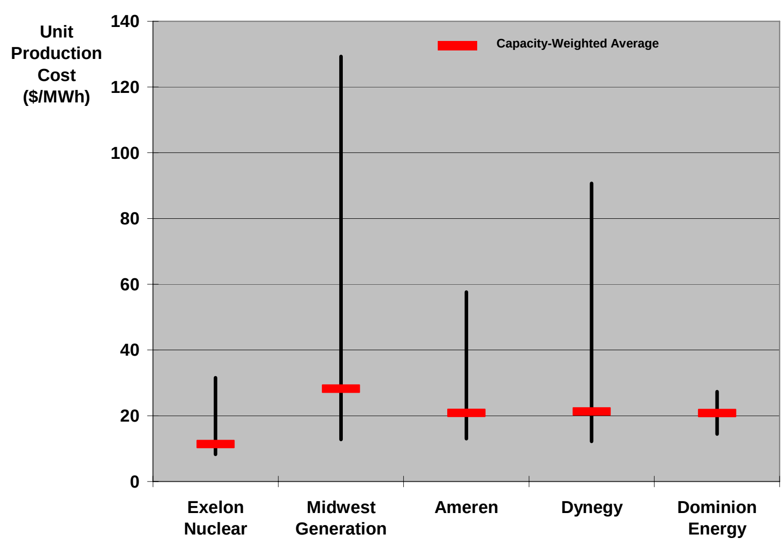


Figure 4.3.2-33 Range of Unit Production Costs and Capacity-Weighted Average (Conservative Assumptions)

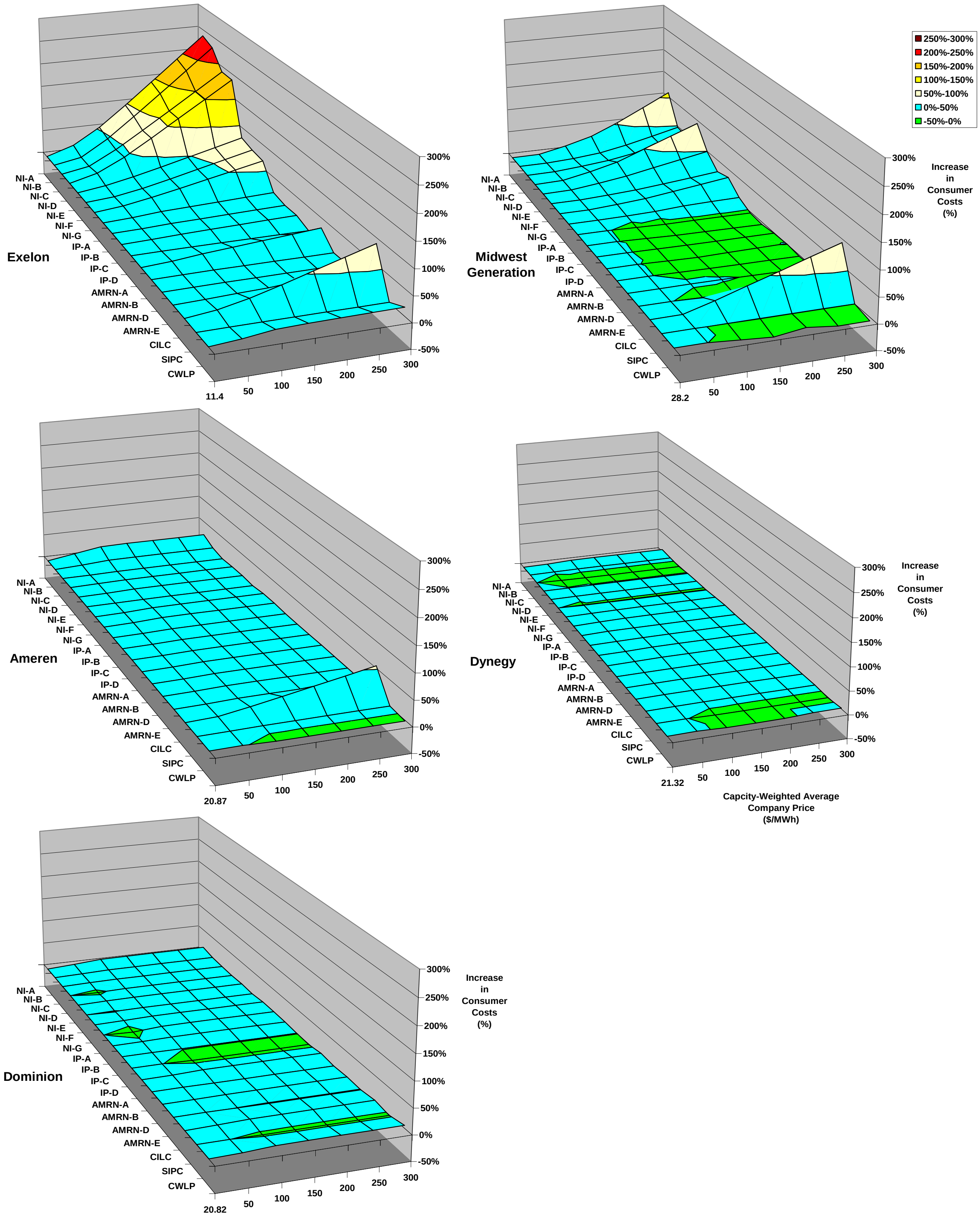


Figure 4.3.2-34 Effect of Companywide Price Increases during Peak Hours on Consumer Costs (Conservative Assumptions)

For Exelon Nuclear, Midwest Generation, and Dynegy, the pattern was very similar, in terms of percentage increase, to the Case Study Assumptions; however, the absolute level of increase was lower under these conditions. This was due to the availability of more generation, since forced outages and company-level unit commitment were not considered here. For Ameren and Dominion, the impact of their price increases on consumer costs in the northern parts of the State was reduced considerably as a result of the availabilty of this extra generation capacity statewide under the Conservative Assumptions.

4.3.3 Economic Withholding Summary

The following summary observations can be made with respect to the economic withholding strategy:

- Economic withholding of single units (i.e., raising prices above production costs for one unit in a company's portfolio) did not generate significant increases in operating profitability. In most cases, it created a loss as the unit's dispatch schedule was reduced. There was adequate generation and transmission capacity to bring cheaper units on-line.

- For a few units that were critical during peak hours, single unit economic withholding provided an increase in operating profit.

- Companywide economic withholding during all hours of a peak-load day was not an attractive strategy for all companies. The higher-priced units were not scheduled for dispatch during low-load periods. The price increases did not compensate for the loss of scheduled generation. In some cases (e.g., large nuclear or coal-fired units), the reduced dispatch schedule was not technically feasible.

- Companywide economic withholding only during peak hours did increase company operating profit significantly on peak days for Exelon Nuclear and Midwest Generation. For Ameren, Dynegy, and Dominion Energy, profitability decreased.

- All companies, with the exception of Dynegy, had the ability to increase market prices by companywide economic withholding on peak days. However, only Exelon Nuclear and Midwest Generation gained significant increases in operating profitability by applying this strategy. Ameren, Dynegy, and Dominion Energy did not have market power by this criterion. Under the Conservative Assumptions, Midwest Generation still displayed the ability to exercise market power. For Exelon Nuclear, under Conservative Assumptions, its prices had to be raised beyond the 20-fold level used here in order for its profits to increase measurably.

- All companies, except Dynegy, caused peak-day consumer costs to rise by the application of a companywide economic withholding strategy. The northeastern part of the State experienced peak-day consumer cost increases of 2½ times. Under Conservative Assumptions, the same was true except that the level of consumer price increases was smaller. Also, Ameren and Dominion had significantly smaller impacts on consumer prices from their increases.

- As a result of transmission limits, the NI and CILC zones were the most susceptible to the exercise of market power using economic withholding. The IP and AMRN zones were affected to a much smaller degree due to less transmission congestion. This was true under both Case Study and Conservative Assumptions.

5 SUMMARY

5.1 OBSERVATIONS AND CONCLUSIONS

As was stated in the opening section of this report, the purpose of this study was to make an initial determination of whether or not the transmission system in Illinois and the surrounding region would be able to support a competitive electricity market, would allow for effective competition to keep prices in check, and would allow for new market participants to effectively compete for market share as the State moves toward full restructuring of the electricity market in 2007. The study was designed to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power (defined here as the ability to unilaterally raise prices and increase company profitability) in one or more portions of the State, and thereby create undue pressure on the prices charged to customers and/or inhibit new market participants from entering the market. The results indicate that the answers to these questions are not simple. Rather, they depend on a number of factors. The following observations can be made from what has been studied thus far under the assumptions applied:

Basic System Status

(a) The State has an adequate supply of generation capability to meet its needs and to export power to surrounding areas. It might even be argued that there is an excess of capacity, given that the projected statewide generation reserve margin (in excess of 40%) is higher than what is generally used for system reliability planning. Further, some generators would not be dispatched at all under the conditions laid out in the PC case.

(b) The ownership of the generation capacity is concentrated in five companies: Exelon Nuclear, Midwest Generation, Ameren, Dynegy, and Dominion Energy. Together, they account for more than 77% of the generation capacity in the State. If they were to be dispatched under PC case market conditions, they would account for about 98% of the electricity generated in the State. Using any one of a number of measures of market competition, the State's generation capacity can be considered to be concentrated. With this degree of concentration and with much of this capacity in the form of low-cost nuclear and coal units, it would be difficult for new generation companies to enter the deregulated market. In fact, many of the existing natural gas units, some of which are only a few years old, would have difficulty competing in this market.

(c) During the high-load periods, which occurred about 5% of the time, electricity prices rose, since higher-cost generators had to be brought on-line to meet loads while maintaining the integrity and stability of the power grid. Even without any attempt to manipulate prices on the part of generation companies, prices were as much as 30% higher in high-load periods.

(d) The transmission system in the State has areas that show evidence of congestion. Some transmission equipment was operated at its capacity limits for a significant number of hours in a year. The congested regions include the City of Chicago, the area north and west of Chicago out to the Iowa border, a broad area stretching southwest of Chicago to Peoria and Springfield, and several smaller isolated areas in the southern part of the State. The effects of the transmission congestion on locational marginal prices were most prevalent during peak-load periods during which there was a pronounced price spread across the State. Price variations across the State due to transmission congestion were as much as 24% during these peak-load periods.

(e) Using Conservative Assumptions, in which more generation capacity was assumed to be made available by the elimination of forced outages and company-level unit commitment decisions, the results did not materially change. The generation market was still concentrated and transmission congestion was still evident. Price variations, though smaller in absolute magnitude, were equivalent in relative terms.

(f) Under a fully competitive market in the State using the market rules assumed here, some generation companies were pressed to maintain operating profitability. Only 6 out of 24 generation companies in the State were able to operate profitably. The dominance of the low-cost nuclear and coal units made it difficult for others to compete. Under Conservative Assumptions, none of the generation companies, except Exelon Nuclear, was profitable. Exelon's operating profit was very small.

Market Power Potential

(g) If generation companies seek to raise market prices by physically withholding single units from service, the results here show that, for the most part, they would not likely benefit. Because of the abundance of generation in the State, there was almost always another unit that could be brought into service to replace one that was withheld. This is true even in light of the transmission limitations.

(h) In contrast, physically withholding multiple units that are strategically located in the transmission network, particularly during peak-load conditions, can increase profitability. A single company using a strategy based on indicators of system reserve margin to identify times to withhold capacity and indicators of locational prices to identify which capacity to withhold could significantly increase its profitability. This type of strategic physical withholding could even create conditions where some load cannot be met and could result in very steep price increases. Exelon Nuclear, Midwest Generation, and Ameren all had market power (as defined here) when using this strategy. Dynegy and Dominion Energy did not.

(i) If the major generation companies sought to raise market prices by unilaterally increasing the price of their units (i.e., by economic withholding) the results would be mixed. Applying a price increase to all units for all hours increased profits for Exelon Nuclear and Midwest Generation, but at the expense of significant loss in generator dispatch, since some of the higher cost units would be selected only sporadically by the market. The resulting dispatch schedule may not be technically practical for the companies' larger units. For Ameren, Dynegy, and Dominion Energy, the higher priced units would not be selected in the market and the price increase gained by other units would not be sufficient to recover the lost revenue. Profitability decreased.

(j) Alternatively, a more limited application of price increases that was restricted to peak hours only allowed Exelon Nuclear and Midwest Generation to significantly increase profits with only a small decrease in generator dispatch. Ameren, Dynegy, and Dominion did not see any profit increase by applying this strategy. The same was true under Conservative Assumptions except that Exelon would need very large price increases to increase its profitability. When using this strategy, Exelon Nuclear and Midwest Generation had market power, according to the definition used here.

(k) By raising their prices, all generation companies could cause consumer costs to rise, some by as much as 250% in some parts of the State on a peak day. However, only Exelon Nuclear and Midwest Generation saw a significant increase in their operating profits by applying this strategy.

Overall, the answer to the basic question of the study, *"Can a company, acting on its own, raise electricity prices and increase its profits?"* is affirmative. There is a concentration in the generation market and evidence of transmission congestion, at least during high-load periods. This will give rise to the ability of some companies to unilaterally raise prices and increase their profits. Consumer costs will increase, in some cases substantially. However, the situations under which this can be done are limited to a number of conditions, especially high-load periods.

5.2 RECOMMENDED ADDITIONAL ANALYSIS

All of the results presented here must be viewed in the light of the limitations of the models, data, and assumptions used. Further, the results presented here provide only an initial indication of how the Illinois electricity market might function. There are many more issues and conditions that need to be investigated to provide a more comprehensive picture of the situation.

A number of additional analyses can be identified to increase the understanding of possible developments in the Illinois market. Included are the following:

- *An expansion of the level of detail in the representation of the out-of-state grid.* The results of both the PowerWorld and EMCAS models showed that out-of-state suppliers and out-of-state loads can have a significant impact on the Illinois market. A more detailed representation of these factors would improve the understanding of these effects.

- *Sensitivity analyses that vary some of the key parameters over a range of possibilities.* Included are:

- Fuel price forecasts
- Forced outage scenarios
- Transmission system configuration
- Decision parameters used in the strategies

- *Evaluation of additional company business strategies.* Only a few business strategies were studied here. There are many more that could be evaluated for their impact on the market.

- *Evaluation of the effect of bilateral contracts.* In this study, it was assumed that there would be no bilateral contracts between GenCos and DemCos. All power would be traded in a pool market. The effect of bilateral contracts, which could mitigate some of the price swings, should be investigated.

- *Effect of consumer price response.* In this study, it was assumed that there is no consumer response to prices and electricity demand is inelastic. An evaluation of how consumers might respond (e.g., by reducing load, by switching electricity suppliers) should be studied.

- *Effect of adding generation and/or transmission resources.* In this study no new transmission resources were added to the system. Modified locations for generation resources (e.g., distributed generation designed to reduce transmission congestion) were also not included here. Both of these warrant further evaluation.

- *Changes in market rules.* This study considered only a single market configuration and a single set of market rules. The effects of changes in the market structure, market rules, and regulatory measures to mitigate against steep price increases need to be studied.

The value of this study and any subsequent studies is not in producing a single projection of how the Illinois electricity market will develop, nor to consider a set of possible scenarios for its development. Rather, the benefit is gained by identifying the configurations to which the market may gravitate. In the terminology of the computer modeling and simulation that was used here, this would "map the solution space." This approach will provide a better understanding of the fundamental forces at work that will shape the evolution of the Illinois electricity market.

EVALUATING THE POTENTIAL IMPACT OF TRANSMISSION CONSTRAINTS ON THE OPERATION OF A COMPETITIVE ELECTRICITY MARKET IN ILLINOIS

APPENDIXES

APPENDIX A
OVERVIEW OF THE POWERWORLD® MODEL

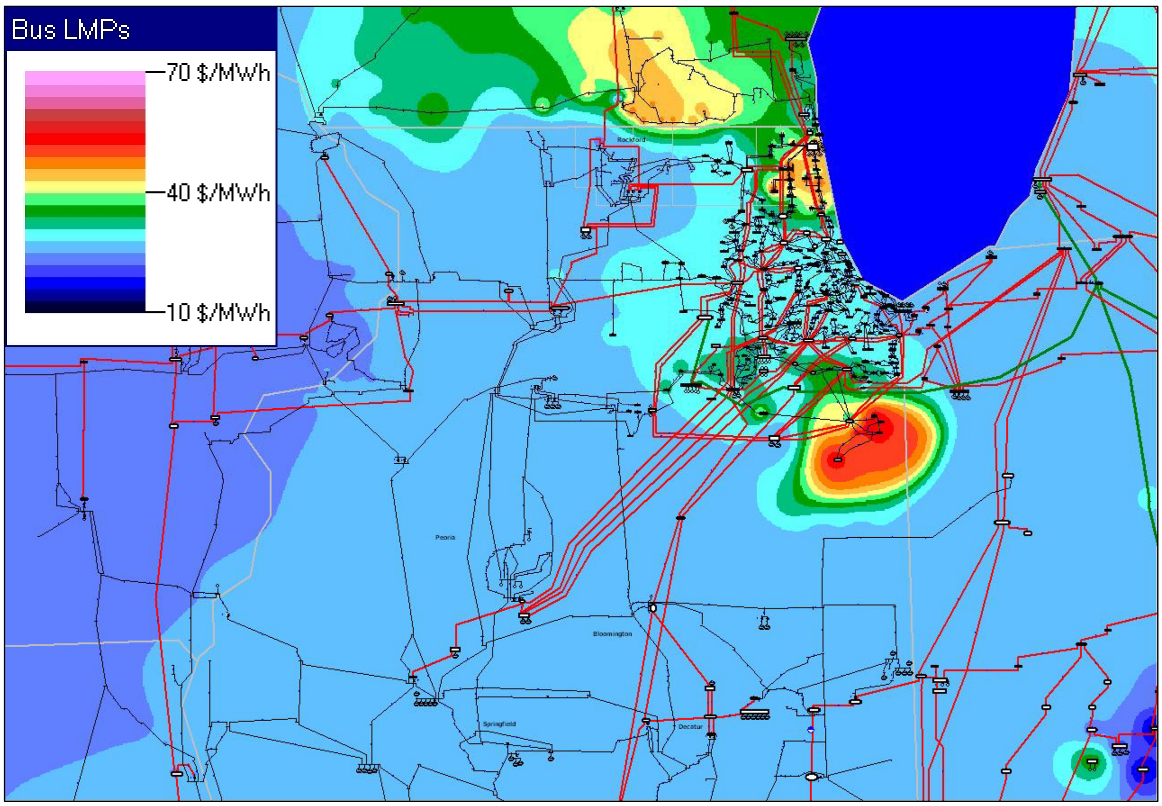
PowerWorld® Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a time frame ranging from several minutes to many days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses. Powerful visualization techniques are used on an interactive basis, resulting in an extremely intuitive and easy-to-use graphical user interface (GUI). The GUI includes animated one-line diagrams with support for panning, zooming, and conditional display of objects.

One of the add-ons available with Simulator is the Security Constrained Optimal Power Flow (SCOPF). The advantage of having a security constrained optimal power flow embedded into Simulator is that it is now possible to optimally dispatch the generation in an area or group of areas while simultaneously enforcing the transmission line and interface limits both for the base case and for a set of statistically likely contingencies. Simulator SCOPF can then calculate the marginal price to supply electricity to a bus (also known as the locational marginal price [LMPs]), taking into account transmission system congestion. The advantage with Simulator is that these values are not just calculated; they can also be shown on a one-line diagram, on a contoured map, or exported to a spreadsheet. An example contour of bus LMPs is shown in Figure A-1.

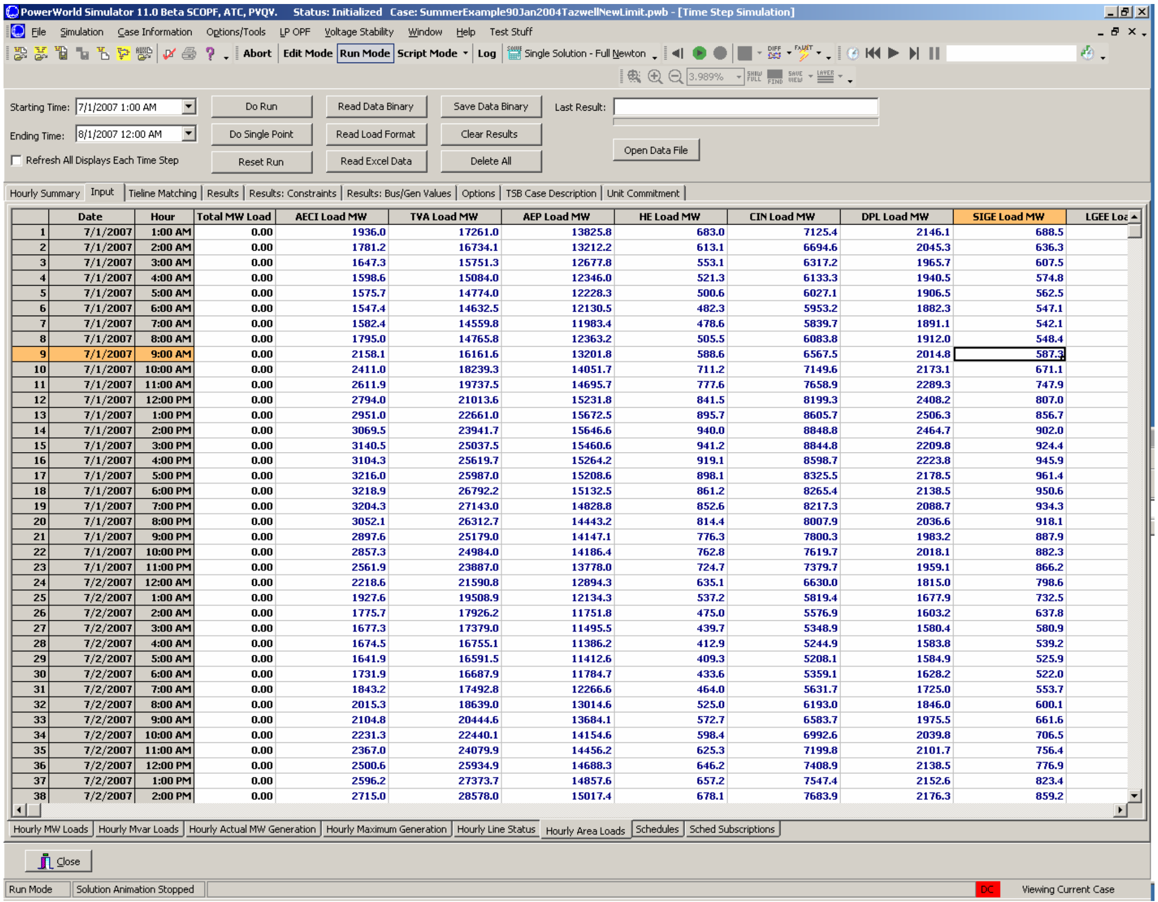
The purpose of an SCOPF is to minimize an objective (or cost) function by changing system controls taking into account both equality and inequality constraints. These constraints are used to model the power balance constraints and various operating limits. In Simulator SCOPF, the algorithm determines the optimal solution by iterating between solving a standard power flow with contingency analysis and then solving a linear program (LP) to change the system controls to remove any limit violations. In solving a constrained optimization problem, such as the SCOPF, there are two general classes of constraints, equality and inequality. Equality constraints are constraints that always have to be enforced. That is, they are always "binding." For example, in the SCOPF the real and reactive power balance equations at system buses must always be satisfied (at least to within a user specified tolerance); likewise the area MW interchange constraints are equality constraints. In contrast, inequality constraints may or may not be binding. For example, a line MVA flow may or may not be at its limit, or a generator real power output may or may not be at its maximum limit.

The version of Simulator used for this project also included the time step simulation enhancement. This enhancement allowed easy hour time step simulations of the power system over relatively long periods of time, such as a month. When run in the time step mode, Simulator sequentially solved the SCOPF for each hour in the time period, taking into account time-specific conditions, such as the total system load and any scheduled generator outages. The time step simulation enhancement also included many features for presenting the results of each study. Figure A-2 shows a sample page from the Time Step Simulation Control Form.

PowerWorld Simulator was originally developed at the University of Illinois at Urbana-Champaign (UIUC) by Professor Thomas J. Overbye beginning in 1994. PowerWorld Simulator is now marketed exclusively by PowerWorld Corporation. PowerWorld Corporation has no direct UIUC affiliation and was not involved with this study. However, since a gratis site license for PowerWorld Simulator (including all add-ons) has been provided by PowerWorld Corporation to UIUC, PowerWorld Simulator was used extensively for the UIUC portion of this study. Additional information about PowerWorld Simulator can be found on the PowerWorld Corporation website, available at www.powerworld.com.



Example LMP Contours for Northern Illinois



	Date	Hour	Total MW Load	AECI Load MW	TVA Load MW	AEP Load MW	HE Load MW	CIN Load MW	DPL Load MW	SIGE Load MW	LGEE Loa
1	7/1/2007	1:00 AM	0.00	1936.0	17261.0	13825.8	683.0	7125.4	2146.1	688.5	
2	7/1/2007	2:00 AM	0.00	1781.2	16734.1	13212.2	613.1	6694.6	2045.3	636.3	
3	7/1/2007	3:00 AM	0.00	1647.3	15751.3	12677.8	553.1	6317.2	1965.7	607.5	
4	7/1/2007	4:00 AM	0.00	1598.6	15084.0	12346.0	521.3	6133.3	1940.5	574.8	
5	7/1/2007	5:00 AM	0.00	1575.7	14774.0	12228.3	500.6	6027.1	1906.5	562.5	
6	7/1/2007	6:00 AM	0.00	1547.4	14632.5	12130.5	482.3	5953.2	1882.3	547.1	
7	7/1/2007	7:00 AM	0.00	1582.4	14559.8	11983.4	478.6	5839.7	1891.1	542.1	
8	7/1/2007	8:00 AM	0.00	1795.0	14765.8	12363.2	505.5	6083.8	1912.0	548.4	
9	7/1/2007	9:00 AM	0.00	2158.1	16161.6	13201.8	588.6	6567.5	2014.8	587.3	
10	7/1/2007	10:00 AM	0.00	2411.0	18239.3	14051.7	711.2	7149.6	2173.1	671.1	
11	7/1/2007	11:00 AM	0.00	2611.9	19737.5	14695.7	777.6	7658.9	2289.3	747.9	
12	7/1/2007	12:00 PM	0.00	2794.0	21013.6	15231.8	841.5	8199.3	2408.2	807.0	
13	7/1/2007	1:00 PM	0.00	2951.0	22661.0	15672.5	895.7	8605.7	2506.3	856.7	
14	7/1/2007	2:00 PM	0.00	3069.5	23941.7	15646.6	940.0	8848.8	2464.7	902.0	
15	7/1/2007	3:00 PM	0.00	3140.5	25037.5	15460.6	941.2	8844.8	2209.8	924.4	
16	7/1/2007	4:00 PM	0.00	3104.3	25619.7	15264.2	919.1	8598.7	2223.8	945.9	
17	7/1/2007	5:00 PM	0.00	3216.0	25987.0	15208.6	898.1	8325.5	2178.5	961.4	
18	7/1/2007	6:00 PM	0.00	3218.9	26792.2	15132.5	861.2	8265.4	2138.5	950.6	
19	7/1/2007	7:00 PM	0.00	3204.3	27143.0	14828.8	852.6	8217.3	2088.7	934.3	
20	7/1/2007	8:00 PM	0.00	3052.1	26312.7	14443.2	814.4	8007.9	2036.6	918.1	
21	7/1/2007	9:00 PM	0.00	2897.6	25179.0	14147.1	776.3	7800.3	1983.2	887.9	
22	7/1/2007	10:00 PM	0.00	2857.3	24984.0	14186.4	762.8	7619.7	2018.1	882.3	
23	7/1/2007	11:00 PM	0.00	2561.9	23887.0	13778.0	724.7	7379.7	1959.1	866.2	
24	7/2/2007	12:00 AM	0.00	2218.6	21590.8	12894.3	635.1	6630.0	1815.0	798.6	
25	7/2/2007	1:00 AM	0.00	1927.6	19508.9	12134.3	537.2	5819.4	1677.9	732.5	
26	7/2/2007	2:00 AM	0.00	1775.7	17926.2	11751.8	475.0	5576.9	1603.2	637.8	
27	7/2/2007	3:00 AM	0.00	1677.3	17379.0	11495.5	439.7	5348.9	1580.4	580.9	
28	7/2/2007	4:00 AM	0.00	1674.5	16755.1	11386.2	412.9	5244.9	1583.8	539.2	
29	7/2/2007	5:00 AM	0.00	1641.9	16591.5	11412.6	409.3	5208.1	1584.9	525.9	
30	7/2/2007	6:00 AM	0.00	1731.9	16687.9	11784.7	433.6	5359.1	1628.2	522.0	
31	7/2/2007	7:00 AM	0.00	1843.2	17492.8	12266.6	464.0	5631.7	1725.0	553.7	
32	7/2/2007	8:00 AM	0.00	2015.3	18639.0	13014.6	525.0	6193.0	1846.0	600.1	
33	7/2/2007	9:00 AM	0.00	2104.8	20444.6	13684.1	572.7	6583.7	1975.5	661.6	
34	7/2/2007	10:00 AM	0.00	2231.3	22440.1	14154.6	598.4	6992.6	2039.8	706.5	
35	7/2/2007	11:00 AM	0.00	2367.0	24079.9	14456.2	625.3	7199.8	2101.7	756.4	
36	7/2/2007	12:00 PM	0.00	2500.6	25934.9	14688.3	646.2	7408.9	2138.5	776.9	
37	7/2/2007	1:00 PM	0.00	2596.2	27373.7	14857.6	657.2	7547.4	2152.6	823.4	
38	7/2/2007	2:00 PM	0.00	2715.0	28578.0	15017.4	678.1	7683.9	2176.3	859.2	

Figure A-2 An Example Input Page from the PowerWorld Simulator Time Step Control Form

APPENDIX B
OVERVIEW OF THE ELECTRICITY MARKET COMPLEX ADAPTIVE SYSTEMS (EMCAS)© MODEL

B.1 INTRODUCTION

Electricity markets around the world are changing. The traditional vertically integrated electric utility that operated as a regulated monopoly that controlled all aspects of electricity service is giving way to new organizational structures. At a minimum, the electricity services are being unbundled with separate companies handling generation, transmission, and distribution services. In markets with the most restructuring, there are multiple companies competing to provide services.

Recent situations have shown the difficulties of understanding the operation of these new markets. The experience in California in 2000/2001 shows the potential pitfalls of not thoroughly analyzing market design, operating rules, business practices, and system operation. Traditional modeling techniques using global optimization approaches and equilibrium analysis have shown to be inadequate to deal with the new electricity markets. The complex interactions and interdependencies among electricity market participants have become much like those studied in game theory. Unfortunately, the strategies used by many electricity participants are often too complex to be conveniently modeled using standard game theoretic techniques. In particular, the ability of market participants to repeatedly probe markets and rapidly adapt their strategies adds additional complexity.

Computational social science includes the use of agent-based modeling and simulation (ABMS) to study complex social systems such as markets (Epstein and Axtell, 1996). An ABMS approach consists of a set of agents and a framework for simulating their decisions and interactions. ABMS is related to a variety of other simulation techniques, including discrete event simulation and distributed artificial intelligence or multi-agent systems (Law and Kelton, 2000; Pritsker, 1986). Although many traits are shared, ABMS is differentiated from these approaches.

In an ABMS model, an agent is a software representation of a decision-making unit. Agents are self-directed objects with specific traits. Agents typically exhibit bounded rationality, meaning that they make decisions using internal decision rules that depend only on imperfect local information. Emergent behavior is a key feature of ABMS. Emergent behavior occurs when the behavior of a system is more complicated than the simple sum of the behavior of its components.

A wide variety of ABMS implementation approaches exist. Live simulation where people play the role of individual agents is an approach that has been used successfully by economists studying complex market behavior. General-purpose tools such as spreadsheets, mathematics packages, or traditional programming languages can also be used. However, special-purpose tools such as Swarm, the Recursive Agent Simulation Toolkit, StarLogo, and Ascape are among the most widely used options (Burkhart et al., 2000; Collier and Sallach, 2001).

Several electricity market ABMS tools have been constructed, including those created by Bower and Bunn (2000), Petrov and Sheblé (2000), as well as Nicolaisen (2001). These models have hinted at the potential of ABMS to act as electronic laboratories, or "e-laboratories," suitable for repeated experimentation under controlled conditions.

The Electricity Market Complex Adaptive System (EMCAS) model was developed by Argonne National Laboratory, a U.S. Department of Energy facility, to improve the ability to analyze restructured (often referred to incorrectly as "deregulated") electricity markets. It is designed for use both in regional U.S. markets and in markets that are undergoing restructuring in other countries.

B.2 OVERVIEW OF THE EMCAS FORMULATION

The EMCAS formulation can be described in terms of three components: agents, interaction layers, and planning periods. The agents represent the participants in the electricity market. The interaction layers represent the environment in which the agents interact with each other. The planning periods represent the different time horizons in which the agents make decisions regarding their participation in the market.

Figure B-1 shows the agents and the interaction layers that are included in the EMCAS formulation. Some agents appear in more than one layer.

B.2.1 PHYSICAL LAYER

The physical layer at the bottom of the figure represents the agents that are involved in the physical generation, transmission, distribution, and consumption of electricity. The *Consumers* represent the final users of electricity that create the demand or load. They can be residential, commercial, industrial, or any other type of electricity user. *Generators* represent the physical generation equipment. They can be driven by thermal (e.g., coal, oil, gas, nuclear), hydro, or renewable energy (e.g., wind, solar, biomass) technologies. The *transmission nodes* represent the points in the power system where consumers and generators are attached to the grid and where elements of the transmission network are connected. The *transmission links* represent the high-voltage lines that connect nodes. It should be noted that in the EMCAS formulation, the transmission nodes and links can represent actual transmission network buses and lines or they can represent a reduced-form network where buses and lines have been aggregated for computational efficiency. Consumers, Generators, and Transmission Nodes and Links together make up the physical part of the electricity market. Note that in EMCAS, the distribution system is generally not modeled in detail. While it is structurally possible to include the details of the distribution network (i.e., by adding distribution nodes and links), in practice this is not done to maintain a reasonable model size and run time for the simulation.

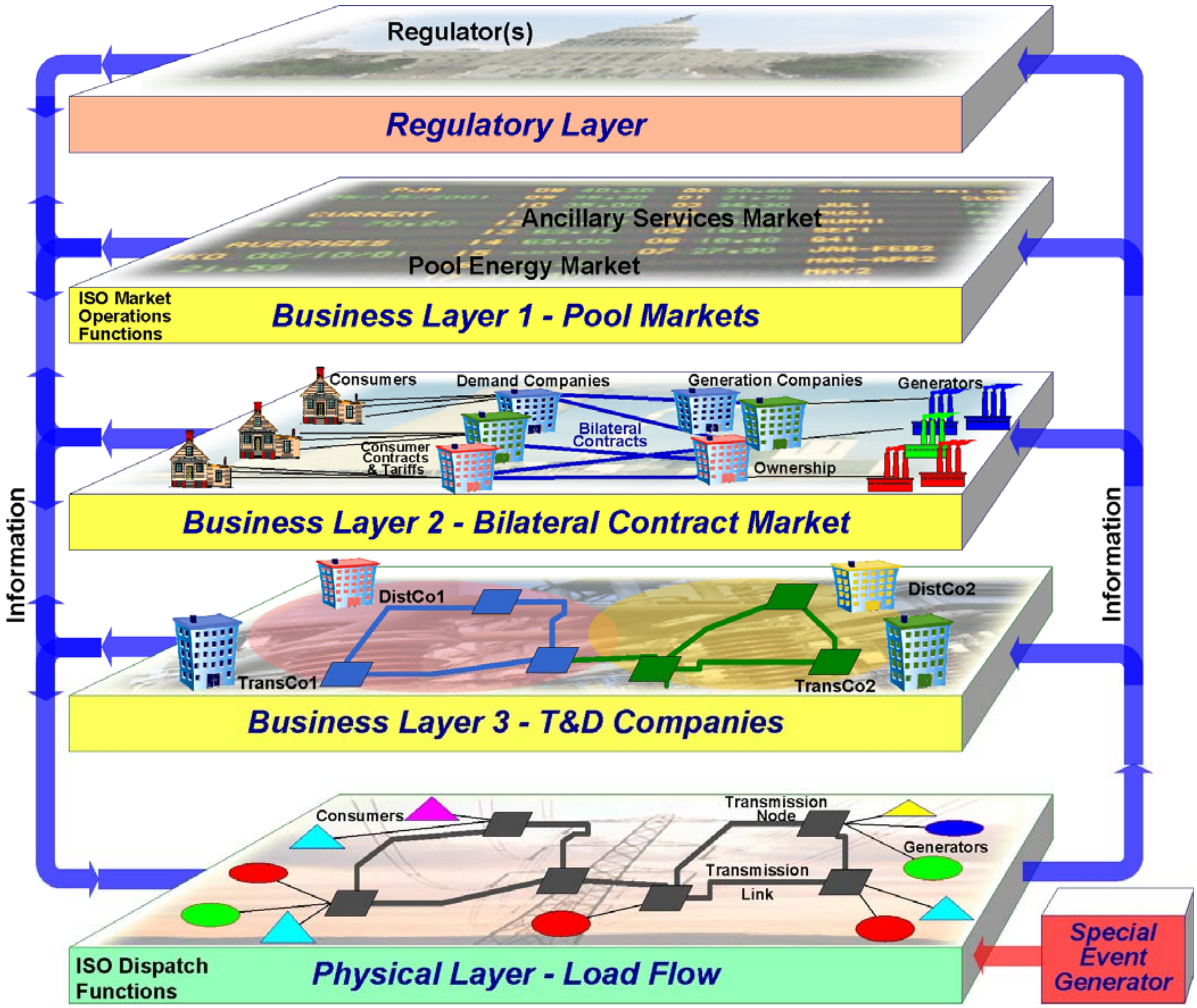


Figure B-1 EMCAS Formulation and Layers

The *independent system operator* (ISO) represents the entity that operates both the transmission system and the electricity markets. This agent could represent an independent system operator, regional transmission organization (RTO), or an independent transmission provider (ITP), depending on what organizational structure is in place. In the physical layer, the ISO exercises its dispatch function to operate the system to match load and generation and to adjust to unscheduled load, generator or transmission outages, and other unplanned events.

B.2.2 BUSINESS LAYERS

Figure B-1 also shows three business layers that represent the business side of the electricity market. The *generation companies* (GenCos) represent the business units that own the generators. It is these agents that make decisions about how to participate in the electricity market and operate the equipment to meet company objectives. The *demand companies* (DemCos) represent the business units that sell electricity directly to consumers. In the EMCAS formulation, all consumers purchase their electricity from a demand company. It is the demand company that buys electricity from generation companies to serve its customer load. It should be noted that in actual practice, a generation company and a demand company might, in fact, be part of the same corporate parent. This can be accounted for in EMCAS.

Generation companies and demand companies can engage in *bilateral contracts* for the sale and purchase of electricity. These contracts are negotiated privately between two agents. In some market structures, the ISO is involved in these contracts only to the extent of determining that there is adequate transmission capacity to accommodate the contractual power transfers.

Pool markets (or spot markets) for energy and ancillary services serve as central clearinghouses for buyers and sellers. The ISO operates these markets by receiving bids from generation companies and demand companies. It selects bids based on price and system security considerations and prepares a generation schedule. In some areas, there is no pool market operating. EMCAS can simulate this situation as well.

The *transmission company* (TransCo) is the business unit that owns the transmission system. There may be more than one transmission company in an EMCAS simulation. The *distribution company* (DistCo) is the business unit that owns the distribution system. In EMCAS, the details of the distribution system generally are not modeled explicitly. This layer is designed to account for the ownership of the transmission and distribution systems and for the fees charged by these companies for the use of their facilities. The transmission and distribution companies may be part of a single corporate parent, along with a generation company and demand company. EMCAS can account for this corporate connection while maintaining a separate accounting of each business unit.

B.2.3 REGULATORY LAYER

The *regulator* is the agent in the regulatory layer that sets the market rules and monitors market performance. In EMCAS, the user provides input as the regulator.

B.2.4 SPECIAL EVENTS

The *special event generator* is a component of EMCAS that allows for the introduction of unplanned events that can affect market performance. The types of events include generator outages, transmission outages, and load forecast errors. The user inputs the specific special events to be tested in the simulation, which may be produced by external routines.

B.3 AGENT DESCRIPTIONS

This section describes each of the agents used in this EMCAS simulation, the manner in which their behavioral characteristics can be described, and the information that needs to be input for each agent.

B.3.1 GENERATORS

Generators included in an EMCAS simulation can represent single units (e.g., a single gas turbine), a plant that has several units at the same location (e.g., a multi-unit coal-fired power station), or an aggregate of several plants. The input data required for each generator include the following:

Generator Identification Information

- Name;
- Ownership;
- Location – geographic coordinates;
- In service date – on-line, retirement;
- Unit type;
- Fuel type; and
- Associated transmission bus.

Technical Performance Information

- Capacity – nameplate, summer rating, winter rating;
- Blocks – size of capacity blocks that the unit can be divided into;
- Heat rate – average, incremental;
- Minimum capacity;
- Spinning reserve capability;
- Maximum hourly ramp rates – up and down;
- Startup time;
- Minimum down time; and
- Outage rates – planned and forced.

Economic Information

- Fuel cost;
- Operating and maintenance cost – fixed, variable;
- Startup cost – cold start, warm start; and
- Shutdown costs.

The generator agents do not have any decision-making capability in the EMCAS formulation. All of the decisions on how and when to operate generators are made by the generation company agent that owns the unit.

B.3.2 TRANSMISSION NODES AND LINKS

The configuration of the transmission system is input into EMCAS as a set of nodes and links that represent buses and links, respectively (Figure B-2). The representation may be an aggregate of buses and links to simplify the analysis. Data input include:

- From-bus identification;
- To-bus identification;
- Line voltage, kV;
- Number of circuits;
- Circuit reactance;
- Line capacity, MW; and
- Line status (i.e., closed or open).

The transmission network data may be input point-by-point or may be read in from common format files such as those used by the National Electric Reliability Council (NERC).

The transmission nodes and links do not exercise any decision-making capability in an EMCAS simulation. The operation of the transmission system is governed by decisions made by the ISO agent and the transmission company agent that owns the facilities.

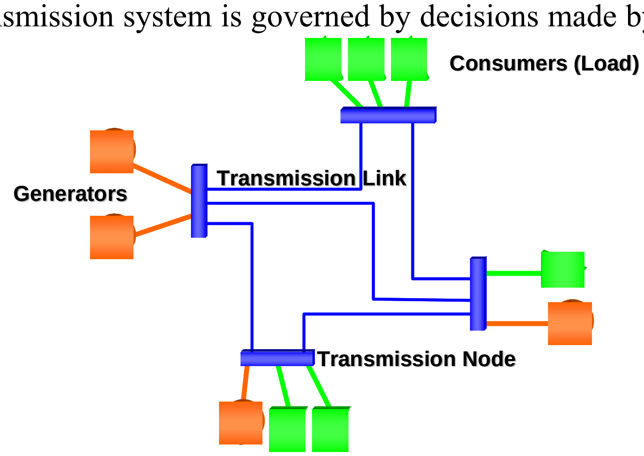


Figure B-2 EMCAS Transmission Components

B.3.3 CONSUMERS

Consumers are the agents in an EMCAS simulation that create the demand for electricity. Consumers may be residential, commercial, industrial, or any other type of electricity user. In theory, an EMCAS simulation may represent individual consumers (e.g., a single household, a single industrial facility). In practice, the number of consumer agents included in a simulation is limited by available data and by computational time. The input for consumer agents includes:

Consumer Identification and Characteristics

- Consumer type – residential, commercial, industrial, other;
- Start and end dates – the times when the agent is on-line and when it is shut down; this allows new consumers to enter the system and old ones to exit a market; and
- Node connection – the point in the transmission network where the consumer is connected.

EMCAS consumer agents have individual identification tags that allow the behavior of each to be tracked during the simulation. In addition, the consumer agent is tagged as to whether it represents a single user (e.g., a single household) or is an aggregate representation of a number of users (e.g., all residential users in a specific area).

Load Information

Hourly load information is input for each consumer agent. The input load represents the basic load pattern in the absence of any unusual events (e.g., unusually higher or lower electricity usage for a short period), random variability in load, or response to electricity prices. All of these can be handled by separate algorithms in an EMCAS simulation.

Price Response

There has been considerable research on consumer response to electricity prices. Studies have shown that consumer reduction in electricity consumption in response to prices, particularly residential customers, is very inelastic in the short term; that is, even high price increases produce only small changes in usage. For this reason, the current version of EMCAS does not simulate consumer price response. However, work is under way to incorporate consumer behavior that would allow agents to switch between different contract types, resulting in changes in load pattern (e.g., load-shifting from peak to off-peak). Contract structures will include fixed pricing, time-of-day pricing, and real-time pricing.

B.3.4 GENERATION COMPANIES

In an EMCAS simulation, the GenCo agents represent the business units that own generators. GenCos may own a single unit and operate like an independent power producer. They may also own multiple plants and be part of a larger corporate parent that offers several products (energy and capacity in spot and bilateral contract markets) to the electricity market (Figure B-3). Decisions on how and when to operate its generation equipment and what prices to charge for its output are made separately by each GenCo agent in EMCAS using a decision process that will be described in more detail later. The GenCo input information includes:

Generation Company Identification

Each GenCo is given a unique identifier. Where a GenCo is part of a larger corporate parent, the generation division of the parent company is identified as the GenCo.

Generation Company Business Strategy

Each GenCo in an EMCAS simulation employs a business strategy that determines how it will behave in the market. An initial version of the strategy is input by the user and specifies the initial techniques

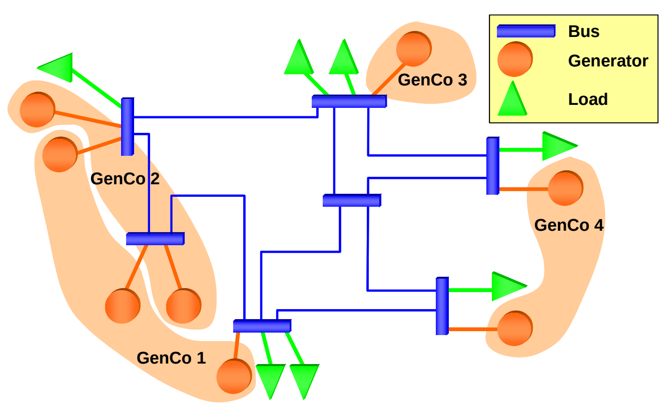


Figure B-3 EMCAS Generation Company Agents that the GenCo will use in an effort to maximize its utility function. This initial strategy is modified as the simulation progresses and the GenCo agent learns and adapts. The business strategy is used by each GenCo to make the following decisions:

- Capacity and pricing for bilateral contracts,
- Capacity and pricing for pool energy market,
- Capacity and pricing for ancillary services market, and
- Maintenance schedule.

The following examples show the types of GenCo business strategies that can be included in an EMCAS simulation:

- Designate capacity to be offered under bilateral contracts to ensure a profitable return;
- Incrementally increase the offer price for bilateral contracts to seek higher returns;
- Offer capacity into the pool energy market at production cost to maximize the probability of acceptance;
- Bid the last blocks of capacity at a high price in an attempt to raise the marginal price in the market (referred to as "hockey stick" bidding);
- Withhold capacity from the market to force the utilization of higher priced units, thus driving up the market price; and
- Bid capacity located at points of transmission congestion at higher prices.

There are many more strategies that can be included in the simulation. The EMCAS approach allows for a wide variety of strategies to be tested for their effectiveness.

The GenCo business strategy is specified by two basic functions: the capacity allocation function and the capacity pricing function. The capacity allocation function determines where the company's available capacity will be bid, taking into account that some capacity is not available due to outages, and is given by the vector:

$$\mathit{Capacity}_{gbh}\ \ [\mathit{Bilateral\ Contracts,\ Pool\ Energy,\ Pool\ Ancillary\ Services,\ Uncommitted}]$$

The elements of the vector indicate the portion of the capacity, in MW, of block b of generator g that is to be committed to each of the markets in hour h of the simulation period. The portion that is designated *Uncommitted* is be allocated to a market based on price expectations and expected returns calculated during the simulation. The capacity pricing function of the GenCo business strategy is specified by the equation:

$$\mathit{Bid\ Price}_{gbh} = A_h*(\mathit{Production\ Cost}_{gb})+B_h*(\mathit{Correlated\ Price})+C_h*(\mathit{Specified\ Price})$$

where:

Bid Price$_{gbh}$ is the bid price that will be offered for block *b* of generator *g* in hour *h*;

Production Cost$_{gb}$ is the production cost of block *b* of generator *g*;

Correlated Price is some price to which the bid may be related (e.g., market price from the day before, projected market price for the next day, price with 50% probability of being accepted, etc.);

Specified Price is a specific price that is user-specified; and

A_h, B_h, C_h are constants for each hour.

This general form provides a means to specify a wide range of pricing strategies. For example, if the business strategy to be simulated is to bid production cost, then A=1.0 and B=C=0. If the business strategy is to bid the projected market clearing price for the next day, then B=1.0, the Correlated Price is the day-ahead price projection for the pool energy market, and A=C=0. If the business strategy is to bid $20/MWh for all situations, then C=1.0, the Specified Price = 20.0, and A=B=0. Various combinations of pricing strategies with each of the coefficients being non-zero can also be specified in this form.

The capacity allocation function and the capacity pricing function uniquely define the GenCo's business strategy. The details of how each GenCo applies its business strategy at each of the planning levels are described in the next section.

Learning and Adaptation

In EMCAS, the business strategy for each GenCo is not static. Rather, it changes as learning and adaptation occurs. The learning and adaptation by each GenCo includes the following (Figure B-4):

- Look Back – an evaluation of past performance of the company's business strategy;
- Look Ahead – a projection of the future state of the electricity markets; and
- Look Sideways – a determination of what competitors have done.

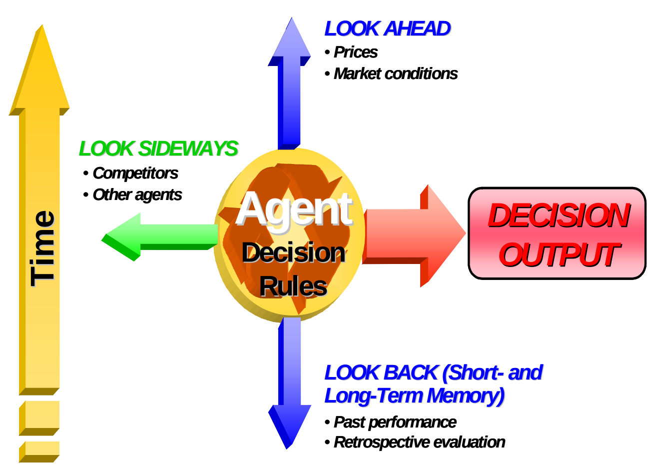


Figure B-4 Agent Adaptation Process

As a result of these evaluations, a GenCo agent can elect one of three basic courses of action:

- *Maintain the current business strategy.* If the evaluation shows that the current business strategy is very successful at meeting company objectives (i.e., providing a high level of utility) and is likely to remain so under projected market conditions, it is maintained. A GenCo that is experiencing good returns and is somewhat risk-averse would adopt this approach.

- *Adjust the current business strategy*. If the evaluation shows that the current business strategy is only moderately successful and is likely to remain so under future market conditions, a company may elect to adjust it somewhat in an attempt to increase its utility. A GenCo that has small returns and that is risk-averse to risk-neutral might take this approach.

- *Switch to a new business strategy*. If the evaluation shows that the current business strategy is not successful or is not providing adequate returns, a company may elect to make a major change in business strategy in an attempt to improve the situation. A company that is not doing well may choose this course. Also, a company that is risk-prone may elect this option in an attempt to probe the market to find a strategy that significantly increases returns.

To illustrate this learning and adaptation process, day-ahead planning can be used as an example. A GenCo's initial business strategy might consist of the following:

- Commit 25% of generation capacity to day-ahead bilateral contracts;
- Offer 75% into the pool energy market; and
- Price the pool energy market bids for each generator at 20% above production costs.

If this strategy results in a modest profit for the GenCo, it would be maintained by a risk-neutral or risk-averse company. If this strategy resulted in the company's bids not being accepted in the pool energy market with a resulting financial loss, the same risk-neutral company could seek to adjust the pool energy market bids down to 15% above production cost in an attempt to gain bid acceptance in the market. If this were still too high for the bids to be accepted, the bids could be adjusted further down to 10% above production cost in the next bidding cycle. Should this still result in unacceptable losses, the company could switch to an entirely new strategy. One of the possibilities would be to commit 75% of the generation capacity to bilateral contracts with a guaranteed return and offer only 25% into the pool energy market.

This simple illustration shows the magnitude of the complexity of simulating how the energy markets will operate. Clearly, there are a large number of possible strategies that could be tried by a GenCo. Further, the strategies employed by other GenCos would impact the success or failure of any one company's approach. It is this level of complexity that cannot be handled by conventional optimization or simulation techniques and where the agent-based modeling approach used by EMCAS can provide insight into market behavior.

B.3.5 DEMAND COMPANIES

In an EMCAS simulation, the demand company (DemCo) agents represent the business units that sell electricity to consumers. The DemCo purchases this electricity either by entering into a bilateral contract with a GenCo or by buying electricity from the pool market. In the

EMCAS formulation, a DemCo does not need to have a specific service territory and may serve consumers from anywhere in the study area (Figure B-5). The DemCo makes decisions on how much electricity to buy, what price it is willing to pay, and what to charge its consumers. The input information for DemCo agents includes:

Demand Company Identification and Business Profile

Each DemCo is given a unique identifier. When a DemCo agent is part of a larger corporate parent, it represents the electricity sales division of the parent.

The DemCo's business profile is described in the same manner as that of a GenCo. That is, the profile consists of objectives, risk preference, and a utility function. The objectives and risk preferences can be different for each DemCo. Throughout a simulation each DemCo seeks to maximize its own utility.

Demand Company Business Strategy

As with the GenCos, each DemCo in an EMCAS simulation starts with an initial business strategy that is modified and adjusted as the simulation progresses. The DemCo business strategies are used to make the following decisions:

- Load to be committed to bilateral contracts;
- Price acceptability for bilateral contract bids;
- Supply to be sought from the pool energy market;
- Price acceptability from the pool energy market; and
- Consumer contract price offerings.

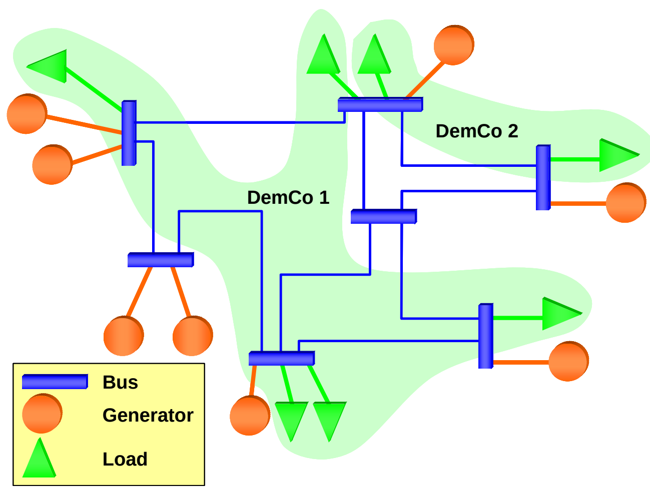


Figure B-5 EMCAS Demand Company Agents

The following examples show the types of DemCo business strategies that can be included in an EMCAS simulation:

- Offer all projected load to potential suppliers under bilateral contracts to secure fixed prices;
- Seek all projected load from the pool energy market;
- Establish price limits above which load will be dropped rather than paying high prices; and
- Reduce consumer contract charges to increase market share.

There are many more strategies that can be included in a simulation. The DemCos have a two-sided structure that they must deal with. On one side, they must interact with the GenCos and the pool energy markets to optimize electricity purchases. On the other side, they must deal with consumers to offer competitive prices for their sales of electricity while maintaining an acceptable level of their own utility (e.g., profit). Their business strategy must address both parts in order to be effective.

The business strategy is specified by three basic functions: the load allocation function, the load price acceptance function, and the consumer contract pricing function. The load allocation function determines where the company will seek supplies to meet its projected load and is given by the vector:

$$\textit{Load Allocation}_{nh}\ \ [\textit{Bilateral Contracts, Pool Energy, Uncommitted}]$$

The elements of the vector indicate the portion of the company's load, in MW, at node *n* of the network that will be sought from bilateral contracts or from the pool energy market. The portion that is designated as *Uncommitted* will be sought from the best source based on price expectations calculated during the simulation.

The load price acceptance function of the DemCo business strategy is specified by the vector:

$$\textit{Load Price Acceptance}_{bnh} = [\textit{Load Fraction}_{bnh}\,,\ \textit{Price}_{bnh}\,]$$

where:

Load Fraction$_{bnh}$ is the portion or block *b* of load at node *n* in hour *h* that will be accepted at the projected price of *Price*$_{bnh}$; if *Load Fraction* is 1.0, the DemCo will seek to meet all of its load as long as the price is less than *Price*$_{bnh}$. If *Load Fraction* is less than 1.0, then the DemCo will not seek to meet all of its load because of high prices. Consumer load will be shed by the DemCo.

The consumer contract pricing function is specified by the equation:

$$\textit{Consumer Charge}_{cnh} = D_h\textit{*(Supply Cost}_n\textit{)} + E_h\textit{*(Correlated Price)} + F_h\textit{*(Specified Price)}$$

where:

Consumer Charge$_{cnh}$ is the charge that will be levied on the different consumers *c* connected to node *n;*

Supply Cost is the cost paid by the DemCo for power withdrawn from node *n;*

Correlated Price is some price to which the charge to consumers may be related (e.g., average market price in the zone where the consumer is located, annual average price paid by the DemCo for its supplies, etc.);

Specified Price is a specific price that is user-specified; and

D_h, E_h, F_h are constants for each hour.

This general form allows for a wide variety of contract prices that the DemCo can use to charge its customers. It is analogous to the GenCo bid pricing strategy in its application.

The load allocation function, the load pricing function, and the consumer contract pricing function uniquely define the business strategy of the DemCo. The details of how each DemCo applies its business strategy at each of the planning levels are described in the next section.

Learning and Adaptation

Learning and adaptation by DemCo agents in EMCAS occurs in a manner analogous to what is experienced by GenCo agents. That is, the DemCos employ an initial business strategy that is evaluated by a Look Back, Look Ahead, and Look Sideways process. With the results of the evaluation, the DemCo agents have the option to maintain, adjust, or switch business strategies.

B.3.6 TRANSMISSION COMPANIES

In EMCAS the transmission companies (TransCos) provide transmission services to GenCos and DemCos, but do not engage in strategic business practices. Instead, they charge a fee for the use of the transmission lines. The input for each TransCo includes the following:

Transmission Company Identification and Line Ownership

Multiple TransCos can be included in an EMCAS simulation. Each TransCo is given a unique identifier. Where the TransCo is part of a larger corporate parent, the transmission division is identified as the TransCo.

Each transmission line and bus in the network is assigned to a TransCo owner. Note that some buses/nodes may have lines attached to them that belong to different TransCos.

Transmission Fee Structure

In EMCAS, the TransCo agents are the owners of transmission lines but do not operate the system. Operation is left to the ISO, which is described in Section B.3.8. TransCos do, however, collect fees for the use of their transmission lines. In practice, these fees would be used to maintain the system and to expand the network to accommodate growth. By convention in EMCAS, the transmission use fee is collected from DemCos and is added to the price they charge consumers. The *Transmission Use Rate* at node n for hour h is input as a $/MW charge. The *Transmission Use Charge (TUC)* in absolute dollars for a given transmission service at node n for hour h is calculated as follows:

$$TUC_{nh} = TUR_{nh} \times LOAD_{nh}$$

where:

TUR_{nh} is the Transmission Use Rate [$/MW], and

$LOAD_{nh}$ is the load [MW] at node n in hour h.

The *TUC* is charged to the DemCo that serves the consumer at node n. The DemCo can pass the *TUC* to the consumer and may or may not add a fee to it. The TransCo owning node n receives the *TUC* as revenue. Currently, the TUR_{nh} is set by the user.

Transmission Congestion Charge

Consumers pay an implicit transmission congestion charge by paying a price that is based on the node they are attached to. The *Transmission Congestion Charge (TCC)* for hour h is calculated as follows:

$$TCC_{h} = \sum_{n} Load_{nh} \times Node\ Price_{nh} - \sum_{m} Generation_{mh} \times Node\ Price_{mh}$$

where:

n are the nodes where load is attached to;

m are the nodes where the generation is attached to;

$Generation_{mh}$ is the generation [MW] at node m in hour h;

$Node\ Price_{nh}$ is the price at nodes n in hour h; and

$Node\ Price_{mh}$ is the price at node m in hour h.

The *TCC* is collected by the ISO and is distributed to the TransCos based on the distribution of load at the nodes owned by the TransCo.

B.3.7 DISTRIBUTION COMPANIES

Distribution companies (DistCos) own and operate the lower-voltage distribution system. They provide distribution services to GenCos and DemCos but do not engage in strategic business practices. In effect, the DistCos in EMCAS take the form of regulated monopolies. The information that is input for DistCos includes:

Distribution Company Identification and Service Territory

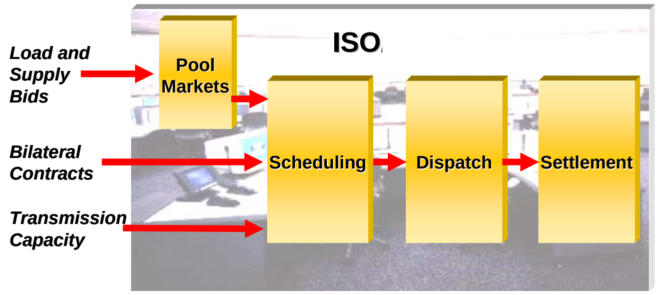


Figure B-6 EMCAS ISO Agent

Multiple DistCos can be included in EMCAS, each with a specific service territory. Each DistCo is given a unique identifier. As with other agents, when a DistCo is part of a larger corporate parent, the division that operates the distribution system is identified as the DistCo.

To identify the service territory of each DistCo, each bus in the network where load is attached is identified as a delivery point in a DistCo's network. All consumer agents at that bus are identified as being served by that DistCo. Network buses that have only generation attached or that are transmission connection points with neither load nor generation attached are not assigned to a DistCo.

Distribution Charge Structure

The distribution charge structure is input. The DistCo levies the distribution charge to all consumers it serves. The charge may be different for different consumer types (e.g., residential, commercial, industrial). The charge may be different for different nodes in the DistCo's service territory. The charge may differ from one DistCo to another. The *Distribution Charge (DC)* in absolute dollars is:

$$DC_{cnh} = DCR_{cnh} \times LOAD_{cnh}$$

where:

DCR_{cnh} is the distribution charge rate [$/MW] for consumer type c at node n and for hour h.

The distribution charge is paid by consumers to DistCos and is tabulated as revenue to the DistCo.

B.3.8 ISO

The ISO follows market rules defined by the regulatory layer and exercises several functions in an EMCAS simulation (Figure B-6) including the following:

- Operation of the day-ahead market for energy,
- Operation of the day-ahead market for ancillary services,
- Confirmation of bilateral contracts,
- Dispatch of the physical system, and
- Computation of settlement payments to market participants.

The ISO does not engage in any strategic behavior but seeks to operate the power system in the most efficient, lowest cost manner given the information it receives from the market participants and the physical characteristics of the system. The ISO is the "honest broker" that seeks to optimize operations from an overall system-wide perspective. The following information is input for the ISO:

ISO Identification

Currently, only one ISO is used in EMCAS. Future enhancements will allow for multiple agents to be included in the simulation.

System Reliability Parameters

The ISO sets the parameters that will be used for system operations including the following:

- Day-ahead regulation reserve margin,
- Day-ahead spinning reserve margin,
- Day-ahead non-spinning reserve margin,
- Day-ahead replacement capacity margin,
- Transmission line overloading limits, and
- Load-shedding priority list.

Day-Ahead Market Parameters

The ISO sets the procedures that are used in the operation of the day-ahead market including:

- *Market order* – In the current version of EMCAS, the day-ahead bilateral contract market completes first, then the pool energy market, and finally the pool ancillary services market;
- *Bilateral contract treatment* – In the current version of EMCAS, bilateral contracts are treated as financial instruments and are subject to the limitations of the transmission system.

Settlement Accounting

The ISO handles the settlements at the completion of the hourly dispatching. This includes the following:

- Payments to GenCos,
- Charges to DemCos, and
- Transmission use and congestion charges.

B.3.9 REGULATOR

The regulator agent in EMCAS sets the market rules that apply. In the current version of EMCAS, the regulator does not adapt or change its behavior. Rather, it relies on input from the user who can take the position of the regulator by changing and testing different market rules. The input information for the regulator includes the following:

Market Structure

- Bilateral contracts (if none allowed, then all energy is provided via the pool market);
- Day-ahead pool market for energy (if none exists, then all energy is provided via bilateral contracts); and
- Day-ahead pool market for ancillary services (if none exists, then all ancillary services are included in the pool energy market).

Market Pricing Rules

- Day-ahead pool energy market payment (e.g., pay locational marginal price, pay as bid); and
- Bid caps.

Tariffs and Taxes

- Tariffs – limitations on prices; and
- Taxes – consumers, GenCos, DemCos, TransCos, DistCos.

