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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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# 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.

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[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

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[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.
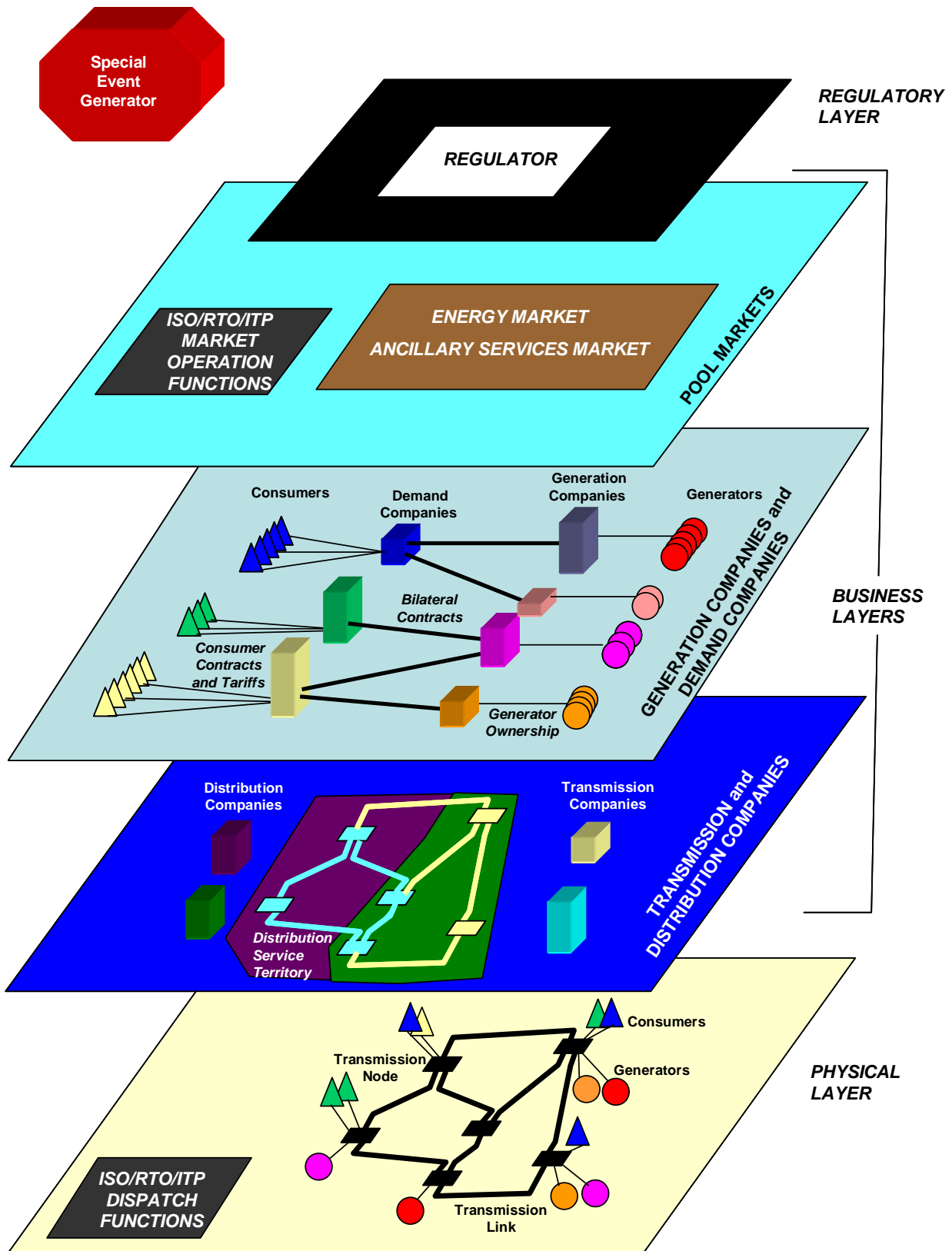
**Figure 1.3.2-1 EMCAS Structure**

The following labels appear within the figure:

- Special Event Generator
- *REGULATORY LAYER*
- *REGULATOR*
- *POOL MARKETS*
- *ISO/RTO/ITP MARKET OPERATION FUNCTIONS*
- *ENERGY MARKET ANCILLARY SERVICES MARKET*
- *BUSINESS LAYERS*
- GENERATION COMPANIES and DEMAND COMPANIES
- Consumers
- Demand Companies
- Generation Companies
- Generators
- *Bilateral Contracts*
- *Consumer Contracts and Tariffs*
- *Generator Ownership*
- TRANSMISSION and DISTRIBUTION COMPANIES
- Distribution Companies
- Transmission Companies
- *Distribution Service Territory*
- *PHYSICAL LAYER*
- Consumers
- Transmission Node
- Generators
- *ISO/RTO/ITP DISPATCH FUNCTIONS*
- Transmission Link

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.

**ISO**

Project next day
system loads

**GENCO**

Project next day prices

Evaluate previous
performance

Run Company Level
Unit Commitment and
Resource Allocation
(CLUCRA)

Select units to be
offered to market

Apply business strategy
to develop bid prices

Submit generation bids
to pool market

**DEMCO**

Project next day
company loads

Submit load bids to
pool  market

**ISO**

Run transmission
constrained system
scheduler
(SYSSCHED)

Develop next day
dispatch schedule

*HOURLY DISPATCH*

SPECIAL EVENTS
Forced Outages

Adjust dispatch
schedule for forced
outages

Run SYSSCHED to
calculate load flows,
generation, LMPs

Compute settlement
payments

**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)<br>• EIA Form 860A – Annual Electric Generator Report – Utility<br>• EIA Form 860B – Annual Electric Generator Report – Nonutility<br>• EIA Form 861 – Annual Electric Power Industry Report<br>• Argonne Power Plant Inventory (APPI database)<br>• NERC's Electricity Supply & Demand (ES&D) database<br>• EIA Electric Power Monthly<br>• EIA Form 767 Steam-Electric Plant Operation and Design Report<br>• EIA Form 906 – Power Plant Report<br>• IL EPA – Electric Power Plant Construction Projects Since 1998 (Status as of June 22, 2001)<br>• IL EPA – Electric Power Plant Construction Projects Since 1998 (Status as of June 13, 2002)<br>• NERC Generation Availability Data Set (GADS) – Generating unit outage factors |
| Load | • FERC Form 714<br>  - Hourly control area loads (aggregated among all power sinks)<br>  - Control area load growth projections<br>• EIA's AEO 2003 with projections to 2025<br>  - Default regional load growth rates (when Form 714 is not available)<br>• 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:<br><br>*Electric utilities* – the public utilities that have franchises to sell electricity to retail customers within a service area.<br><br>*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:<br><br>*Tariffed services* – electricity service that is provided by an electric utility under rates that are regulated by the ICC.<br><br>*Unbundled services* – portions of a tariffed service that electric utilities offer separately to their customers.<br><br>*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.<br><br>*Contract services* – electricity service that is provided by mutual agreement between an electric utility and a retail customer.<br><br>*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:<br><br>*Market based prices* – prices for electricity based on the cost of obtaining the service at wholesale through a competitive bidding or similar process.<br><br>*Real-time prices* – prices for electricity that vary with time; typically hourly for non-residential customers, periodically during the day for residential customers.<br><br>*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:<br>        *Large commercial and industrial customers* – October 1, 1999.<br>        *All other non-residential customers* – December 31, 2000.<br>        *Residential customers* – May 1, 2002.<br>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.



Source: Energy Information Administration
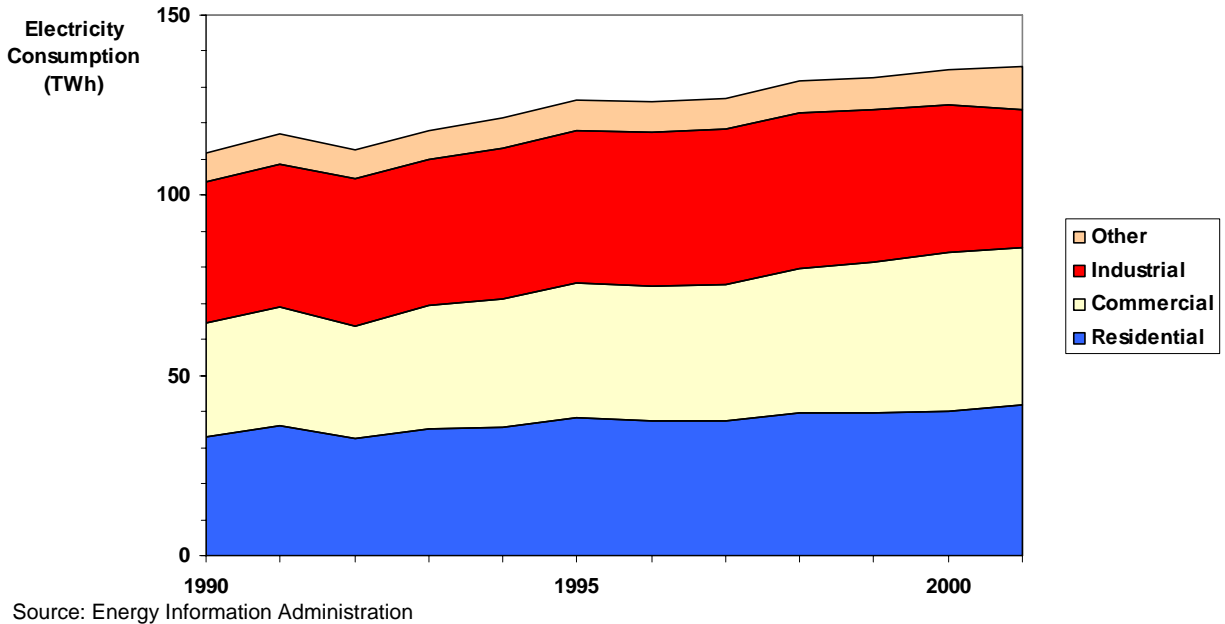
**Figure 2.2-1  Electricity Demand Growth in Illinois**

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.
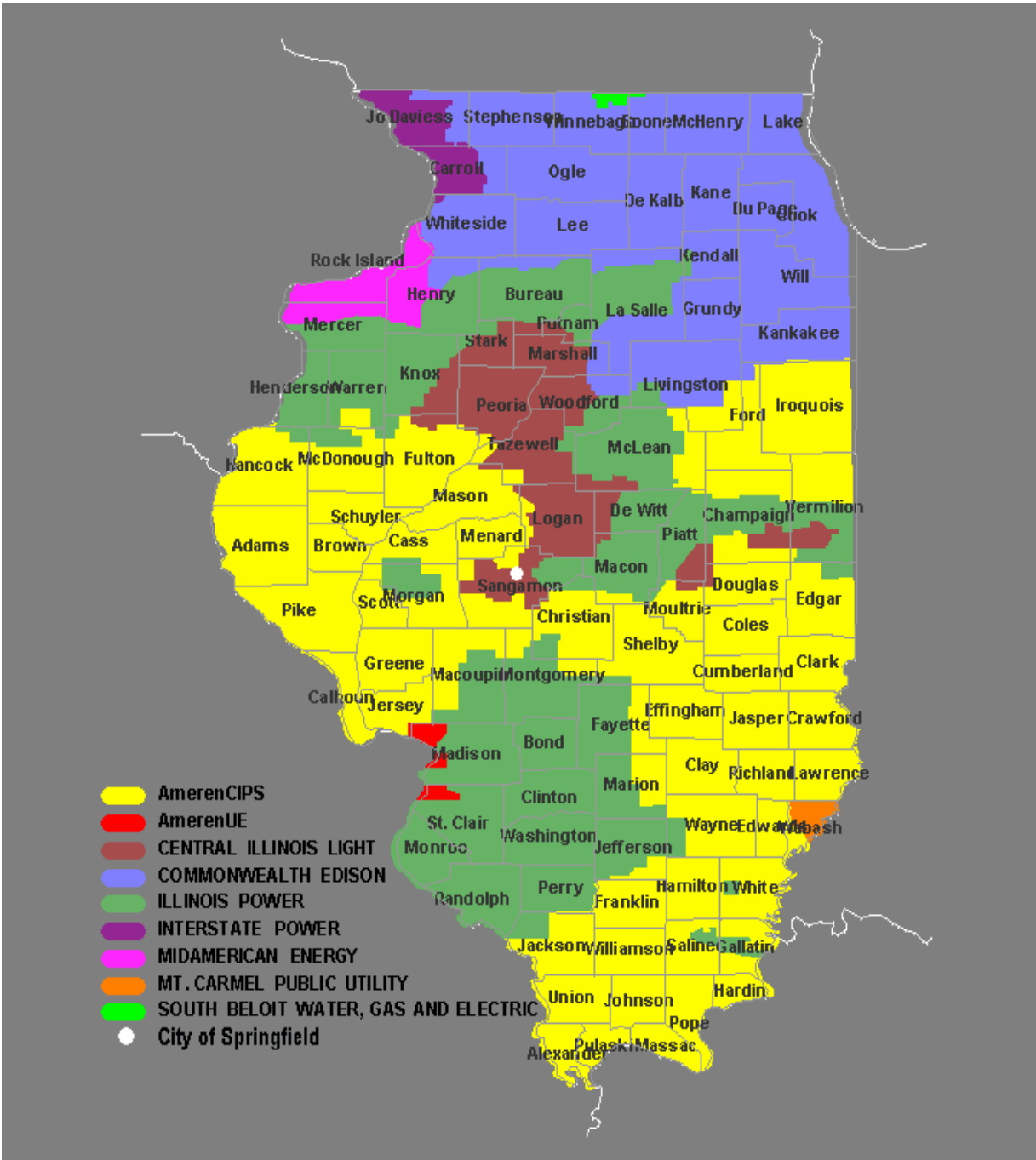


**Figure 2.2-2 Distribution Company Service Territories**

**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<br>          Ameren – CILCO<br>          Ameren – CIPS<br>          Ameren – UE (Illinois portion)<br>          Ameren – Electric Energy Inc. | Private |
| 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**

| DemCo: Electric Utility Affiliates | 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 (%) | |
|---|---|---|---|---|---|---|---|
| | | 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.
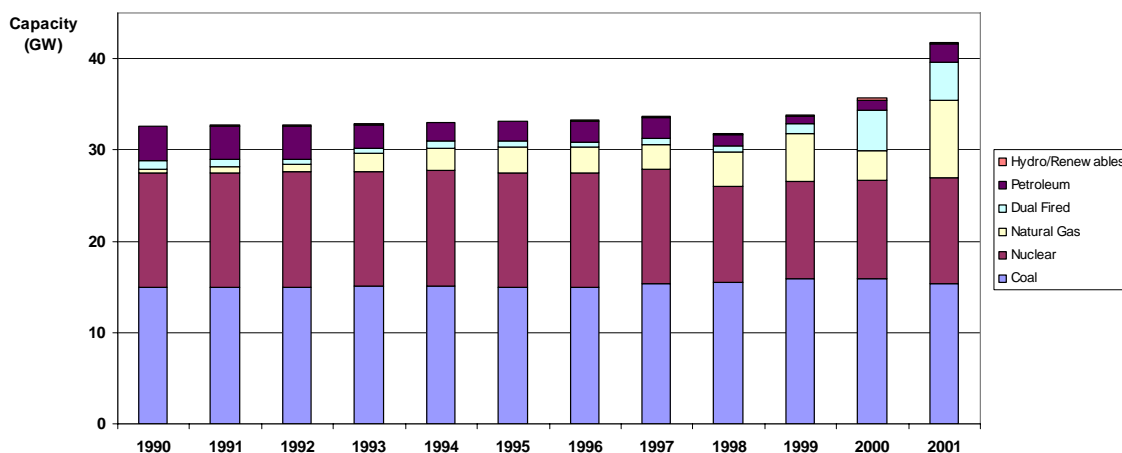
Sources: Energy Information Administration (1990-2000),
State of Illinois data (2001)

**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 |

*19*

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.
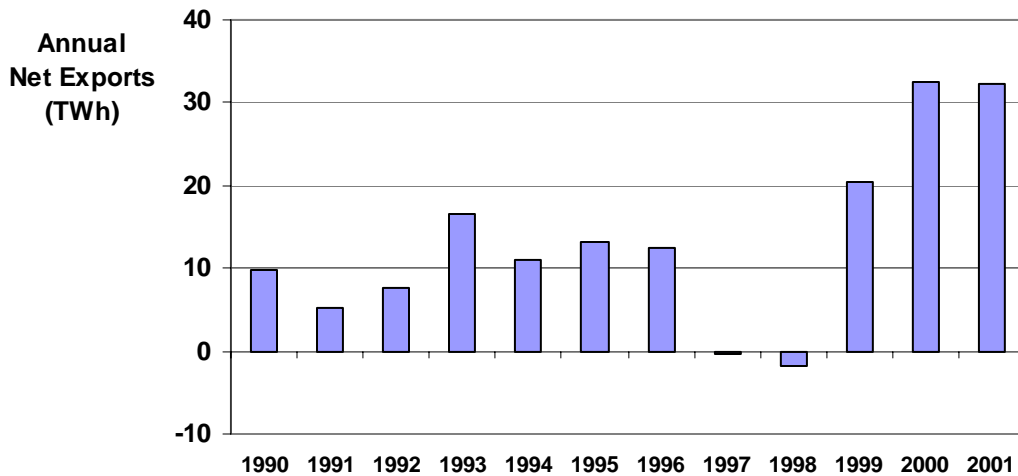


Source: Energy Information Administration

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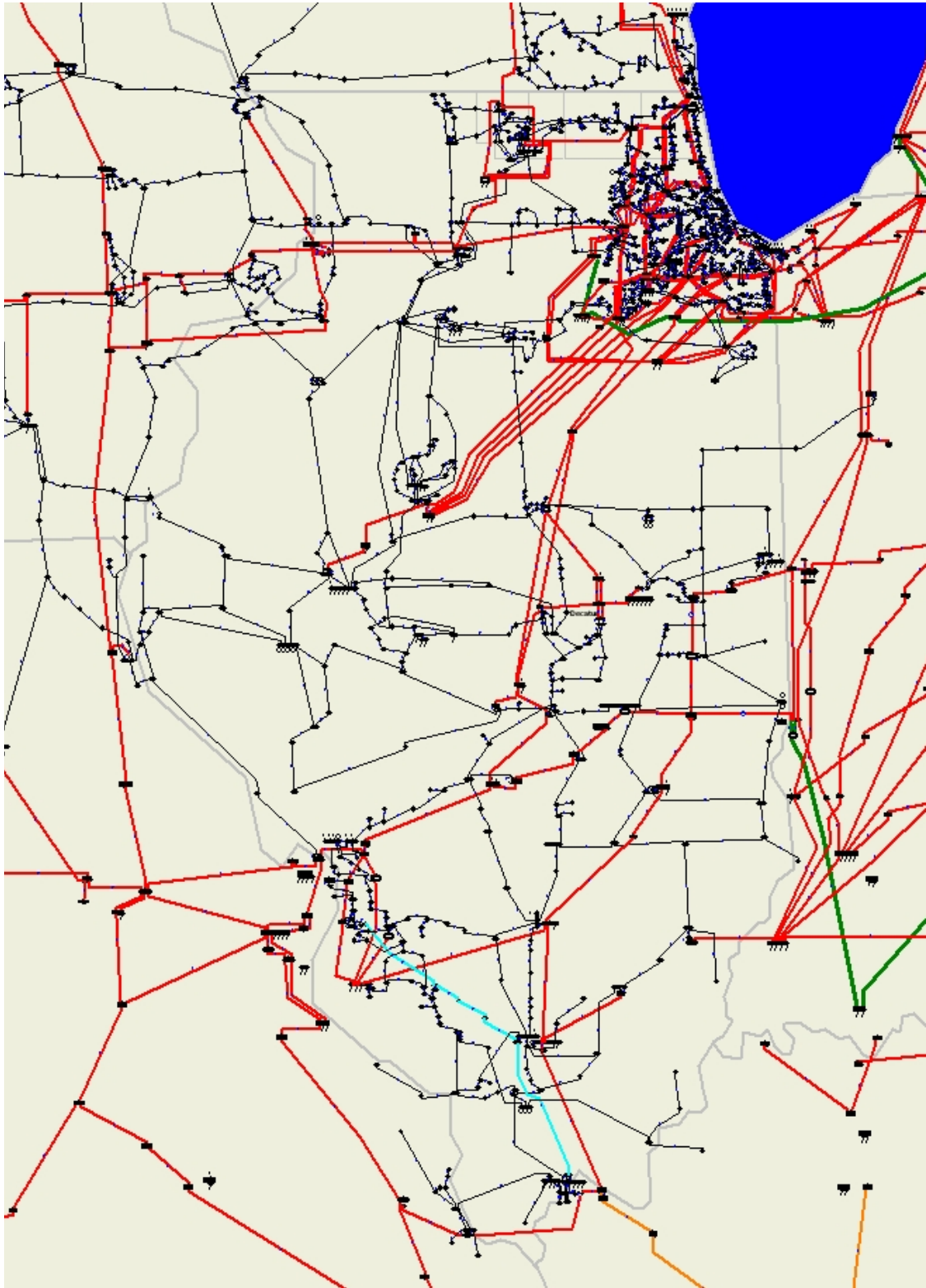
**Figure 2.4-1  Detailed PowerWorld Simulator One-line Diagram of Illinois Transmission, along with High Voltage Transmission in Other States**

**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

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[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

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[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.
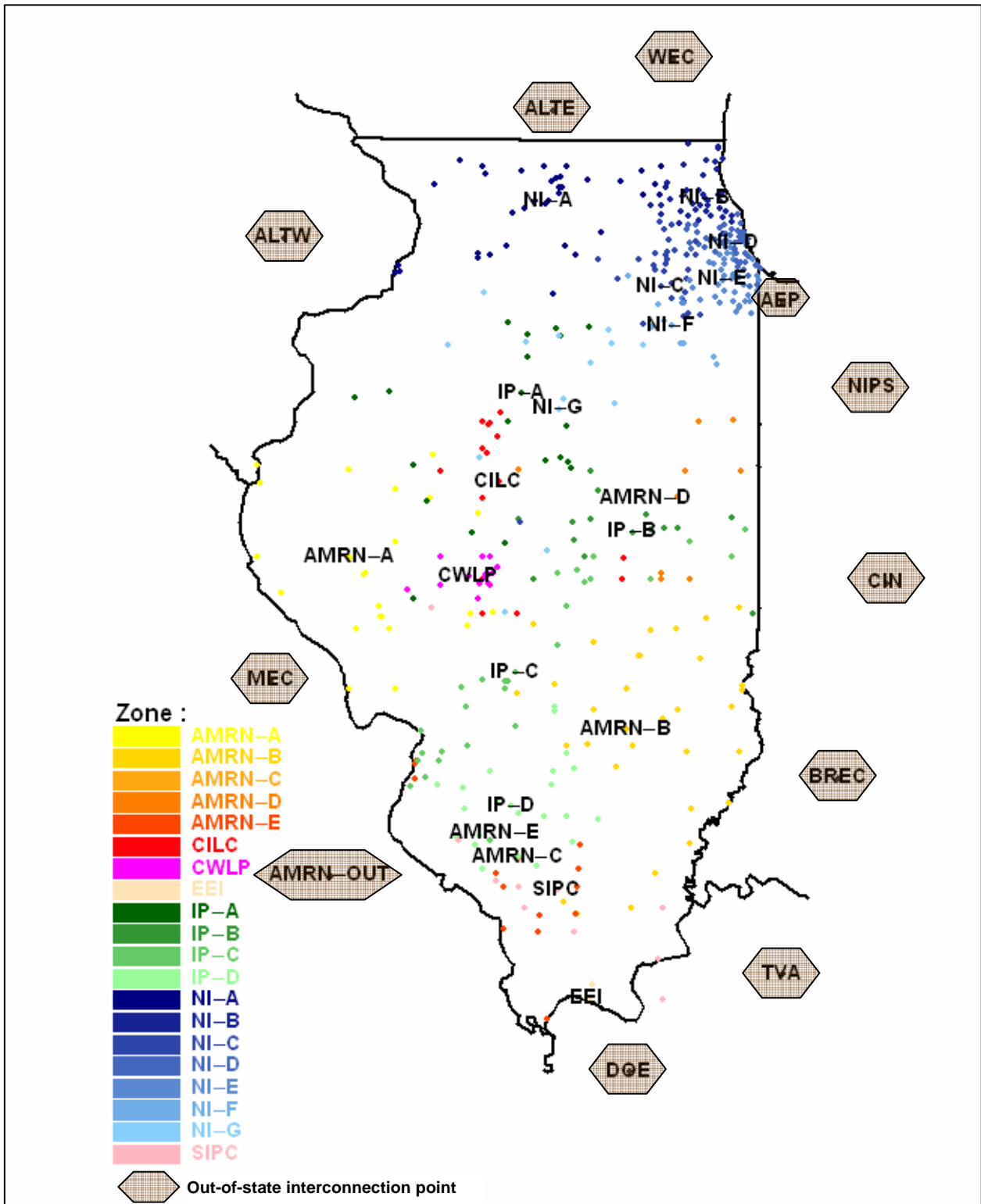
**Figure 3.3-1  In-State Zones and Out-of-State Interconnection Points**
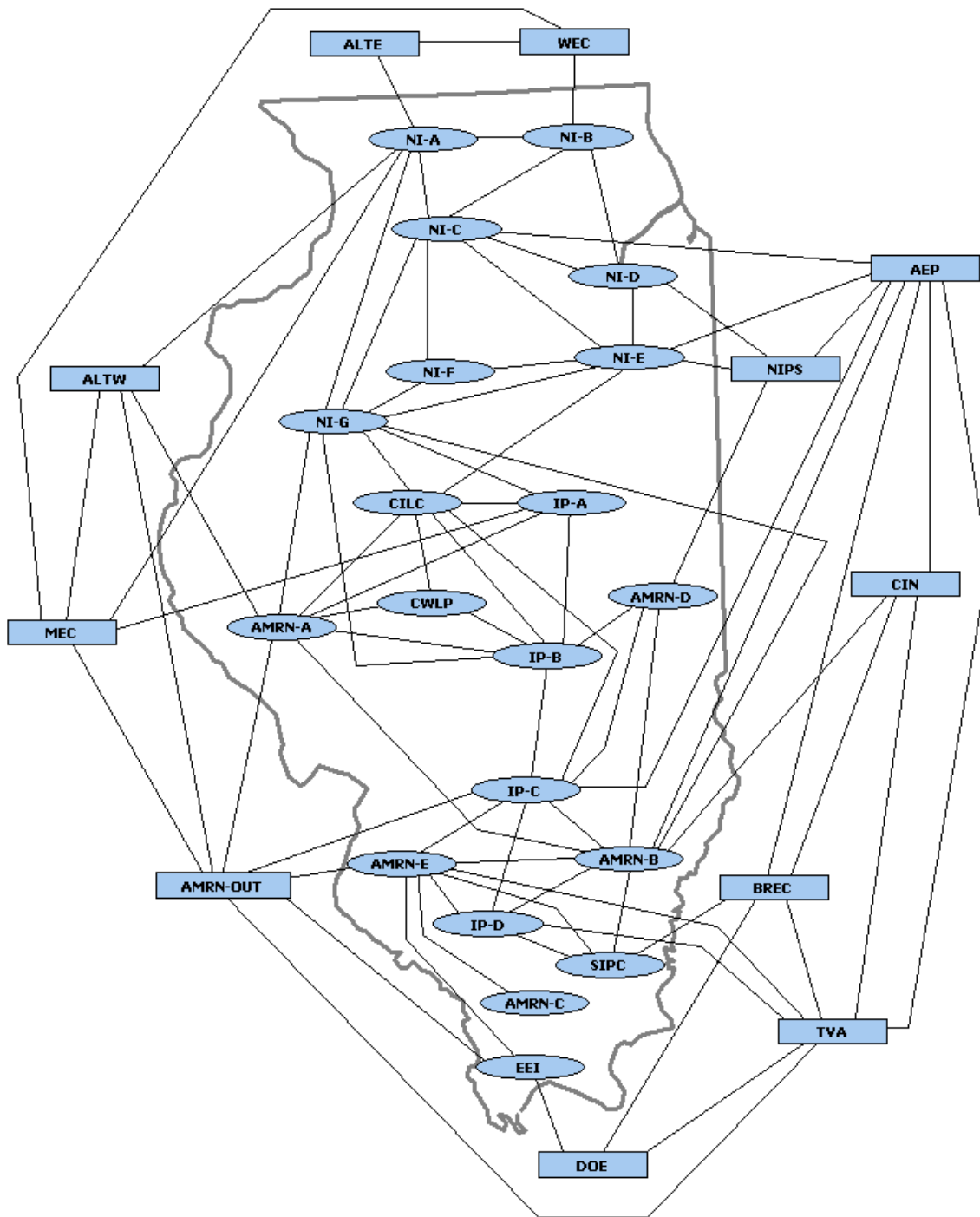
**Figure 3.3-2  Zone Power Transfer Links**

**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
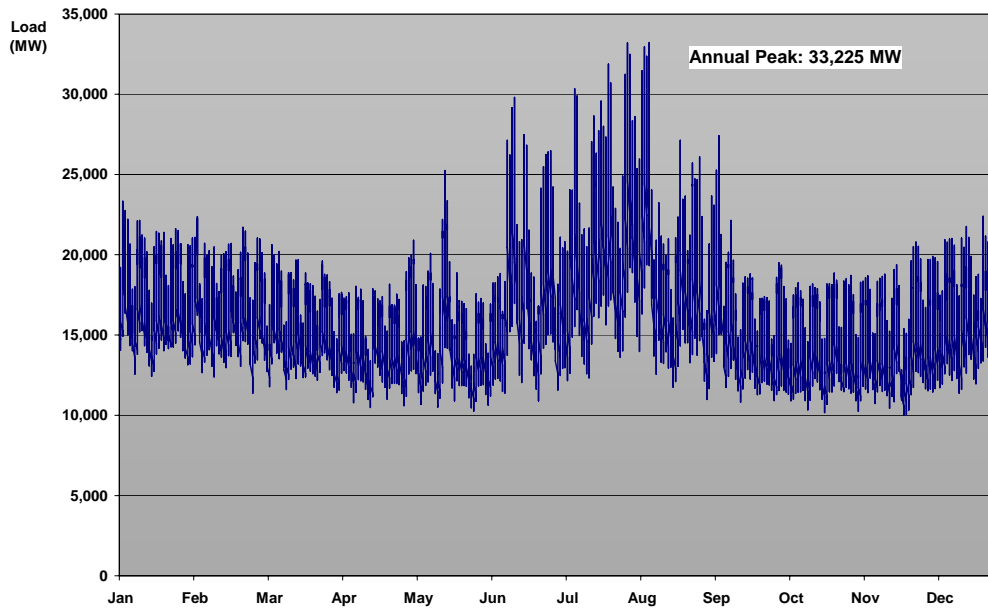
**Figure 3.4-1  Statewide Hourly Load for the Analysis Year**
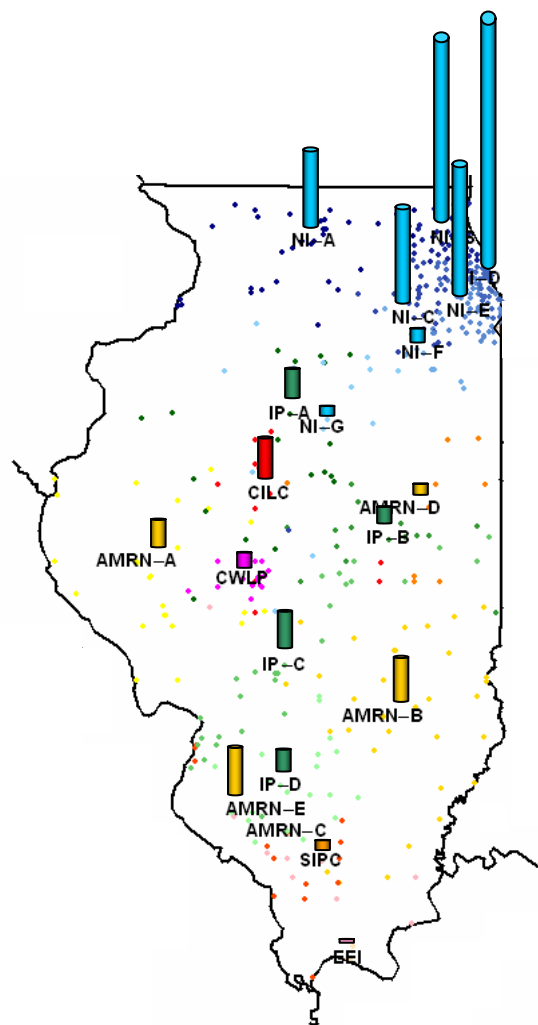


