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

APPENDIXES

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APPENDIX A
OVERVIEW OF THE POWERWORLD® MODEL

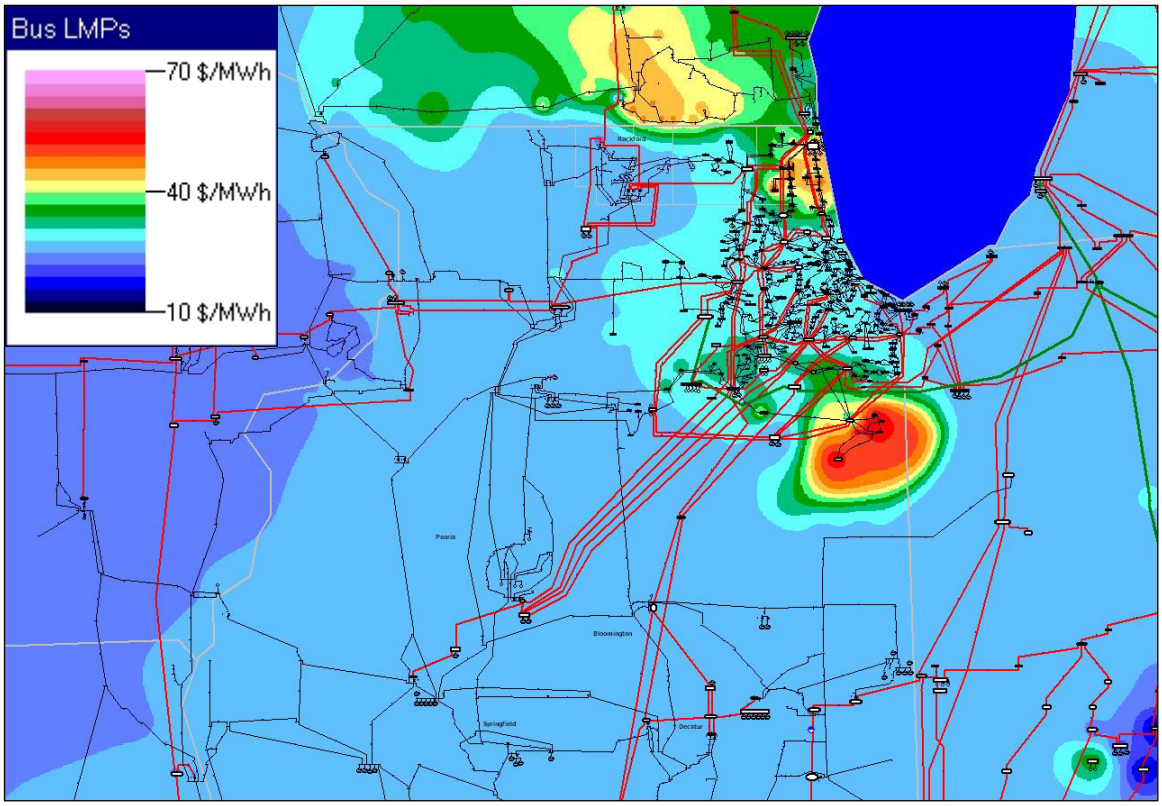
PowerWorld® Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a time frame ranging from several minutes to many days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with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

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

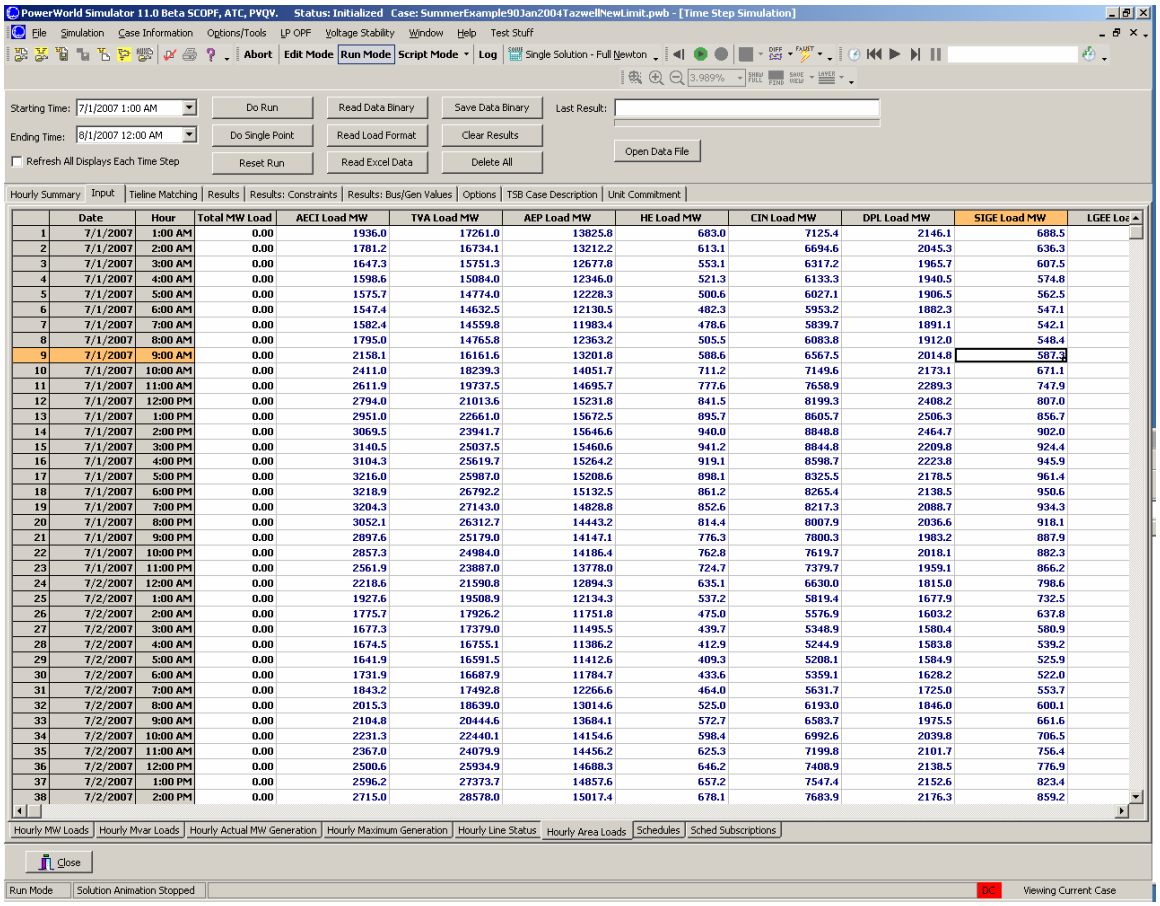
The purpose of an SCOPF is to minimize an objective (or cost) function by changing system controls taking into account both equality and inequality constraints. These constraints are used to model the power balance constraints and various operating limits. In Simulator SCOPF, the algorithm determines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

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

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



Example LMP Contours for Northern Illinois



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

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

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

B.1 INTRODUCTION

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

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

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

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

A wide variety of ABMS implementation approaches exist. Live simulation where people play the role of individual agents is an approach that has been used successfully by economists studying complex market behavior. General-purpose tools such as spreadsheets, mathematics packages, or traditional programming languages can also be used. However, special-purpose

tools such as Swarm, the Recursive Agent Simulation Toolkit, StarLogo, and Ascape are among the most widely used options (Burkhart et al., 2000; Collier and Sallach, 2001).