B.3.10 SPECIAL EVENT GENERATOR

The special event generator provides the EMCAS user with the ability to inject events into the simulation that force the system to deviate from the procedures developed at the planning levels. Currently, the special event generator can be used to inject unplanned incidents at the hourly dispatch level. The unplanned events that can be input are:

- Load forecast errors – increases or decreases in the load that deviate from the load projections used in the planning periods;

- Generator outages – unplanned outages of generators for varying periods of time ranging from hours to days; and

- Transmission link outages – unplanned loss of transmission lines for varying periods of time ranging from hours to days.

B.4 EMCAS DAY-AHEAD MARKETS

The EMCAS modeling system operates at different time scales or decision levels. Dependent on user-defined rules, different types of markets are available to agents at each time scale. The types of markets available and the specific rules under which each operates will influence decisions made by market participants. This section describes the markets available at the day-ahead decision level.

At the day-ahead level, EMCAS simulates three types of markets that include bilateral contract markets, energy pool markets, and ancillary services markets. Generally, bilateral contracts are agreements between a single GenCo agent and a single DemCo agent. These contracts have time scales that range from hours and days to several years. In the pool markets, EMCAS agents submit buy and sell bids to a central clearinghouse that is operated by the ISO. The pool markets are typically conducted at the day-ahead time scales and include both energy and ancillary services markets.

Figure B-7 shows the sequence of market activities that are carried out in the day-ahead planning level. In the EMCAS simulation, the only agents that participate at this level are the ISO, DemCos, and GenCos. Consumers do not exercise any decision-making at the day-ahead level. Most electricity users do not have access to daily market price information; therefore, there is no basis on which they can adjust their planned consumption for the next day in response to market conditions. Only a few large users (e.g., large industrial facilities) might be considered to have access to daily price information and be in a position to react on a day-by-day basis.

ISO Day-Ahead System Status Projections

The initial step in the day-ahead planning simulation is for the ISO to develop a projection of the next day’s load and system conditions. This includes any known outages of generators and transmission lines. The information is made available to all the DemCos and GenCos, analogous to the process used by several operating electricity markets currently posting public information.

DemCo and GenCo Market Price Projections

Each DemCo and GenCo prepares its own projections of the day-ahead situation for the company’s system. For the DemCos, the focus is on the expected load from the consumers they are serving and the expected prices in the day-ahead energy market and for bilateral contracts. For the GenCos, the focus is on the status of their own generation equipment, the prices that bilateral contracts might bring, and expected prices in the day-ahead energy and ancillary services markets.

The market price projections are unique for each company and form the basis of how they will bid into the day-ahead markets. The projections include hourly prices in the pool energy market, hourly prices in the ancillary services market, and hourly projections of bilateral contract prices. The price projections are developed by DemCos and GenCos in one of several ways:

- Correlation to previous day(s),
- Next day forecast, and
- Price probability distribution.

The correlation to previous day(s) is the simplest price projection method. It assumes that the day-ahead prices will be the same as the previous day. In the simulation, the average price of the previous five weekdays (or two weekend days) is used to avoid unrealistic fluctuations from one day to the next. This type of "myopic hindsight" is the simplest form of price projection.

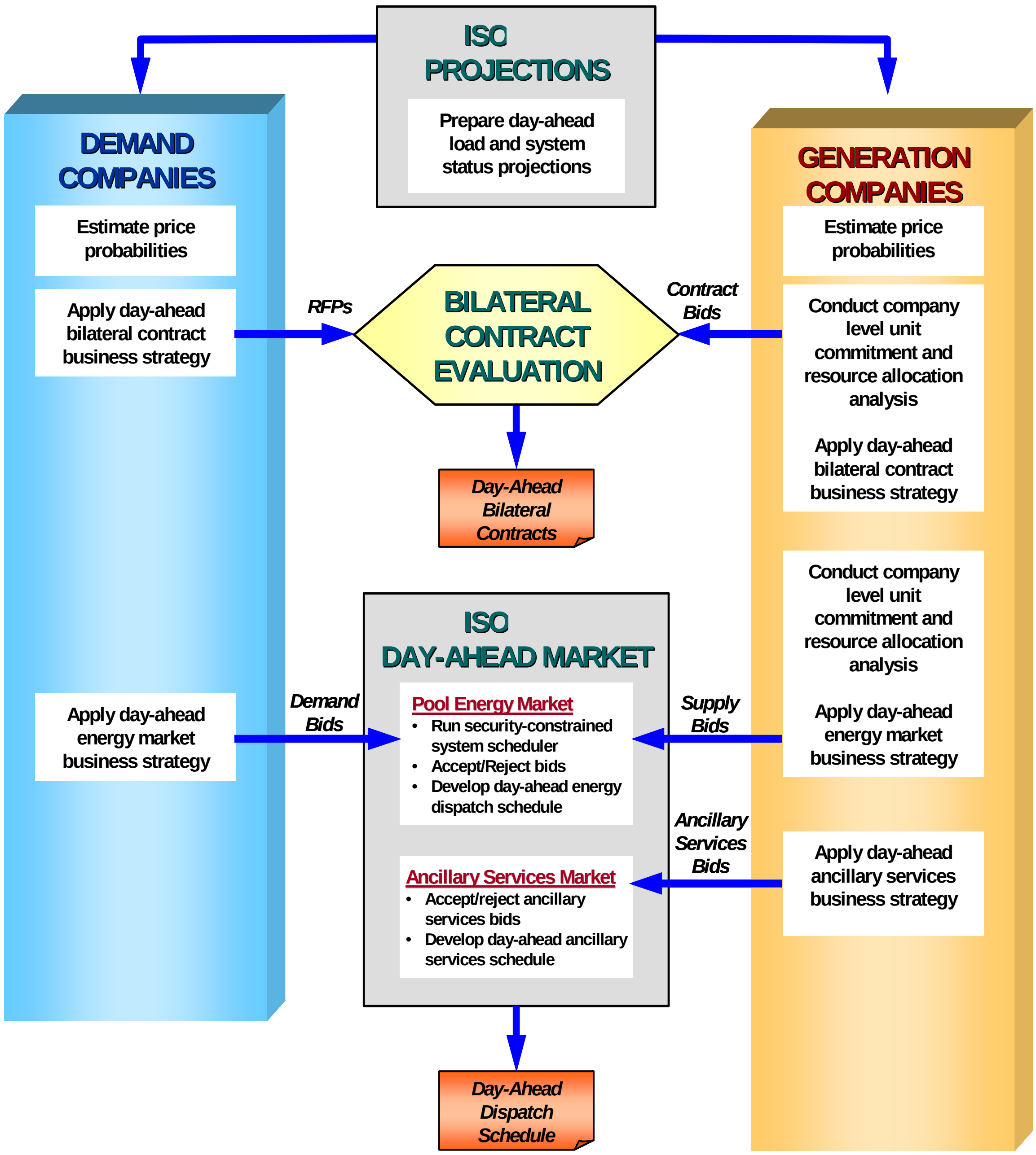


Figure B-7 Day-Ahead Planning Sequence

The next day forecast method of price projection is a type of "myopic foresight" approach. GenCos and DemCos using this method look at the forecasted load and system status for the day ahead and use this to project what the prices will be in the markets. The method uses a very simple projection technique that relates prices to system conditions.

The most sophisticated price projection technique is to use a price probability distribution. The price probability distribution gives the probability that a bid for a specific generator at a given node will be accepted in any of the available markets (i.e., energy, ancillary services, bilateral contracts), given system conditions.

Day-Ahead Bilateral Contracts

The day-ahead bilateral contract market operates next in the simulation. The process begins with DemCos developing requests for proposals (RFPs) for day-ahead bilateral contracts for energy (Figure B-8). Included in each RFP are load for each hour and points of withdrawal. The load quantities in an RFP account for demand that is already under a longer-term bilateral contract and include only the additional demand that must be met for the next day. The points of withdrawal indicate the node(s) at which the load will occur. The RFPs are sent to all GenCos participating in the bilateral contract market.

In the next step of the simulation, the GenCos prepare their responses to the RFPs. Using the price projections for the next day, which include projections for the pool energy market and for bilateral contracts, each GenCo conducts a company-level unit commitment and resource allocation analysis (CLUCRA). This analysis seeks to maximize the company's utility by assigning generation that (a) will be bid in response to bilateral contract RFPs, (b) will be reserved for bidding into the pool energy market, or (c) will be bid into the ancillary services market. The CLUCRA objective function is:

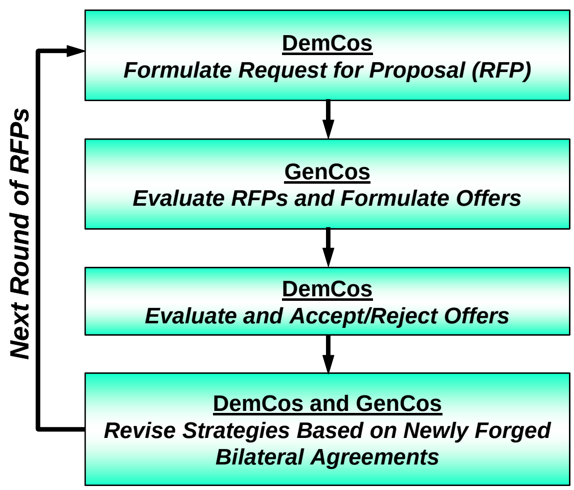


Figure B-8 Sequence of Events for Modeling Bilateral Contracts

$$\begin{aligned}\textbf{MaxCorporate\_Objective} \; = & \sum_{n=1,n} \sum_{h=1,24} \left[Projected\_Price_{nh} \; * \; \sum_{b=1,n} Production\_Level_{hb} \right] \\ & + \sum_{h=1,24} \sum_{c} Bilateral\_Revenue_{hc} \\ & - \sum_{h=1,24} \sum_{b=1,n} Production\_Cost_{hb} \; * \; Production\_Level_{hb} \\ & - Startup\_Cost_{g} \; * \; Number\_Starts \\ & - Shutdown\_Cost_{g} \; * \; Number\_Shutdowns \end{aligned}$$

The constraints imposed are the physical limitations of the generation equipment including:

- Start-up time,
- Minimum run time,
- Minimum capacity, and
- Shut-down time.

In maximizing its individual utility in this manner, each GenCo determines whether the projected prices for bilateral contracts or the pool markets will provide an adequate return to warrant the operation of each generation unit. The result of this analysis is a decision on whether to commit the unit to a bilateral contract, to offer the unit into the pool energy market, or to shut it down.

After the completion of the day-ahead CLUCRA, each GenCo applies its day-ahead bilateral contract business strategy. The use of the business strategy at this point accounts for the fact that each company's CLUCRA analysis is based on limited information. It has only its own price projections and its own record of success or failure from previous bids. It does not have access to similar information for other companies. The application of the business strategy allows the company to test other approaches that may be more beneficial (i.e., increase its utility) than one based solely on its own limited information.

As described in an earlier section on GenCos, the day-ahead bilateral contract business strategy is made up of two parts. The first is the use of the capacity allocation function to allocate resources in response to RFPs. In its simplest form, the capacity allocation function would set all the available capacity to the *Uncommitted* category, thus allocating capacity according to the company's CLUCRA results. That is, capacity would be offered in response to those RFPs that maximized the company's utility for the next day. Alternative strategies that can be applied include forcing a portion of capacity to be offered in response to RFPs independent of the CLUCRA result, forcing a response to an RFP from a particular DemCo, and other variations. These would be implemented by changing the capacity allocation function. This capability in EMCAS allows a GenCo to try different resource allocation strategies that may prove more beneficial to the company.

The second part of the GenCo's day-ahead bilateral contract business strategy is the pricing of its bids using the capacity pricing function, as described earlier. The general form of the function provides a means to specify a wide range of pricing strategies. Since the GenCos have the ability to try business strategies that do not rely solely on the outcome of the CLUCRA optimization results, they can explore for solutions that increase their utility.

When the GenCo bid responses to the RFPs are received by the DemCos, they go through a process to determine which bids to accept or whether to rely on the pool energy market to meet their requirements. The process used is the Demand Company Resource Allocation (DCRA). In applying the DCRA, each DemCo seeks to maximize its own utility function. The price bids received in response to the RFPs and the projected prices for the day-ahead energy market are compared and the best mix of bilateral contracts and planned purchases from the day-ahead pool energy market is determined. The EMCAS algorithm that simulates a demand company's bilateral contract purchase portfolio uses an "intelligent" heuristic to test various purchase portfolios (solution states) and selects the one that maximizes the corporate utility functions. The algorithm is based on a methodology that combines “greedy adding” and “pair-wise substitution” techniques. The initial portfolio state assumes that all energy purchases would be from the day-ahead energy market. Individual bilateral contract offers from GenCos are then tested in the portfolio mix, and the one that yields the highest objective function value is temporarily added to the mix. The process of adding bilateral contracts into the mix using this greedy-adding method continues until no additional bilateral contract increases the corporate utility.

Other portfolios are then tested by swapping one or previous rejected bilateral contract offers with one that has been accepted. This includes a fictitious “null” contract that contains no capacity or energy. If swapping rejected bilateral offer(s) into the portfolio mix in place of an accepted offer increases the corporate utility, the swap is implemented. Swapping of contracts into and out of the corporate mix continues until a better utility function cannot be found.

After completion of the DCRA, each DemCo applies its day-ahead business strategy to the result. As described earlier, the DemCo business strategy includes the application of the load allocation function and the load price acceptance function. The strategy can include decisions to force a portion of the load to be under a day-ahead bilateral contract independent of the DCRA result, force a response to an RFP from a particular GenCo, and other variations. In a manner analogous to that used by the GenCos, this capability in EMCAS allows the user to try different resource allocation strategies for DemCos that may prove more beneficial to the company.

In EMCAS, the bilateral contract market can consist of multiple rounds of DemCo RFP / GenCo Bid / DemCo selection. This allows for an iterative process of contract negotiations to be simulated. In general, one to three bilateral contract bidding rounds are used in a simulation. At the completion of the last round, the day-ahead bilateral contract market is considered closed, and the simulation proceeds to the day-ahead pool markets.

Day-Ahead Pool Energy Market

The day-ahead pool energy market represents the operation of a pool market for wholesale electricity sales and purchases. In certain applications where no such market exists, this may be bypassed. The day-ahead pool energy market operates by accepting supply bids from GenCos and demand bids from DemCos.

GenCos begin the preparation of their supply bids in a manner similar to what was done for the day-ahead bilateral contract market. Beginning with the prices that they have projected for the market, the CLUCRA optimization analysis is run. At this point, decisions are made concerning the day-ahead pool energy market, the ancillary services market, and the withdrawing of capacity in situations when the projected market prices are below production costs. The same objective function and constraints that were used in the bilateral contract analysis are used in the pool energy market analysis.

With the CLUCRA results, each GenCo applies its day-ahead energy market business strategy, which consists of two parts, similar to what was used in the bilateral contract market: the capacity allocation function and the capacity pricing function. As with the bilateral contract market, this capability in EMCAS allows the user to try different resource allocation strategies that may prove more beneficial to the company.

DemCos also submit bids to the day-ahead pool energy market. These demand bids specify the quantity of electricity the DemCo is willing to accept at a specified price. The DemCo demand bids show a decreasing purchase quantity with increasing price. A DemCo can reduce its purchase of electricity if the price is too high by not serving a portion of its projected load. This means that the load will be curtailed voluntarily (e.g., by exercising service interruption provisions of agreements with consumers, mostly large industrial or commercial users) or involuntarily (e.g., by load shedding). In either case, by the way in which its demand bids are submitted to the pool energy market, the DemCo can set a limit on the price it is willing to pay for electricity. Of course, a DemCo can submit a demand bid with no price limits, in which case it is indicating that it will pay any price to meet its load. The bid is then considered to be price inelastic.

The supply bids from the GenCos and the demand bids from the DemCos are on an hour-by-hour basis for the next day. In addition, the bids specify the point of injection (for supply bids) into the transmission network and the point of withdrawal (for demand bids). The ISO must balance the system based on these bids. In the EMCAS simulation, the bids are first rank-ordered by price, as illustrated in Figure B-9. Bids from all GenCos and all DemCos for each hour are included.

The ISO then runs a transmission-constrained system scheduler (TCSS) analysis to determine if the supply and demand can be balanced while maintaining the security and stability of the transmission system. TCSS uses a direct current Optimal power flow (DCOPF) algorithm. The algorithm consists of an objective function and a set of constraints that place limits on generation levels, load curtailments, and power flows. Constraints also ensure that at each bus there is an energy balance at all buses. Linear programming (LP) techniques are used to find the best solution to the problem.

The TCSS objective function is to minimize the overall costs, supply purchases, and load reductions (e.g., variable payment for hourly demand side management measures). Supply costs are those incurred when a block of energy is purchased at a specified price from the market. The objective function also accounts for the cost of unserved energy, power transport costs, penalties for transmission line overloads, and the cost of calling spinning reserves into service.

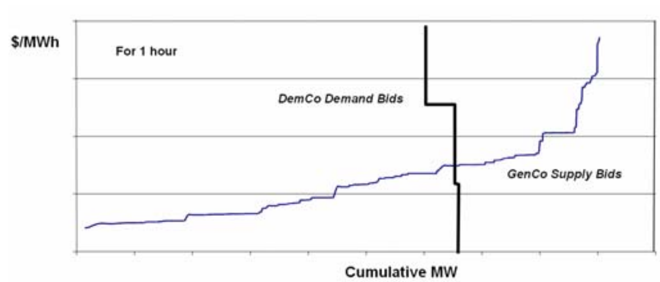


Figure B-9 Ranking of Day-Ahead Supply and Demand Bids with No Transmission Congestion

The TCSS cost minimization objective function is subject to several constraints. On the supply side, the amount of energy purchased at a specific bus cannot exceed the block amount offered by a GenCo. Likewise, the amount of load reduction that is accepted cannot exceed the block-amount offered by a DemCo.

The flow of power from generators (power injections) to loads (power sinks) is governed by a set of physical constraints. Injections include power from both accepted energy offers and spinning reserves that are called into service. One transmission flow constraint requires that there is an energy balance at all buses. As shown in the equation below, the amount of power flowing on all power lines (branches) into a bus must exactly equal the amount of power that is flowing out of a bus.

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}}\left(\theta_i - \theta_j\right)$$

where:

P_i	sum of generation (+) and load (–) at bus *i* (MW);
P_{ij}	power flow from bus *i* to bus *j* (MW);
x_{ij}	line inductive reactance;
θ_i	phase angle at bus *i* (radians); and,
θ_j	phase angle at bus *j* (radians).

Power flows on a transmission line connecting bus *i* to bus *j* are given by:

$$P_{ij} = \frac{1}{x_{ij}}\left(\theta_i - \theta_j\right)$$

Real power flows on lines, measured in MW, are limited. Currently the model includes three line rate limits, namely, rate A, rate B, and rate C. Typically, costs for line usage up to rate A are minimal, but very rapidly increase for any flows above that level.

The TCSS determines the supply and demand intersection points in the network. In the absence of any transmission congestion, the TCSS load flow analysis will show that the initial rank ordering of supply and demand bids of Figure B-9 and will provide the least cost way to dispatch the system. However, when congestion of the transmission system appears, such as during high load periods, it may not be possible to utilize the least cost generators without violating thermal limits of transmission lines or contingency situations. Lower-cost generators may need to be bypassed in favor of more expensive units that can be used without creating transmission problems. The supply curve is then shifted as shown on Figure B-10.

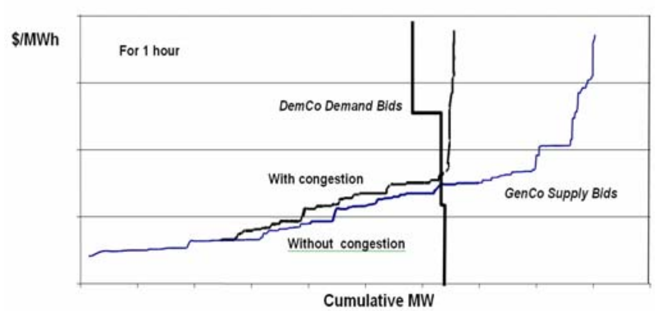


Figure B-10 Shift of Supply Bids Due to Transmission Congestion

The ISO will accept or reject bids from GenCos and DemCos based on the results of the TCSS analysis. Notification of acceptance or rejection is sent back to the GenCos and DemCos and the day-ahead energy market is closed.

Day-Ahead Pool Ancillary Services Market

Ancillary services are functions provided to maintain the reliability of the power system in response to both normal and unplanned variability in supply and demand. Some of the key ancillary services are:

- Regulation/automatic generation control (AGC) services,
- Spinning reserve,
- Non-spinning reserve, and
- Replacement reserve.

Regulation or AGC services are designed to match the output of generators to variations in load on a very short time frame, usually seconds. This requires the ability to adjust generator output on an almost instantaneous basis. Not all generator equipment is capable of this type of fine control. Spinning reserve is the ability of units that are in operation at a level below their maximum output and synchronized to the grid to increase their output generating capacity in response to changes in system demands. Typically, the criterion for this capacity increase is that it must be fully available within 10 minutes. Non-spinning reserve, frequently called non-synchronous or supplemental reserve, consists of capacity that is not operating but that can be started and fully available within 10 minutes. In some places, interruptible loads that can be shut down within the 10-minute window can also be included as a non-spinning reserve. Replacement reserve is a standby capacity that must be fully available within 30 to 60 minutes and then maintained until substitute capacity from the market is available.

EMCAS provides an explicit modeling of the ancillary services for spinning reserve, non-spinning reserve, and replacement reserve. The modeling of regulation/AGC services is handled in an approximate way. In an EMCAS simulation, the day-ahead pool ancillary services market for spinning reserve, non-spinning reserve, and replacement reserve is run after the closing of the day-ahead pool energy market. In this market, GenCos apply their company ancillary services business strategy to determine how they will participate. As with the bilateral contract and energy markets, the strategy has two parts. The first is a determination of how much capacity to commit to the various components of the ancillary services market: spinning reserve, non-spinning reserve, or replacement reserve. This analysis is based on the company's projections of day-ahead prices for each of these reserve markets. GenCos may consider offering any capacity that has not been committed to bilateral contracts or to the energy market into the ancillary services market, provided the particular units being considered can meet the technical start-up requirements for each of the reserve categories. In EMCAS, the company analysis is done by a simple comparison of the projected revenue in the market to the cost of operating the unit, should it be called upon. The market payment for having the capacity available, even if it is not needed, is factored into this comparison.

The second part of the GenCo's day-ahead ancillary services market business strategy is the pricing of its bids. The formulation of the bid price accounts for the probability that it will be called upon and follows the same structure that was used for bilateral contracts and the pool energy market. That is, the bid can be related to production cost, can be correlated to some other price, or can be a specified price as was shown earlier.

The ancillary service for regulation/AGC is modeled in EMCAS in an approximate manner. Additional capacity that would be needed to meet the need for regulation/AGC services is selected as part of the pool energy market. It is made available for dispatch as needed.

Day-Ahead Dispatch Schedule

After the closing of the day-ahead bilateral contract, pool energy, and pool ancillary services markets, the dispatch schedule for the next day is established. This schedule specifies which units are to be run in each hour of the next day to meet expected loads. Variations to this schedule due to changes in load or generator or transmission outages are dealt with at the hourly dispatch time line.

B.5 EMCAS HOURLY DISPATCH

Figure B-11 shows the operation of the hourly dispatch in EMCAS. Hourly simulations are the smallest time step used in EMCAS. In actual practice, dispatching is adjusted in periods of minutes and seconds. This level of detail is not used in EMCAS.

In some electricity markets, there is an hour-ahead market (sometimes called a "real time market"). This is a bit of a misnomer in that this market generally operates two to four hours in advance of the actual dispatch time. For simplification, this market is not currently included in an EMCAS simulation. Rather, the variation between actual demand and the day-ahead schedule for the dispatch of generators is handled by using the ancillary service capacity that is available.

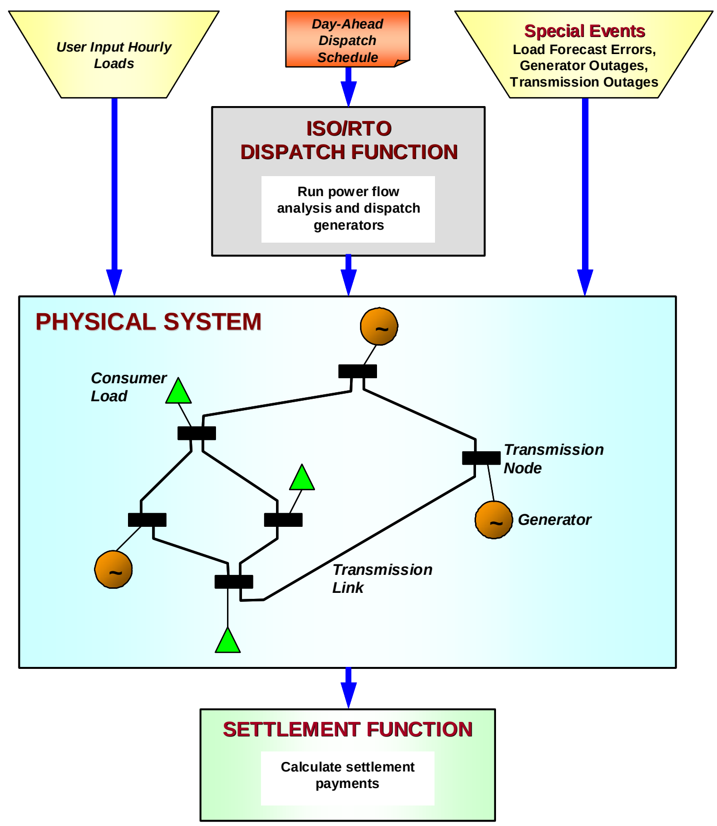


Figure B-11 Hourly Dispatch Sequence

User Input Loads

As the EMCAS hourly dispatch simulation begins, the load from each of the consumers for each hour is determined from user-input load data. The simulation can be run with no load forecast error, in which case the load information that was used at the day-ahead planning level is identical to what is experienced in the hourly dispatch. Alternatively, at the user's discretion, the load can be allowed to include a random variability.

ISO Dispatch Function

The dispatch schedule of which generators are planned to operate in each hour to meet the load is available from the day-ahead planning level. Using this schedule as a starting point, the ISO operates the power system to balance supply and demand and to maintain the integrity and security of the overall system. In the real world, power system operation involves balancing a number of critical variables simultaneously including power flow, frequency, voltage, and other parameters. EMCAS uses a DC-OPF formulation, the same TCSS that was used in the day-ahead pool energy market segment of the simulation described earlier. If there were no variations in load, generator availability, or transmission system topology from the information used in the day-ahead planning, the results of the hourly dispatch would be identical to the results of the day-ahead TCSS and would follow the dispatch schedule developed there.

Special Events

The EMCAS user can specify several unplanned events to simulate how the system will respond to variations is load, generator outages, and transmission outages using the *Special Event Generator* described earlier. Each of these events will require that the system operation be adjusted from what was included in the day-ahead schedule. In general, these adjustments will result in increased costs in the system. In some cases, it may not be possible for the system to adjust and some load will not be served. EMCAS tracks these conditions.

Locational Marginal Prices

One of the primary focuses of this type of analysis is the locational differences in electricity prices across the network. The locational marginal price (LMP), expressed in $/MWh, is defined as the cost of serving one additional MW of load at any point in the network. The LMP has three components: (1) the marginal cost to produce the last MW of power, (2) a transmission congestion charge, and (3) the cost of marginal transmission losses. In situations where there is no transmission congestion, LMPs at all buses in a network are similar, varying only by a relatively small amount to cover small transmission losses. An uncongested state only occurs when power units can be dispatched according to an economic merit order dispatch without overloading transmission lines and violating security measures. The economic merit ordering of units or blocks of units is typically based on marginal production costs such that generators that are the least expensive to operate are dispatched first while the most expensive units are utilized only during times of highest demand. However, the actual dispatch of units must often deviate from the economic merit order to keep the transmission system operating within a stable and secure state. This change in the order of dispatch of units when transmission congestion occurs leads to variations in LMPs across a region. In some cases, the variation in LMPs among network nodes can be significant.

In simulating the hourly dispatch, EMCAS calculates the LMP for each node in the network. The LMP is set equal to the dual value computed for the energy balance constraint in the TCSS. These dual values are computed by the DCOPF/LP routine. Essentially, the dual value is a measure of the cost saving, in $/MWh, associated with relaxing the bus energy balance constraint by a very small amount. For load and generation buses, it can also be interpreted as the change in the objective function value if the net power injection at a bus is increased by 1 MWh.

Settlement Function

At the completion of the dispatch for each hour, the information needed to settle the charges and payments to each of the market participants is tabulated. In principle, these settlements can be displayed for each hour of a simulation. In practice, they are displayed as monthly or annual aggregations. Table B-1 summarizes the settlements that are calculated.

All of the settlement payments are calculated using the market rules that have been established. For example, if there is a tariff on consumer electricity purchases, the tariff value is used to calculate their payment for purchases.

Table B-1 Settlement Payments Calculated in EMCAS

Agent	Revenues	Expenses
Consumers	• N/A	• Payments to DemCos for electricity purchased • Payments to DistCos for distribution charges • Payments to TransCos for transmission use charges
DemCos	• Payments from consumers for electricity purchased	• Bilateral contract payments to GenCos • Energy payments to pool market based on actual purchases
GenCos	• Bilateral contract payments from DemCos • Energy payments from pool market; based on actual generation • Ancillary services payments: capacity charge for units on standby plus energy payment if unit is actually dispatched	• Generator fuel costs • Generator variable operating costs • Generator fixed operating costs • Off schedule charges to make up supply for generators that were scheduled to operate but were out of service; based on market price
DistCos	• Distribution charges for use of distribution system; paid by consumers	• N/A
TransCos	• Transmission use charges for use of transmission lines; paid by consumers through DemCos • Transmission congestion charge from differences in LMPs	• N/A

B.6 MODEL OUTPUTS

An EMCAS simulation can produces a substantial amount of output information. The simulation is done on an hour-by-hour basis for any period from days to years. At each step of the simulation, EMCAS can output the behavior of each component of the physical system (e.g., output of each generator unit, loading of each transmission line) and each agent (e.g., bids by each GenCo, bid acceptance/rejection by ISO, revenues, costs). Summaries and aggregations of information (e.g., by company, by geographical area) are available to provide an overview of results. EMCAS provides both tabular and graphical output at the user's choice and can output its information to spreadsheets or other data processing software.

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APPENDIX C
COMPARISON OF POWERWORLD® AND EMCAS© RESULTS

This appendix briefly discusses a comparison of the model results from EMCAS and PowerWorld. The comparison focused on the hourly LMPs and was conducted for February and July for buses located in the IP and all NI zones; that is, NI-A to NI-G. The EMCAS results used in the comparison were the LMPs from the Production Cost case. PowerWorld results were based on an assumed production cost-based bidding.

Figure C-1 shows hourly LMPs for February for bus 32271 located in the IP zone. As can be seen, EMCAS LMPs were consistently higher (on average $5.5/MWh) than LMPs projected by PowerWorld. An initial assessment concluded that this was based on several differences in the modeling approach as well as some of the underlying data assumptions, including:

- Differences in assumed unit production costs – the EMCAS results included a fixed O&M cost component, while PowerWorld did not;
- Differences in derating of out-of-state units to account for outages;
- Unit commitment – EMCAS included a unit commitment algorithm, while PowerWorld did not; and
- Unit heat rates – EMCAS used heat rates by block (up to 5 blocks per unit), while PowerWorld used only one heat rate (full-load heat rate) per unit.

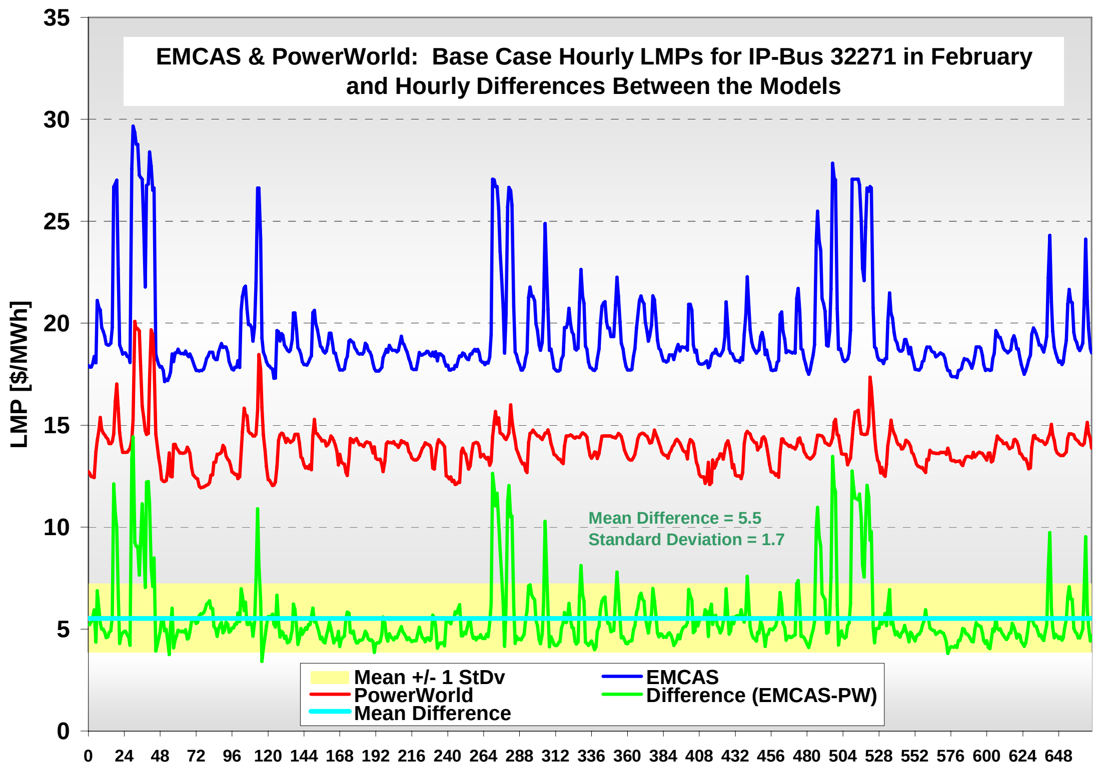

Figure C-1 Differences in Hourly LMPs for IP-Bus 32271 (February)

After identifying the main factors leading to the differences in LMP results, an EMCAS case was created that included the same production cost assumptions, the same out-of-state derating factors, and the same unit-level heat rates. In addition, the unit commitment algorithm was disabled. The following graphs show a comparison of PowerWorld results with the original EMCAS results (Original Case) and with the modified case (Modified Case). It can be seen that these four changes explained most of the differences in model results.

Figure C-2 shows that the differences typically dropped from around 4–6 $/MWh to less than 1 $/MWh in the Modified Case. (EMCAS results were slightly lower than PowerWorld in this case.) Expressed in relative terms, Figure C-3 shows that while the Original Case had LMPs to be around 25–30% different, the Modified Case reduced this to less than 5%. Figure C-4 shows that the hourly LMPs from both models varied well together; that is, they showed very similar daily fluctuations. In general, the Modified Case slightly improved the correlation between the data sets.

Figure C-5 shows the comparison for July. For the most part, the Modified Case leads to a significant reduction in differences, except for buses in the NI-D zone (Chicago). However, even in this zone, average differences for the month of July are still less than 5 $/MWh. Figure C-6 shows July differences in percent. Again, except for buses in NI-D, differences drop from around 20–30% to about –5% to +5%. Figure C-7 shows very good correlation for July, except for NI-D. The reason for the noticeably different behavior of NI-D buses is likely a result of the more detailed modeling of phase shifters by PowerWorld. This is discussed in Appendix E.

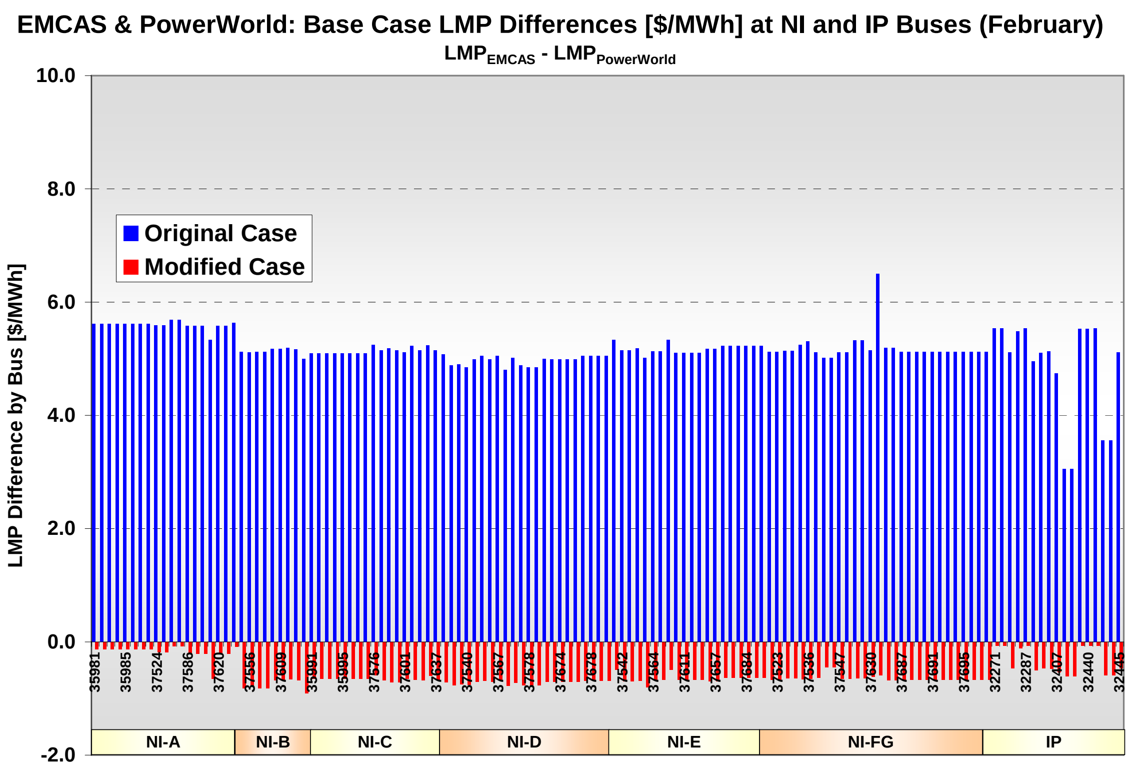

Figure C-2 Average Monthly Differences (February) by Bus for all IP and NI Buses

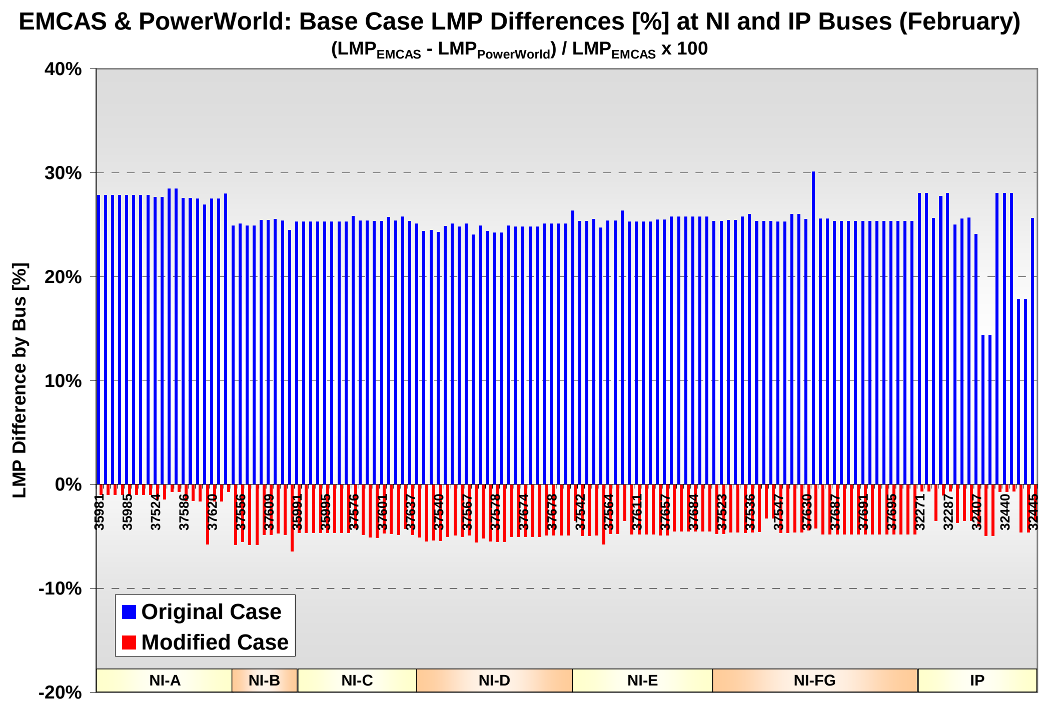

Figure C-3 Average Monthly Differences (February) by Bus for all IP and NI Buses in Percent

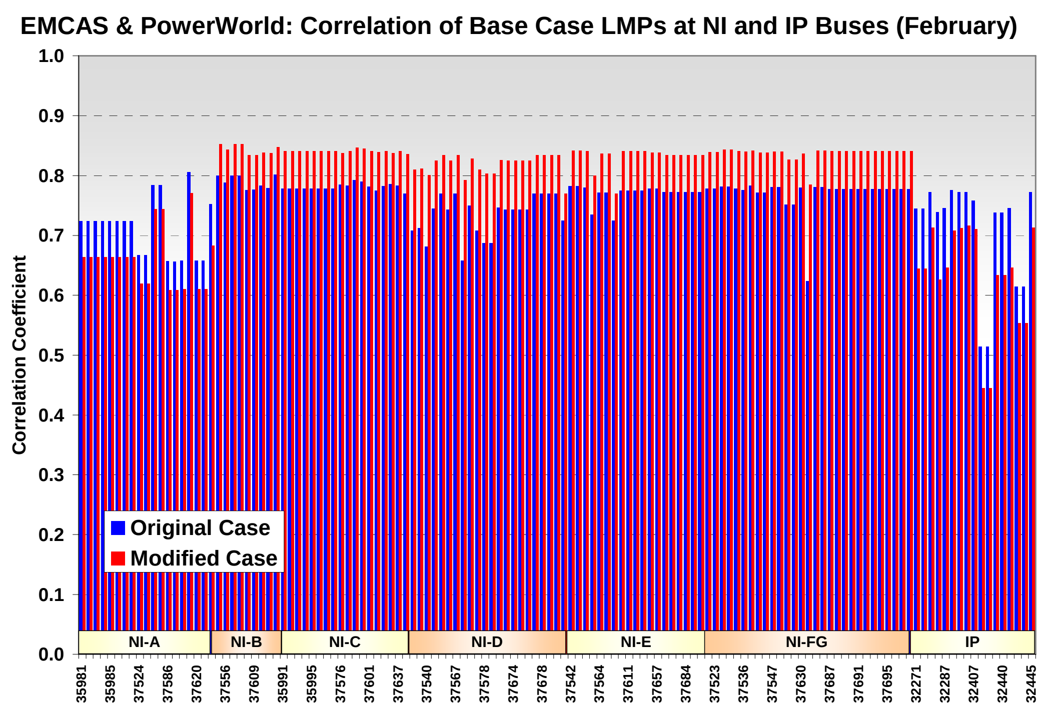

Figure C-4 Correlations between EMCAS and PowerWorld Results (February)

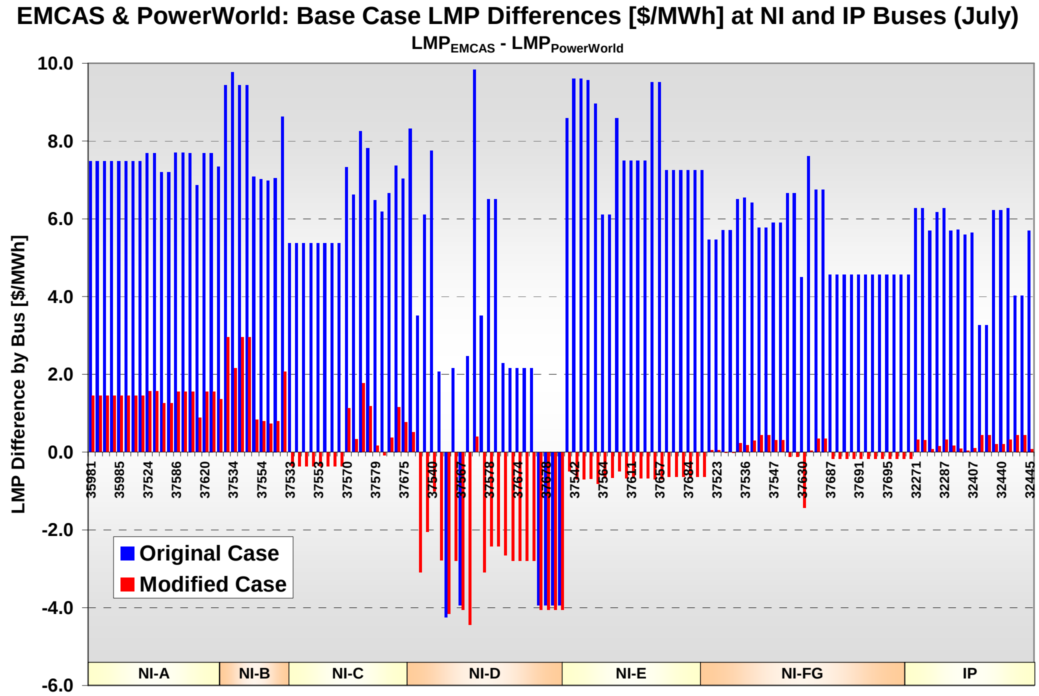

Figure C-5 Average Monthly Differences (July) by Bus for All IP and NI Buses

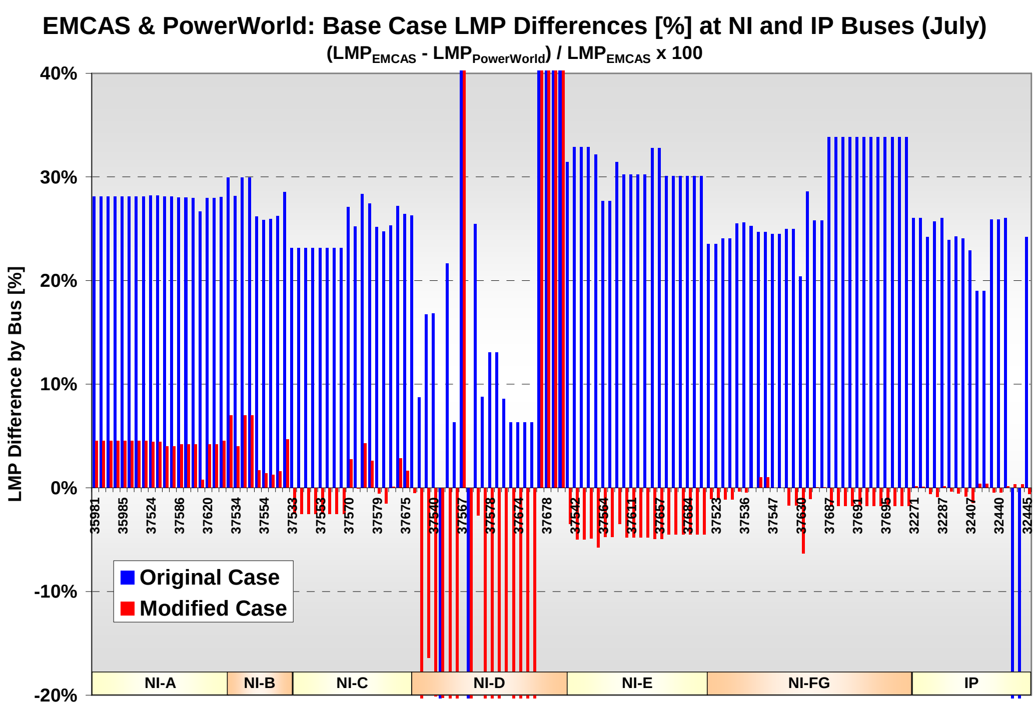

Figure C-6 Average Monthly Differences (July) by Bus for All IP and NI Buses, in Percent

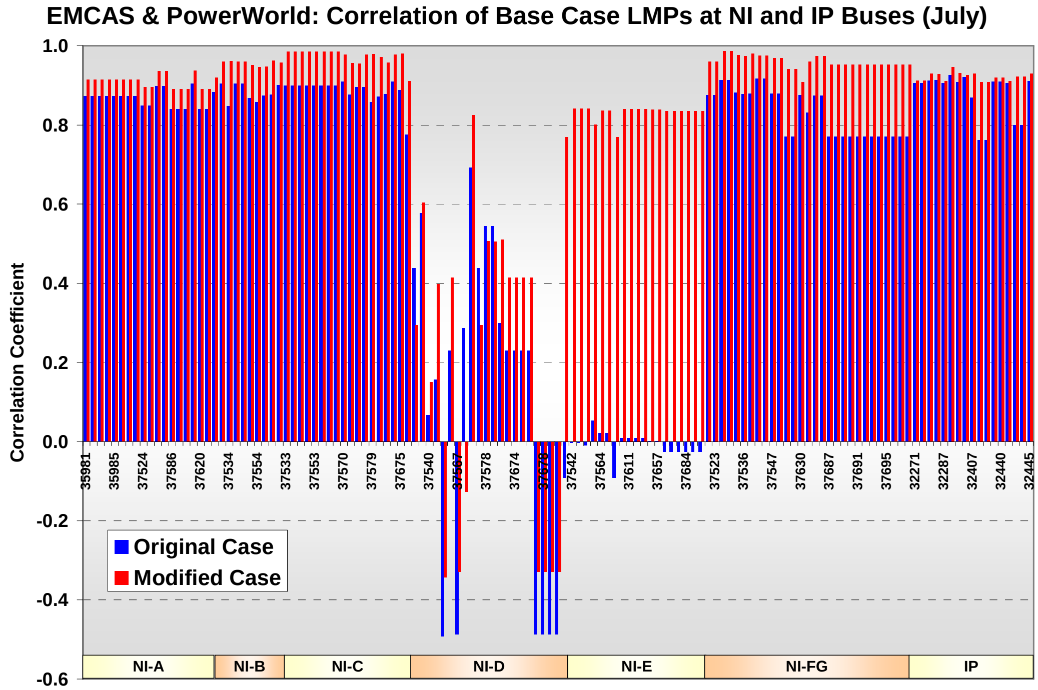

Figure C-7 Correlations between EMCAS and PowerWorld Results (July)

APPENDIX D
MODELING OF OUT-OF-STATE GENERATION AND LOAD

This appendix contains information on the modeling of generation capacity and electric loads in the areas outside of Illinois. In the EMCAS model, the representation of generation capacity and loads outside of Illinois was simplified. While all generating units operating within Illinois were modeled individually, out-of-state generation was modeled using aggregate production cost curves. These production cost curves, or so-called supply curves, represent generating units independent of ownership and show the cost of electricity generation as a function of the total power output. The electricity generation cost from out-of-state suppliers can be directly determined from the production cost curve as a value that corresponds to the level of power output.

The equivalent network of out-of-state areas (see Section 3.3 of the main report) included a number of control areas ranging from the Northern States Power Company (NSP – now Xcel Energy) in the northwest, to the Associated Electric Cooperative (AECI) in the southwest, to the Tennessee Valley Authority (TVA) in the southeast, to the Consumers Energy (CSU) and American Electric Power (AEP) areas in the east, and all of the large Wisconsin utilities in the north. A total of 24 out-of-state generation companies and their corresponding supply curves were included in the EMCAS simulation. The names and abbreviations of out-of-state generation companies are as follows:

1. AECI — Associated Electric Cooperative
2. AEP — American Electric Power
3. ALTE — Alliant Energy (East)
4. ALTW — Alliant Energy (West)
5. Ameren-Out — Ameren (areas outside of Illinois)
6. BREC — Big Rivers Electric Corporation
7. CIN — Cinergy Corporation
8. CONS — Consumers Energy
9. DPC — Dairyland Power Cooperative
10. DPL — Dayton Power & Light
11. HE — Hoosier Energy
12. IPL — Indianapolis Power & Light Company
13. LGEE — LG&E Energy
14. MEC — MidAmerican Energy Company
15. MGE — Madison Gas and Electric Company
16. MPW — Muscatine Power and Water
17. NIPS — Northern Indiana Public Service Company
18. NSP — Northern States Power Company (Xcel Energy)
19. OVEC — Ohio Valley Electric Corporation
20. SIGE — Southern Indiana Gas & Electric Company
21. TVA — Tennessee Valley Authority
22. UPPC — Upper Peninsula Power Company
23. WEC — Wisconsin Energy Corporation
24. WPS — Wisconsin Public Service Corporation

Hourly load profiles for the analysis year for the out-of-state areas were developed based on the same FERC Form 714 projections used for the Illinois companies. The load forecasts, developed on a control area basis, were aggregated into the same nodes used for the generation companies. Thus, each out-of-state connection point had both load and generation associated with it.

One of the assumptions for the PowerWorld and EMCAS analyses was that out-of-state companies would actively participate in the same electricity market as the in-state companies. This included both sales and purchases of electric power. For the production cost case, it was assumed that electric power in out-of-state areas was generated on a production cost basis, according to the supply curves for out-of-state generation companies. In other scenarios, out-of-state companies were allowed to deviate from the production cost-based bidding and, in some cases, to apply strategic bidding.

In principle, an excess of available power in the out-of-state areas could be offered and sold in the Illinois electricity market if the price was lower than that of other competitors. In the same manner, the out-of-state demand companies were allowed to purchase power from the Illinois market if the price was lower than what was available from other sources. In both cases, the constraints imposed by the available transfer capabilities of transmission lines connecting Illinois with the out-of-state areas were strictly observed.

The following figures show the generation supply curves and the hourly load curves used for each of the out-of-state areas.