**Figure 3.4-2  Peak Load by Zone for the Analysis Year**

## 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.

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

**Table 3.5-1  Analysis Year Generation Capacity by Company**

| Generation Company | 2001 Capacity (MW) | Capacity Additions/ Retirements (MW) | Type | Analysis Year Capacity 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.
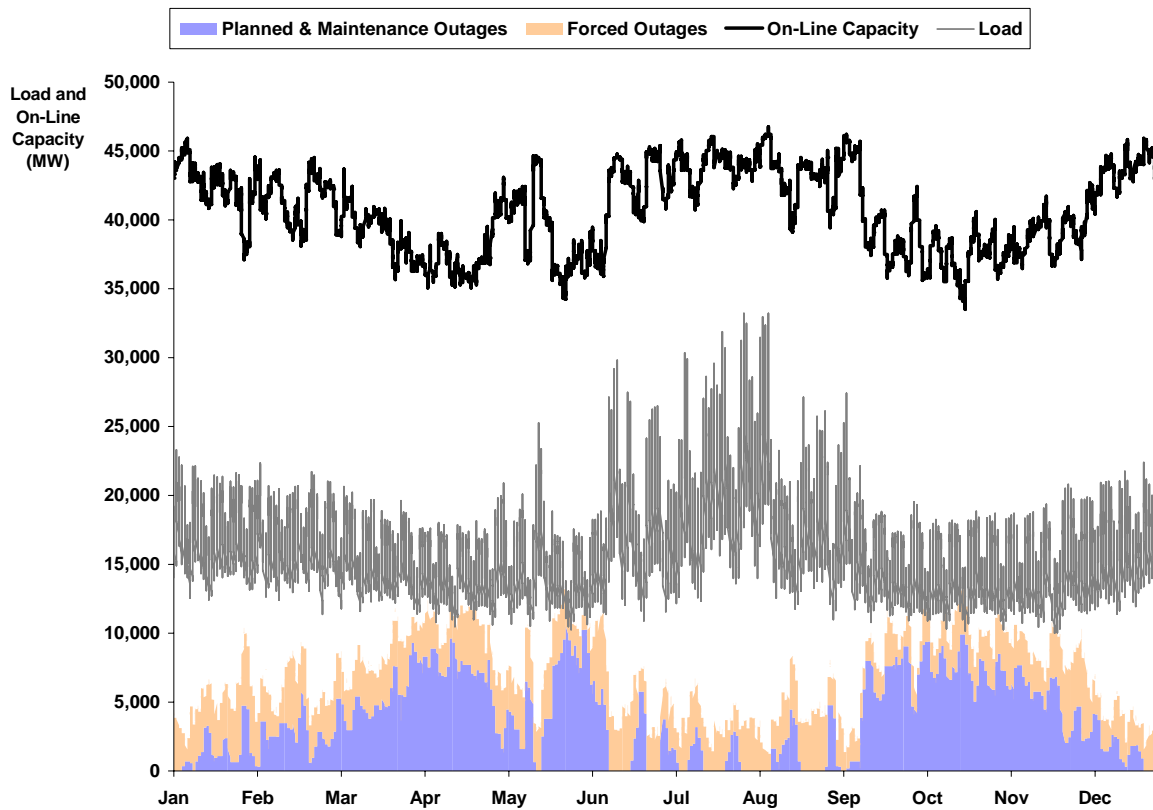


**Figure 3.5-1  Analysis Year Available Generation Capacity (Case Study Assumptions)**
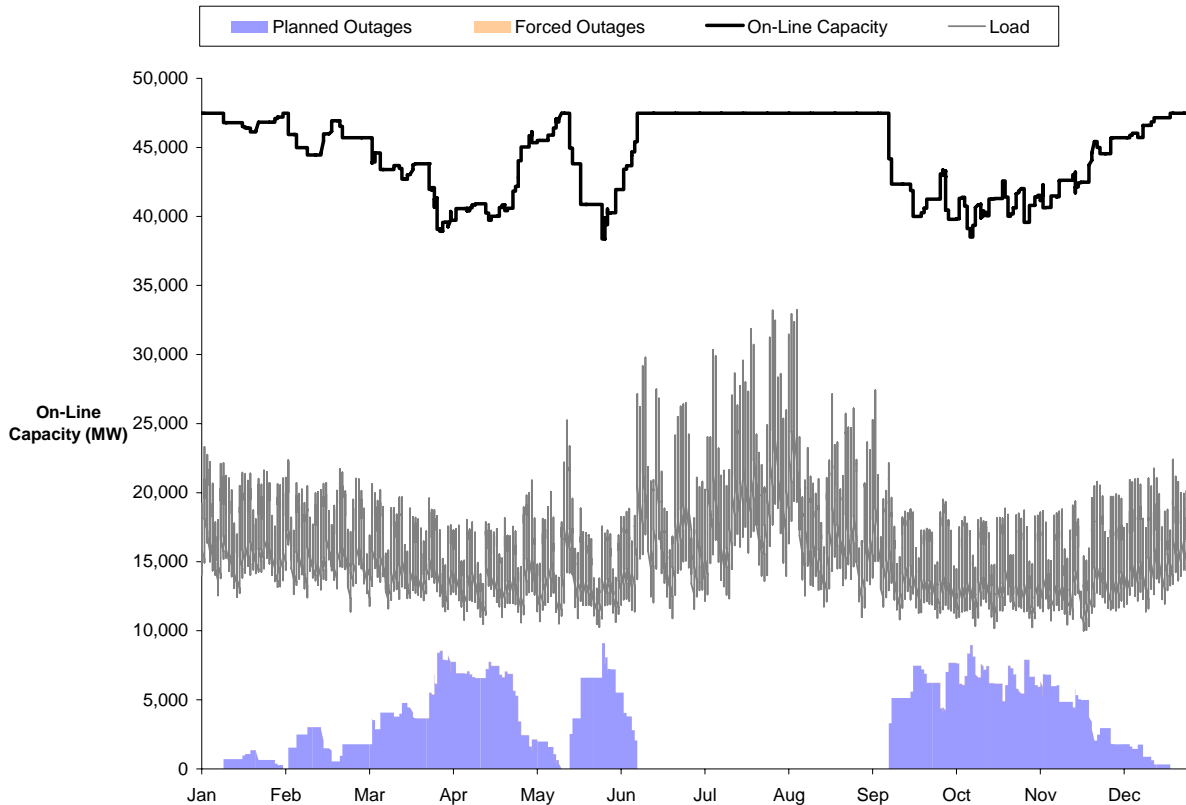
**Figure 3.5-2  Analysis Year Available Generation Capacity (Conservative Assumptions)**

## 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.
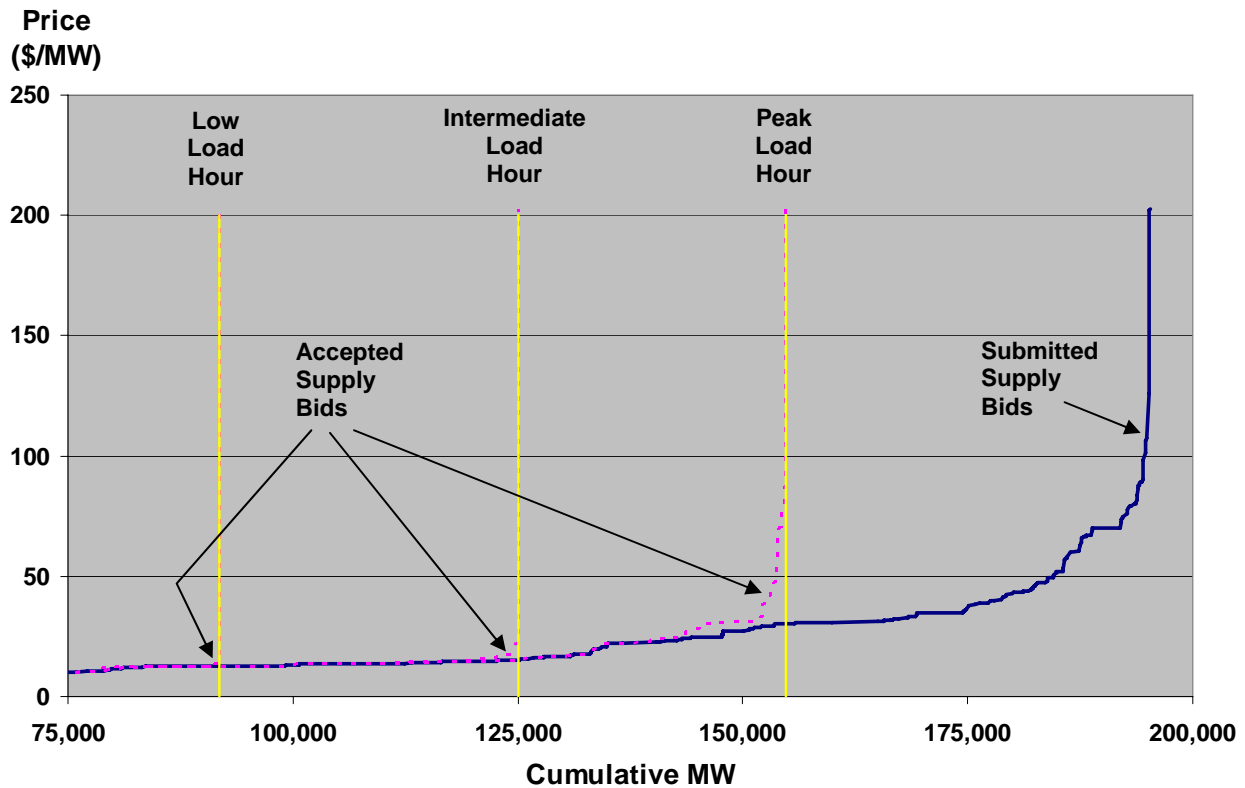


Figure 4.1.1-1  Typical Day-Ahead Market Supply/Demand Curves

### 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.

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[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 | | Zone | | Equipment | | | Hours Per Year Operated at Capacity |
|---|---|---|---|---|---|---|---|---|
| | **From** | **To** | **From** | **To** | | | | |
| **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 |
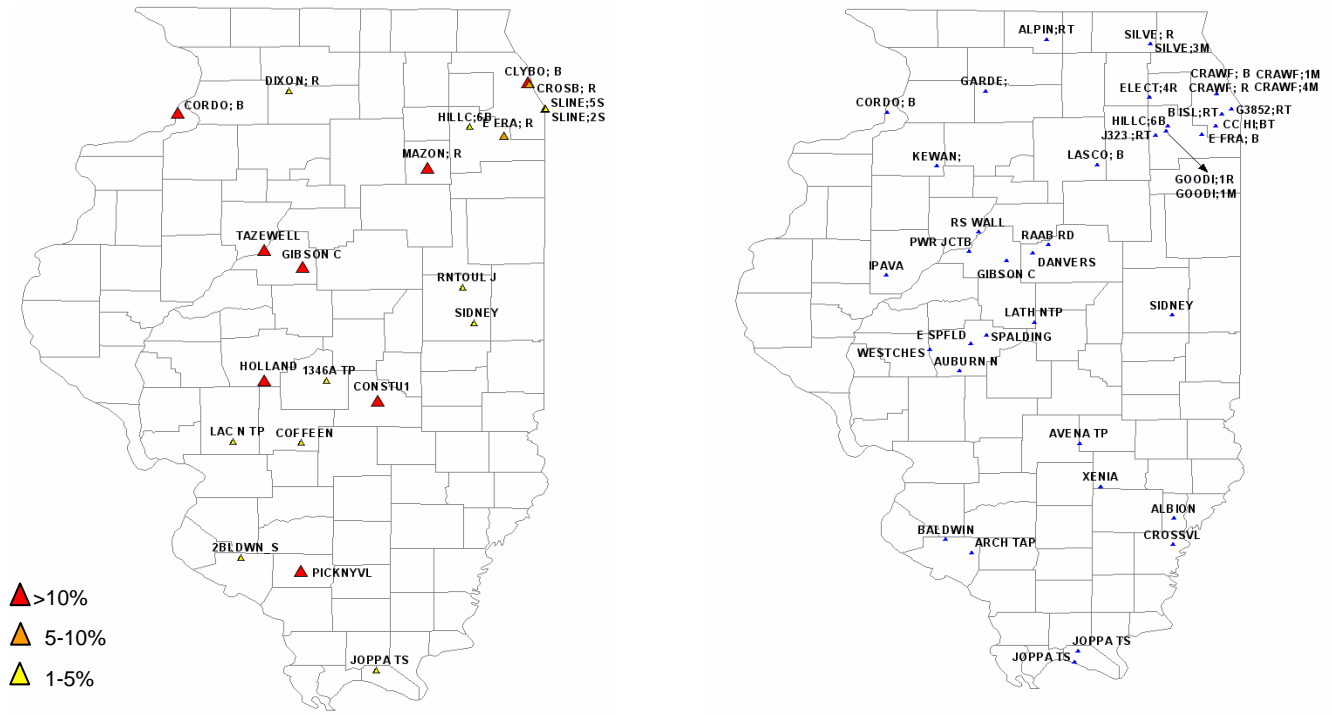


**(a) Loaded to capacity limit equal to or more than 1% of the time**

**(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

| ID | Bus From | Bus To | Zone From | Zone To | Equipment | | | Hours Per Year Operated at Capacity |
|---|---|---|---|---|---|---|---|---|
| **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**

| ID | Bus From | Bus To | Zone From | Zone To | Equipment | | | Hours Per Year Operated at Capacity |
|---|---|---|---|---|---|---|---|---|
| 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.

| Portion of Time LMP Was Exceeded | | | LMP | | | | |
|---|---|---|---|---|---|---|---|
| (Fraction) | (Approximate Hours per Month) | (Hours per Year) | 30 | 35 | 45 | 60 | >60 |
| .01 | 8 | 88 | blue | blue | blue | yellow | orange |
| .05 | 40 | 438 | blue | blue | yellow | orange | orange |
| .10 | 80 | 876 | blue | blue | yellow | orange | red |
| >.10 | >80 | >876 | blue | yellow | orange | red | red |

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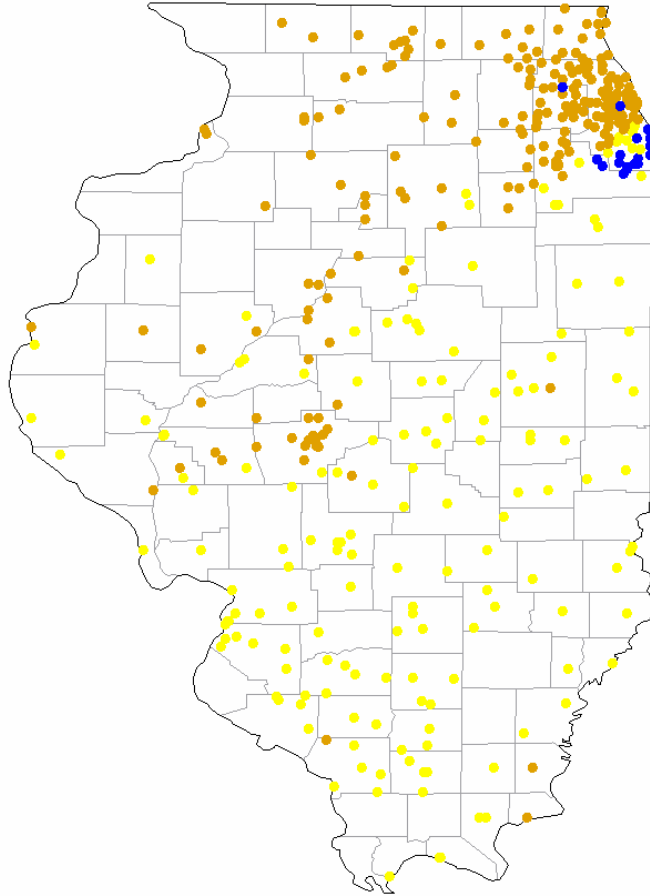
**Figure 4.1.3-3  PC Case (Case Study Assumptions) Potential Load Pocket Identification
Based on Annual Data**

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

| Month | | Zone | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 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)**

| Month | | IP-A | IP-B | IP-C | IP-D | | CWLP |
|---|---|---|---|---|---|---|---|
| | | | | Zone | | | |
| 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)

| Month | | Zone | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 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
35 $/MWh ≤ LMP < 45 $/MWh
45 $/MWh ≤ LMP < 60 $/MWh
LMP ≥ 60 $/MWh

*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.
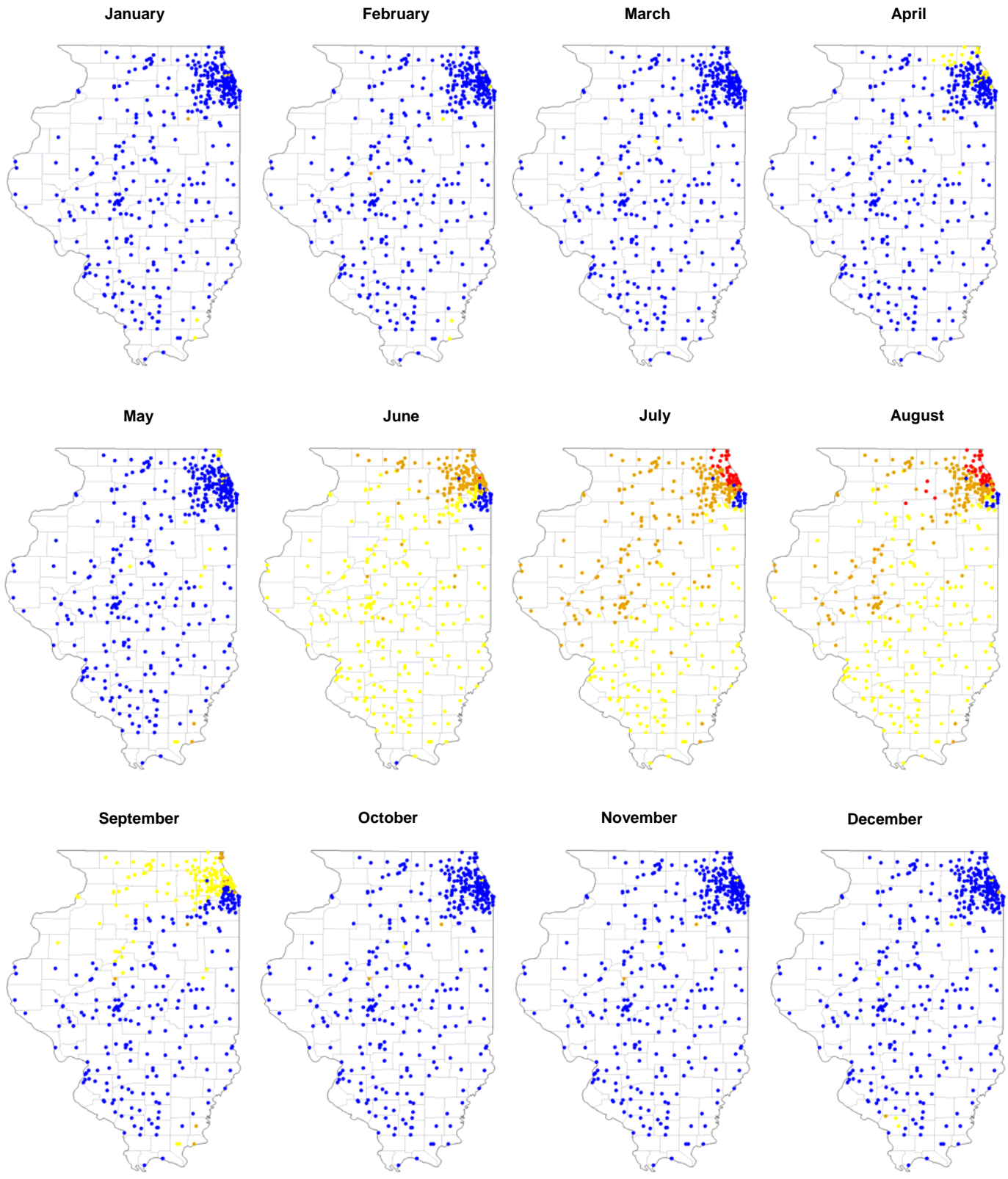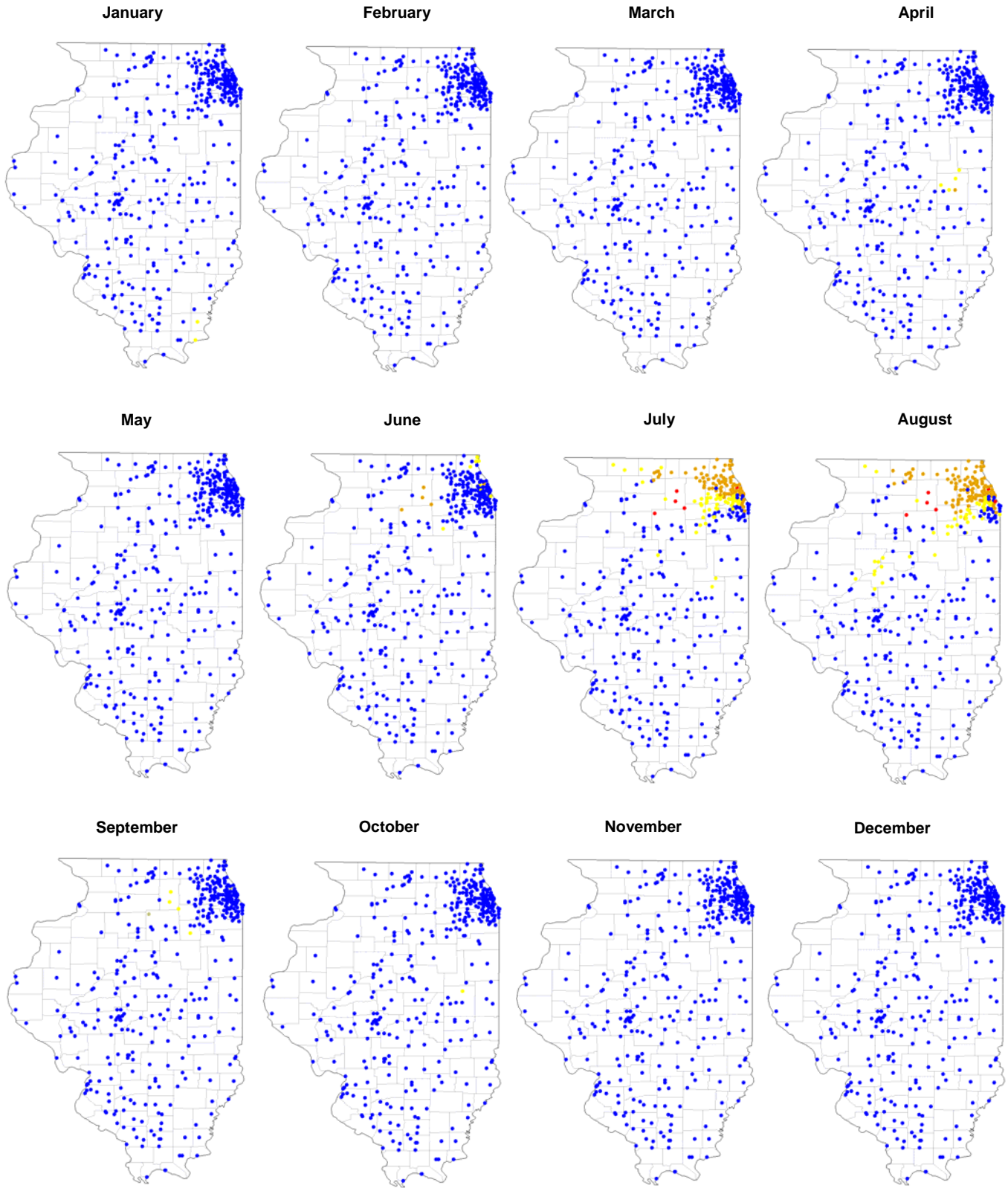
**Figure 4.1.3-4  PC Case (Conservative Assumptions) Potential Load Pocket Identification Based on Monthly Data**
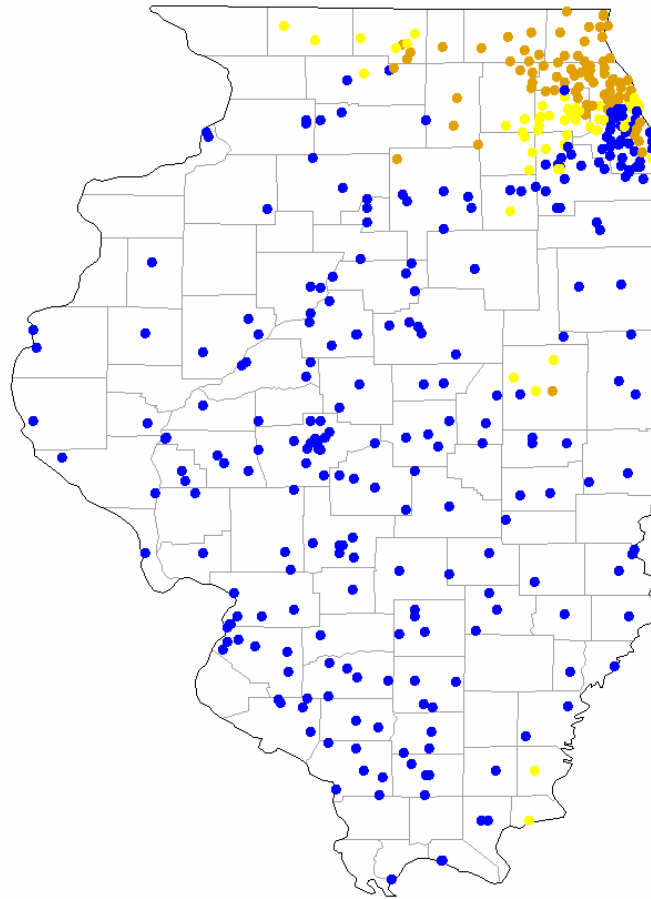
**Figure 4.1.3-5  PC Case (Conservative Assumptions) Potential Load Pocket Identification Based on Annual Data**

| 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**

| Zone | Load-Weighted Locational Marginal Price ($/MWh) | | |
|------|------|--------|---------|
|      | 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 |
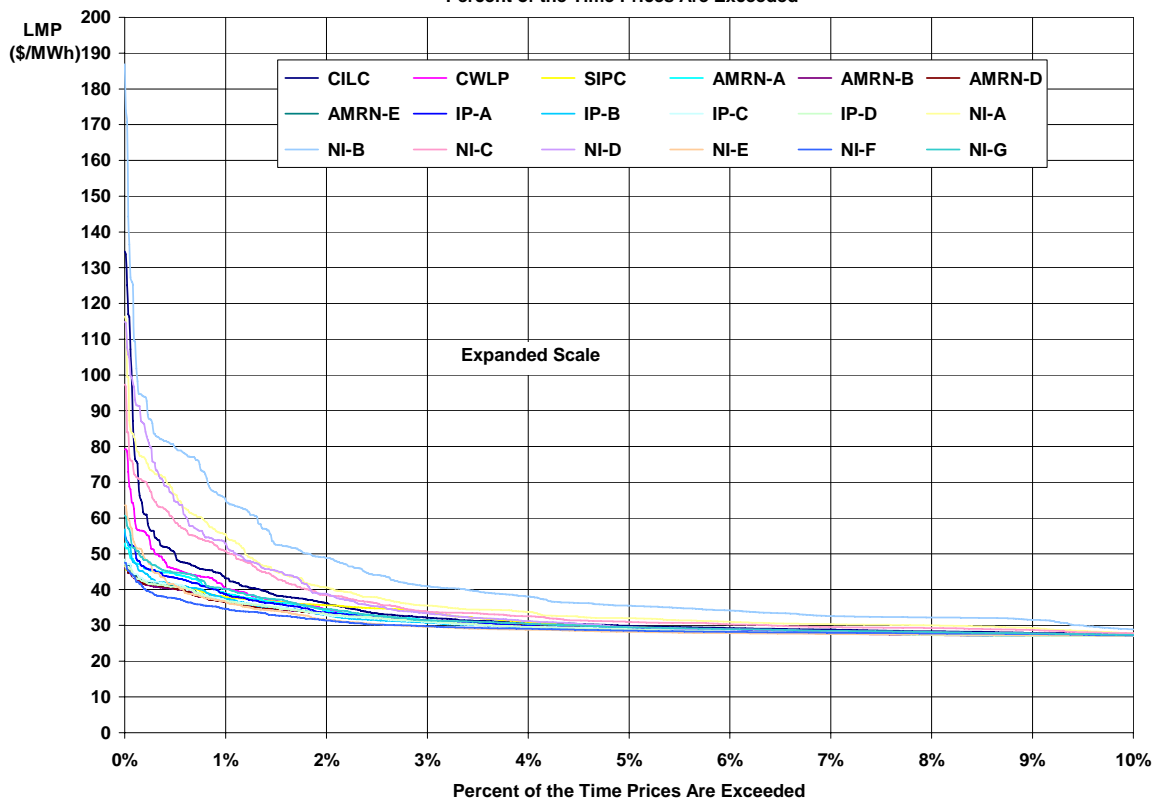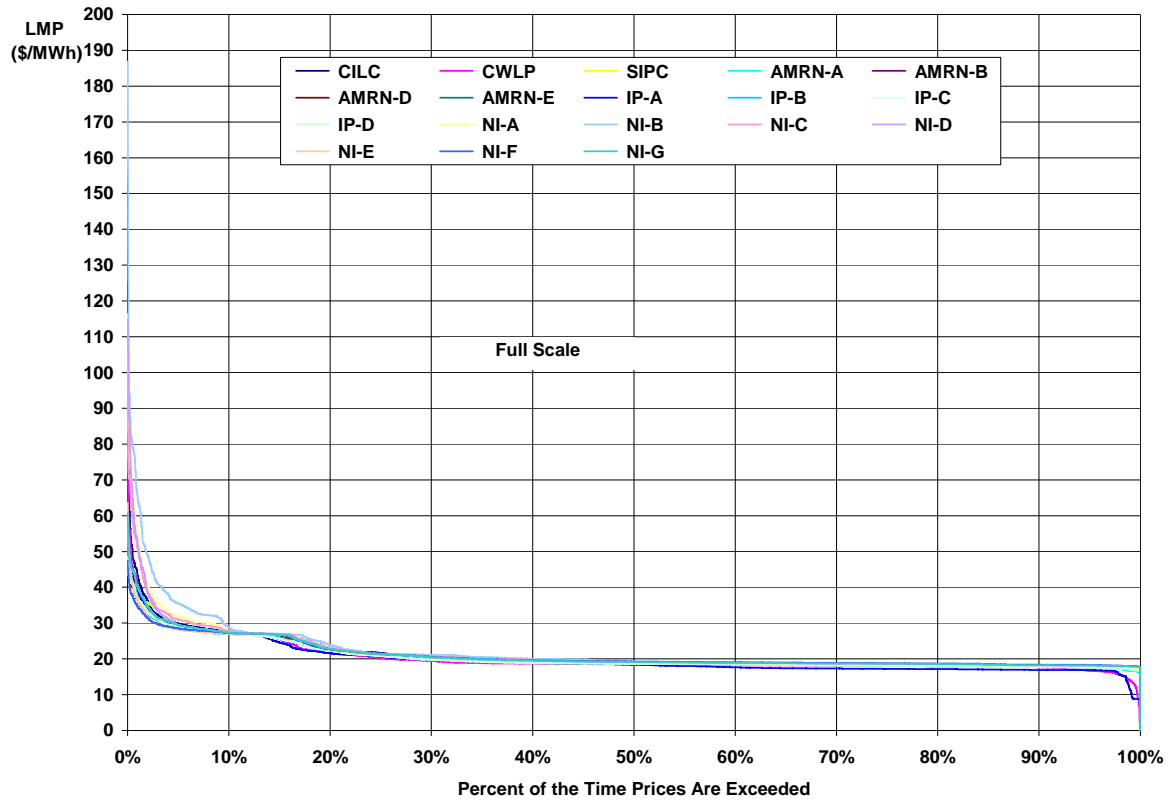
**Figure 4.1.4-2  PC Case (Case Study Assumptions) Frequency Distribution of Load-Weighted LMPs by Zone**

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.