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

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

B.2 OVERVIEW OF THE EMCAS FORMULATION

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

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

B.2.1 PHYSICAL LAYER

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

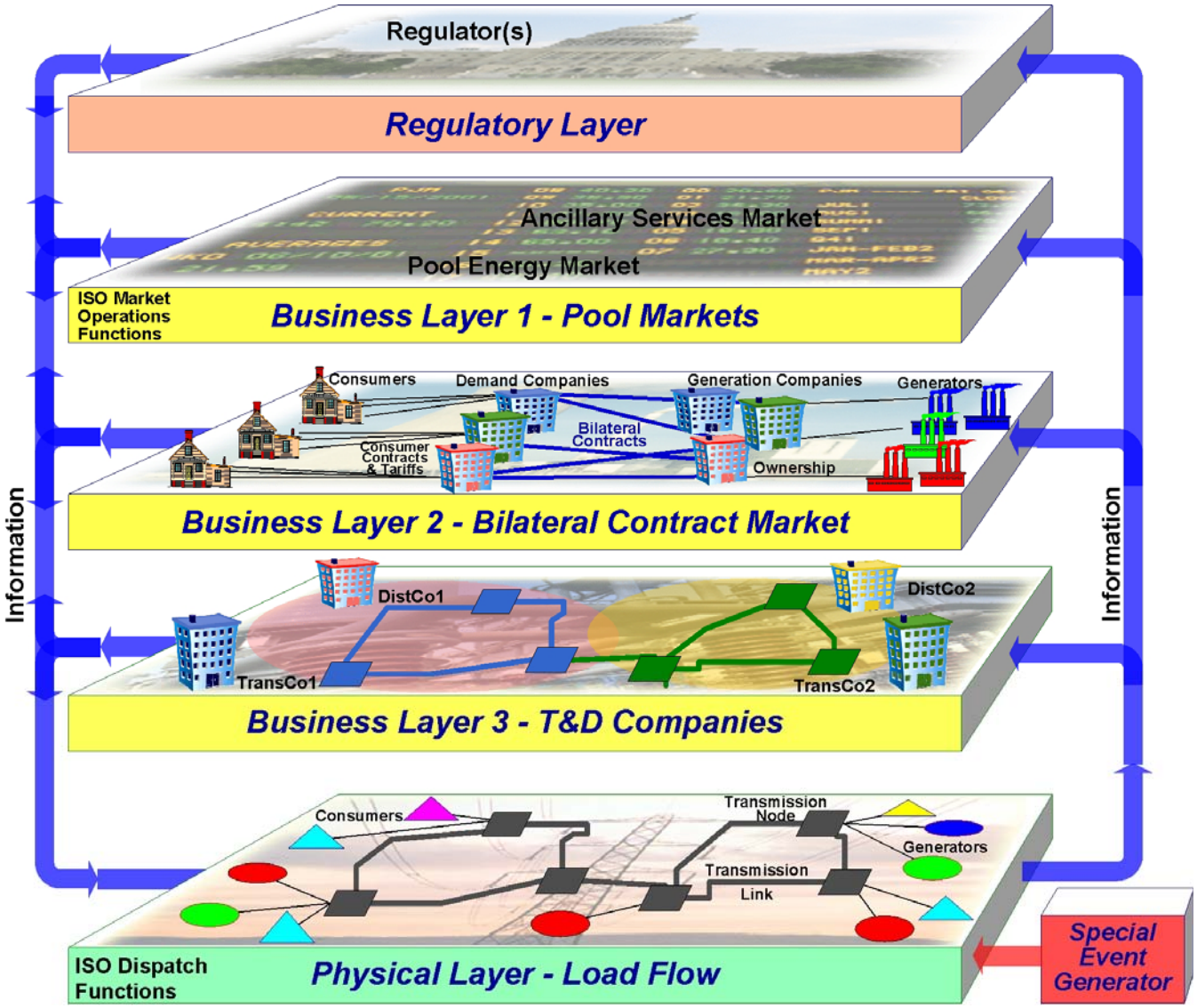


Figure B-1 EMCAS Formulation and Layers

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

B.2.2 BUSINESS LAYERS

Figure B-1 also shows three business layers that represent the business side of the electricity market. The *generation companies* (GenCos) represent the business units that own the generators. It is these agents that make decisions about how to participate in the electricity

market and operate the equipment to meet company objectives. The *demand companies* (DemCos) represent the business units that sell electricity directly to consumers. In the EMCAS formulation, all consumers purchase their electricity from a demand company. It is the demand company that buys electricity from generation companies to serve its customer load. It should be noted that in actual practice, a generation company and a demand company might, in fact, be part of the same corporate parent. This can be accounted for in EMCAS.

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

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

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

B.2.3 REGULATORY LAYER

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

B.2.4 SPECIAL EVENTS

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

B.3 AGENT DESCRIPTIONS

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

B.3.1 GENERATORS

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

Generator Identification Information

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

Technical Performance Information

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

Economic Information

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

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

B.3.2 TRANSMISSION NODES AND LINKS

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

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

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

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

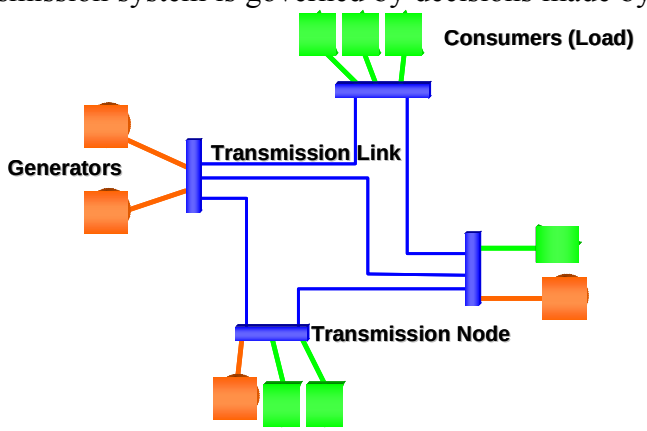


Figure B-2 EMCAS Transmission Components

B.3.3 CONSUMERS

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

Consumer Identification and Characteristics

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

EMCAS consumer agents have individual identification tags that allow the behavior of each to be tracked during the simulation. In addition, the consumer agent is tagged as to whether

it represents a single user (e.g., a single household) or is an aggregate representation of a number of users (e.g., all residential users in a specific area).

Load Information

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

Price Response

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

B.3.4 GENERATION COMPANIES

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

Generation Company Identification

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

Generation Company Business Strategy

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

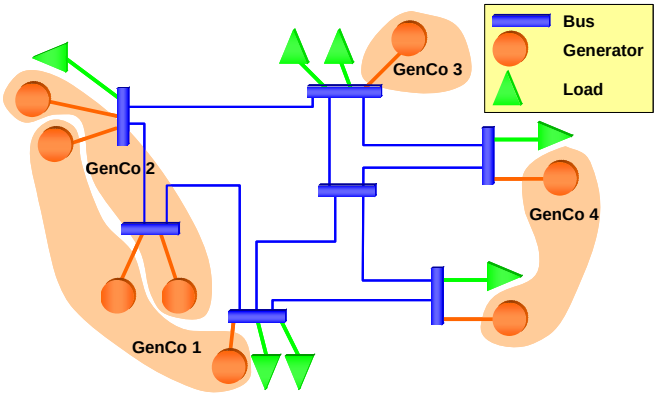


Figure B-3 EMCAS Generation Company Agents

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

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

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

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

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

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

$$Capacity_{gbh} \ [Bilateral\ Contracts,\ Pool\ Energy,\ Pool\ Ancillary\ Services,\ Uncommitted]$$

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

$$Bid\ Price_{gbh} = A_h*(Production\ Cost_{gb})+B_h*(Correlated\ Price)+C_h*(Specified\ Price)$$

where:

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

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

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

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

A_h, B_h, C_h are constants for each hour.