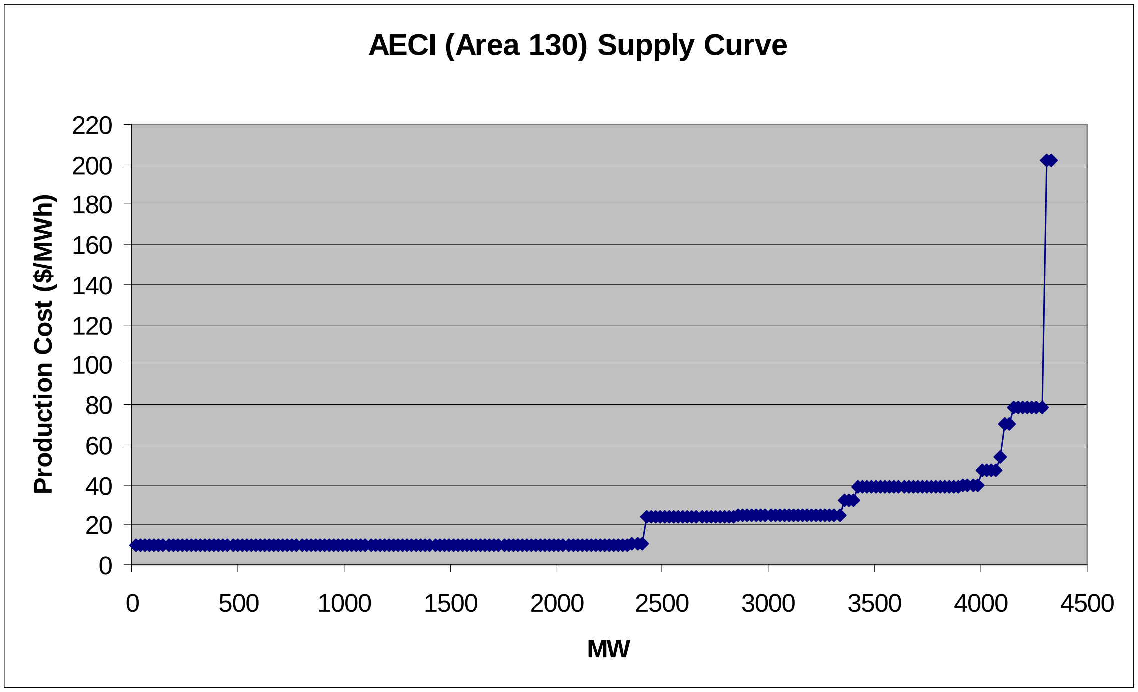

Figure D-1 AECI Generation Supply Curve

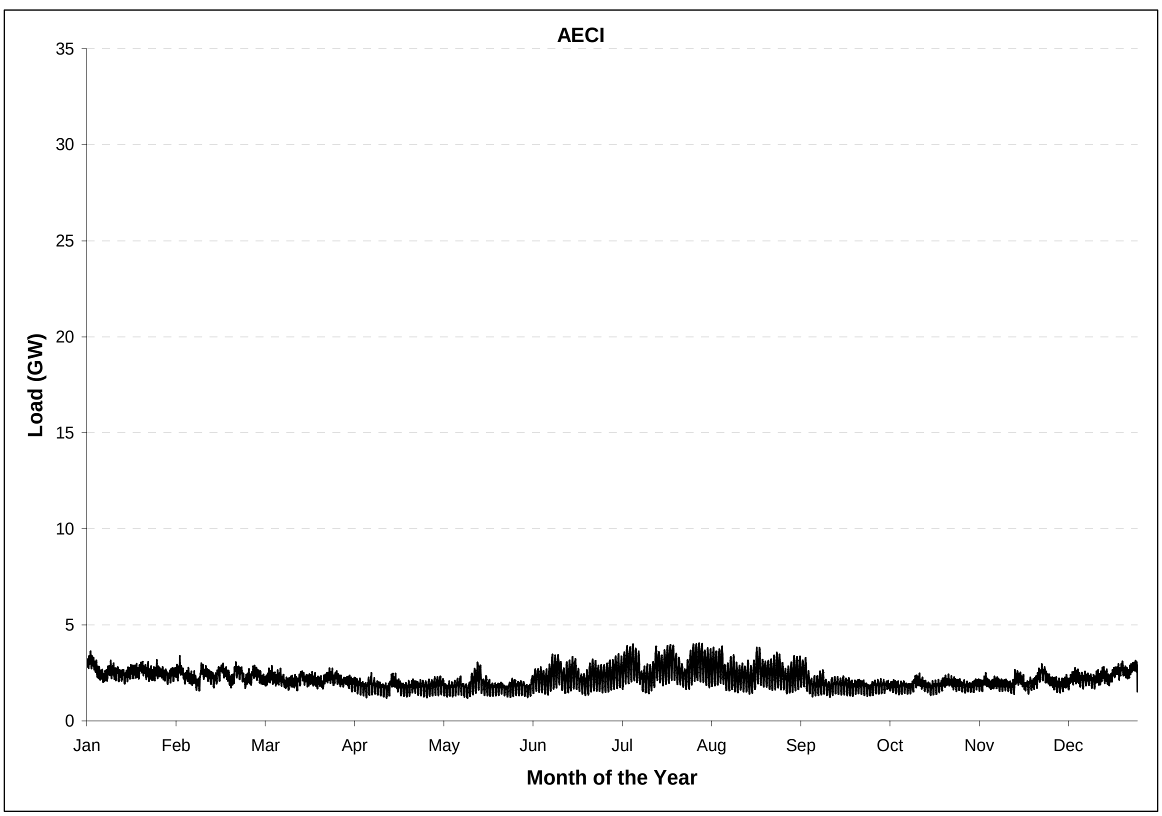

Figure D-2 AECI Load Curve

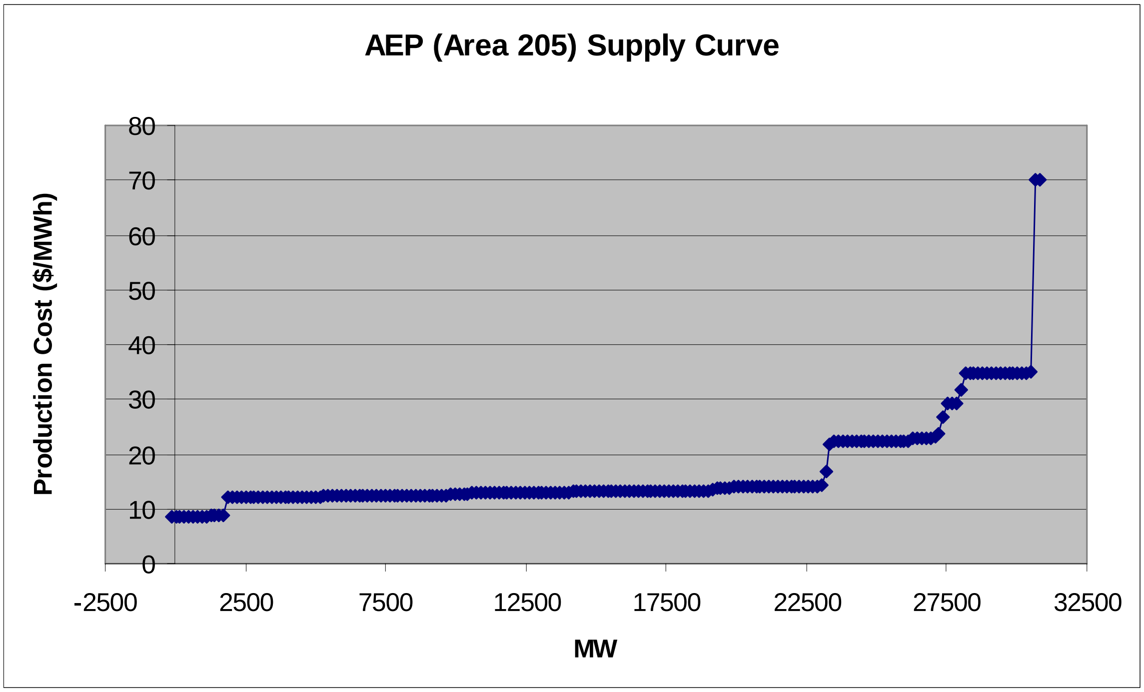

Figure D-3 AEP Generation Supply Curve

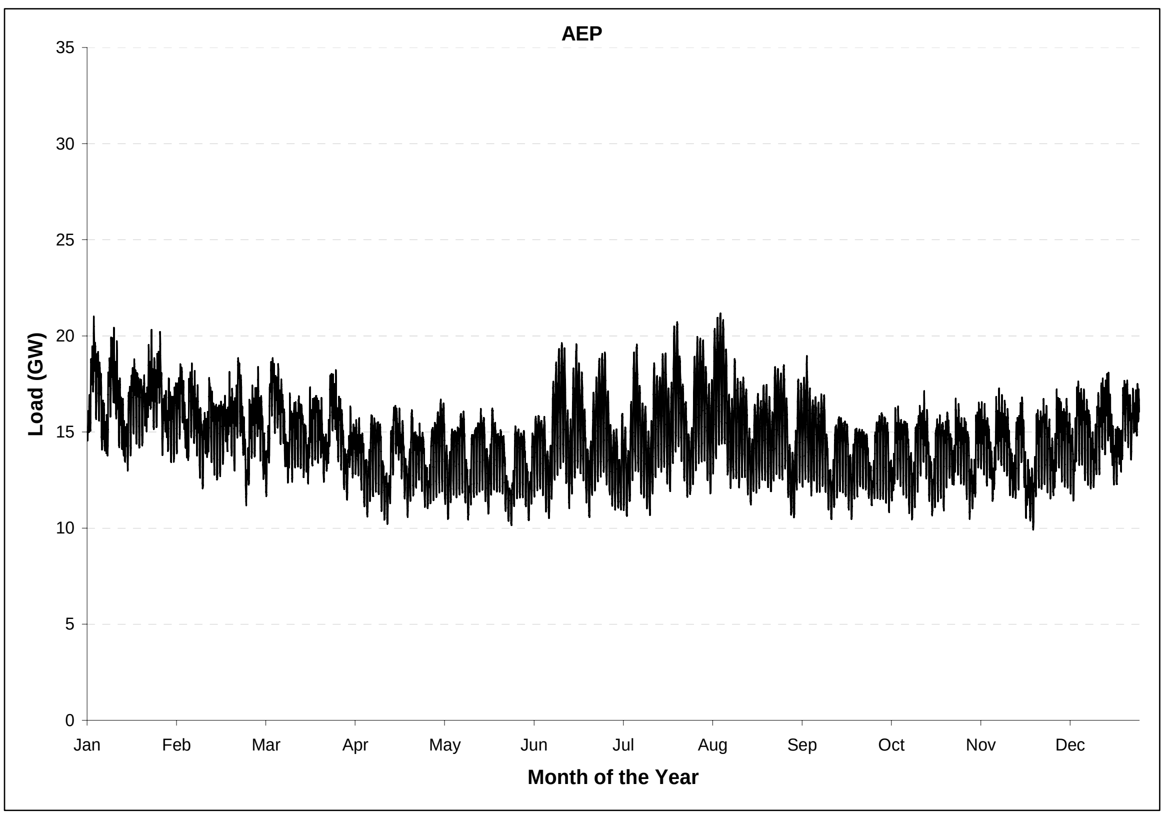

Figure D-4 AEP Load Curve

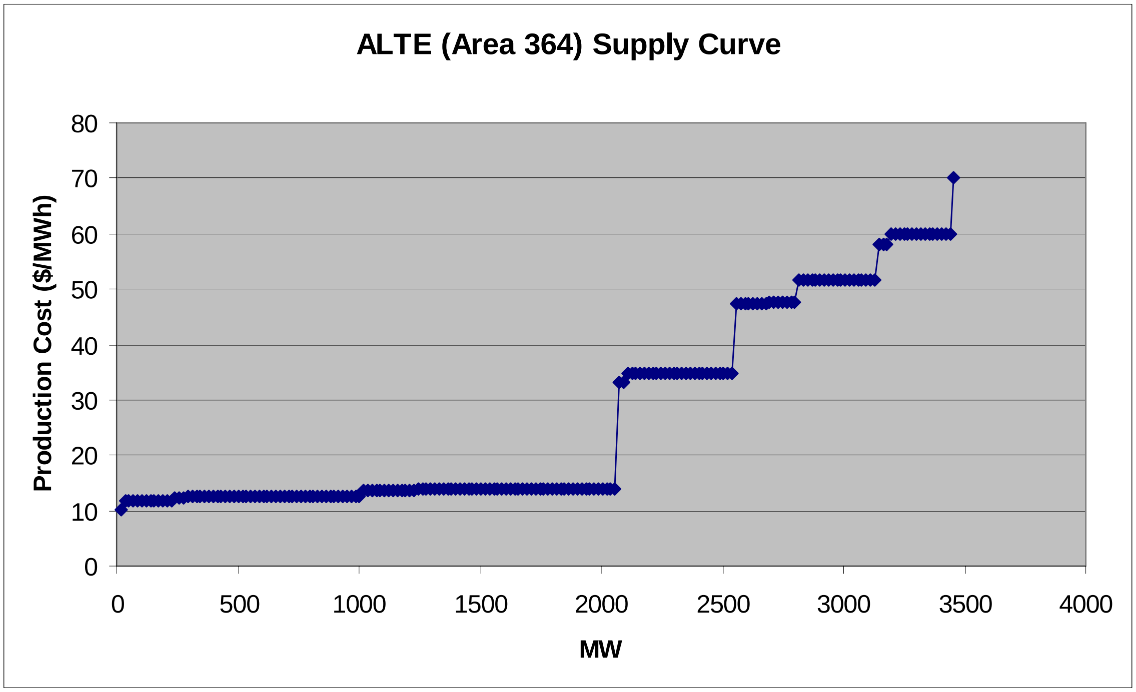

Figure D-5 ALTE Generation Supply Curve

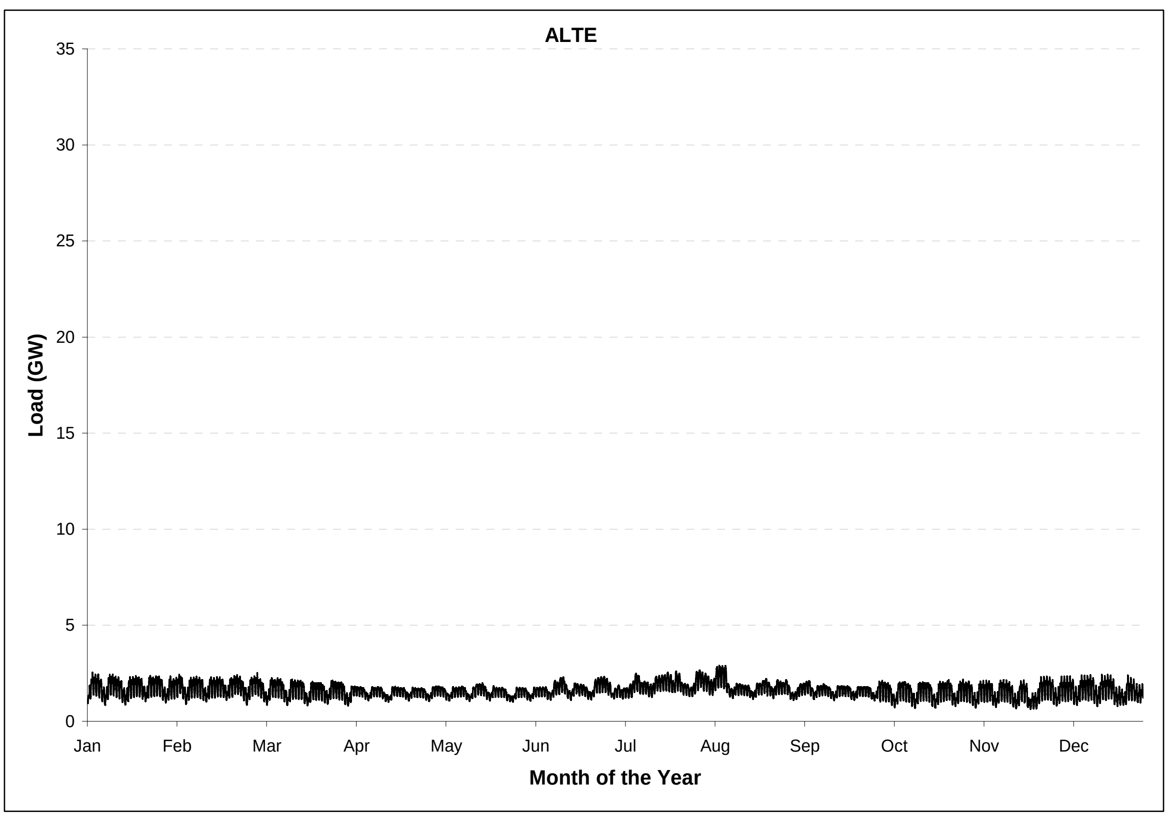

Figure D-6 ALTE Load Curve

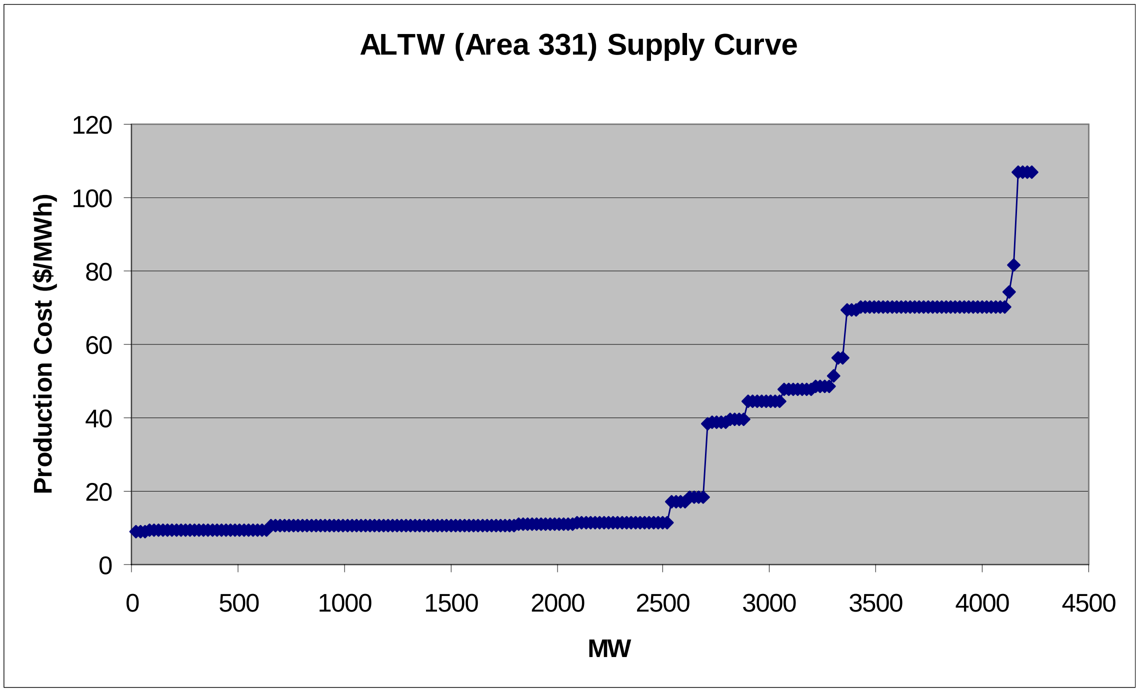

Figure D-7 ALTW Generation Supply Curve

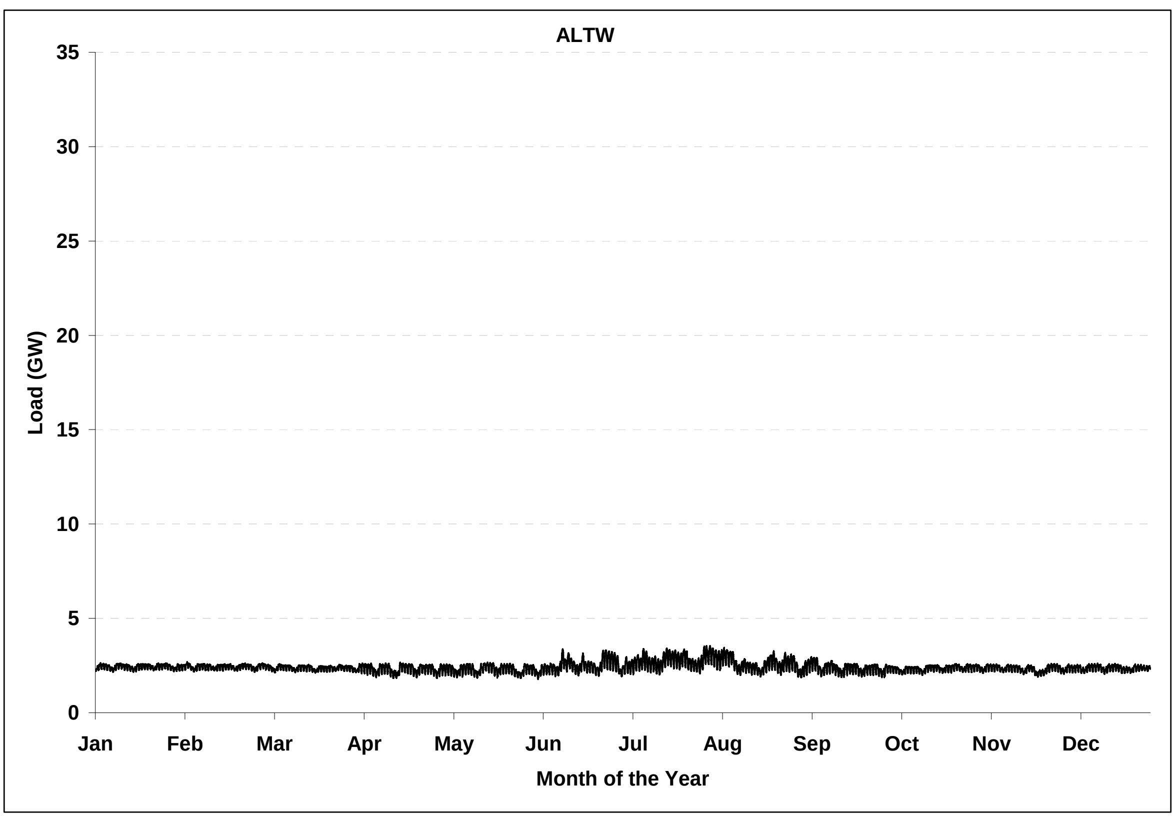

Figure D-8 ALTW Load Curve

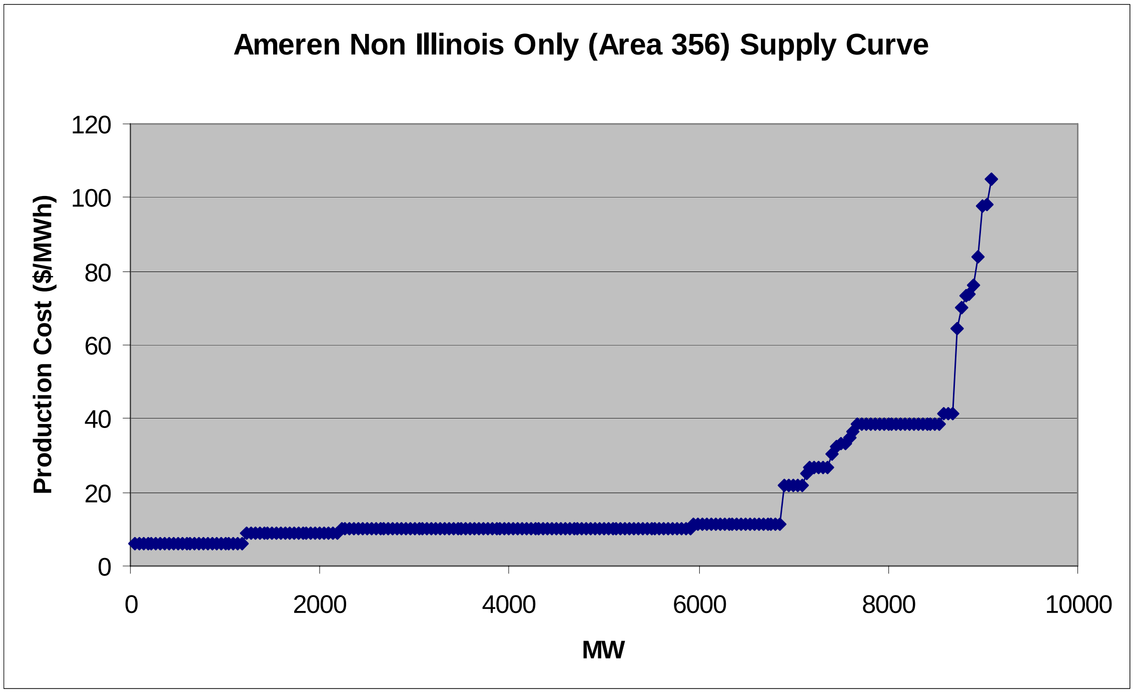

Figure D-9 Ameren Out Generation Supply Curve

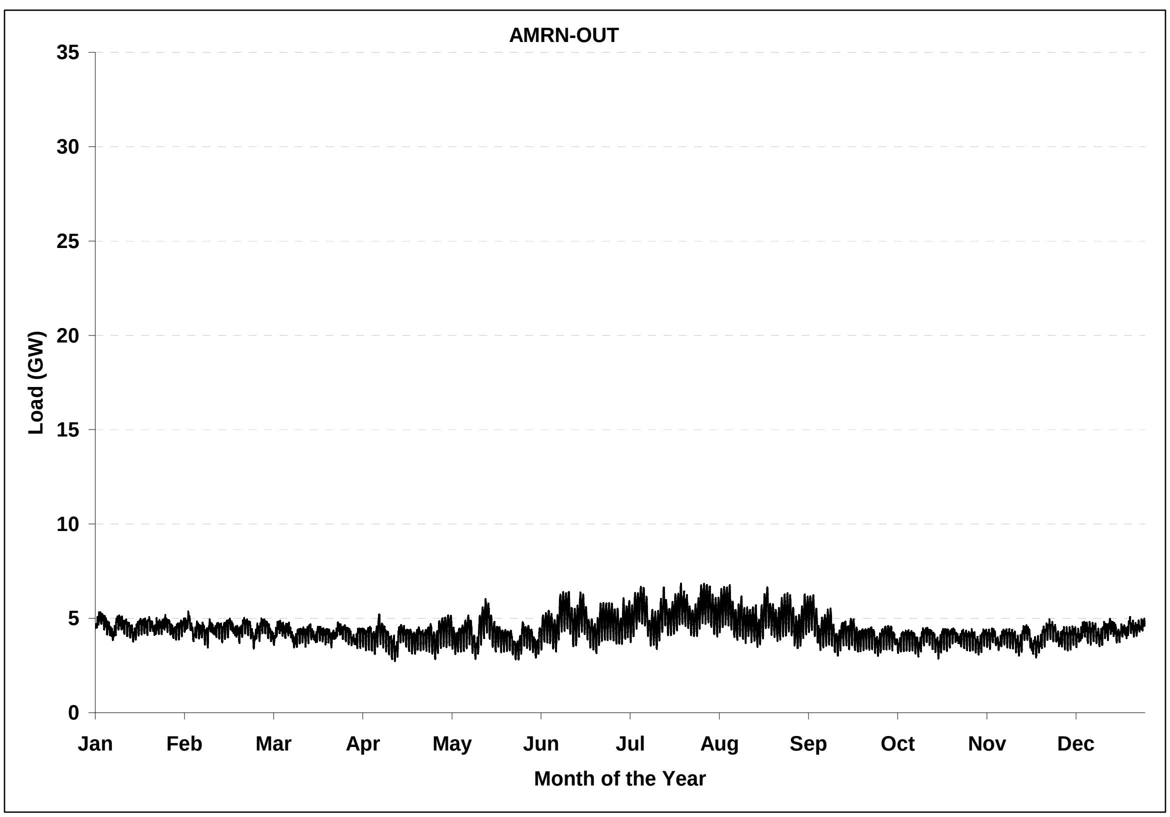

Figure D-10 Ameren Out Load Curve

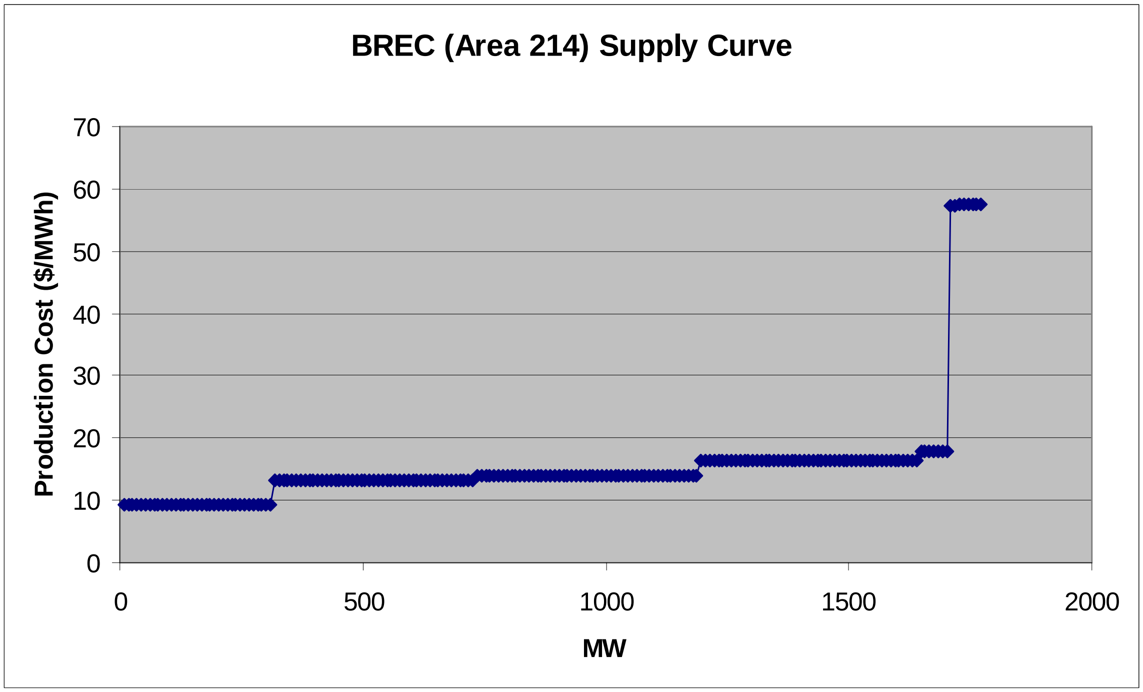

Figure D-11 BREC Generation Supply Curve

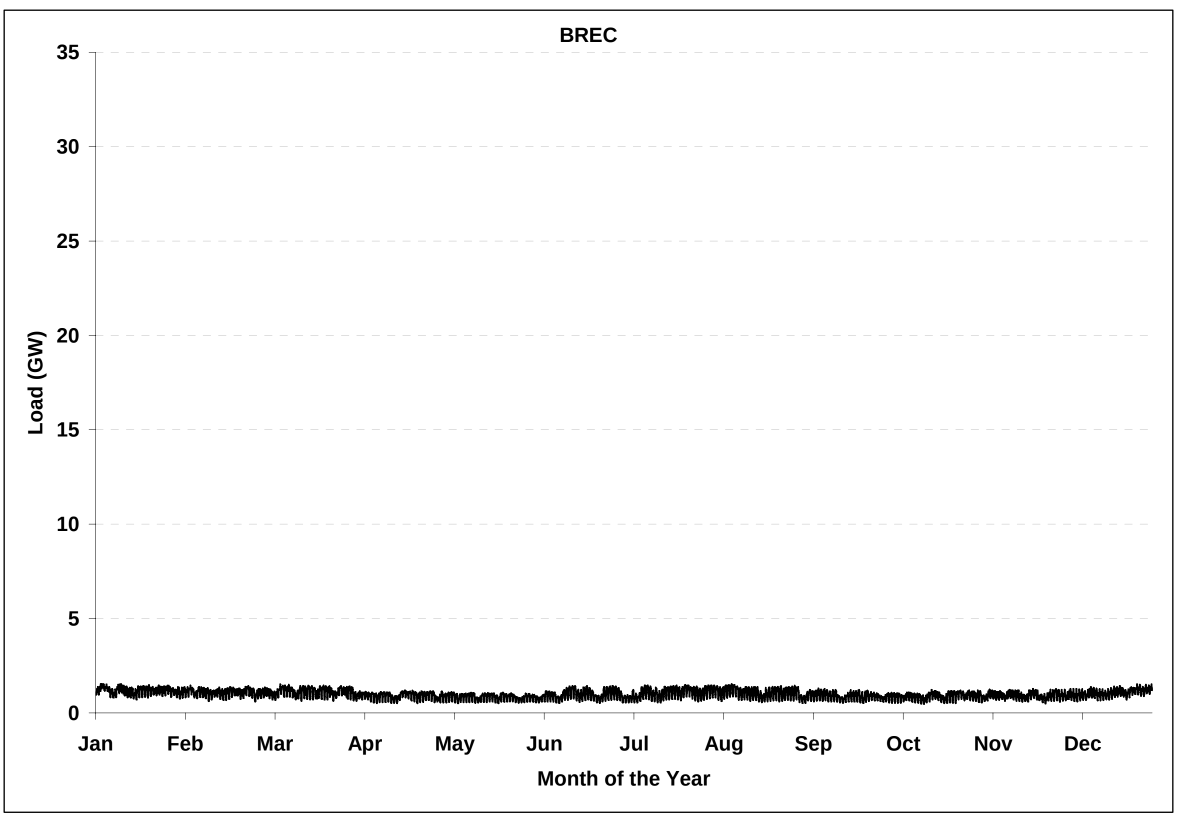

Figure D-12 BREC Load Curve

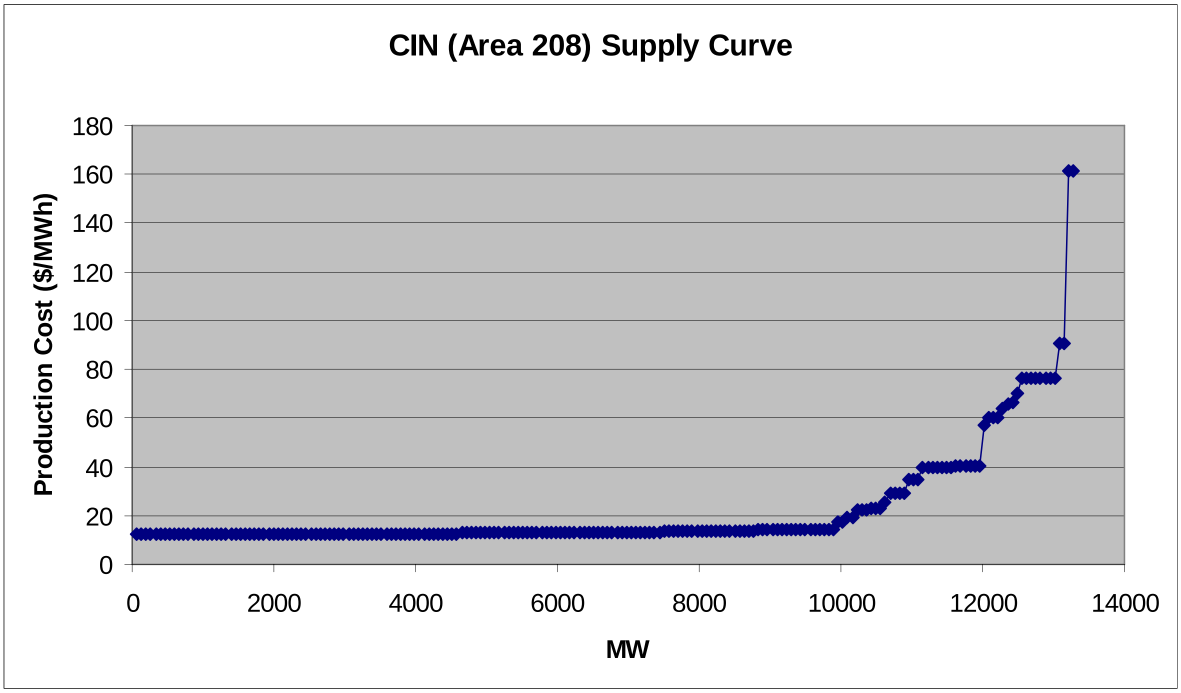

Figure D-13 CIN Generation Supply Curve

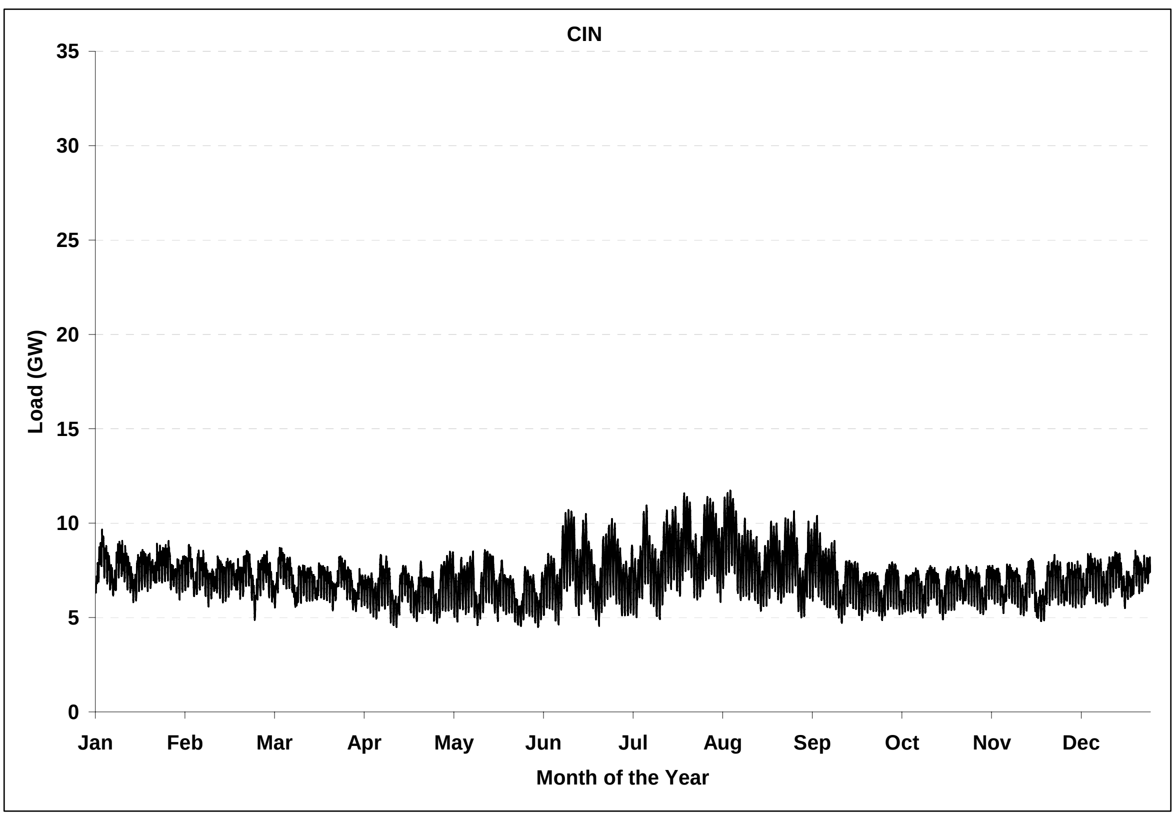

Figure D-14 CIN Load Curve

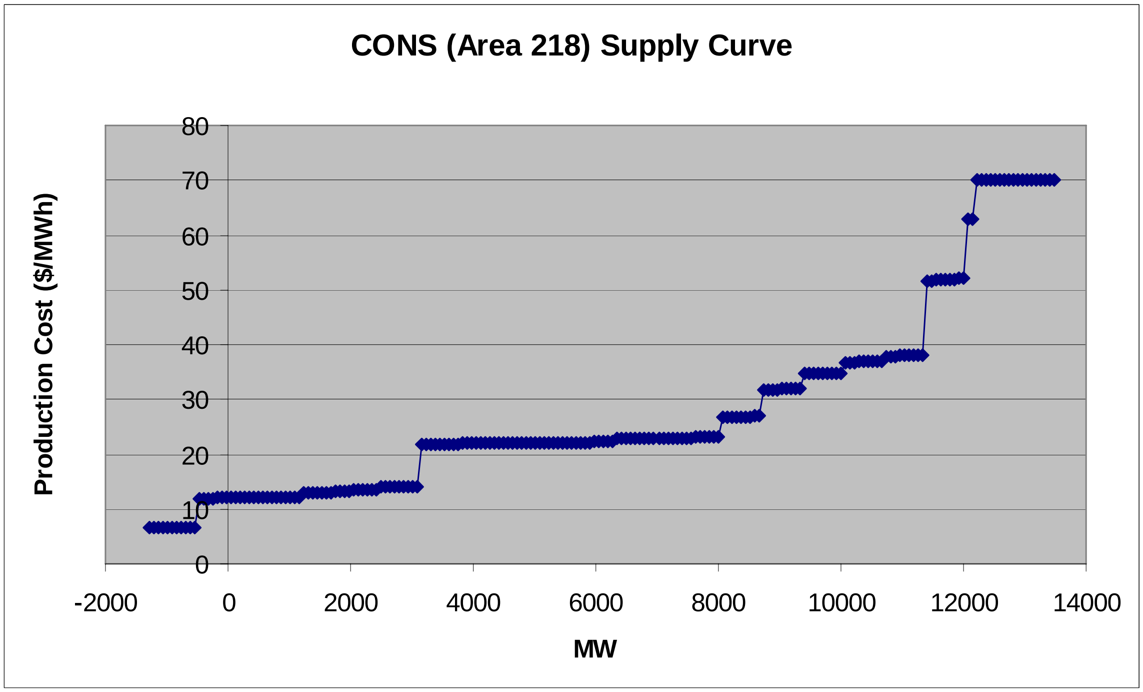

Figure D-15 CONS Generation Supply Curve

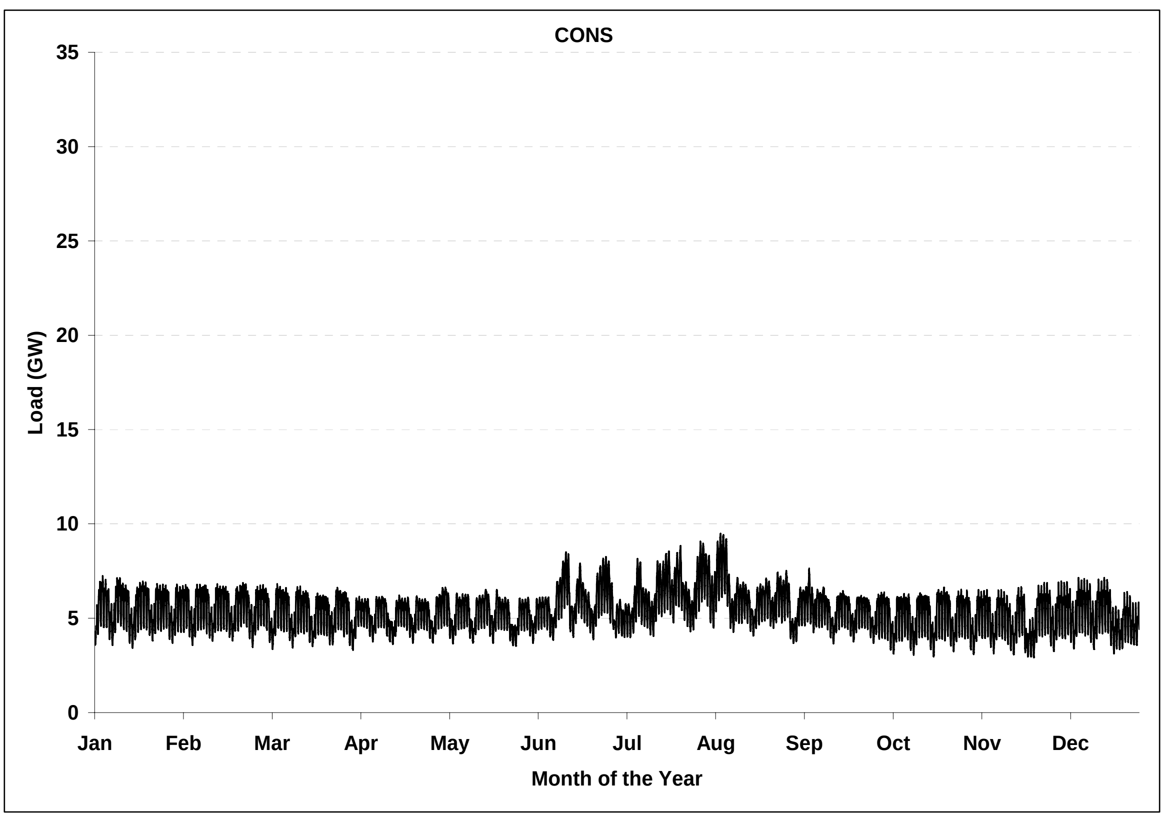

Figure D-16 CONS Load Curve

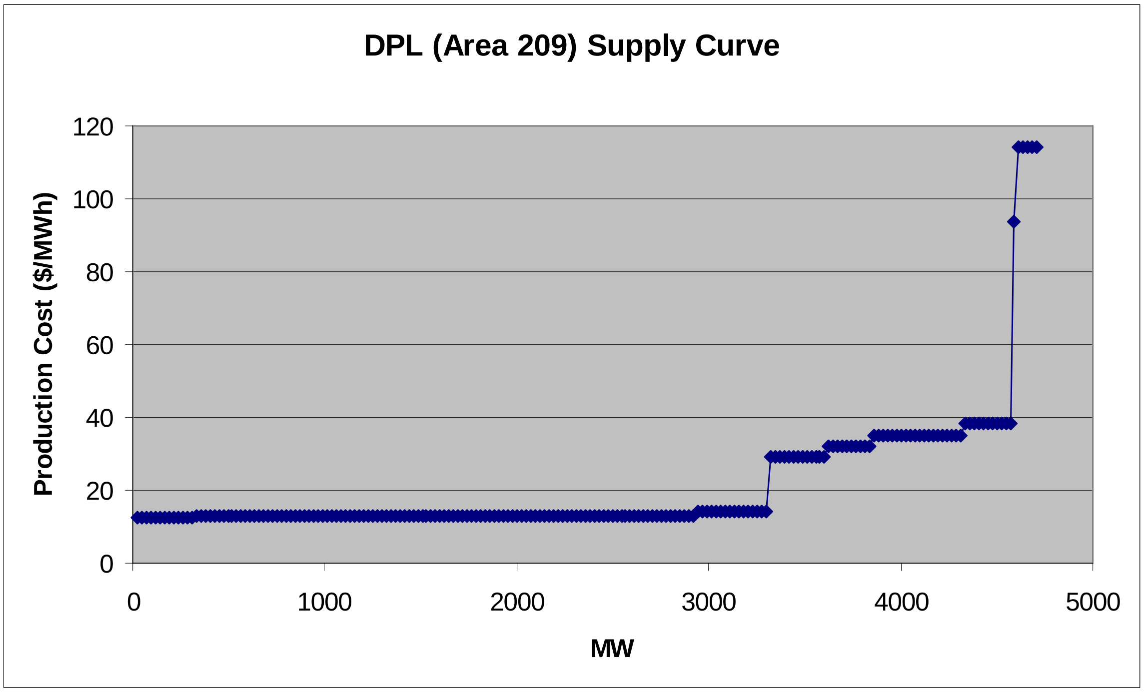

Figure D-17 DPL Generation Supply Curve

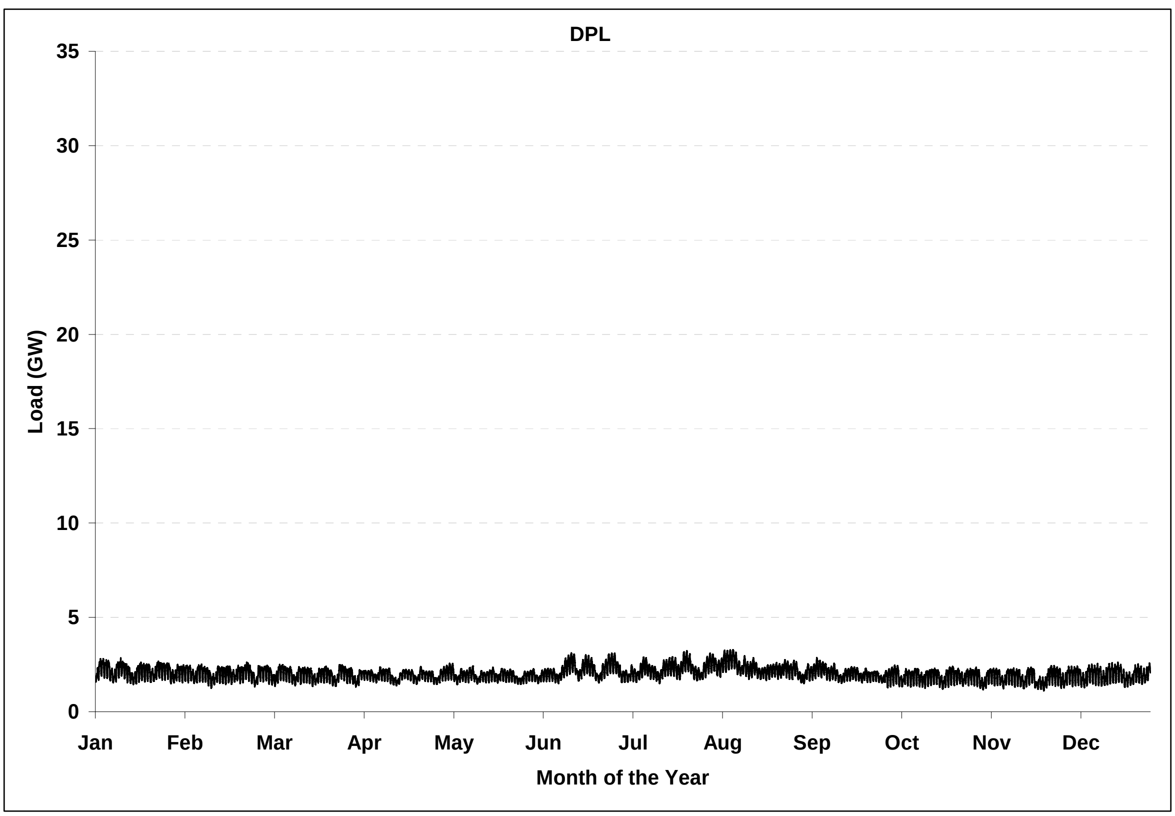

Figure D-18 DPL Load Curve

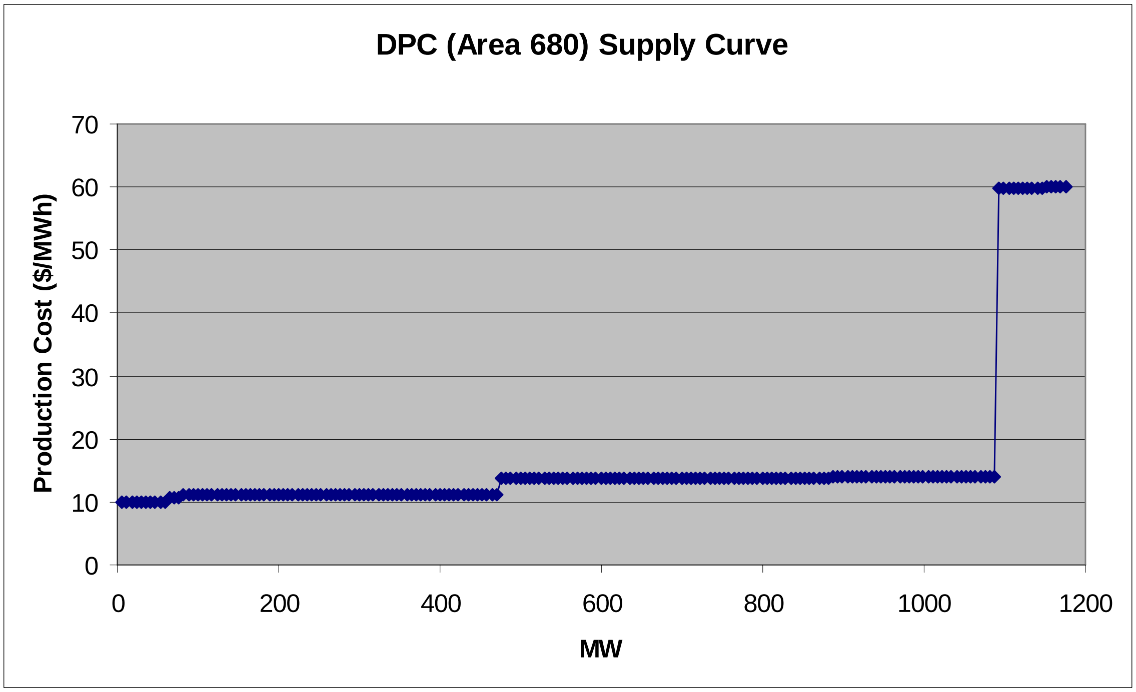

Figure D-19 DPC Generation Supply Curve

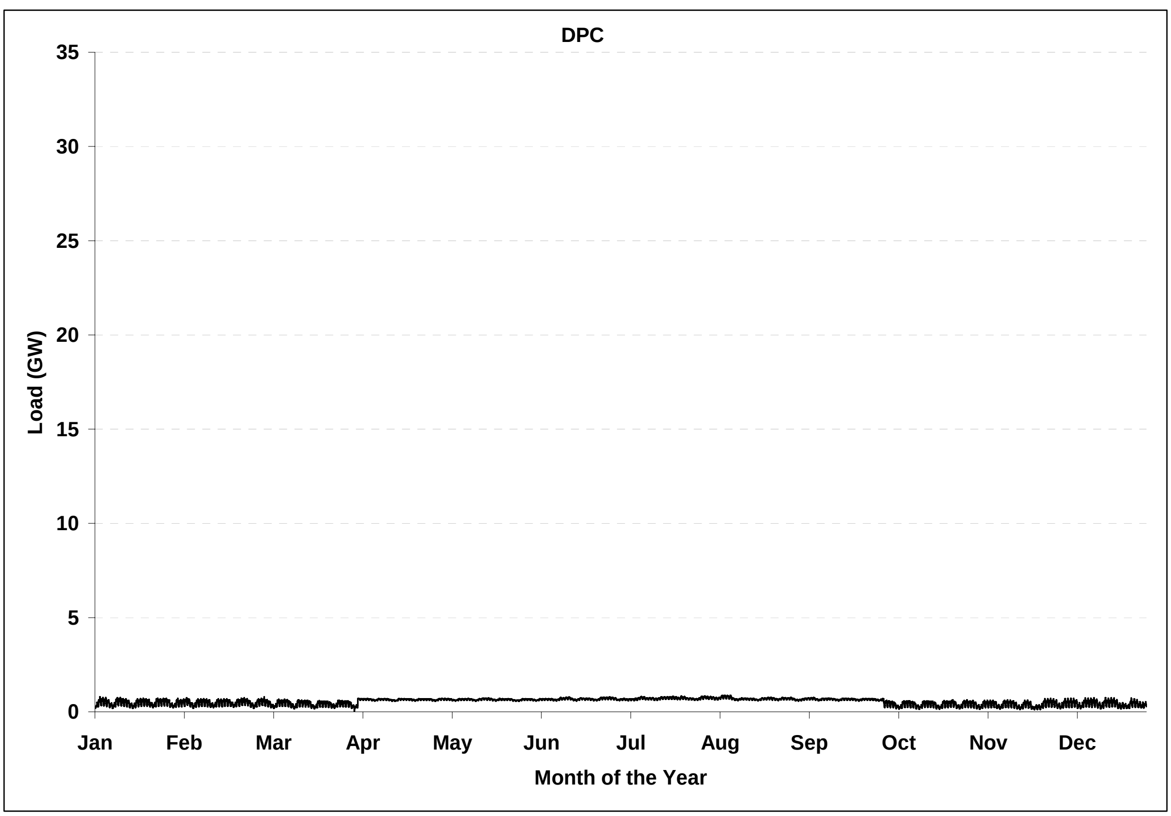

Figure D-20 DPC Load Curve

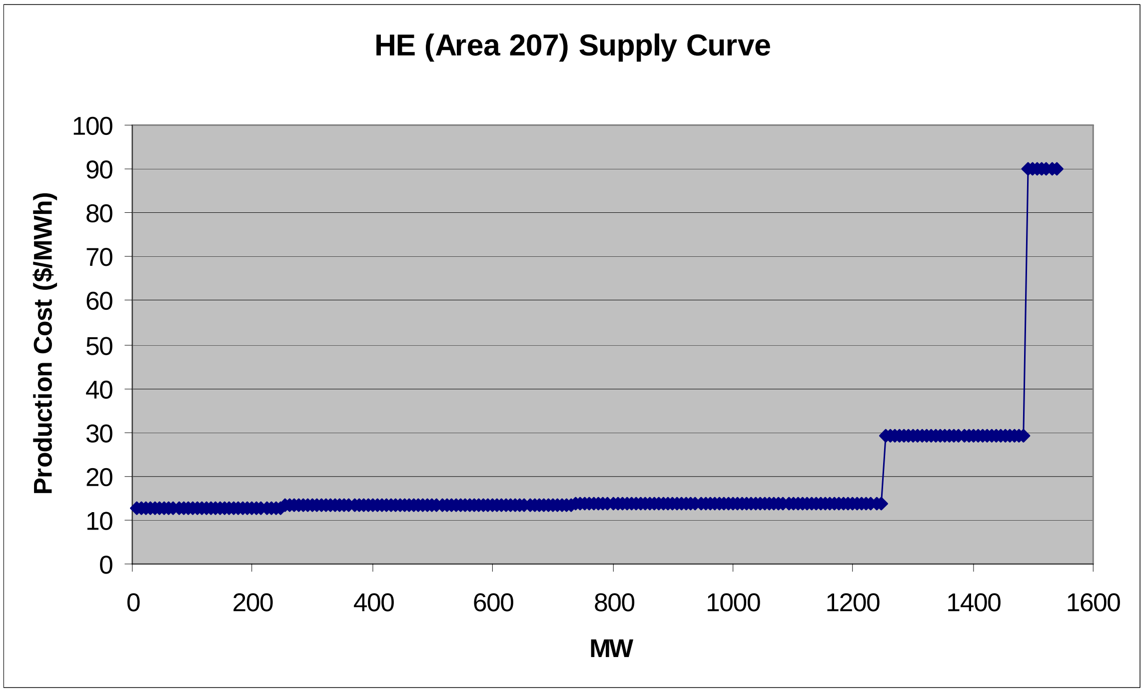

Figure D-21 HE Generation Supply Curve

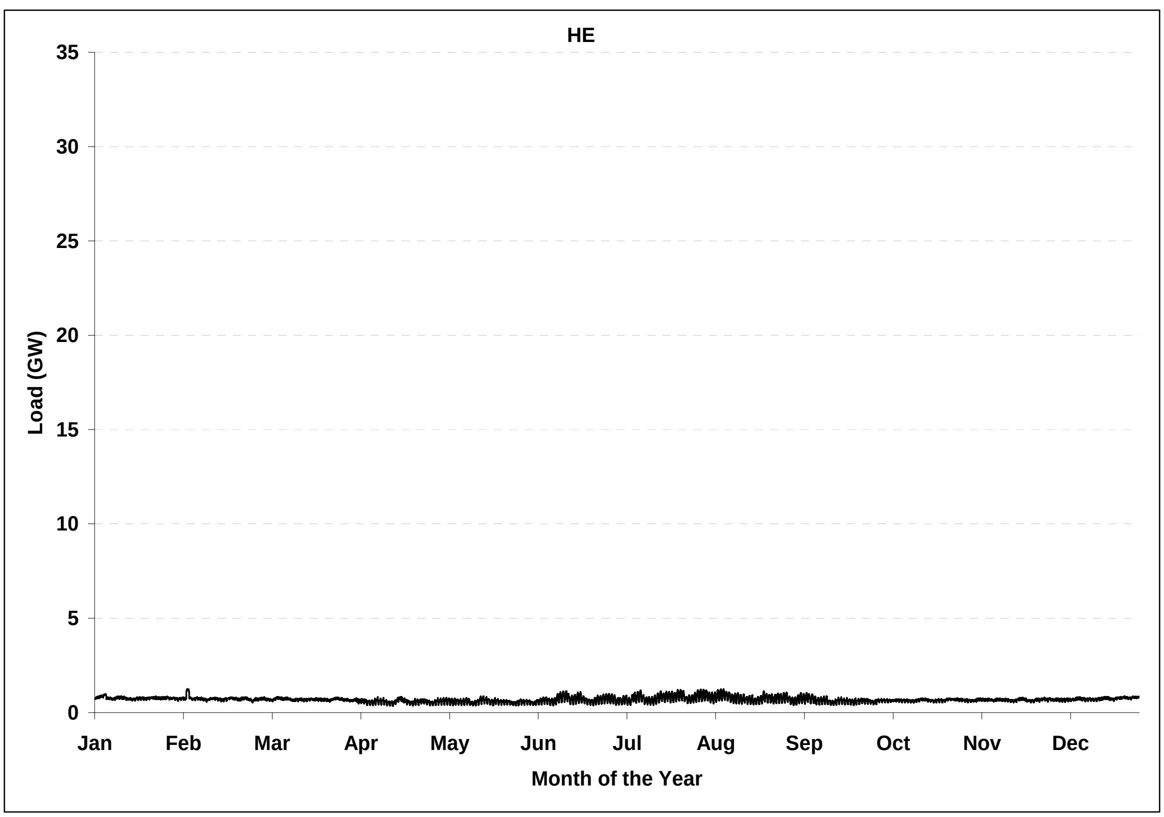

Figure D-22 HE Load Curve

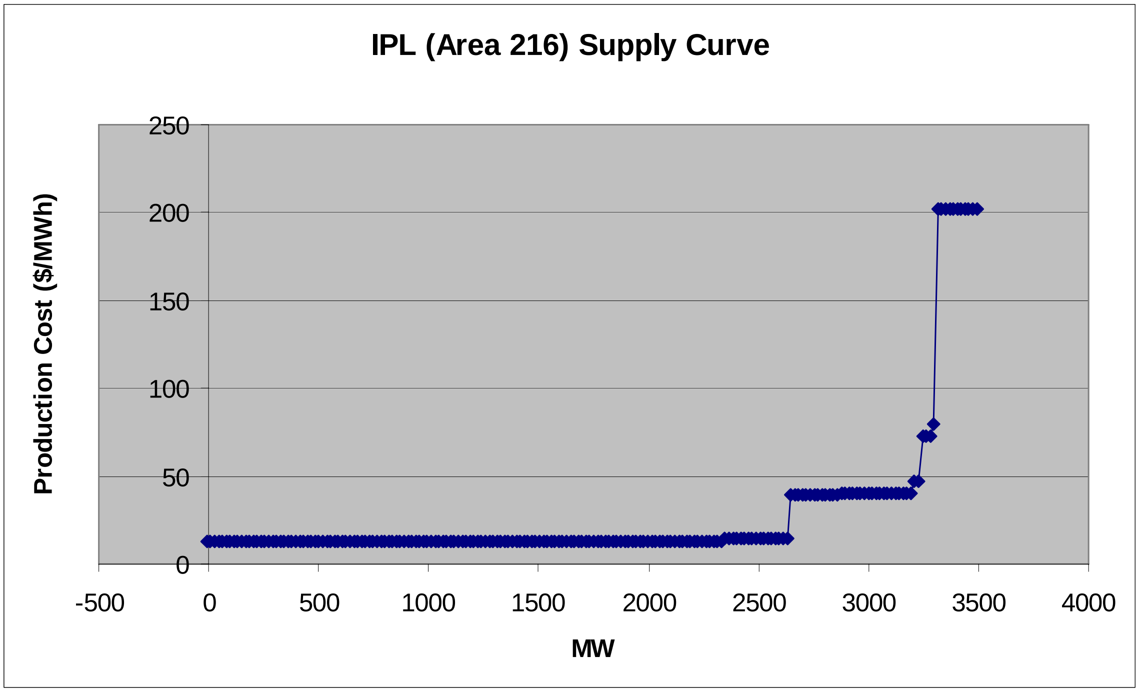

Figure D-23 IPL Generation Supply Curve

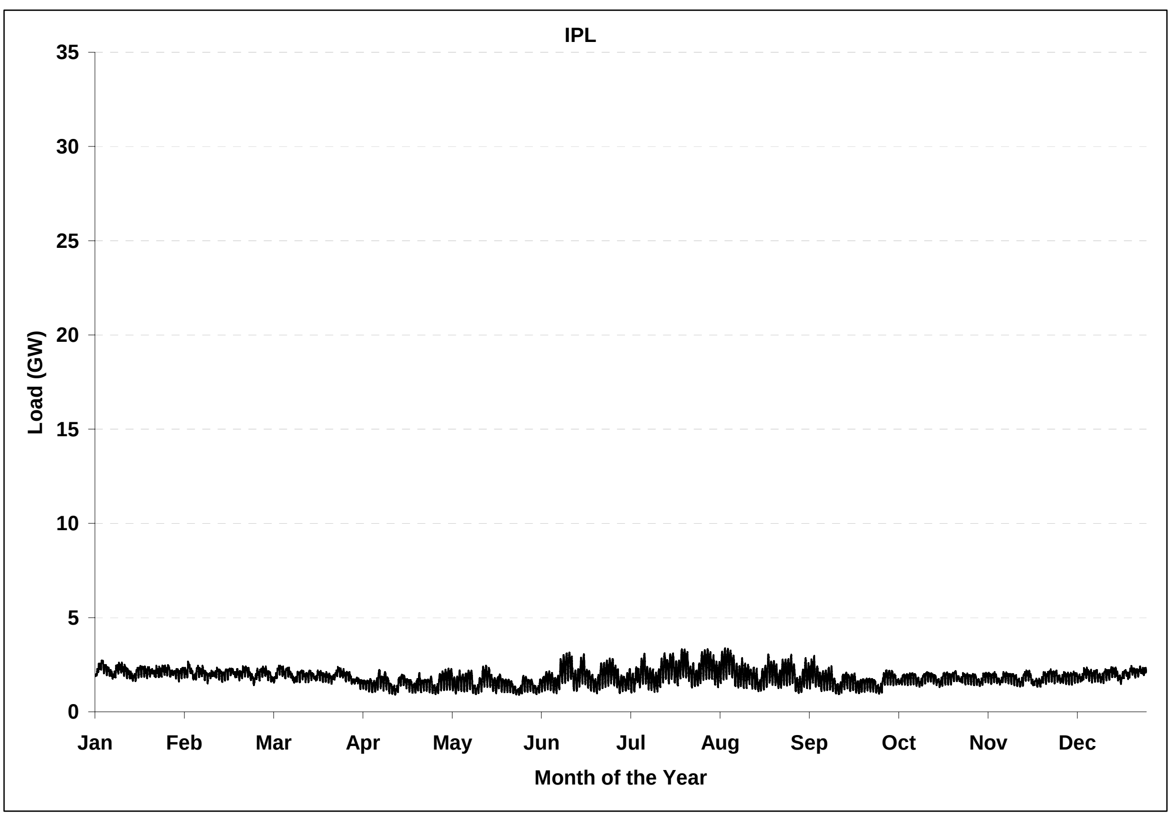

Figure D-24 IPL Load Curve

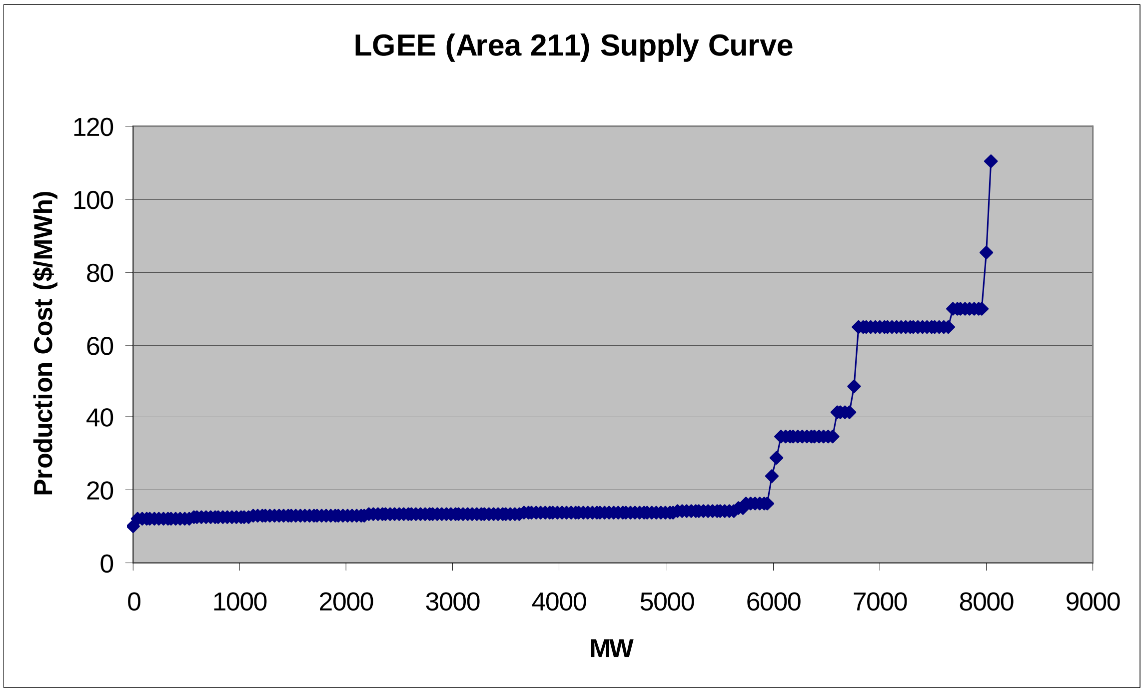

Figure D-25 LGEE Generation Supply Curve

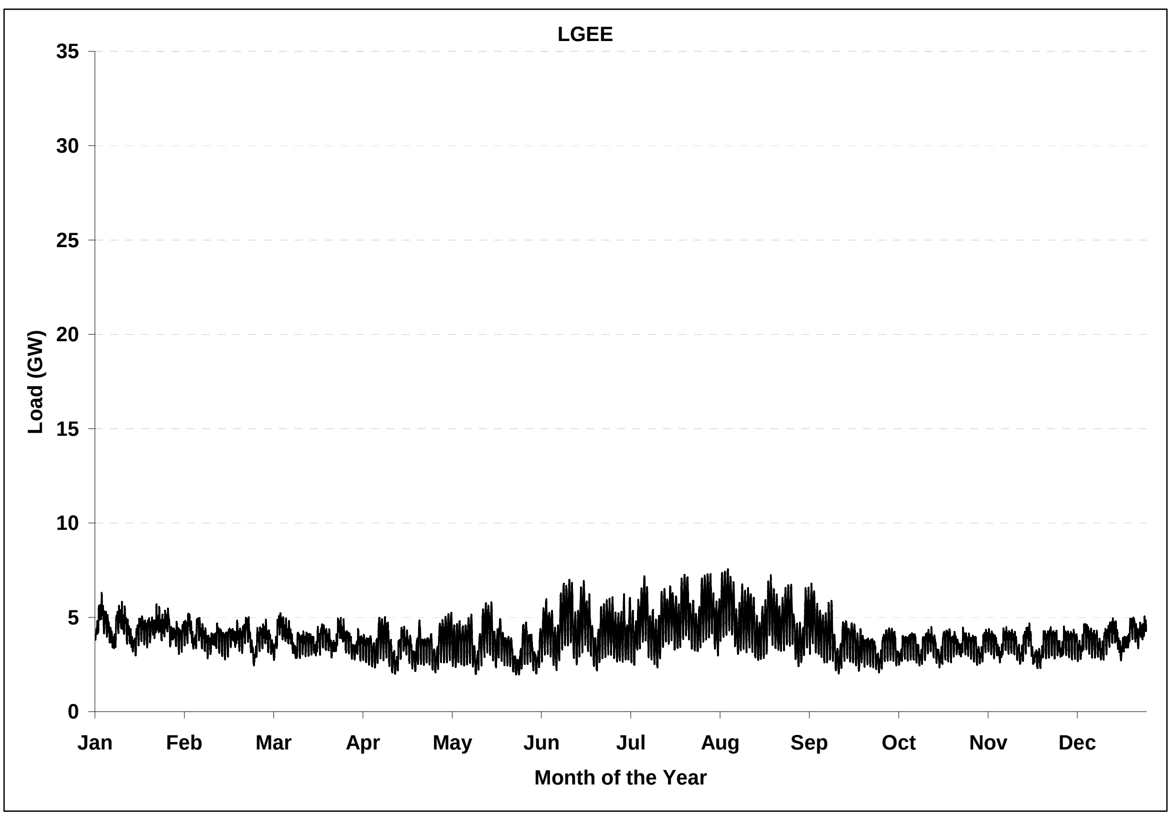

Figure D-26 LGEE Load Curve

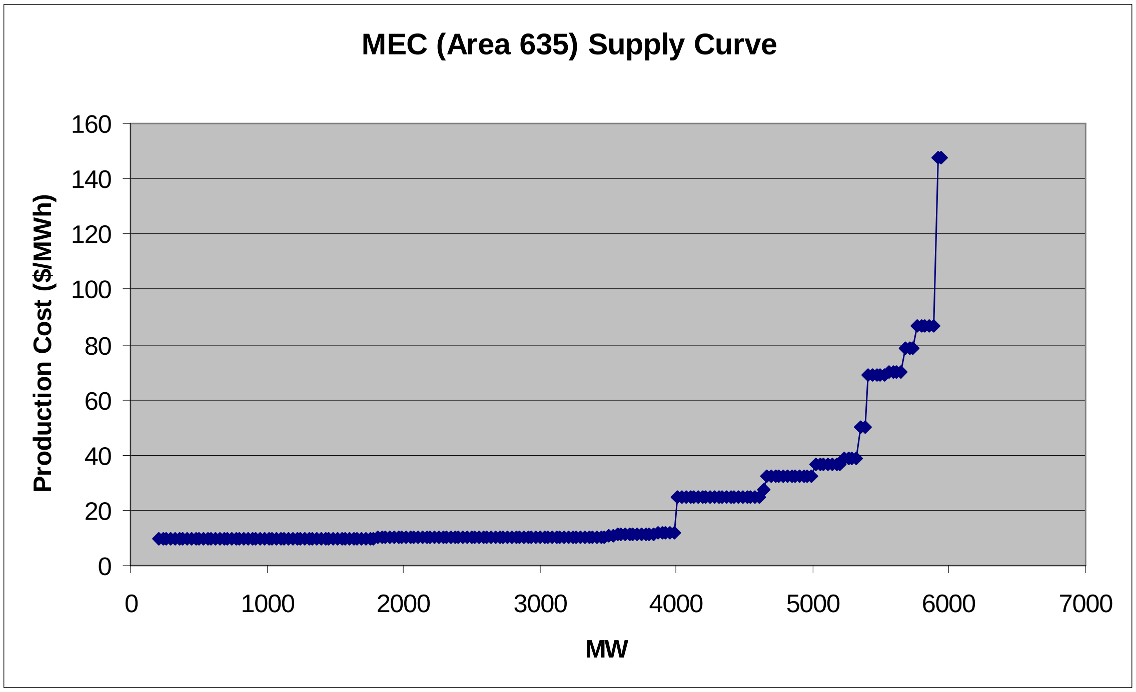

Figure D-27 MEC Generation Supply Curve

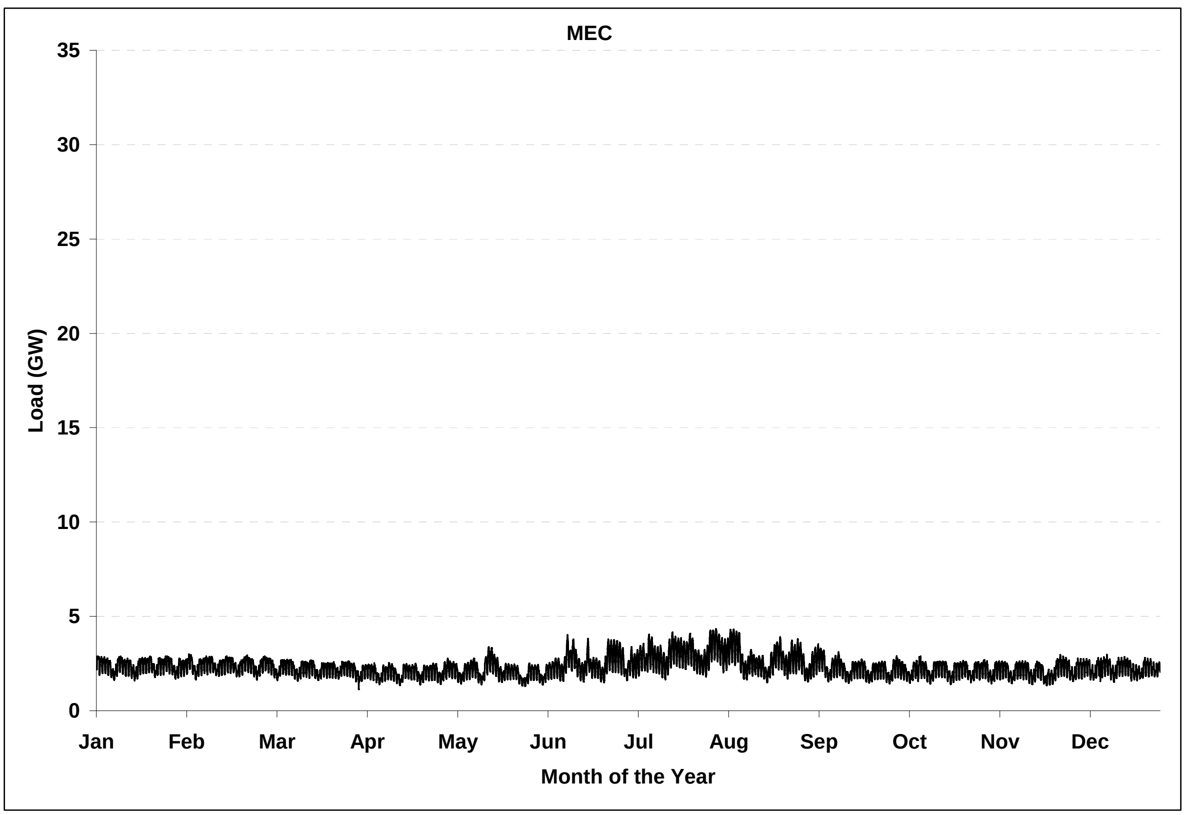

Figure D-28 MEC Load Curve

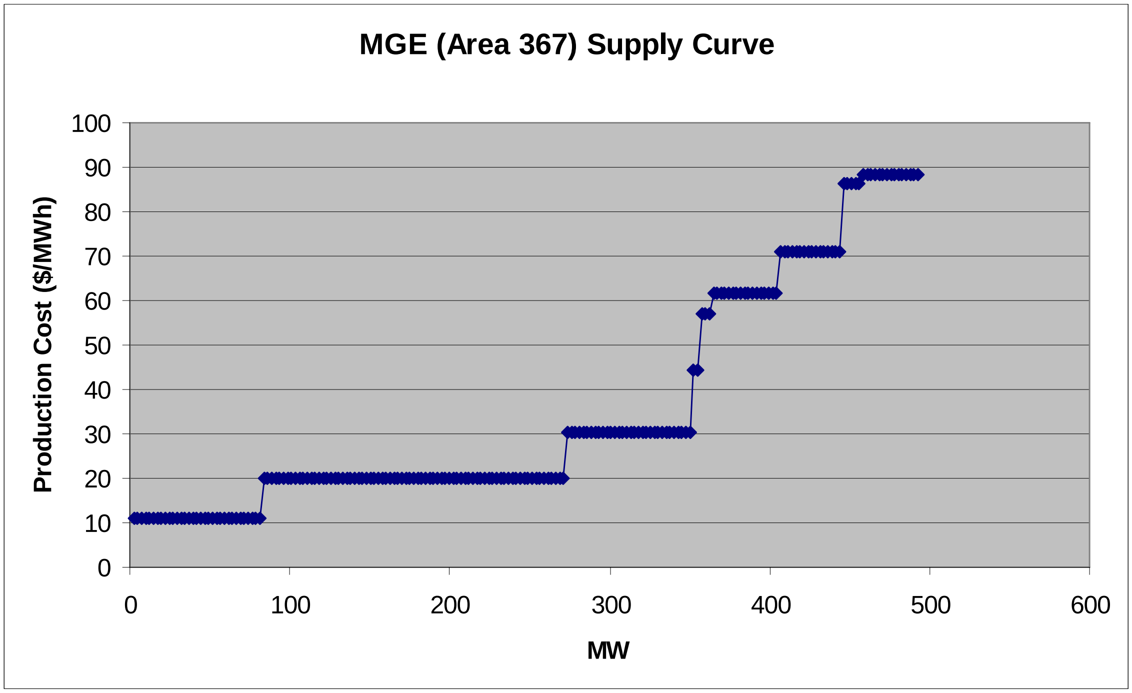

Figure D-29 MGE Generation Supply Curve

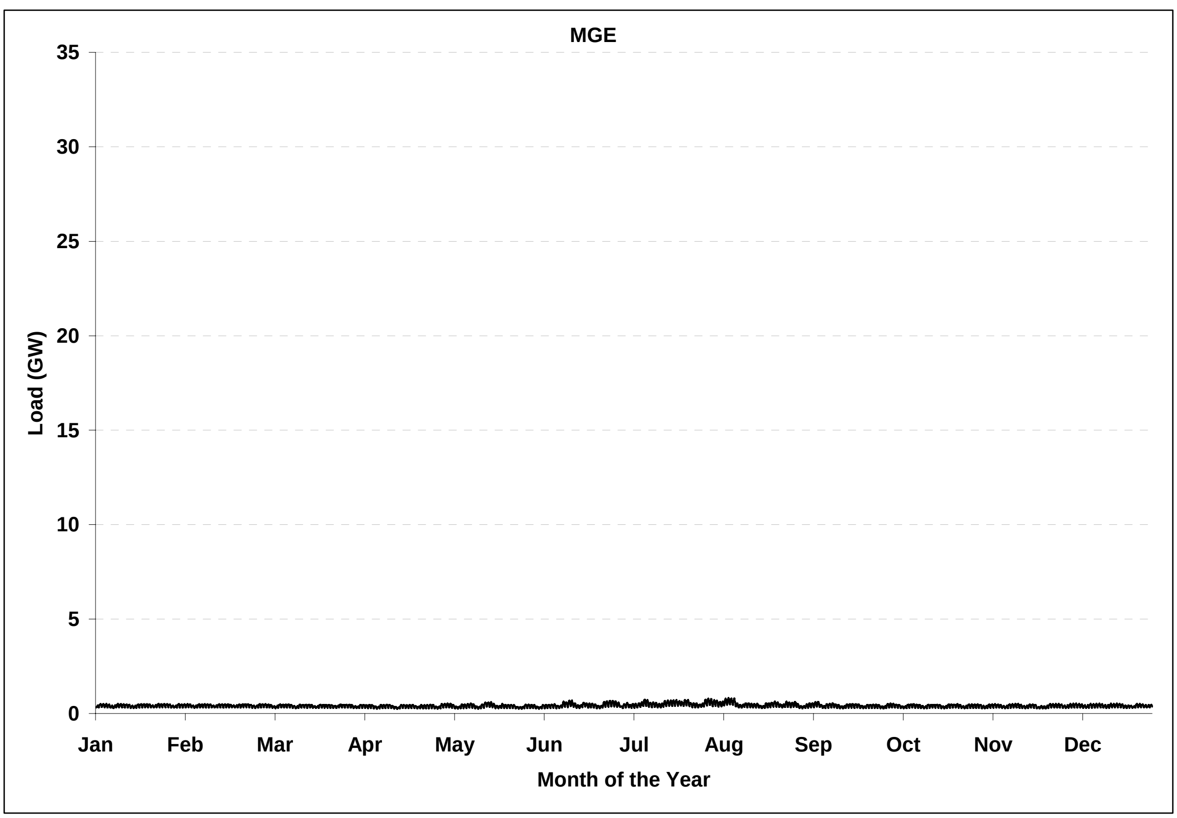

Figure D-30 MGE Load Curve

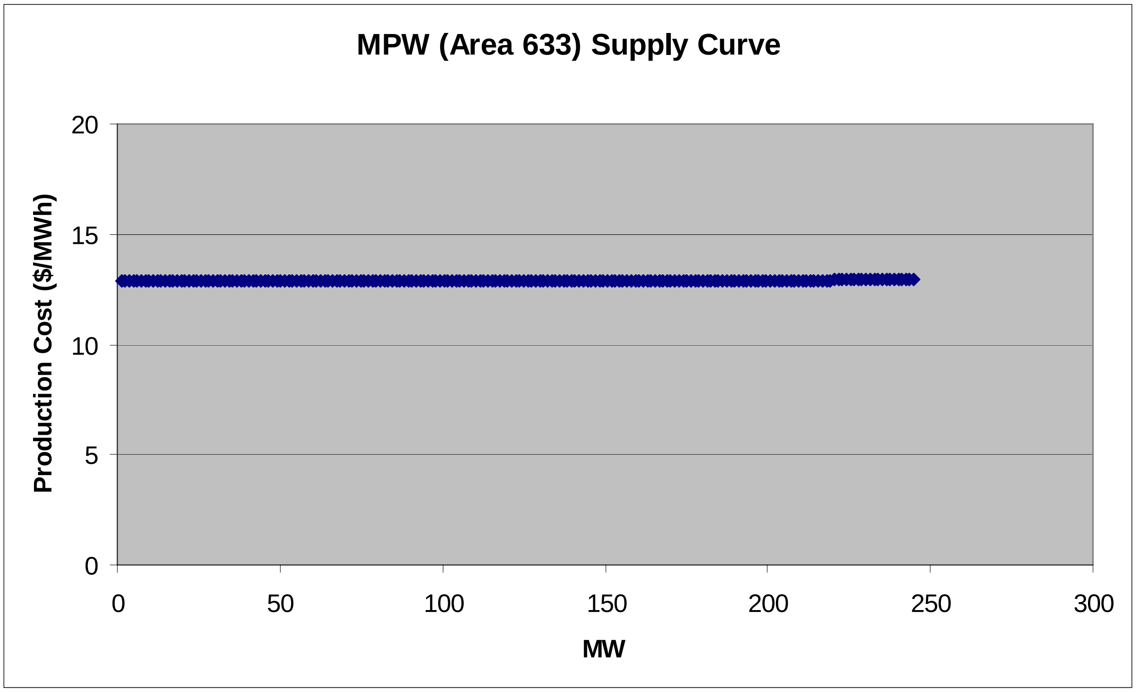

Figure D-31 MPW Generation Supply Curve

No loads projected in this area

Figure D-32 MPW Load Curve

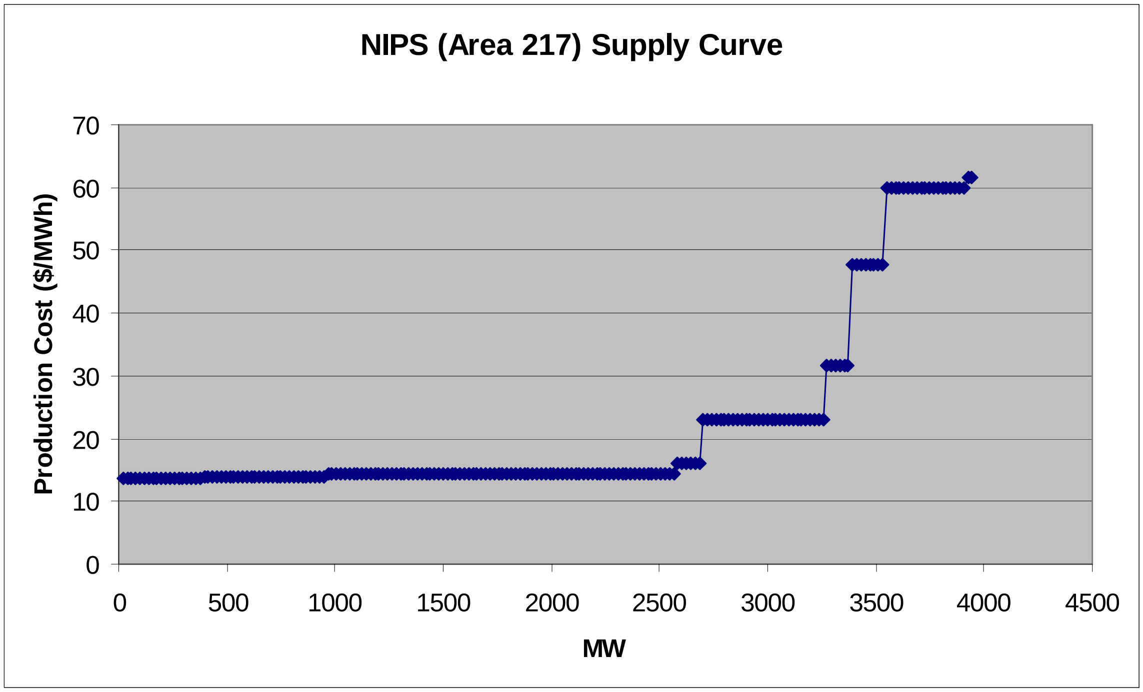

Figure D-33 NIPS Generation Supply Curve

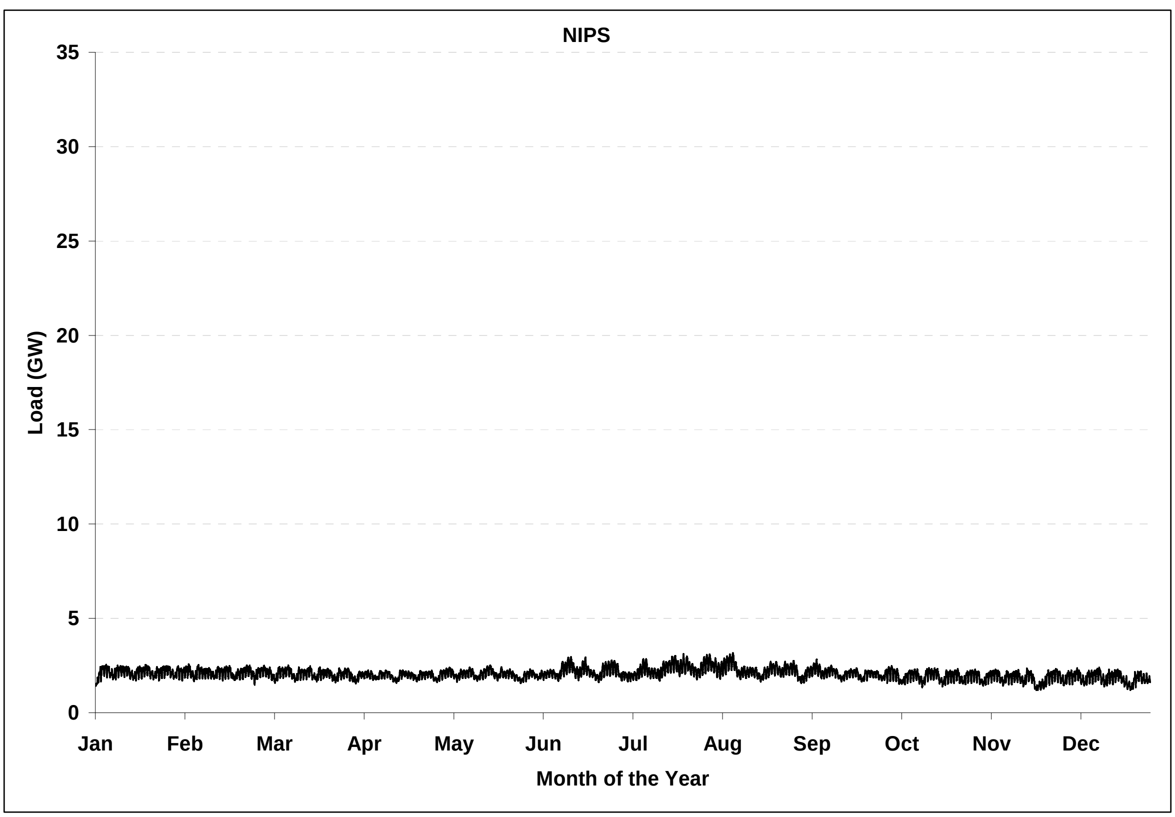

Figure D-34 NIPS Load Curve

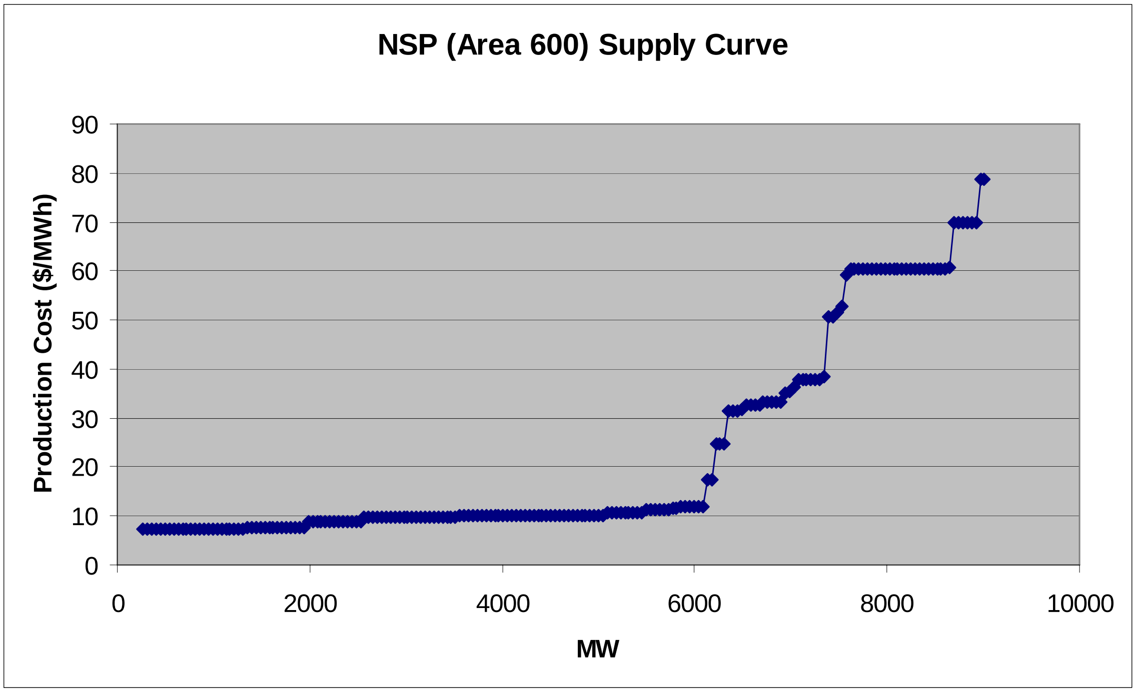

Figure D-35 NSP Generation Supply Curve

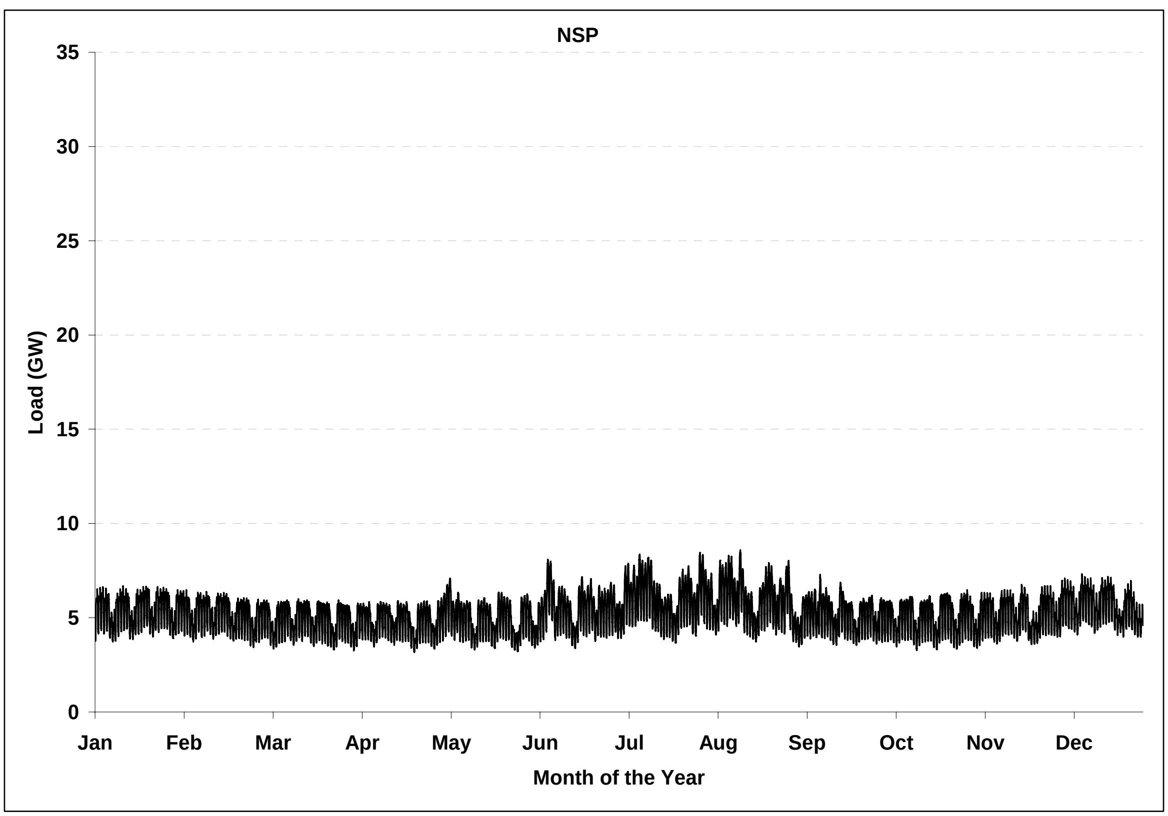

Figure D-36 NSP Load Curve

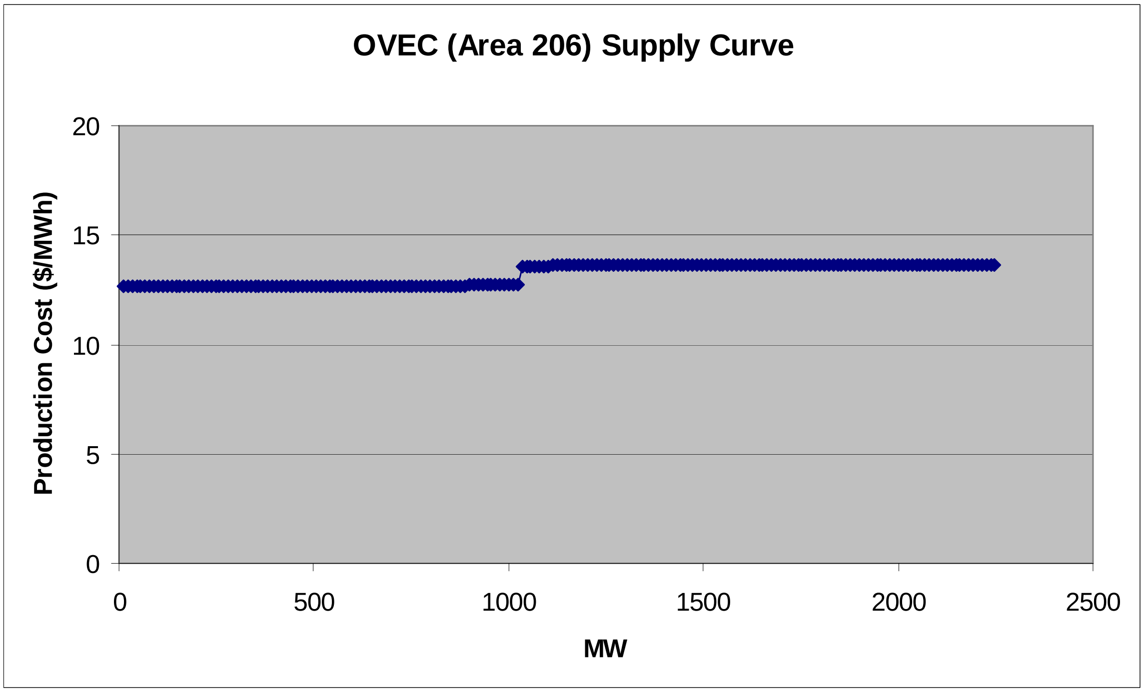

Figure D-37 OVEC Generation Supply Curve

No loads projected in this area

Figure D-38 OVEC Load Curve

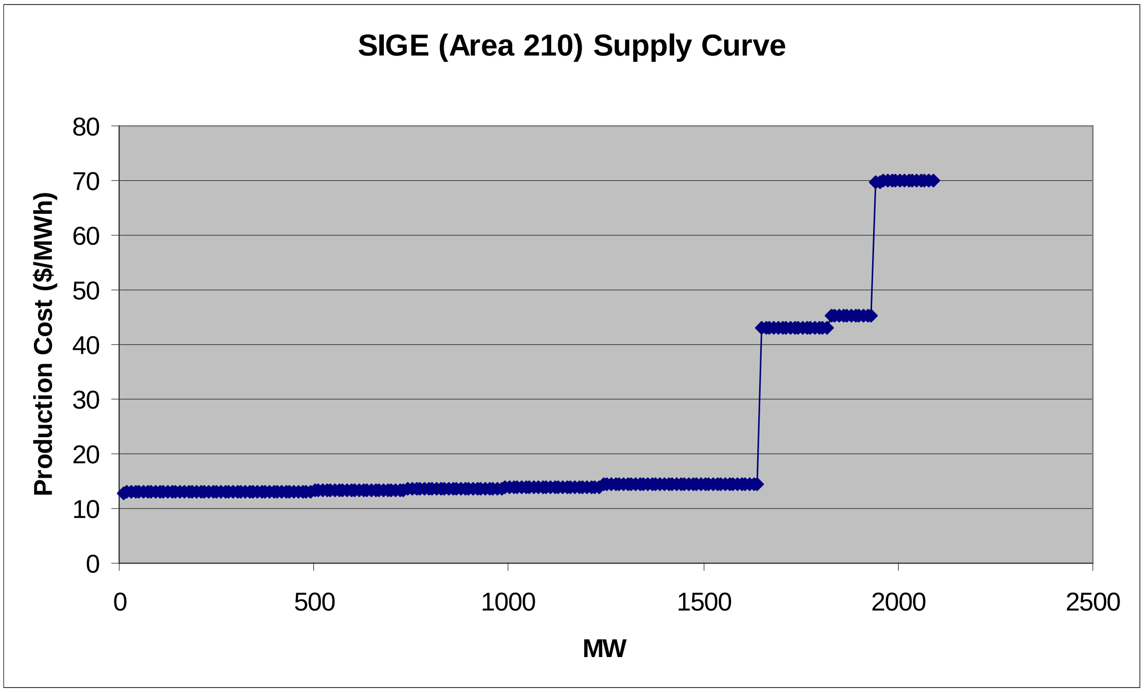

Figure D-39 SIGE Generation Supply Curve

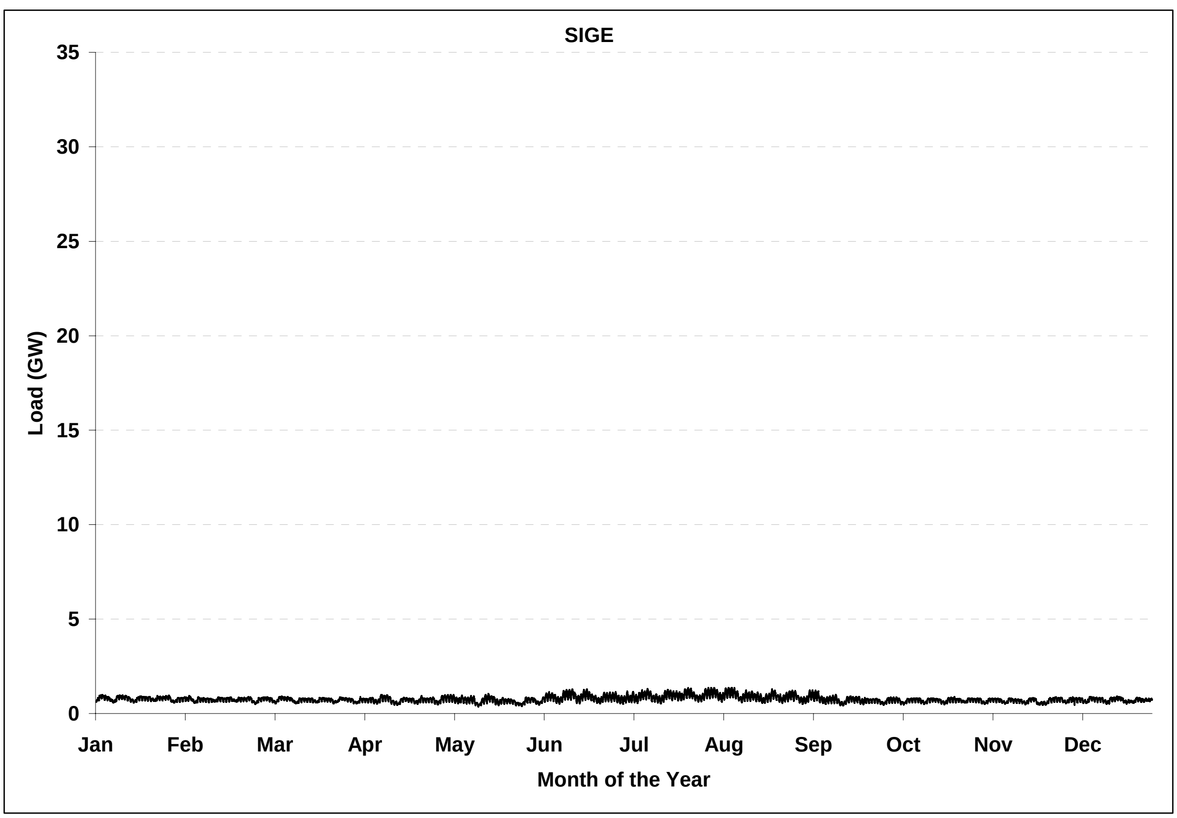

Figure D-40 SIGE Load Curve

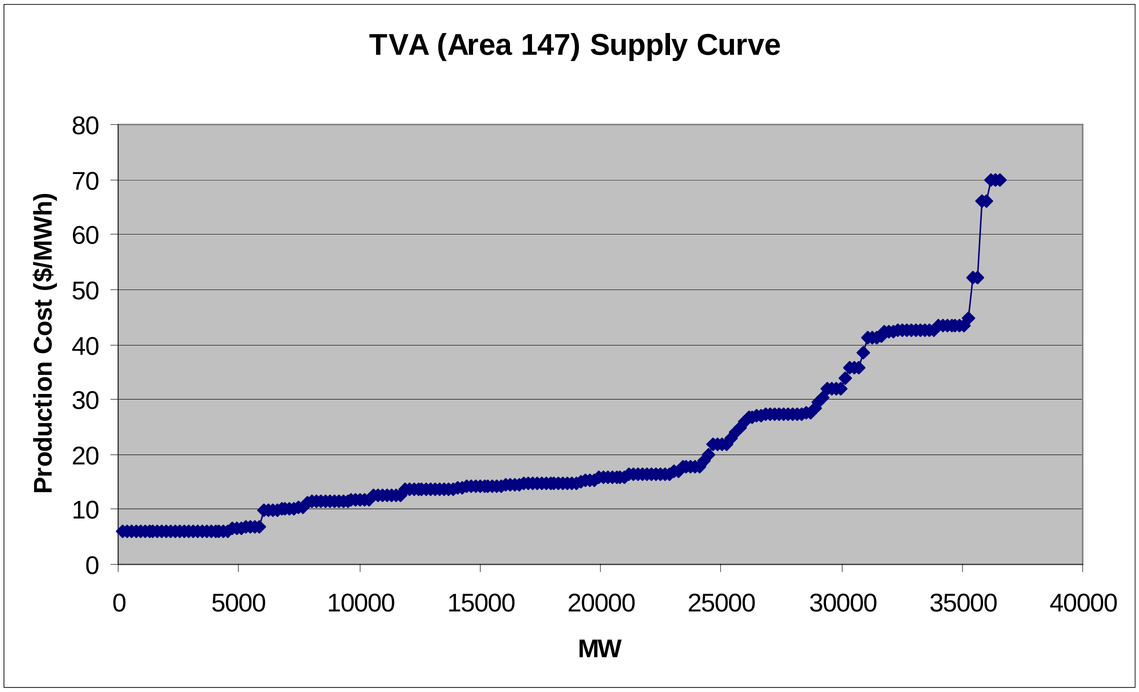

Figure D-41 TVA Generation Supply Curve

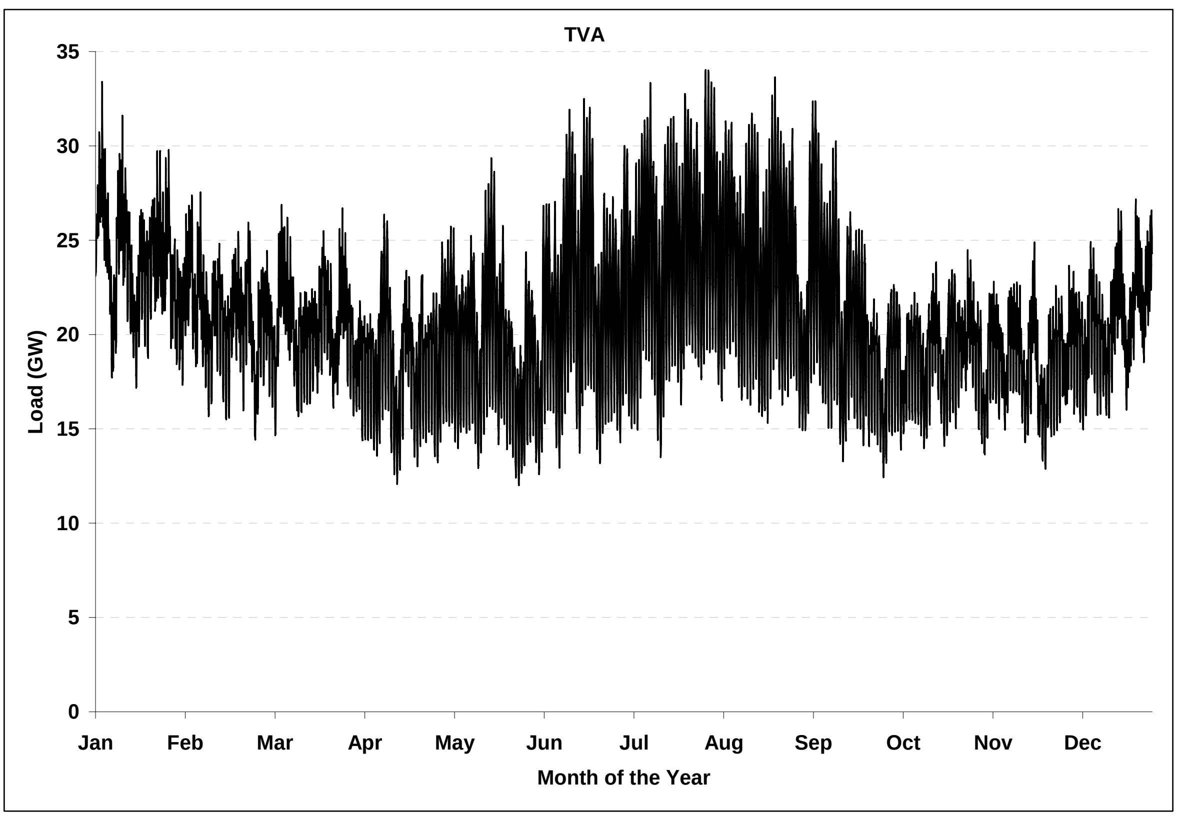

Figure D-42 TVA Load Curve

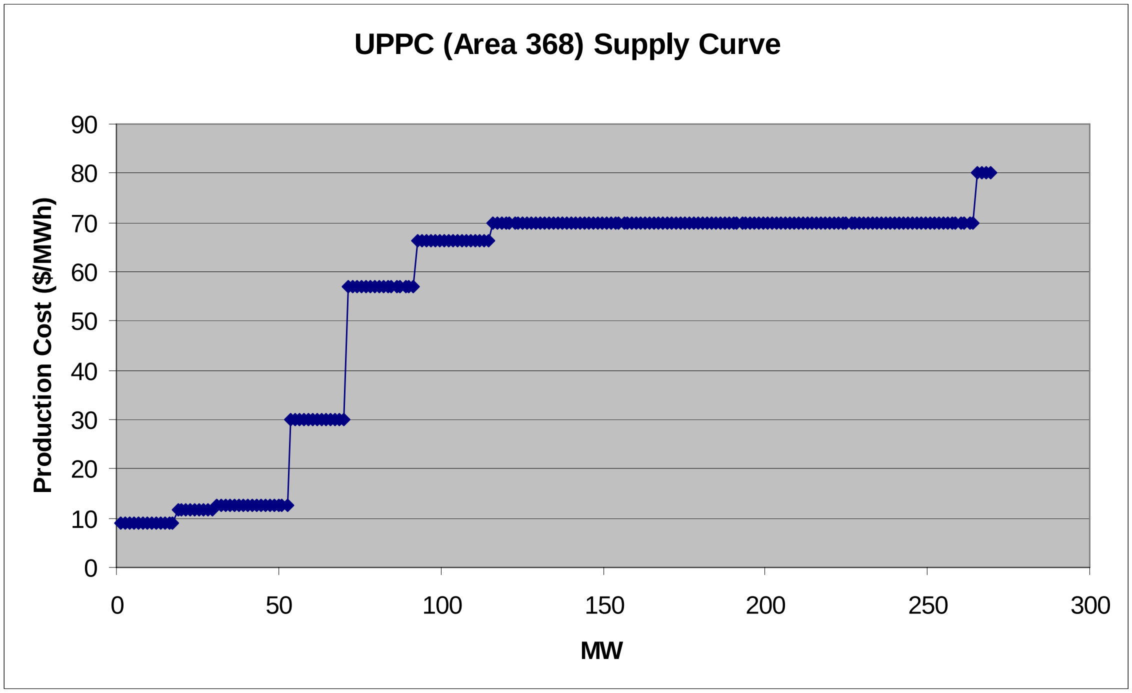

Figure D-43 UPPC Generation Supply Curve

No loads projected in this area

Figure D-44 UPPC Load Curve

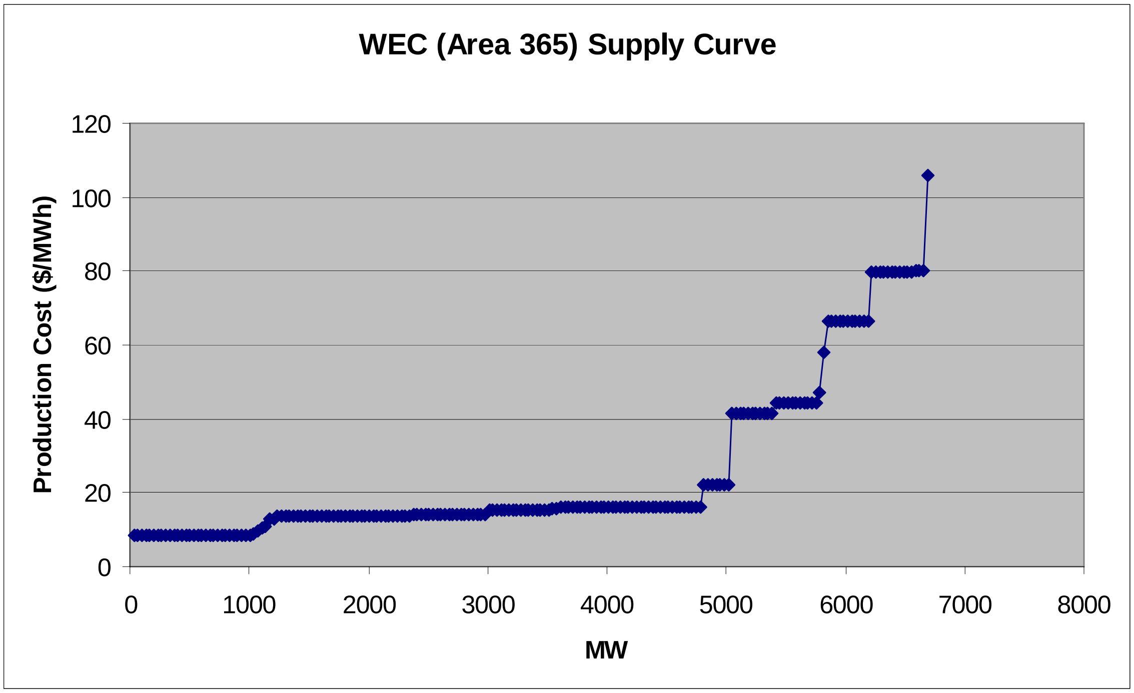

Figure D-45 WEC Generation Supply Curve

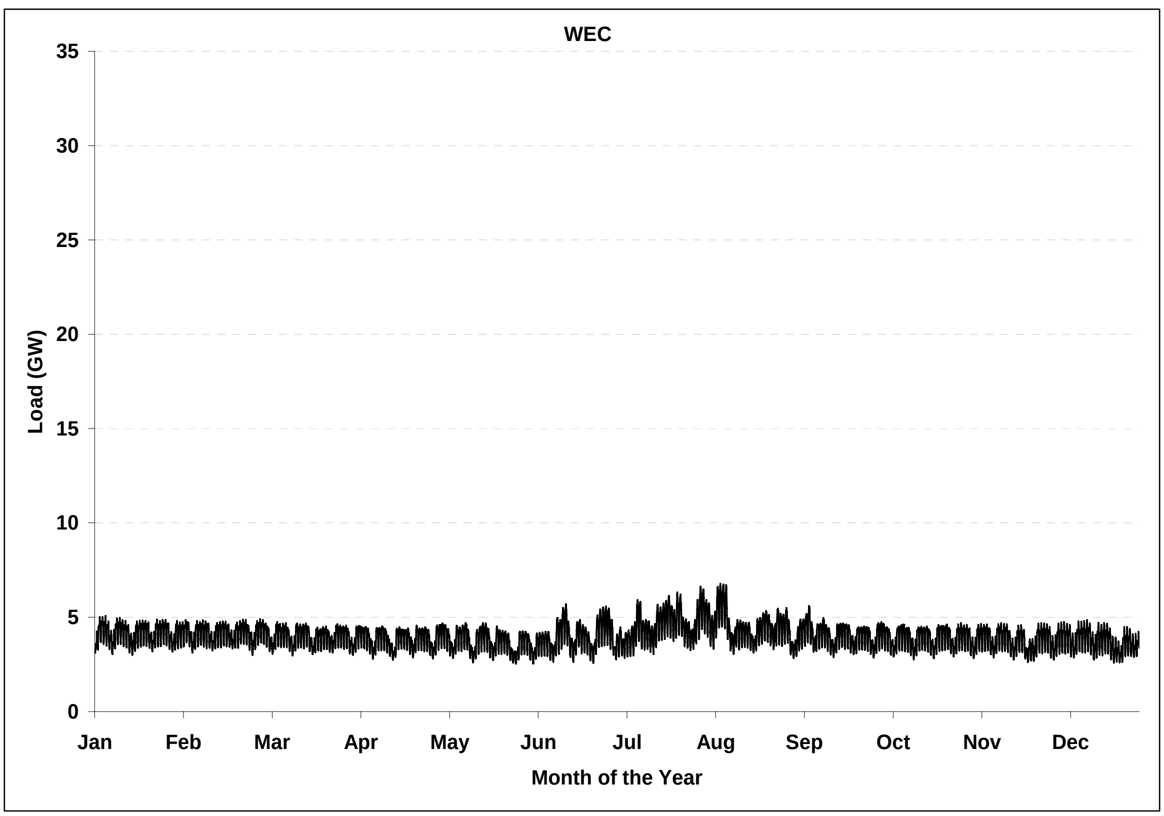

Figure D-46 WEC Load Curve

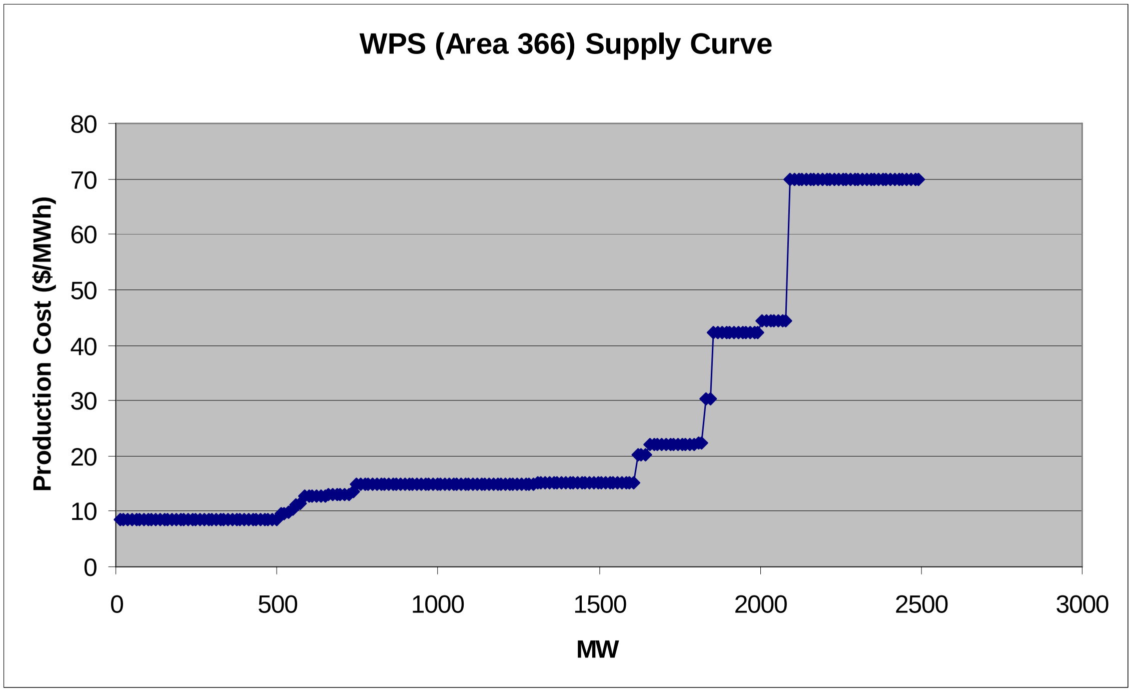

Figure D-47 WPS Generation Supply Curve

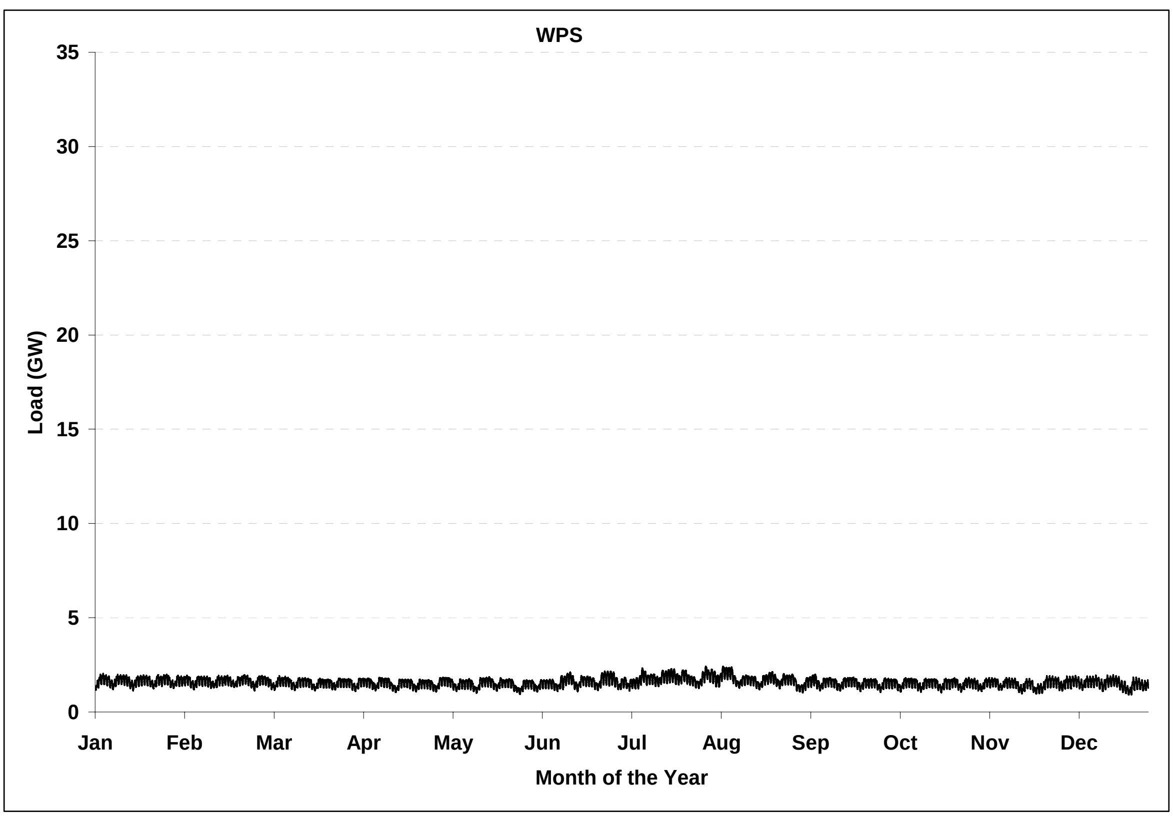

Figure D-48 WPS Load Curve

APPENDIX E
POWERWORLD® SUMMARY RESULTS

E.1 INTRODUCTION

E.1.1 PURPOSE OF THE STUDY

Despite the current adequacy of the generation and transmission system in Illinois, there is concern that the uncertainties of electricity restructuring warrant a more detailed analysis to determine if there might be pitfalls that have not been identified under current conditions. The problems experienced elsewhere in the country emphasizes the need for an evaluation of how Illinois might fare under a restructured electricity market.

The Illinois Commerce Commission (ICC) commissioned this study to be undertaken as a joint effort by the University of Illinois at Urbana-Champaign (UIUC) and Argonne National Laboratory to evaluate the Illinois situation in the 2007 period when restructuring is scheduled to be fully implemented in the State. The purpose of this study is to make an initial determination if the transmission system in Illinois and the surrounding region would be able to support a competitive electricity market, would allow for effective competition to keep prices in check, and would allow for new market participants to effectively compete for market share. The study seeks to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power in one or more portions of the State and thereby create undue pressure on the prices charged to customers and/or inhibit new market participants from entering the market. It should be noted that the intent of the study is not to predict whether or not such market power would be exercised by any company. Rather, it is designed to determine if a set of reasonably expected conditions could allow any company to do so.

It should also be emphasized that this study is not intended to be a comprehensive evaluation of the electric power system in the State. Rather, it is intended to identify some issues that may impact the effective functioning of a competitive market.

E.1.2 PURPOSE OF THIS APPENDIX

This purpose of this appendix is to provide supplemental information on the portion of this study performed by researchers at UIUC.

E.1.3 METHODOLOGY

The full study used two analytical tools in tandem: the Electricity Market Complex Adaptive Systems (EMCAS)©, developed by Argonne, and PowerWorld® Simulator. EMCAS is used to calculate the behavior of the agents participating in an electricity market. It focuses on the manner in which the market participants make decisions and on how they adapt their behavior to market changes and to their own success or failure in the marketplace. PowerWorld is used to calculate the detailed operation of the physical power system. It provides a detailed look at generator dispatching, transmission loading, and contingency conditions for the various behavior patterns of the market participants. The use of both models provides the ability to look at the details of the market and the details of the physical power system in an integrated fashion. This appendix focuses on the results obtained at UIUC with PowerWorld using a model of the Midwest electricity system jointly developed by Argonne and UIUC.

E.1.3.1 PowerWorld Model

PowerWorld Simulator is an interactive power system simulation package designed to simulate high-voltage power system operation on a time frame ranging from several minutes to many days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses (i.e., transmission network connection points) using either a detailed ac power flow model or a less detailed but much faster dc power flow model. Powerful visualization techniques are used on an interactive basis, resulting in an intuitive and easy-to-use graphical user interface (GUI). The GUI includes animated one-line diagrams with support for panning, zooming, and conditional display of objects.

One of the add-ons available with Simulator is the security constrained optimal power flow (SCOPF). The advantage of having an SCOPF embedded into Simulator is that it is now possible to optimally dispatch the generation in an area or group of areas while *simultaneously* enforcing the transmission line and interface limits, both for the base case and for a set of contingencies. Simulator SCOPF can then calculate the marginal price to supply electricity to a bus (also known as the locational marginal price, or LMP), taking into account transmission system congestion. The advantage with Simulator is that these values are not just calculated; they can also be shown on a one-line diagram, on a contoured map, or exported to a spreadsheet. Simulator SCOPF was used to perform the power flow studies reported here.

E.1.3.2 UIUC Methodology

The overall methodology used in this study was to perform time-domain simulations (with a step size of one hour) of the anticipated 2007 Illinois region electricity market, using varying assumptions on the behavior of market participants. The UIUC portion of the study focused on doing the hourly SCOPF solutions using PowerWorld Simulator. Results from this portion of the study provide detailed information about the behavior of the power network, including power flow patterns, locations of congestion, and bus LMPs. In order to perform the simulations in a timely fashion, a dc power flow model was used for all the results presented in this report.

E.2 SCOPF MODEL

The key information needed for the hourly SCOPF analysis are: (1) the transmission network configuration including the electrical characteristics of the attached generators and loads, (2) the set of contingencies, (3) cost information for all the generators in the system, and (4) hourly changes to the system including variation in the load and the assumed on-line generators.

E.2.1 TRANSMISSION NETWORK CONFIGURATION (POWER FLOW MODEL)