**APRIL** **JULY**

**Load (MW)**
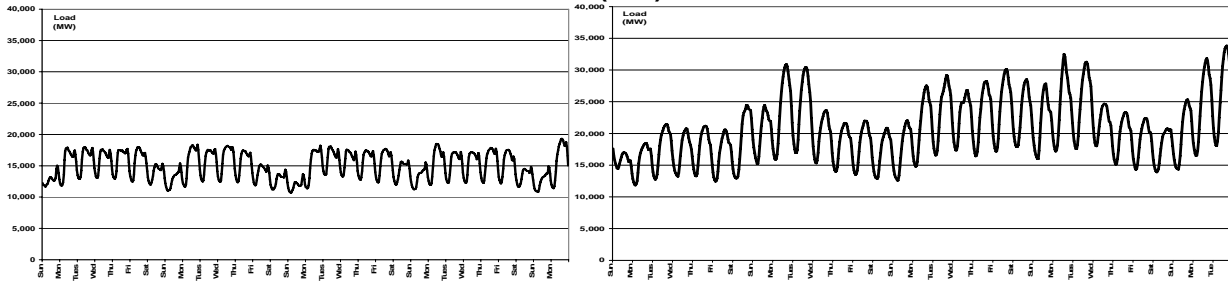
**Load-Weighted Locational Marginal Prices by Zone ($/MWh)**
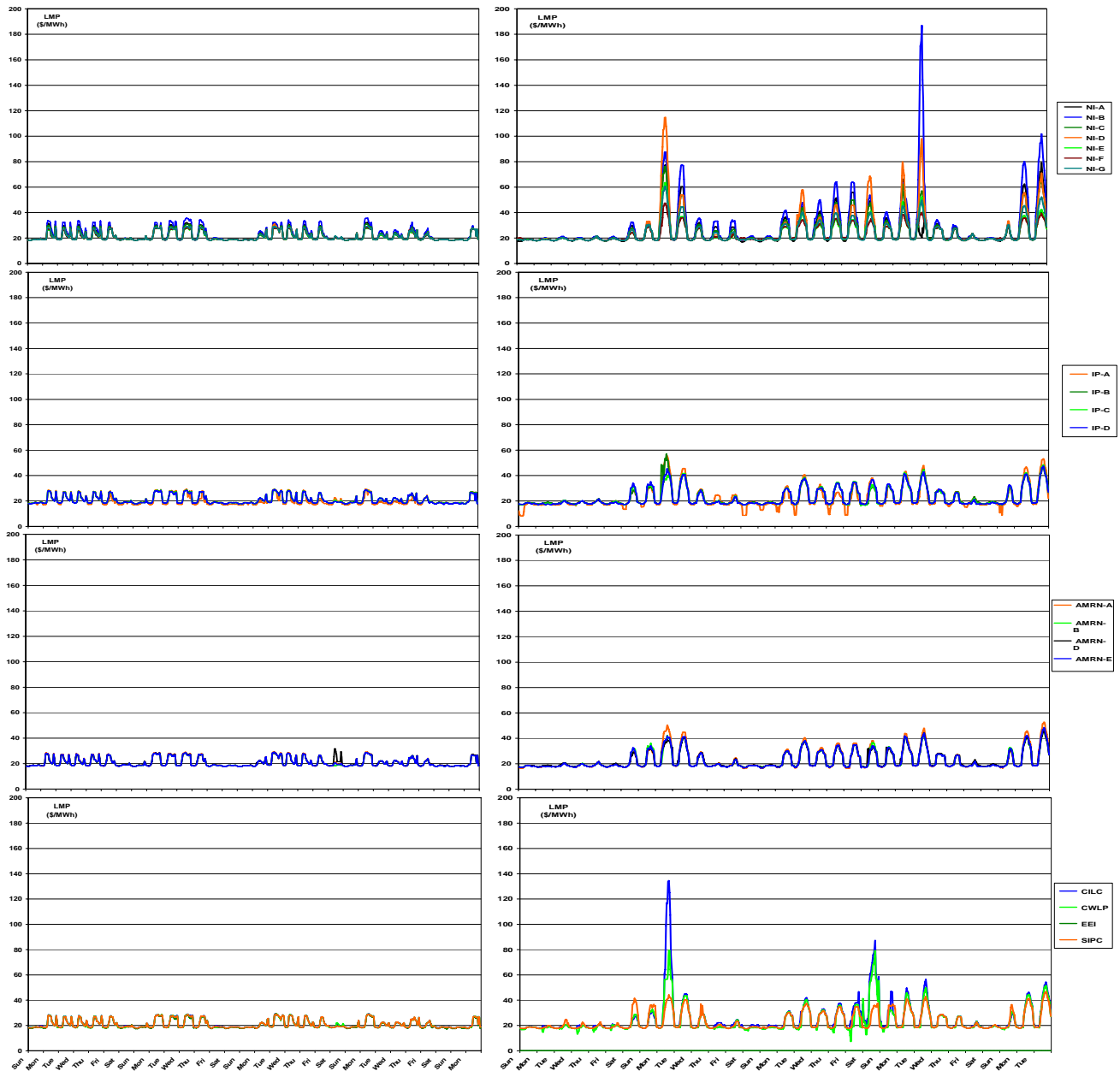
**Figure 4.1.4-3  PC Case (Case Study Assumptions) Load-Weighted Zone LMPs
for April and July**

*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.
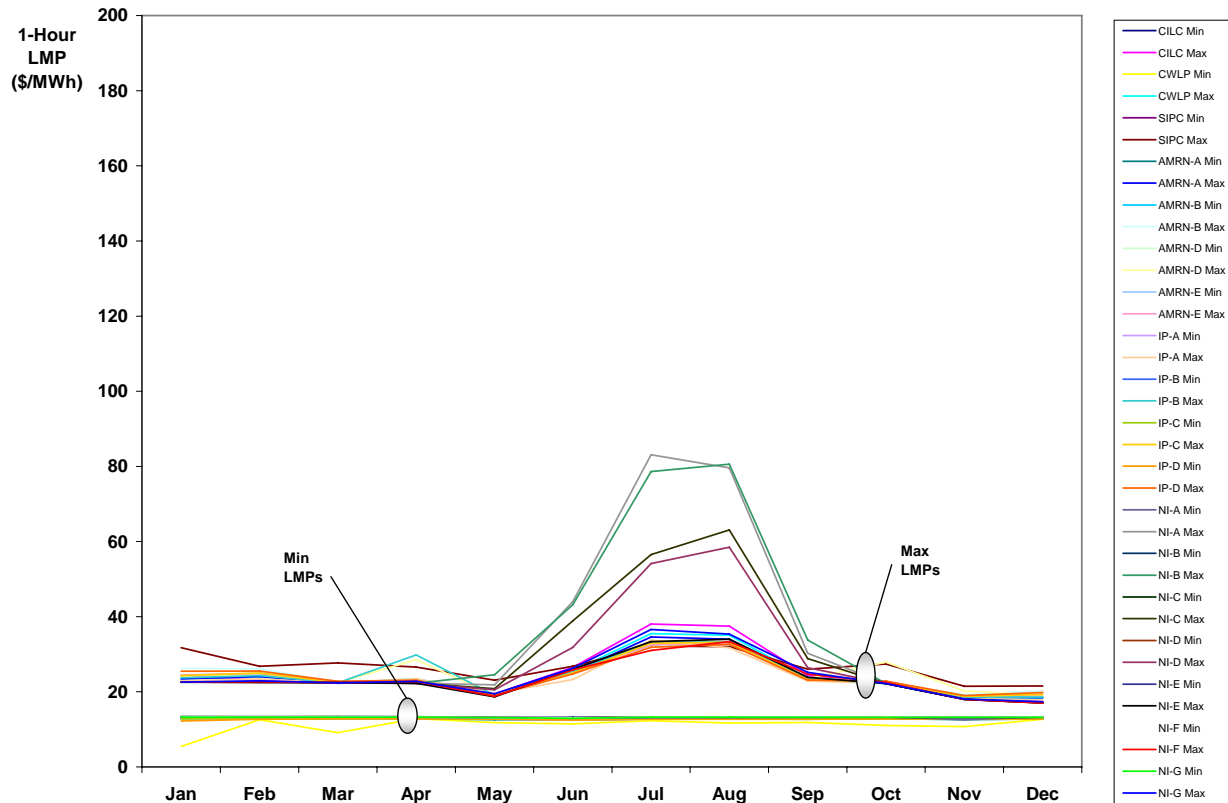


**Figure 4.1.4-4  PC Case (Conservative Assumptions) Variation in Monthly Maximum and Minimum Load-Weighted LMPs**
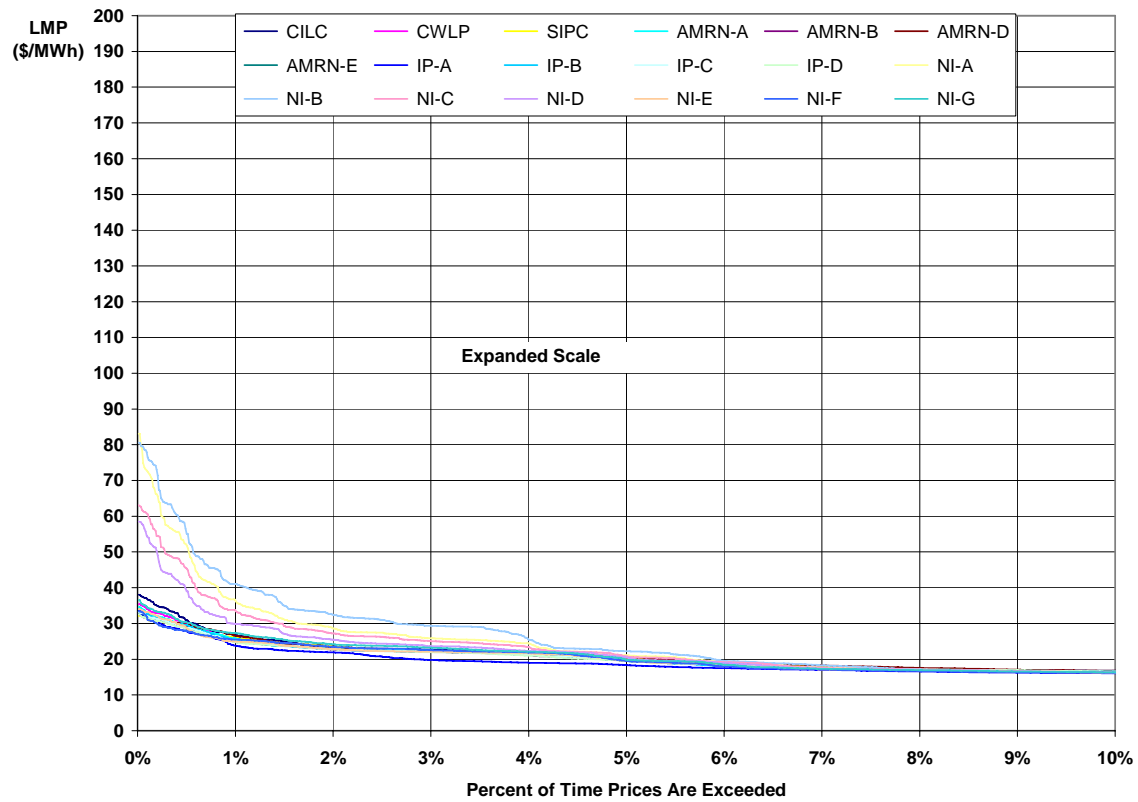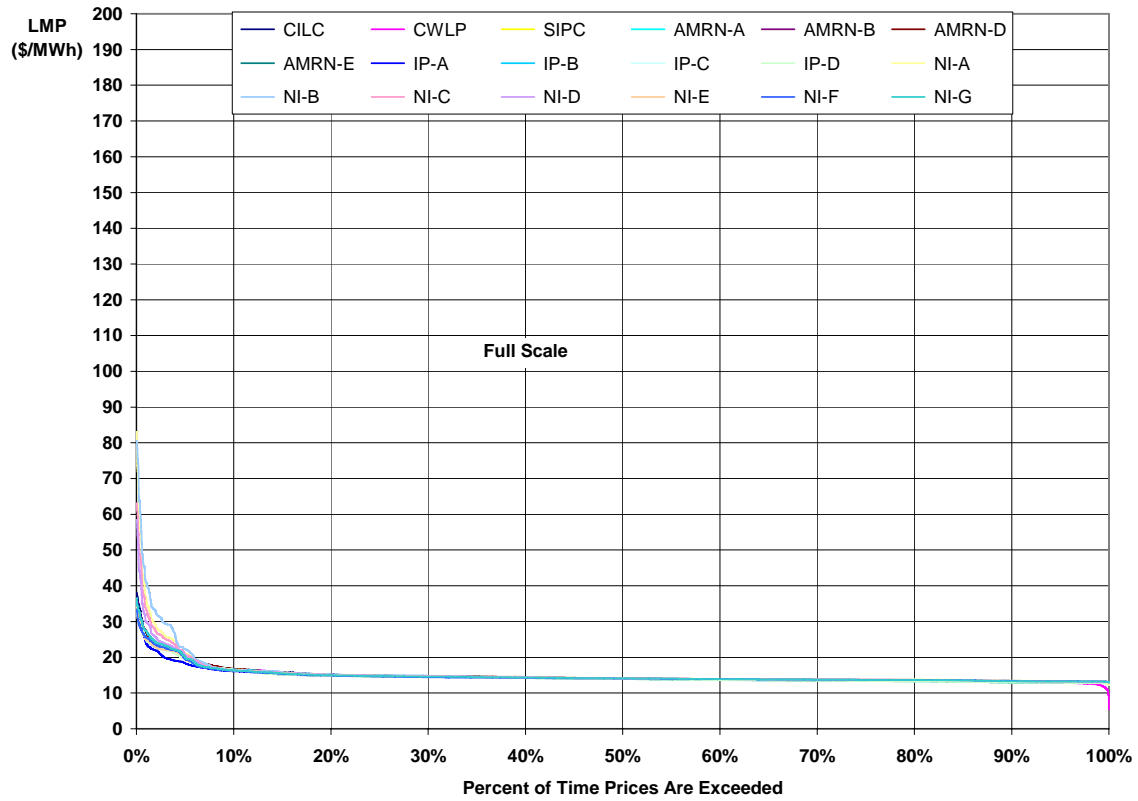
**Figure 4.1.4-5  PC Case (Conservative Assumptions) Frequency Distribution of Load-Weighted LMPs by Zone**

### 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.
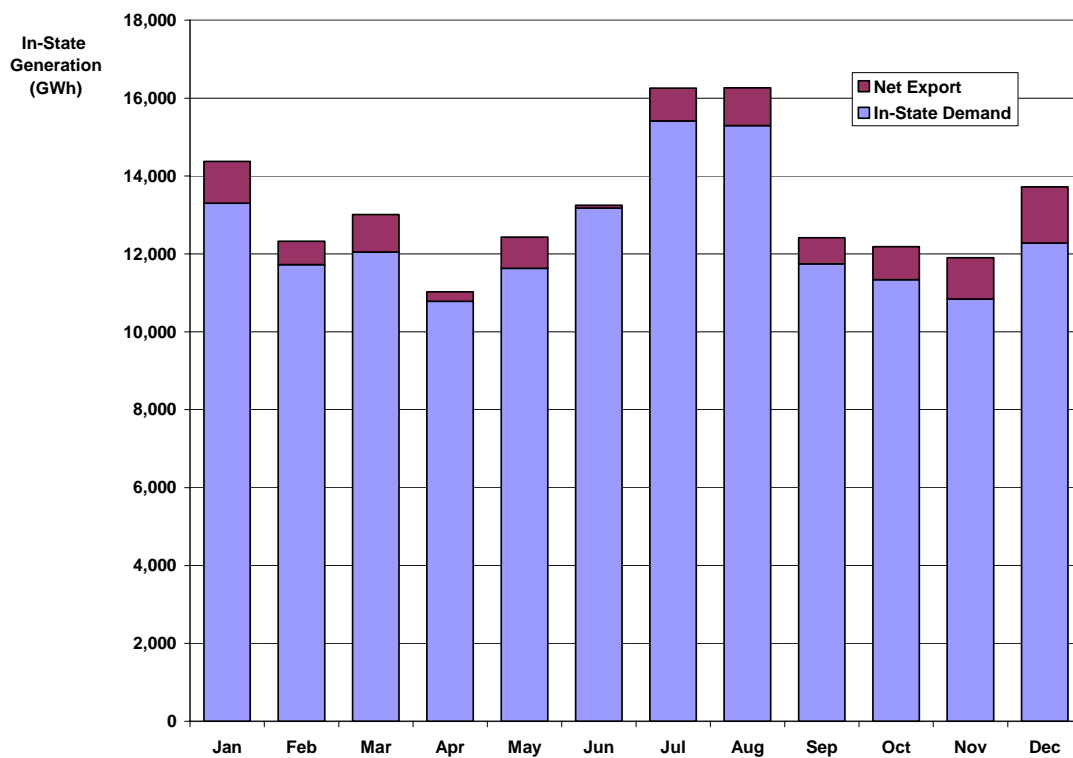


**Figure 4.1.5-1  PC Case (Case Study Assumptions) In-State Generation and Exports**

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.
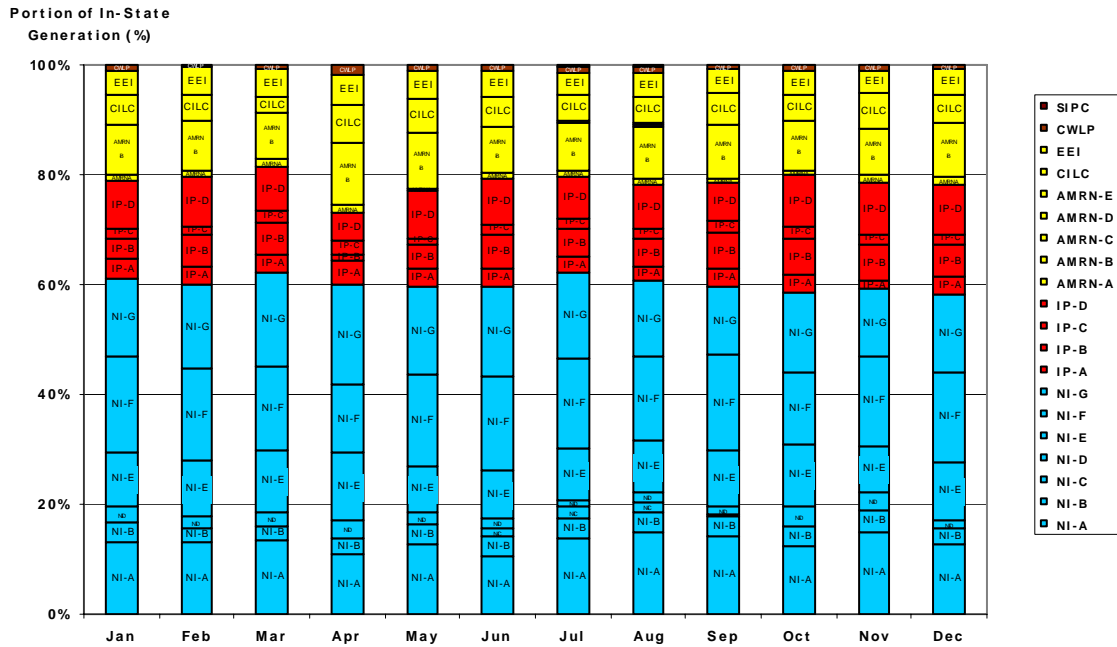


**Figure 4.1.5-2  PC Case (Case Study Assumptions) In-State Generation by Zone**
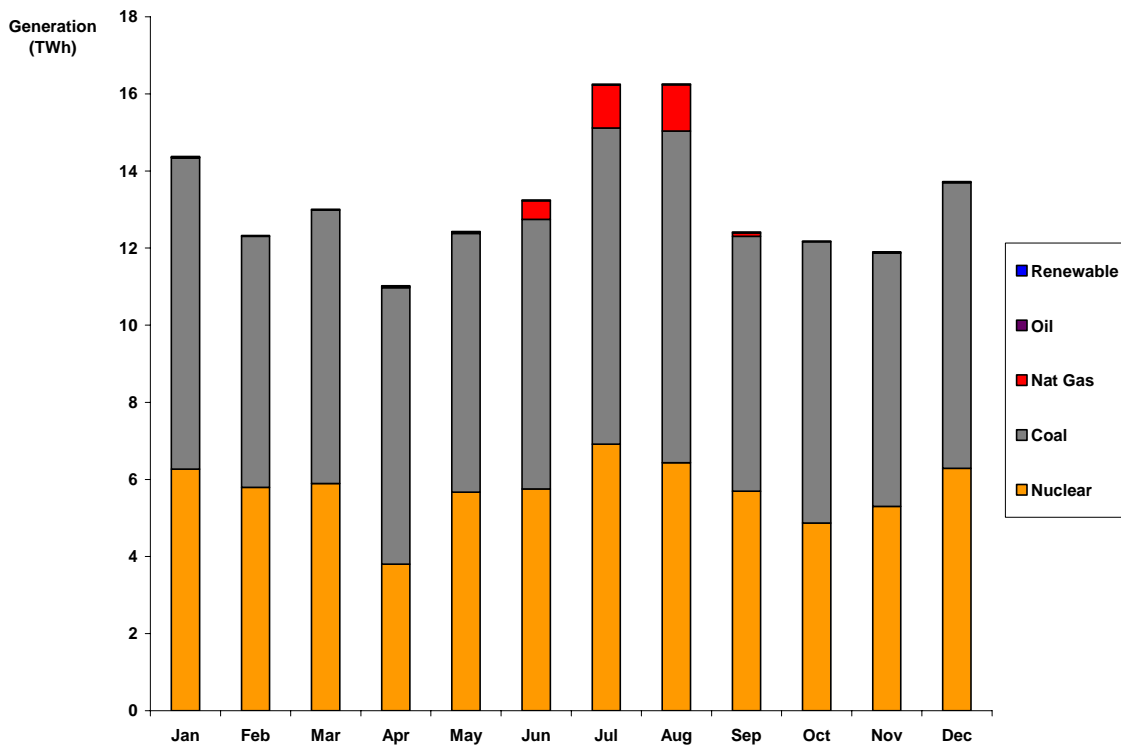


**Figure 4.1.5-3  PC Case (Case Study Assumptions) In-State Generation by Fuel Type**

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[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.
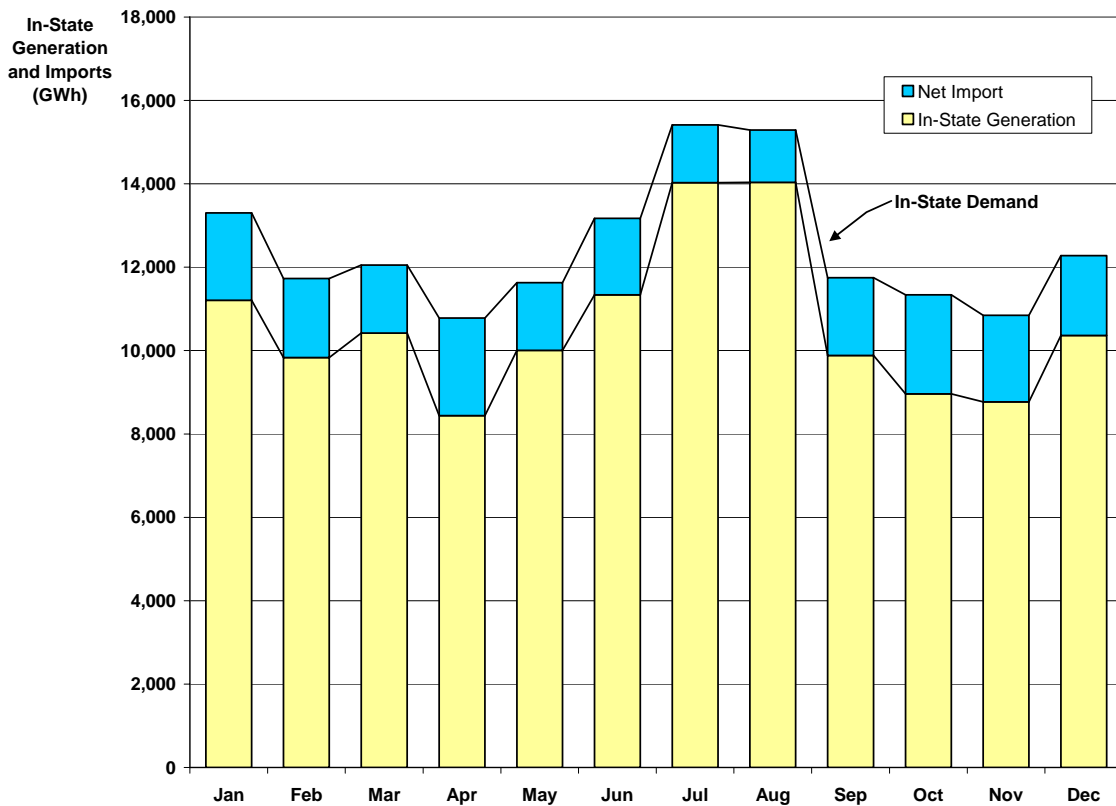


**Figure 4.1.5.-4  PC Case (Conservative Assumptions) In-State Generation and Imports**
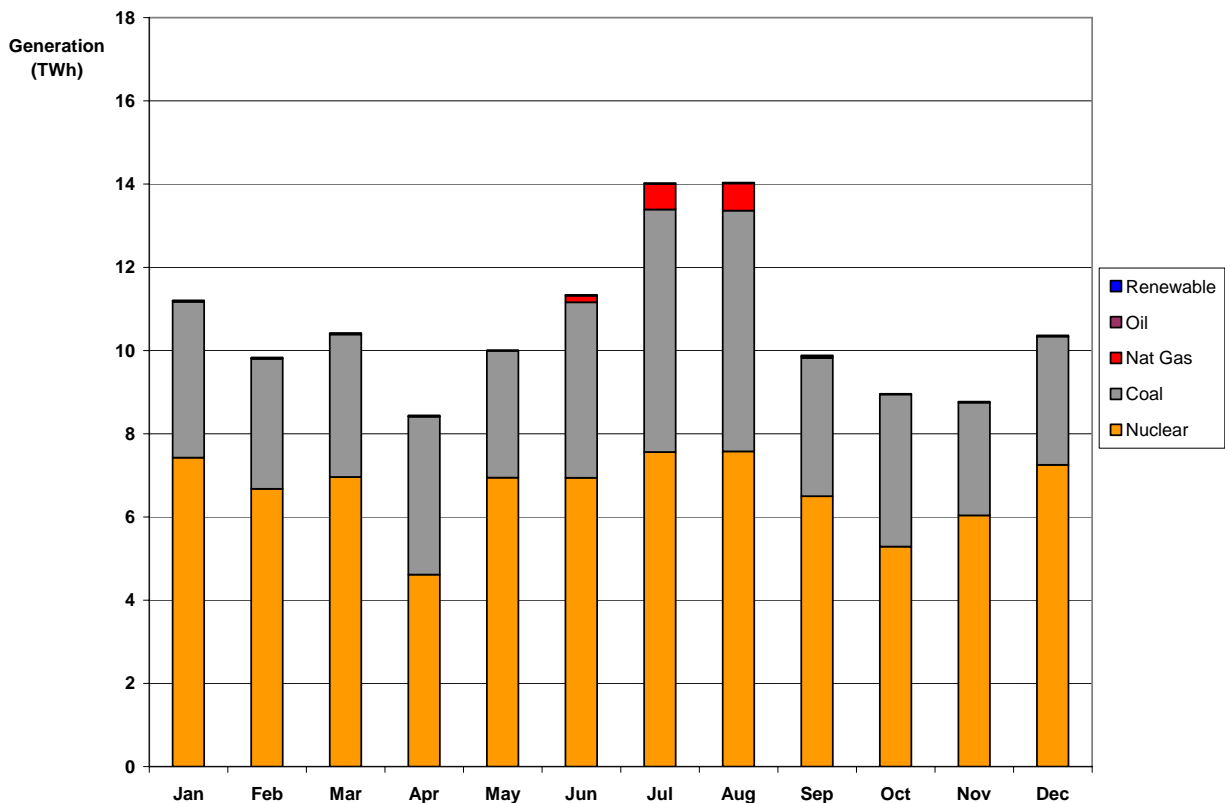
**Figure 4.1.5-5  PC Case (Conservative Assumptions) In-State Generation by Fuel Type**

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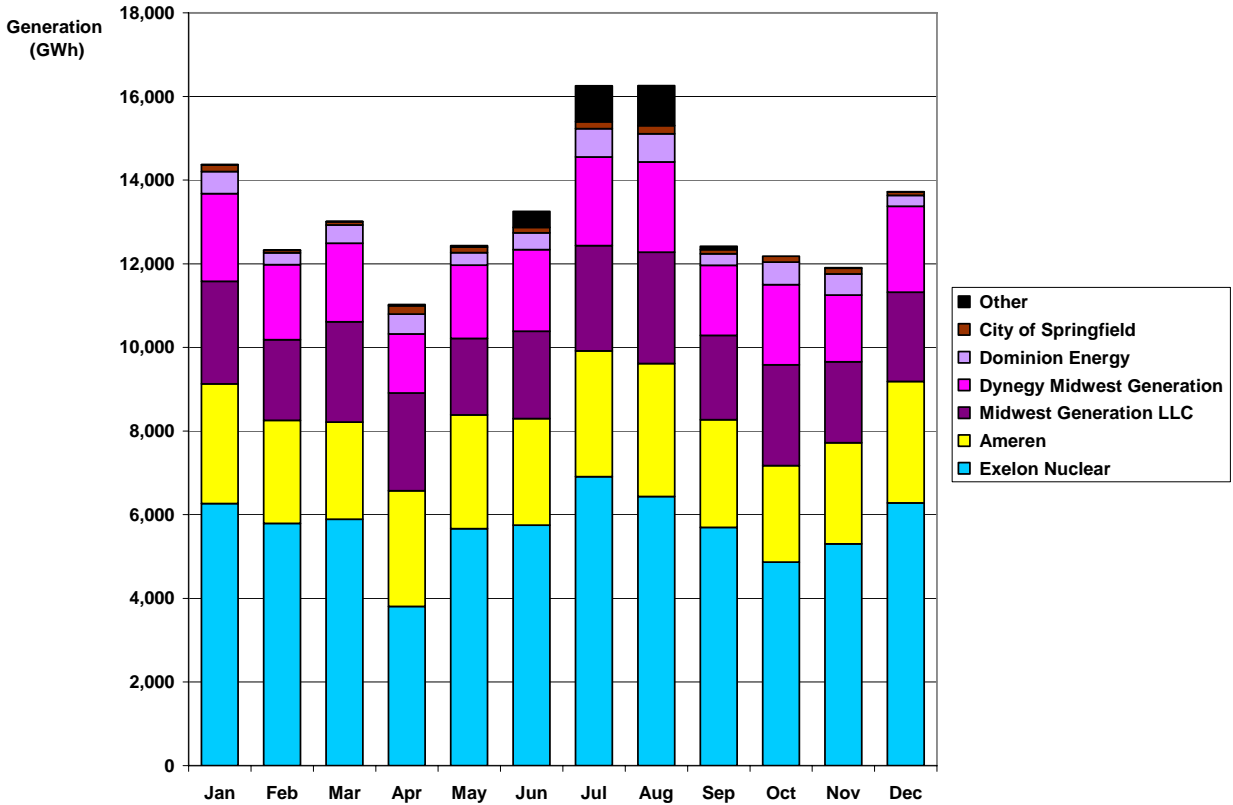
**Figure 4.1.6-1  PC Case (Case Study Assumptions) Generation by Company**
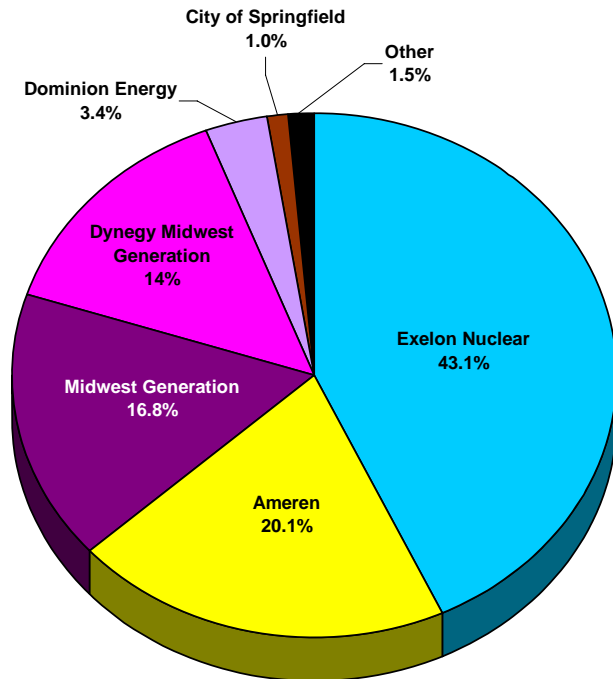