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

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

Learning and Adaptation

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

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

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

- *Maintain the current business strategy*. If the evaluation shows that the current business strategy is very successful at

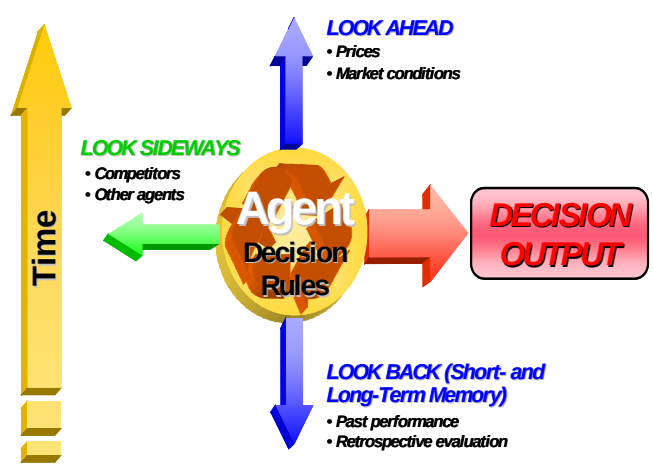


Figure B-4 Agent Adaptation Process

meeting company objectives (i.e., providing a high level of utility) and is likely to remain so under projected market conditions, it is maintained. A GenCo that is experiencing good returns and is somewhat risk-averse would adopt this approach.

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

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

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

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

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

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

B.3.5 DEMAND COMPANIES

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

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

Demand Company Identification and Business Profile

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

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

Demand Company Business Strategy

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

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

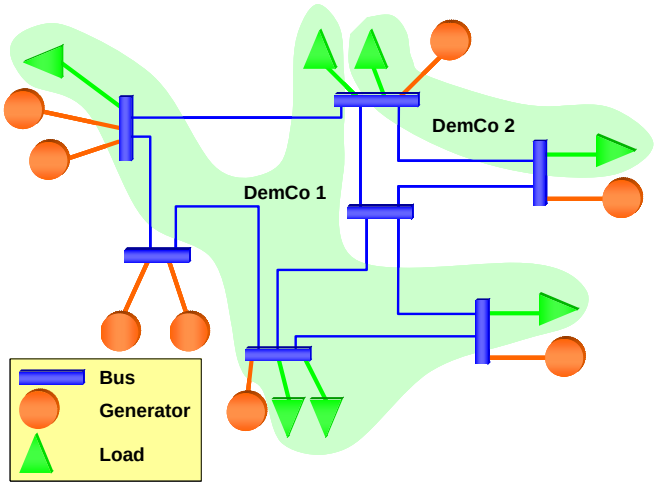


Figure B-5 EMCAS Demand Company Agents

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

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

There are many more strategies that can be included in a simulation. The DemCos have a two-sided structure that they must deal with. On one side, they must interact with the GenCos

and the pool energy markets to optimize electricity purchases. On the other side, they must deal with consumers to offer competitive prices for their sales of electricity while maintaining an acceptable level of their own utility (e.g., profit). Their business strategy must address both parts in order to be effective.

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

$$Load\ Allocation_{nh}\ \ [Bilateral\ Contracts,\ Pool\ Energy,\ Uncommitted]$$

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

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

$$Load\ Price\ Acceptance_{bnh} = [Load\ Fraction_{bnh}\ ,\ Price_{bnh}\ ]$$

where:

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

The consumer contract pricing function is specified by the equation:

$$Consumer\ Charge_{cnh} = D_h*(Supply\ Cost_n) + E_h*(Correlated\ Price) + F_h*(Specified\ Price)$$

where:

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

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

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

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

D_h, E_h, F_h are constants for each hour.

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

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

Learning and Adaptation

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

B.3.6 TRANSMISSION COMPANIES

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

Transmission Company Identification and Line Ownership

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

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

Transmission Fee Structure

In EMCAS, the TransCo agents are the owners of transmission lines but do not operate the system. Operation is left to the ISO, which is described in Section B.3.8. TransCos do, however, collect fees for the use of their transmission lines. In practice, these fees would be used to maintain the system and to expand the network to accommodate growth. By convention in EMCAS, the transmission use fee is collected from DemCos and is added to the price they

charge consumers. The *Transmission Use Rate* at node *n* for hour *h* is input as a $/MW charge. The *Transmission Use Charge (TUC)* in absolute dollars for a given transmission service at node *n* for hour *h* is calculated as follows:

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

where:

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

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

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

Transmission Congestion Charge

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

$$TCC_h = \sum_n Load_{nh} \times Node\ Price_{nh} - \sum_m Generation_{mh} \times Node\ Price_{mh}$$

where:

n are the nodes where load is attached to;

m are the nodes where the generation is attached to;

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

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

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

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

B.3.7 DISTRIBUTION COMPANIES

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

Distribution Company Identification and Service Territory

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

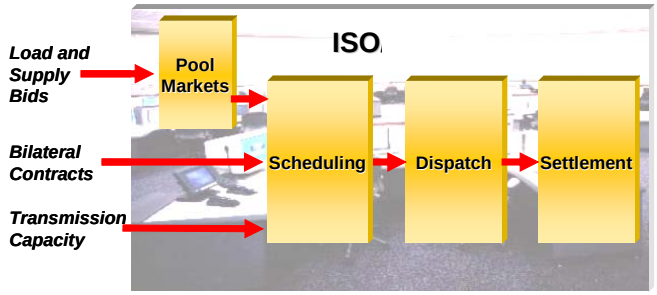


Figure B-6 EMCAS ISO Agent

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

Distribution Charge Structure

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

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

where:

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

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

B.3.8 ISO

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

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

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

ISO Identification

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

System Reliability Parameters

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

- Day-ahead regulation reserve margin,
- Day-ahead spinning reserve margin,
- Day-ahead non-spinning reserve margin,
- Day-ahead replacement capacity margin,
- Transmission line overloading limits, and
- Load-shedding priority list.

Day-Ahead Market Parameters

The ISO sets the procedures that are used in the operation of the day-ahead market including:

- *Market order* – In the current version of EMCAS, the day-ahead bilateral contract market completes first, then the pool energy market, and finally the pool ancillary services market;
- *Bilateral contract treatment* – In the current version of EMCAS, bilateral contracts are treated as financial instruments and are subject to the limitations of the transmission system.

Settlement Accounting

The ISO handles the settlements at the completion of the hourly dispatching. This includes the following:

- Payments to GenCos,
- Charges to DemCos, and
- Transmission use and congestion charges.

B.3.9 REGULATOR

The regulator agent in EMCAS sets the market rules that apply. In the current version of EMCAS, the regulator does not adapt or change its behavior. Rather, it relies on input from the user who can take the position of the regulator by changing and testing different market rules. The input information for the regulator includes the following:

Market Structure

- Bilateral contracts (if none allowed, then all energy is provided via the pool market);
- Day-ahead pool market for energy (if none exists, then all energy is provided via bilateral contracts); and
- Day-ahead pool market for ancillary services (if none exists, then all ancillary services are included in the pool energy market).

Market Pricing Rules

- Day-ahead pool energy market payment (e.g., pay locational marginal price, pay as bid); and
- Bid caps.

Tariffs and Taxes

- Tariffs – limitations on prices; and
- Taxes – consumers, GenCos, DemCos, TransCos, DistCos.

B.3.10 SPECIAL EVENT GENERATOR

The special event generator provides the EMCAS user with the ability to inject events into the simulation that force the system to deviate from the procedures developed at the planning levels. Currently, the special event generator can be used to inject unplanned incidents at the hourly dispatch level. The unplanned events that can be input are:

- Load forecast errors – increases or decreases in the load that deviate from the load projections used in the planning periods;

- Generator outages – unplanned outages of generators for varying periods of time ranging from hours to days; and

- Transmission link outages – unplanned loss of transmission lines for varying periods of time ranging from hours to days.

B.4 EMCAS DAY-AHEAD MARKETS

The EMCAS modeling system operates at different time scales or decision levels. Dependent on user-defined rules, different types of markets are available to agents at each time scale. The types of markets available and the specific rules under which each operates will influence decisions made by market participants. This section describes the markets available at the day-ahead decision level.

At the day-ahead level, EMCAS simulates three types of markets that include bilateral contract markets, energy pool markets, and ancillary services markets. Generally, bilateral contracts are agreements between a single GenCo agent and a single DemCo agent. These contracts have time scales that range from hours and days to several years. In the pool markets, EMCAS agents submit buy and sell bids to a central clearinghouse that is operated by the ISO. The pool markets are typically conducted at the day-ahead time scales and include both energy and ancillary services markets.