The transmission network configuration was constructed from the 2003 summer peak power flow case prepared by the North American Electric Reliability Council (NERC) in November 2002, supplemented by slightly more up-to-date models provided by the Illinois utilities. The NERC model covered the entire North American Eastern Interconnect, a region stretching from the Atlantic to the Rockies (almost). Since the focus area of this study was the Midwest in general and Illinois in particular, this original 42,700-bus, 6,800-generator, 57,000-line/transformer NERC case modeled was equivalenced to reduce its size.

Determining the amount of detail to explicitly retain in an equivalent is a judgment call. Retaining more buses results in a potentially more accurate model (provided one has detailed cost information for the vast majority of the retained generators!) but the model takes longer to solve. Eliminating more buses results in improved solution times, but with a potential loss of accuracy. Given the study's focus on Illinois, all of the electric devices within Illinois were retained. Then, in order to provide a sufficiently large market for the Illinois generators and load yet one that was still manageable from a computational and data gathering viewpoint, the system was reduced to one covering the region roughly bounded by Minnesota, Missouri, Tennessee, Ohio, and Michigan.

Overall, the equivalent had 12,925 buses, 1,790 generators, and 17,647 lines and transformers. The total generation capacity was reduced from about 780 GW in the original NERC case to about 216 GW. While the reduced case had only about one-quarter the generation capacity of the original case, it still contained more than four times the total Illinois generation capacity (171 GW out-of-state and 45 GW in-state). Hence, the reduced case provided the desired "large" generation and load market. The breakdown of the 12,925 buses by NERC region was 2,207 in SERC, 4,052 in ECAR, 1,929 in MAPP, and 4,737 in MAIN (1,847 in-state and 2,890 out-of-state). During the study, the limits on all in-state transmission lines were enforced, but limits were only enforced for out-of-state lines with nominal voltage levels above 200 kV. This allowed direct consideration of the major transmission constraints on Illinois power imports/exports. Figure E.2-1 shows a one-line of the Illinois portion of this model, while Table E.2-1 shows a breakdown of the out-of-state generation and load.

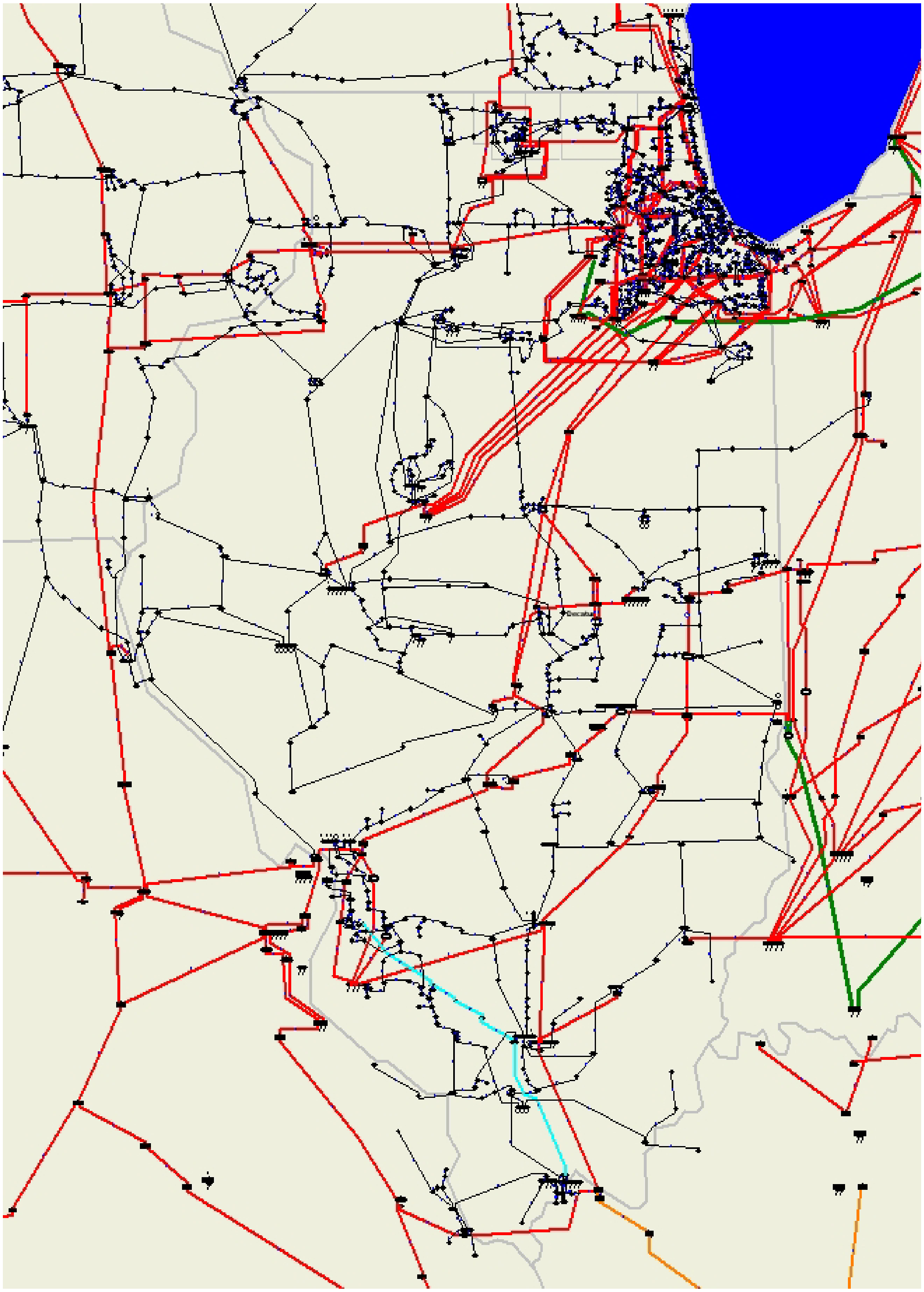

Figure E.2-1 Detailed PowerWorld Simulator One-line of Illinois Transmission, along with High Voltage Transmission in Other States

Table E.2-1 Out-of-State Generation and Load Modeled in PowerWorld Simulator

Control Area	Load (MW)	Generation Capacity by Fuel Type (MW)				
		Coal	Nuclear	Gas	Hydro/ Pumped	Other or Unknown
AECI (SERC)	4,415	2,412	0	1,614	58	249
TVA (SERC)	30,435	16,256	5,902	7,363	6,581	560
DOE (SERC0	500	0	0	0	0	0
AEP (ECAR)	23,094	21,300	2,060	6,455	731	292
OVEC (ECAR)	2,251	2,251	0	0	0	0
HE (ECAR)	1,250	1,250	0	240	0	50
CIN (ECAR)	11,775	10,171	0	1,831	75	1,220
DPL (ECAR)	3,437	3,305	0	1,410	0	0
SIGE (ECAR)	1,647	1,647	0	309	0	135
LGEE (ECAR)	7,314	5,928	0	796	71	1,259
BREC (ECAR)	1,558	1,709	0	0	0	65
IPL (ECAR)	2,971	2,664	0	742	0	100
NIPS (ECAR)	3,244	2,684	0	890	0	375
CONS (ECAR)	9,407	3,372	774	5,887	1,872	1,999
Other (ECAR)	0	0	0	1,776	0	0
ALTW (MAIN)	3,454	2,100	590	499	0	1,049
AMRN-NonIL	7,639	5,672	1,194	1,050	808	371
ALTE (MAIN)	2,505	2,034	0	1,136	26	264
WEC (MAIN)	6,792	3,640	1,012	1,032	143	868
WPS (MAIN)	2,486	1,019	500	432	131	414
Other (MAIN)	1,157	251	0	244	30	348
NSP (MAPP)	9,367	4,110	1,716	1,059	254	1,883
MEC (MAPP)	4,802	3,799	0	1,700	0	450
Other (MAPP)	939	1,257	0	84	21	60
Total	**142,439**	**98,831**	**13,748**	**36,549**	**10,801**	**12,011**

E.2.2 CONTINGENCIES

Secure power system operation requires that the system be operated both with no base case limit violations and also with no violations under a specified set of contingent conditions. Individual contingencies usually consist of the loss of one or more transmission lines/transformers or generators. When the operation of the power system is constrained due to transmission limitations, it is practically always constrained by contingent (as opposed to base case) violations. Hence, determining which contingencies to include in a study is vitally important. In this study, the impacts of 1,360 different contingencies were considered. While many of the contingencies consisted of single-line or transformer outages, others consisted of multiple-device outages (with the most complex contingency having 18 different actions). This set of 1,360 was developed using two sources. First, the in-state contingencies were developed from the list of contingencies provided by Illinois utilities. Second, the out-of-state contingencies consisted of single transmission line/transformer outages on key devices located electrically close to Illinois. Table E.2.2 shows a breakdown of the contingencies by company. During the study, contingent line flows were enforced using the power flow case "B" limit set (as indicated by the Illinois utilities). This was done using PowerWorld Simulator's security constrained optimal power flow (SCOPF).

Table E.2-2 Contingencies by Company

Company	Number of Contingencies
Ameren	266
Central Illinois Light Company (CILCO)	38
Commonwealth Edison (ComEd)	450
ECAR (Total)	196
Electric Energy Inc. (EEI)	35
Illinois Power	120
MAIN (other)	129
MAPP (Total)	86
SERC (Total)	10
Southern Illinois Power Co-operative (SIPC)	12
Springfield City Water Light & Power (CWLP)	18

E.2.3 GENERATOR COST INFORMATION

The electrical characteristics for all the generators in the study were contained within the original NERC power flow case. These characteristics included the location of the generator on the grid and its minimum/maximum generation capacity. However, power flow cases do not include cost information for the generators, since this information tends to be viewed as more proprietary. But to perform this study, such cost information was crucial, with the necessary data including generator heat-rate, fuel type, variable O&M costs, and fixed-cost information. The initial model used here for the marginal generation costs was heat rate (MBtu/MWh) multiplied by fuel cost ($/Mbtu) plus variable O&M cost ($/MWh). For the in-state generation, all model information was provided by Argonne. For the out-of-state generation, this information was determined by UIUC using a variety of sources. The assumed fuel costs for both the in-state and out-of-state generators were provided by Argonne using DOE Energy Information Administration (EIA) data grouped by census region.

E.2.4 HOURLY SYSTEM VARIATIONS

The UIUC portion of the study consisted of doing hourly SCOPF simulations for year 2007 conditions. The hourly variation in the electric load was as provided by Argonne, with the same scaling values used for the in-state and out-of-state load. For the generator variation, all generators were assumed to be available at all times, unless they were explicitly outaged or derated. For the in-state generation, the studies were done using a generator outage schedule provided by Argonne. The purpose of this schedule was to model the planned and forced outages of individual generators that occur in actual system operation. For the out-of-state generation, the maximum real power capacities of the generators were derated to represent planned and forced outages; individual generator outages were not modeled for the out-of-state generators. The assumed derate values varied by month, representing the fact that most planned outages occur during the spring and fall when the electric loads are lower.

E.3 SCOPF RESULTS

In order to identify potential congestion regions for 2007, the full 12,925-bus, 1360-contingency model was solved using the PowerWorld SCOPF for all 8,760 hours in year 2007. The inputs to the model were essentially identical to those used in EMCAS, with the important exception that the SCOPF simulated a much larger network, and included the contingency constraints.

The hourly simulation approach, coupled with the scheduled and forced generator outages discussed in Section E.2.4, examined a wide variety of different system operating conditions. This wide variety of operating points caused a large number of constraints (i.e., contingency and line/transformer pairs) to become binding for different hours. This helped to identify the set of constraints that could be used by generators to exploit market power. However, such a detailed approach also generated a tremendous amount of data. For example, a full-year study creates over 100 million LMPs (i.e., LMPs at each of the 12,925 buses for every hour of the year) and over 50,000 binding constraint-hours. Effectively summarizing these results has been a significant challenge. This section (Appendix E) attempts to provide such a summary, with more detailed results contained in Appendix F.

E.3.1 RESULTS OVERVIEW

The initial 2007 run modeled a market in which all generators submitted bids equal to their actual production cost, that is (using the model from Section E.2.3), heat rate multiplied by fuel cost plus variable O&M cost. Table E.3.1 summaries the monthly results of this run, with the second column showing the monthly load, the third column showing the generation, the fourth showing the net exports for the month, and the last showing the average LMP (in \$/MWh). Table E.3.2 shows a breakdown of the quarterly exports between Illinois and the rest of the model by direction, with the North direction, the net flow on the tie-lines with Wisconsin; East, the net flow on the tie-lines with Indiana (ECAR); South, the tie-lines with Kentucky (TVA); and West, the tie-lines with Iowa and Missouri.