**Figure 4.1.6-2  PC Case (Case Study Assumptions) GenCo Market Share of Annual GWh of Generation**

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

| Generation Company | Annual Generation (GWh) | | | | | | Market Share of Annual GWh of Generation |
|---|---|---|---|---|---|---|---|
| | Nuclear | Coal | Natural Gas | Oil | Other | Total | |
| 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.
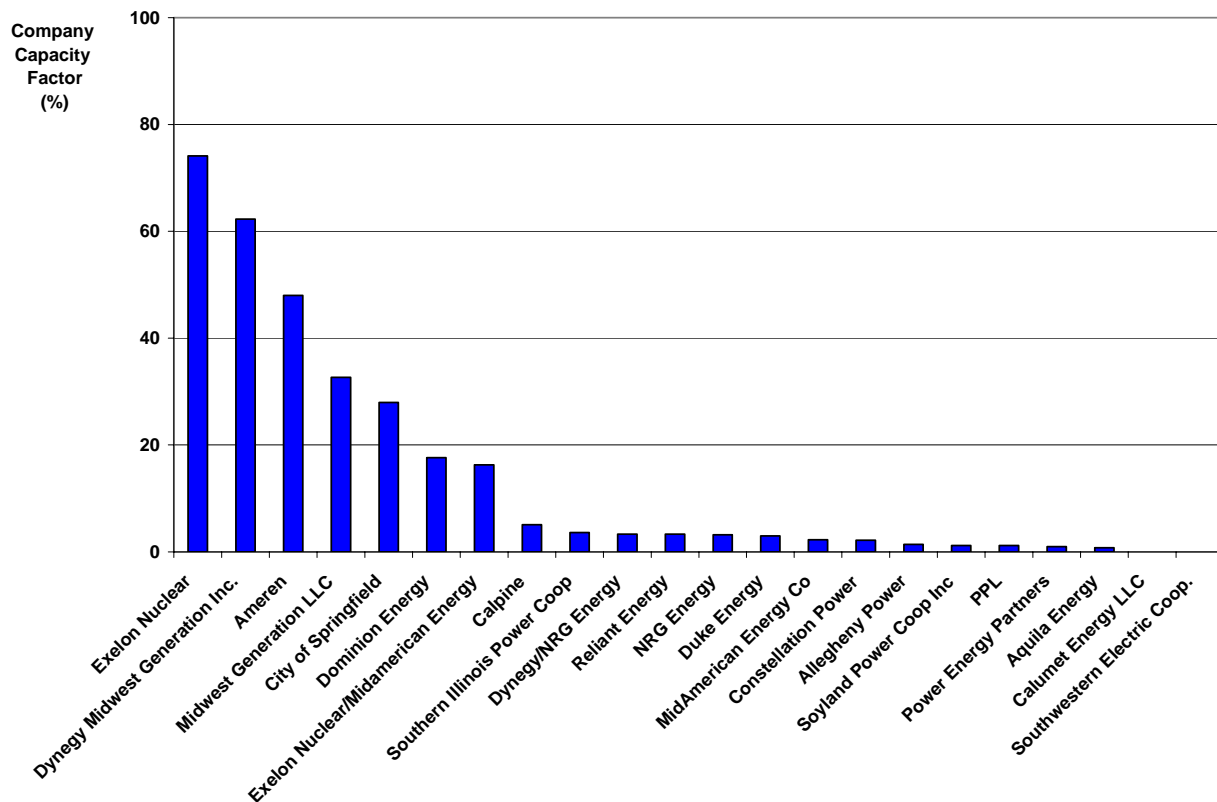


**Figure 4.1.6-3  PC Case (Case Study Assumptions) Generation Company Capacity Factors**

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**

| Generation Company | Company Annual Average Based on PC Case Generation | | |
|---|---|---|---|
| | 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**

| Type | Generation (GWh) | Costs ($million) | | | | | Effective Operating Cost [a] ($/MWh) | Effective Production Cost [b] ($/MWh) |
|---|---|---|---|---|---|---|---|---|
| | | Fuel | Variable O/M | Fixed O/M | Startup/ Shutdown | Total Cost | | |
| 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.
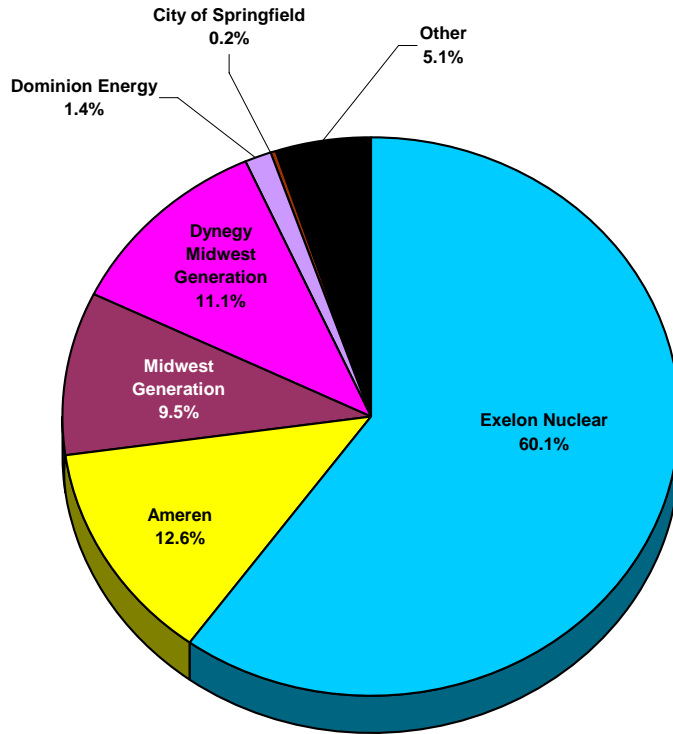
**Figure 4.1.6.-5  PC Case (Conservative Assumptions) GenCo Market Share of Annual GWh of Generation**
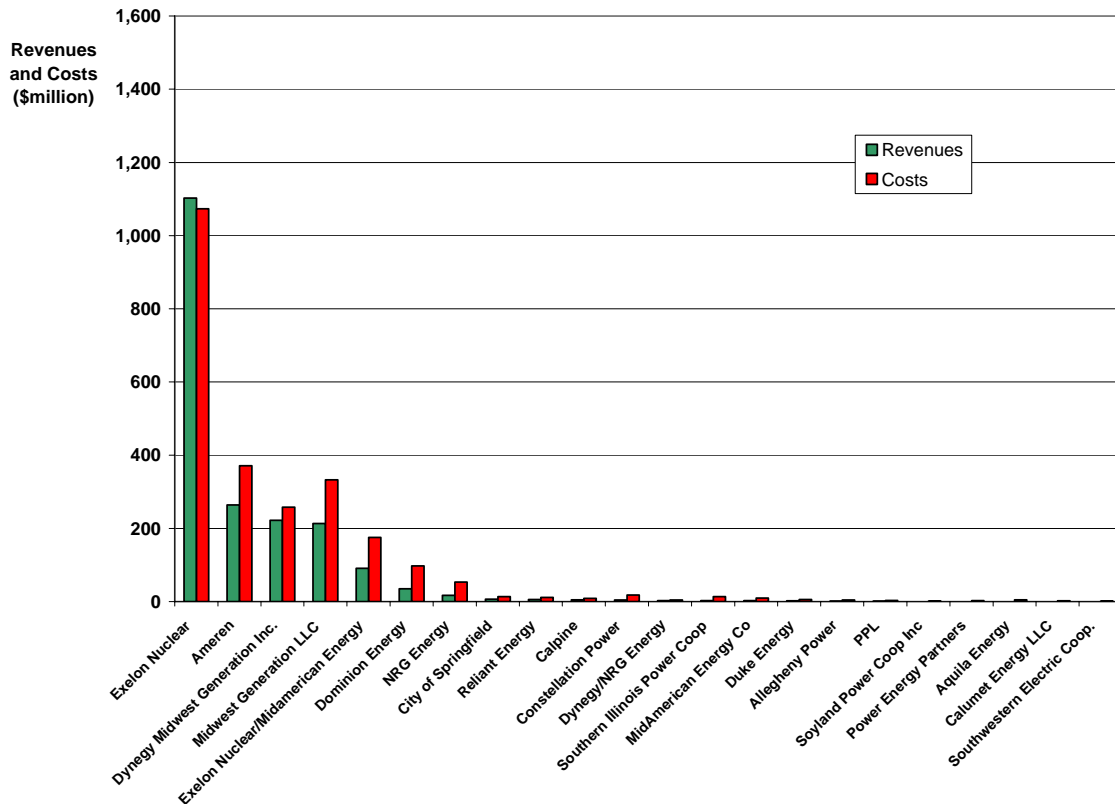


**Figure 4.1.6-6  PC Case (Conservative Assumptions) Generation Company Revenues and Costs**

**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.
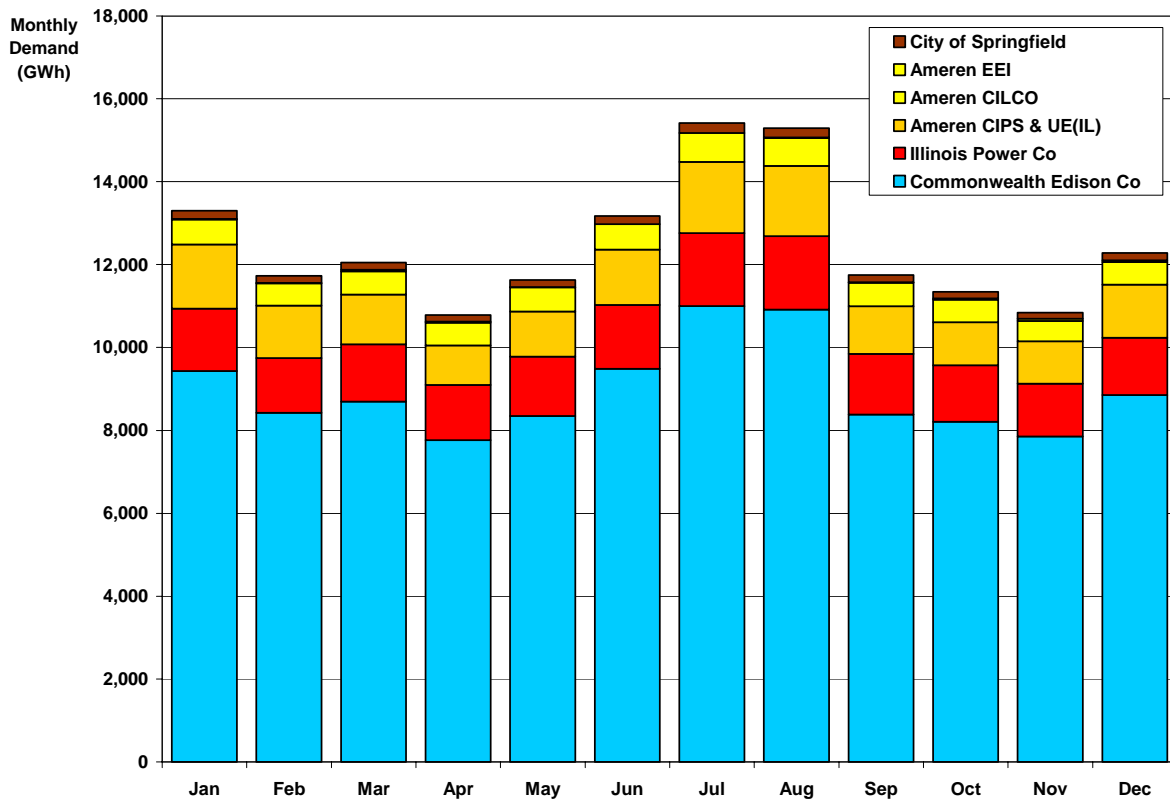


**Figure 4.1.6-7  PC Case (Case Study Assumptions) Load Served by Demand Company**
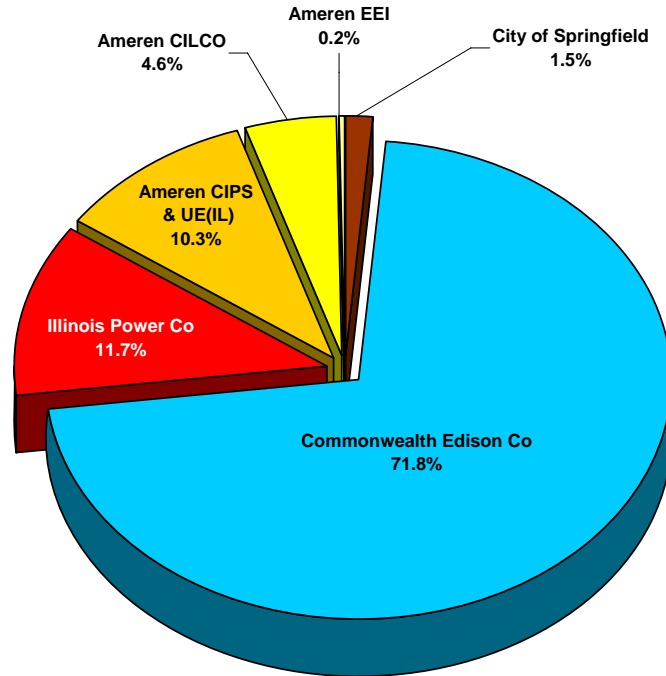
**Figure 4.1.6-8  PC Case (Case Study Assumptions) Demand Company Market Share**

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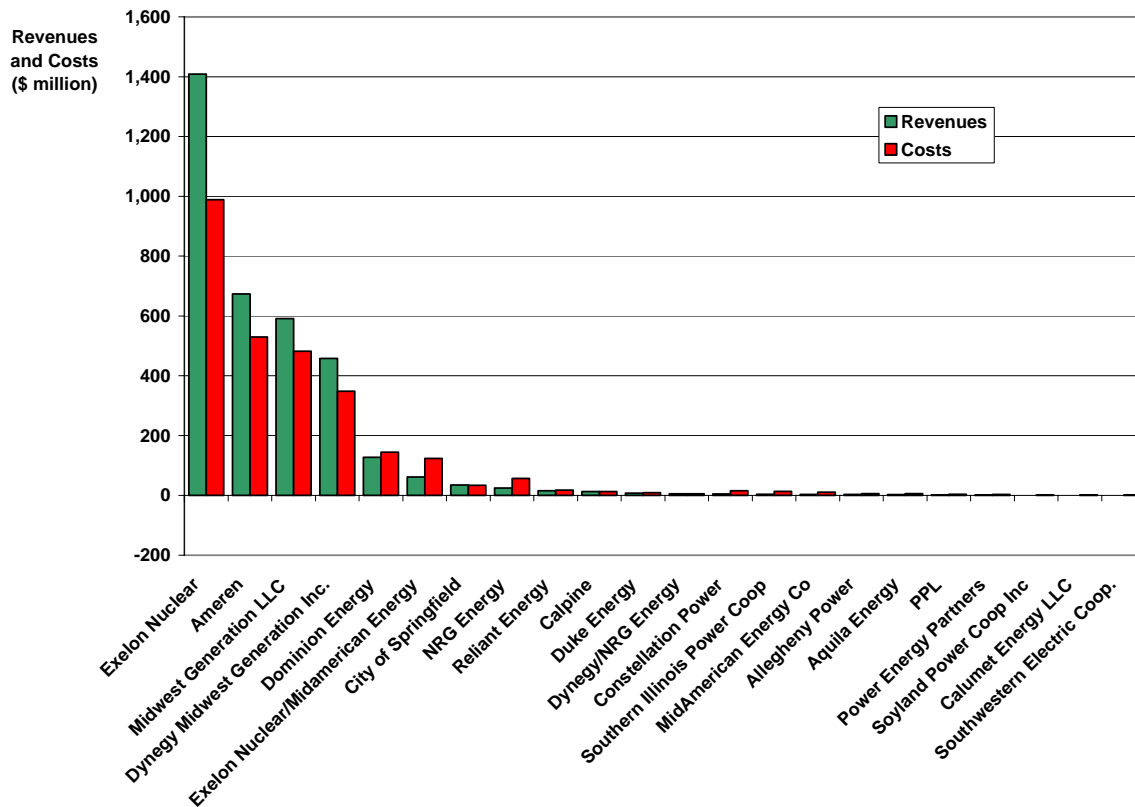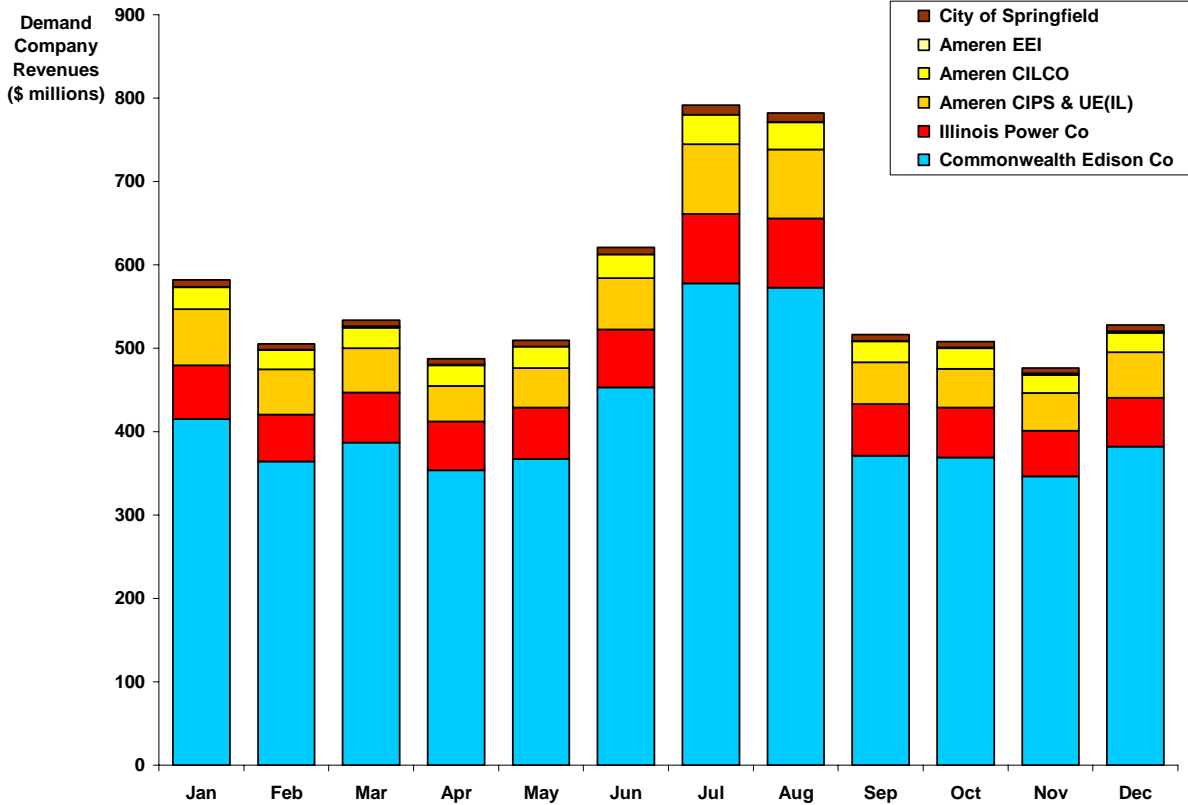
**Figure 4.1.6-9  PC Case (Case Study Assumptions) Demand Company Revenues**

**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.
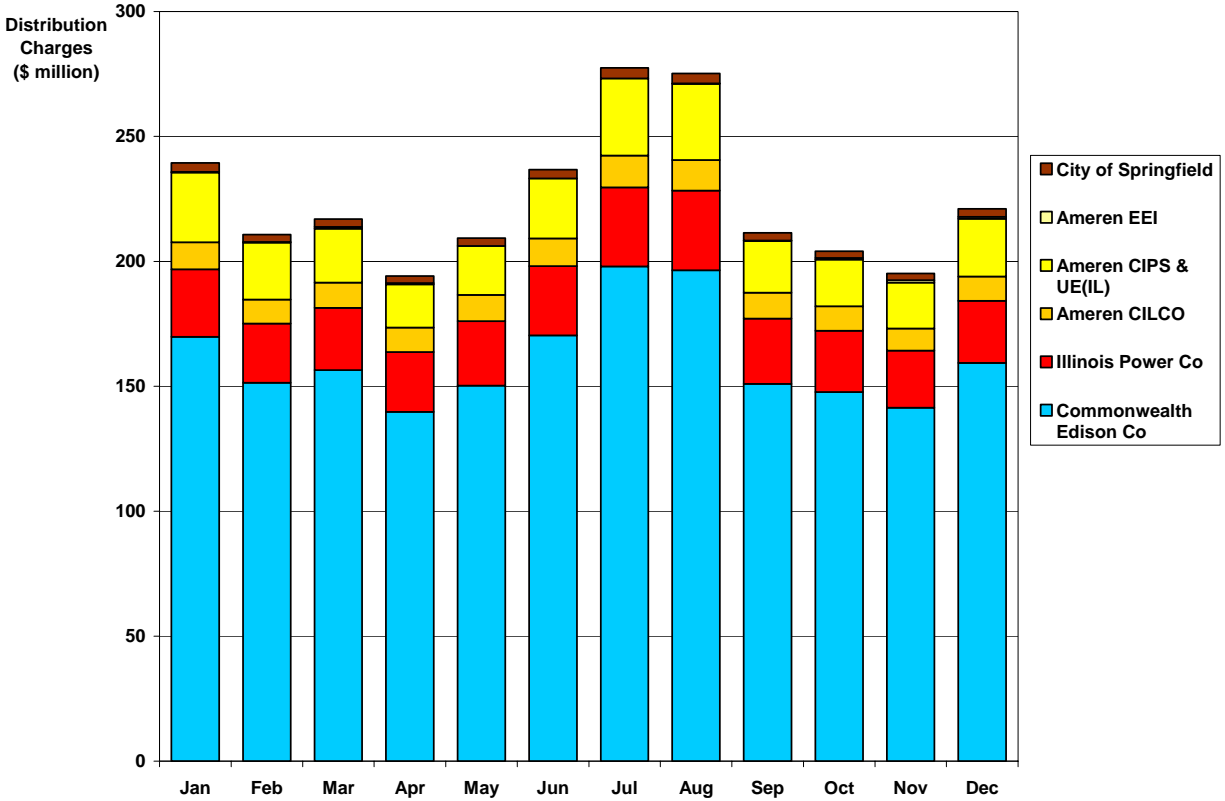
**Figure 4.1.6-10  PC Case Distribution Company Revenues**

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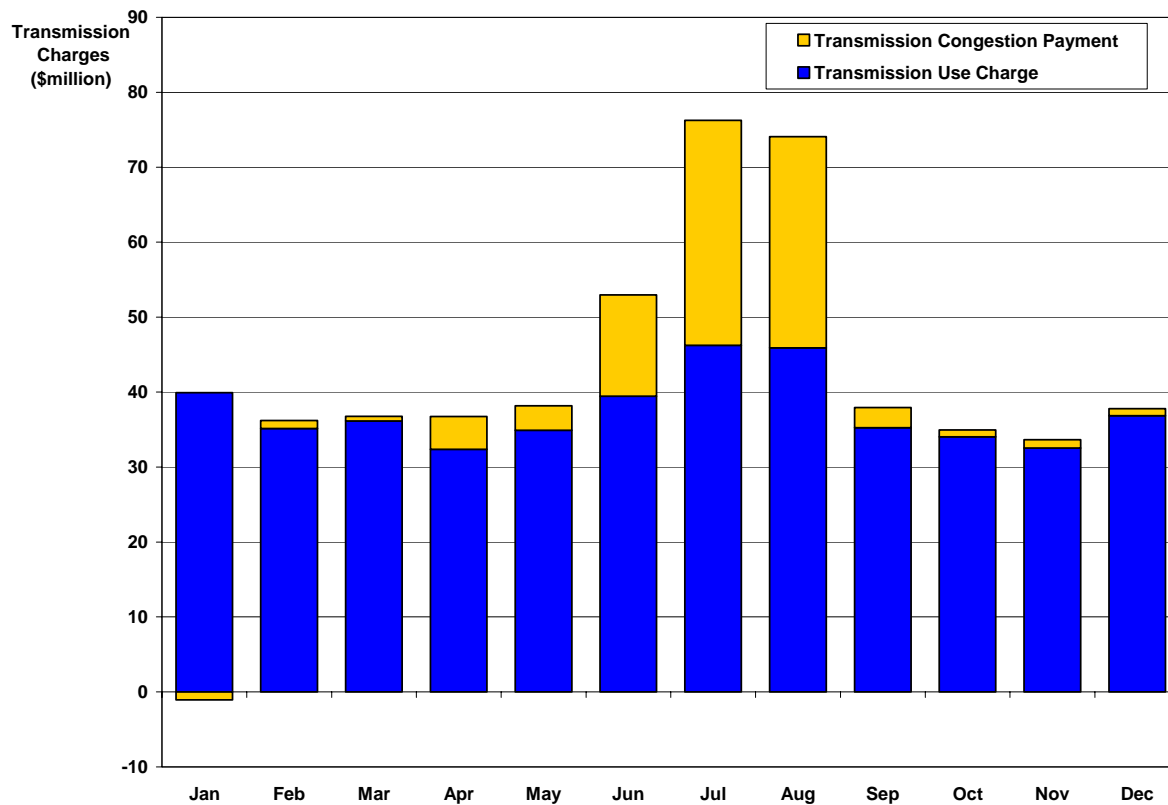
**Figure 4.1.6-11 PC Case (Case Study Assumptions) Transmission Company Revenue**

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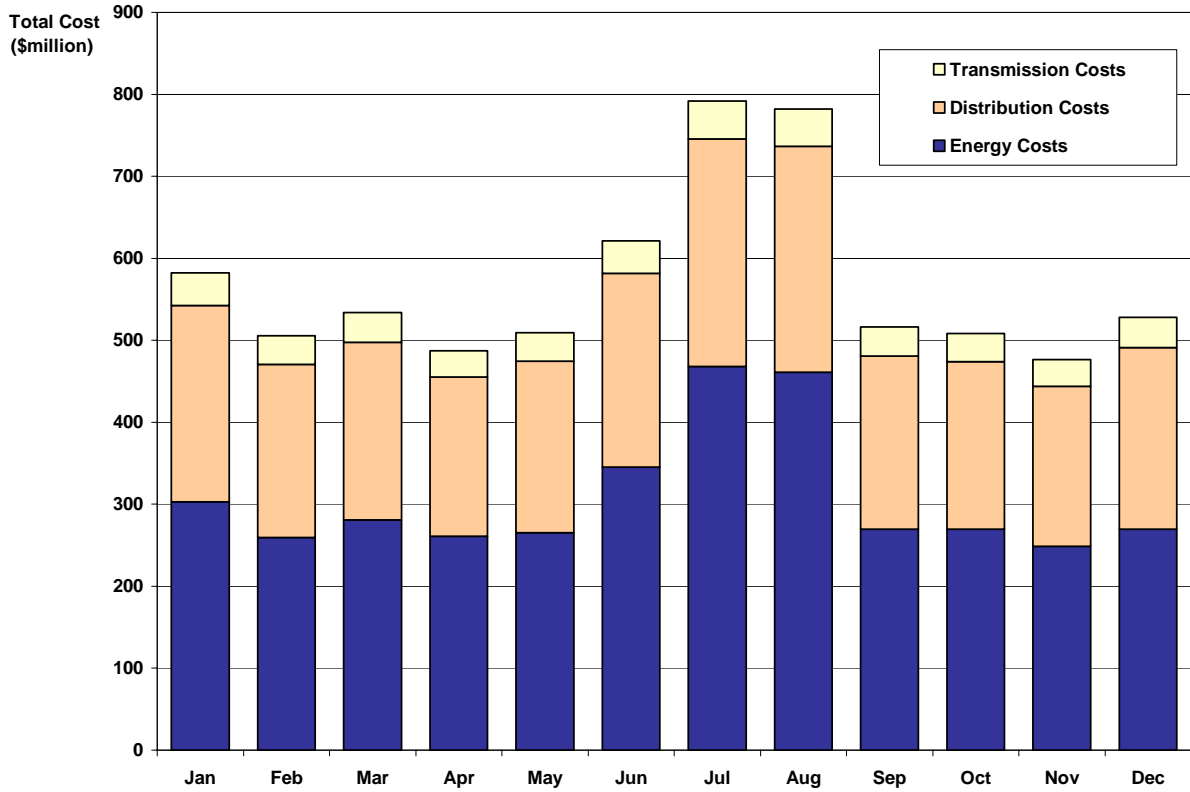
**Figure 4.1.6-12 PC Case (Case Study Assumptions) Consumer Costs**
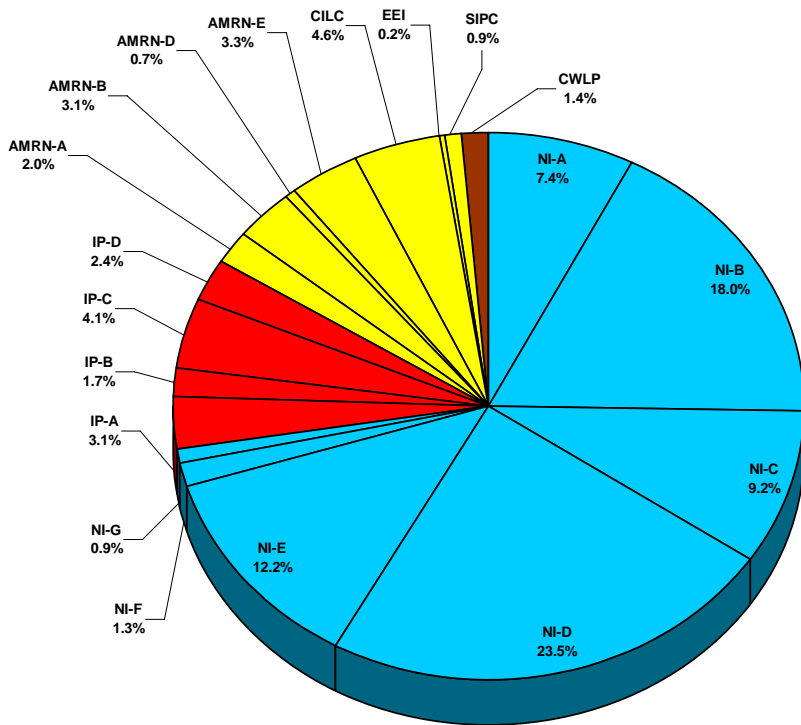