Figure B-7 shows the sequence of market activities that are carried out in the day-ahead planning level. In the EMCAS simulation, the only agents that participate at this level are the ISO, DemCos, and GenCos. Consumers do not exercise any decision-making at the day-ahead level. Most electricity users do not have access to daily market price information; therefore, there is no basis on which they can adjust their planned consumption for the next day in response to market conditions. Only a few large users (e.g., large industrial facilities) might be considered to have access to daily price information and be in a position to react on a day-by-day basis.

ISO Day-Ahead System Status Projections

The initial step in the day-ahead planning simulation is for the ISO to develop a projection of the next day's load and system conditions. This includes any known outages of generators and transmission lines. The information is made available to all the DemCos and GenCos, analogous to the process used by several operating electricity markets currently posting public information.

DemCo and GenCo Market Price Projections

Each DemCo and GenCo prepares its own projections of the day-ahead situation for the company's system. For the DemCos, the focus is on the expected load from the consumers they are serving and the expected prices in the day-ahead energy market and for bilateral contracts. For the GenCos, the focus is on the status of their own generation equipment, the prices that bilateral contracts might bring, and expected prices in the day-ahead energy and ancillary services markets.

The market price projections are unique for each company and form the basis of how they will bid into the day-ahead markets. The projections include hourly prices in the pool energy market, hourly prices in the ancillary services market, and hourly projections of bilateral contract prices. The price projections are developed by DemCos and GenCos in one of several ways:

- Correlation to previous day(s),
- Next day forecast, and
- Price probability distribution.

The correlation to previous day(s) is the simplest price projection method. It assumes that the day-ahead prices will be the same as the previous day. In the simulation, the average price of the previous five weekdays (or two weekend days) is used to avoid unrealistic fluctuations from one day to the next. This type of "myopic hindsight" is the simplest form of price projection.

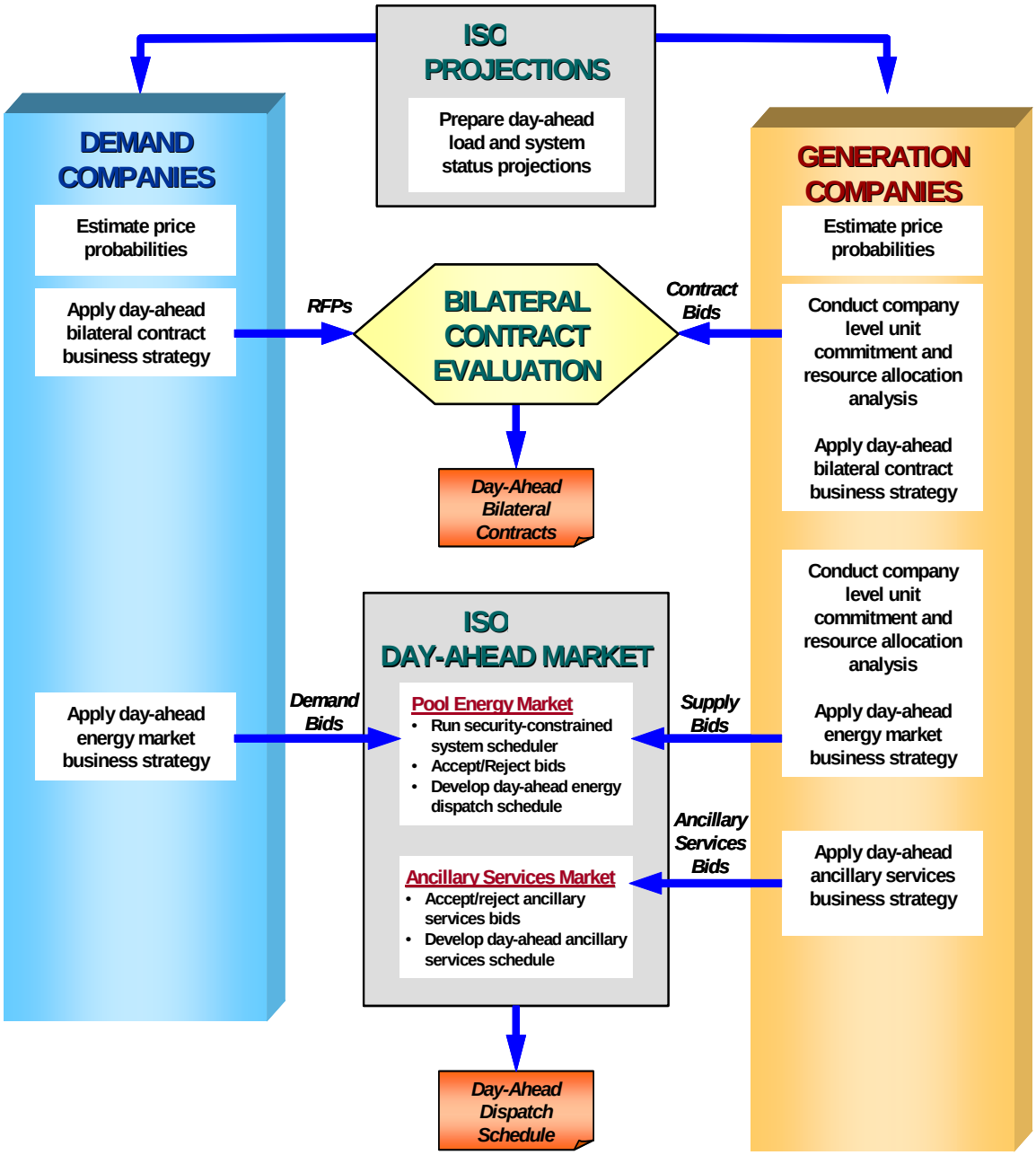


Figure B-7 Day-Ahead Planning Sequence

The next day forecast method of price projection is a type of "myopic foresight" approach. GenCos and DemCos using this method look at the forecasted load and system status for the day ahead and use this to project what the prices will be in the markets. The method uses a very simple projection technique that relates prices to system conditions.

The most sophisticated price projection technique is to use a price probability distribution. The price probability distribution gives the probability that a bid for a specific generator at a given node will be accepted in any of the available markets (i.e., energy, ancillary services, bilateral contracts), given system conditions.

Day-Ahead Bilateral Contracts

The day-ahead bilateral contract market operates next in the simulation. The process begins with DemCos developing requests for proposals (RFPs) for day-ahead bilateral contracts for energy (Figure B-8). Included in each RFP are load for each hour and points of withdrawal. The load quantities in an RFP account for demand that is already under a longer-term bilateral contract and include only the additional demand that must be met for the next day. The points of withdrawal indicate the node(s) at which the load will occur. The RFPs are sent to all GenCos participating in the bilateral contract market.