Table E.3-1 Initial In-State Load, Generation, and Exports

Month	Load (GWh)	Gen. (GWh)	Exports (GWh)	Avg LMP $/MWh
January	13,588	13,541	–50	15.26
February	12,028	11,665	–365	14.57
March	12,442	12,202	–242	15.14
April	11,206	10,212	–995	15.14
May	12,062	11,406	–657	14.64
June	13,550	12,611	–941	16.21
July	15,740	15,310	–432	17.84
August	15,628	15,381	–247	18.30
September	12,155	11,586	–570	14.83
October	11,749	11,051	–699	14.95
November	11,233	10,620	–614	14.60
December	12,647	12,345	–304	14.20

Table E.3-2 Initial Exports by Quarter and Direction

Qtr.	Total (GWh)	North (GWh)	East (GWh)	South (GWh)	West (GWh)
1st	–657	1,331	–1,465	2,117	–2,640
2nd	–2,592	1,101	–2,229	1,978	–3,442
3rd	–1,249	1,992	–3,756	2,122	–1,607
4th	–1,617	1,406	–1,447	1,841	–3,417

The tables show Illinois as a net importer of electricity, a result contradicted by historical data for most recent years. However, it must be pointed out that the results are quite sensitive to the cost models used for both the in-state and the out-of-state generation. Small changes in the assumed generator cost characteristics can substantially alter the net Illinois interchange.

There appear to be several reasons for this interchange discrepancy. First, because of the scope of the study, detailed cost models were only developed for in-state generation. While significant time was spent determining the unit type and fuel type for the over 1400 out-of-state generators, the model parameters were not researched as extensively as for the in-state generators. In particular, the variable O&M costs are probably not as accurate, with the average values for the out-of-state coal units about $1/MWh less than those in-state. While this value may seem small, upping these variable O&M costs would substantially alter the interchange patterns. Second, the breakdown of the EIA fuel prices by census division resulted in the modeled prices of coal and natural gas for units immediately to the west of the Mississippi river (within the West North Central Census Division) to be substantially lower than the price in Illinois (within the East North Central Census Division). This is the primary reason for the heavy imports from the West shown in Table E.3-2, and for the low LMPs in Table E.3.3 for areas AMRN, NSP, MPW, MEC, and DPC. Third, while the 12,925 bus model contained a significant portion of the Midwest electric grid, it did not include PJM and areas further to the East, areas that tend to have higher costs than the Midwest and tend to be net importers from Illinois. Hence the impact of exports to these areas was not included in the study, somewhat skewing the results.

Table E.3-3 Initial Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
130	AECI	SERC	16.01	600
147	TVA	SERC	16.26	–4,165
148	DOE	SERC	14.52	–325
205	AEP	ECAR	15.68	2,162
206	OVEC	ECAR	15.57	1,776
207	HE	ECAR	15.52	306
208	CIN	ECAR	15.52	950
209	DPL	ECAR	15.63	415
210	SIGE	ECAR	15.30	414
211	LGEE	ECAR	15.56	708
214	BREC	ECAR	15.19	32
216	IPL	ECAR	15.37	203

Table E.3-3 Initial Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
217	NIPS	ECAR	15.59	–541
218	CONS	ECAR	15.70	–3,589
221	AEWC	ECAR	15.23	–1
222	AEWI	ECAR	15.28	–1
223	DEVI	ECAR	15.28	0
224	DEWO	ECAR	15.66	36
331	ALTW	MAIN	14.19	–424
355	CWLD	MAIN	14.70	–175
356	AMRN	MAIN	14.74	1,279
357	IP	MAIN	15.02	–162
359	CILC	MAIN	15.84	–414
360	CWLP	MAIN	15.23	–199
361	SIPC	MAIN	14.78	–144
362	EEI	MAIN	14.15	846
363	NI	MAIN	15.73	73
364	ALTE	MAIN	16.76	94
365	WEC	MAIN	16.44	–885
366	WPS	MAIN	17.29	–249
367	MGE	MAIN	16.30	–319
368	UPPC	MAIN	16.64	–51
600	NSP	MAPP	13.01	1,189
633	MPW	MAPP	14.65	49
635	MEC	MAPP	14.28	523
680	DPC	MAPP	13.71	–14

In order to assess the impact of this interchange skew on the results, a second year 2007 case was run with the generator costs altered to increase the cost of the external generation. This was done by adding an allocation of each generator's annual fixed costs to its bids, with the allocation done such that the costs of the out-of-state generators were increased slightly relative to the in-state generation (the net change was about $1/MWh). Results from this modified study are shown in Tables E.3-4 to E.3-6. More detailed results for both cases are presented in Appendix F.

A comparison of Tables E.3-1 to E.3-3 with E.3-4 to E.3-6 indicates that with the allocation of the fixed costs, Illinois has changed from being a net importer (with an average import of about 700 MW) to being a net exporter (with an average export of about 1,844 MW). This rather dramatic change is actually not unexpected, since in the second case the costs of the out-of-state generators have been increased relative to the in-state generation. A comparison of Tables E.3.2 and E.3.5 indicates most of this change is due to a dramatic increase in the Illinois exports to the east. The reason: the original cost differentials between the costs in the east and Illinois were small, partly due to both being in the same census region, and hence having the same modeled fuel costs. Hence, even small changes in the relative costs could dramatically alter the interchange. Also, there are relatively few transmission limitations to the east.

Table E.3-4 Modified In-State Load, Generation, and Exports

Month	Load (GWh)	Gen. (GWh)	Exports (GWh)	Avg LMP $/MWh
January	13,588	15,264	1,675	17.79
February	12,028	13,575	1,547	17.23
March	12,442	13,935	1,493	17.65
April	11,206	11,713	507	17.56
May	12,062	13,511	1,449	17.28
June	13,550	14,704	1,154	18.82
July	15,740	16,878	1,138	20.54
August	15,628	16,976	1,348	21.03
September	12,155	13,825	1,670	17.53
October	11,749	12,609	860	17.39
November	11,233	12,370	1,137	17.14
December	12,647	14,825	2,178	16.84

Table E.3-5 Modified Exports by Quarter and Direction

Qtr.	Total (GWh)	North (GWh)	East (GWh)	South (GWh)	West (GWh)
1st	4,715	2,152	3,181	1,936	–2,554
2nd	3,110	2,228	2,176	1,979	–3,273
3rd	4,156	3,041	793	1,888	–1,566
4th	4,175	2,591	3,160	1,767	–3,343

Table E.3-6 Modified Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
130	AECI	SERC	18.01	562
147	TVA	SERC	18.44	–2,326
148	DOE	SERC	17.71	–321
205	AEP	ECAR	18.21	1,201
206	OVEC	ECAR	18.15	1,557
207	HE	ECAR	18.19	1,245
208	CIN	ECAR	18.16	462
209	DPL	ECAR	18.21	331
210	SIGE	ECAR	18.06	264
211	LGEE	ECAR	18.18	124
214	BREC	ECAR	18.07	-68
216	IPL	ECAR	18.05	154
217	NIPS	ECAR	18.20	–1,073
218	CONS	ECAR	18.25	–3,895
221	AEWC	ECAR	17.95	–1

Table E.3-6 Modified Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
222	AEWI	ECAR	17.98	–1
223	DEVI	ECAR	17.98	0
224	DEWO	ECAR	18.21	26
331	ALTW	MAIN	16.97	–466
355	CWLD	MAIN	17.31	–175
356	AMRN	MAIN	17.45	1,498
357	IP	MAIN	17.66	768
359	CILC	MAIN	18.42	101
360	CWLP	MAIN	17.74	–128
361	SIPC	MAIN	17.64	–141
362	EEI	MAIN	17.64	754
363	NI	MAIN	18.33	992
364	ALTE	MAIN	19.67	40
365	WEC	MAIN	19.17	–1,261
366	WPS	MAIN	20.03	–321
367	MGE	MAIN	19.26	–322
368	UPPC	MAIN	19.41	–51
600	NSP	MAPP	15.91	1,059
633	MPW	MAPP	17.46	57
635	MEC	MAPP	17.05	513
680	DPC	MAPP	16.60	–41

In contrast, the costs in the west were originally substantially lower than Illinois's, primarily due to a lower assumed cost for coal. Hence, a slight change in the assumed generator costs will have a lower impact. Also, transmission imports from the west are more constrained.

While the differences between the two cases may seem significant, the different assumptions on the generator costs actually had little impact on the focus of this study, that is, evaluating the impact transmission constraints would have on competitive electricity markets in Illinois. The reason is that, as previously stated, the hourly simulation approach placed the system in a wide variety of different operating conditions. Over the course of a day, the hourly interchanges would swing over a wide range, with power being imported for some hours and exported for others. This is illustrated in Figures F.1-1 to F.1-4 and F.2-1 to F.2-4 (in Appendix F), which plot the hourly Illinois interchange. While the average value is higher in the Appendix F.2 cases, the wide variation means that essentially the same constraints are binding in both cases, albeit perhaps for a different number of hours. The impact of transmission constraints on the Illinois electricity market is discussed in the next section.

E.3.2 ILLINOIS TRANSMISSION SYSTEM CONSTRAINTS

Constraints are the cause of LMP variation. Without constraints, all of the LMPs in the system would be identical, with their values set each time period by the cost of the single marginal generator. Power would flow freely from any generator in the system to any load. Of course, for a real power market, such a situation seldom, if ever, occurs. The operation of the grid is constrained by the need to avoid overloading any device under either base case conditions or during one of the contingencies. Therefore, to identify potential congestion regions, the impact of the individual constraints needs to be considered.

Tables F.1-1 and F.2-1 in Appendix F list the different binding device/contingency pairs in the two studies under consideration here, including both in-state and out-of-state constraints. As was mentioned earlier, devices practically always bind for contingencies, as opposed to base case conditions. For the first case (Appendix F.1 results), there were 240 different binding device/contingency pairs, with a total of 50,844 binding device-hours for the year, or an average of about 6 per hour. Table F.1-1 lists just the 104 device-contingency pairs that were binding for 25 or more hours for the year, along with the average and maximum marginal costs (in $/MWh) of enforcing these constraints. For the second case (Appendix F.2 results), there were 206 different binding device/contingency pairs, with a total of 38,605 binding device-hours for the year, or an average of about 4.4 per hour. Table F.2-1 lists just the 88 device-contingency pairs that were binding for 25 or more hours for the year.

However, in accessing the potential for congestion to segment the Illinois electricity market, it is actually better to focus on the variation in the bus LMPs rather than on the constraints themselves. As was mentioned earlier, the variation in the LMPs is caused by the constraints. But the determination of how a particular constraint affects the bus LMPs is actually rather complicated. One of the beauties of an LMP-based market is that end users do not (usually) need to worry about the details of how a particular LMP is determined. Rather, they can just respond to the result. The remainder of this section focuses on market segmentation caused by the constraints, with the individual constraints discussed only when necessary to understand the reason for the market segmentation.

Before moving on, it is important to briefly discuss one somewhat unique characteristic of the Illinois market – the presence of ten phase-shifting transformers in the ComEd control area. Usually, the flow of power through transmission lines and transformers can only be indirectly controlled by changing the real power outputs of the generator. Indeed, LMP price variations arise because at least some generation needs to be dispatched in a non-economic manner to avoid overloading the transmission systems. With few exceptions, the flow of power through a transmission line or transformer cannot be directly controlled. Phase-shifting transformers, however, are one of those exceptions (others include HVDC transmission lines, which are not present in Illinois). By controlling the phase angle of a phase-shifting transformer, the flow of power can be directly controlled. Such control is routinely done by ComEd to avoid overloading transmission lines in the City of Chicago. The impact of this phase-shifter control was included in the PowerWorld Simulator software used for this project, with the result being that there was very little congestion seen in the City of Chicago. If the impact of the phase shifters had not been considered, one would have expected substantial congestion, with a pronounced increase in the LMPs in northeast Illinois (Lake and northern Cook Counties).

E.3.3 ILLINOIS TRANSMISSION SYSTEM CONGESTION REGIONS

This section details the regions of Illinois in which the LMPs are unusually high. The challenge in doing this assessment has been to make sense out of the many millions of LMPs generated by the computer runs done for this study. Figures F.1-5 to F.1-16 and F.2-5 to F.2-16 in Appendix F show the hourly variation (by month) of the average bus LMPs for the various utilities in Illinois. The figures indicate several general characteristics about the LMPs. First, the LMPs for all areas tend to increase during high-load periods (e.g., daytime during the summer) and decrease during times of low load. Because the generators are submitting bids equal to their marginal costs, the lowest LMP values tend to be fairly constant, with the value dictated by the costs for the base-load units. Second, for many hours, the changes in at least the average LMPs tend to be fairly uniform between the various utilities. That is, for many hours they have the same average LMP. However, the last characteristic is that there are some hours in which the average LMPs diverge quite significantly, particularly for Ameren-CILCO (CILCO), even under non-peak conditions. Also, periods of high prices in one area can result in low prices in another (e.g., March 2007, with several days of high prices in CILCO and low prices in CWLP). These deviations in the average prices are caused by transmission system constraints, which may be aggravated by planned or unplanned generator outages. However, while useful, just looking at the variation in the average LMPs across an entire control area can mask the effects of more localized congestion. To highlight the impacts of this congestion, we need to look at metrics derived from the individual bus LMPs.

There are a number of different metrics that could be used to highlight these regions of localized congestion. For example, Figures 17 to 28 in Appendix F show bus contour plots for each quarter in 2007 of the average LMP, the highest bus LMP, and the number of times the LMPs exceed a specified threshold (either \$30/MWh or \$40/MWh). The average LMP has the advantage of giving an overall feel for the price a consumer would pay at a particular bus, but has the disadvantage of masking significant variations in the price, particularly if a given bus's LMP is greater than average during times of high load and less than average during times of low load. Contouring the highest LMP for a time period (quarterly, in the figures) has the advantage of clearly showing the maximum price that occurred at each location. But the disadvantage is that information about the duration of the high prices is lost. Contouring the number of hours a given point is above a threshold combines some of the advantages of both, but at the expense of not showing the impact of very high but short-duration prices.

A complementary approach is to count the number of times a bus LMP is greater than the state-wide average by a specified percentage (10% here), and then to calculate the cumulative \$/MWh by which it exceeds this threshold. The results of such a ranking are given in Tables F.1-2 and F.2-2 in Appendix F, with the top 100 buses with the highest cumulative \$/MWh shown. For example, the first entry in Table F.1-2, bus 33002 (RS WALL) had an LMP greater than 110% of the hourly state-wide average for 298 hours (out of 8,640) with a cumulative \$/MWh value of 11,739. This means on average its LMP exceeded 110% of the average by 11,739/298 = $39.4/MWh. Figures E.3-1 and E.3-2 below show contours of this metric for all the buses in the State, with more detailed figures shown in Appendix F (Figures F.2-30 to F.2-33). A comparison of Tables F.1-2 and F.2-2, along with Figures E.3-1 and E.3-2, indicates that the regions of congestion in the State are fairly constant. For example, about 80% of the Table F.1-2 entries also appear in Table F.2-2, albeit with different values. The remainder of this section provides a detailed look at each one of these in-state congestion zones, along with a discussion of how congestion in the zone could be used by the generation companies to increase profits.

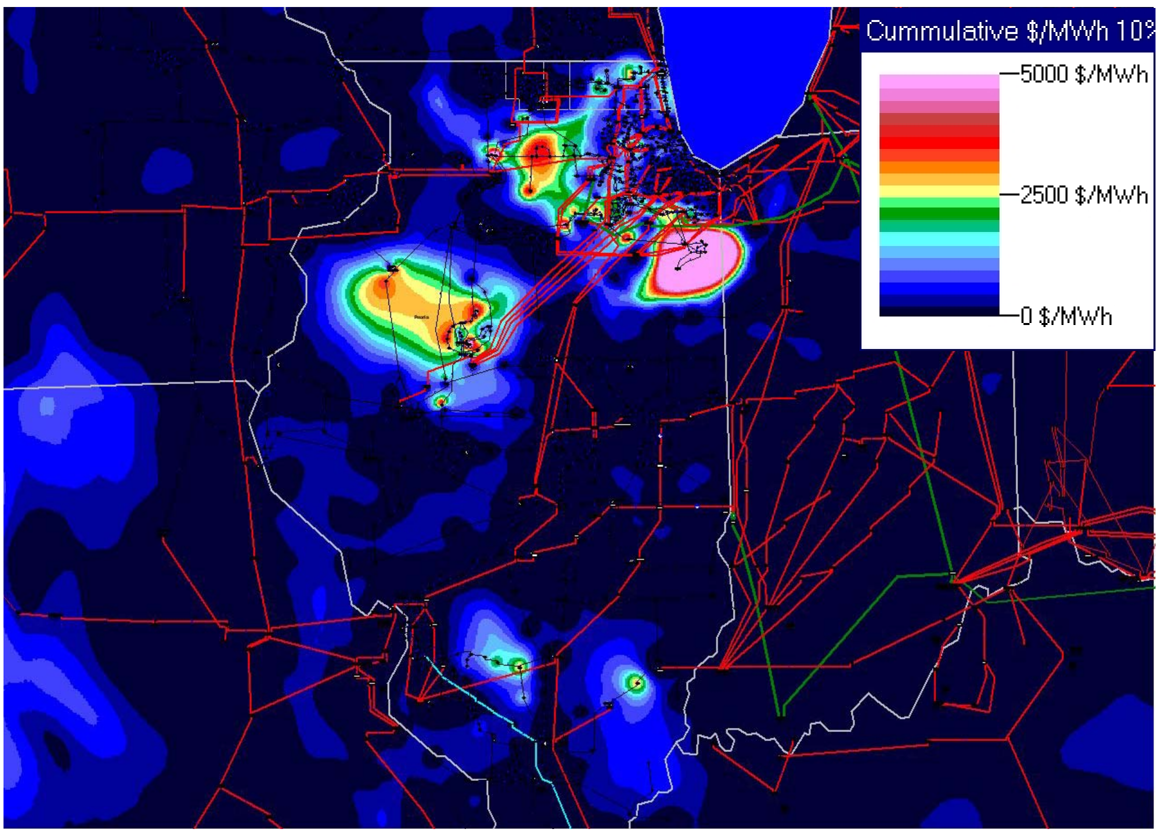

Figure E.3-1 Cumulative $/MWh 10% above Average for the Appendix F.1 Case

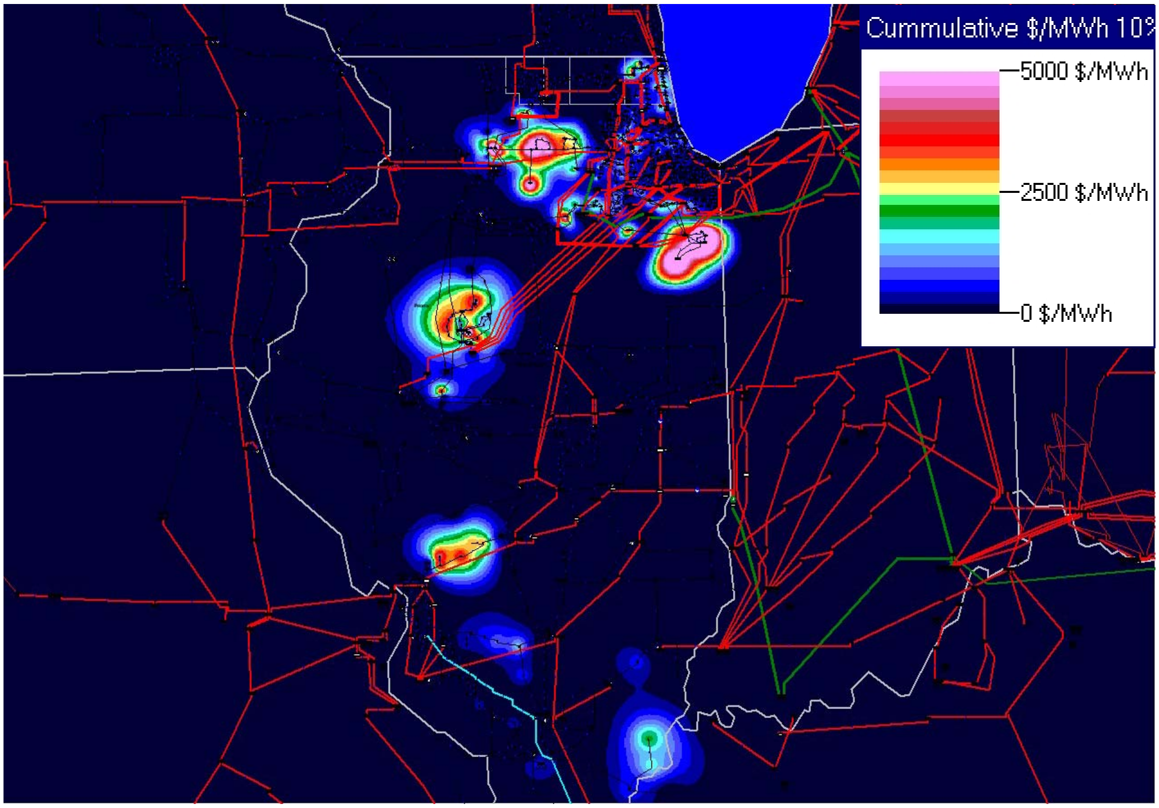

Figure E.3-2 Cumulative $/MWh 10% above Average for the Appendix F.2 Case

E.3.3.1 Peoria Congestion Region

The most significant congestion region occurred in the CILCO control area for both the Appendix F.1 and F.2 cases, with the values slightly higher in the latter. The presence of this congestion region is most evident in the control area average LMP plots for February, March, June, July, August, and November. The region also appears prominently in the highest LMP color contours for each quarter. As shown in Tables F.1-2 and F.2-2, the highest LMPs occur at the RS Wall and Edwards1 69-kV buses, followed closely by the Peoria and Pekin 138-kV buses. The complete extent of this region is shown visually in Figures F.1-31 and F.2-31.

These high LMPs are essentially due to SCOPF binding constraints on just two devices, the Holland-Mason 138-kV line (which is binding more than 80% of the time; these buses have high LMPs) and the RS Wall 138/69-kV transformer #1. The Holland-Mason 138-kV line binds for flow north from Holland to Mason (and on to Tazewell) for either the CIL-6 contingency (loss of Duck Creek-Tazewell 345 kV) or the ComEd 345-L0304_R-S contingency (loss of Tazewell-Powerton 345 kV). The RS Wall 138/69-kV transformer is binding for base case problems (due to it having a 90 MVA base case and 150 MVA contingency limit) with the flow always from the 138-kV to 69-kV buses.

The presence of above average LMPs at these buses also has good correlation with generator outages in the area. For example, for the Appendix F.1 case of the 298 hours during which the RS Wall 69-kV bus has high LMPs, 220 hours are associated with an outage of the Edwards #2 generator, 114 hours are associated with an outage of Edwards #3, 175 hours are associated with an outage of the Dresden #2 generator, and 157 hours with Quad City #2. In additional, several other ComEd generators have associates of more than 80 hours. Clearly, a localized congestion region is possible during times of generator outages either at Edwards or at electrically close ComEd generators.

The degree to which generators in the CILCO area could take advantage of this congestion to profitably increase the bus LMPs depends, of course, upon the particular system conditions, such as the load level, and which generators and/or lines are out of service. To provide more generic results, a case with load equal to 90% of system peak and no generator outages was studied using the Appendix F.2 cost characteristics. The system load should be at or above 90% of peak for about 80 hours per year.

The main generator within the congestion region is Edwards, a relatively low-cost coal plant with a total capacity of about 600 MW. To assess the ability of Edwards to profitably manipulate prices, its bids were scaled from initially being equal to its actual marginal cost (as was assumed in the Appendix F.1 and F.2 cases), to being equal to a scalar multiplier by its marginal cost. The results are shown in Table E.3-7, with the second column showing the total CILCO generation, the third column showing the relative profit (with unity corresponding to a marginal cost bid), while the last two columns show the average and maximum LMP for the CILCO area. Small increases in the Edwards bids have no impact on prices, since Edwards is initially dispatched at full capacity with bus LMPs above its marginal costs. When the bid scaling is 2.0, the share of the Edwards generation drops off, decreasing profit slightly. Then for higher bids, a situation is reached in which some Edwards generation needs to run, regardless of price. Once this point is reached, additional increases in the Edwards bids result in increased profits. For example, when the bid multiplier is 4.0, the total CILCO profits are 1.32 the initial profits. The minimum Edwards generation for the assumed 90% system load is 170 MW, with the binding constraint being the Holland-Mason 138-kV line. Hence we could conclude that under heavy system loading, even with all generators in-service, the Edwards generator has localized market power.

Table E.3-7 Variation in CILCO Profit Modified Edwards Bids (Base Case)

Edwards Bid Multiplier	Total CILCO Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	1,106	1.000	27.25	27.57
1.5	1,106	1.000	27.26	27.57
2.0	777	0.952	31.23	39.67
2.5	583	0.964	37.44	58.52
3.0	579	1.136	44.42	70.24
3.5	578	1.226	50.86	76.97
4.0	578	1.320	56.46	83.22

However, this binding constraint is currently in the process of being upgraded, with the changes affecting the entire Tazwell-Holland-Mason-East Springfield 138-kV line. The study results reported here were done using the original limits. Also, during the process of doing this analysis, it was noticed that the 138-kV ties between CILCO and IP at Richland (north side of CILCO) were modeled as being normally open in the base case. Subsequent checking indicates that these two lines should be modeled as closed. If these two changes are considered (with the most significant being the line upgrade), the Table E.3-7 results change substantially, with the new values given in Table E.3-8. The Edwards generator still has market power, but with its required generation decreased from 170 MW to 120 MW, requiring that its bid be about 6 times marginal cost for an increased profit. The binding constraint is now the Tazwell-East Peoria 138-kV line.

Table E.3-8 Variation in CILCO Profit Modified Edwards Bids with Upgraded Tazwell to East Springfield 138 kV Line

Edwards Bid Multiplier	Total CILCO Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	1,106	1.000	27.20	27.56
1.5	1,106	1.000	27.20	27.56
2.0	529	0.538	31.90	38.01
2.5	527	0.609	36.64	55.02
3.0	524	0.642	42.32	72.13
3.5	529	0.683	41.00	72.75
4.0	529	0.780	41.30	85.30
5.0	532	0.918	43.94	110.38
6.0	532	1.094	47.75	135.47

E.3.3.2 Kankakee Area Congestion Region

The second most significant congestion region occurs in the Kankakee area (ComEd operating area), with the most significant buses in the pocket listed in the second to twelfth entries in Table F.1-2, as well as the Wilmington 138 kV bus, and to a lesser extent the red Dresden 138-kV bus. This congestion region also is shown visually in Figures E.3-1, E.3-2, and in the bottom right of Figures F.1-32 and F.2-32. These high LMPs are due to an SCOPF binding constraint on the blue Davis Creek 345/138-kV transformer for the ComEd 345-L17704_R-S contingency (loss of the red Davis Creek transformer and several other devices). These high LMPs mostly occur on high-load days. The total peak load in this region is between 300 and 400 MW.

The higher marginal costs in the Kankakee area arise from needing to do a constrained dispatch to avoid the contingent overload of the 345/138-kV transformer at Davis Creek. For the 90% of peak case mentioned earlier, this constrained dispatch involves using the University Park natural gas turbine generators owned by Constellation Power. University Park has a total of six 50-MW turbines. For this case, the highest LMP in the Kankakee region is $54.18/MWh. Since the University Park generators are “marginal units,” changes to their bids will directly affect the bus LMPs, with the potential that such changes could increase Constellation’s total Illinois profit. The results of this analysis, which are shown in Table E.3-9, indicate that increases in the bids for the University Park generators could indeed increase Constellation’s profit, with the tradeoff again between lower market share and higher prices. If the bids were increased to the profit maximizing value of 1.7 times marginal cost (assumed here to be $35.26/MWh), the highest LMP in the Kankakee region almost triples to $147.66/MWh.

Table E.3-9 Variation in Constellation Power Profit for Modified University Park Bids

University Park Bid Multiplier	Total University Park Gen. (MW)	University Park LMP	Relative Profit
1.0	104	35.26	1.000
1.1	103	38.79	1.128
1.2	45	42.31	1.193
1.3	42	45.83	1.171
1.4	42	49.35	1.204
1.5	33	52.89	1.192
1.6	29	56.42	1.201
1.7	29	59.94	1.232
1.8	0	63.22	1.008

E.3.3.3 Dixon Area Congestion Region

The next most significant congestion region appears in the vicinity of the ComEd Dixon 138-kV bus extending to the east to include Mendota and Steward. This congestion region is shown visually in the upper center of Figures E.3-1 and E.3-2, and in more detail in the left center of Figures F.1-32 and F.2-32 in Appendix F. The high prices at these buses are often caused by a binding constraint on one of the 138-kV lines going from Nelson to Dixon. These lines bind for the ComEd 138-L15507_B-R contingency (loss of the blue Nelson to Dixon 138-kV line) and the 138-L15508_B-R contingency (loss of the Nelson red 138 kV bus) (essentially the loss of the parallel line). These high LMPs mostly occur on high-load days, particularly with generator outages in the Rockford area.

There are no generators in the direct area of the constraint, so exploiting this constraint to maximize generation profit seems unlikely unless there is an outage of a large generator, such as one of the Byron units. Then the NRG units at Rockford may be able to increase their profit by submitting bids above marginal cost. For example, in the 90% of peak case with one of the Byron units outaged (and all other units in-service), if the NRG Rockford units bid 20% above marginal cost, their dispatch falls from 421 to 147 MW, but their profit increases by about 13%. Bidding 40% above marginal cost results in a 0 MW dispatch.

E.3.3.4 Mazon Area Congestion Region

The next congestion region appears in the vicinity of the ComEd Mazon 138-kV bus, extending towards the J-375, J-371, and J-339 buses. This congestion region is best seen visually on Figures F.1-32 and F.2-32 in Appendix F, to the southeast of the Dixon area. The high prices here are practically always caused by a binding constraint on the Oglesby-Mazon 138-kV line, with the binding constraint flow always going from Oglesby to Mazon. This constraint is usually caused by the ComEd 345-L15502_B-R contingency (loss of the Nelson-Electric Junction 345-kV line), with a significant minority caused by the ComEd 345-L2101-S contingency (loss of a Brokaw 345-kV bus – also IP contingency IP108). The LMPs at Mazon are more than 10% above the state-wide average for more than 700 hours in the year, although usually they are not significantly above the average. A wide variety of generators are capable of helping to mitigate this constrain, so it is unlikely to be exploited for profit maximization.

E.3.3.5 Lombard Congestion Region

The next most severe congestion region appears for just 25 hours at the blue Lombard 138-kV bus and several surrounding blue buses (e.g., Glen Ellyn, Glendale, Nordic, Butte, Addison). The high LMPs are always caused by a binding constraint on the blue Lombard 345/138-kV transformer due to ComEd contingency 345-L12001_B-N (loss of the blue Itasca 345/138-kV transformer and the blue Lombard-Itasca 345-kV line). This constraint is only binding at the times of highest loading.

The most sensitive generators for controlling the flow on the constrained transformer, and hence with the best potential for inducing or enhancing the congestion, are all owned by Midwest Generation. The generating plants are Will County Unit 4, Joliet Unit 9, Crawford 7 and 8, Fisk 9, and Waukegan 6 and 8. Analysis of the 90% load case indicates that no single generator, or group of two or three generators, can benefit from this congestion (however, see Section E.3.4.2 for a discussion of a more company-wide strategy for Midwest Generation).

E.3.3.6 Galesburg Congestion Region

The LMPs at the Galesburg 138-kV bus and several surrounding buses are more than 10% above the state-wide average for about 1,700 hours in the Appendix F.1 case; they are much less problematic in the Appendix F.2 case. This congestion zone is shown visually in Figure E.3-1 and Figures F.1-30 and F.1-31. These high prices are caused by a binding constraint on the Galesburg 161/138-kV transformers (there are two, each with a rating of 100 MVA), with the flow direction always from the 161-kV to the 138-kV. Most of the time, these transformers are binding for ComEd contingency 345-L15502_B-R (loss of the Nelson-Electric Junction 345-kV line), but they are sometimes binding for contingency L0304-A (loss of the Tazewell-Powerton 345-kV line and the Tazewell-Mason 138-kV line), or contingency 345-L0404_R (loss of the Quad City-H471 [NW Steel] 345-kV line). This constraint occurs when there are high imports from Iowa. Since there is little generation in the immediate vicinity of the constrained buses, it is unlikely that this constraint could be exploited for profit maximization.

E.3.3.7 Wilson/Round Lake/Antioch Congestion Region

The next congestion zone is associated with the red 138-kV buses at Wilson, Round Lake, Antioch, and, to a lesser extent, Gurnee. It is shown visually in Figures E.3-1 and E.3-2 in the far northeast part of the State, and in more detail in Figures F.1-32 and F.2.32. These high prices are always caused by a binding constraint on the Marengo-Pleasant Valley 138-kV line (with flow from Marengo to Pleasant Valley) for the ComEd 345-L15616-R contingency (loss of the Cherry Valley-Silver Lake 345-kV line).

The generators with the most sensitivity for controlling this constraint (on the constrained side) are Rocky Road owned by Dynegy, Elgin owned by Ameren-UE, Waukegan owned by

Midwest Generation, and Aurora owned by Reliant. Given the diversity of ownership, it is unlikely that this constraint could be exploited by a single company for profit maximization.

E.3.3.8 Gillespie Congestion Region

The Gillespie congestion zone, which is only significant for the Appendix F.2 case, is associated with the 138 kV buses at the Gillespie, N. Staunton, and to a lesser extent, the Litchfield substation. It is shown visually in Figures E.3-2 and F.2-33, immediately to the northeast of St. Louis. These high prices are always caused by a binding constraint on the N. Lac-Gillespie 138 kV line with the binding flow always from N. Lac to Gillespie. Most of the time (> 90%) this congestion is due to the Ameren AMRNMTL71A contingency (loss of the Coffeen-Roxford 345 kV line; this is also the IP95 contingency), with most of the other times due to the IP96 contingency (loss of the West Frankfort-Mt. Vernon 345 kV line).

This constraint tends to occur during lower load periods, when sensitive generators on the constrained side of the line are either on an outage, or not dispatched because of low system LMPs. These generators include Coffeen owned by Ameren-CIPS, the Holland Energy Center owned by Constellation Power, and Kincaid owned by Dominion Energy. Given the diversity of ownership, and the associated low load conditions, it is unlikely that this constraint could by exploited by a single company for profit maximization.

E.3.3.9 Northbrook Congestion Region

The Northbrook congestion zone is a localized problem that occurs for just a handful of hours. It is caused by an overload on the Northbrook-Dearfield 138-kV line (with flow going from Northbrook to Dearfield) during the 138-L15912_B_N contingency (loss of the parallel line from Northbrook to Dearfield) under very heavy load situations (> 30 GW) with a simultaneous outage of one of large Waukegan units. This results in very high LMPs on the Waukegan buses, greatly increasing total profits. During the few hours, this constraint that is binding Midwest Generation could probably increase profits by submitting high bids for the non-outaged Waukegan units.

To examine the extend to which Midwest Generation could increase its profits under high but not peak load conditions, the 90% of peak case was examined (again with the assumption that all Illinois units are in-service). The results of bid manipulation at Waukegan are shown in Table E.3-10. Once their bids exceed their existing bus LMP (multiplier equal 2), their net generation at Waukegan rapidly decreases, resulting in a reduced overall profit. For a range of bids, they seem to have about 45 MW of must-run generation at Waukegan, but there is a limit. For high enough bids, their net generation drops to zero, with overall decreased profits. So in general just modifying the Waukegan bids would not be profitable under the 90% of peak scenario. But the presence of the Northbrook Congestion region in the marginal cost studies indicates that for extremely high loads, coupled perhaps with other generator outages, Midwest Generation could profitably benefit from high bids at Waukegan.

Table E.3-10 Variation in Midwest Power's Profit for Modified Waukegan Bids

Waukegan Bid Multiplier	Total Waukegan Generation (MW)	Waukegan LMP	Midwest's Relative Profit
1.0	789	28.9	1.000
1.5	789	28.9	1.004
2.0	65	31.8	0.891
3.0	44	37.5	0.908
4.0	49	38.7	0.904
6.0	43	53.5	0.921
8.0	0	69.2	0.875

E.3.3.10 Gallatin Congestion Region

The LMPs at the Carmel and Gallatin 69-kV buses are occasionally high due to congestion on an electrical equivalent 69-kV line from Hamilton to Carmel. Since the high LMPs are due to congestion only on an equivalent line (i.e., mathematically the line represents the aggregate impedance of several lines), this congestion may not actually occur in actual operation.

E.3.4 PROFIT MAXIMIZATION BY INDUCING NEW CONGESTION

The previous section examined the major congestion regions that would be expected if all generators submitted marginal cost bids, and discussed how different companies might exploit this congestion to increase their profits. This section discusses the potential for profit maximization by inducing new congestion. Examples are given using the 90% loading case from the previous section, which assumes all in-state generation is in-service. This case models a total load of about 30 GW of Illinois load. As was mentioned earlier, the system load should be at or above 90% of peak for about 80 hours per year.

E.3.4.1 Exelon Generation

In year 2007, Exelon Generation will own the largest percentage of the in-state generation, with a just over 20% market share. However, even with such a large percentage, no profit maximization potential was observed with its nuclear plants for the 90% of peak case. Attempts to increase profits by upping the bids resulted in a rapid loss of market share. Since the nuclear plants have costs well below their bus LMPs during the high-load condition, loss of market share resulted in substantial loss of revenue. Initially the Exelon Generation plants were producing 9,764 MW. With bids equal to 2 times marginal cost, their generation was reduced to 8,064 MW and their net profit to about 89% of that obtained with marginal cost bids. When bids are increased to 3 times marginal cost, the generation falls to 2,771 MW and the profit to 40% of marginal cost bids. Increasing the bids to 4 times marginal cost results in a dispatch of only 200 MW and profits well below 10% of marginal cost bids. Of course, unusual situations, such as the outage of several large coal units, could result in profit maximization opportunities. However, given the costs associated with starting/restarting and cycling nuclear plants, it is doubtful that a strategy of trying to maximize profits by submitting bids significantly above marginal costs would be beneficial.

E.3.4.2 Midwest Generation

In year 2007, Midwest Generation will own approximately 20% of the total in-state generation. The analysis presented here first looked at the 90% of peak loading case, which assumes all in-state generation is available. Figure E.3-3 shows a contour of the northern Illinois LMPs for this case assuming all generators submit marginal cost bids. Midwest Generation is producing 5,328 MW, with an average bus LMP of \$28.0/MWh and a maximum LMP of \$32.9/MWh. If any of their generators or even a small number try to increase profits by submitting higher than marginal costs bids (assuming all other companies do not), then the result will be a decreased profit.

However, if a large number of their units submit bids substantially above their marginal costs, they can increase their profit. Table E.3-11 provides results for the case in which generators at Collins, Powerton, and Waukegan submit bids equal to their marginal cost, while all the other Midwest Generation plants submit bids equal to a bid multiplier times their marginal cost. As indicated in the table, for small values above marginal cost, there is an initial slight increase in their profit. This increase would be expected, since initially some of the Midwest Generation units are marginal units (that is, they are not dispatched at their limits, and hence are being used to set prices). Then, there is a rapid decrease in profit as Midwest Generation loses market share. Eventually, however, their market share stabilizes as the other available generators become fully dispatched and lines begin to congest. For high enough values, they have several units reduced to must-run status, allowing them to arbitrarily set the LMPs at these buses. In this example, this situation occurs at Will County, Crawford, and Fisk. This situation then allows them to increase their profit substantially above the marginal cost value. The LMP contours for the ten times marginal cost case are shown in Figure E.3-4. Note that while the presence of an extremely high cost band stretching across the southern part of the Chicago metro area, prices throughout the entire Chicago metro region have increased but those further west have actually decreased.

Next, this profit maximization approach was tested for an 85% of peak load case, again with all units in-service. The system load should be at or above this value for about 150 hours per year. For this level of loadings, Midwest Generation could raise the average bus LMPs, but could not do so profitably. As their bid multiplier was increased, their total generation and relative profit both rapidly decreased, until eventually none of their generation with non-marginal costs bids was being dispatched.

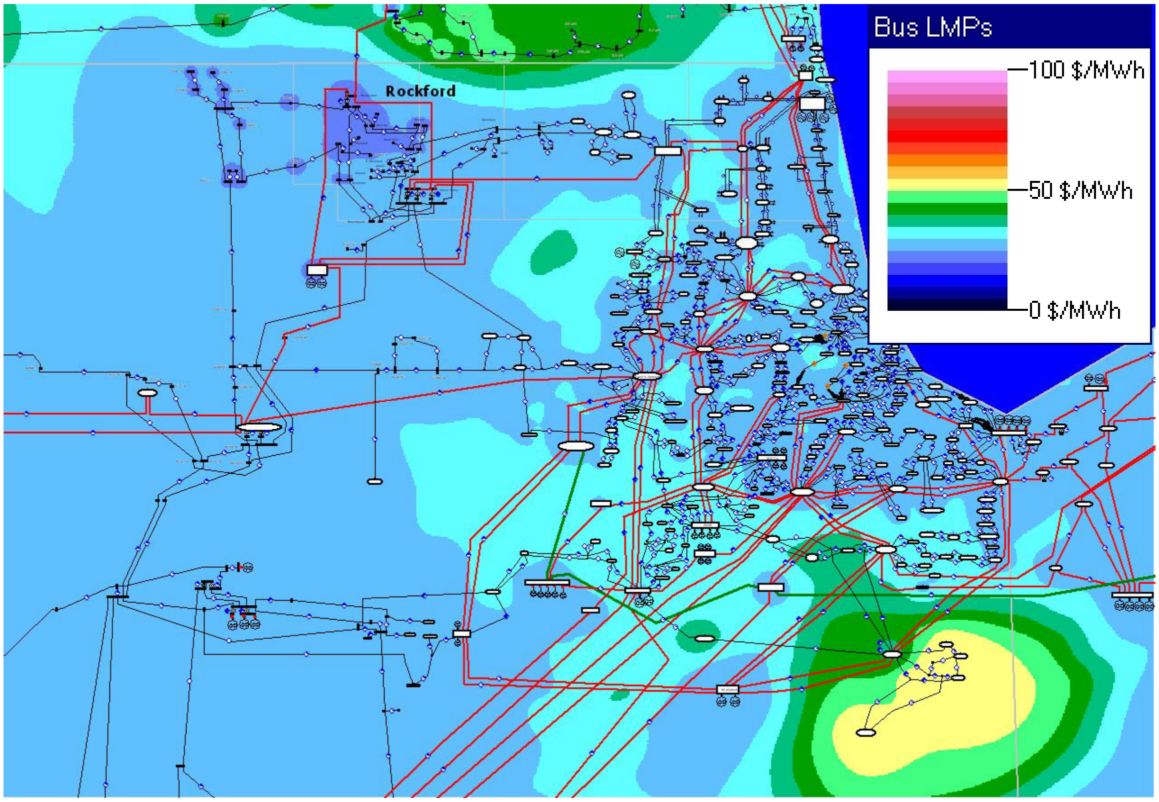

Figure E.3-3 Northern Illinois LMP Contours for 90% of Peak Case with Marginal Cost Bids

Table E.3-11 Variation in Midwest Generation Relative Profit

Bid Multiplier	Total Midwest Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	5,330	1.000	28.0	32.9
1.5	5,330	1.033	28.3	32.9
2.0	4,587	0.985	30.3	35.2
3.0	2,981	0.75	36.6	55.1
4.0	2,935	0.89	43.3	73.4
5.0	2,860	0.98	49.7	91.7
6.0	2,851	1.12	42.32	110
8.0	2,831	1.37	41.00	147
10.0	2,717	1.46	41.30	183
12.0	2,683	1.57	98.2	200
14.0	2,673	1.73	110.0	257

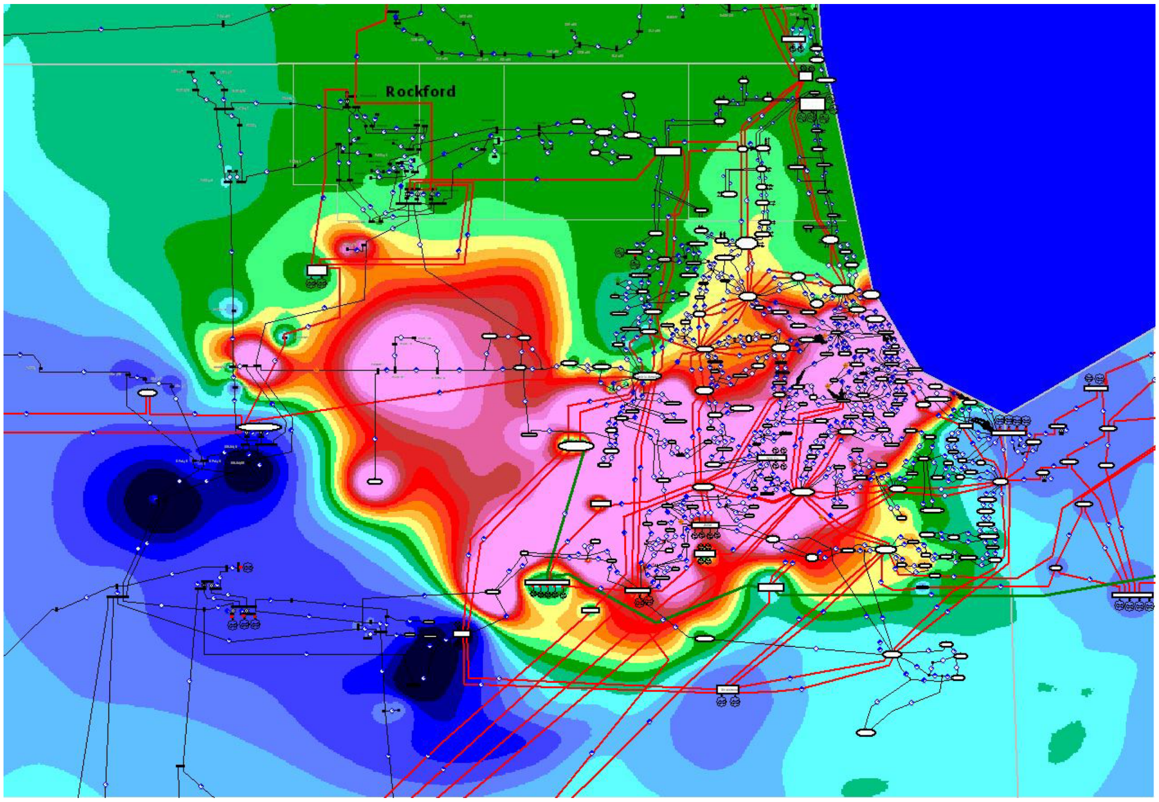

Figure E.3-4 Northern Illinois LMP Contours for 90% of Peak Case with Select Midwest Generation Units Bidding 10 Times Marginal Cost

E.3.4.3 Ameren – CIPS and Ameren – UE

In year 2007, Ameren CIPS and Ameren UE will own slightly more than 10% of the in-state generation. No profit maximization potential was observed for their combined generation portfolio for the 90% of peak case. This is probably due to the generators being more geographically dispersed, located near plants from other companies (such as Dynegy), and located in portions of the State with a relatively low load density. Of course, unusual situations may result in profit maximization opportunities.

E.3.4.4 Dynegy

In year 2007, Dynegy will own about 8 or 9 percent of the in-state generation. As with Ameren, no profit maximization potential was observed for the Dynegy generators for the 90% of peak case. The Dynegy generators are also geographically dispersed with significant amounts of generation from other companies (such as Ameren) sharing the same footprint. Of course, unusual situations may result in profit maximization opportunities.

E.3.4.5 Ameren – CILCO

Results for CILCO are discussed in Section E.3.3.1, the Peoria Congestion Region.

E.3.4.6 CWLP

CWLP is a municipally owned utility, so it would seem unlikely that they would seek profit maximization. Nevertheless, for completeness, results for CWLP are included here. Bid increases for the CWLP generators initially result in loss of market share and decreased profit. However, eventually a situation is reached in which some generation becomes must-run. For CWLP, this generation is at the Dallman 69-kV bus (Dallman 1 and 2). The binding constraint is the Auburn-Chatham 138-kV line (with flow from Auburn to Chatham) for contingency IP109 (the loss of the entire Latham 345 kV and some 138 kV). Full results are given in Table E.3-12.

Table E.3-12 Variation in CWLP Relative Profit

Bid Multiplier	Total CWLP Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	448	1.000	28.6	26.6
2.0	143	0.612	35.0	39.8
3.0	121	1.001	53.5	65.6
4.0	121	1.503	72.6	114.8

APPENDIX F
POWERWORLD® DETAILED RESULTS

APPENDIX F.1

Appendix F.1 provides additional results for the original case with all generators bidding their marginal costs with no inclusion of their fixed costs.

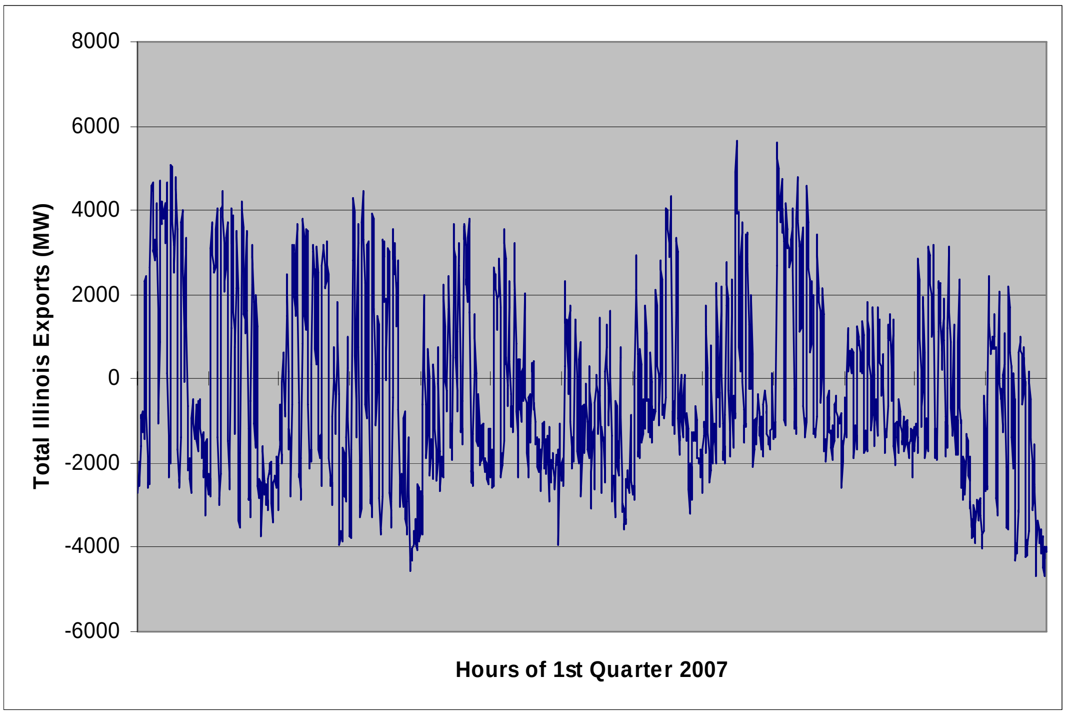

Figure F.1-1 Hourly Power Exports for Illinois during the 1st Quarter 2007

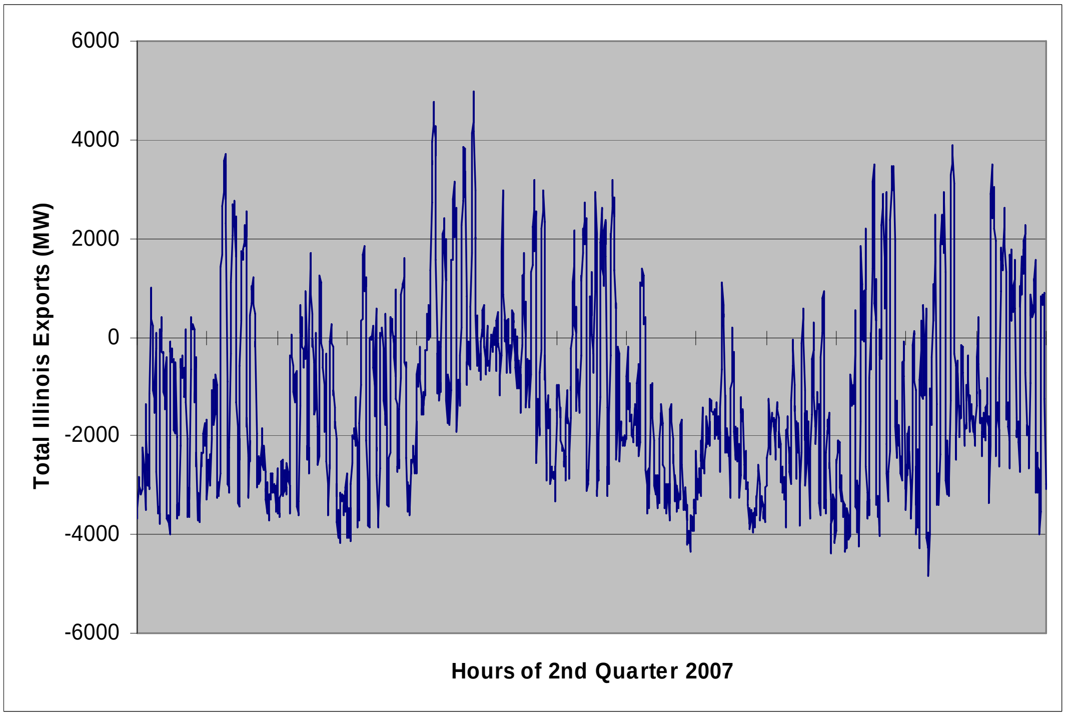

Figure F.1-2 Hourly Power Exports for Illinois during the 2nd Quarter 2007

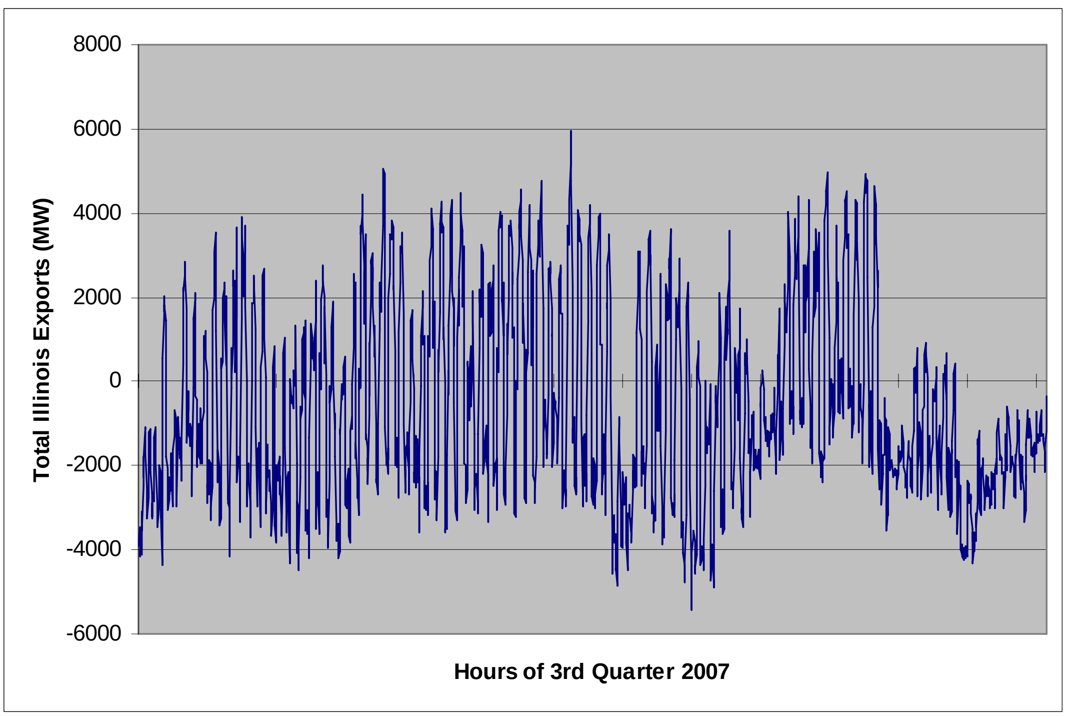

Figure F.1-3 Hourly Power Exports for Illinois during the 3rd Quarter 2007

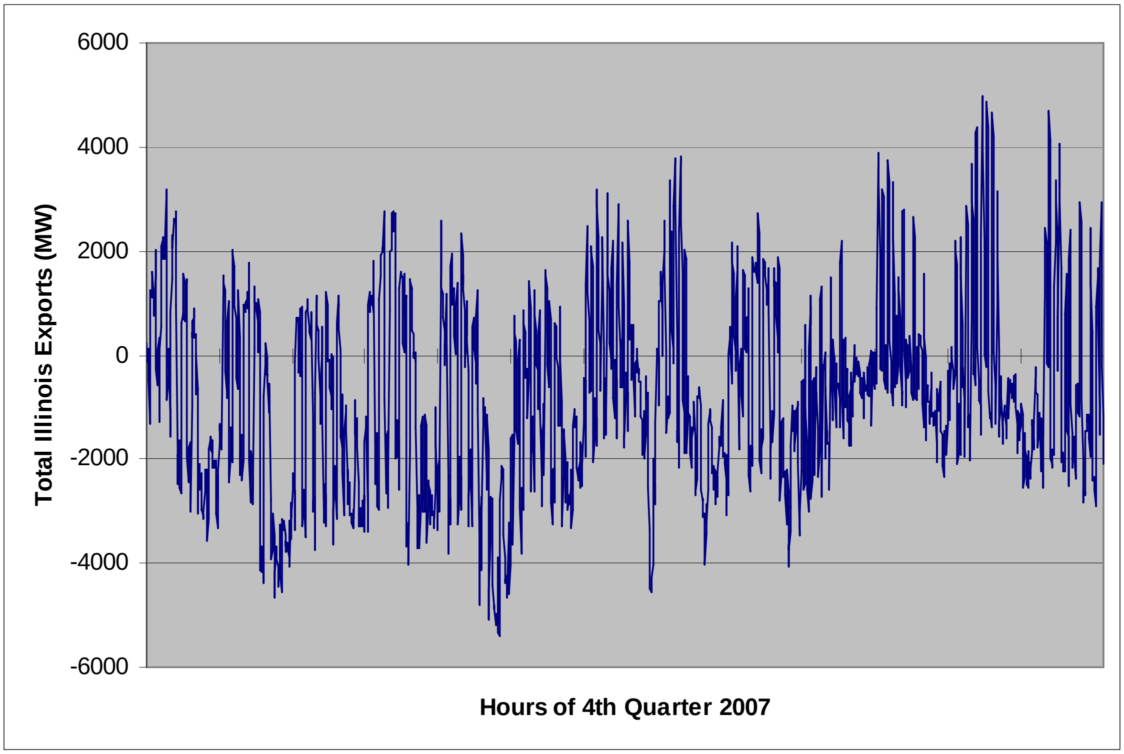

Figure F.1-4 Hourly Power Exports for Illinois during the 4th Quarter 2007

Table F.1-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
WI	ARP 138	ARP 345	1	WIS39244ARP345-39785ROCKYRNC1	7580	21.64	129.65
Ameren-MO	ORAN	STODDARD	1	AMRNMTL51	5705	54.56	383.3
EEI	JOPPA S	JOPTAPY	3	EEIDOE33392JOPPAS-33395JOPTAPXC2	4980	1.74	16.28
IP-MEC	GALESBRG	GALESBR5	2	345-L15502_B-R	2708	10.25	33.47
Ameren-MO	FRED TAP	FREDTOWN	1	AMRNMTL73	2393	19.05	167.75
WI	OK CRK9	OC CRK6	1	WIS38857OCCRK8-39367OKCRKC1	2374	1.04	12.87
WI	EDG 345	CEDRSAUK	1	WIS38870GRANVL2-39433PTBCH1C1	1985	2.47	5.58
TN (TVA)	8JVILLE	8CUMBERL	1	TVA184258CUMBERL-184308DAVIDSOC1	1984	9.24	36.29
ComEd	MAREN;RT	P VAL; R	1	345-L15616-R	1866	9.65	119.49
WI	BAIN 5	PLS PR4	2	WIS38850PLSPR3-38851PLSPR4C1	1807	4.97	45.85
TN (TVA)	8CUMBERL	8DAVIDSO	1	TVA184228JVILLE-184258CUMBERLC1	1175	1.93	21.58
WI	PAD 345	PAD 138	1	WIS39058PAD345-39119ROE345C1	903	14.78	61.82
WI	DEAD RVR	DR NEU1	1	WIS39917DEADRVR-39898DRNEU1AC1	896	0.51	2.8
IN	08KOK HP	08KO IN5	1	AEP2266505GRNTWN-2266705JEFRSOC1	880	80.61	413.34
Ameren	ALBION	CROSSVL	1	IP98	650	9.63	95.02
ComEd	MAZON; R	OGLES; T	1	345-L15502_B-R	633	16.72	79.55
MO	MARIES	5MARIES	1	AMRNVSS17	629	67.84	180.62
Ameren-MO	CEE TAP	CENTRAL	1	Basecase	611	12.25	19.14
Ameren-MO	CEE TAP	CENTRAL	1	AMRNMTL55	510	10.65	14.98
IN	08WEBSTE	08NEWLON	1	AEP2266505GRNTWN-2266705JEFRSOC1	477	3.74	64.39
ComEd	FISK ; R	FISK STR	19	TR81_TAYLR_R-C	430	12.5	159.36

Table F.1-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
IA (MEC)	DAVNPRT3	WALCOTT3	1	MEC64402LOUISA3-64403EMOLIN3C1	361	1.69	3.67
CILCO	HOLLAND	MASON	1	CIL-6	349	16.66	92.19
Ameren-CWLP	AUBURN N	CHATHAM	1	IP109	347	4.9	43.16
ComEd	HILLC;6B	WILL ;BT	1	Basecase	332	3.76	9.36
IP-CILCO	1346A TP	KICKAPOO	1	345-L0304_R-S	289	2.87	20.47
ComEd	FISK ; B	FISK STR	19	TR82_TAYLR_B-C	258	8.39	18.86
ComEd	SLINE;5S	WASHI; R	1	345-L17723_B-C	232	7.48	141.32
IP-MEC	GALESBRG	GALESBR5	2	L0304-A	231	5.02	19.97
ComEd	LASCO; B	MAZON; B	1	345-L1223_R-S	218	37.42	104.26
Ameren	HAMLTNAM	HAMLTNAM	1	AMRNMTL32	198	5.19	11.97
ComEd	CLYBO; B	CROSB; B	1	138-L4018_R-C	184	0.53	8.89
CILCO	RS WALL	RSW EAST	1	Basecase	184	197.49	1000
CILCO	HOLLAND	MASON	1	345-L0304_R-S	180	14.29	139.47
MI	05BENTON	05COOK	1	AEP2265405COOK-2853818PALISAC1	179	8.48	14.76
ComEd	ELECT;3R	ELECT;3M	1	TR84_ELECT_R-N	177	5.36	35.99
ComEd	CLYBO; B	CROSB; B	1	345-L4621_B-N	167	1.73	35.92
SIPC-BREC	14MORGAN	2GALTN_S	1	IP98	167	24.73	113.49
IP-MEC	GALESBRG	GALESBR5	2	345-L0404-R	162	9.76	22.88
ComEd	BARTL;BT	SPAUL; B	1	345-L14402_B-N	157	8.17	17.82
IP	SPRTA TP	ARCH TAP	1	IP96	156	11.64	46.63
ComEd	ELMHU;3I	F PAR; B	1	TR81_ELMHU_R-N	156	4.44	103.21
ComEd	JEFFE; B	KINGS; B	1	138-L1110_B-C	145	6.72	121.8
ComEd	DAVIS; B	DAVIS;3M	1	345-L17704_R-S	145	72.36	511.77
Ameren-MO	MARBHD N	PALMYRA	1	AMRNMTL58	137	5.91	15.55
WI	EDG 345	CEDRSAUK	1	WIS38898PTBCH2-39433PTBCH1C1	132	2.64	5.44
IP	MT VRNON	ASHLEY	1	IP96	132	49.24	166.79
ComEd	MAZON; R	OGLES; T	1	345-L2101-S	129	20.54	61.22
ComEd	CLYBO; B	DIVER; B	1	138-L4018_R-C	129	0.25	0.35
ComEd	SLINE;2S	WASHI; B	1	138-L0708_B-C	123	2.4	29.3
ComEd	MAZON; R	OGLES; T	1	IP108	123	22.33	62.23
Ameren	HAMLTNAM	KH2 XFMR	1	AMRNMTL32	118	18.29	29.93
Ameren	E.QUINCY	S.QUINCY	1	AMRNVSS112	106	4.34	11.27
Ameren	KINMUNDY	LOUISVL	1	IP98	105	7.66	20.23
IP-ComEd	PWR JCTB	POWER;	1	CIL-6A	97	36.76	94.55
ComEd	RIDGE; B	RIDGE;BS	1	138-L5118_B-S	95	9.85	210.56
ComEd	DIXON; R	NELSO;RT	1	138-L15507_B-R	92	80.81	300.08
Ameren-AEP	05BREED	CASEY	1	AEP2266705JEFRSO-2267105ROCKPTC1	89	0.91	2.68
ComEd	HARBO;8S	UNIVE; B	1	345-L17723_B-C	89	1.68	14.15
IA	HAZLTON5	HAZLTON3	1	ALTW34020HAZLS5-34018HAZLTON3C2	86	43.8	71.76
WI	OC CRK8	OK CRK	1	WIS39367OKCRK-39369OKCRK9C1	84	1.1	5.25
Ameren	RNTOUL J	SIDNYCPS	1	IP45	83	5.99	14.71
IN	07RAMSEY	07RAMSY5	2	CIN2518107RAMSY5-2538808SPEEDC1	81	557.74	1000