**Figure 4.1.6-13 PC Case (Case Study Assumptions) Consumer Cost Distribution by Zone**
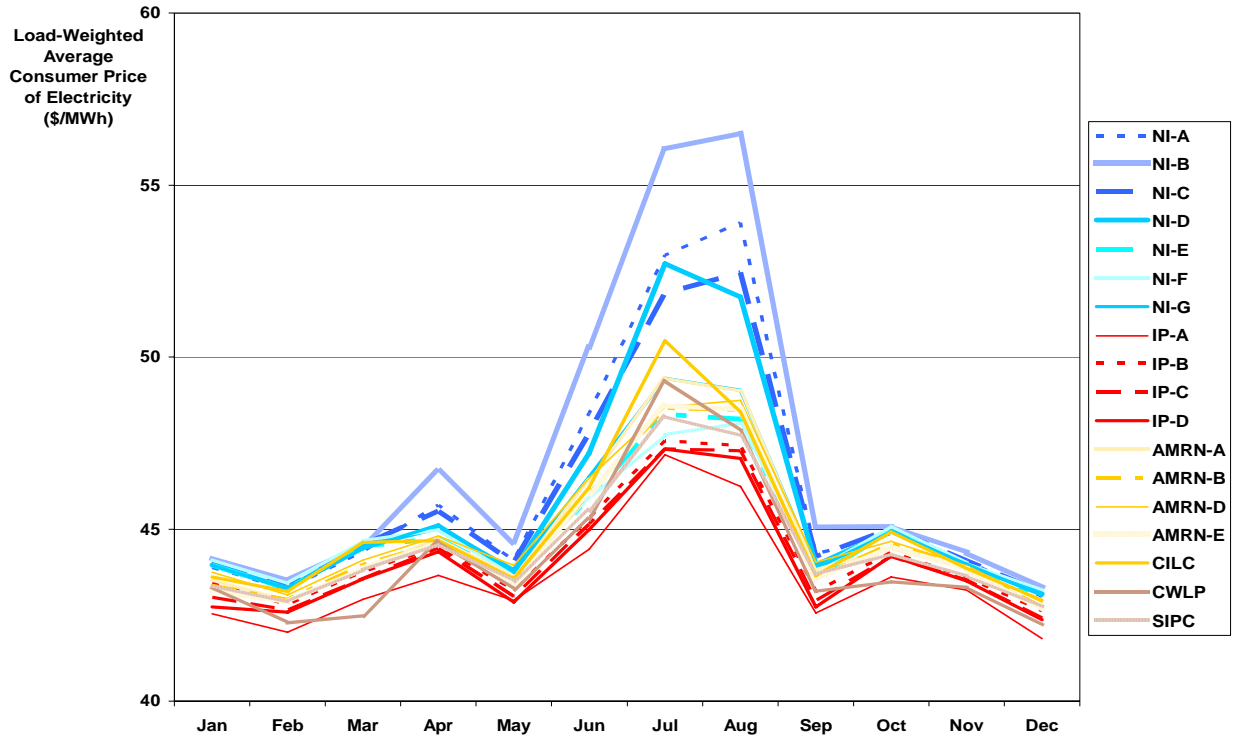
**Figure 4.1.6-14  PC Case (Case Study Assumptions) Consumer Price of Electricity**

**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.
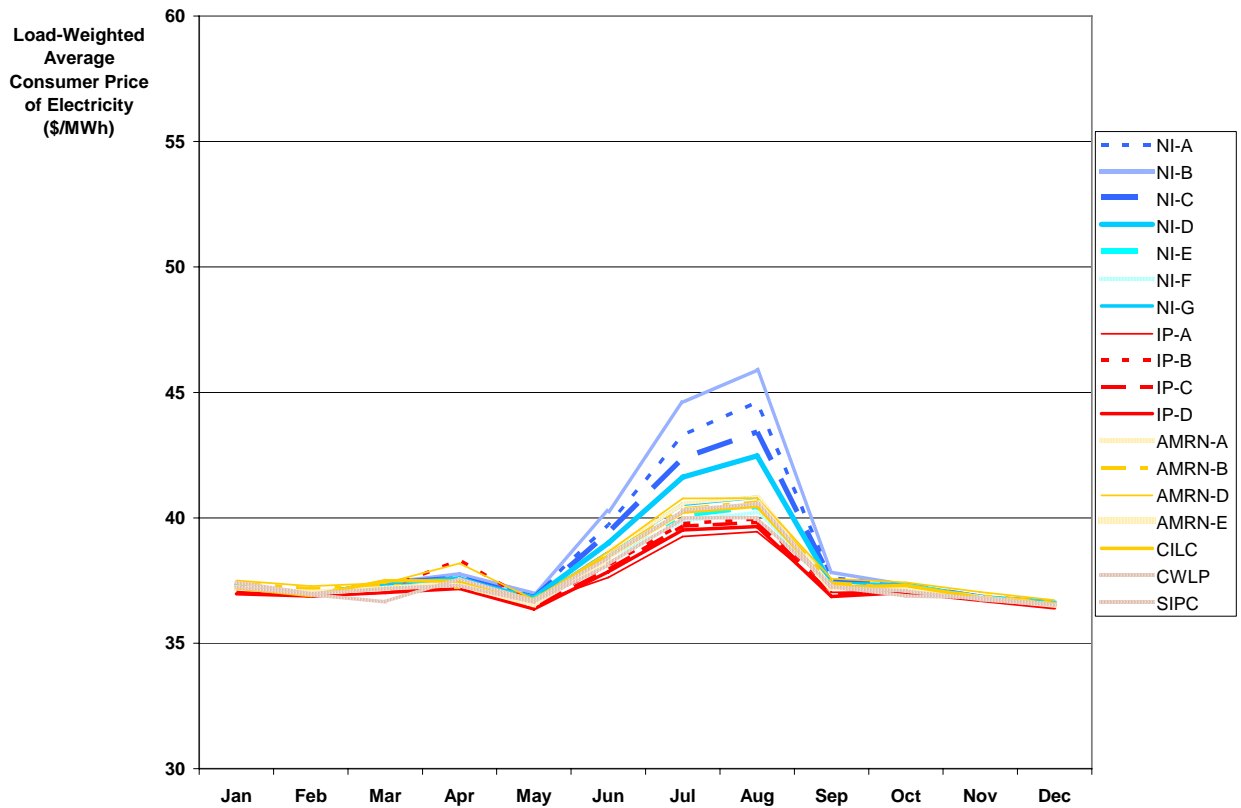


**Figure 4.1.6-15  PC Case (Conservative Assumptions) Consumer Price of Electricity**

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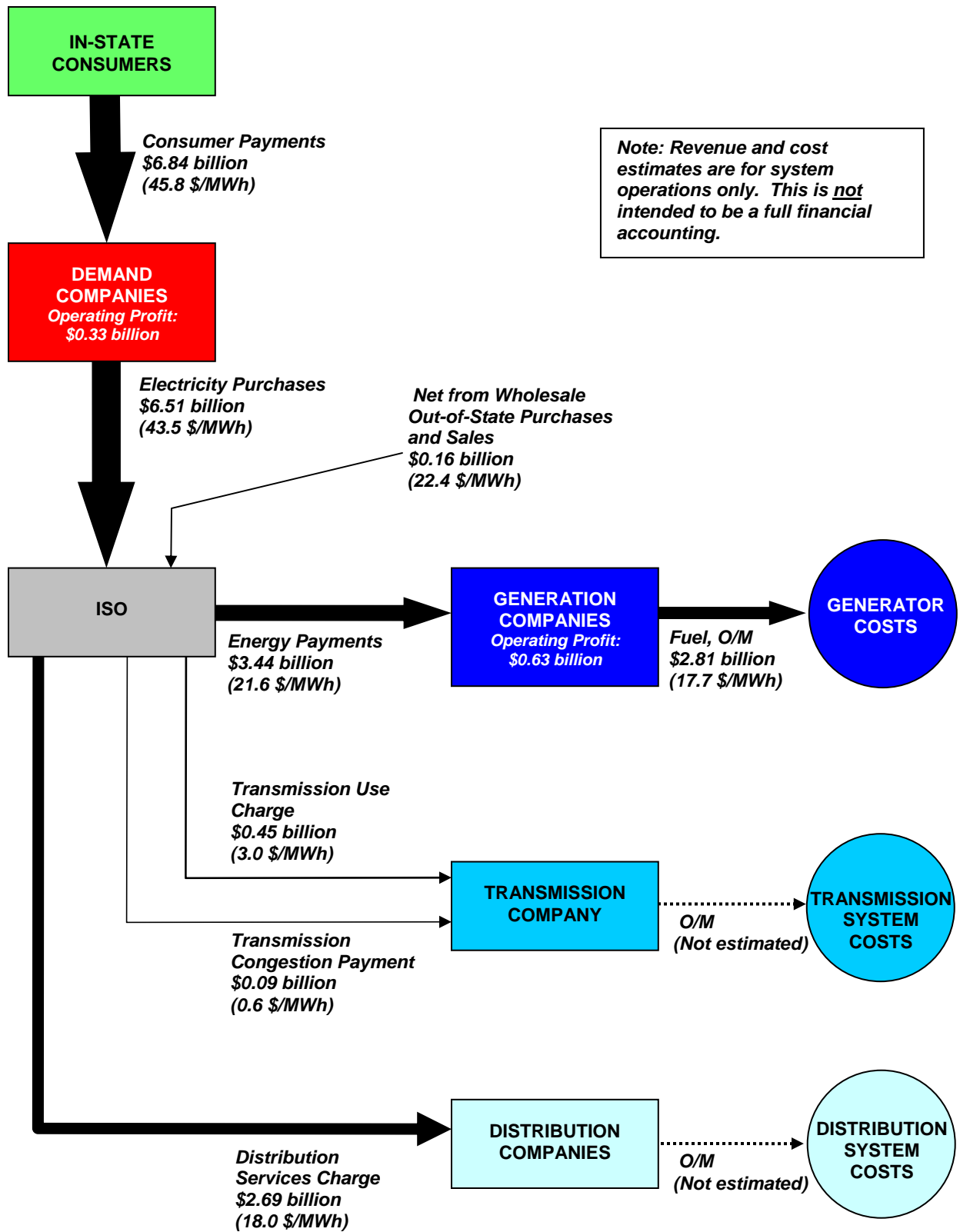
**Figure 4.1.6-16  PC Case (Case Study Assumptions) Revenue and Cost Flow**

**IN-STATE CONSUMERS**

*Consumer Payments*
*$5.72 billion*
*(38.3 $/MWh)*

**DEMAND COMPANIES**
*Operating Profit:*
*$0.231.97+.45+.07+2.6*
*9*

*Note: Revenue and cost estimates are for system operations only.  This is <u>not</u> intended to be a full financial accounting.*

*Electricity Purchases*
*$5.49 billion*
*(36.7 $/MWh)*

*Net from Wholesale Out-of-State Purchases and Sales*
*$0.32 billion*
*(16.1 $/MWh)*

**ISO**

*Energy Payments*
*$1.97 billion*
*(15.5 $/MWh)*

**GENERATION COMPANIES**
*Operating Profit:*
*-$0.49 billion*

*Fuel, O/M*
*$2.46 billion*
*(19.4 $/MWh)*

**GENERATOR COSTS**

*Transmission Use Charge*
*$0.45 billion*
*(3.0 $/MWh)*

**TRANSMISSION COMPANY**

*O/M*
*(Not estimated)*

**TRANSMISSION SYSTEM COSTS**

*Transmission Congestion Payment*
*$0.06 billion*
*(0.4 $/MWh)*

**DISTRIBUTION COMPANIES**

*O/M*
*(Not estimated)*

**DISTRIBUTION SYSTEM COSTS**

*Distribution Services Charge*
*$2.69 billion*
*(18.0 $/MWh)*

**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**

| | 2002 Historical Data [a] | PC Case Analysis Year Approximately Comparable Result | |
| --- | --- | --- | --- |
| | | 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

| Unit Being Withheld [a] | Owner | Capacity Withheld (MW) | GenCo Peak Day Operating Profit [b] ($1000) PC Case | Change by Withholding | Other GenCos Peak Day Operating Profit [b] ($1000) 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 | 98.4 | 54.3 | 43.7 | 48.8 | 43.8 | 43.4 | 43.4 | 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 | 53.8 | 47.7 | 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 | 48.9 | 43.3 | 43.7 | 43.3 | 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.
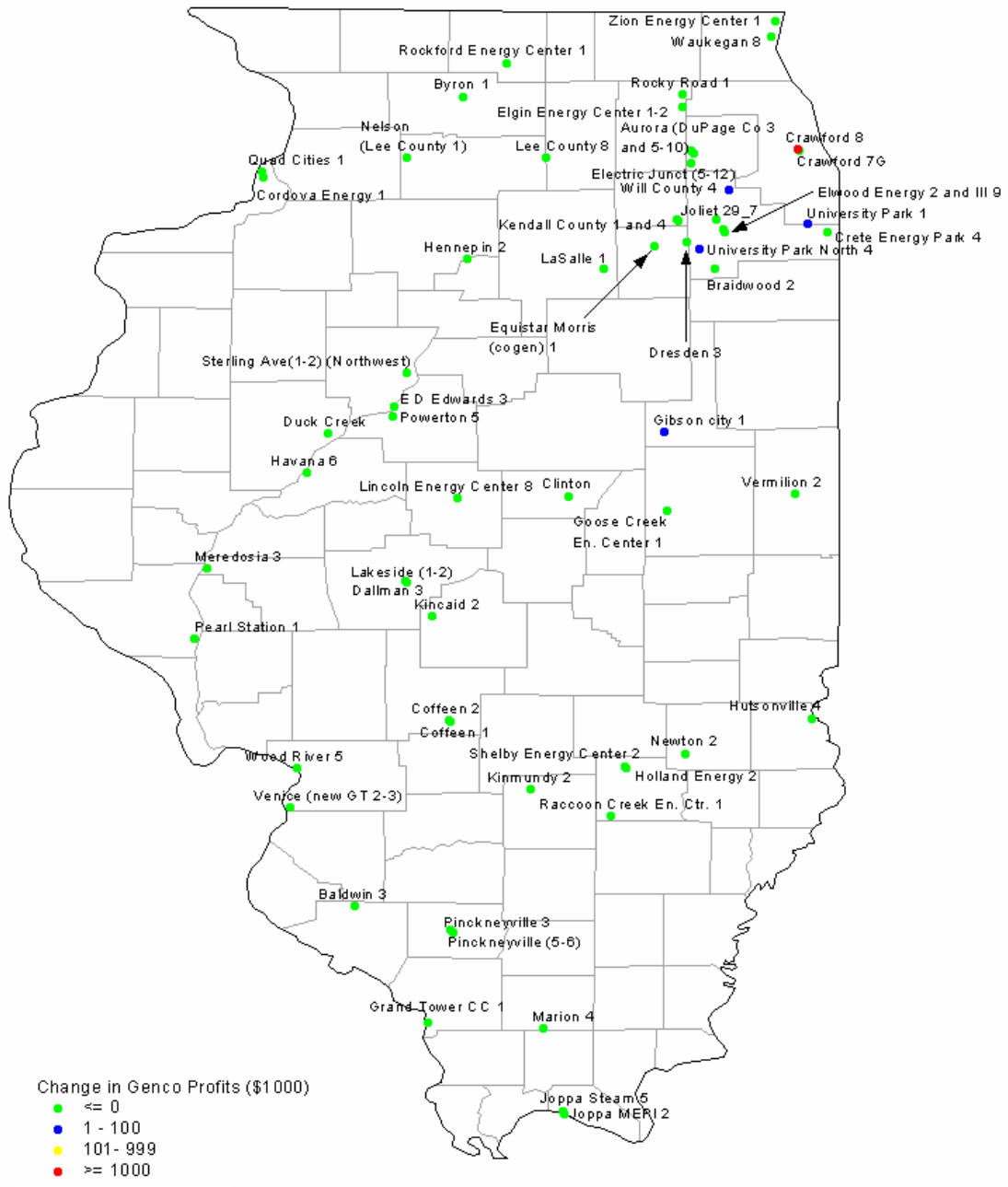
**Figure 4.2.1-3  PW-SU Cases Effect of Location of Units Withheld on Company Operating Profitability**

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**

| Unit Being Withheld | Owner | Capacity Withheld (MW) | Change in GenCo Operating Profit ($1,000) | |
| | | | 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**

| Unit Being Withheld [a] | Owner | Capacity Withheld (MW) | GenCo Peak Day Operating Profit[b] ($1,000) | | Other GenCos Peak Day Operating Profit[b] ($1,000) | | Load Cur-tailed (MW) |
| | | | PC Case | Change by With-holding | PC Case | Change by With-holding) | |
|---|---|---|---|---|---|---|---|
| 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**

| Units Being Withheld [a] | Owner | Capacity Withheld (MW) | GenCo Peak Day Operating Profit[b] ($1000) PC Case | Change by With-holding | Other GenCos Peak Day Operating Profit[b] ($1000) 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.*<br>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.*<br><br>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 $_{g\,h\,d+1}$*<br><br>$= (LMP_{n\,h\,d+1} - \alpha\ x\ Production\ Cost_g)\ x\ Unit\ Size_g$<br><br>*[α=1.50]*<br><br>*If Expected Hourly Profit $_{g\,h\,d+1} \geq 0$*<br><br>*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 $_{g\,h\,d+1} < 0$*<br><br>*Unit is withheld from the market for that hour* |
| *GenCos run the unit commitment algorithm.*<br>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$_{n\,d+1}$) → Unit commitment with units withheld* |
| *GenCos apply production cost bidding for units that are offered to the market.* | |
| | *d = day*<br>*h= hour*<br>*n=network node*<br>*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**

| Owner | Units Being Withheld by Application of the 150% Profit Margin Screen [a] | Capacity Withheld (MW) | Hours Withheld | GenCo Peak Day Operating Profit[b] ($1000) | |
|---|---|---|---|---|---|
| | | | | PC Case | Change by With-holding |
| Allegheny Power | - | | | 31 | 1 |
| Ameren | Meredosia 4 | 200 | 1 to 24 | 1,730 | 4 |
| | Grand Tower CC 1 | 240 | 1, 24 | | |
| | Grand Tower CC 2 | 240 | 1, 24 | | |
| Aquila Energy | - | | | 23 | 0 |
| Calpine | - | | | 237 | -2 |
| Calumet Energy LLC | - | | | -5 | 0 |
| City of Springfield | - | | | 121 | 3 |
| Constellation Power | Holland Energy 1 | 288 | 1 to 24 | 34 | -1 |
| | Holland Energy 2 | 288 | 1 | | |
| Dominion Energy | State Line 3 | 197 | 1 to 24 | 602 | 6 |
| | State Line 4 | 318 | 1 to 24 | | |
| Duke Energy | - | | | 77 | -1 |
| Dynegy Midwest Generation Inc. | Havana (1-5) | 238 | 1 to 24 | 1,062 | 9 |
| | Hennepin 1 | 74 | 1 to 6 | | |
| | Wood River 1 | 46.3 | 1 to 24 | | |
| | Wood River 2 | 46.3 | 1 to 24 | | |
| | Wood River 3 | 46.3 | 1 to 24 | | |
| Dynegy/NRG Energy | - | | | 137 | 0 |
| Exelon Nuclear | - | | | 4,335 | 3 |
| Exelon Nuclear/Midamerican Energy | - | | | 261 | -6 |
| MidAmerican Energy Co. | Cordova Energy 1 | 240 | 1, 24 | 52 | 0 |
| | Cordova Energy 2 | 240 | 1, 24 | | |
| Midwest Generation LLC | Collins 1 | 554 | 1 to 24 | 2,418 | 68 |
| | Collins 2 | 554 | 1 to 24 | | |
| | Collins 3 | 530 | 1 to 24 | | |
| | Crawford 7G | 106.5 | 9 to 24 | | |
| | Fisk 19 | 326 | 8 to 24 | | |
| NRG Energy | Kendall County 1 | 240 | 1, 24 | 511 | -1 |
| | Kendall County 2 | 240 | 1, 24 | | |
| | Kendall County 3 | 240 | 1, 24 | | |
| | Kendall County 4 | 240 | 1, 24 | | |
| | Nelson (Lee County 1) | 274.56 | 1, 24 | | |
| | Nelson (Lee County 2) | 274.56 | 1, 24 | | |
| | Nelson (Lee County 3) | 274.56 | 1, 24 | | |
| | Nelson (Lee County 4) | 274.56 | 1, 24 | | |
| | Rockford Energy Center 3 | 147 | 1 to 10, 23, 24 | | |
| Power Energy Partners | - | | | 19 | 2 |
| PPL | - | | | 8 | 0 |
| Reliant Energy | - | | | 334 | 0 |
| Southern Illinois Power Coop. | Marion 1 | 34 | 1 to 24 | 26 | 4 |
| | Marion 2 | 34 | 1 to 24 | | |
| | Marion 3 | 34 | 1 to 24 | | |
| 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.*<br>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)*<br><br>$= (Available\ Capacity_{h\ d+1}\ /\ Load_{h\ d+1}\ -\ 1)$<br><br>$LMP_{n\ h\ d+1} = LMP_{n\ h\ d}\ (SR_{h\ d}\ /\ SR_{h\ d+1})$ |
| *GenCos apply the Physical Withholding – System Reserve Criteria strategy to adjust the unit commitment.*<br><br>If the system reserve margin is expected to be lower than a trigger point, units are considered for withholding.<br><br>    Units are rank-ordered by the projected price (LMP) from highest to lowest.<br><br>    Capacity to be withheld is that which will bring the SR down by a target amount.<br><br>    Units are withheld up to a specified portion of the company's total capacity.<br><br>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%]*<br><br><br>*Unit ranking: Highest LMP, second highest, …*<br><br>*Target reduction in system reserve by withholding = σ*<br>*[σ=5%]*<br><br>*Capacity Withheld $= \sum_{\sigma}$ Units in rank order*<br><br>    *where Capacity Withheld $\leq \delta$ x Company Capacity*<br>*[δ=25%]*<br><br><br>*If $SR_{h\ d+1}\ >\ \theta$*<br><br>*No withholding* |
| *GenCos run the unit commitment algorithm.*<br>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 ($LMP_{n\ d+1}$) → Unit commitment with units withheld* |
| *GenCos apply production cost bidding for units that are offered to the market.* | |
| | *d = day*<br>*h= hour*<br>*n=network node*<br>*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 Applying PW-SR Strategy | Units Withheld | Capacity Withheld (MW) | GenCo Peak Day Operating Profit ($1,000) | | Other GenCo Peak Day Operating Profit ($1,000) | | Load Cur-tailed (MW) |
|---|---|---|---|---|---|---|---|
| | | | PC Case | Change by With-holding | PC Case | Change by With-holding | |
| 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 | | | | | | | |
| 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 | | | | | 1,089 |
| | 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% |
|---|---|---|---|---|
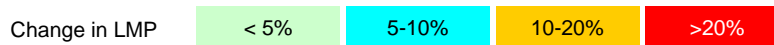
**Figure 4.2.4-2  PW-SR Cases (Case Study Assumptions) – Impact on Zonal LMP**

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**

| Zone | PC Case Peak Day Consumer Costs ($1,000) | Company Applying PW-SR Strategy | | | | | |
| | | 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 Applying PW-SR Strategy | Units Withheld | Capacity Withheld (MW) | GenCo Peak Day Operating Profit ($1,000) | | Other GenCo Peak Day Operating Profit ($1,000) | | Load Cur-tailed (MW) |
|---|---|---|---|---|---|---|---|
| | | | PC Case | Change by With-holding | PC Case | Change by With-holding | |
| 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 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 | | | | | 253 |
| | 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 ($/MWh) | Maximum Zonal LMP during Peak Day Zone | Load Curtailed during Off-Peak Hours of Peak Day (MW) |
|---|---|---|---|---|---|
| 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 Oper-ating 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.
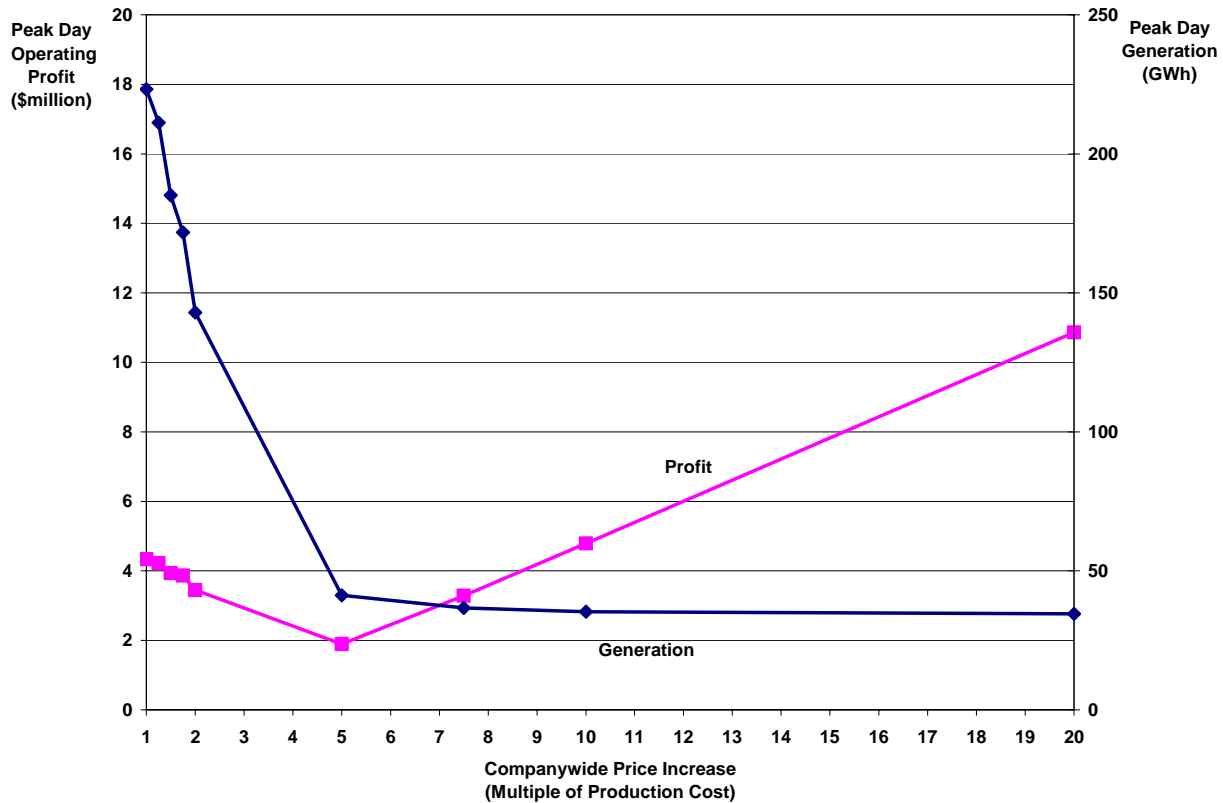


**Figure 4.3.2-1  Exelon Nuclear Peak Day Generation and Operating Profit
with All Day Price Increases (Case Study Assumptions)**
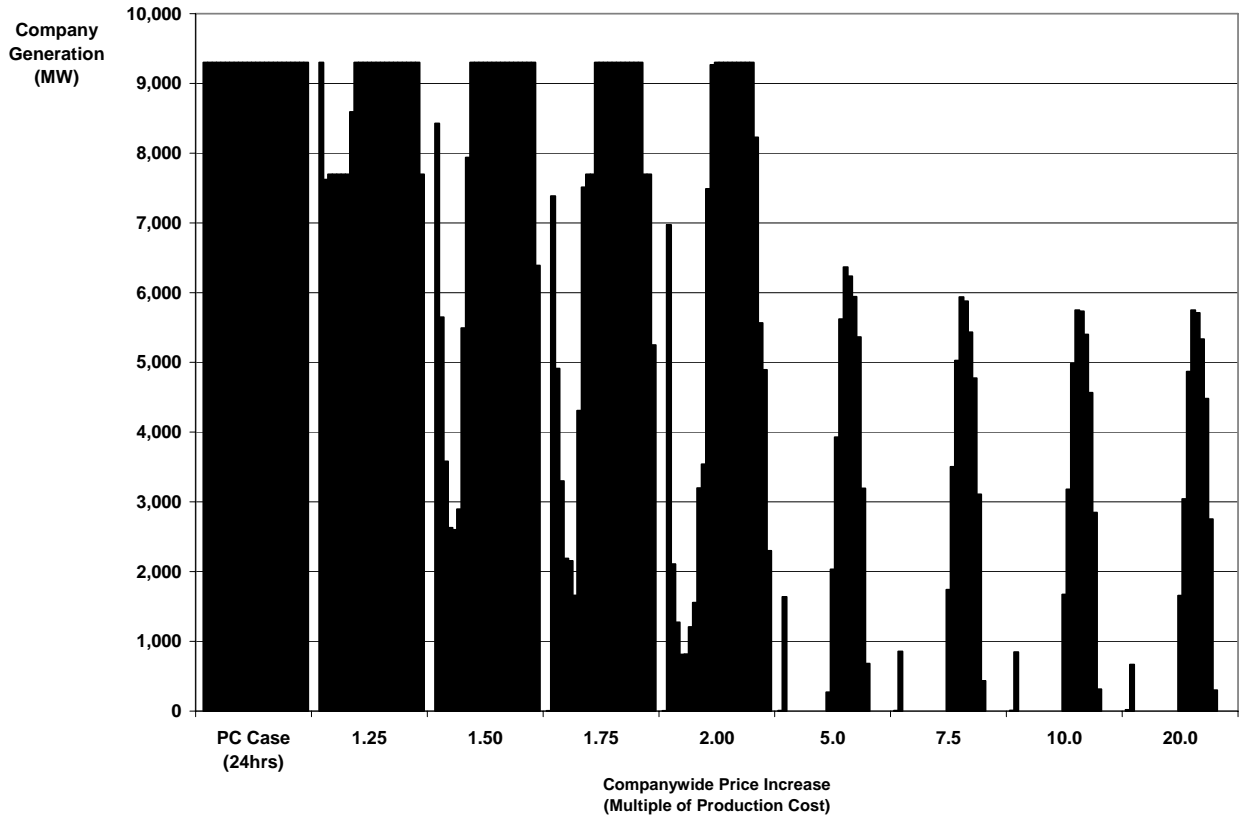
**Figure 4.3.2-2 Exelon Nuclear Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)**