In the next step of the simulation, the GenCos prepare their responses to the RFPs. Using the price projections for the next day, which include projections for the pool energy market and for bilateral contracts, each GenCo conducts a company-level unit commitment and resource allocation analysis (CLUCRA). This analysis seeks to maximize the company's utility by assigning generation that (a) will be bid in response to bilateral contract RFPs, (b) will be reserved for bidding into the pool energy market, or (c) will be bid into the ancillary services market. The CLUCRA objective function is:

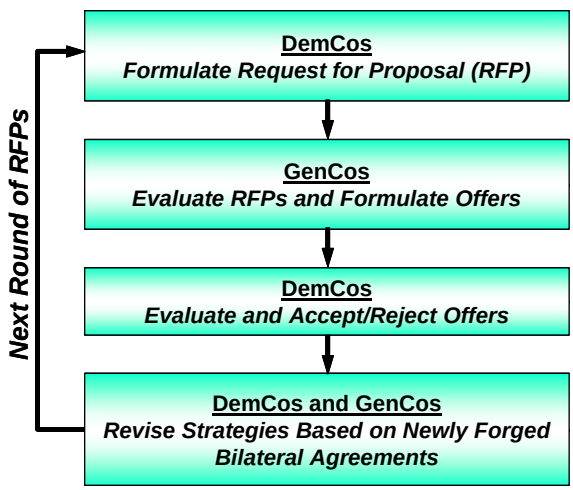


Figure B-8 Sequence of Events for Modeling Bilateral Contracts

$$
\begin{aligned}
\textbf{MaxCorporate_Objective} = & \sum_{n=1,n} \sum_{h=1,24} [Projected_Price_{nh} * \sum_{b=1,n} Production_Level_{hb}] \\
& + \sum_{h=1,24} \sum_{c} Bilateral_Revenue_{hc} \\
& - \sum_{h=1,24} \sum_{b=1,n} Production_Cost_{hb} * Production_Level_{hb} \\
& - Startup_Cost_{g} * Number_Starts \\
& - Shutdown_Cost_{g} * Number_Shutdowns
\end{aligned}
$$

The constraints imposed are the physical limitations of the generation equipment including:

- Start-up time,
- Minimum run time,
- Minimum capacity, and
- Shut-down time.

In maximizing its individual utility in this manner, each GenCo determines whether the projected prices for bilateral contracts or the pool markets will provide an adequate return to warrant the operation of each generation unit. The result of this analysis is a decision on whether to commit the unit to a bilateral contract, to offer the unit into the pool energy market, or to shut it down.

After the completion of the day-ahead CLUCRA, each GenCo applies its day-ahead bilateral contract business strategy. The use of the business strategy at this point accounts for the fact that each company's CLUCRA analysis is based on limited information. It has only its own price projections and its own record of success or failure from previous bids. It does not have access to similar information for other companies. The application of the business strategy allows the company to test other approaches that may be more beneficial (i.e., increase its utility) than one based solely on its own limited information.

As described in an earlier section on GenCos, the day-ahead bilateral contract business strategy is made up of two parts. The first is the use of the capacity allocation function to allocate resources in response to RFPs. In its simplest form, the capacity allocation function would set all the available capacity to the *Uncommitted* category, thus allocating capacity according to the company's CLUCRA results. That is, capacity would be offered in response to those RFPs that maximized the company's utility for the next day. Alternative strategies that can be applied include forcing a portion of capacity to be offered in response to RFPs independent of the CLUCRA result, forcing a response to an RFP from a particular DemCo, and other variations. These would be implemented by changing the capacity allocation function. This capability in EMCAS allows a GenCo to try different resource allocation strategies that may prove more beneficial to the company.

The second part of the GenCo's day-ahead bilateral contract business strategy is the pricing of its bids using the capacity pricing function, as described earlier. The general form of the function provides a means to specify a wide range of pricing strategies. Since the GenCos have the ability to try business strategies that do not rely solely on the outcome of the CLUCRA optimization results, they can explore for solutions that increase their utility.

When the GenCo bid responses to the RFPs are received by the DemCos, they go through a process to determine which bids to accept or whether to rely on the pool energy market to meet their requirements. The process used is the Demand Company Resource Allocation (DCRA). In applying the DCRA, each DemCo seeks to maximize its own utility function. The price bids received in response to the RFPs and the projected prices for the day-ahead energy market are compared and the best mix of bilateral contracts and planned purchases from the day-ahead pool energy market is determined. The EMCAS algorithm that simulates a demand company's bilateral contract purchase portfolio uses an "intelligent" heuristic to test various purchase portfolios (solution states) and selects the one that maximizes the corporate utility functions. The

algorithm is based on a methodology that combines "greedy adding" and "pair-wise substitution" techniques. The initial portfolio state assumes that all energy purchases would be from the day-ahead energy market. Individual bilateral contract offers from GenCos are then tested in the portfolio mix, and the one that yields the highest objective function value is temporarily added to the mix. The process of adding bilateral contracts into the mix using this greedy-adding method continues until no additional bilateral contract increases the corporate utility.

Other portfolios are then tested by swapping one or previous rejected bilateral contract offers with one that has been accepted. This includes a fictitious "null" contract that contains no capacity or energy. If swapping rejected bilateral offer(s) into the portfolio mix in place of an accepted offer increases the corporate utility, the swap is implemented. Swapping of contracts into and out of the corporate mix continues until a better utility function cannot be found.

After completion of the DCRA, each DemCo applies its day-ahead business strategy to the result. As described earlier, the DemCo business strategy includes the application of the load allocation function and the load price acceptance function. The strategy can include decisions to force a portion of the load to be under a day-ahead bilateral contract independent of the DCRA result, force a response to an RFP from a particular GenCo, and other variations. In a manner analogous to that used by the GenCos, this capability in EMCAS allows the user to try different resource allocation strategies for DemCos that may prove more beneficial to the company.

In EMCAS, the bilateral contract market can consist of multiple rounds of DemCo RFP / GenCo Bid / DemCo selection. This allows for an iterative process of contract negotiations to be simulated. In general, one to three bilateral contract bidding rounds are used in a simulation. At the completion of the last round, the day-ahead bilateral contract market is considered closed, and the simulation proceeds to the day-ahead pool markets.

Day-Ahead Pool Energy Market

The day-ahead pool energy market represents the operation of a pool market for wholesale electricity sales and purchases. In certain applications where no such market exists, this may be bypassed. The day-ahead pool energy market operates by accepting supply bids from GenCos and demand bids from DemCos.

GenCos begin the preparation of their supply bids in a manner similar to what was done for the day-ahead bilateral contract market. Beginning with the prices that they have projected for the market, the CLUCRA optimization analysis is run. At this point, decisions are made concerning the day-ahead pool energy market, the ancillary services market, and the withdrawing of capacity in situations when the projected market prices are below production costs. The same objective function and constraints that were used in the bilateral contract analysis are used in the pool energy market analysis.

With the CLUCRA results, each GenCo applies its day-ahead energy market business strategy, which consists of two parts, similar to what was used in the bilateral contract market: the capacity allocation function and the capacity pricing function. As with the bilateral contract

market, this capability in EMCAS allows the user to try different resource allocation strategies that may prove more beneficial to the company.

DemCos also submit bids to the day-ahead pool energy market. These demand bids specify the quantity of electricity the DemCo is willing to accept at a specified price. The DemCo demand bids show a decreasing purchase quantity with increasing price. A DemCo can reduce its purchase of electricity if the price is too high by not serving a portion of its projected load. This means that the load will be curtailed voluntarily (e.g., by exercising service interruption provisions of agreements with consumers, mostly large industrial or commercial users) or involuntarily (e.g., by load shedding). In either case, by the way in which its demand bids are submitted to the pool energy market, the DemCo can set a limit on the price it is willing to pay for electricity. Of course, a DemCo can submit a demand bid with no price limits, in which case it is indicating that it will pay any price to meet its load. The bid is then considered to be price inelastic.

The supply bids from the GenCos and the demand bids from the DemCos are on an hour-by-hour basis for the next day. In addition, the bids specify the point of injection (for supply bids) into the transmission network and the point of withdrawal (for demand bids). The ISO must balance the system based on these bids. In the EMCAS simulation, the bids are first rank-ordered by price, as illustrated in Figure B-9. Bids from all GenCos and all DemCos for each hour are included.

The ISO then runs a transmission-constrained system scheduler (TCSS) analysis to determine if the supply and demand can be balanced while maintaining the security and stability of the transmission system. TCSS uses a direct current Optimal power flow (DCOPF) algorithm. The algorithm consists of an objective function and a set of constraints that place limits on generation levels, load curtailments, and power flows. Constraints also ensure that at each bus there is an energy balance at all buses. Linear programming (LP) techniques are used to find the best solution to the problem.

The TCSS objective function is to minimize the overall costs, supply purchases, and load reductions (e.g., variable payment for hourly demand side management measures). Supply costs are those incurred when a block of energy is purchased at a specified price from the market. The objective function also accounts for the cost of unserved energy, power transport costs, penalties for transmission line overloads, and the cost of calling spinning reserves into service.