Table F.1-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
SIPC-BREC	14MORGAN	2GALTN_S	1	AMRNVSS76	76	8.91	42.41
ComEd	DAVIS;3M	DAVIS; B	1	345-L17704_R-S	74	65.09	352.35
CWLP	EASTDALE	EASTDALE	1	CWLPDALLMAN-DALLMANC1	70	3.57	6.87
WI	EDG 138	EDG 345	1	WIS39215EDG138-39214EDG345C2	67	223.54	372.49
Ameren	ROXFORD	SIOUX	1	Basecase	67	2.17	4.78
ComEd	Y450 ; R	CONGR; R	1	Basecase	63	1.37	17.32
Ameren	ALBION	CROSSVL	1	IP96	60	21.53	78.89
ComEd	HANOV; B	SPAUL; B	1	345-L14402_B-N	59	2.82	14.17
IP-Ameren	LANSVILL	LANSVILL	1	CWLPILLOPTP-INTERSTAC1	59	22.48	43.46
ComEd	CROSB; R	ROCKW; R	1	138-L6721_B-C	58	0.46	1.5
ComEd	ELECT;3M	ELECT;3R	1	TR84_ELECT_R-N	57	4.74	22.74
ComEd	TOLLW; B	TOLLW;3M	1	138-L7910_B-R	56	8.42	26.75
IP	SPRTA TP	ARCH TAP	1	IP30	55	8.84	25.04
SIPC	5MRN_PLN	5RNSHW_S	1	TVA184018SHAWNEE-184068MARSHALC1	50	8.82	28.31
OH	08BUFTN1	08BUFTN1	1	CIN2496206PIERC2-2602908FOSTERC1	47	98.03	181.51
ComEd	E FRA; B	GOODI;3B	1	Basecase	46	7.33	24.82
ComEd	ELWOO; R	GOODI;1R	1	345-L1223_R-S	45	6.97	28.56
ComEd	HILLC;6B	WILL ;BT	1	138-L0907_B-S	43	6.64	9.63
ComEd	CROSB; R	DIVER; R	1	138-L4013_B-C	43	0.08	0.17
ComEd	MAZON; R	OGLES; T	1	CIL-6A	42	13.4	34.13
ComEd	D799 ;6B	RIDGE; B	1	138-L1321_G-C	42	40.14	176.92
ComEd	CORDO; B	NELSO; B	1	345-L0404-R	40	1.78	14.28
ComEd	DEVON;3R	ROSEH;RT	1	138-L11416_R-C	39	35.93	329.23
IP-AEP	05EUGENE	BUNSONVL	1	AMRNVSS1	36	1.09	3.08
ComEd	WAYNE; B	WAYNE;1M	1	345-L14402_B-N	35	8.14	19.28
Ameren-IP	MAZON CY	1346A TP	1	CIL-6	33	8.94	32.63
IN	08GALAGH	08GALAGH	1	AEP2266705JEFRSO-2267105ROCKPTC1	33	0.58	1.34
ComEd	DIXON; B	NELSO; B	1	138-L15508_R-R	33	101.3	295.12
ComEd	MAZON; R	OGLES; T	1	345-L0302_B-S	32	10.88	39.5
SIPC-BREC	14MORGAN	2GALTN_S	1	SIPC333515MRN_PLN-333525RNSHW_SC1	31	40.94	83.52
ComEd	RIDGE; B	RIDGE;BS	1	138-L3705_B-C	31	2.16	43.42
ComEd	NELSO;RT	NELSO; R	1	138-L15507_B-R	31	7.68	26.98
IP-CILCO	1346A TP	KICKAPOO	1	CIL-6	31	17.41	49.4
ComEd	ELECT; B	ELECT;1M	1	TR82_ELECT_B-N	30	3.36	8.38
ComEd	UNIVE; B	WASHI; B	1	138-L13701_R-C	30	0.29	0.33
Ameren	COFFEEN	PANA	1	AMRNVSS36	29	0.9	2.19
ComEd	F PAR;5S	NATOM; B	1	138-L19209_B-C	27	0.36	0.78
ComEd	Y450 ; R	CRAWF;YS	1	Basecase	27	4.87	41.58
ComEd	Y450 ; R	CONGR; R	1	138-L6721_B-C	27	17.82	196.85
CWLP	WESTCHES	WESTCHES	1	CWLPPALOMINO-PALOMINOC1	27	4.59	9.29
ComEd	F PAR;0S	NATOM; R	1	Basecase	25	0.3	1.91

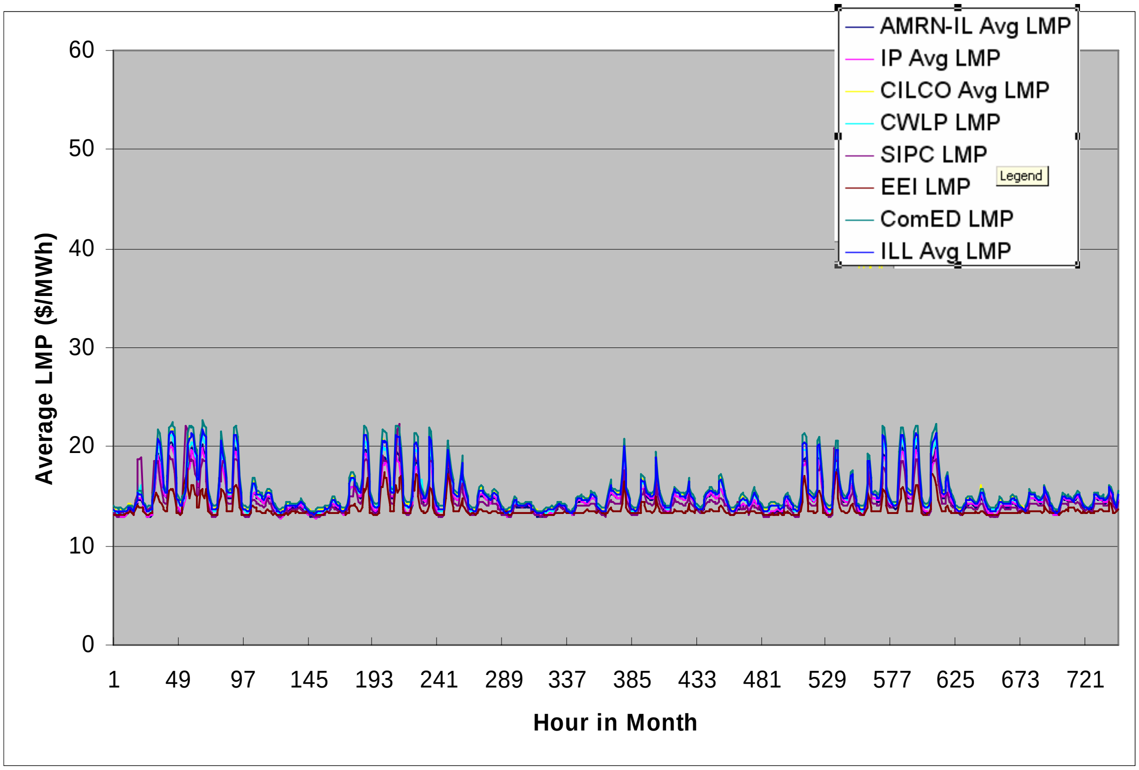

Figure F.1-5 Average LMPs for January 2007

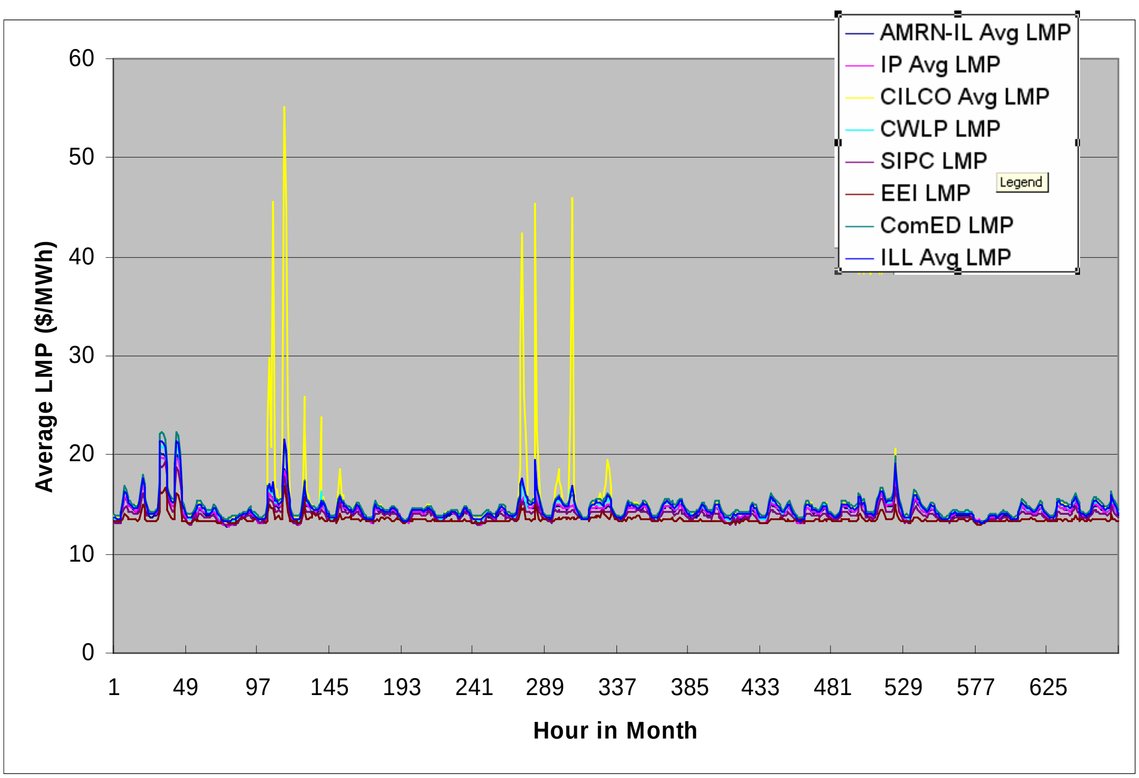

Figure F.1-6 Average LMPs for February 2007

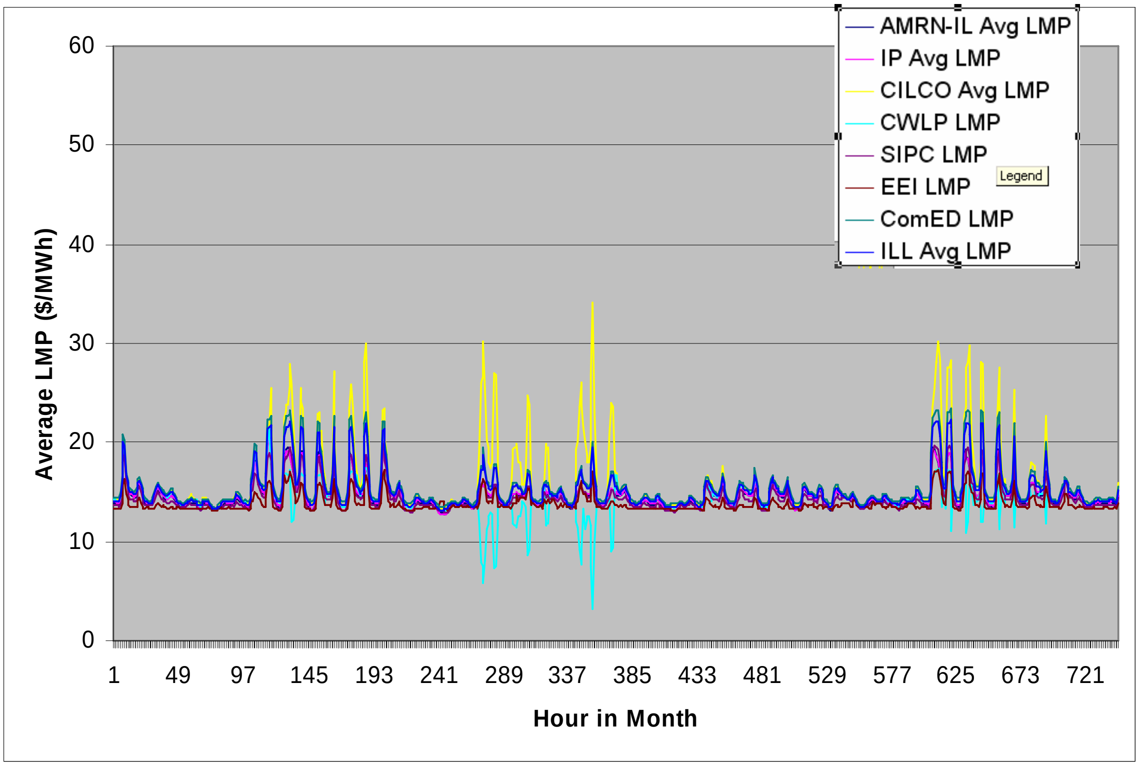

Figure F.1-7 Average LMPs for March 2007

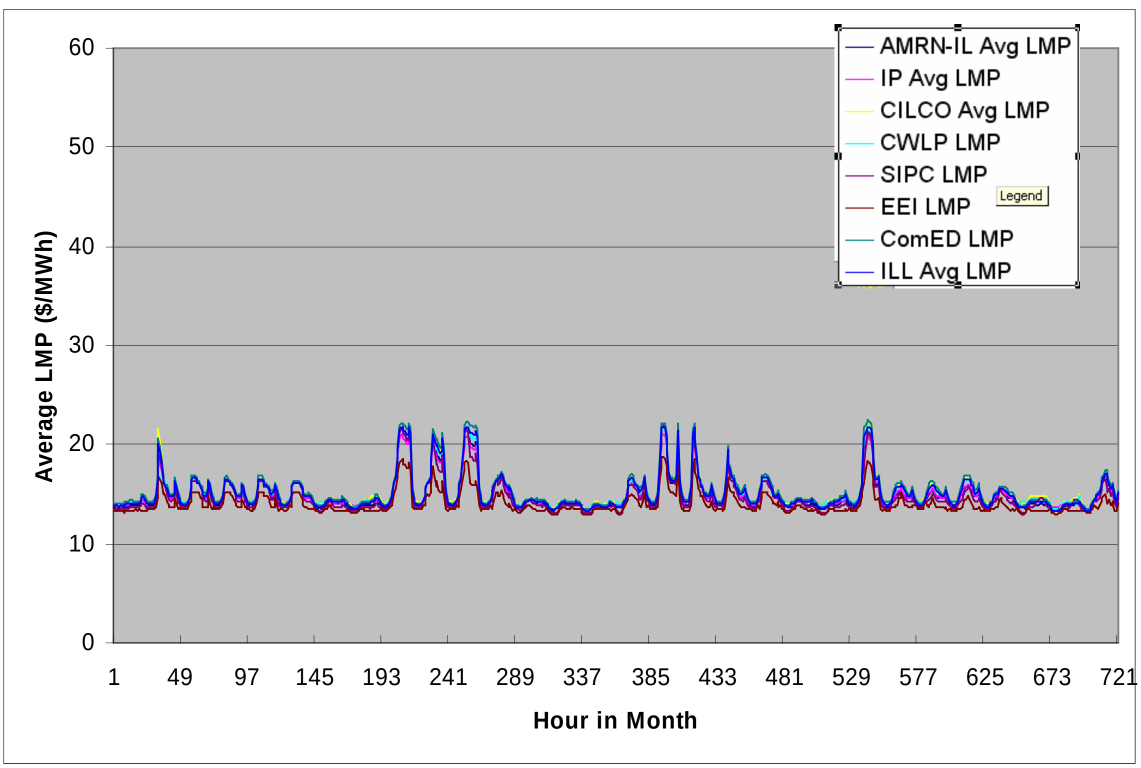

Figure F.1-8 Average LMPs for April 2007

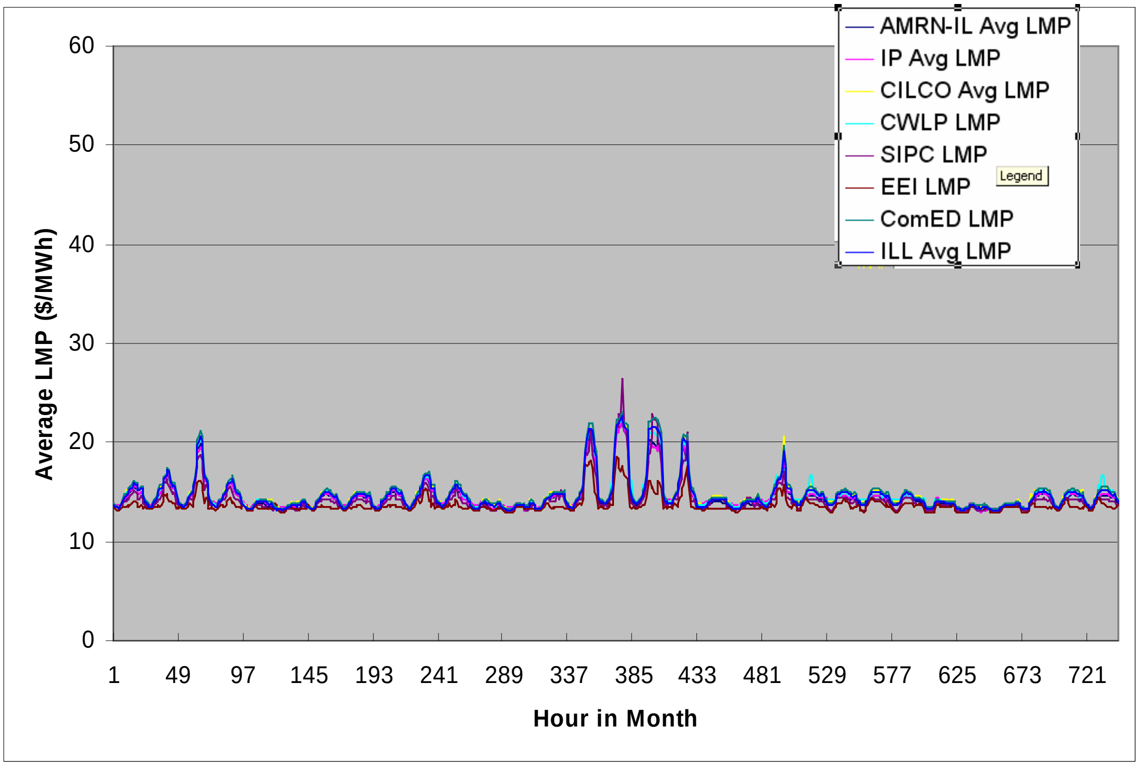

Figure F.1-9 Average LMPs for May 2007

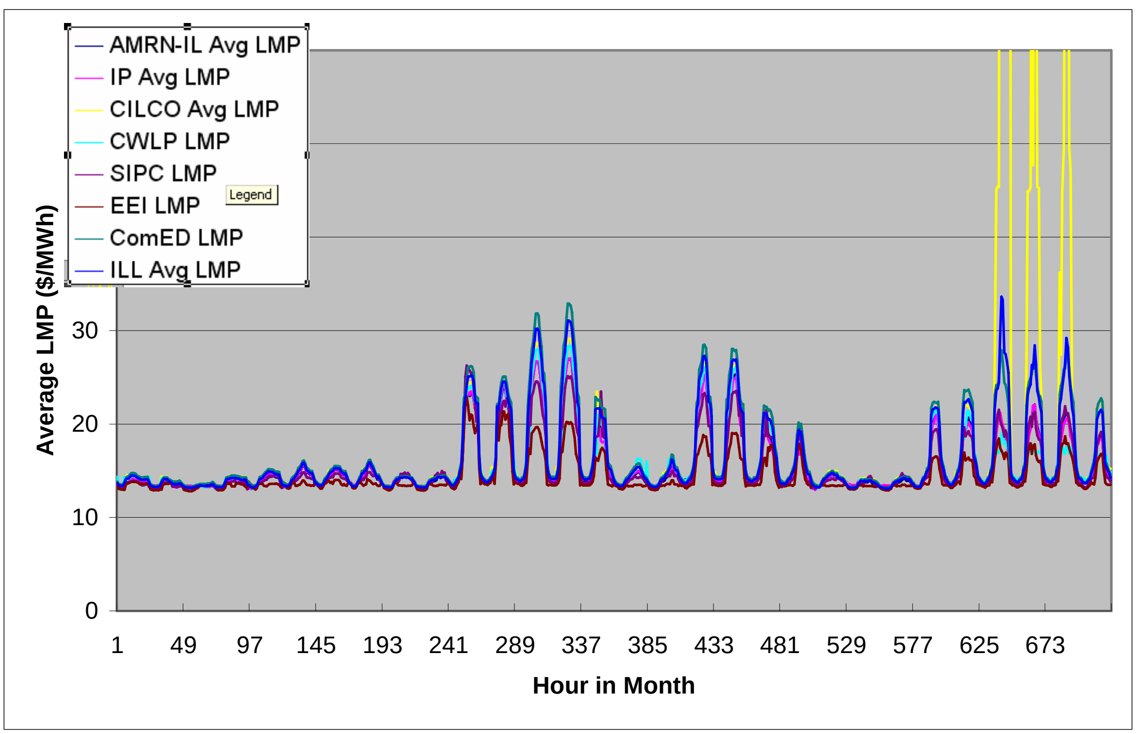

Figure F.1-10 Average LMPs for June 2007

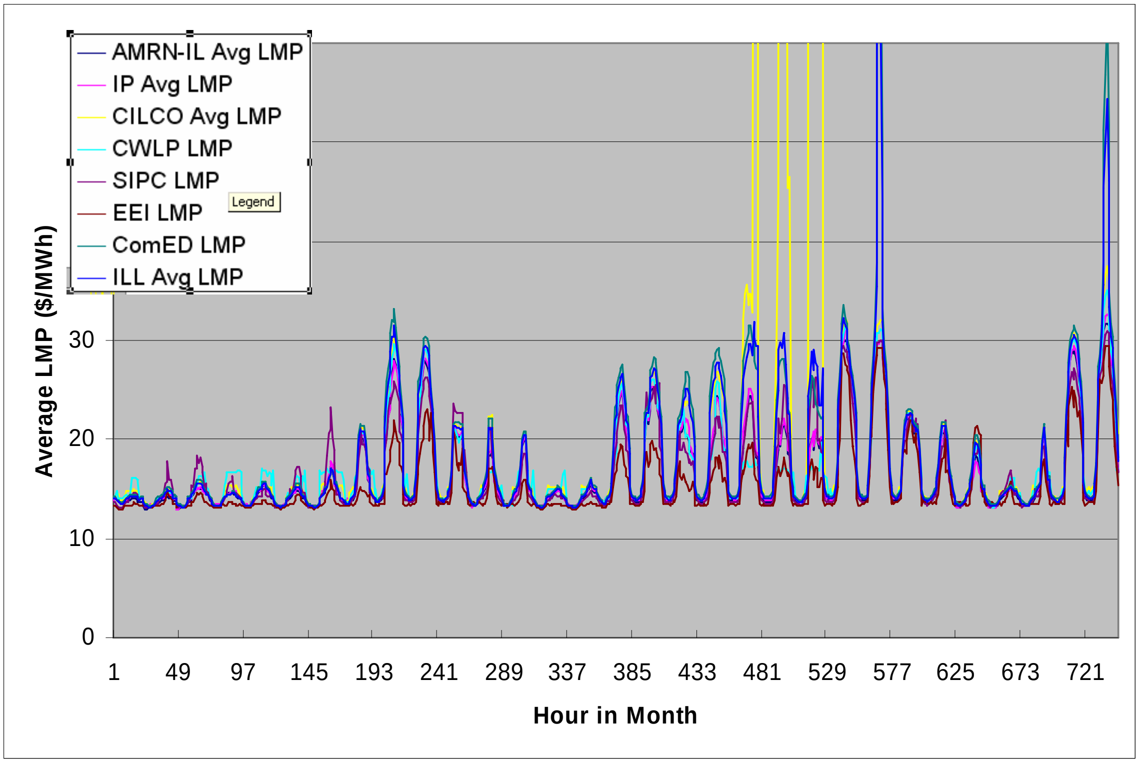

Figure F.1-11 Average LMPs for July 2007

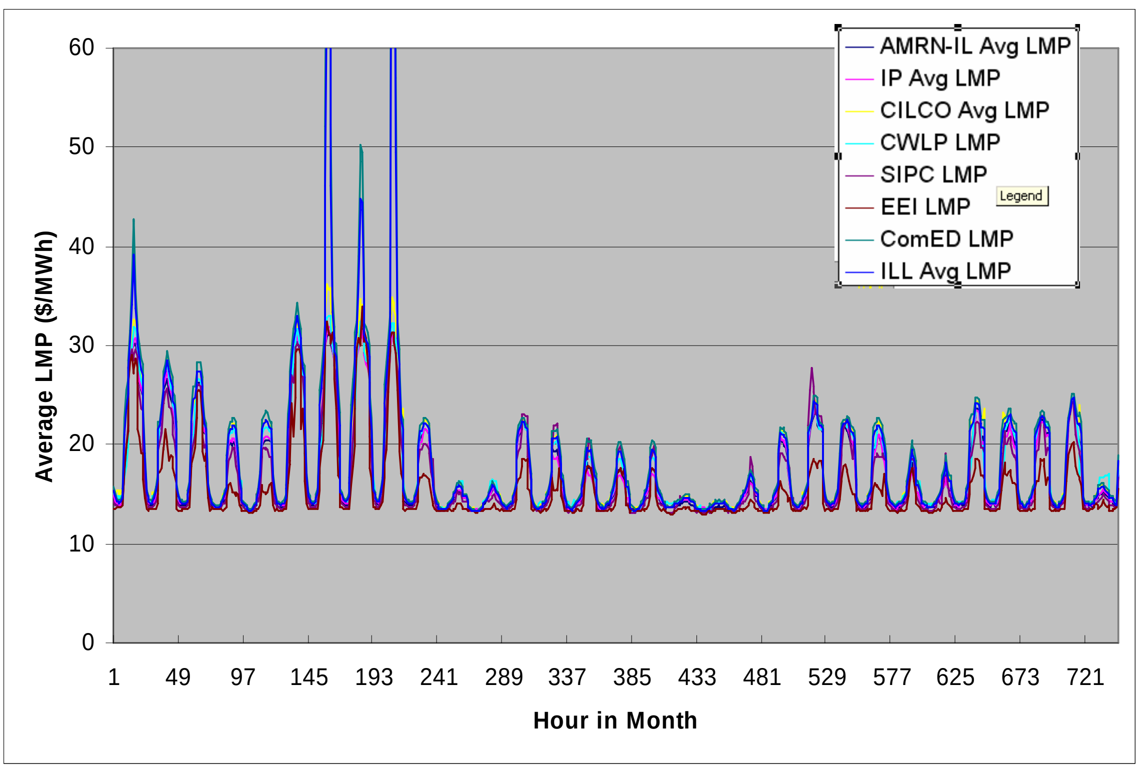

Figure F.1-12 Average LMPs for August 2007

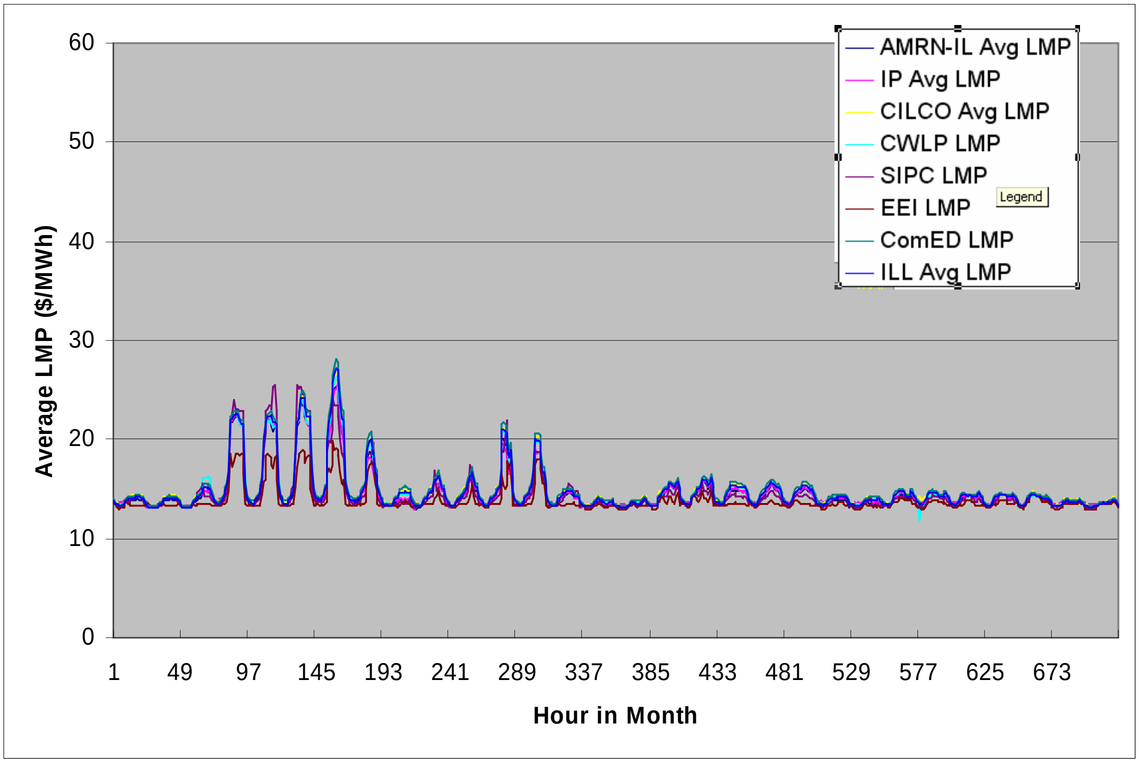

Figure F.1-13 Average LMPs for September 2007

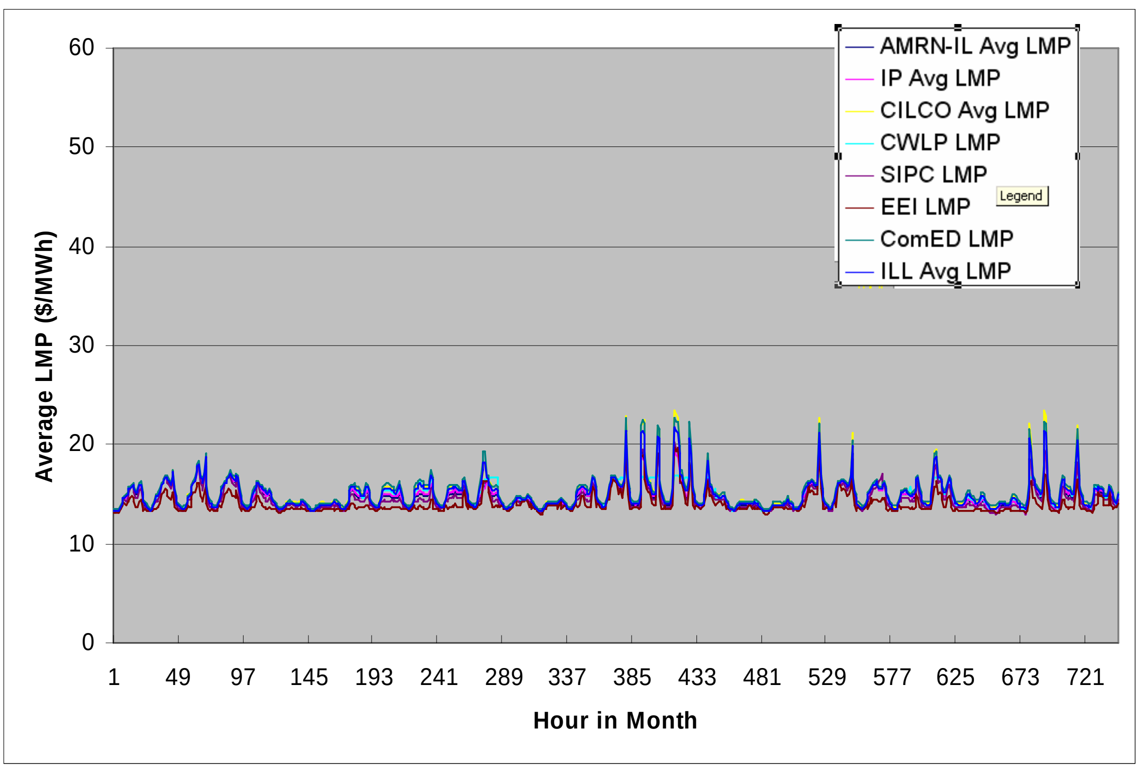

Figure F.1-14 Average LMPs for October 2007

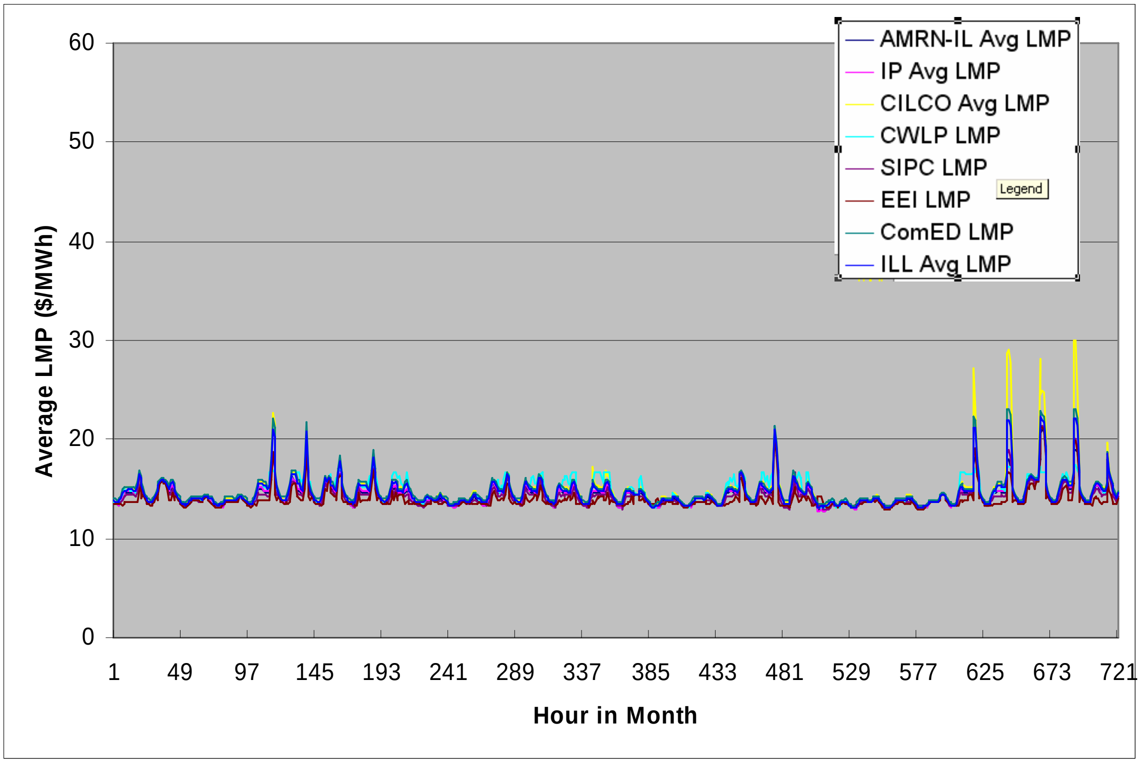

Figure F.1-15 Average LMPs for November 2007

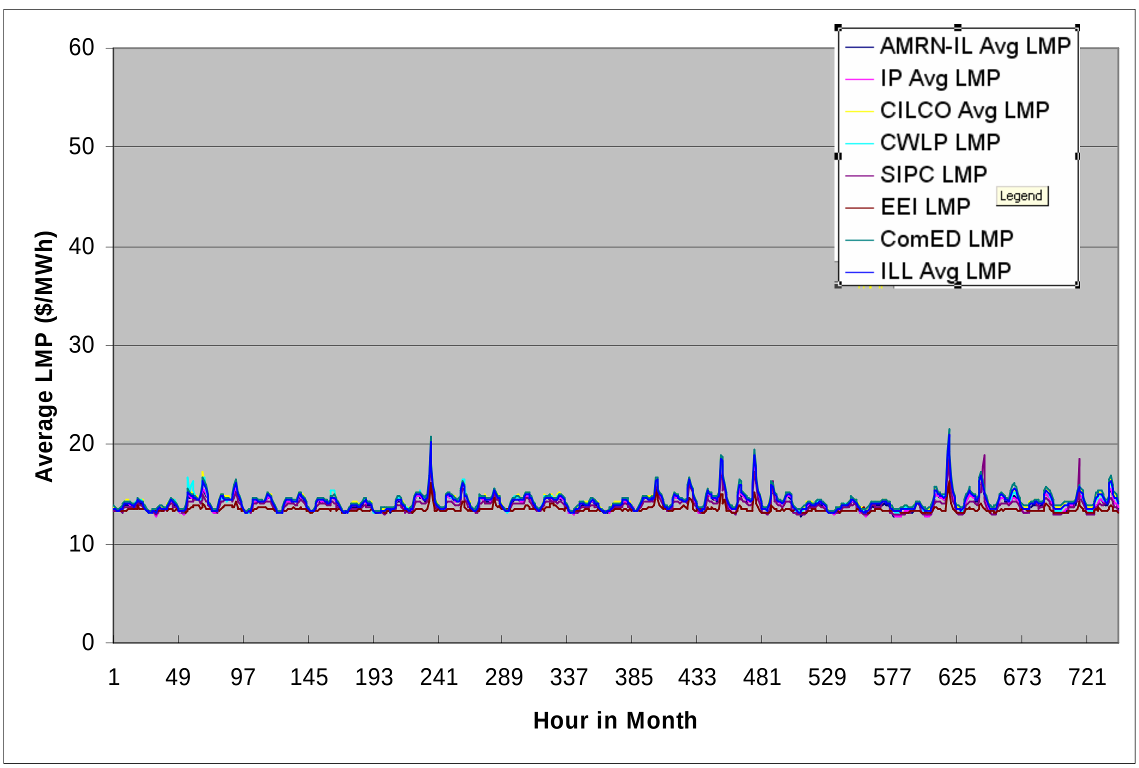

Figure F.1-16 Average LMPs for December 2007

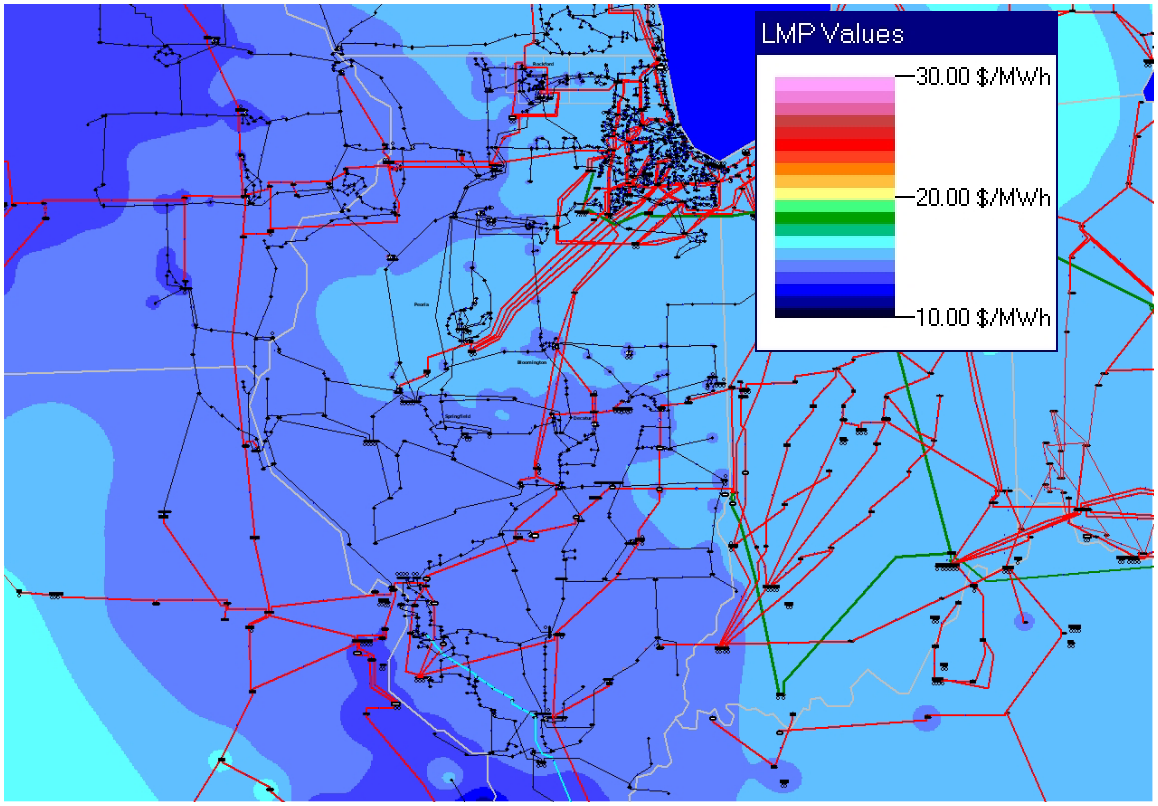

Figure F.1-17 Average LMPs for January to March 2007

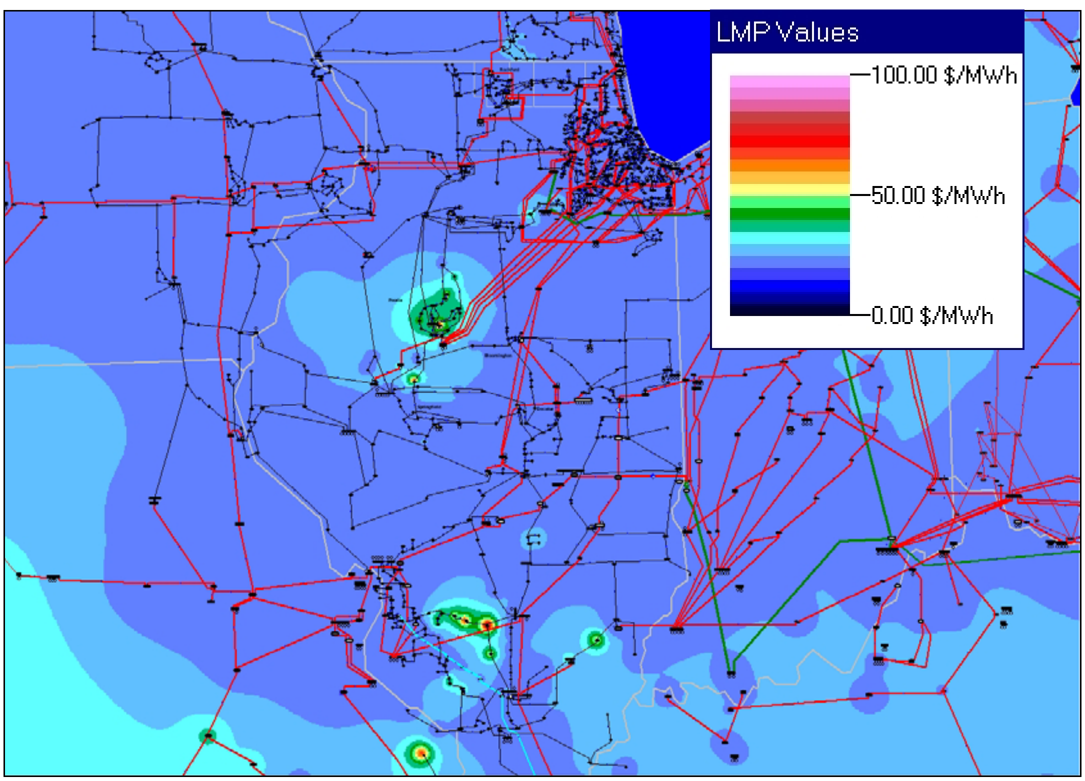

Figure F.1-18 Highest LMPs for January to March 2007

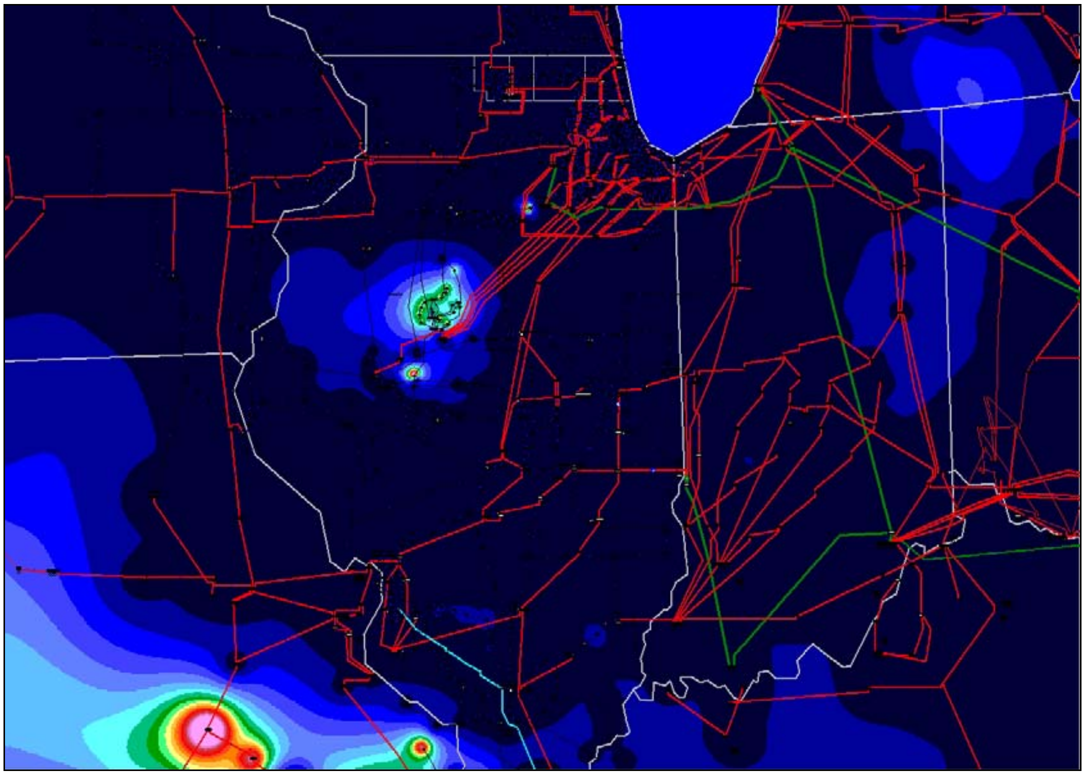

Figure F.1-19 Hours LMP Exceed $30/MWh for January to March 2007

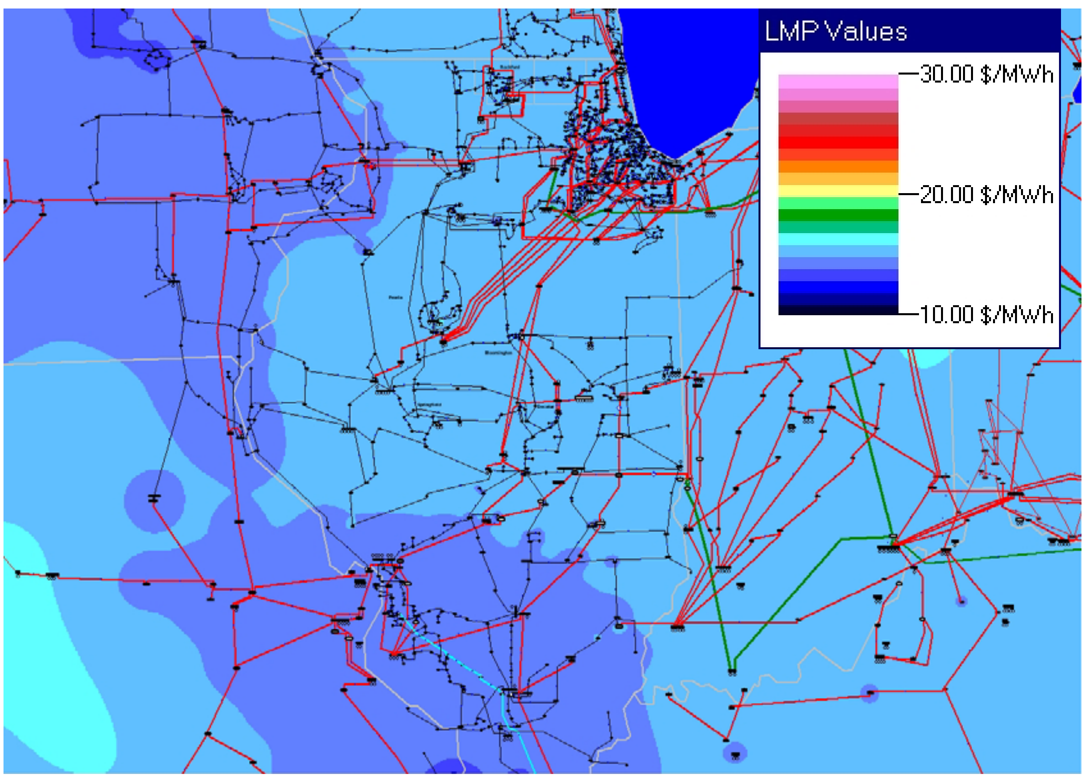

Figure F.1-20 Average LMPs for April to June 2007

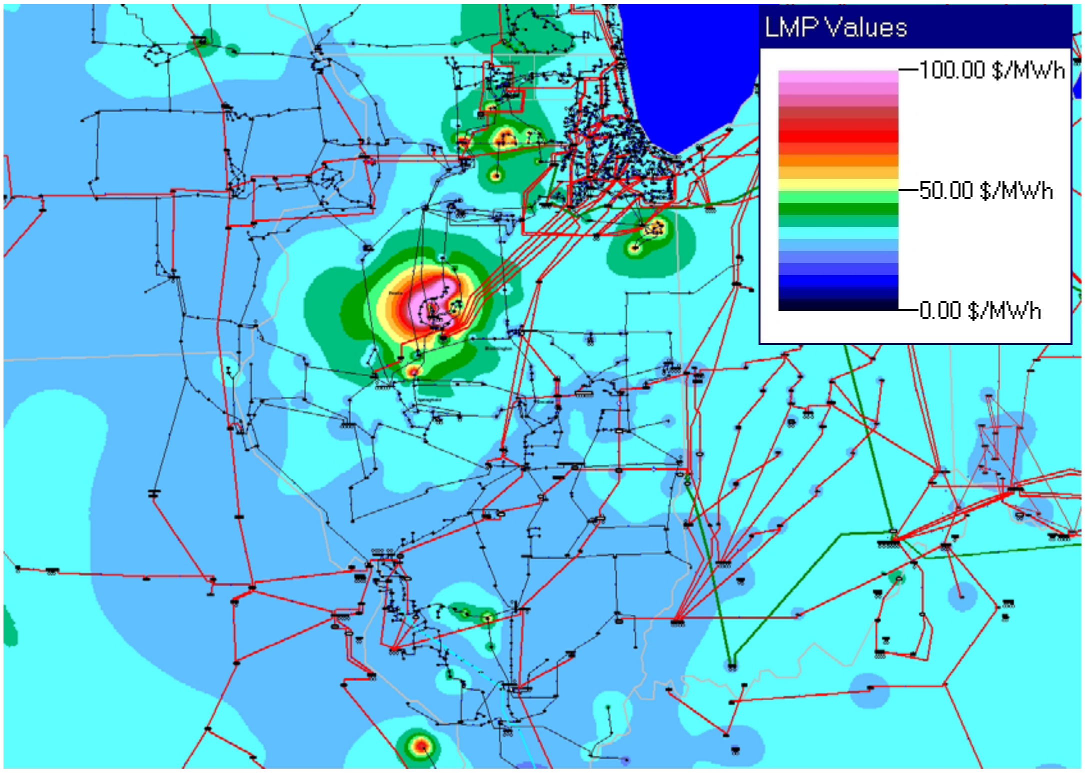

Figure F.1-21 Highest LMPs for April to June 2007

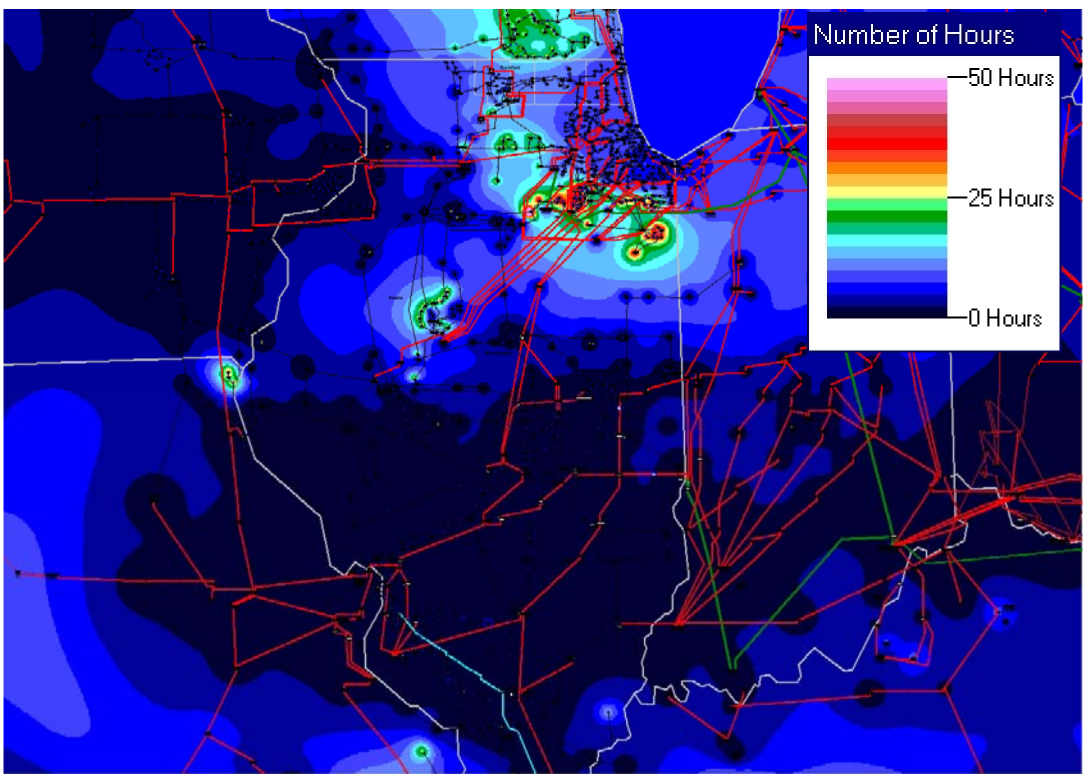

Figure F.1-22 Hours LMP Exceed $30/MWh for April to June 2007

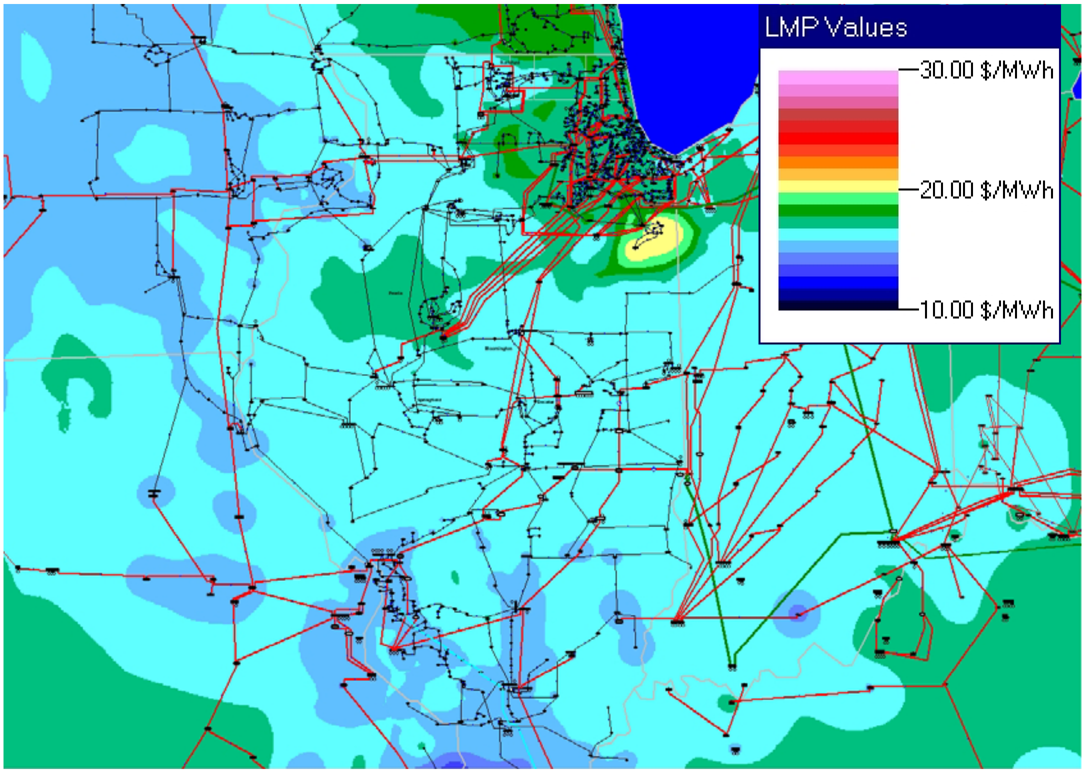

Figure F.1-23 Average LMPs for July to September 2007

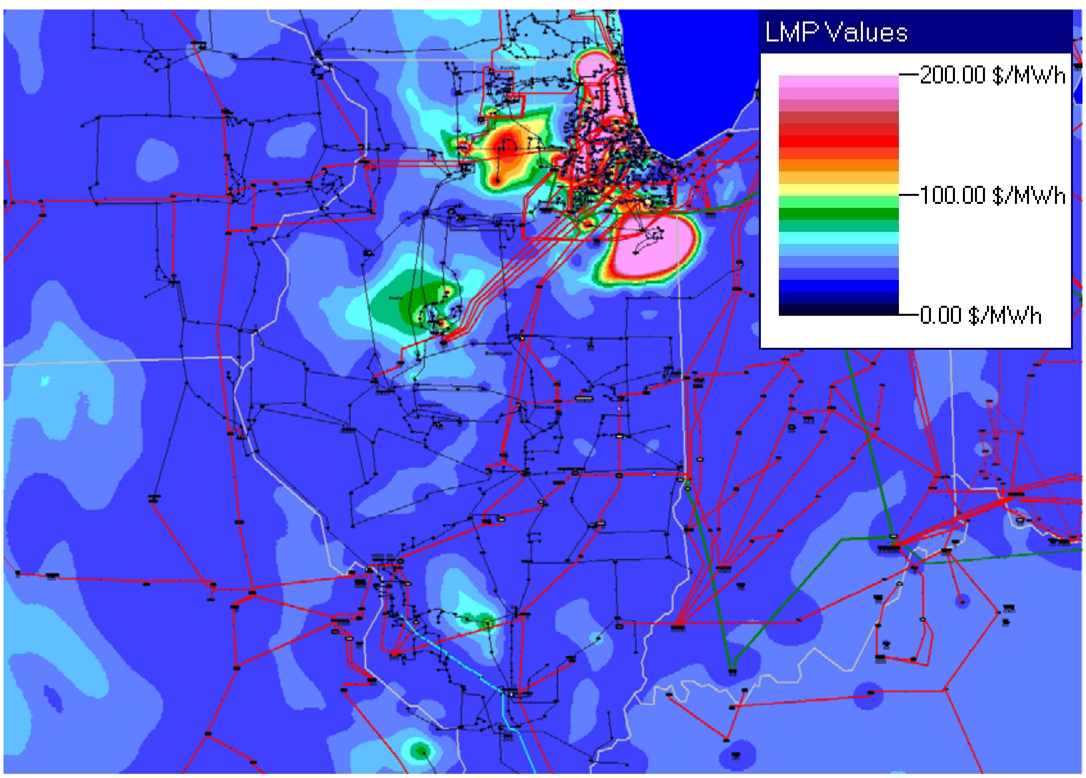

Figure F.1-24 Highest LMPs for July to September 2007

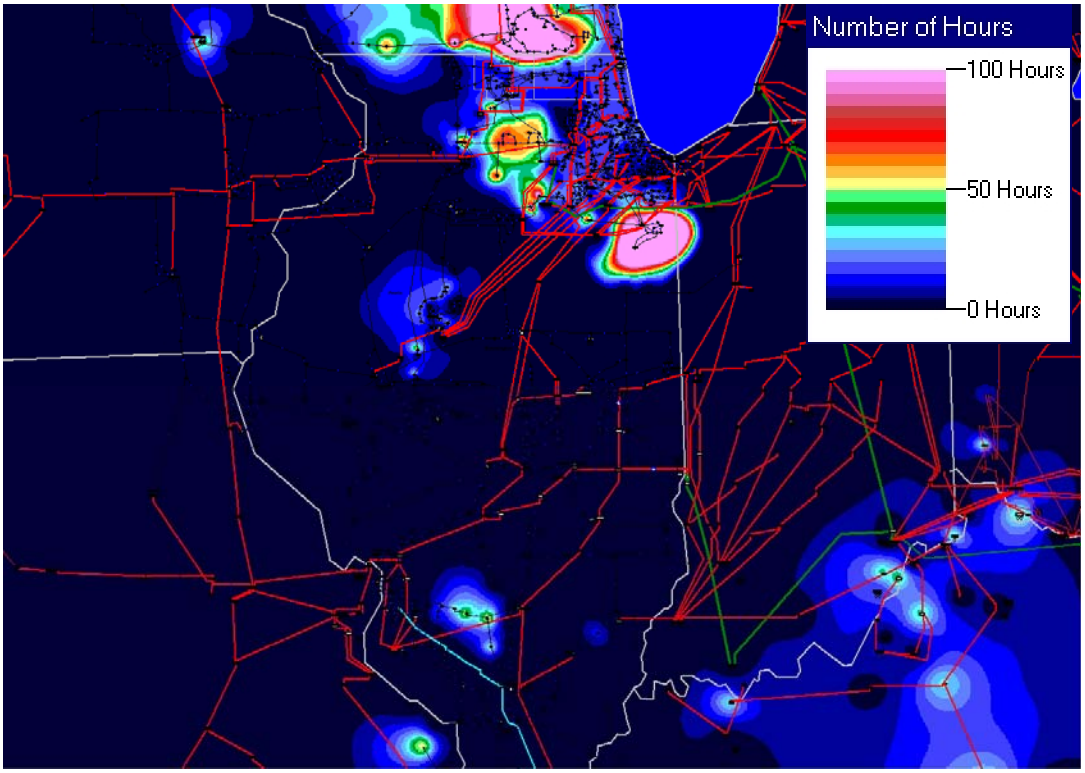

Figure F.1-25 Hours LMP Exceed $40/MWh for July to September 2007

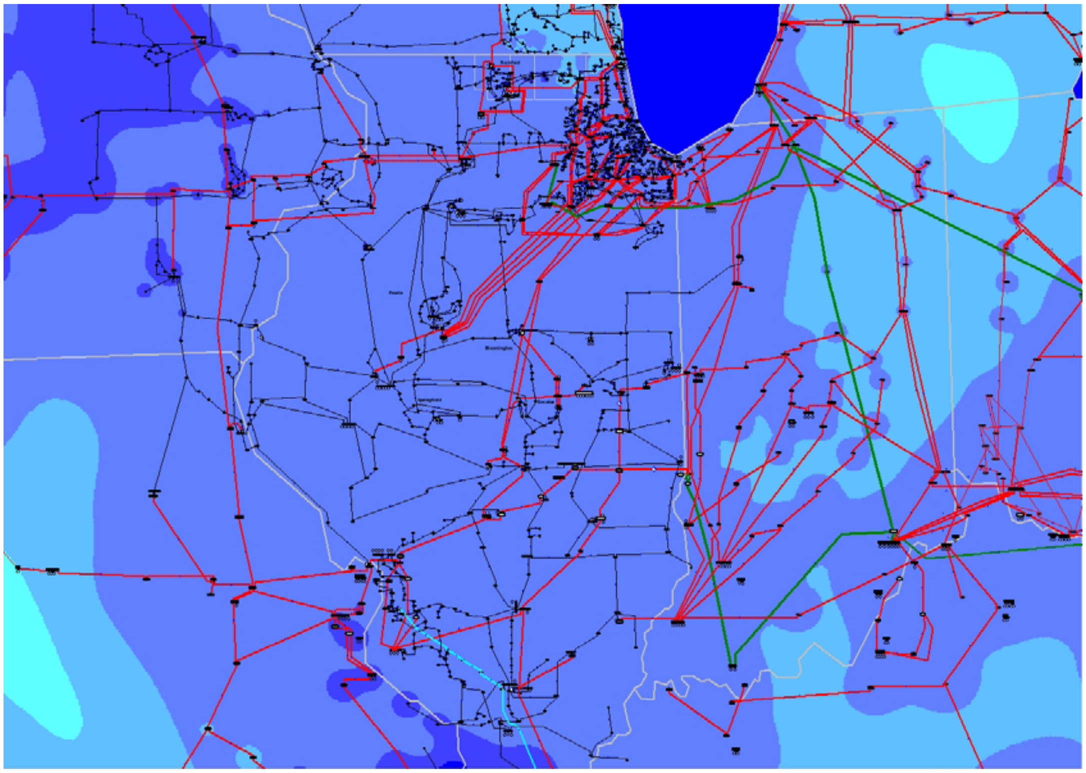
Figure F.1-26 Average LMPs for October to December 2007