**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 | | 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-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)**
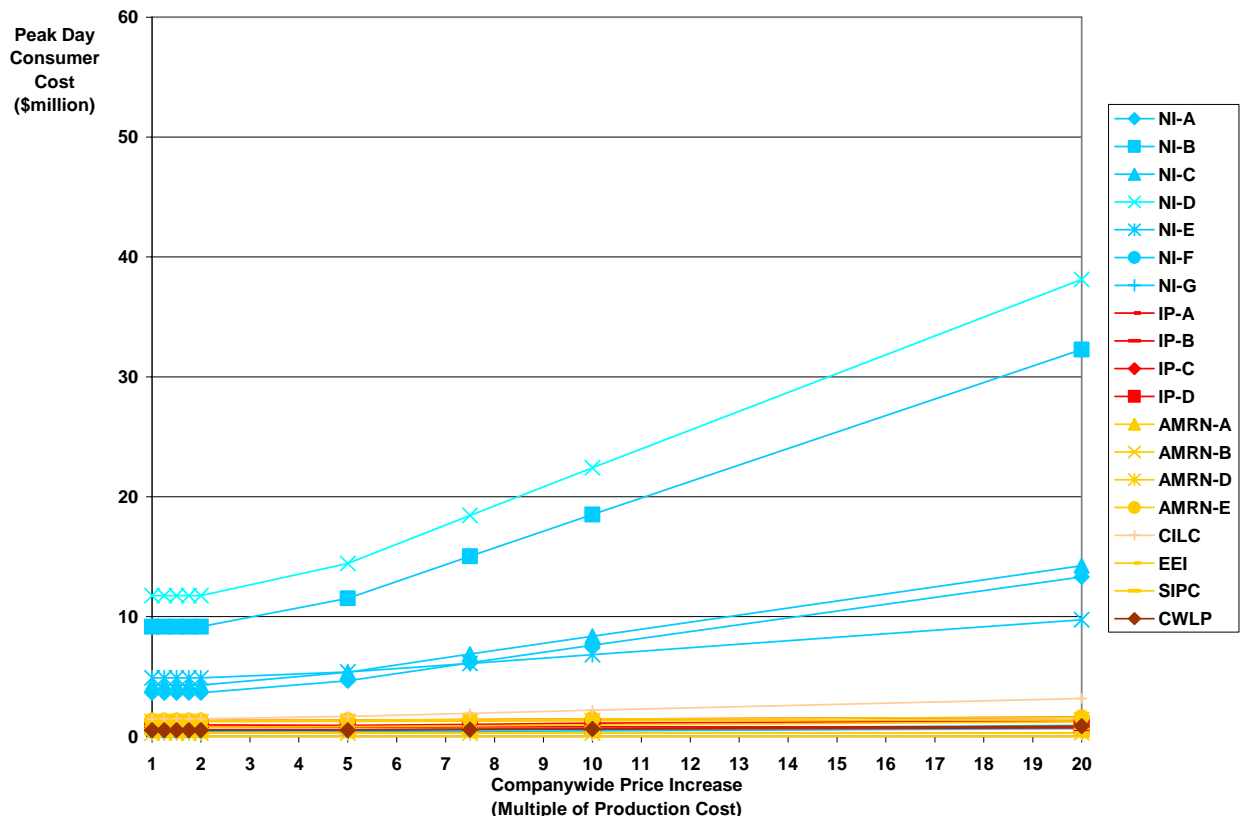


**Figure 4.3.2-5  Exelon Nuclear Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)**

*130*

*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.
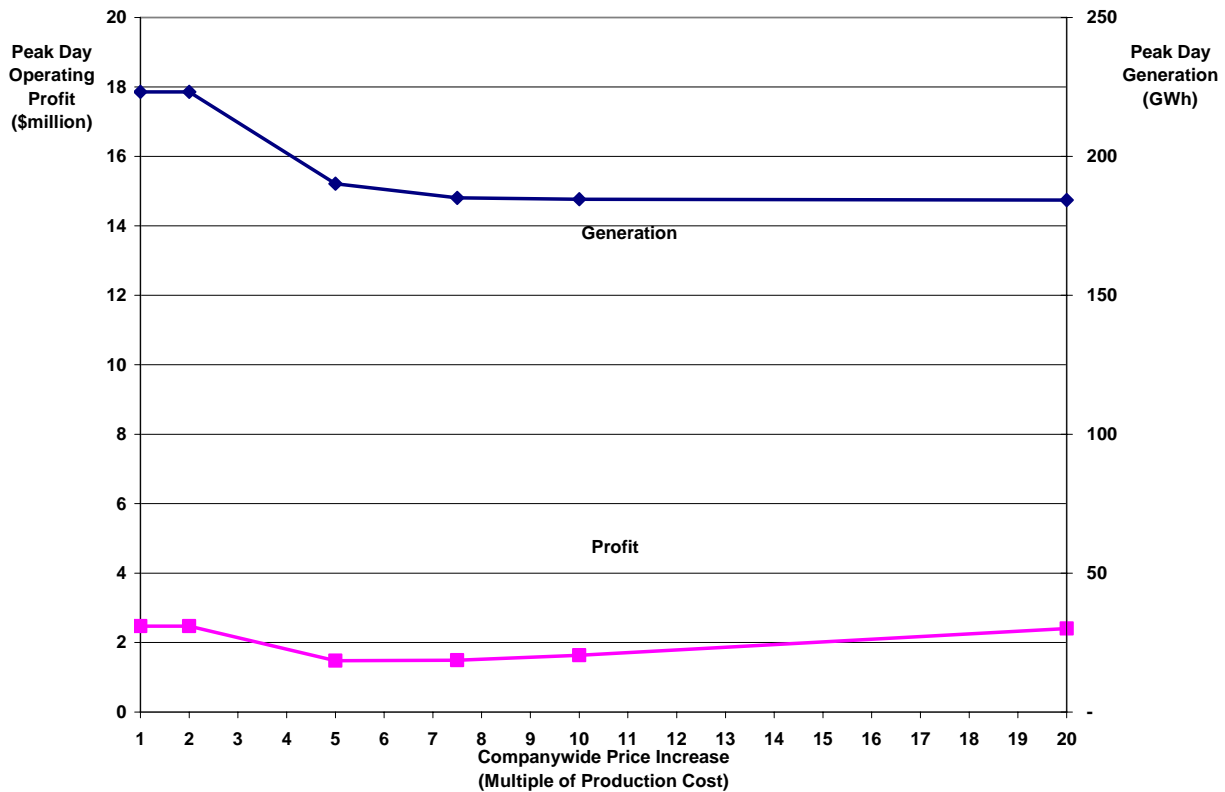


**Figure 4.3.2-6  Exelon Nuclear Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)**

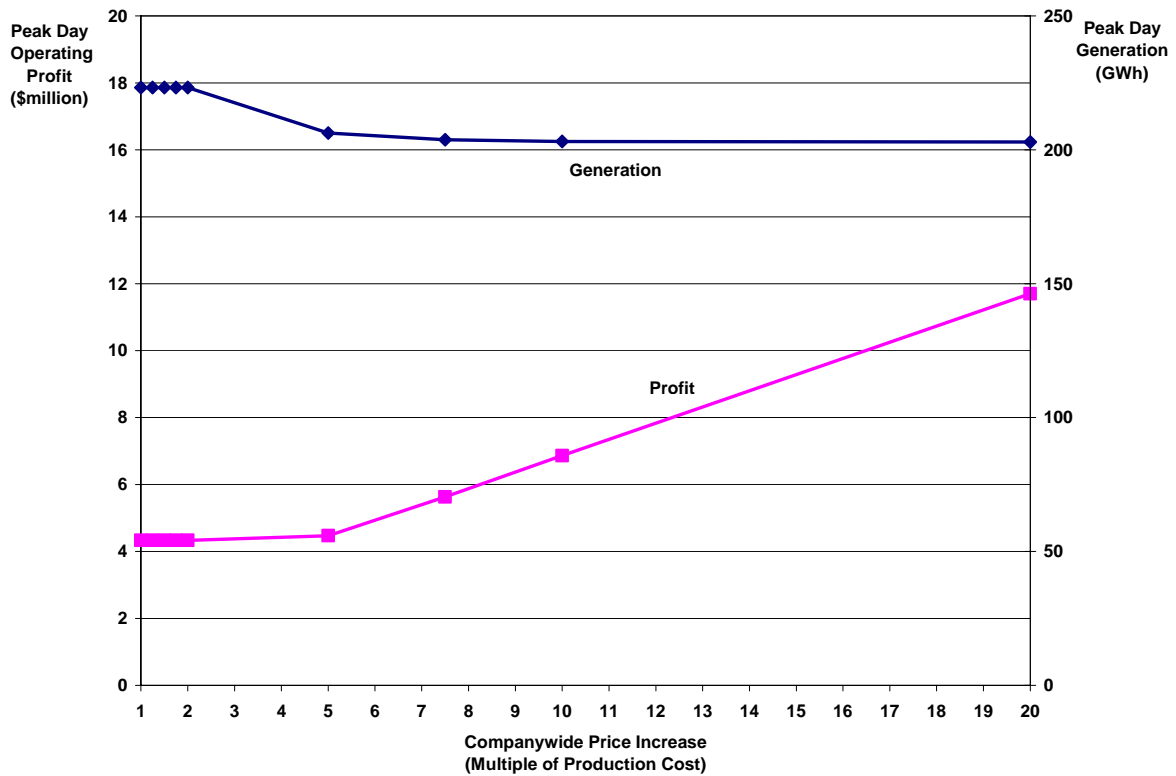Table 4.3.2-2 shows the transmission components that were at capacity limits at the twenty-fold price increase level under Conservative Assumptions. There was a similar change in the transmission loading as some lines remained at their capacity limits (normal print), some began to experience congestion (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 | | 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 |
| **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 | | Zone | | Equipment | | |
|---|---|---|---|---|---|---|---|
| | **From** | **To** | **From** | **To** | | | |
| **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.
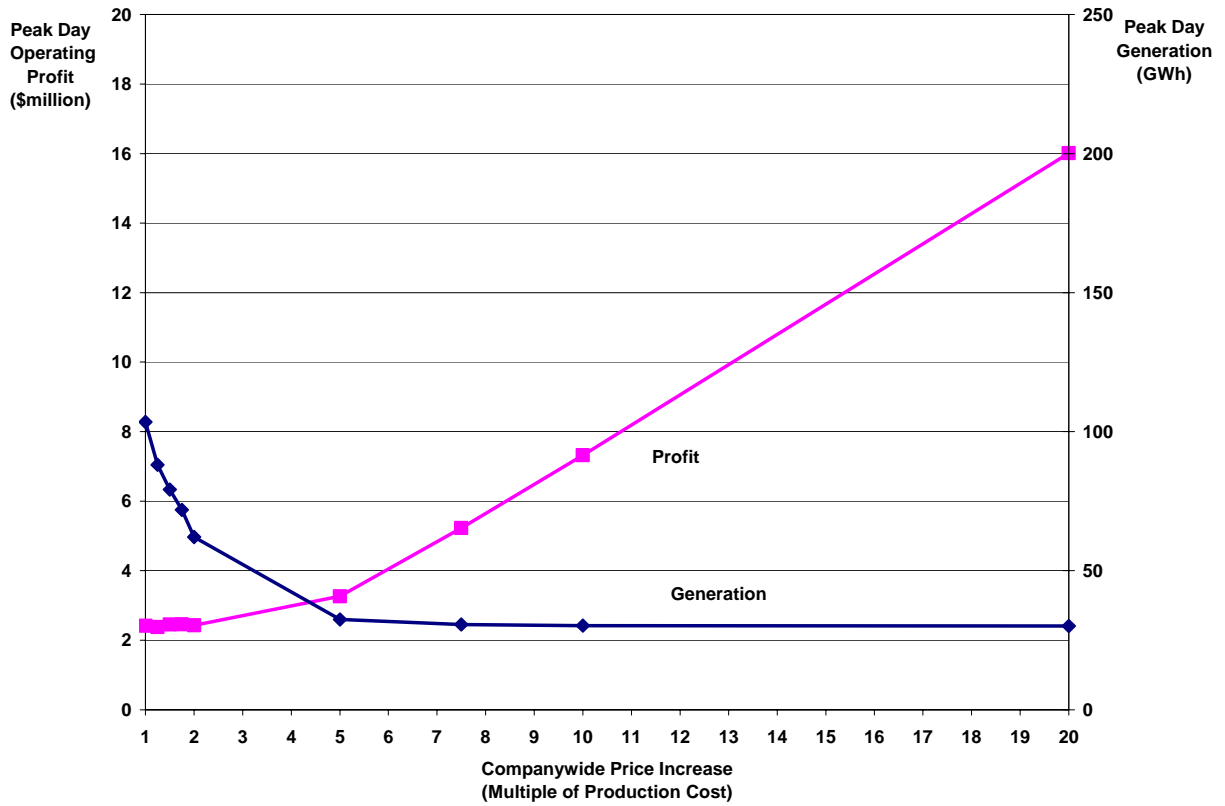
**Figure 4.3.2-7  Midwest Generation Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)**
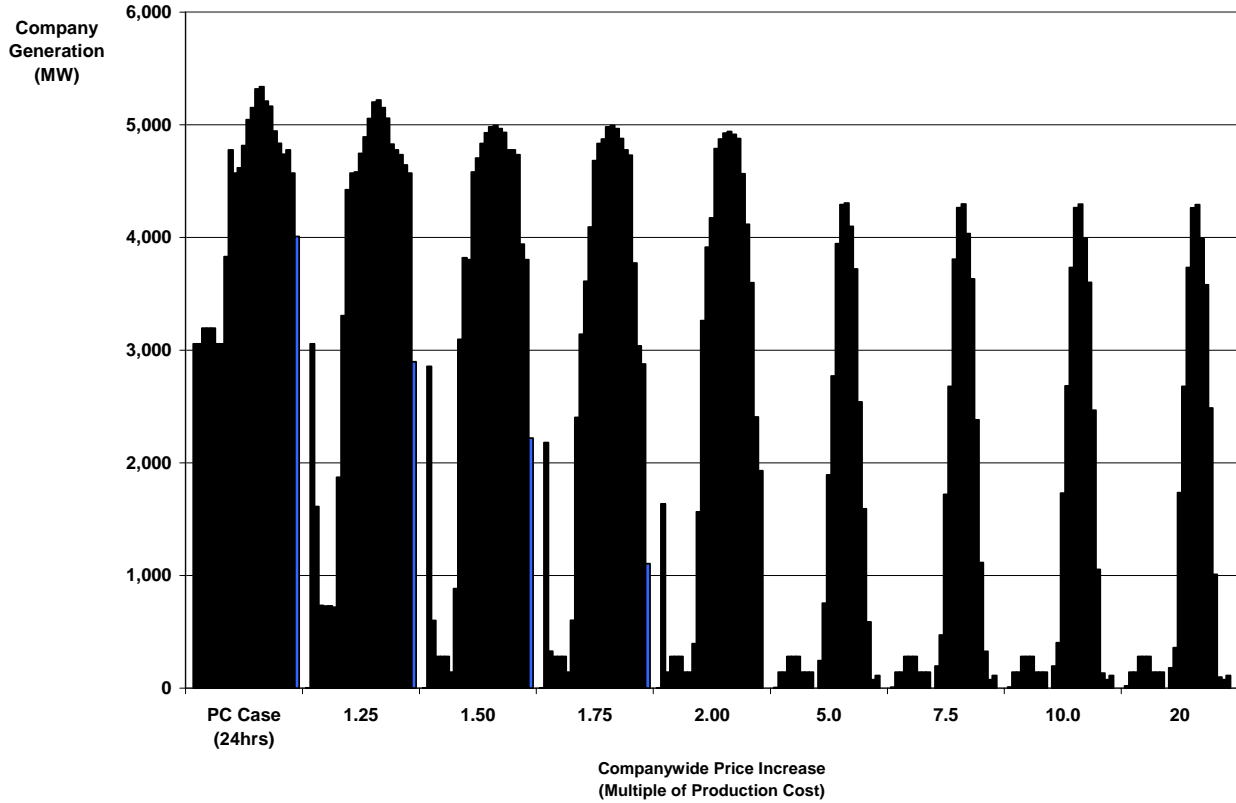


**Figure 4.3.2-8  Midwest Generation Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)**

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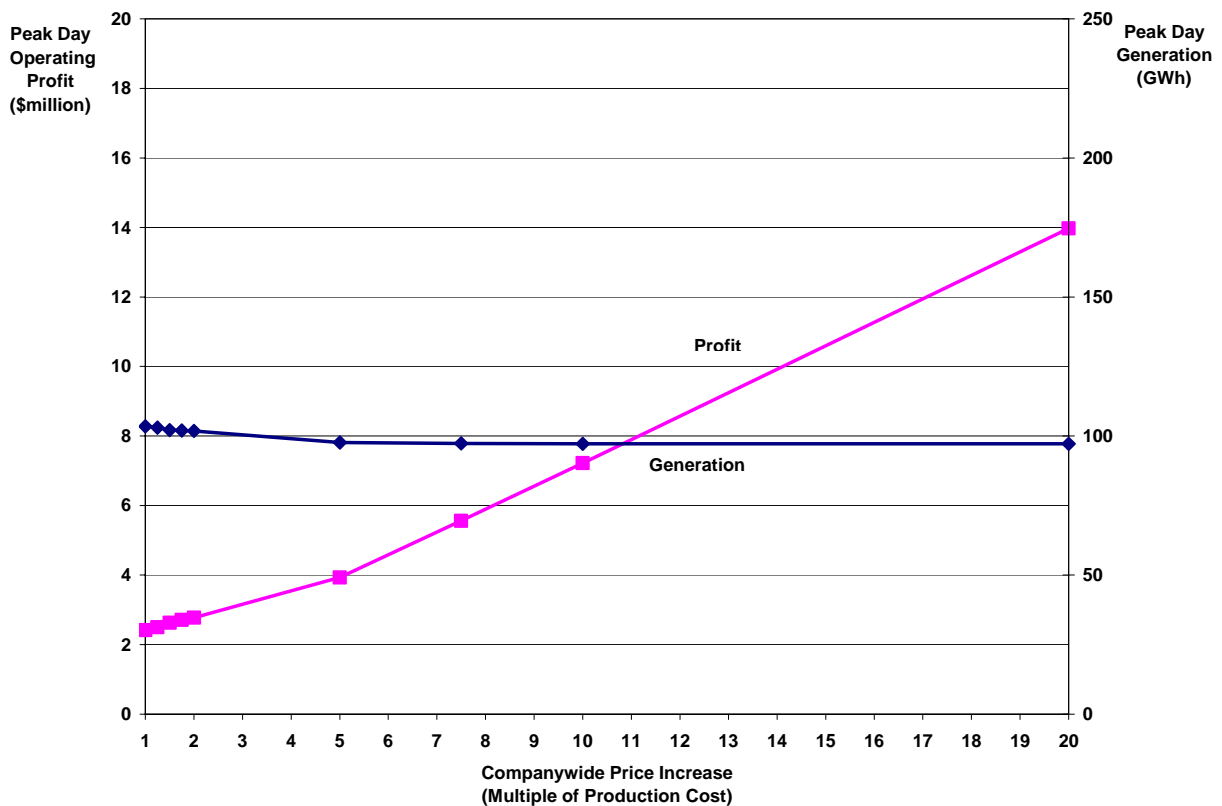
**Table 4.3.2-3  Transmission Components at Capacity Limits
under Midwest Generation 20-Fold Price Increase (Case Study Assumptions)**

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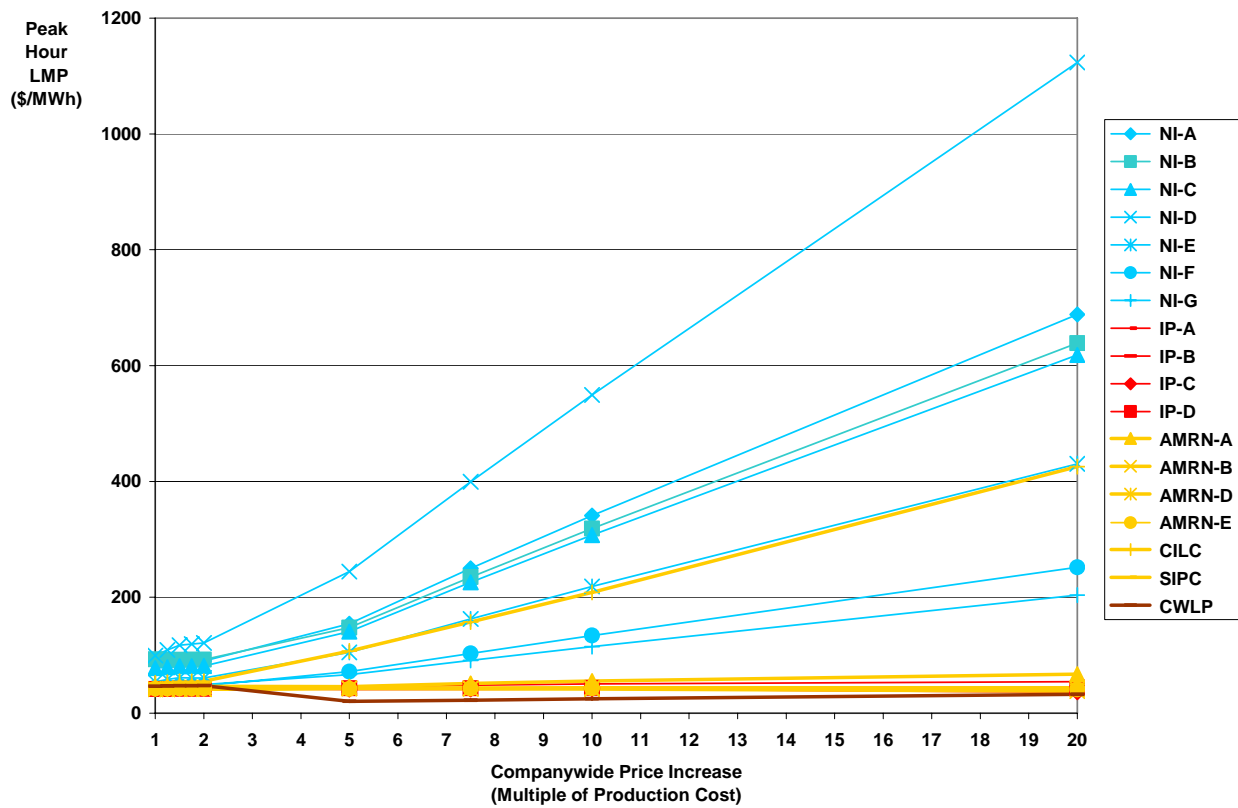
**Figure 4.3.2-10  Midwest Generation Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)**
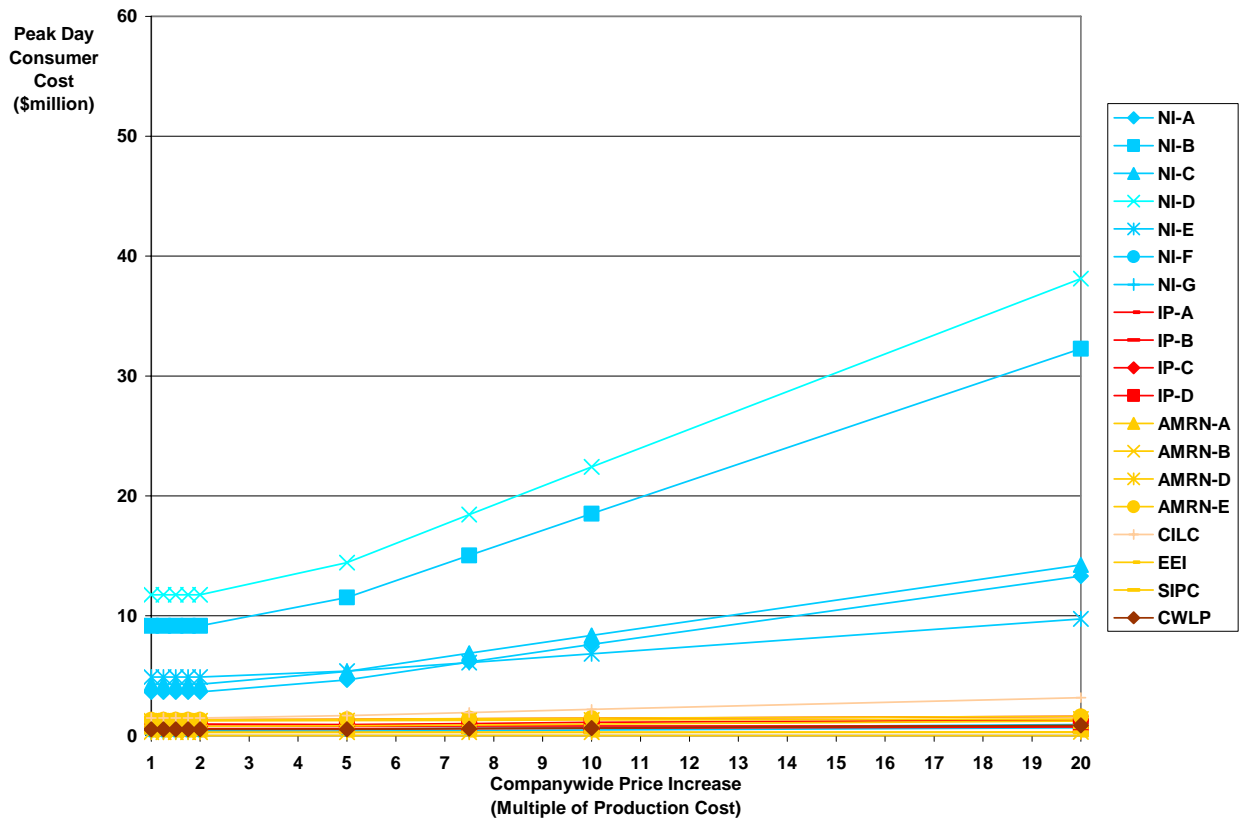


**Figure 4.3.2-11  Midwest Generation Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)**

*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.
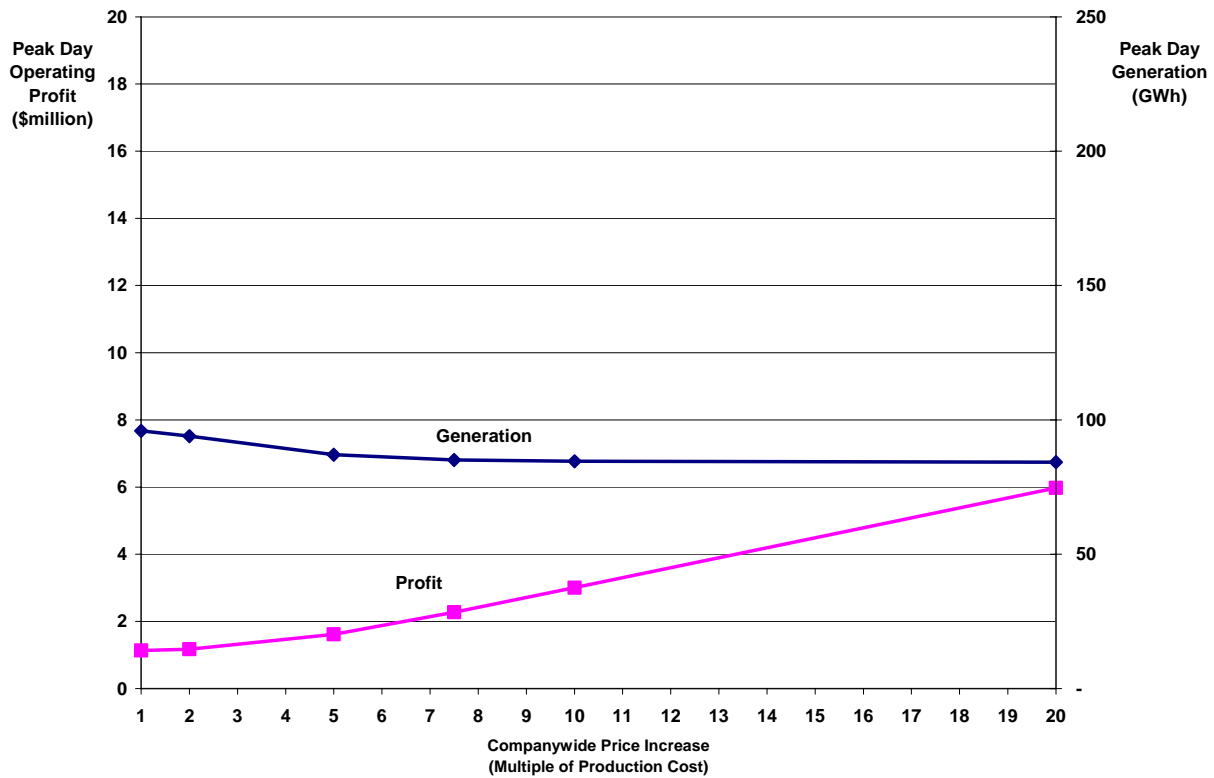


**Figure 4.3.2-12  Midwest Generation Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)**

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

| ID | Bus | | 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 |
| 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.
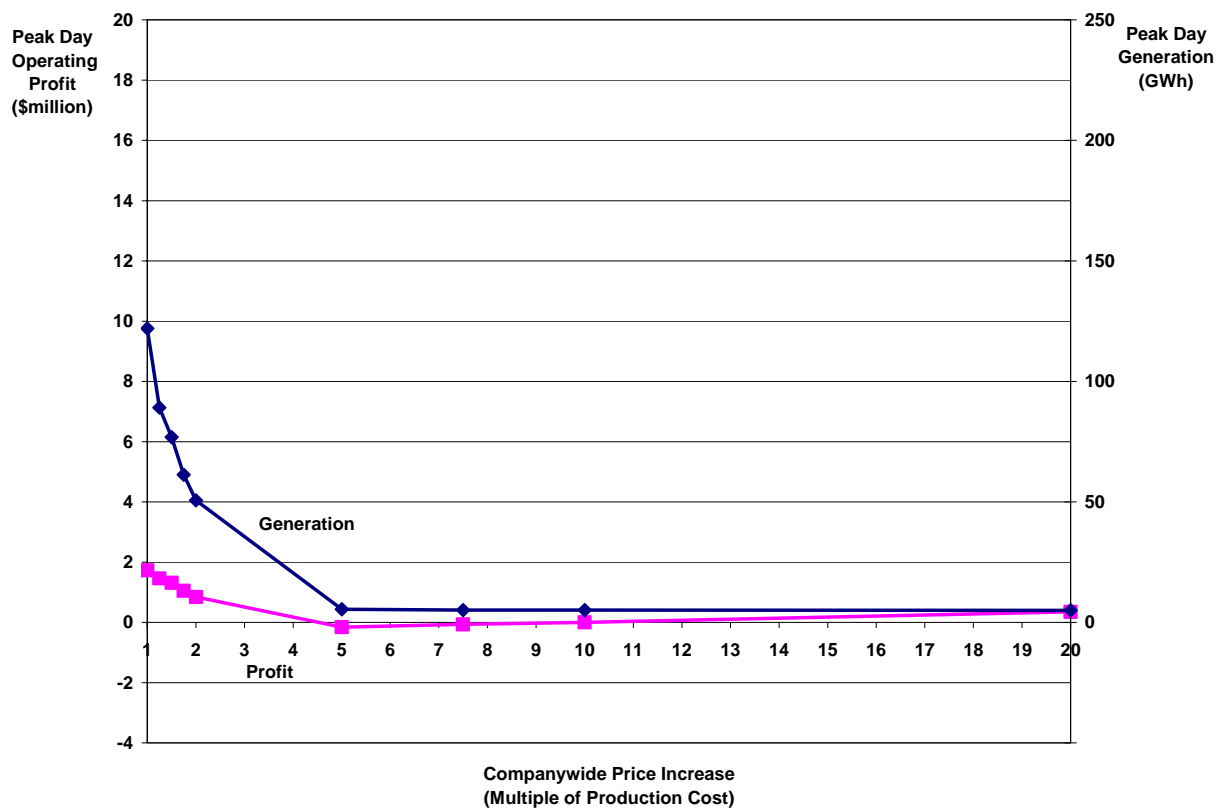