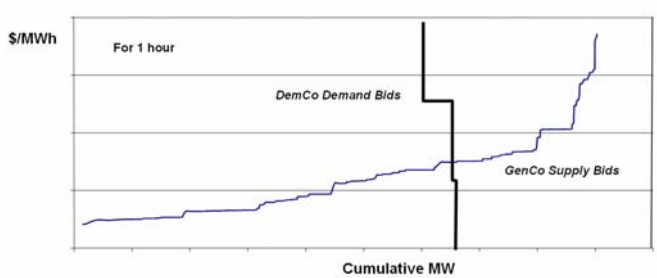


Figure B-9 Ranking of Day-Ahead Supply and Demand Bids with No Transmission Congestion

The TCSS cost minimization objective function is subject to several constraints. On the supply side, the amount of energy purchased at a specific bus cannot exceed the block amount offered by a GenCo. Likewise, the amount of load reduction that is accepted cannot exceed the

block-amount offered by a DemCo.

The flow of power from generators (power injections) to loads (power sinks) is governed by a set of physical constraints. Injections include power from both accepted energy offers and spinning reserves that are called into service. One transmission flow constraint requires that there is an energy balance at all buses. As shown in the equation below, the amount of power flowing on all power lines (branches) into a bus must exactly equal the amount of power that is flowing out of a bus.

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}} \left(\theta_i - \theta_j \right)$$

where:

P_i sum of generation (+) and load (–) at bus i (MW);
P_{ij} power flow from bus i to bus j (MW);
x_{ij} line inductive reactance;
θ_i phase angle at bus i (radians); and,
θ_j phase angle at bus j (radians).

Power flows on a transmission line connecting bus i to bus j are given by:

$$P_{ij} = \frac{1}{x_{ij}} \left(\theta_i - \theta_j \right)$$

Real power flows on lines, measured in MW, are limited. Currently the model includes three line rate limits, namely, rate A, rate B, and rate C. Typically, costs for line usage up to rate A are minimal, but very rapidly increase for any flows above that level.

The TCSS determines the supply and demand intersection points in the network. In the absence of any transmission congestion, the TCSS load flow analysis will show that the initial rank ordering of supply and demand bids of Figure B-9 and will provide the least cost way to dispatch the system. However, when congestion of the transmission system appears, such as during high load periods, it may not be possible to utilize the least cost generators without violating thermal limits of transmission lines or contingency situations. Lower-cost generators may need to be bypassed in favor of more expensive units that can be used without creating transmission problems. The supply curve is then shifted as shown on Figure B-10.

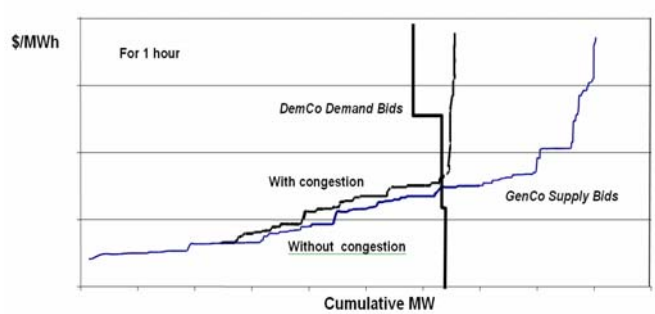


Figure B-10 Shift of Supply Bids Due to Transmission Congestion

The ISO will accept or reject bids from GenCos and DemCos based on the results of the TCSS analysis. Notification of acceptance or rejection is sent back to the GenCos and DemCos and the day-ahead energy market is closed.

Day-Ahead Pool Ancillary Services Market

Ancillary services are functions provided to maintain the reliability of the power system in response to both normal and unplanned variability in supply and demand. Some of the key ancillary services are:

- Regulation/automatic generation control (AGC) services,
- Spinning reserve,
- Non-spinning reserve, and
- Replacement reserve.

Regulation or AGC services are designed to match the output of generators to variations in load on a very short time frame, usually seconds. This requires the ability to adjust generator output on an almost instantaneous basis. Not all generator equipment is capable of this type of fine control. Spinning reserve is the ability of units that are in operation at a level below their maximum output and synchronized to the grid to increase their output generating capacity in response to changes in system demands. Typically, the criterion for this capacity increase is that it must be fully available within 10 minutes. Non-spinning reserve, frequently called non-synchronous or supplemental reserve, consists of capacity that is not operating but that can be started and fully available within 10 minutes. In some places, interruptible loads that can be shut down within the 10-minute window can also be included as a non-spinning reserve. Replacement reserve is a standby capacity that must be fully available within 30 to 60 minutes and then maintained until substitute capacity from the market is available.

EMCAS provides an explicit modeling of the ancillary services for spinning reserve, non-spinning reserve, and replacement reserve. The modeling of regulation/AGC services is handled in an approximate way. In an EMCAS simulation, the day-ahead pool ancillary services market for spinning reserve, non-spinning reserve, and replacement reserve is run after the closing of the day-ahead pool energy market. In this market, GenCos apply their company ancillary services business strategy to determine how they will participate. As with the bilateral contract and energy markets, the strategy has two parts. The first is a determination of how much capacity to commit to the various components of the ancillary services market: spinning reserve, non-spinning reserve, or replacement reserve. This analysis is based on the company's projections of day-ahead prices for each of these reserve markets. GenCos may consider offering any capacity that has not been committed to bilateral contracts or to the energy market into the ancillary services market, provided the particular units being considered can meet the technical start-up requirements for each of the reserve categories. In EMCAS, the company analysis is done by a simple comparison of the projected revenue in the market to the cost of operating the unit, should it be called upon. The market payment for having the capacity available, even if it is not needed, is factored into this comparison.

The second part of the GenCo's day-ahead ancillary services market business strategy is the pricing of its bids. The formulation of the bid price accounts for the probability that it will be called upon and follows the same structure that was used for bilateral contracts and the pool energy market. That is, the bid can be related to production cost, can be correlated to some other price, or can be a specified price as was shown earlier.

The ancillary service for regulation/AGC is modeled in EMCAS in an approximate manner. Additional capacity that would be needed to meet the need for regulation/AGC services is selected as part of the pool energy market. It is made available for dispatch as needed.

Day-Ahead Dispatch Schedule

After the closing of the day-ahead bilateral contract, pool energy, and pool ancillary services markets, the dispatch schedule for the next day is established. This schedule specifies which units are to be run in each hour of the next day to meet expected loads. Variations to this schedule due to changes in load or generator or transmission outages are dealt with at the hourly dispatch time line.

B.5 EMCAS HOURLY DISPATCH

Figure B-11 shows the operation of the hourly dispatch in EMCAS. Hourly simulations are the smallest time step used in EMCAS. In actual practice, dispatching is adjusted in periods of minutes and seconds. This level of detail is not used in EMCAS.

In some electricity markets, there is an hour-ahead market (sometimes called a "real time market"). This is a bit of a misnomer in that this market generally operates two to four hours in advance of the actual dispatch time. For simplification, this market is not currently included in an EMCAS simulation. Rather, the variation between actual demand and the day-ahead schedule for the dispatch of generators is handled by using the ancillary service capacity that is available.