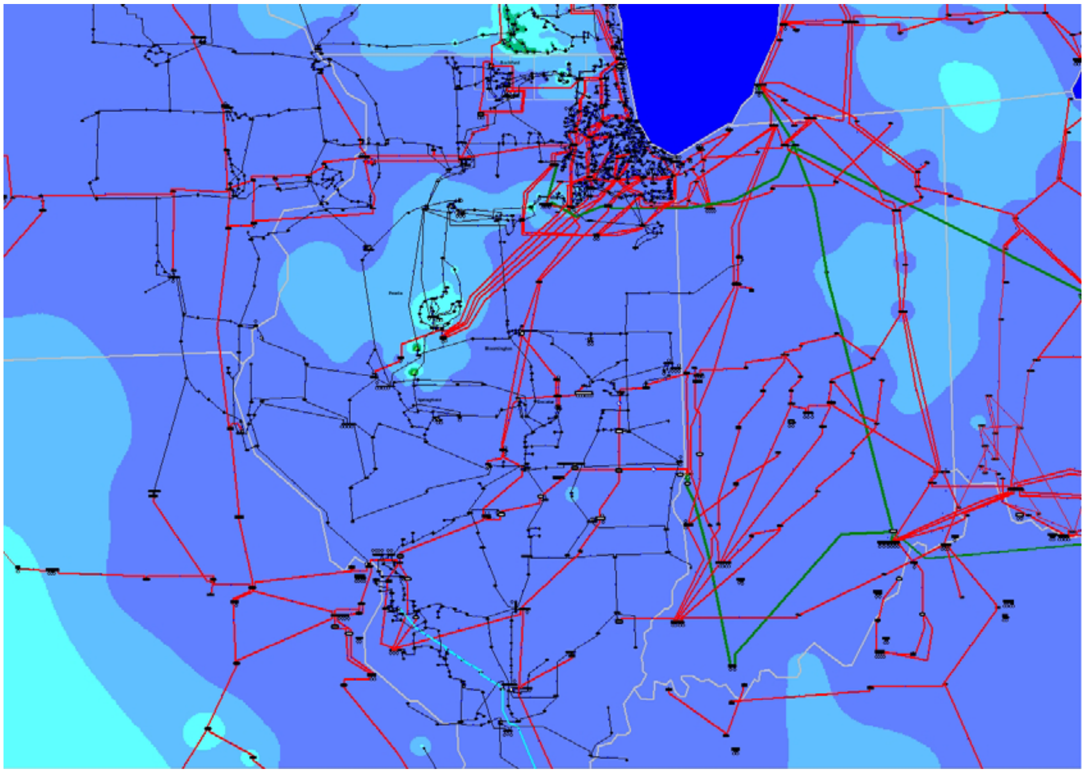

Figure F.1-27 Highest LMPs for October to December 2007

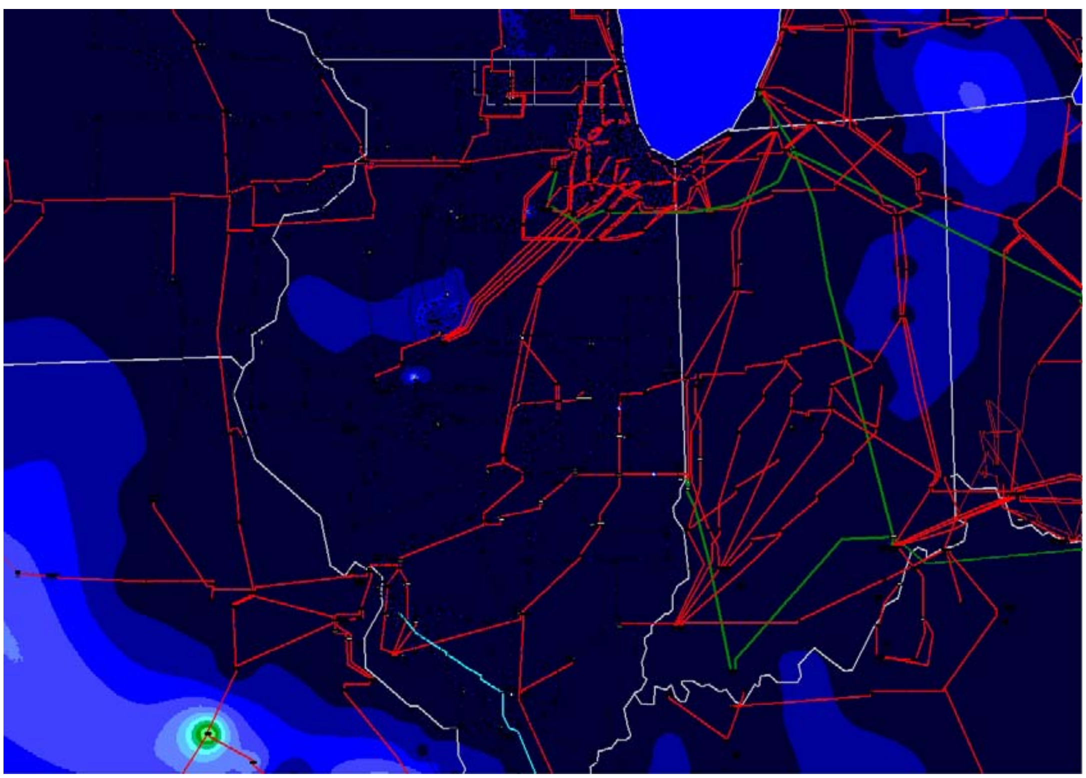

Figure F.1-28 Hours LMP Exceed $30/MWh for October to December 2007

Table F.1-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
33002	RS WALL	CILC	69	298	11,739
36544	K3192;4T	NI	138	218	8,847
36546	K3191;4T	NI	138	218	8,847
36548	K3192;4B	NI	138	218	8,847
36660	DAVIS; B	NI	138	218	8,847
36670	K3192;5T	NI	138	218	8,839
36874	K3192;5B	NI	138	218	8,839
36882	KANKE;BT	NI	138	218	8,837
36884	KANKE; B	NI	138	218	8,837
36562	BRADL; B	NI	138	218	8,837
36883	KANKE;RT	NI	138	218	8,837
36885	KANKE; R	NI	138	218	8,837
36661	DAVIS; R	NI	138	218	8,829
33001	EDWARDS1	CILC	69	282	8,217
33299	PEORIA	CILC	138	281	8,107
33300	PEKIN	CILC	138	279	7,714
33073	MIDWEST	CILC	69	278	7,700
36688	DIXON; B	NI	138	139	7,074
36689	DIXON; R	NI	138	139	7,071
33040	EASTERN	CILC	69	275	6,424
33023	HINES	CILC	69	273	6,192
33029	NORTHWST	CILC	69	273	5,970
36969	MAZON; R	NI	138	737	5,635
36027	DAVIS;3M	NI	138	147	5,475
36127	DAVIS;3C	NI	34.5	147	5,475
36968	MAZON; B	NI	138	235	5,273
36942	LOMBA; B	NI	138	25	5,141
37582	LOMBA;BP	NI	138	25	5,141
37114	PLEAS;BT	NI	138	25	5,116
37116	PLEAS; B	NI	138	25	5,116
33108	FARGO	CILC	69	267	4,913
36778	GLEND;BT	NI	138	25	4,501
36780	GLEND; B	NI	138	25	4,501
33088	HALLOCK	CILC	69	263	4,482
37369	WILMI;	NI	138	468	4,480
33175	MASON	CILC	138	337	4,403
32415	GALESBRG	IP	138	1,865	4,359
33144	HINES	CILC	138	262	4,209
37371	WILSO; R	NI	138	176	4,161
33146	EASTERN	CILC	138	264	3,994
32603	EGAL #1	IP	69	1,777	3,945

Table F.1-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
32602	EGAL #2	IP	69	1,774	3,934
36776	G ELL; B	NI	138	25	3,923
37048	NORDI; B	NI	138	25	3,911
37195	ROUND; R	NI	138	145	3,892
36981	MENDO;	NI	138	130	3,848
36982	MENDO; T	NI	138	130	3,848
37167	H440 ;RT	NI	138	130	3,823
37169	H440 ; R	NI	138	130	3,776
37168	H445 ;3B	NI	138	130	3,776
33152	PIONEERC	CILC	138	262	3,759
32601	MONB #5	IP	69	1,728	3,746
33155	HALLOCK	CILC	138	260	3,715
33084	TAZEWELL	CILC	69	264	3,708
32600	MONB #4	IP	69	1,713	3,700
37166	STEWA; B	NI	138	130	3,679
36483	ANTIO;RT	NI	138	104	3,602
36485	ANTIO; R	NI	138	104	3,602
32416	MONMOUTH	IP	138	1,656	3,488
33154	CAT MOSS	CILC	138	256	3,430
33151	RADNOR	CILC	138	256	3,426
37063	NB212; R	NI	138	25	3,270
36667	DEERF;RT	NI	138	25	3,225
36669	DEERF; R	NI	138	25	3,225
37141	J375 ; R	NI	138	682	3,222
37631	EQUIS; R	NI	13.8	682	3,222
36813	GURNE; R	NI	138	50	3,218
36578	BUTTE; B	NI	138	25	3,211
36794	GRACE; B	NI	138	22	3,203
37140	J375 ; B	NI	138	235	3,176
37630	EQUIS; B	NI	13.8	235	3,176
36843	HIGHL; R	NI	138	26	3,130
36658	DAVIS;1T	NI	138	231	3,094
37091	O ELM; R	NI	138	26	3,075
36471	J371 ; R	NI	138	669	3,071
36473	J371 ;RT	NI	138	669	3,071
36470	J371 ; B	NI	138	236	3,066
36472	J371 ;BT	NI	138	236	3,066
33150	FARGO	CILC	138	254	3,015
37066	J339 ; B	NI	138	236	2,987
37040	N LEN; B	NI	138	238	2,982
33143	CAT SUB2	CILC	138	257	2,979

Table F.1-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
37067	J339 ; R	NI	138	662	2,974
36448	ADDIS; B	NI	138	22	2,954
32334	ASHLEY	IP	138	119	2,941
36045	ITASC;1M	NI	138	27	2,937
36145	ITASC;1C	NI	34.5	27	2,937
36864	ITASC; B	NI	138	27	2,933
30439	CROSSVL	AMRN	138	528	2,888
36807	A450 ; R	NI	138	26	2,881
36433	1A431; R	NI	138	26	2,867
36439	1A431;5T	NI	138	26	2,867
37061	N CHI; R	NI	138	26	2,840
36754	FFORT; B	NI	138	230	2,785
36909	LAKEH; R	NI	138	29	2,782
36032	DRESD;1M	NI	138	613	2,722
36132	DRESD;1C	NI	34.5	613	2,722
36050	LISLE;2M	NI	138	26	2,709
36150	LISLE;2C	NI	34.5	26	2,709
36659	DAVIS;2T	NI	138	229	2,691

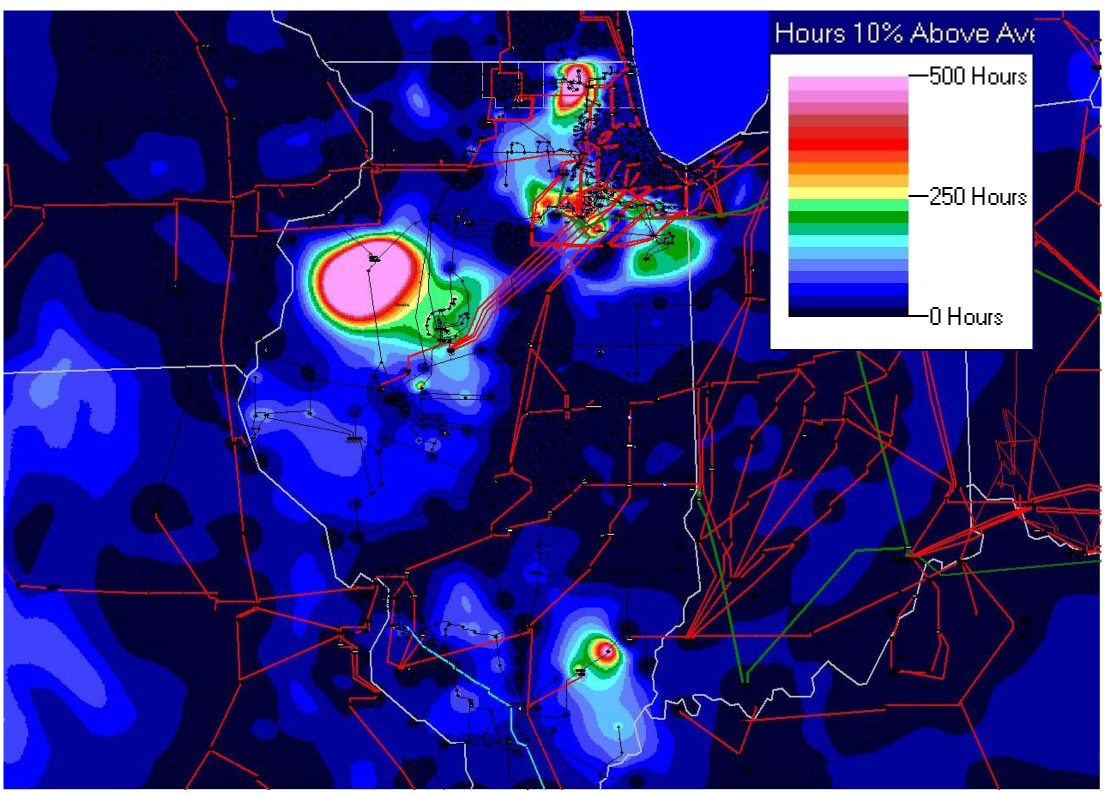

Figure F.1-29 Number of Hours Bus LMPs at Least 10% above the State Average

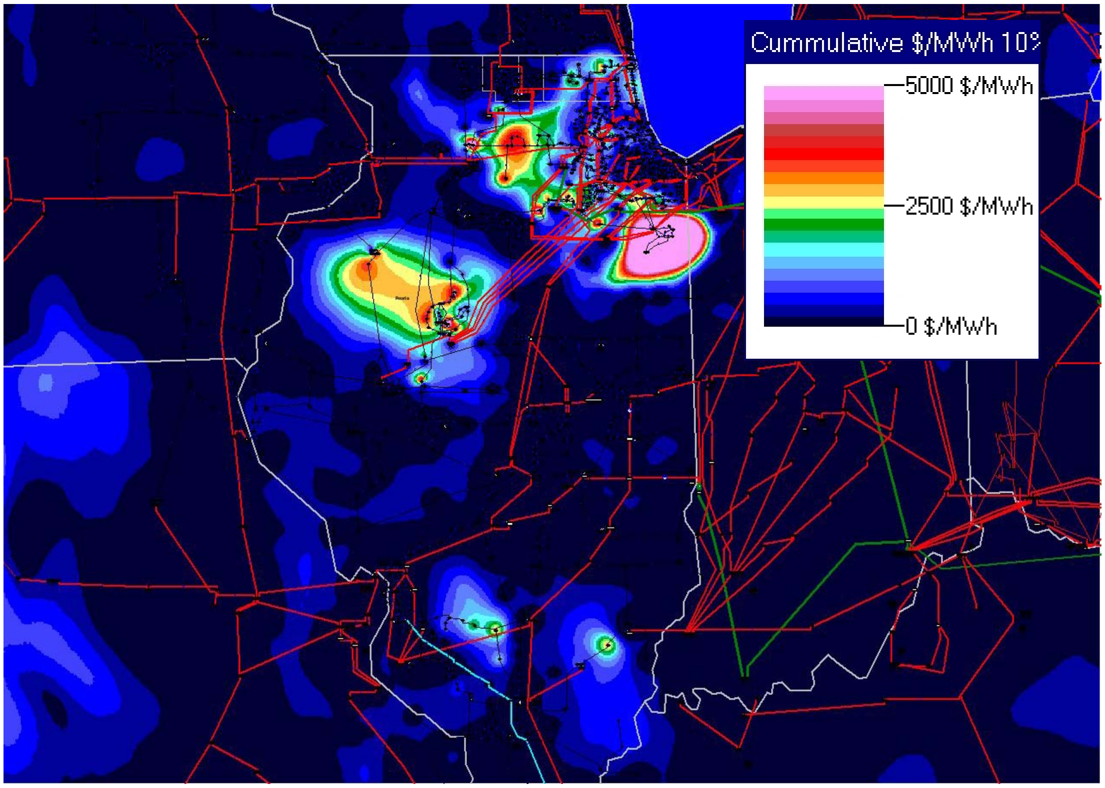

Figure F.1-30 Cumulative $/MWh 10% above the State Average

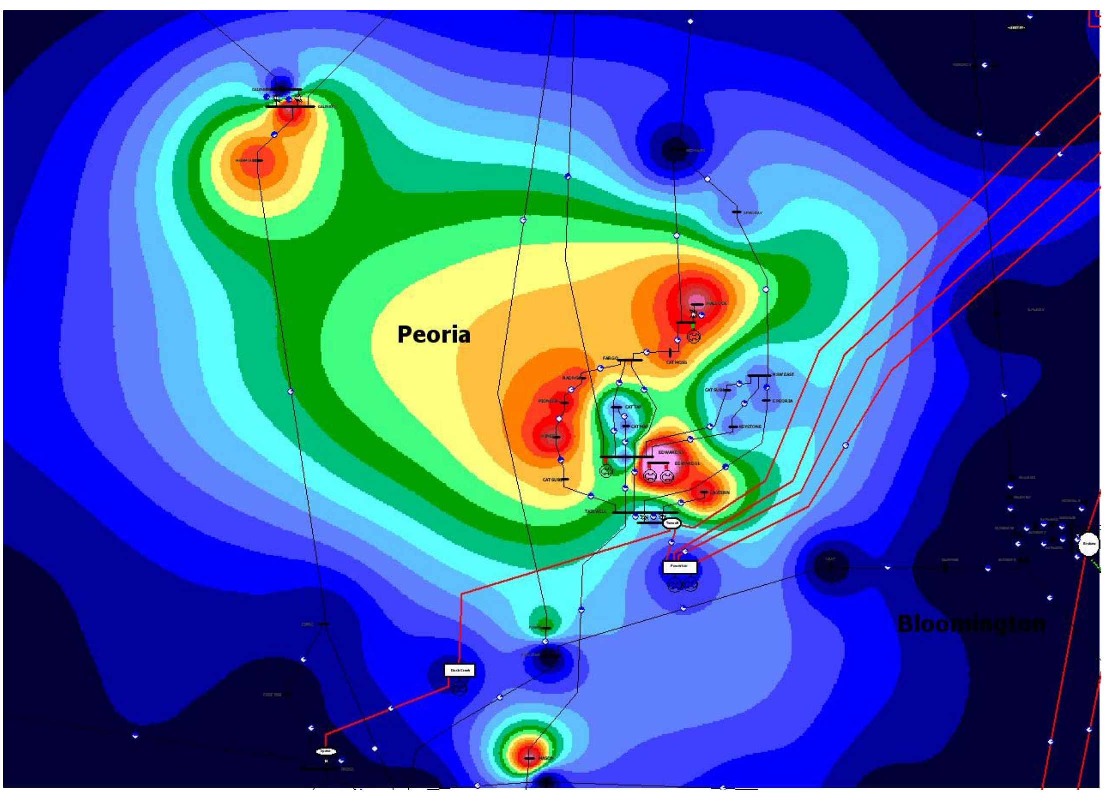

Figure F.1-31 Figure F.1-30 with Zoomed View of Peoria Area

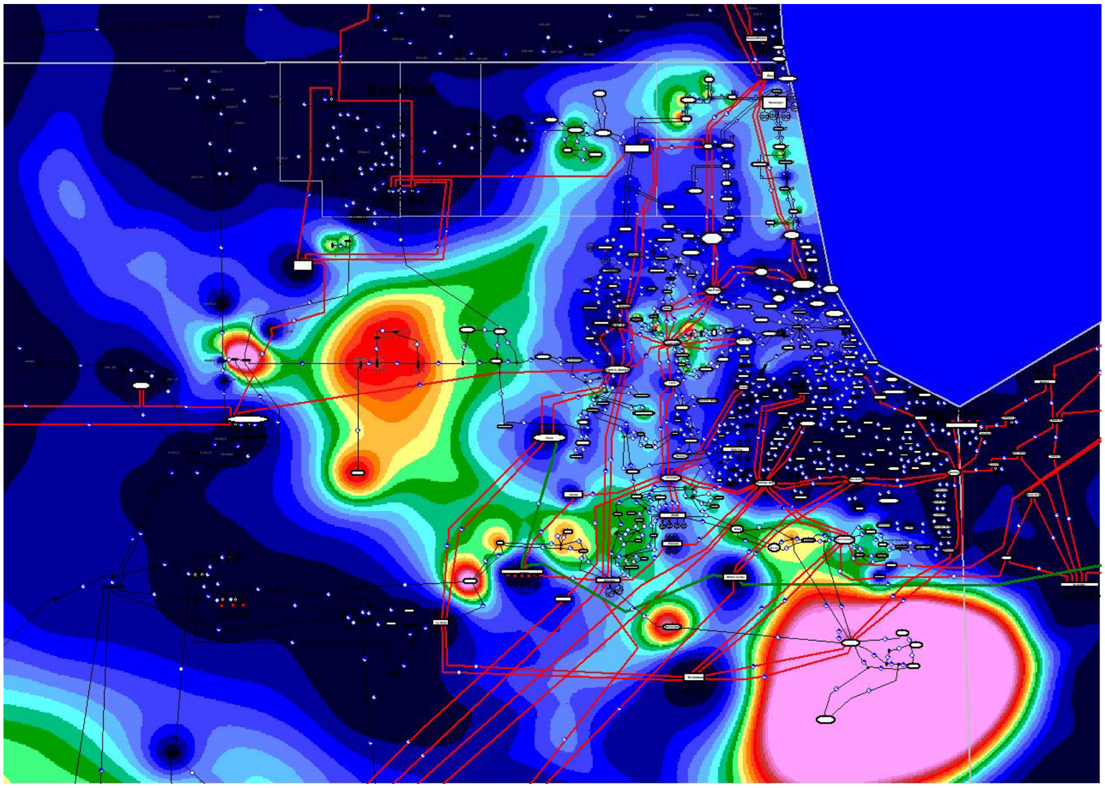

Figure F.1-32 Figure F.1-30 with Zoomed View of Northern Illinois

APPENDIX F.2

Appendix F.2 provides additional results for the modified case. The modified case is the same as the original case, except the generator cost curves have been modified to include a component that includes the impact of fixed costs in the generator bids. In general, higher fixed costs were added to out-of-state generators, causing Illinois to switch from being a net importer to being a net exporter.

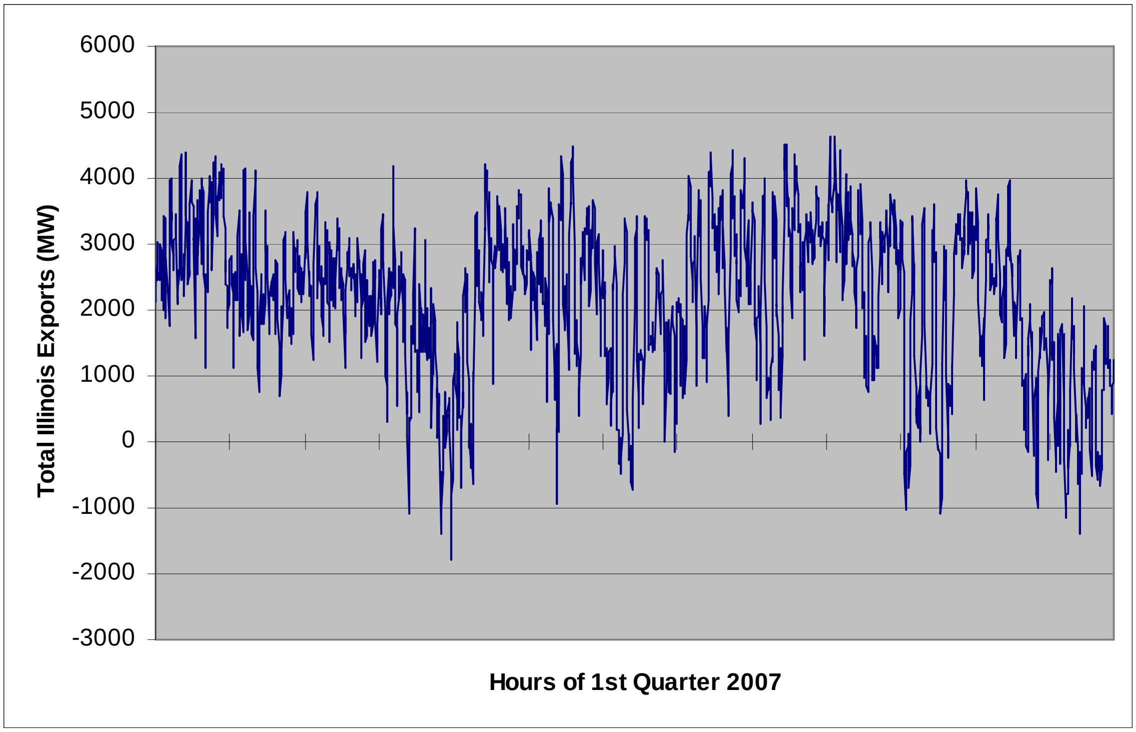

Figure F.2-1 Hourly Power Exports for Illinois during the 1st Quarter 2007

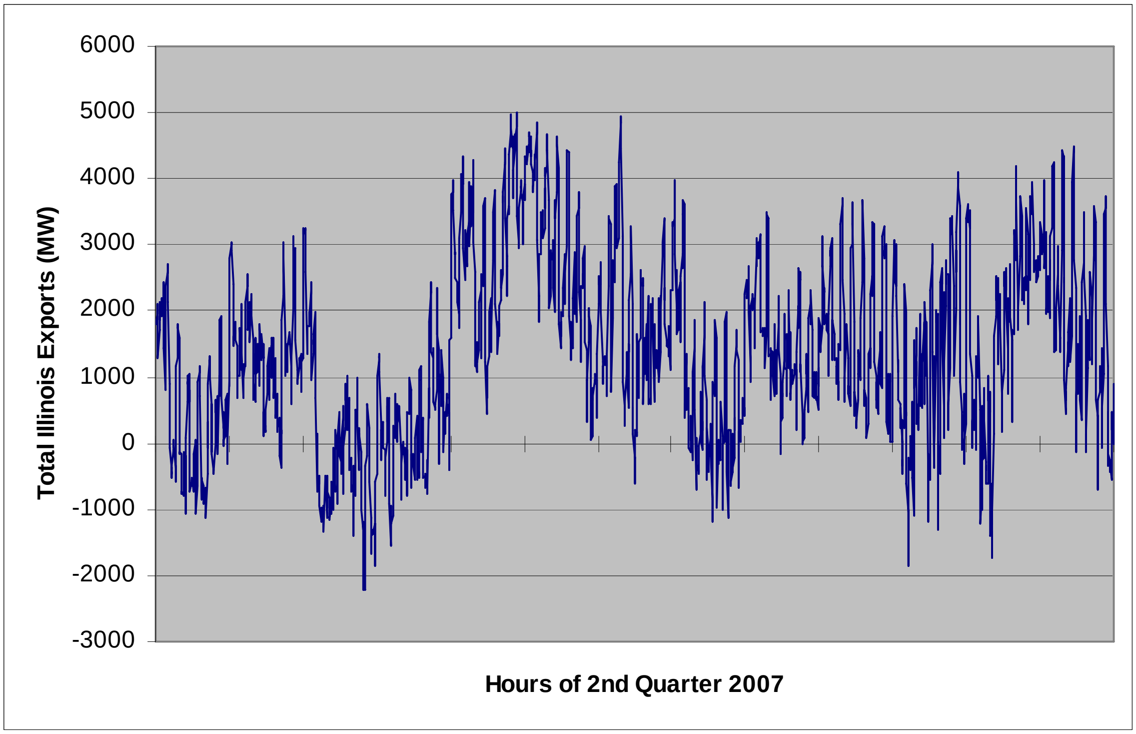

Figure F.2-2 Hourly Power Exports for Illinois in 2nd Quarter 2007

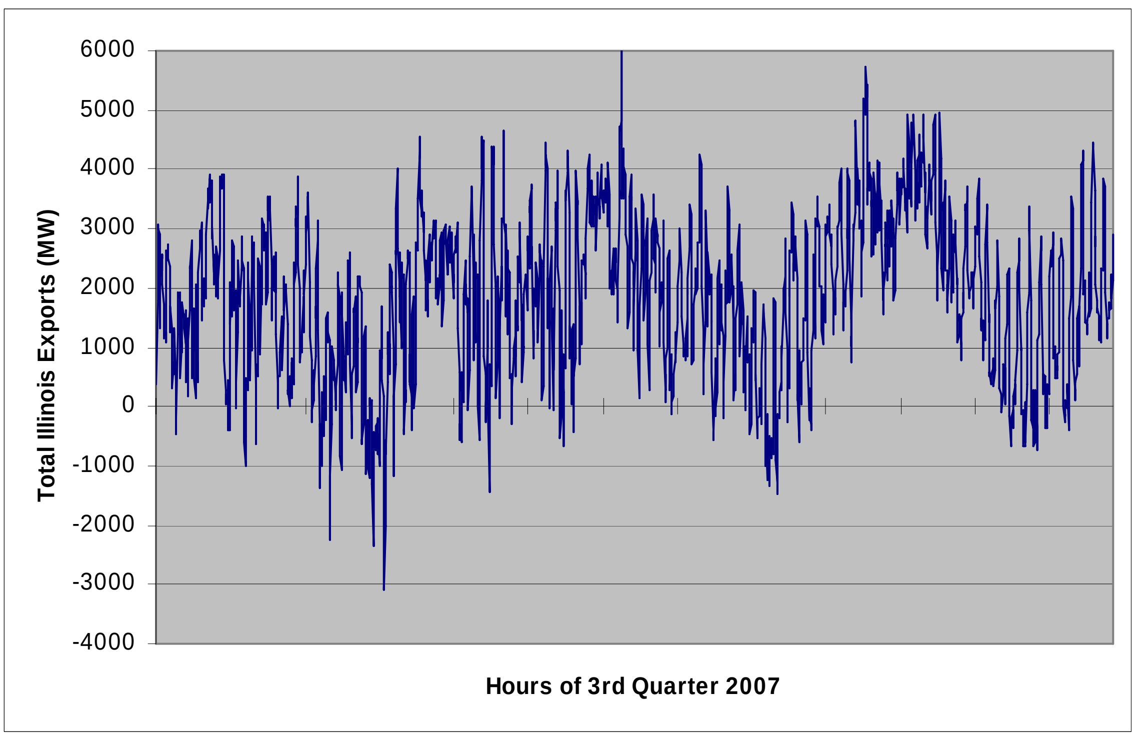

Figure F.2-3 Hourly Power Exports for Illinois in 3rd Quarter 2007

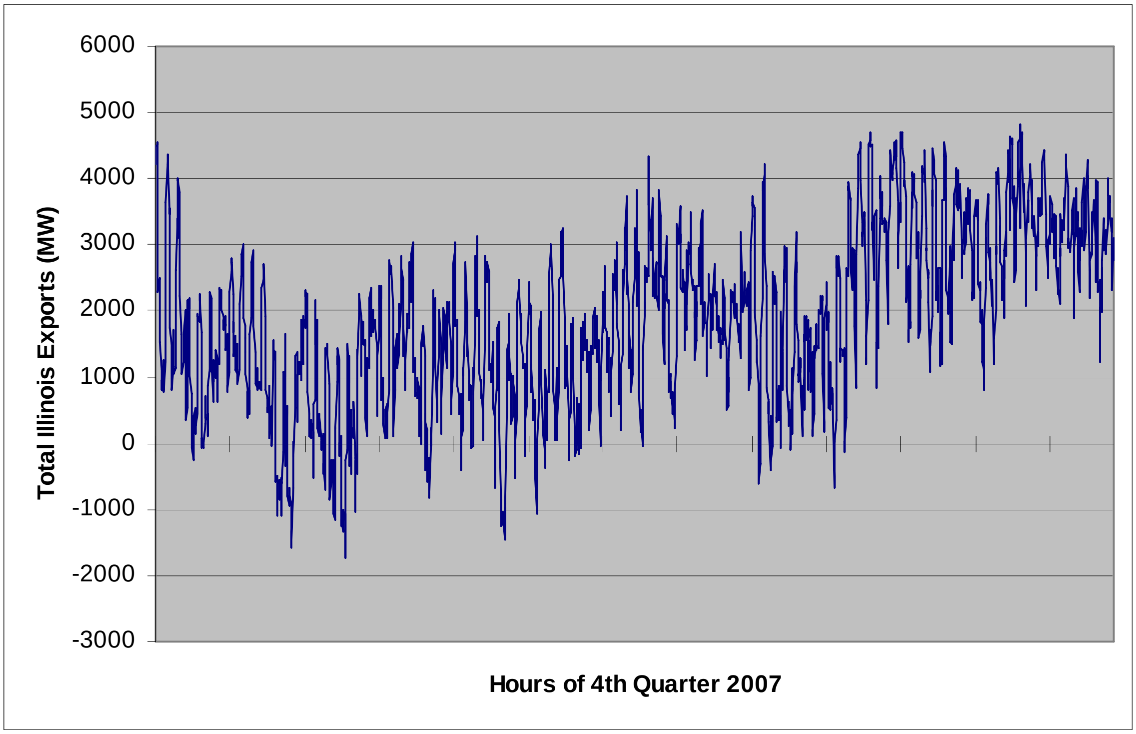

Figure F.2-4 Hourly Power Exports for Illinois in 4th Quarter 2007

Table F.2-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
WI	ARP 138	ARP 345	1	WIS39244ARP345-39785ROCKYRNC1	7,939	19.28	129.52
Ameren-MO	FRED TAP	FREDTOWN	1	AMRNMTL73	3,666	16.97	150.72
Ameren-MO	ORAN	STODDARD	1	AMRNMTL51	2,873	38.65	206.72
Brec-SIPC	14MORGAN	2GALTN_S	1	SIPC2761814LIVIN5-333525RNSHW_SC1	1,782	7.5	36.31
ComEd	MAZON; R	OGLES; T	1	345-L15502_B-R	1,750	10.78	60.49
WI	PAD 345	PAD 138	1	WIS39058PAD345-39119ROE345C1	1,727	12.5	70.12
IP	LAC N TP	GILSP TP	1	AMRNMTL71A	1,489	7.38	15.06
WI	BAIN 5	PLS PR4	2	WIS38850PLSPR3-38851PLSPR4C1	1,228	6.33	49.53
Ameren-IP	MASON CY	1346A TP	1	CIL-6	798	4.6	30.33
CILCO	HOLLAND	MASON	1	CIL-6	736	9.35	65.59
WI	EDG 345	CEDRSAUK	1	WIS38870GRANVL2-39433PTBCH1C1	734	0.98	4.92
IA (MEC)	DAVNPRT3	WALCOTT3	1	MEC64402LOUISA3-64403EMOLIN3C1	713	2.89	5.6
TVA	8CUMBERL	8DAVIDSO	1	TVA184228JVILLE-184258CUMBERLC1	677	0.83	13.47
ComEd	MAZON; R	OGLES; T	1	345-L2101-S	661	6.43	61.86
TVA	8JVILLE	8CUMBERL	1	TVA184258CUMBERL-184308DAVIDSOC1	641	14.07	37.76
Cinergy	08WEBSTE	08NEWLON	1	AEP2266505GRNTWN-2266705JEFRSOC1	595	3.43	57.91
Cinergy	08KOK HP	08KO IN5	1	AEP2266505GRNTWN-2266705JEFRSOC1	530	76.38	466.63
ComEd	MAZON; R	OGLES; T	1	CIL-6A	512	6.2	51.03
WI	OK CRK9	OC CRK6	1	WIS38857OCCRK8-39367OKCRKC1	502	0.53	14.96
Ameren-MO	MARIES	5MARIES	1	AMRNVSS17	483	78.58	201.72

Table F.2-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
ComEd	MAZON; R	OGLES; T	1	IP108	472	6.21	62.76
ComEd	MAREN;RT	P VAL; R	1	345-L15616-R	467	5.72	31.72
ComEd	MAZON; R	OGLES; T	1	345-L0302_B-S	345	3.83	54.56
SIPC	2CARML_S	2HMLTN_S	99	AMRNVSS76	322	35.02	88.57
ComEd	FISK ; R	FISK STR	19	TR81_TAYLR_R-C	305	16.43	155.7
Ameren-MO	CEE TAP	CENTRAL	1	AMRNMTL55	262	2.71	12.01
WI	DEAD RVR	DR NEU1	1	WIS39917DEADRVR-39898DRNEU1AC1	242	0.14	1.05
ComEd	FISK ; B	FISK STR	19	TR82_TAYLR_B-C	192	9.31	28.46
ComEd-WI	ZION ; R	PLS PR2	1	345-L17101-R	189	0.17	1.37
ComEd	SLINE;5S	WASHI; R	1	345-L17723_B-C	182	10.74	141.11
CILCO	RS WALL	RSW EAST	1	Basecase	178	205.88	1000
ComEd	LASCO; B	MAZON; B	1	345-L1223_R-S	171	13.27	47.54
ComEd	CLYBO; B	CROSB; B	1	138-L4018_R-C	157	0.67	14.32
ComEd	CLYBO; B	CROSB; B	1	345-L4621_B-N	145	1.83	31.42
Ameren-MO	HAMLTNAM	HAMLTNAM	1	AMRNMTL32	144	6.49	14.83
ComEd	HILLC;6B	WILL ;BT	1	138-L0907_B-S	143	9.31	12.73
IP	SPRTA TP	ARCH TAP	1	IP30	142	4.25	23.74
ComEd	DAVIS; B	DAVIS;3M	1	345-L17704_R-S	139	74.69	546.83
ComEd	WAUKE; B	ZION ;	1	345-L2221_R-N	132	1.36	4.29
ComEd	ELMHU;3I	F PAR; B	1	TR81_ELMHU_R-N	127	8.11	140.69
IP	LAC N TP	GILSP TP	1	IP95	124	7.83	12.21
Cinergy	08GALAGH	08GALAGH	1	AEP2266705JEFRSO-2267105ROCKPTC1	118	0.66	1.5
BREC-SIPC	14MORGAN	2GALTN_S	1	IP98	118	48.92	134.34
SIPC	2CARML_S	2HMLTN_S	99	SIPC31023MARIONS-333515MRN_PLNC1	117	41.74	84.74
ComEd	DIXON; R	NELSO;RT	1	138-L15507_B-R	108	101.67	494.23
ComEd	BARTL;BT	SPAUL; B	1	345-L14402_B-N	103	5.15	23.63
CILCO	HOLLAND	MASON	1	345-L0304_R-S	98	28.46	91.04
IP-ComEd	PWR JCTB	POWER;	1	CIL-6A	89	13.84	92.51
Ameren-CWLP	AUBURN N	CHATHAM	1	IP109	88	2.59	27.04
ComEd	ELECT;3R	ELECT;3M	1	TR84_ELECT_R-N	87	3.44	16.38
ComEd	SLINE;2S	WASHI; B	1	138-L0708_B-C	84	3.62	24.11
ComEd	TOLLW; B	TOLLW;3M	1	138-L7910_B-R	84	4.26	21.6
Ameren-IP	MASON CY	1346A TP	1	CIL-6A	83	4.58	23.67
ComEd	JEFFE; B	KINGS; B	1	138-L1110_B-C	82	14.12	137.33
ComEd	RIDGE; B	RIDGE;BS	1	138-L5118_B-S	79	18.69	215.76
IA (ALTW)	HAZLTON5	HAZLTON3	1	ALTW34020HAZLS5-34018HAZLTON3C2	79	47.41	73.64
AEP	05BENTON	05COOK	1	AEP2265405COOK-2853818PALISAC1	79	3.34	16.54
IP	MT VRNON	ASHLEY	1	IP96	78	40.63	133.72
Ameren-MO	CEE TAP	CENTRAL	1	Basecase	73	4.16	12.95
IN	07RAMSEY	07RAMSY5	2	CIN2518107RAMSY5-2538808SPEEDC1	72	549	1000
WI	EDG 345	CEDRSAUK	1	WIS38898PTBCH2-39433PTBCH1C1	69	1.07	3.86

Table F.2-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
ComEd	HILLC;6B	WILL ;BT	1	Basecase	69	9.25	17.28
WI	EDG 138	EDG 345	1	WIS39215EDG138-39214EDG345C2	66	228.55	389.86
ComEd	Y450 ; R	CONGR; R	1	Basecase	66	12.52	200.55
Ameren	ALBION	CROSSVL	1	IP96	65	12.41	56.18
ComEd	MAZON; R	OGLES; T	1	TR81_DRESD_B-S	60	12.54	46.73
ComEd	HARBO;8S	UNIVE; B	1	345-L17723_B-C	57	2.47	11.48
Cinergy	08BUFTN1	08BUFTN1	1	CIN2496206PIERC2-2602908FOSTERC1	55	111.11	224.67
Ameren	EFFINGHM	NEWTON	1	AMRNVSS35	53	3.4	27.03
Ameren	HAMLTNAM	KH2 XFMR	1	AMRNMTL32	52	15.36	22.46
ComEd	UNIVE; B	WASHI; B	1	138-L13701_R-C	51	0.26	0.34
WI	WESTONWP	WESTON	1	WIS39245ARP138-39244ARP345C1	51	0.95	1.71
ComEd	D799 ;6B	RIDGE; B	1	138-L1321_G-C	50	48.38	230.38
ComEd	CROSB; R	ROCKW; R	1	138-L6721_B-C	47	0.49	1.37
ComEd	DIXON; B	NELSO; B	1	138-L15508_R-R	45	88.71	463.33
ComEd	O PAR; B	RIDGE;9I	1	Basecase	41	0.59	1.9
ComEd	ELWOO; R	GOODI;1R	1	345-L1223_R-S	39	8.23	36.39
ComEd	DEVON;3R	ROSEH;RT	1	138-L11416_R-C	38	49.92	331.8
Ameren	ALBION	CROSSVL	1	IP98	36	25.31	93.9
ComEd	SLINE;2S	WASHI; B	1	345-L17723_B-C	36	0.25	0.45
Cinergy	08M.FTHS	08MFTM9	1	Basecase	35	48.08	109.45
WI	WESTONWP	WESTON	1	Basecase	35	1.19	2.06
ComEd-WI	ZION ; R	PLS PR2	1	WIS36406WEMPL;B-39058PAD345C1	31	0.16	0.43
ComEd	F PAR;0S	NATOM; R	1	345-L12002_R-N	31	0.48	3.06
CILCO	HOLLAND	MASON	1	345-L2101-S	31	3.42	7.12
ComEd	DAVIS;3M	DAVIS; B	1	345-L17704_R-S	27	65.3	313.8
ComEd	E FRA; R	GOODI;1R	1	Basecase	26	6.82	27.49
ComEd	TAYLO; R	TAYLO;1M	1	TR82_TAYLR_B-C	26	64.32	215.94