**Figure 4.3.2-13  Ameren Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)**
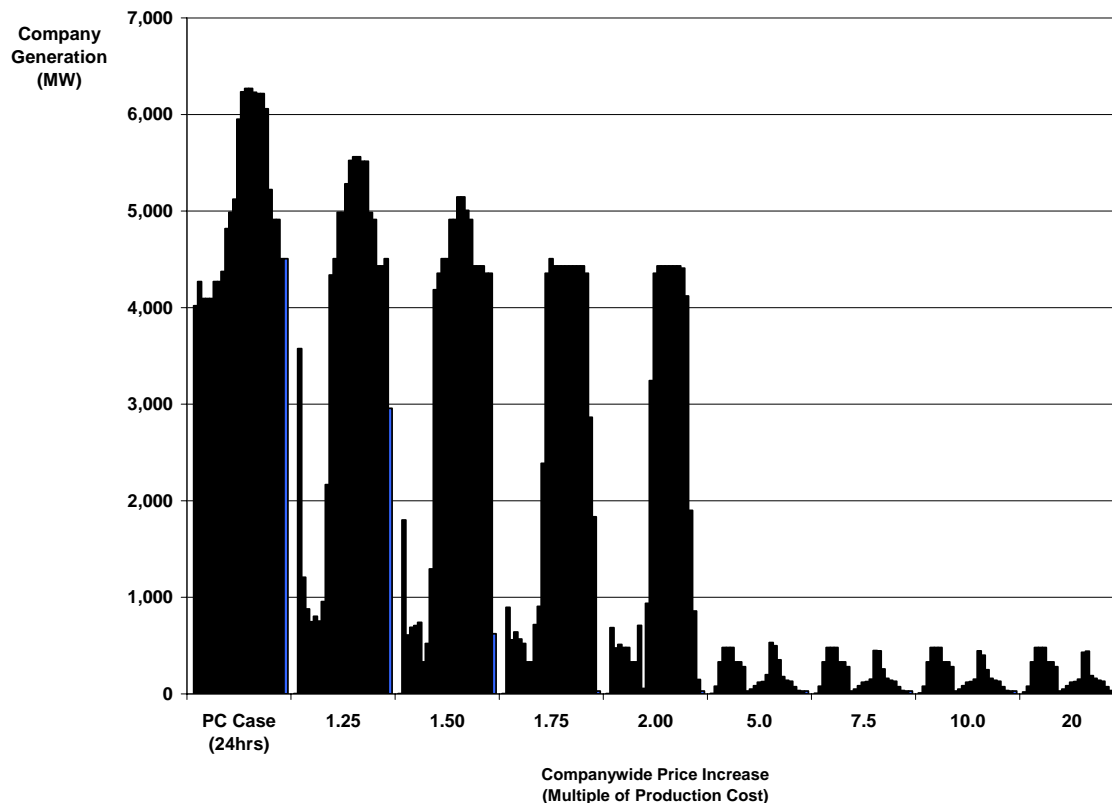
**Figure 4.3.2-14  Ameren Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)**

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.
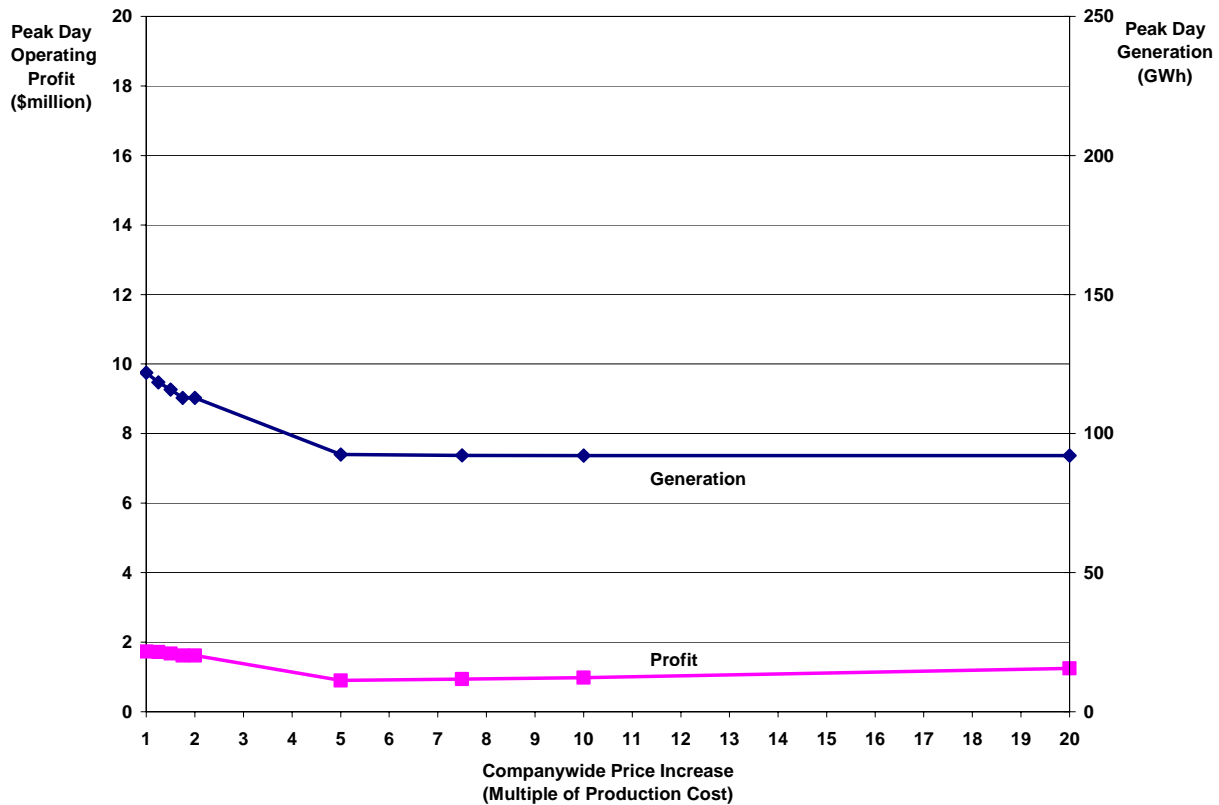


**Figure 4.3.2-15 Ameren Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)**

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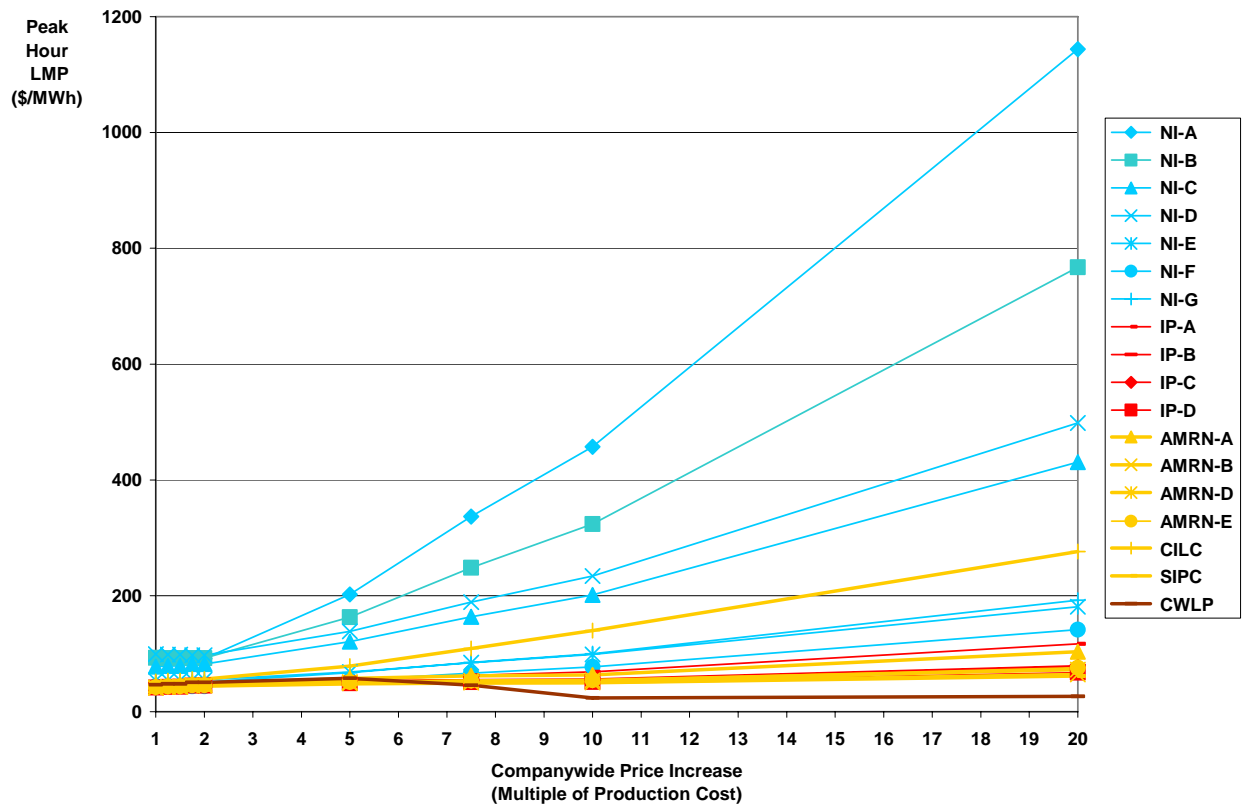
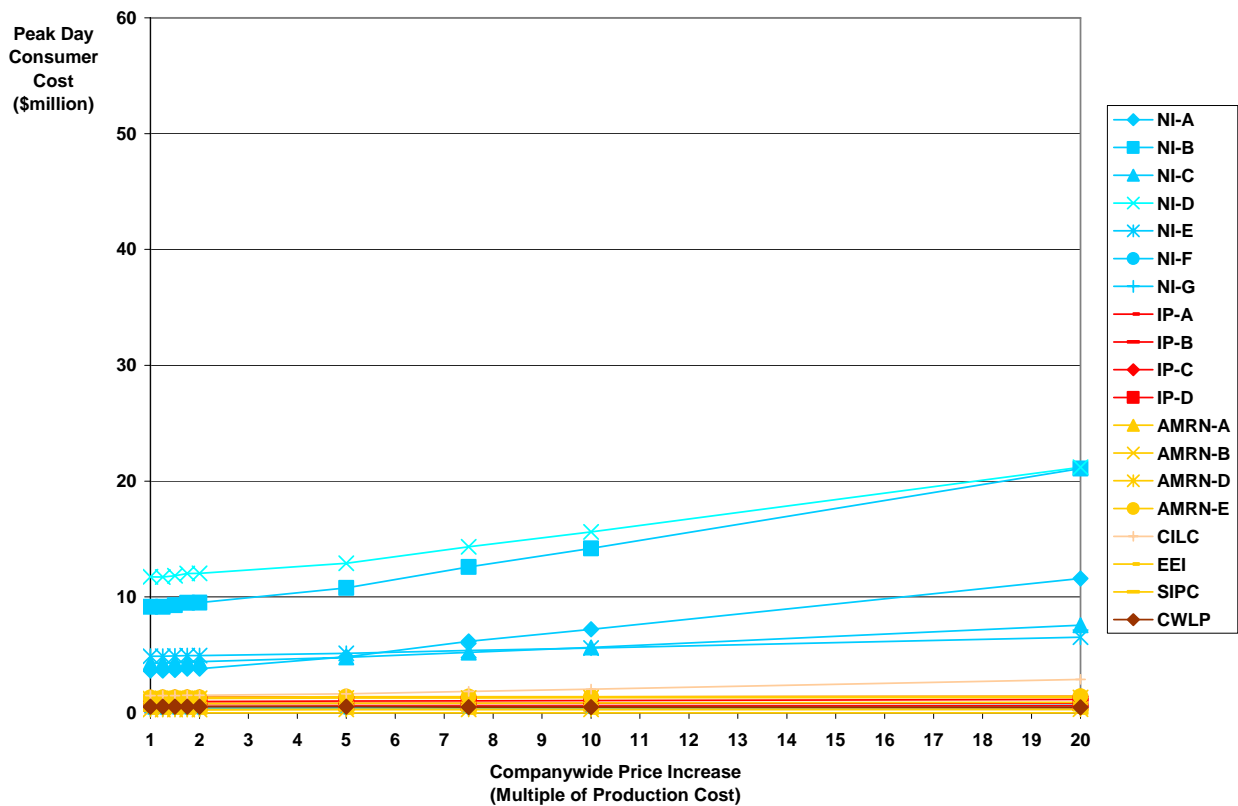**Figure 4.3.2-16  Ameren Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)**



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

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*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.
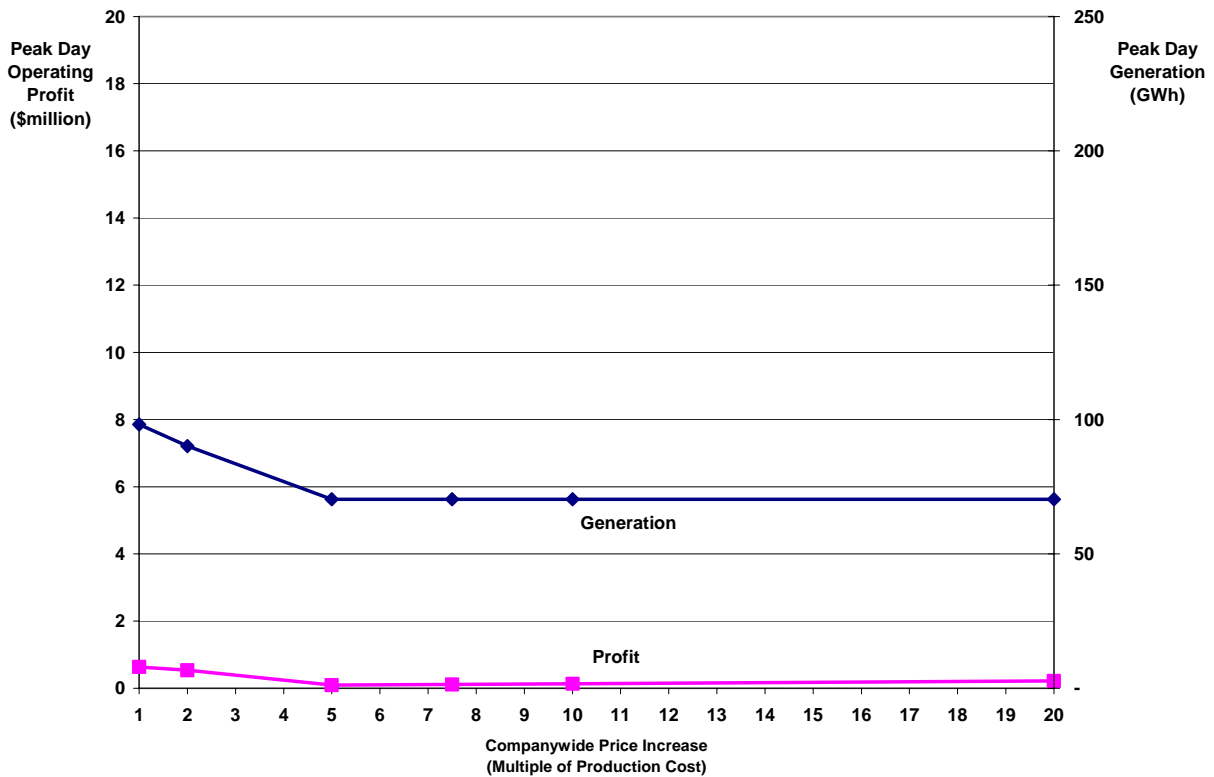


**Figure 4.3.2-18  Ameren Peak Day Generation and Operating Profit
with Peak Hour Price Increases (Conservative Assumptions)**

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

| ID | Bus | | 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 |
| **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.
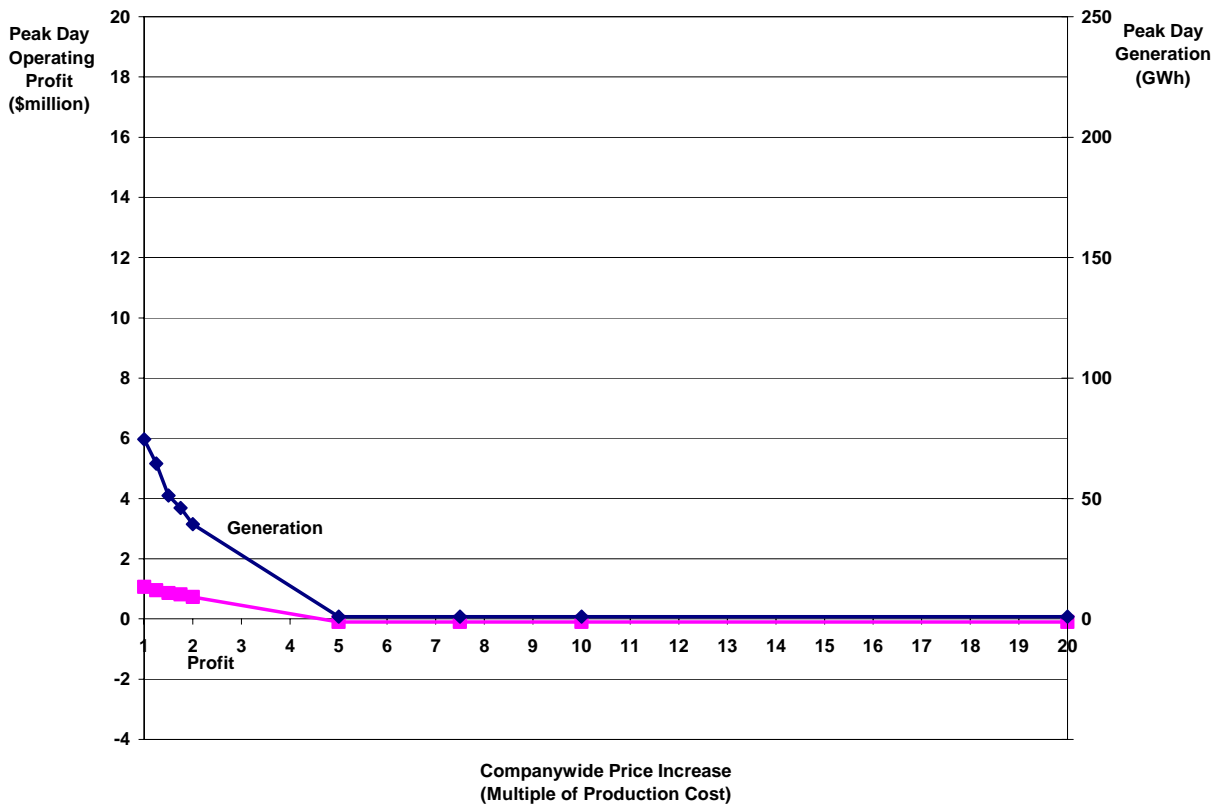


**Figure 4.3.2-19  Dynegy Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)**
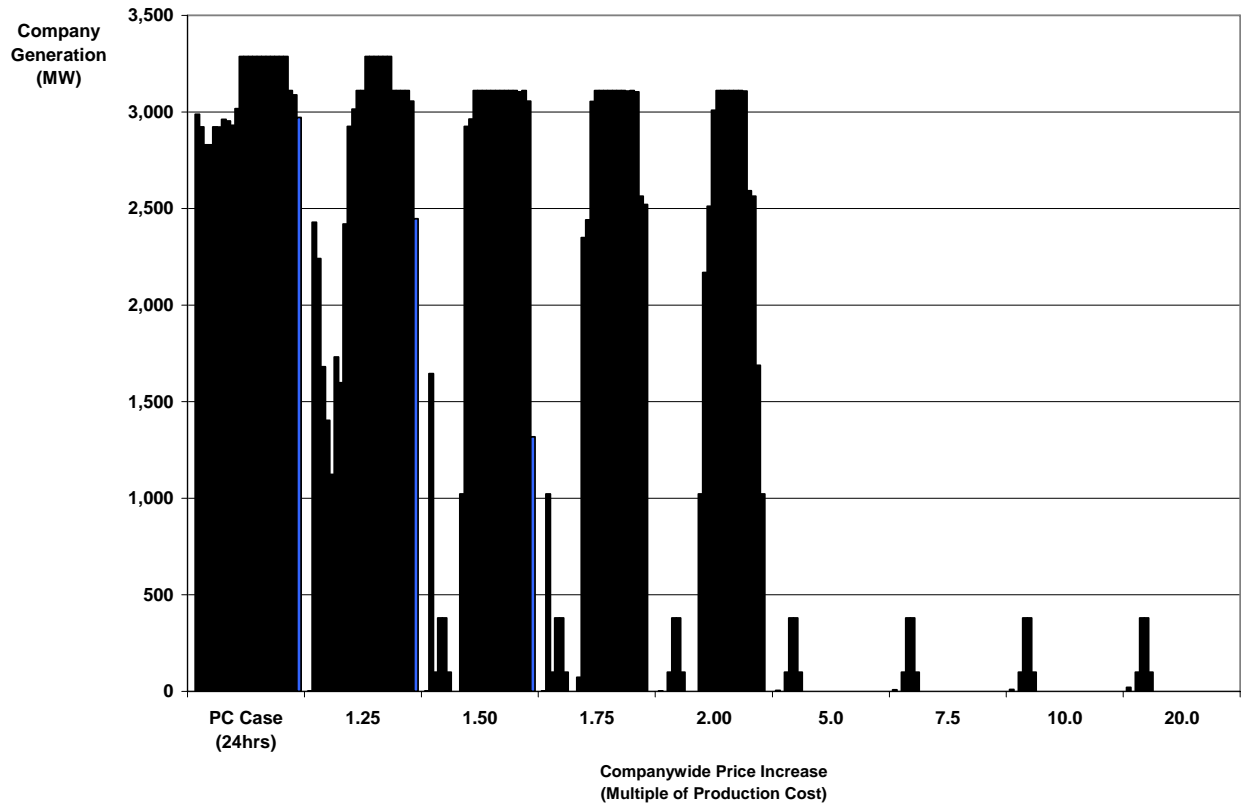
**Figure 4.3.2-20 Dynegy Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)**
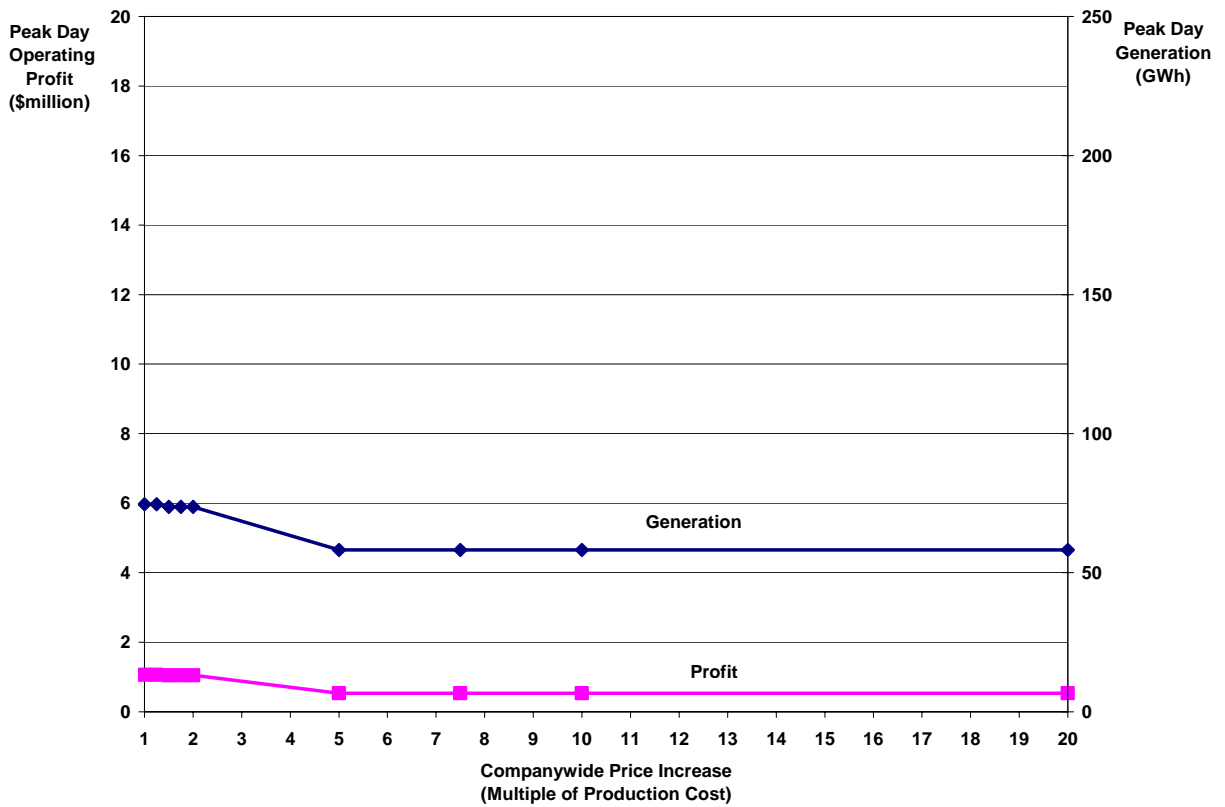


**Figure 4.3.2-21 Dynegy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)**

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**Table 4.3.2-7 Transmission Components at Capacity Limits
under Dynegy 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 |
| **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.
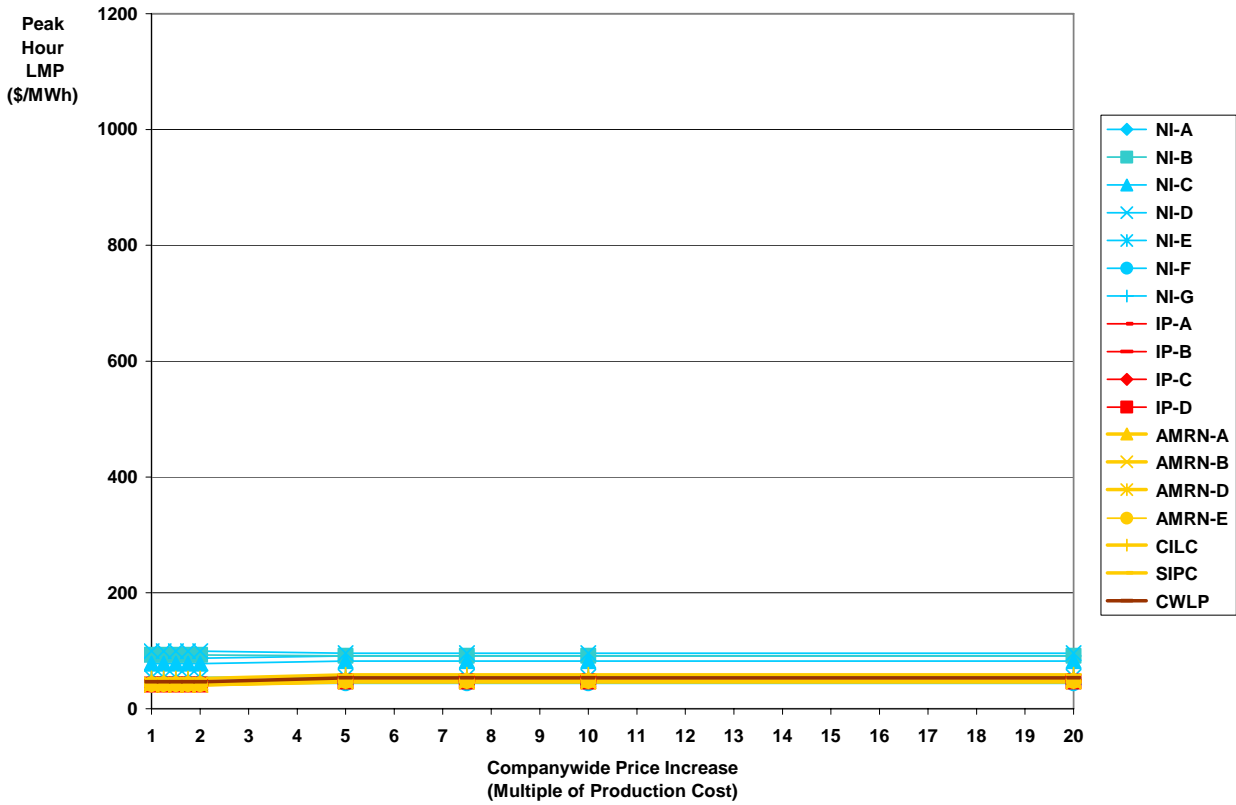
**Figure 4.3.2-22  Dynegy Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)**
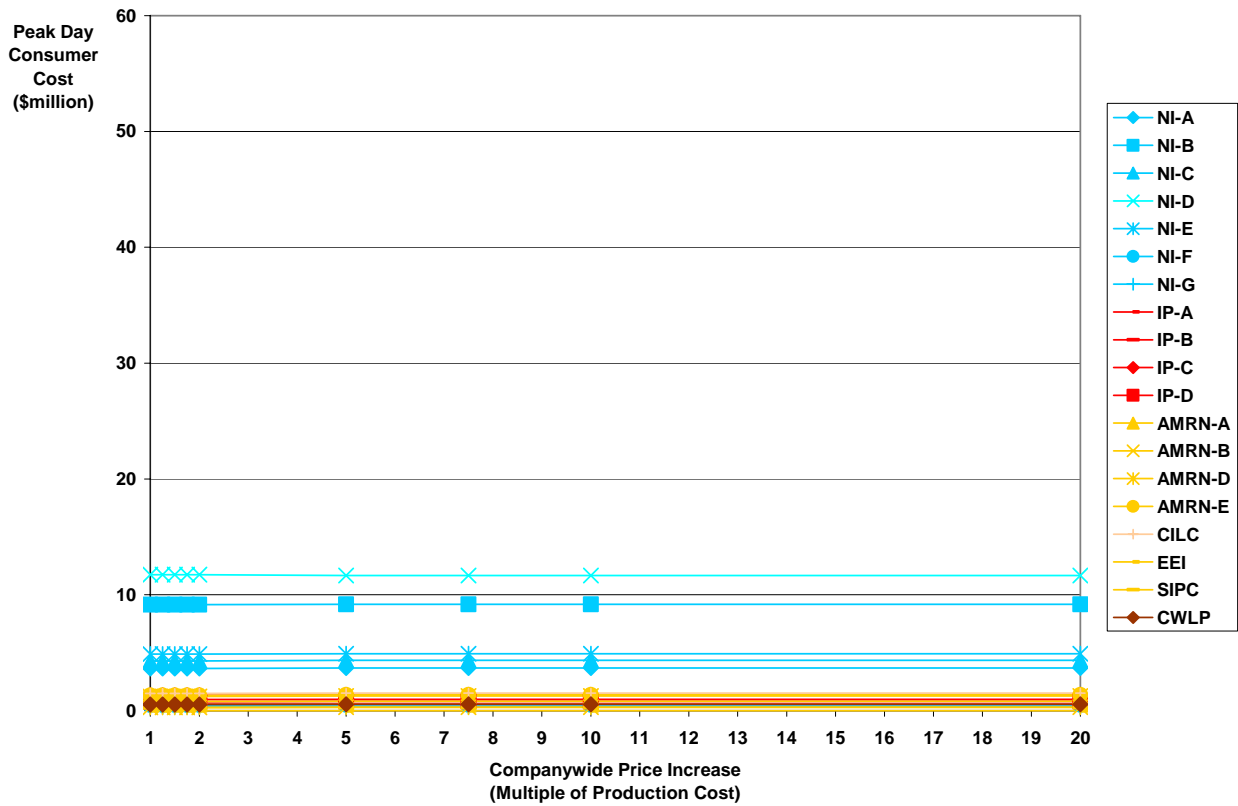