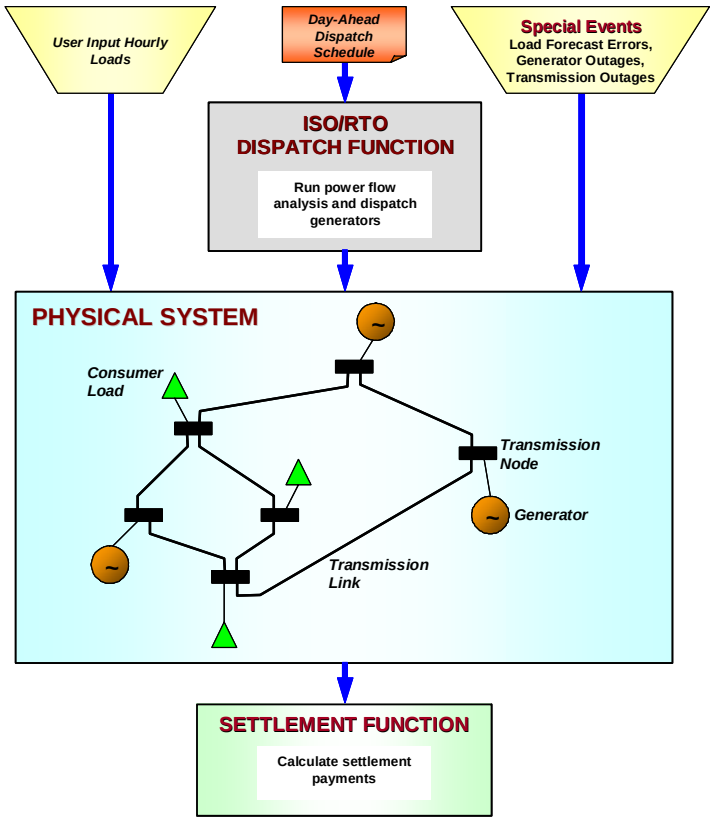


Figure B-11 Hourly Dispatch Sequence

User Input Loads

As the EMCAS hourly dispatch simulation begins, the load from each of

the consumers for each hour is determined from user-input load data. The simulation can be run with no load forecast error, in which case the load information that was used at the day-ahead planning level is identical to what is experienced in the hourly dispatch. Alternatively, at the user's discretion, the load can be allowed to include a random variability.

ISO Dispatch Function

The dispatch schedule of which generators are planned to operate in each hour to meet the load is available from the day-ahead planning level. Using this schedule as a starting point, the ISO operates the power system to balance supply and demand and to maintain the integrity and security of the overall system. In the real world, power system operation involves balancing a number of critical variables simultaneously including power flow, frequency, voltage, and other parameters. EMCAS uses a DC-OPF formulation, the same TCSS that was used in the day-ahead pool energy market segment of the simulation described earlier. If there were no variations in load, generator availability, or transmission system topology from the information used in the day-ahead planning, the results of the hourly dispatch would be identical to the results of the day-ahead TCSS and would follow the dispatch schedule developed there.

Special Events

The EMCAS user can specify several unplanned events to simulate how the system will respond to variations is load, generator outages, and transmission outages using the *Special Event Generator* described earlier. Each of these events will require that the system operation be adjusted from what was included in the day-ahead schedule. In general, these adjustments will result in increased costs in the system. In some cases, it may not be possible for the system to adjust and some load will not be served. EMCAS tracks these conditions.

Locational Marginal Prices

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

In simulating the hourly dispatch, EMCAS calculates the LMP for each node in the network. The LMP is set equal to the dual value computed for the energy balance constraint in the TCSS. These dual values are computed by the DCOPF/LP routine. Essentially, the dual value is a measure of the cost saving, in $/MWh, associated with relaxing the bus energy balance constraint by a very small amount. For load and generation buses, it can also be interpreted as the change in the objective function value if the net power injection at a bus is increased by 1 MWh.

Settlement Function

At the completion of the dispatch for each hour, the information needed to settle the charges and payments to each of the market participants is tabulated. In principle, these settlements can be displayed for each hour of a simulation. In practice, they are displayed as monthly or annual aggregations. Table B-1 summarizes the settlements that are calculated.

All of the settlement payments are calculated using the market rules that have been established. For example, if there is a tariff on consumer electricity purchases, the tariff value is used to calculate their payment for purchases.

Table B-1 Settlement Payments Calculated in EMCAS

Agent	Revenues	Expenses
Consumers	• N/A	• Payments to DemCos for electricity purchased • Payments to DistCos for distribution charges • Payments to TransCos for transmission use charges
DemCos	• Payments from consumers for electricity purchased	• Bilateral contract payments to GenCos • Energy payments to pool market based on actual purchases
GenCos	• Bilateral contract payments from DemCos • Energy payments from pool market; based on actual generation • Ancillary services payments: capacity charge for units on standby plus energy payment if unit is actually dispatched	• Generator fuel costs • Generator variable operating costs • Generator fixed operating costs • Off schedule charges to make up supply for generators that were scheduled to operate but were out of service; based on market price
DistCos	• Distribution charges for use of distribution system; paid by consumers	• N/A
TransCos	• Transmission use charges for use of transmission lines; paid by consumers through DemCos • Transmission congestion charge from differences in LMPs	• N/A

B.6 MODEL OUTPUTS

An EMCAS simulation can produces a substantial amount of output information. The simulation is done on an hour-by-hour basis for any period from days to years. At each step of the simulation, EMCAS can output the behavior of each component of the physical system (e.g., output of each generator unit, loading of each transmission line) and each agent (e.g., bids by each GenCo, bid acceptance/rejection by ISO, revenues, costs). Summaries and aggregations of information (e.g., by company, by geographical area) are available to provide an overview of results. EMCAS provides both tabular and graphical output at the user's choice and can output its information to spreadsheets or other data processing software.

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APPENDIX C
COMPARISON OF POWERWORLD® AND EMCAS© RESULTS

This appendix briefly discusses a comparison of the model results from EMCAS and PowerWorld. The comparison focused on the hourly LMPs and was conducted for February and July for buses located in the IP and all NI zones; that is, NI-A to NI-G. The EMCAS results used in the comparison were the LMPs from the Production Cost case. PowerWorld results were based on an assumed production cost-based bidding.

Figure C-1 shows hourly LMPs for February for bus 32271 located in the IP zone. As can be seen, EMCAS LMPs were consistently higher (on average $5.5/MWh) than LMPs projected by PowerWorld. An initial assessment concluded that this was based on several differences in the modeling approach as well as some of the underlying data assumptions, including:

- Differences in assumed unit production costs – the EMCAS results included a fixed O&M cost component, while PowerWorld did not;
- Differences in derating of out-of-state units to account for outages;
- Unit commitment – EMCAS included a unit commitment algorithm, while PowerWorld did not; and
- Unit heat rates – EMCAS used heat rates by block (up to 5 blocks per unit), while PowerWorld used only one heat rate (full-load heat rate) per unit.

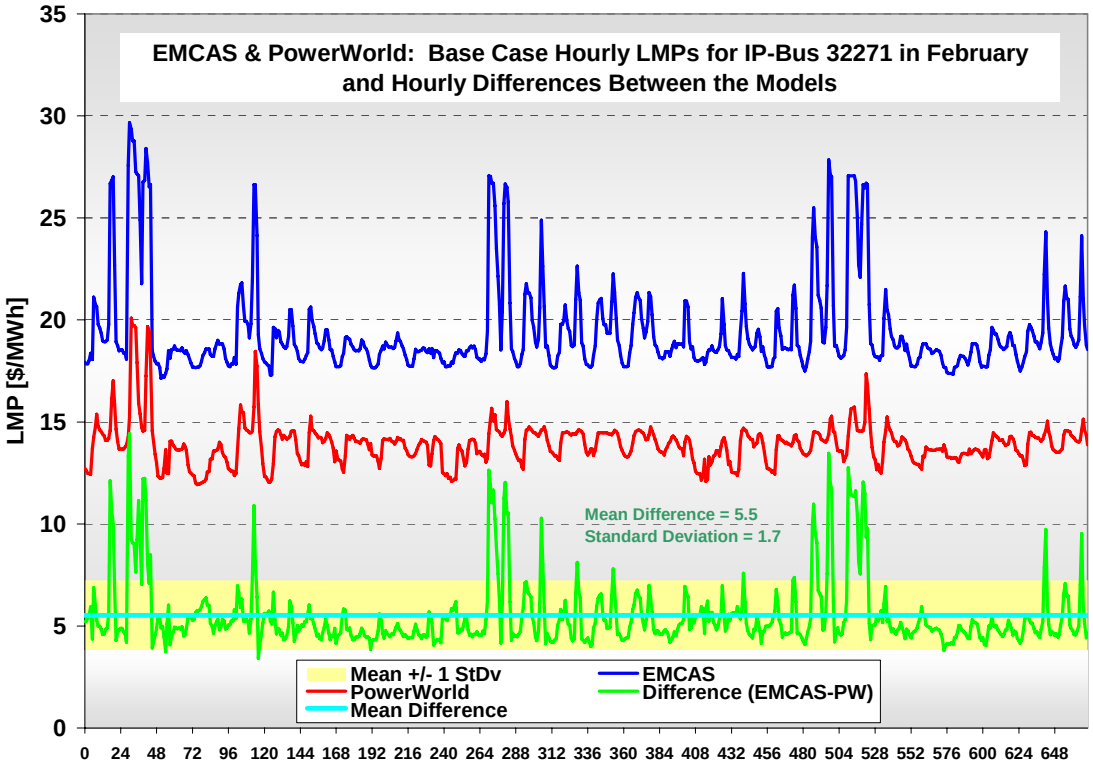

Figure C-1 Differences in Hourly LMPs for IP-Bus 32271 (February)