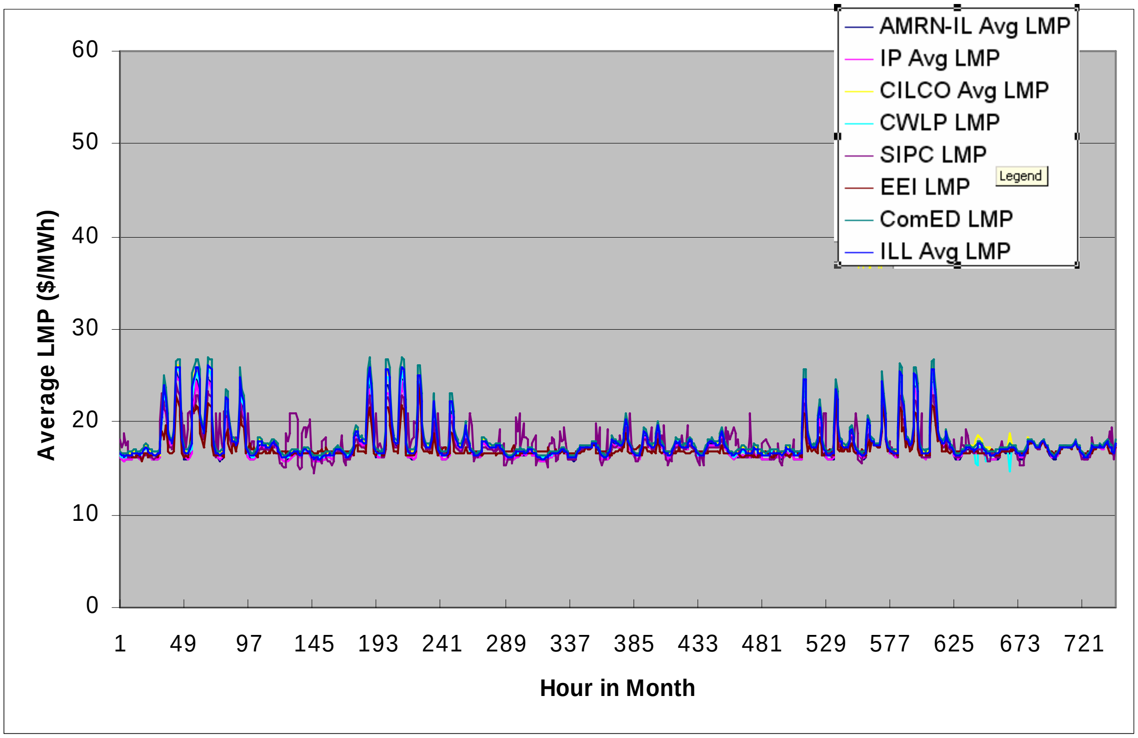

Figure F.2-5 Average LMPs for January 2007

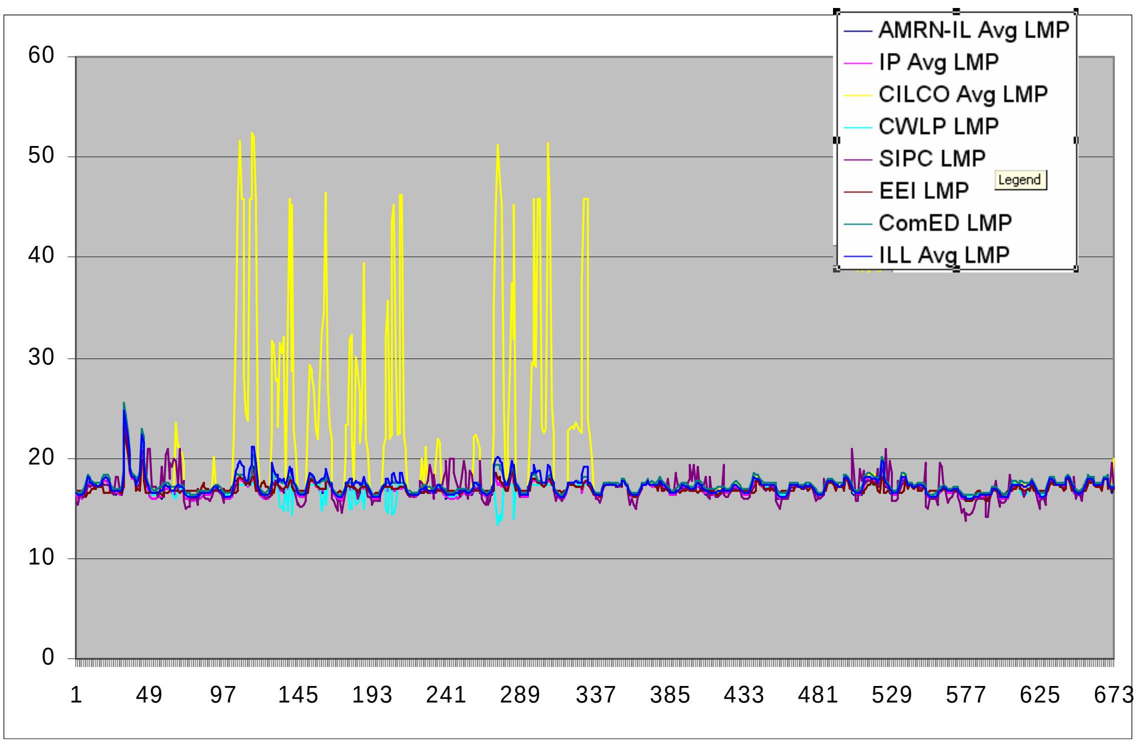

Figure F.2-6 Average LMPs for February 2007

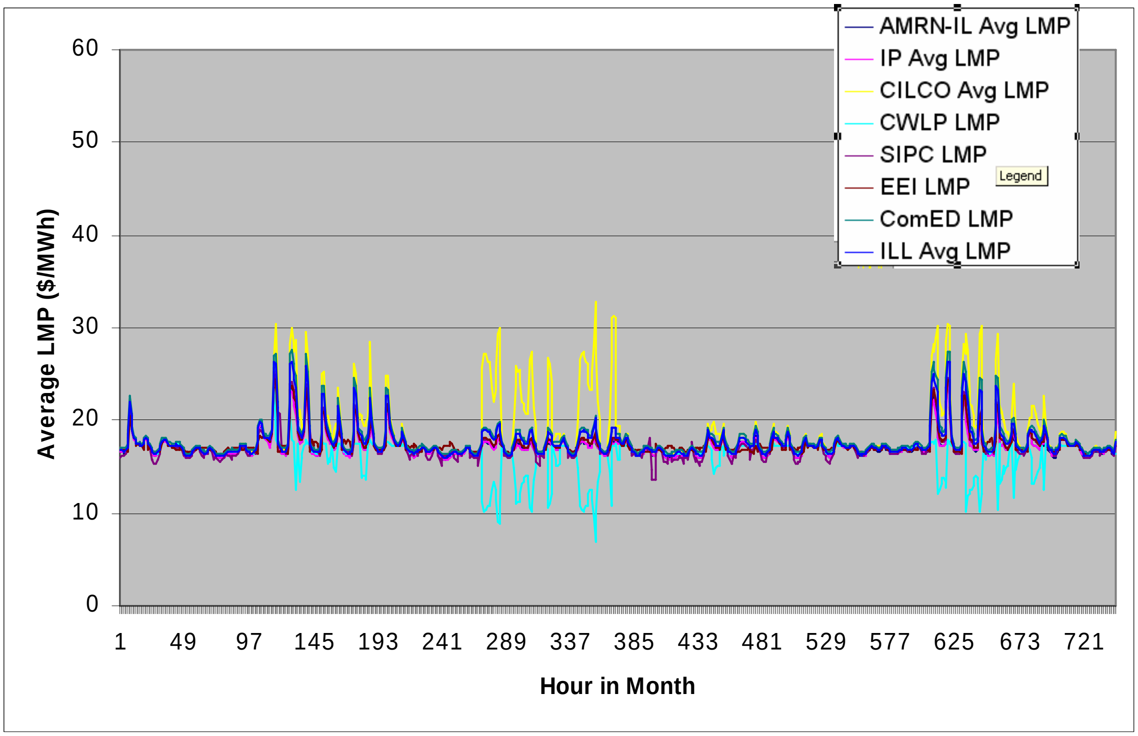

Figure F.2-7 Average LMPs for March 2007

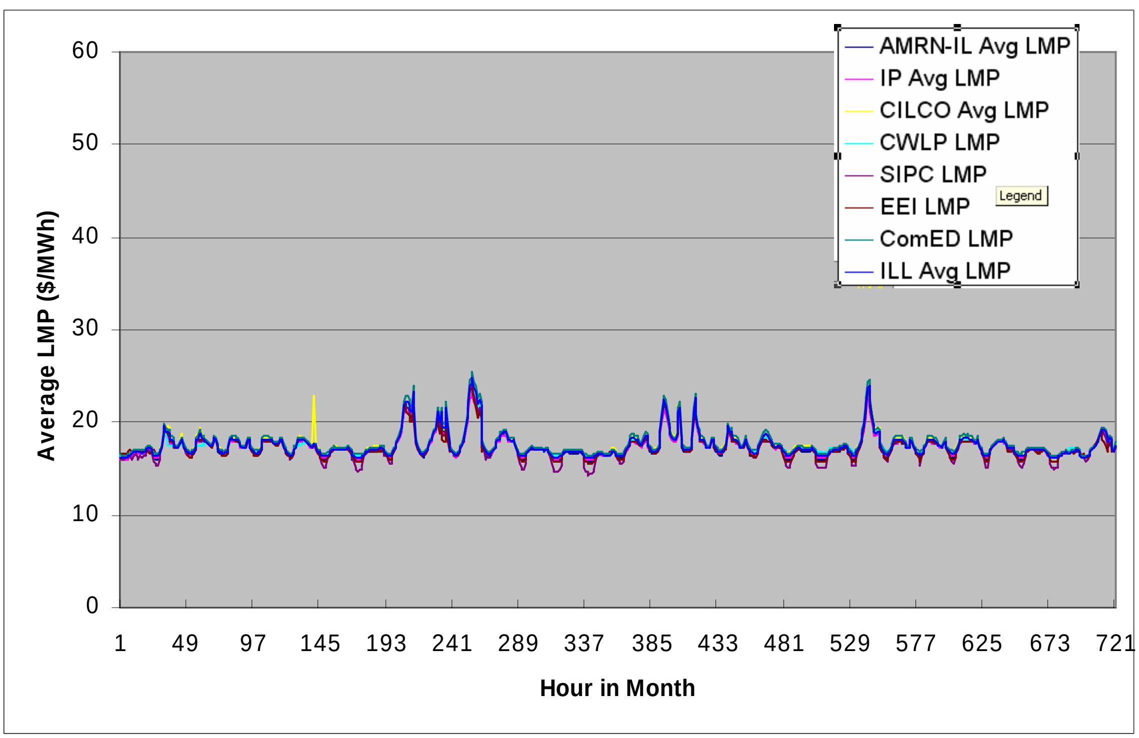

Figure F.2-8 Average LMPs for April 2007

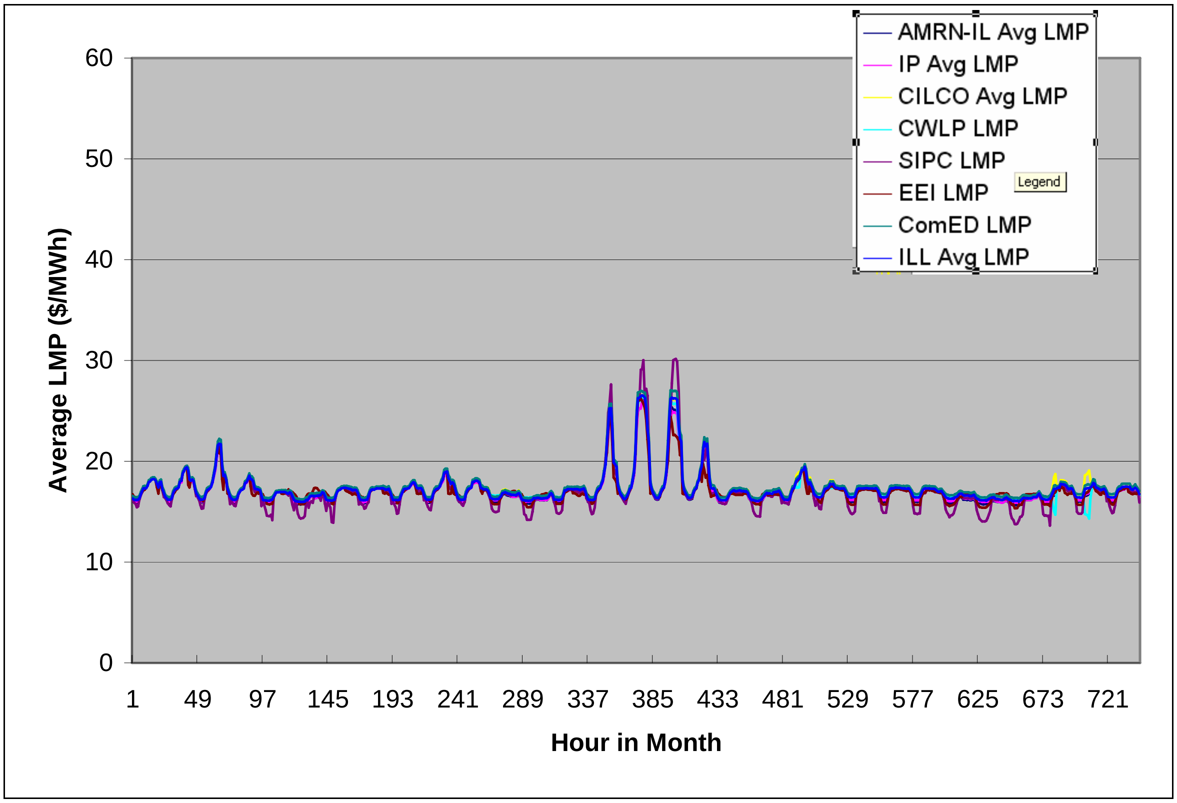

Figure F.2-9 Average LMPs for May 2007

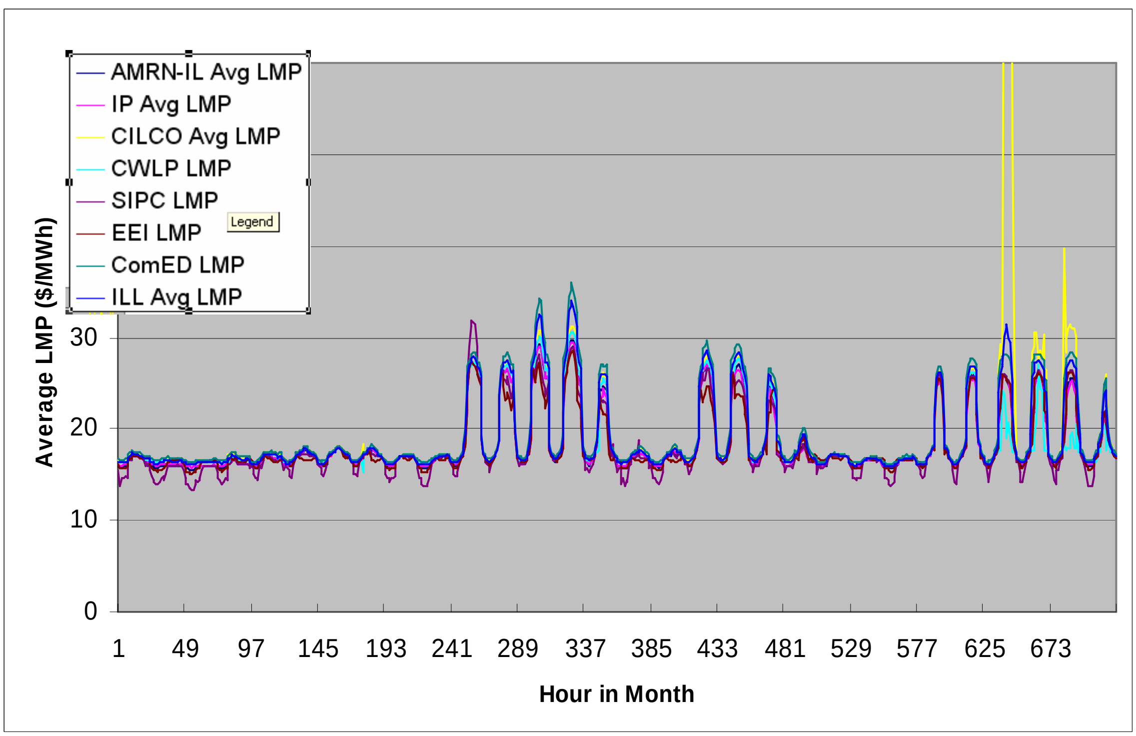

Figure F.2-10 Average LMPs for June 2007

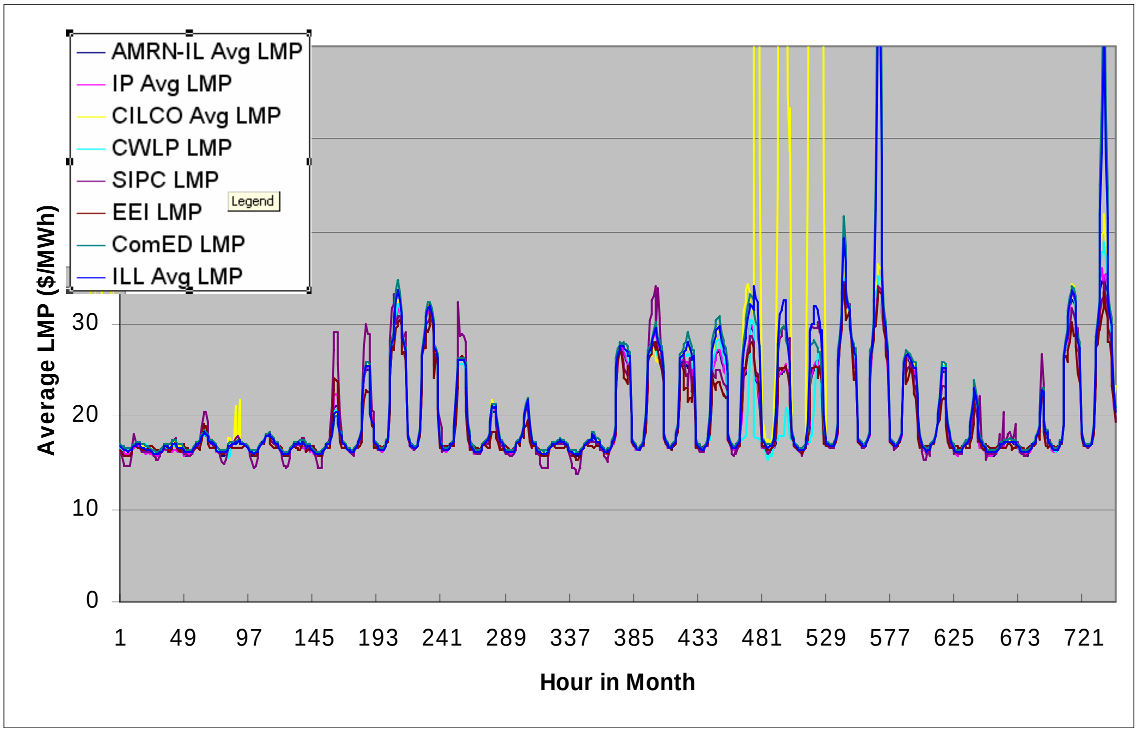

Figure F.2-11 Average LMPs for July 2007

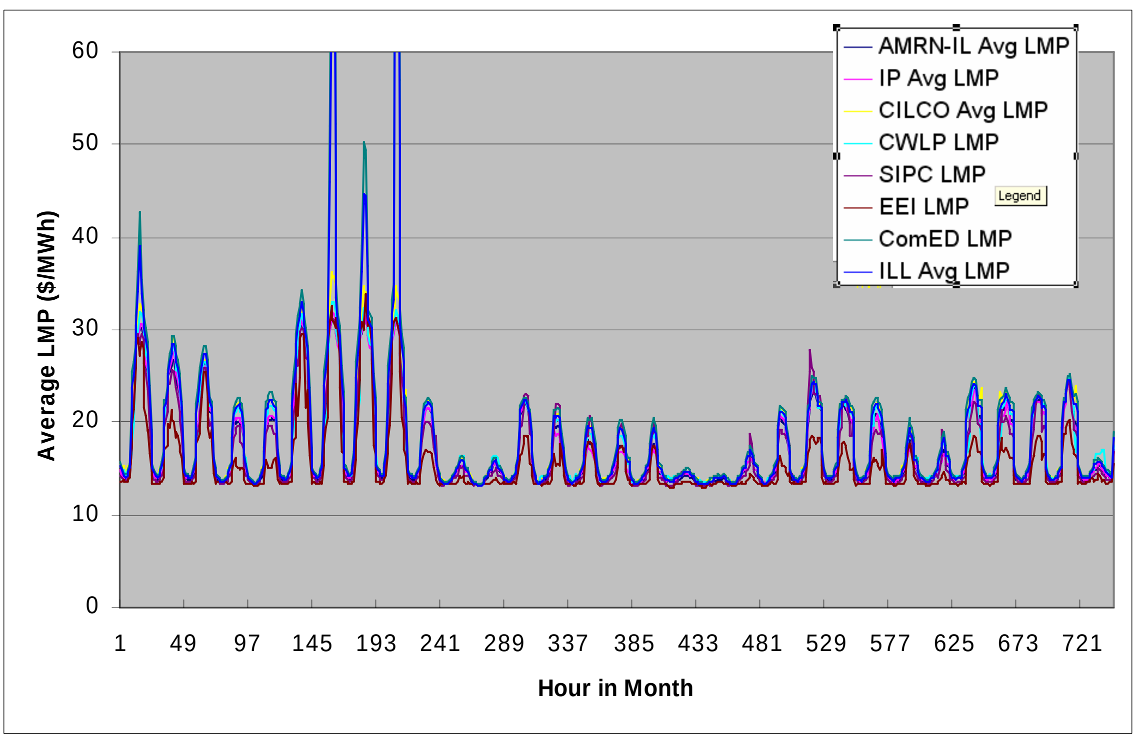

Figure F.2-12 Average LMPs for August 2007

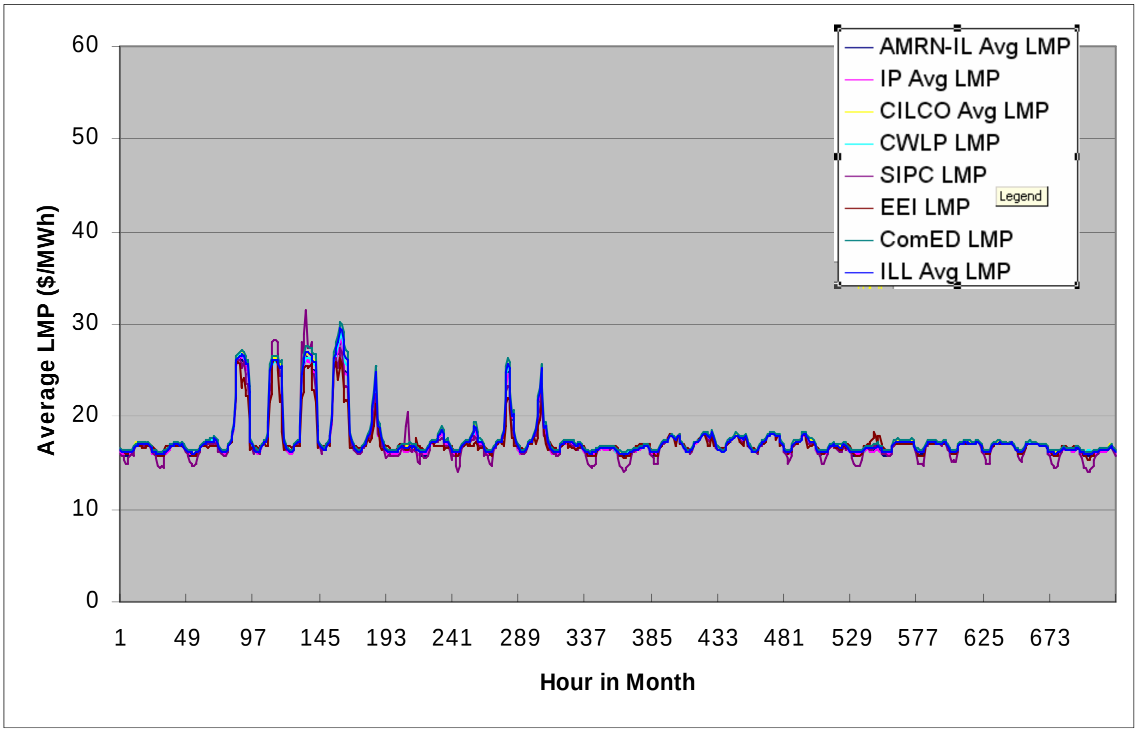

Figure F.2-13 Average LMPs for September 2007

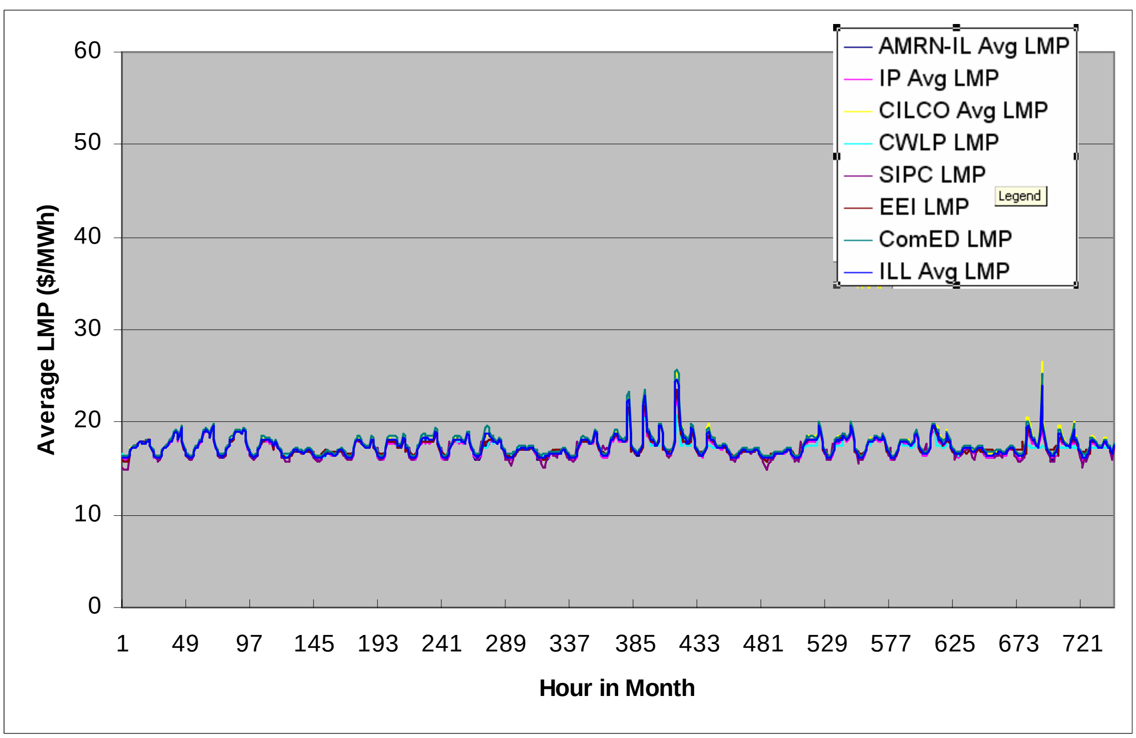

Figure F.2-14 Average LMPs for October 2007

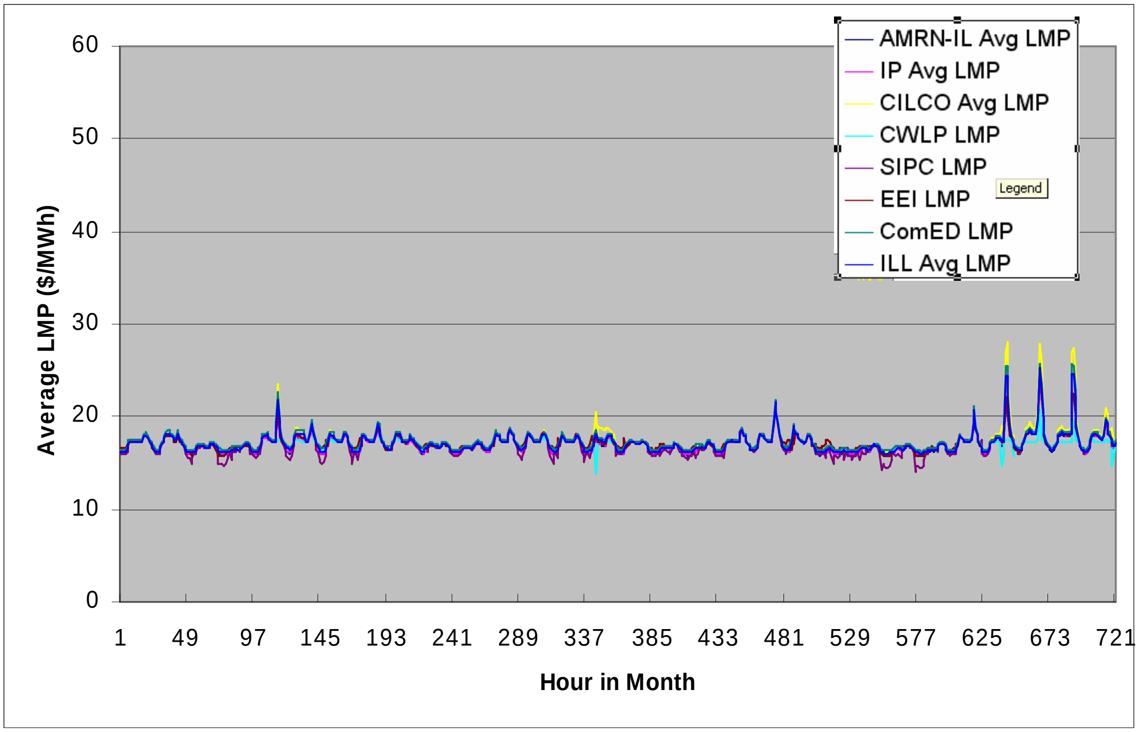

Figure F.2-15 Average LMPs for November 2007

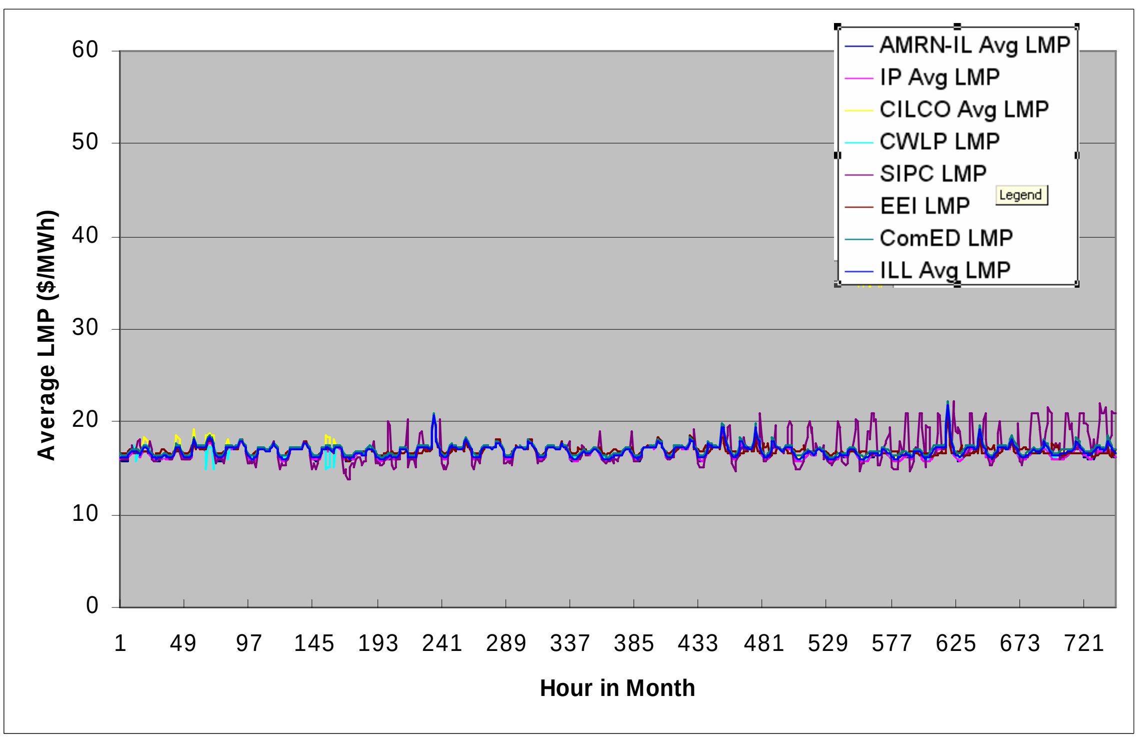

Figure F.2-16 Average LMPs for December 2007

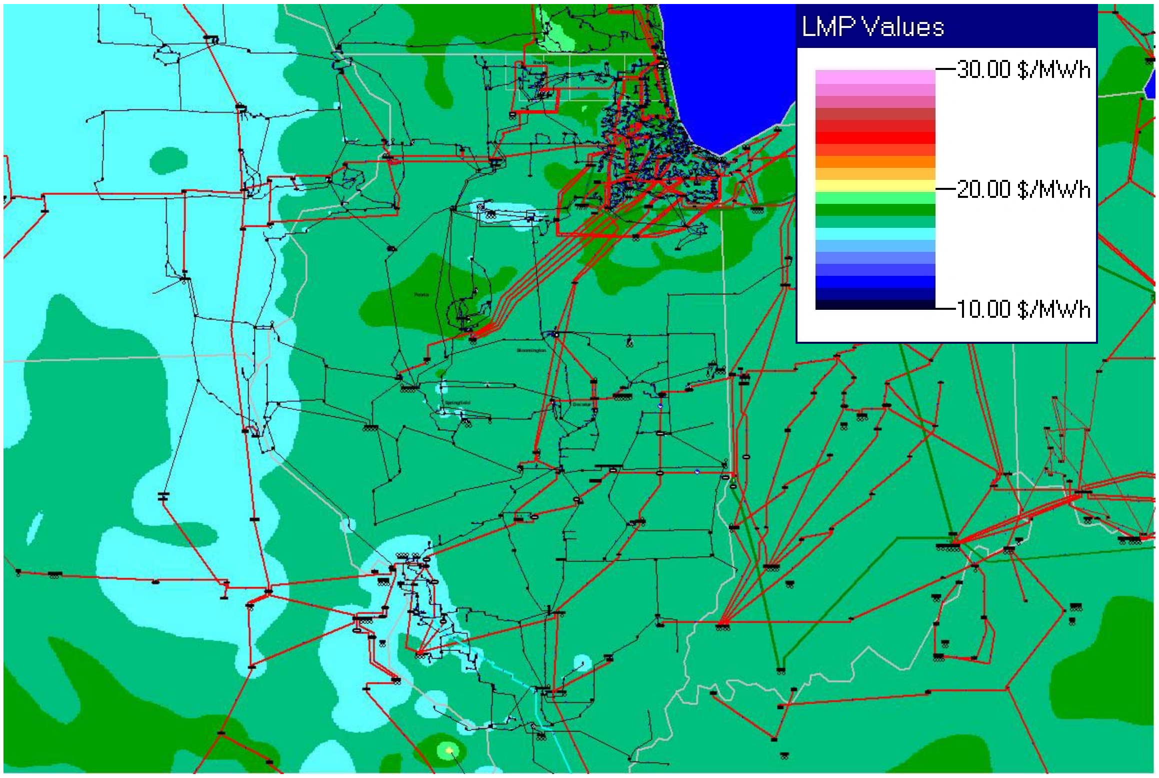

Figure F.2-17 Average LMPs for January to March 2007

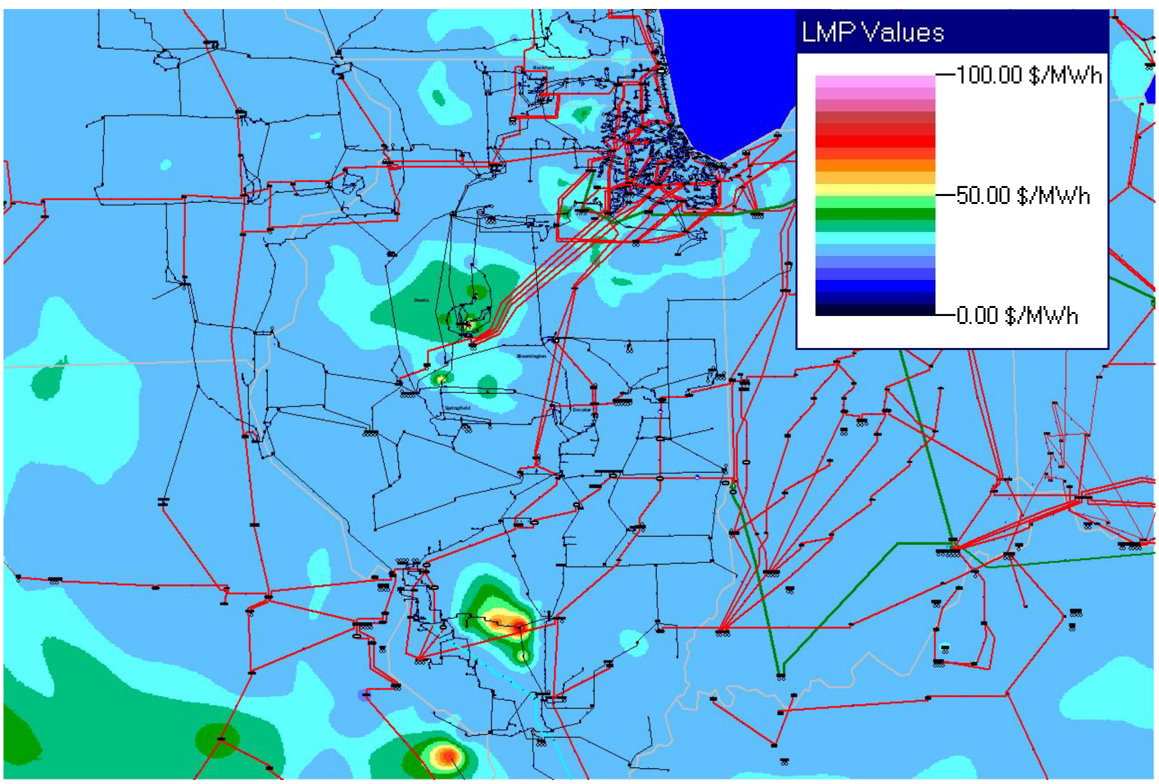

Figure F.2-18 Highest LMPs for January to March 2007

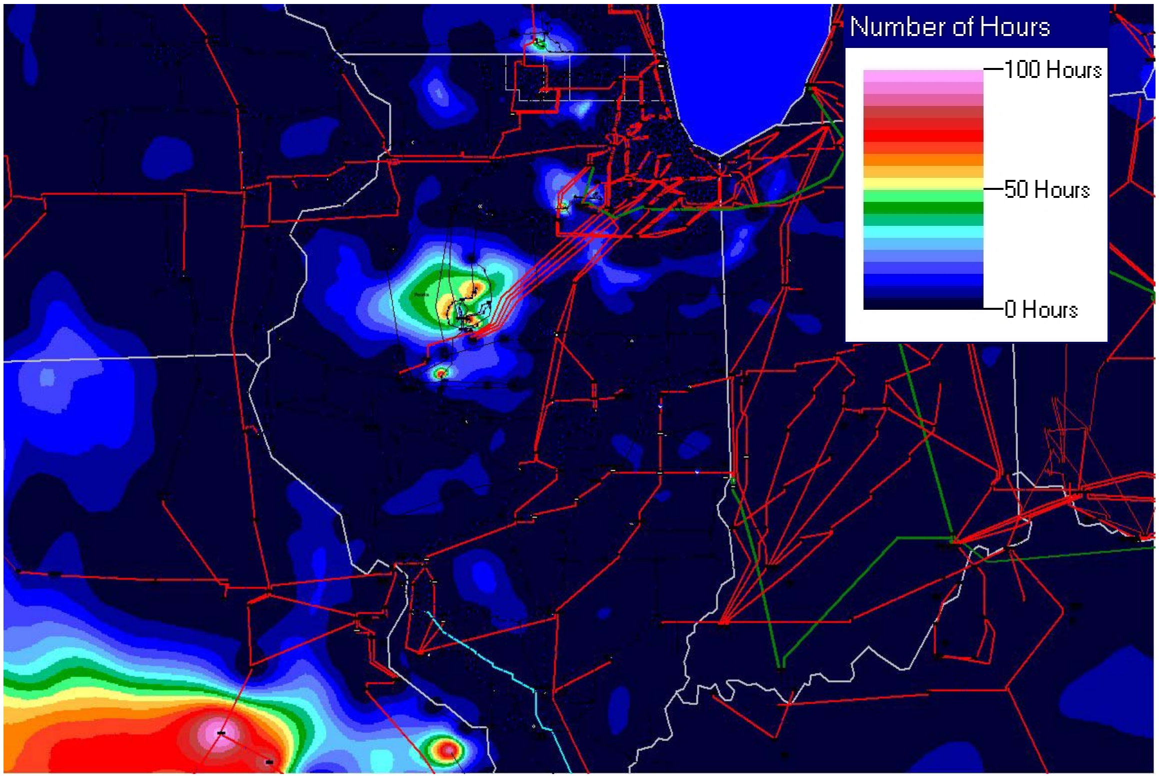

Figure F.2-19 Hours LMP Exceed $30/MWh for January to March 2007

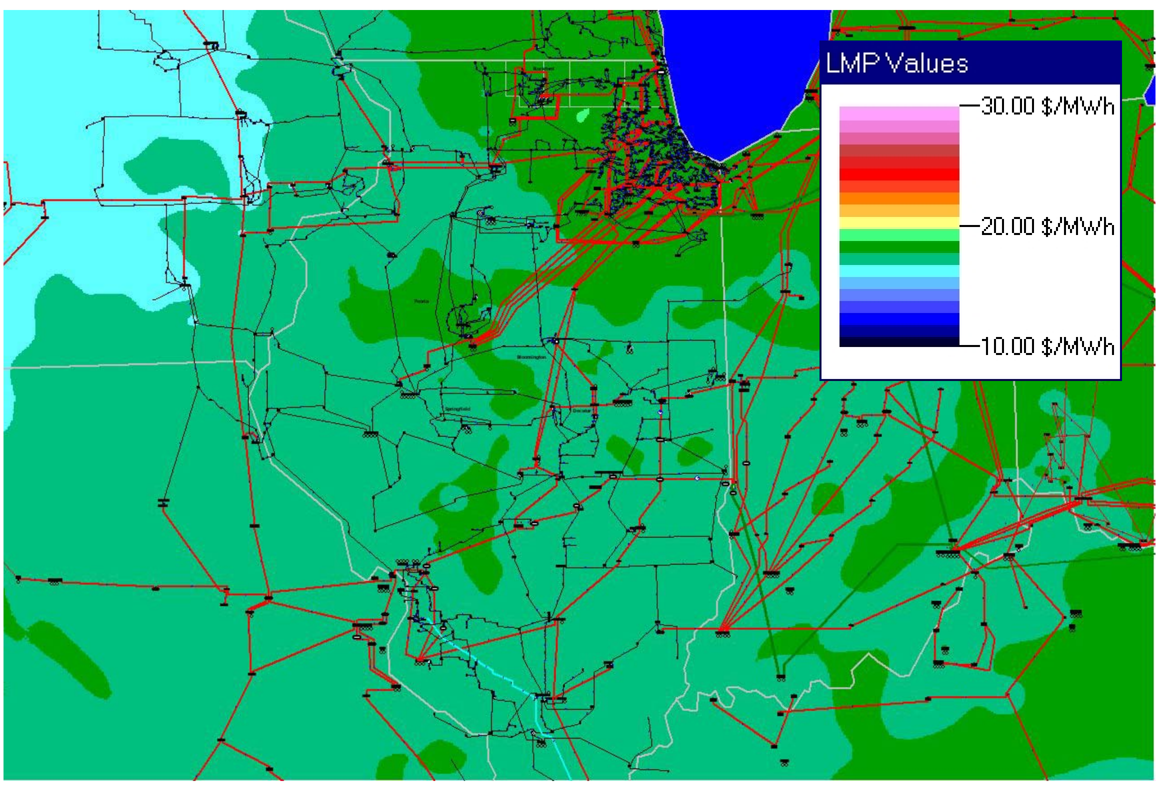

Figure F.2-20 Average LMPs for April to June 2007

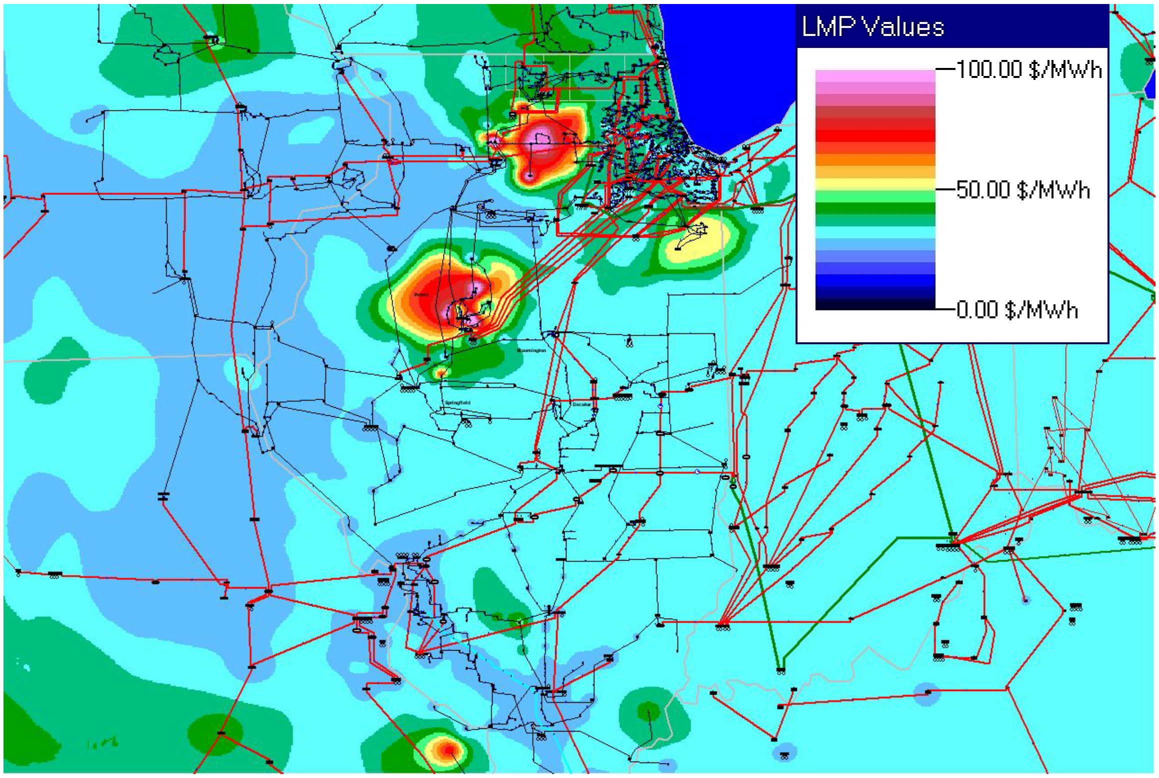

Figure F.2-21 Highest LMPs for April to June 2007

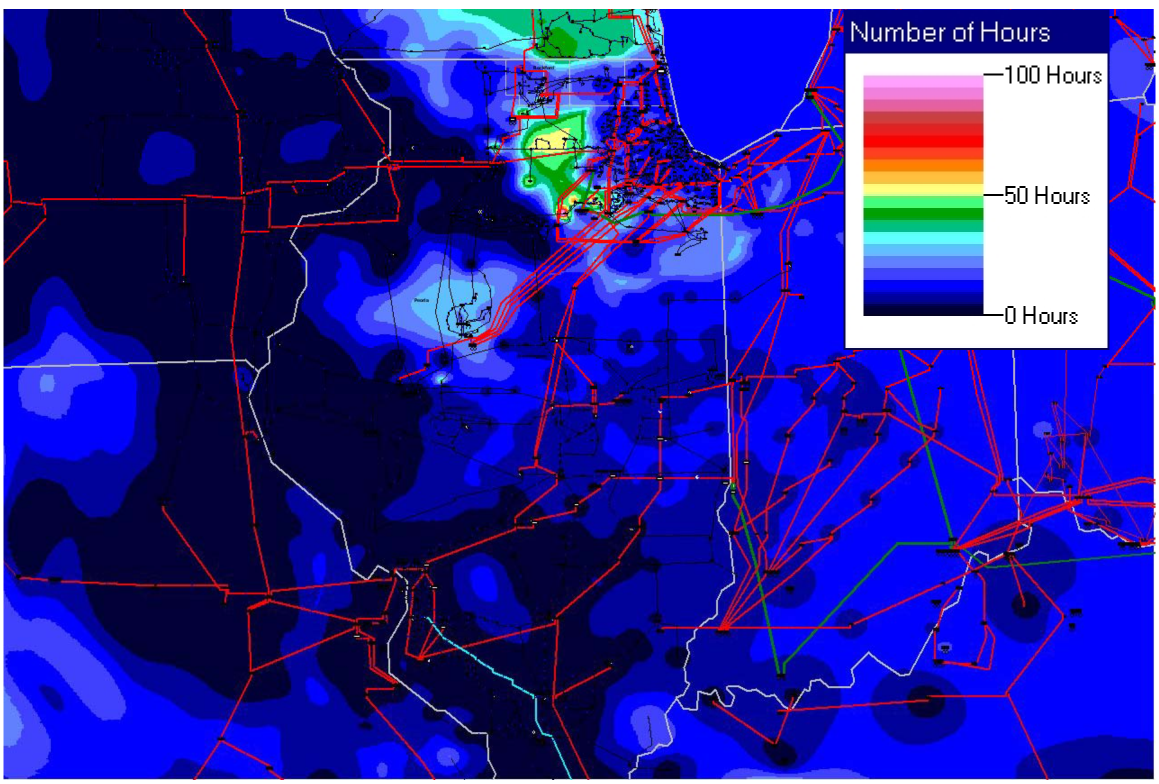

Figure F.2-22 Hours LMP Exceed $30/MWh for April to June 2007

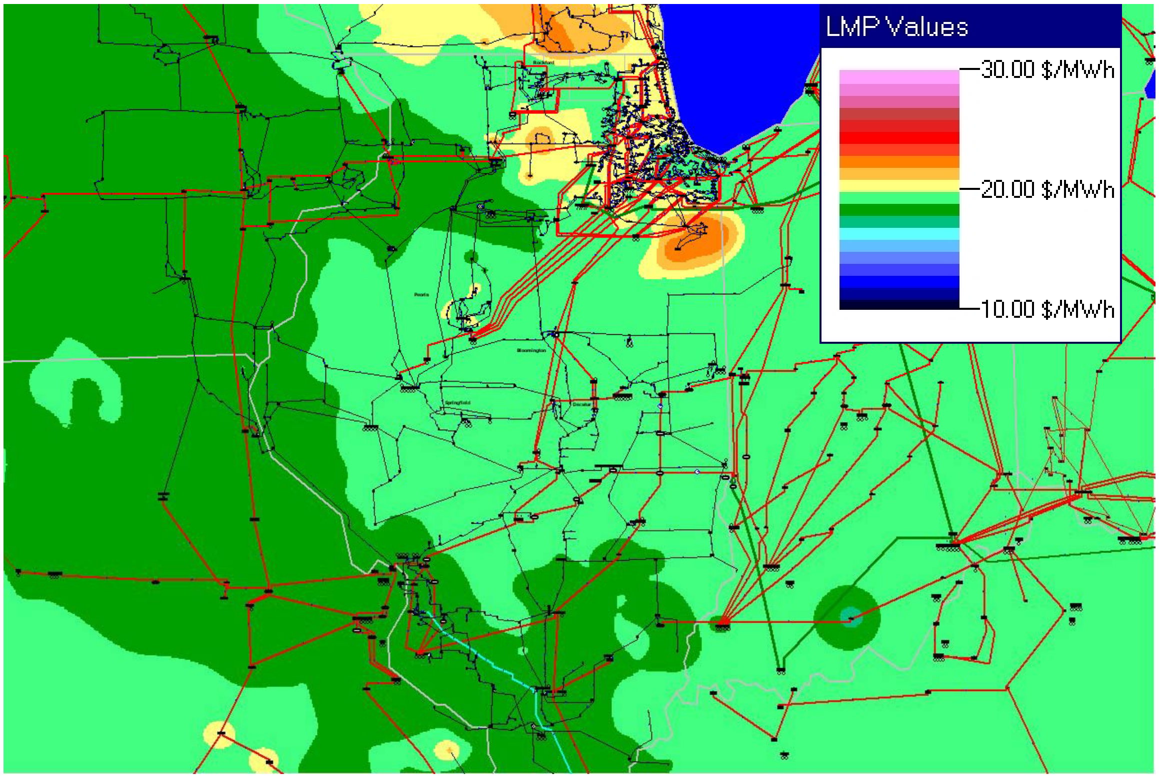

Figure F.2-23 Average LMPs for July to September 2007

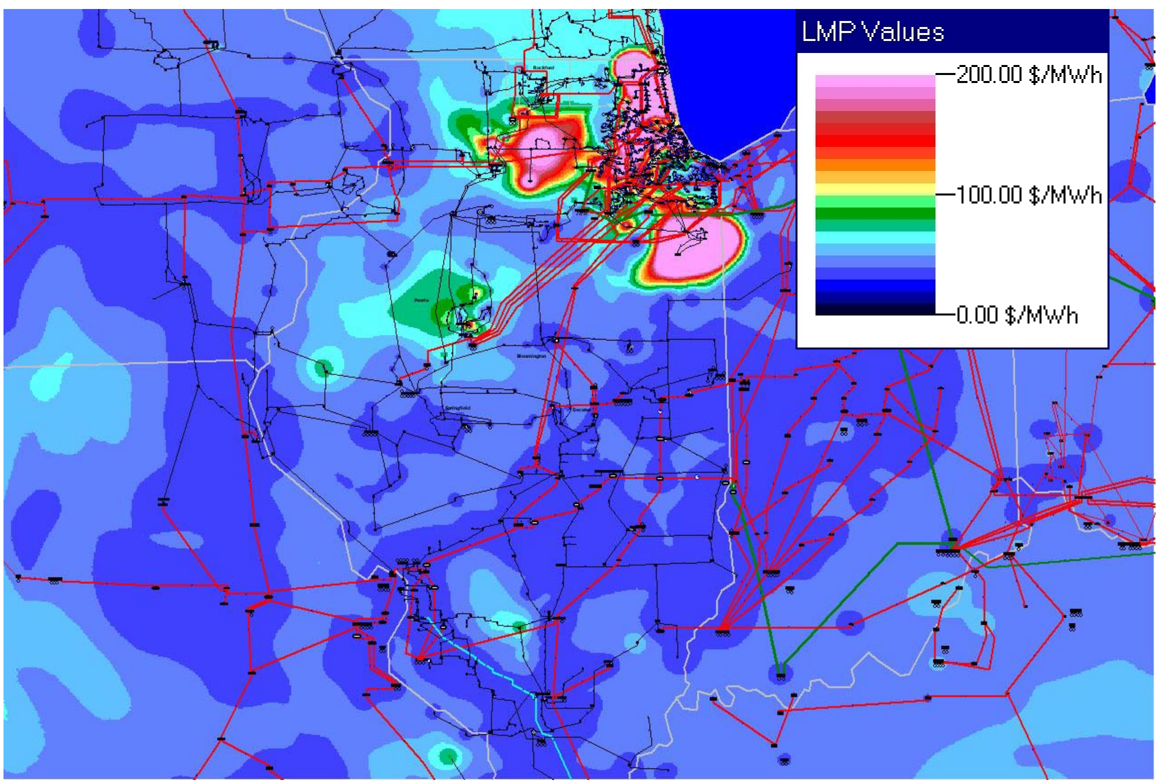

Figure F.2-24 Highest LMPs for July to September 2007

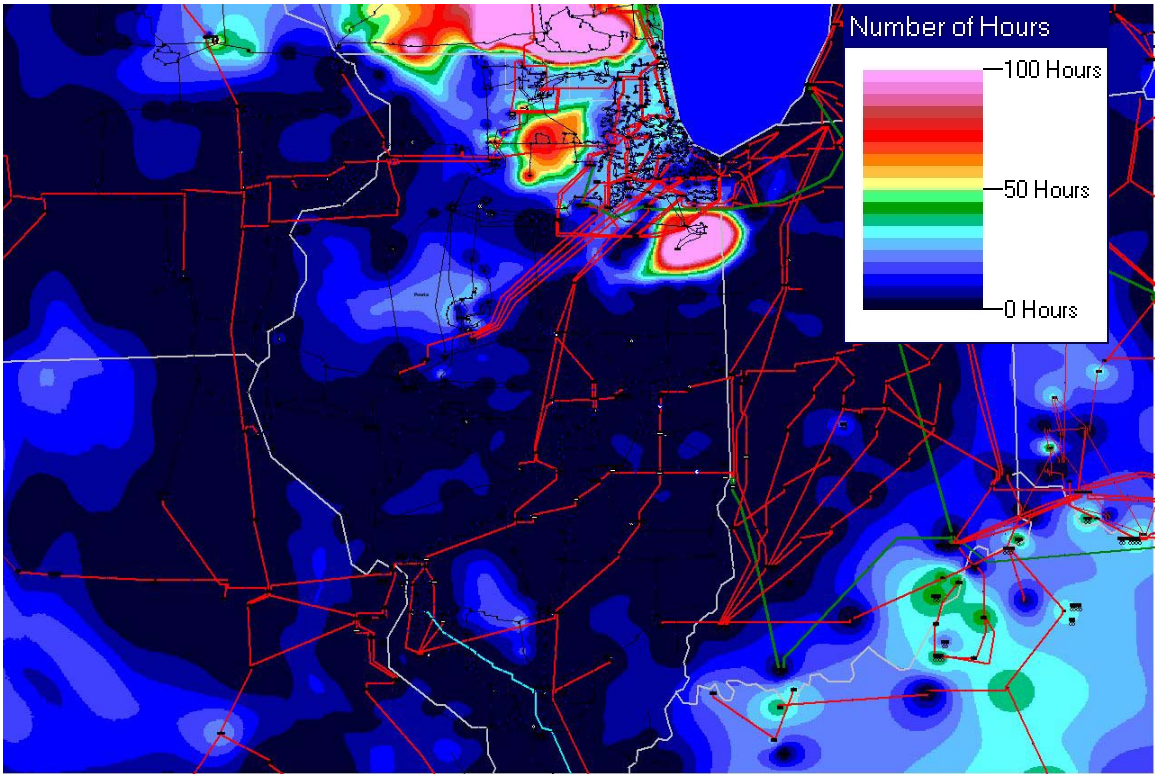

Figure F.2-25 Hours LMP Exceed $40/MWh for July to September 2007

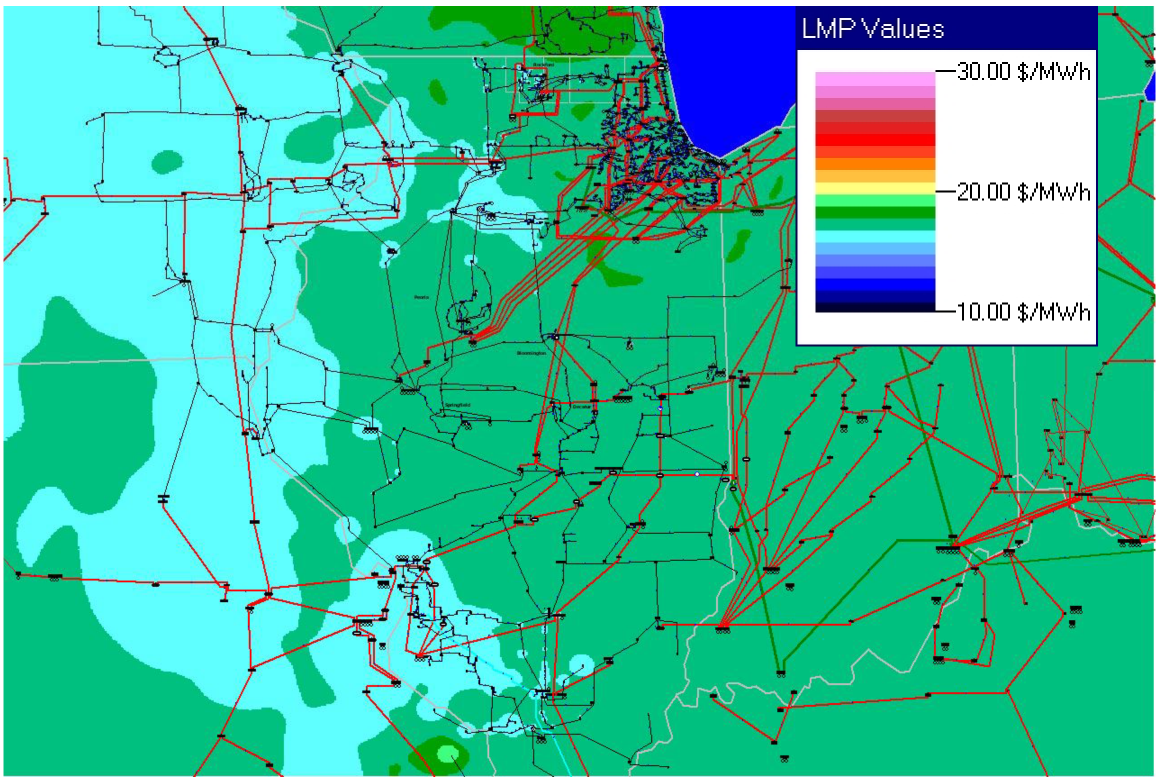

Figure F.2-26 Average LMPs for October to December 2007

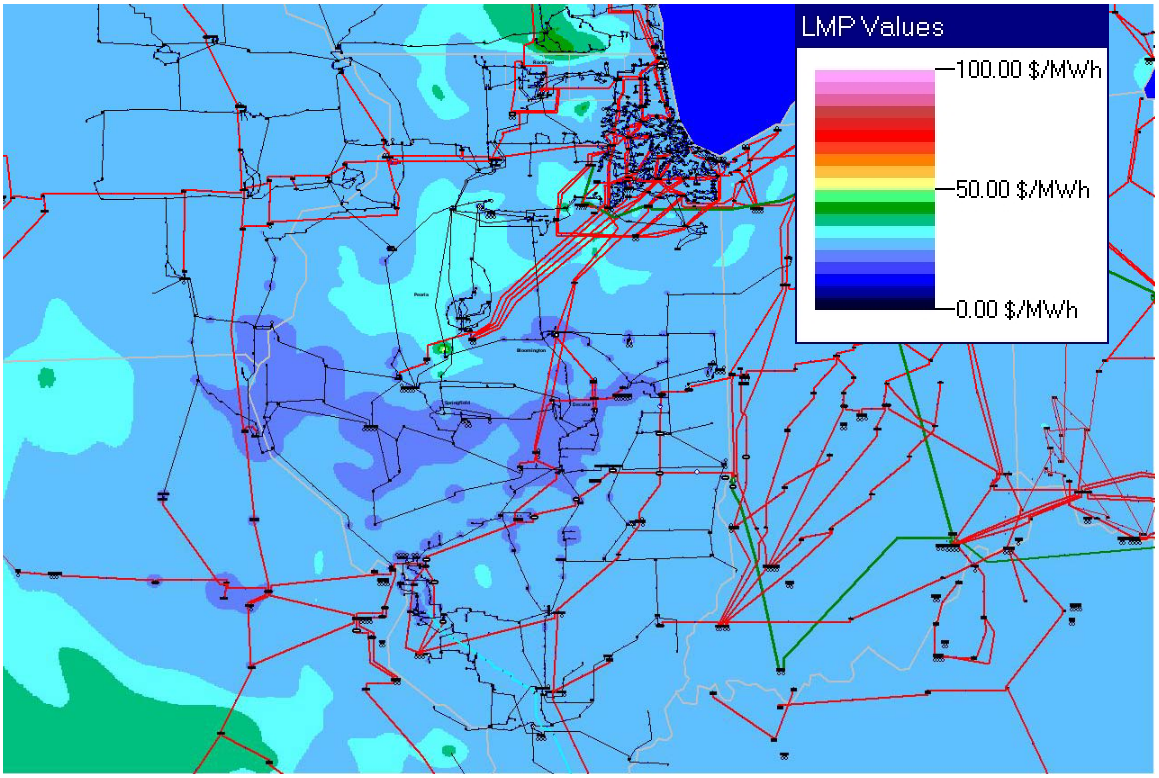

Figure F.2-27 Highest LMPs for October to December 2007

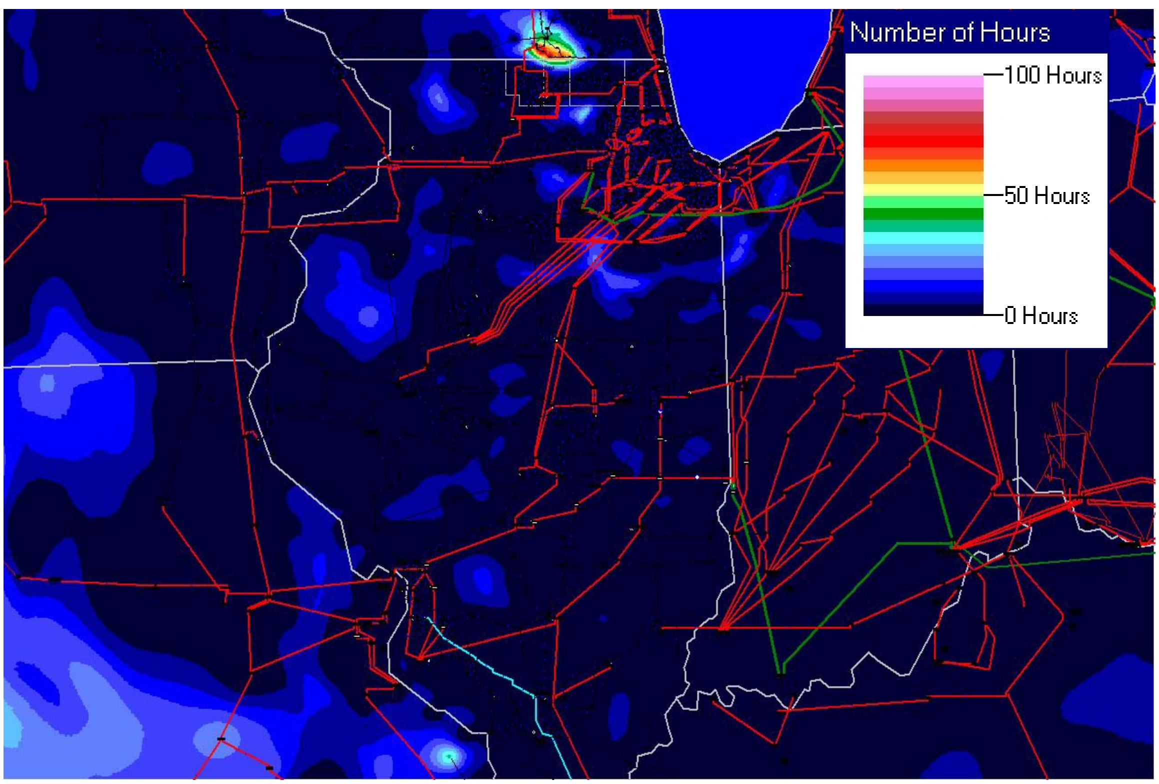

Figure F.2-28 Hours LMP Exceed $30/MWh for October to December 2007

Table F.2-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
33002	RS WALL	CILC	69	399	12,623
36688	DIXON; B	NI	138	159	9,994
36689	DIXON; R	NI	138	159	9,990
33001	EDWARDS1	CILC	69	403	8,801
33299	PEORIA	CILC	138	399	8,679
36969	MAZON; R	NI	138	1,576	8,267
33300	PEKIN	CILC	138	404	8,256
33073	MIDWEST	CILC	69	403	8,241
36548	K3192;4B	NI	138	163	6,924
36544	K3192;4T	NI	138	163	6,924
36546	K3191;4T	NI	138	163	6,924
36660	DAVIS; B	NI	138	163	6,924
36874	K3192;5B	NI	138	163	6,918
36670	K3192;5T	NI	138	163	6,918
36884	KANKE; B	NI	138	163	6,917
36882	KANKE;BT	NI	138	163	6,917
36562	BRADL; B	NI	138	163	6,917
36883	KANKE;RT	NI	138	163	6,916
36885	KANKE; R	NI	138	163	6,916
36661	DAVIS; R	NI	138	163	6,910
33040	EASTERN	CILC	69	405	6,850
33023	HINES	CILC	69	399	6,593
33029	NORTHWST	CILC	69	399	6,350
33371	2CARML_S	SIPC	69	523	5,847
36981	MENDO;	NI	138	154	5,487
36982	MENDO; T	NI	138	154	5,487
37167	H440 ;RT	NI	138	154	5,452
37169	H440 ; R	NI	138	154	5,386
37168	H445 ;3B	NI	138	154	5,386
36027	DAVIS;3M	NI	138	136	5,346
36127	DAVIS;3C	NI	34.5	136	5,346
37166	STEWA; B	NI	138	151	5,242
33108	FARGO	CILC	69	399	5,202
36942	LOMBA; B	NI	138	21	5,162
37582	LOMBA;BP	NI	138	21	5,162
37114	PLEAS;BT	NI	138	21	5,137
37116	PLEAS; B	NI	138	21	5,137
33088	HALLOCK	CILC	69	398	4,733
32298	GILSP TP	IP	138	1,327	4,590
33175	MASON	CILC	138	490	4,581
32295	GILESPIE	IP	138	1,326	4,556
36778	GLEND;BT	NI	138	21	4,525

Table F.2-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
36780	GLEND; B	NI	138	21	4,525
37371	WILSO; R	NI	138	17	4,519
33144	HINES	CILC	138	400	4,436
32654	GILESPIE	IP	34.5	1,308	4,260
37195	ROUND; R	NI	138	17	4,246
33146	EASTERN	CILC	138	406	4,198
32653	STAUNTON	IP	34.5	1,297	4,097
32296	STAUNTON	IP	138	1,289	4,025
36485	ANTIO; R	NI	138	17	3,955
36483	ANTIO;RT	NI	138	17	3,955
37048	NORDI; B	NI	138	21	3,939
36776	G ELL; B	NI	138	21	3,938
33152	PIONEERC	CILC	138	397	3,937
33155	HALLOCK	CILC	138	395	3,891
33084	TAZEWELL	CILC	69	405	3,882
37269	STILL;	NI	138	141	3,836
37267	STILL;RT	NI	138	141	3,836
37341	W DEK;4R	NI	138	141	3,612
37344	W DEK;3T	NI	138	141	3,612
33154	CAT MOSS	CILC	138	389	3,575
33151	RADNOR	CILC	138	389	3,569
36813	GURNE; R	NI	138	14	3,560
37369	WILMI;	NI	138	350	3,455
33356	2GALTN_S	SIPC	69	471	3,303
37063	NB212; R	NI	138	14	3,288
36667	DEERF;RT	NI	138	14	3,256
36669	DEERF; R	NI	138	14	3,256
36578	BUTTE; B	NI	138	21	3,222
36843	HIGHL; R	NI	138	14	3,187
36794	GRACE; B	NI	138	19	3,186
37091	O ELM; R	NI	138	14	3,148
37631	EQUIS; R	NI	13.8	700	3,147
37141	J375 ; R	NI	138	700	3,147
33150	FARGO	CILC	138	373	3,099
33143	CAT SUB2	CILC	138	376	3,050
32283	LITCH TP	IP	138	1,172	3,032
36807	A450 ; R	NI	138	15	3,018
36433	1A431; R	NI	138	16	3,010
36439	1A431;5T	NI	138	16	3,010
32297	LITCHFLD	IP	138	1,167	3,008
37061	N CHI; R	NI	138	16	2,991
36045	ITASC;1M	NI	138	22	2,969

Table F.2-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
36145	ITASC;1C	NI	34.5	22	2,969
36864	ITASC; B	NI	138	21	2,962
36909	LAKEH; R	NI	138	16	2,946
36448	ADDIS; B	NI	138	19	2,934
37340	WATER;3B	NI	138	138	2,924
37318	WATER; B	NI	138	138	2,924
37211	SANDW; R	NI	138	138	2,924
32655	LITCHFLD	IP	34.5	1,154	2,899
36473	J371 ;RT	NI	138	646	2,890
36471	J371 ; R	NI	138	646	2,890
37556	WAUKE;7U	NI	18	16	2,840
37327	WAUKE; R	NI	138	16	2,840
36873	A418 ; R	NI	138	16	2,827
36871	A418 ;RT	NI	138	16	2,827
36429	A429 ;4R	NI	138	16	2,827
36427	A429 ;RT	NI	138	16	2,827

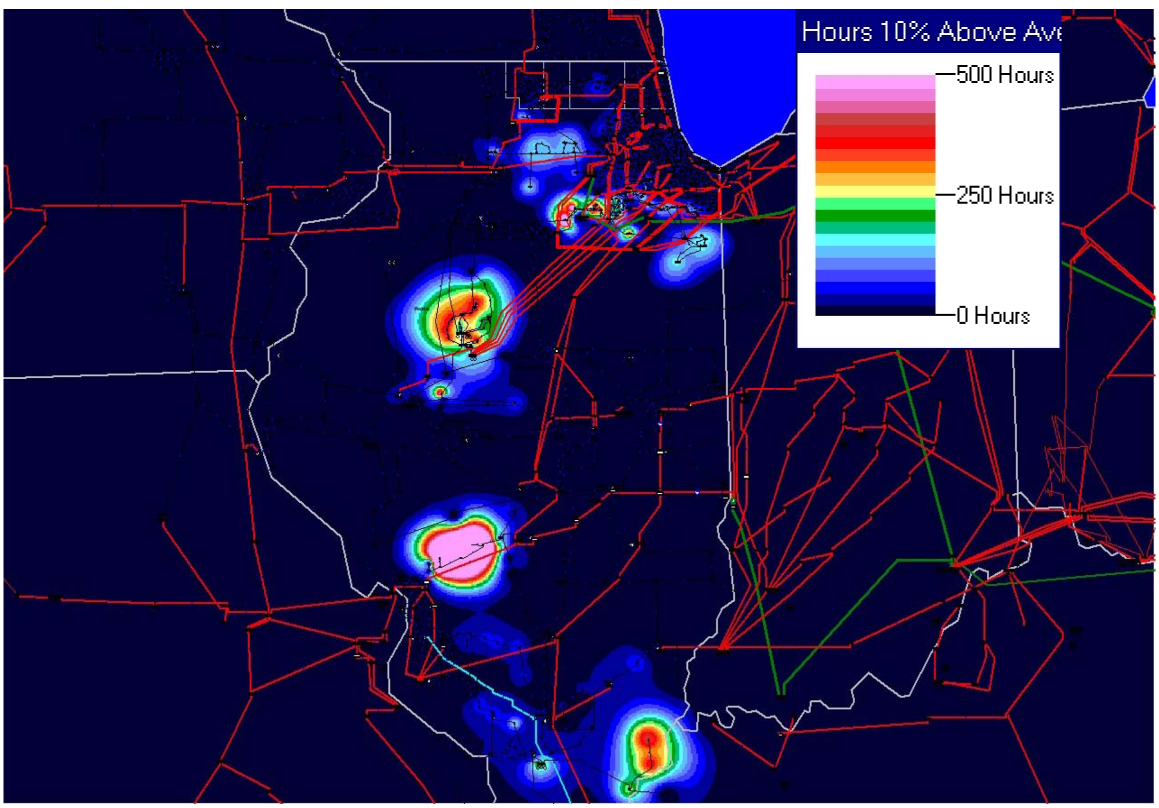

Figure F.2-29 Number of Hours Bus LMPs at Least 10% above the State Average

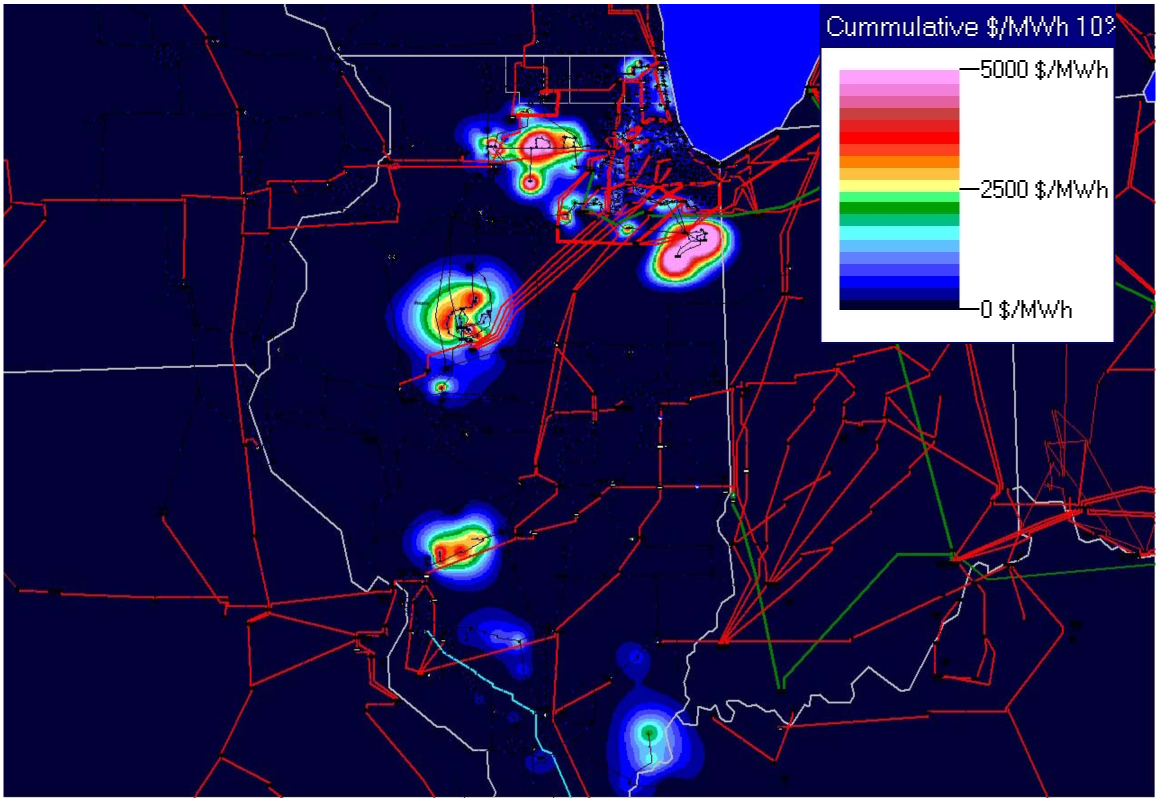

Figure F.2-30 Cumulative $/MWh 10% above the State Average

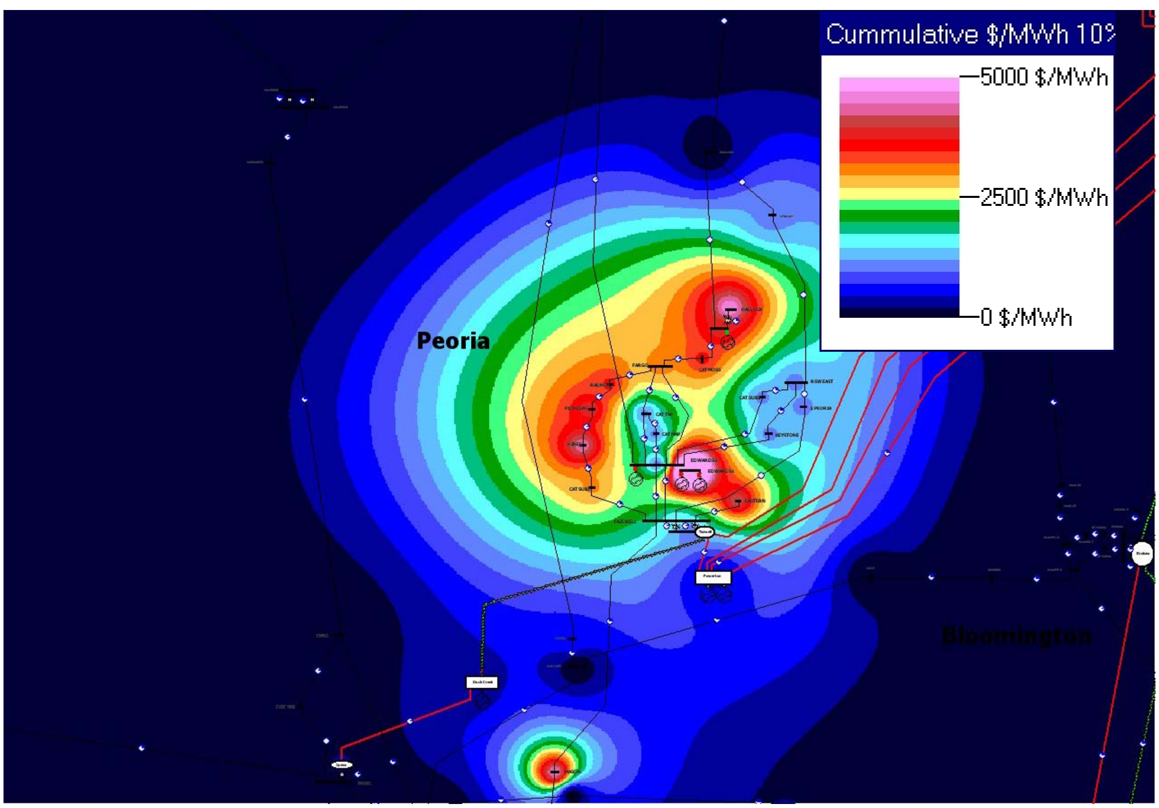

Figure F.2-31 Figure F.2-30 with Zoomed View of Peoria Area

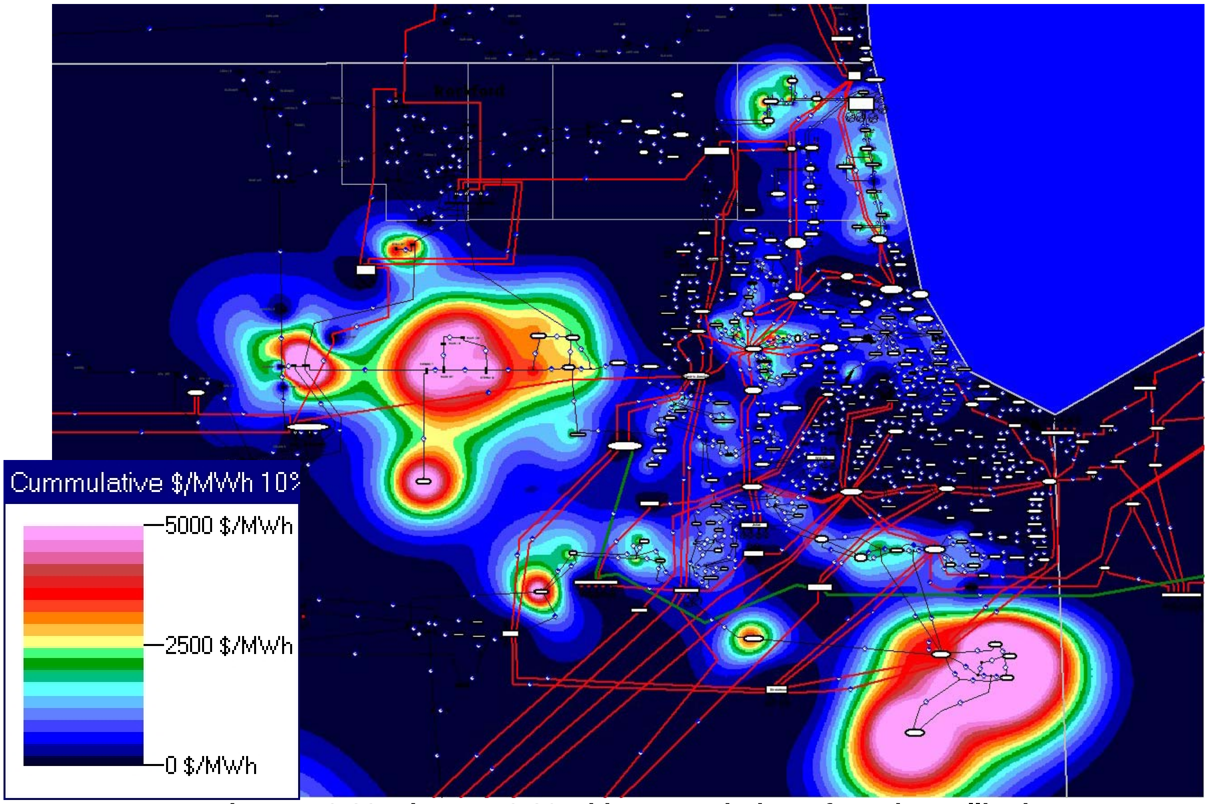

Figure F.2-32 Figure F.2-30 with Zoomed View of Northern Illinois

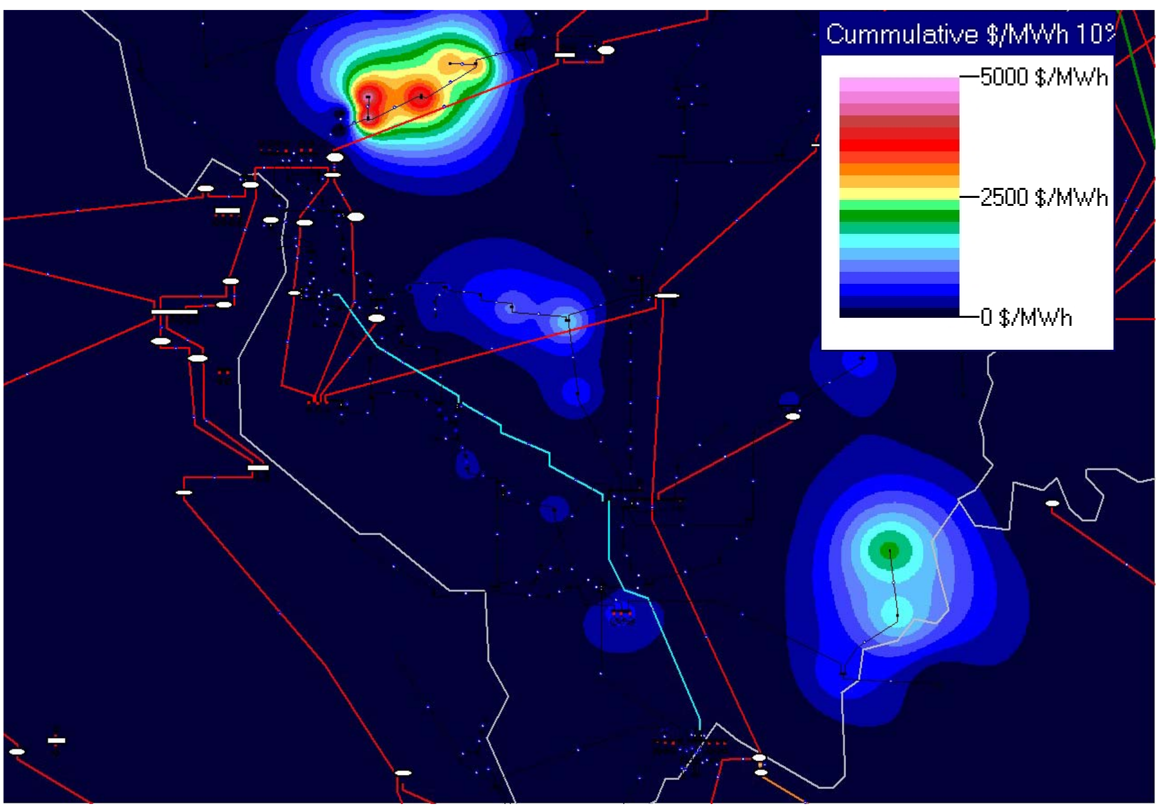

Figure F.2-33 Figure F.2-30 with Zoomed View of Southern Illinois

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