**Figure 4.3.2-23  Dynegy Effect of Companywide Peak Hour Price Increases on Consumer Cost (Case Study Assumptions)**

## 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.
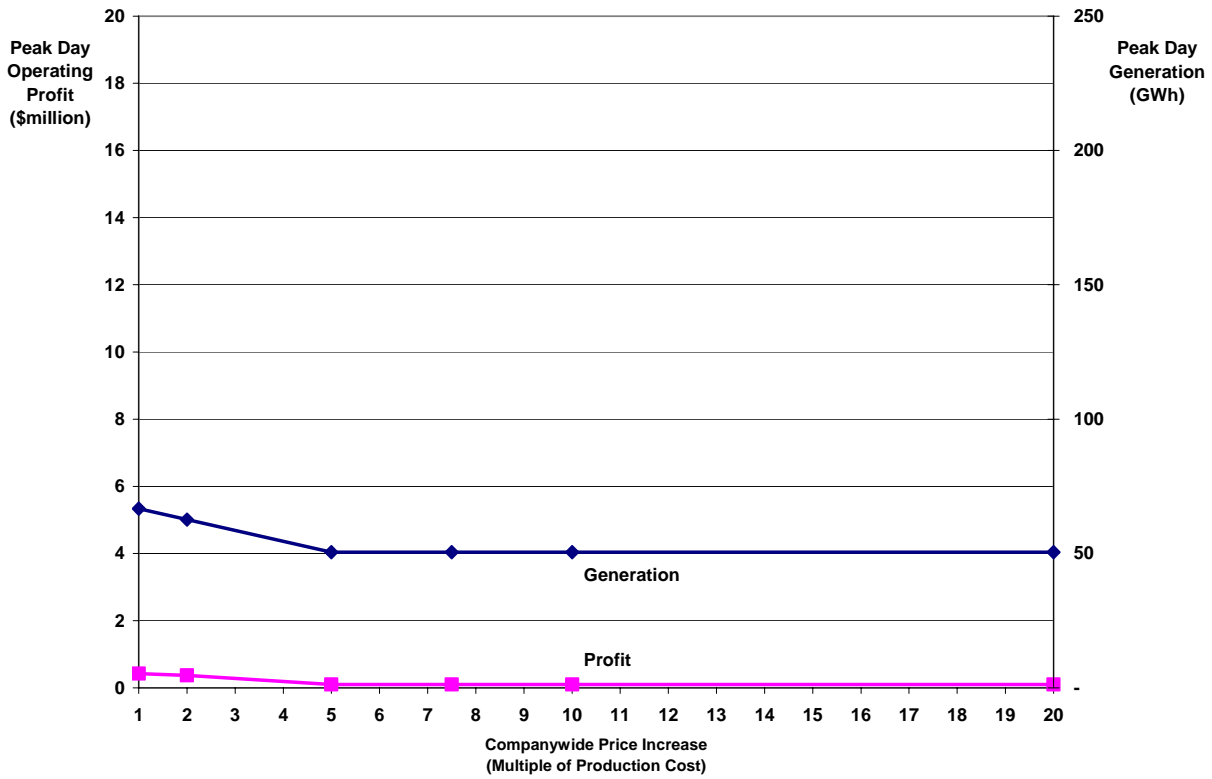


**Figure 4.3.2-24  Dynegy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)**

**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.
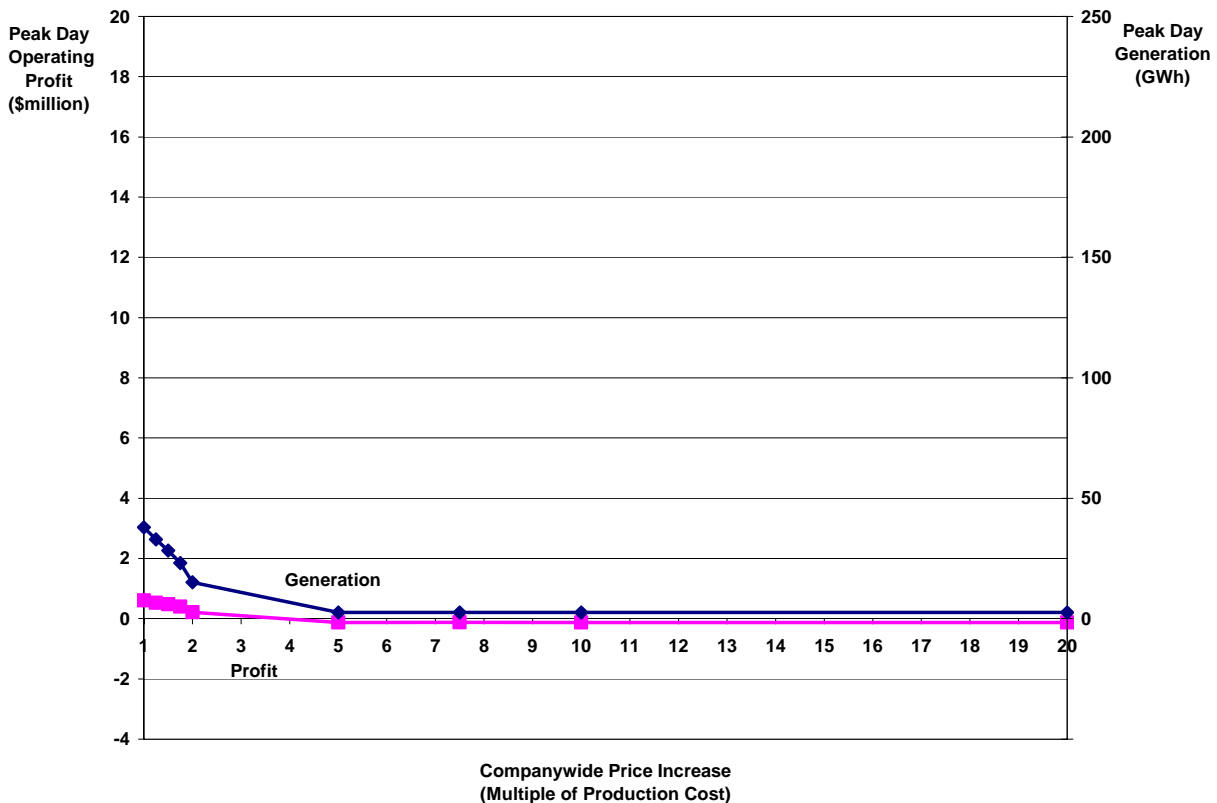


**Figure 4.3.2-25  Dominion Energy Peak Day Generation and Operating Profit with All Day Price Increases (Case Study Assumptions)**
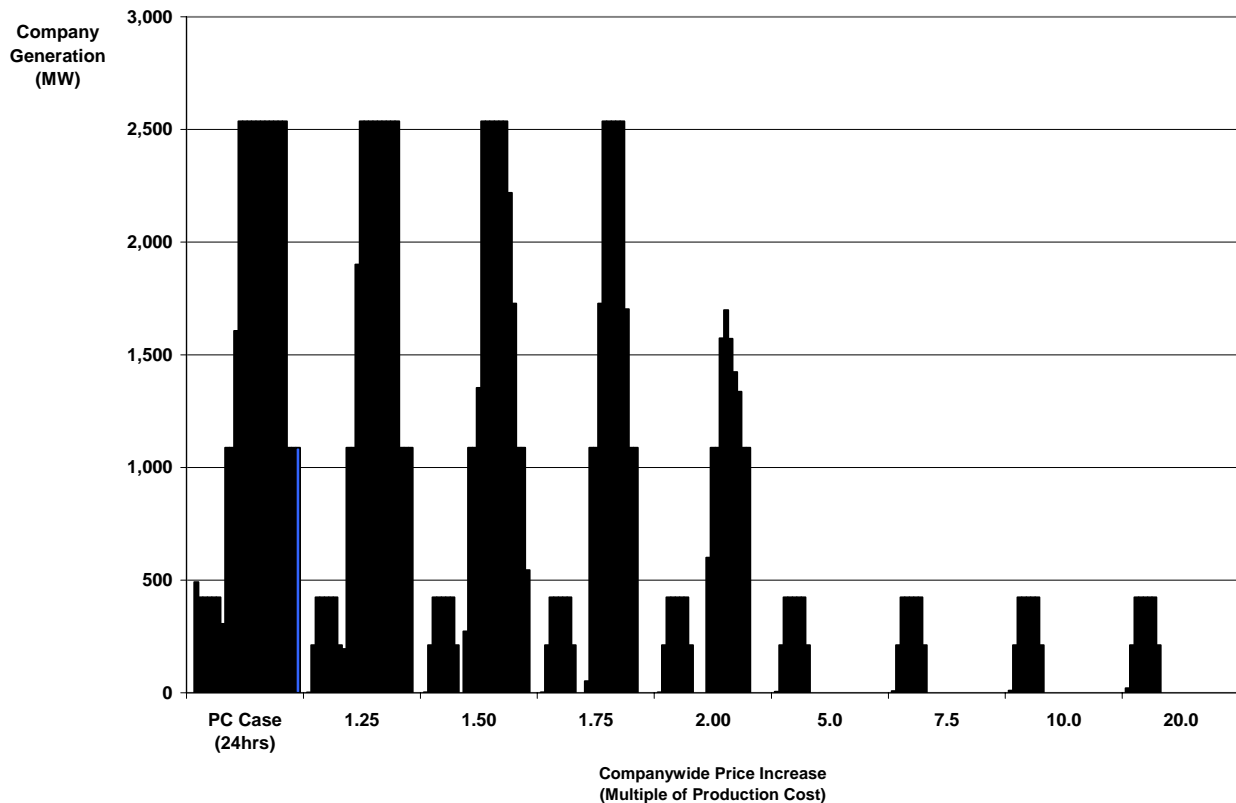
**Figure 4.3.2-26  Dominion Energy Peak Day Generation Dispatch with All Day Price Increases (Case Study Assumptions)**

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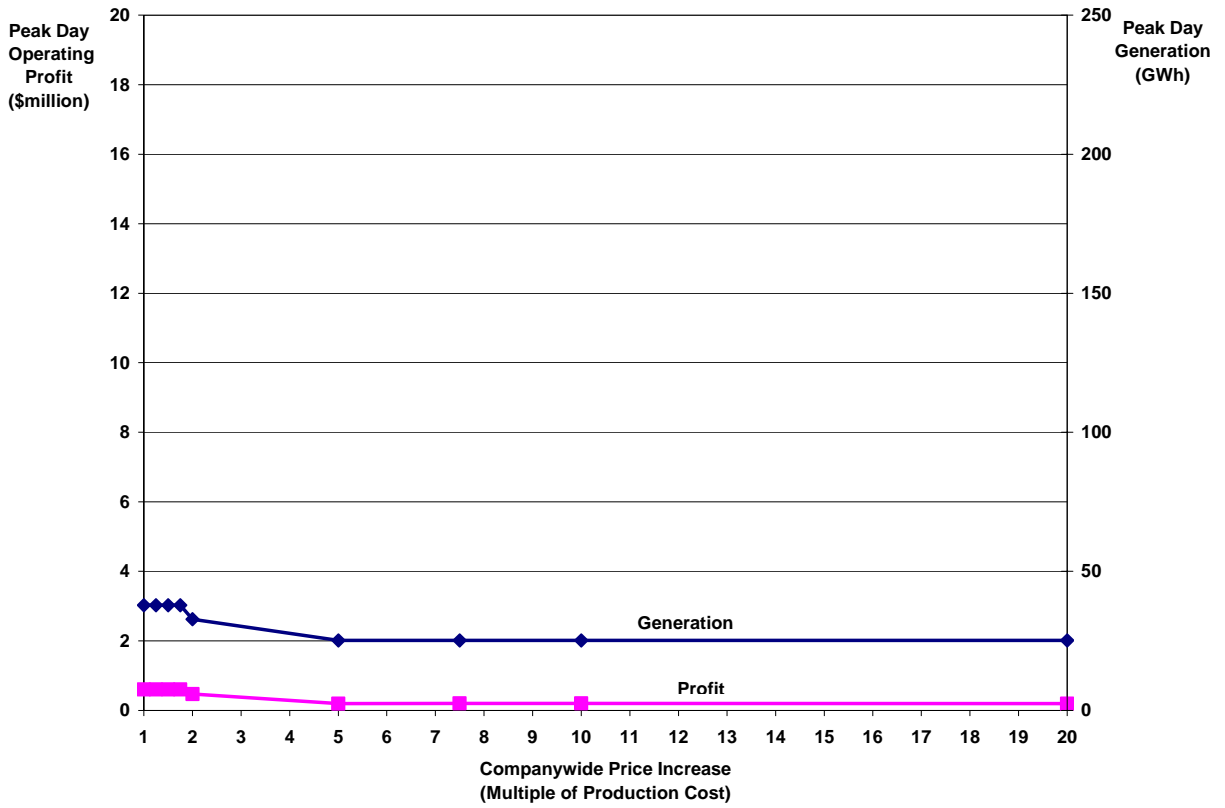
**Figure 4.3.2-27  Dominion Energy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Case Study Assumptions)**

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

| ID | Bus | | 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 |
| 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.
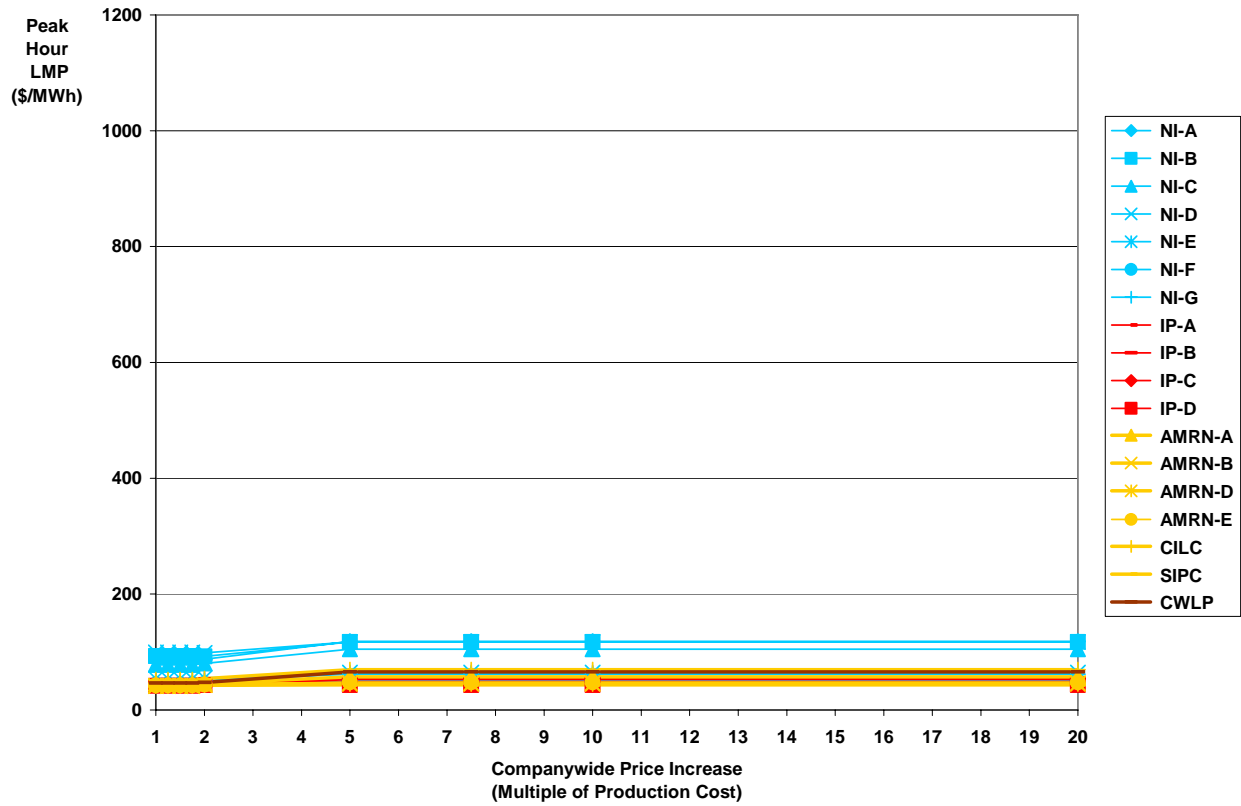Bold row indicates component at capacity under these conditions but not under PC case conditions.

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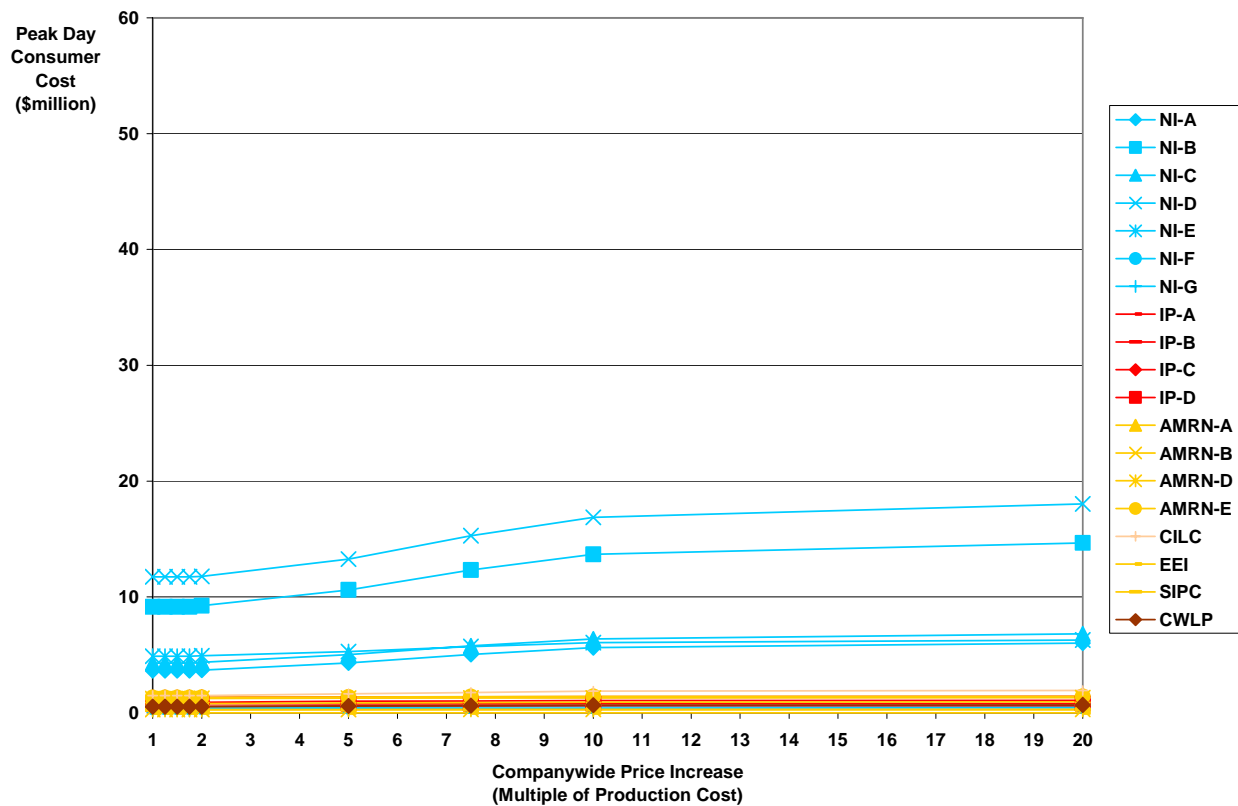**Figure 4.3.2-28  Dominion Energy Effect of Companywide Peak Hour Price Increases on Zonal LMPs (Case Study Assumptions)**



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

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*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.
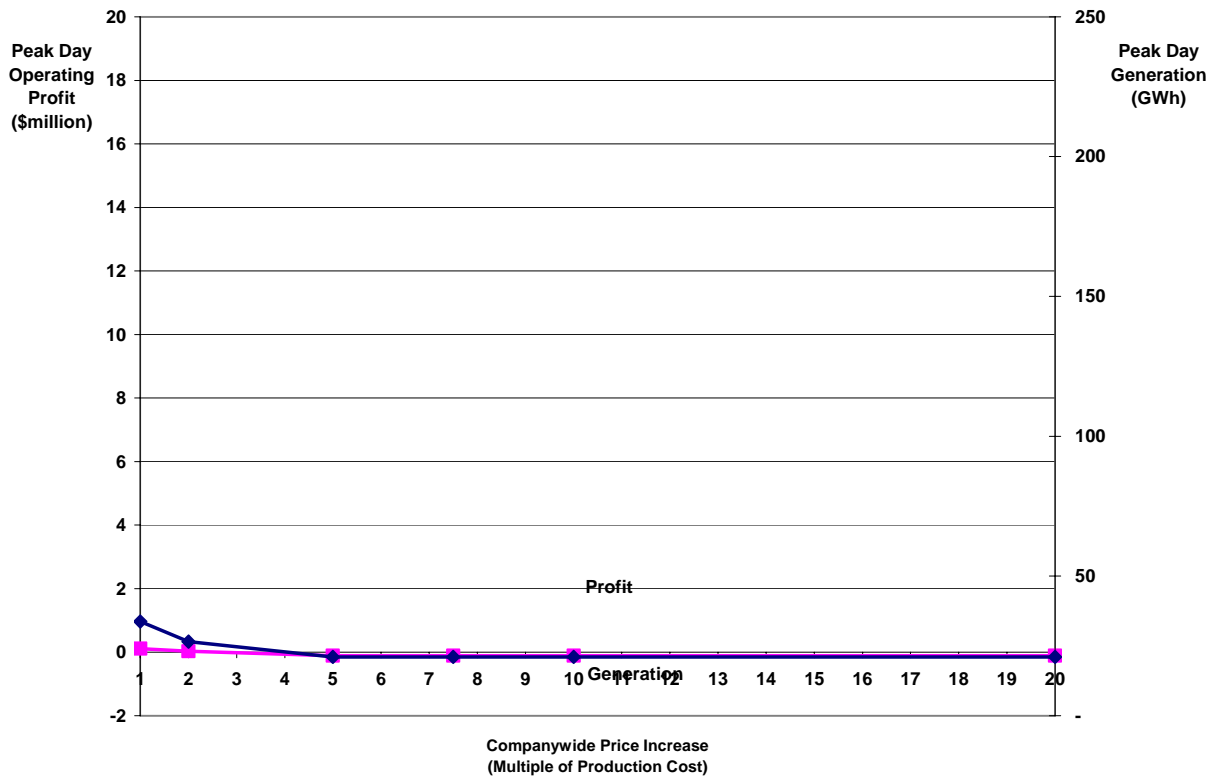


**Figure 4.3.2-30  Dominion Energy Peak Day Generation and Operating Profit with Peak Hour Price Increases (Conservative Assumptions)**

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

| ID | Bus | | 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 |
| **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.
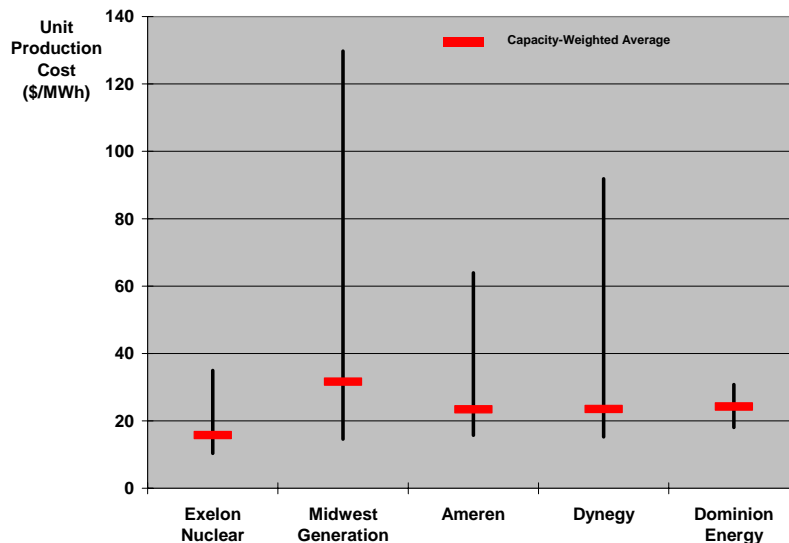


**Figure 4.3.2-31  Range of Unit Production Costs and Capacity-Weighted Average**

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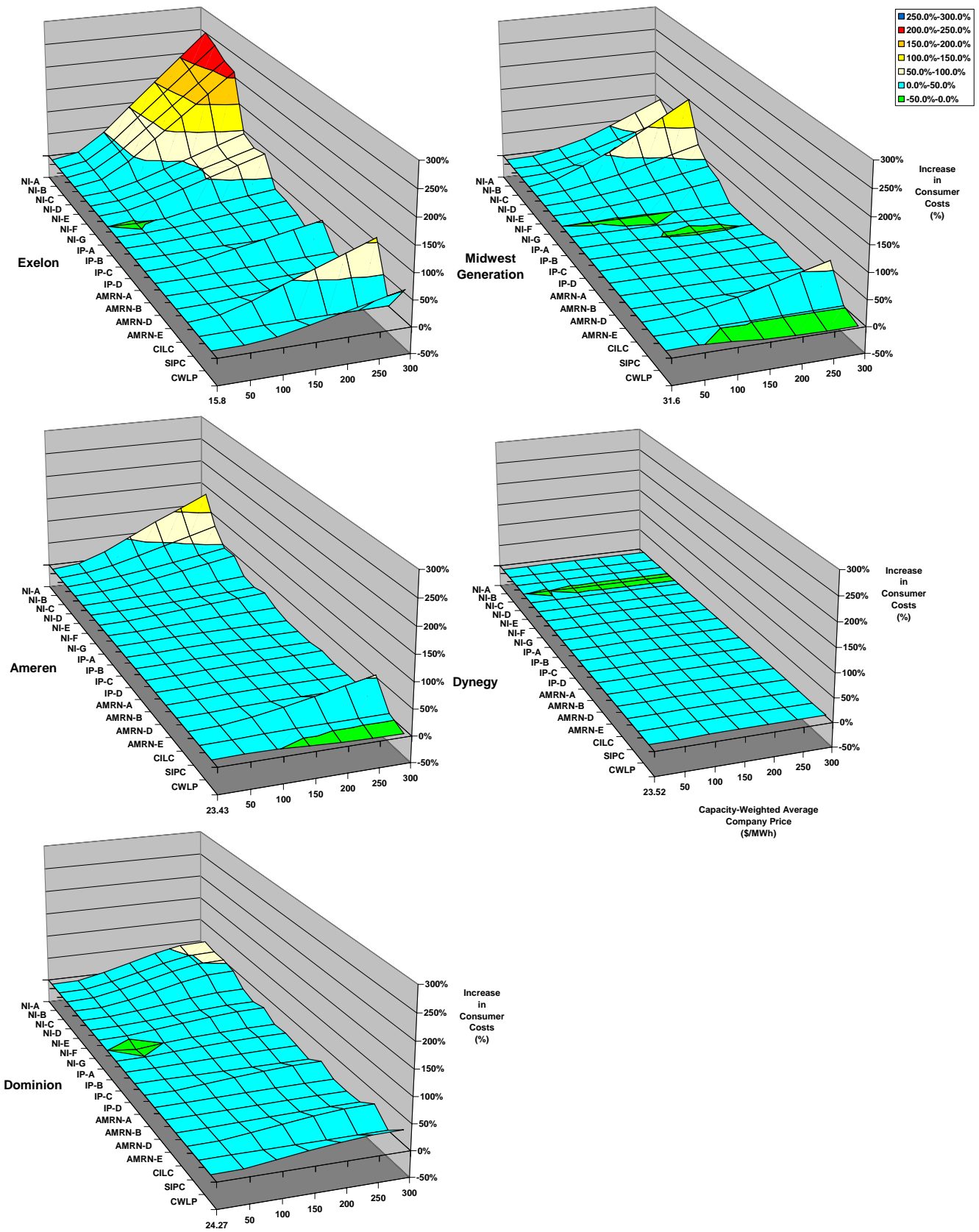
**Figure 4.3.2-32  Effect of Companywide Price Increases during Peak Hours on Consumer Costs (Case Study Assumptions)**

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.
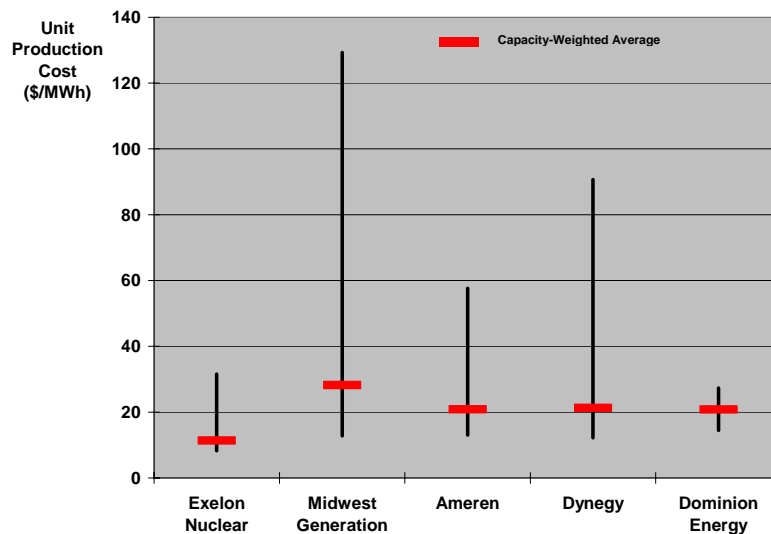


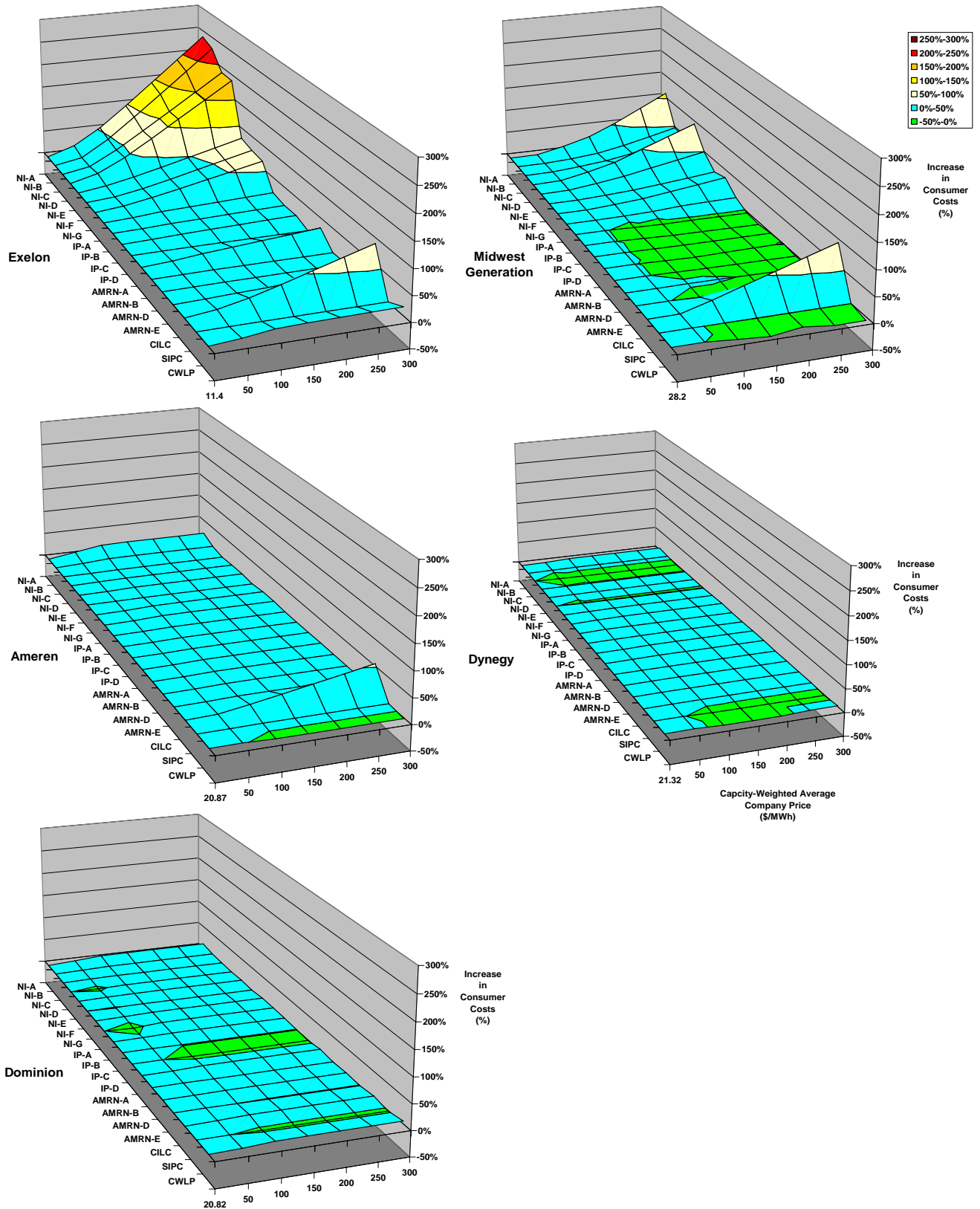**Figure 4.3.2-33  Range of Unit Production Costs and Capacity-Weighted Average (Conservative Assumptions)**

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

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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.