After identifying the main factors leading to the differences in LMP results, an EMCAS case was created that included the same production cost assumptions, the same out-of-state derating factors, and the same unit-level heat rates. In addition, the unit commitment algorithm was disabled. The following graphs show a comparison of PowerWorld results with the original EMCAS results (Original Case) and with the modified case (Modified Case). It can be seen that these four changes explained most of the differences in model results.

Figure C-2 shows that the differences typically dropped from around 4–6 $/MWh to less than 1 $/MWh in the Modified Case. (EMCAS results were slightly lower than PowerWorld in this case.) Expressed in relative terms, Figure C-3 shows that while the Original Case had LMPs to be around 25–30% different, the Modified Case reduced this to less than 5%. Figure C-4 shows that the hourly LMPs from both models varied well together; that is, they showed very similar daily fluctuations. In general, the Modified Case slightly improved the correlation between the data sets.

Figure C-5 shows the comparison for July. For the most part, the Modified Case leads to a significant reduction in differences, except for buses in the NI-D zone (Chicago). However, even in this zone, average differences for the month of July are still less than 5 $/MWh. Figure C-6 shows July differences in percent. Again, except for buses in NI-D, differences drop from around 20–30% to about –5% to +5%. Figure C-7 shows very good correlation for July, except for NI-D. The reason for the noticeably different behavior of NI-D buses is likely a result of the more detailed modeling of phase shifters by PowerWorld. This is discussed in Appendix E.

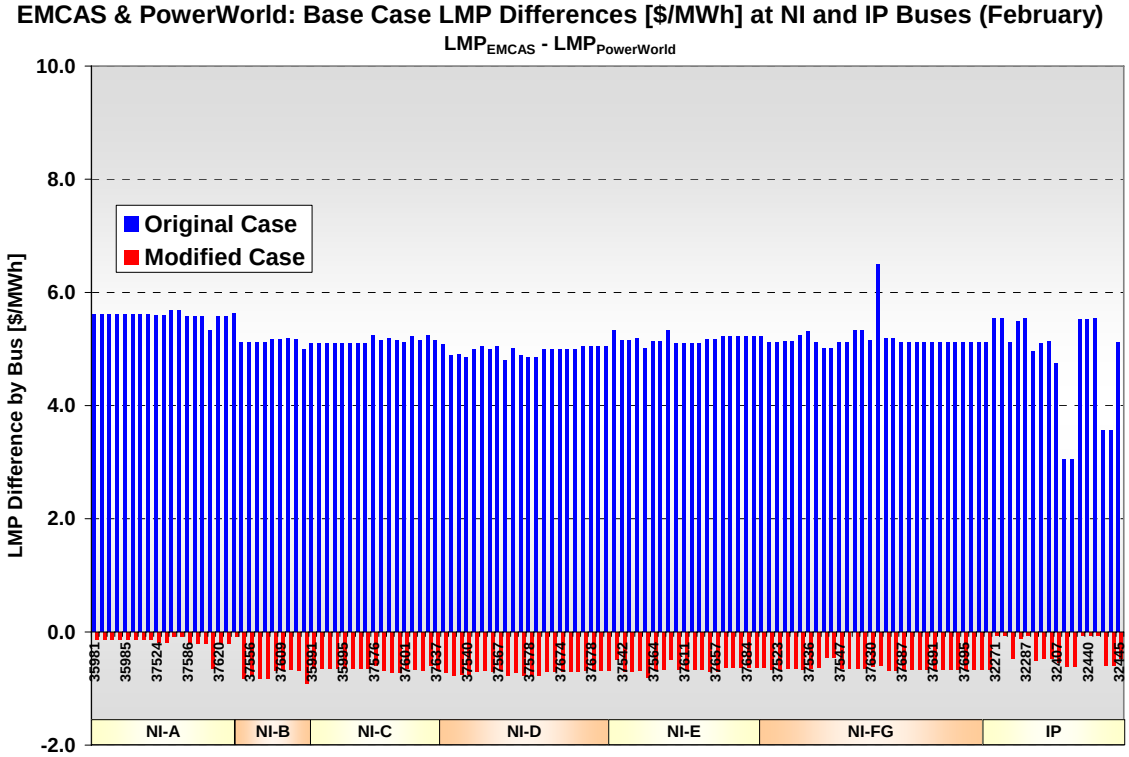

Figure C-2 Average Monthly Differences (February) by Bus for all IP and NI Buses

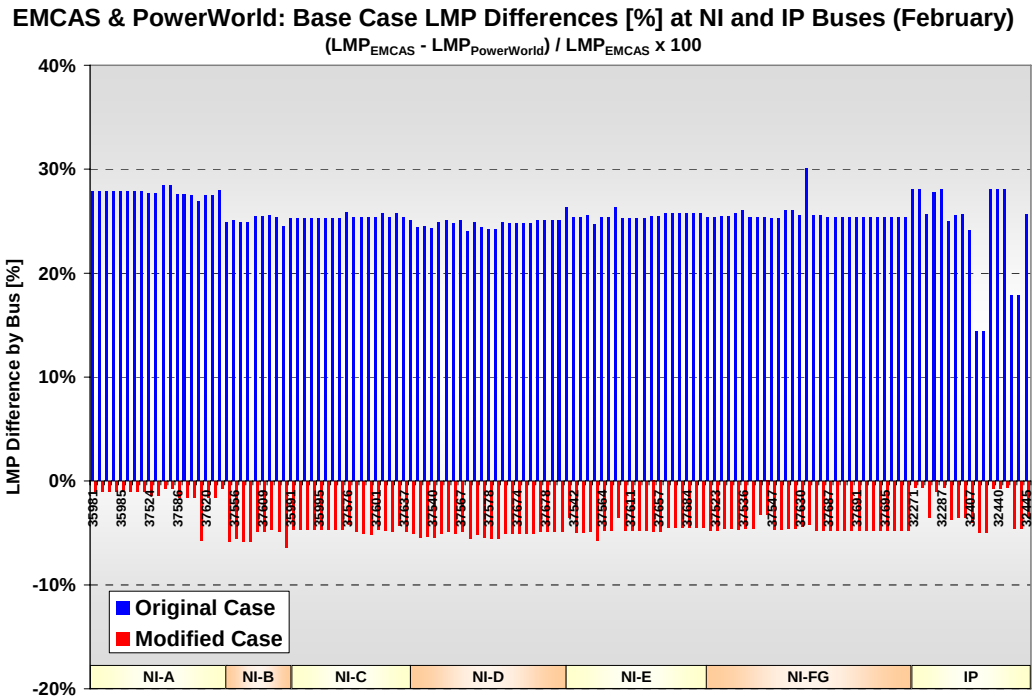

Figure C-3 Average Monthly Differences (February) by Bus for all IP and NI Buses in Percent

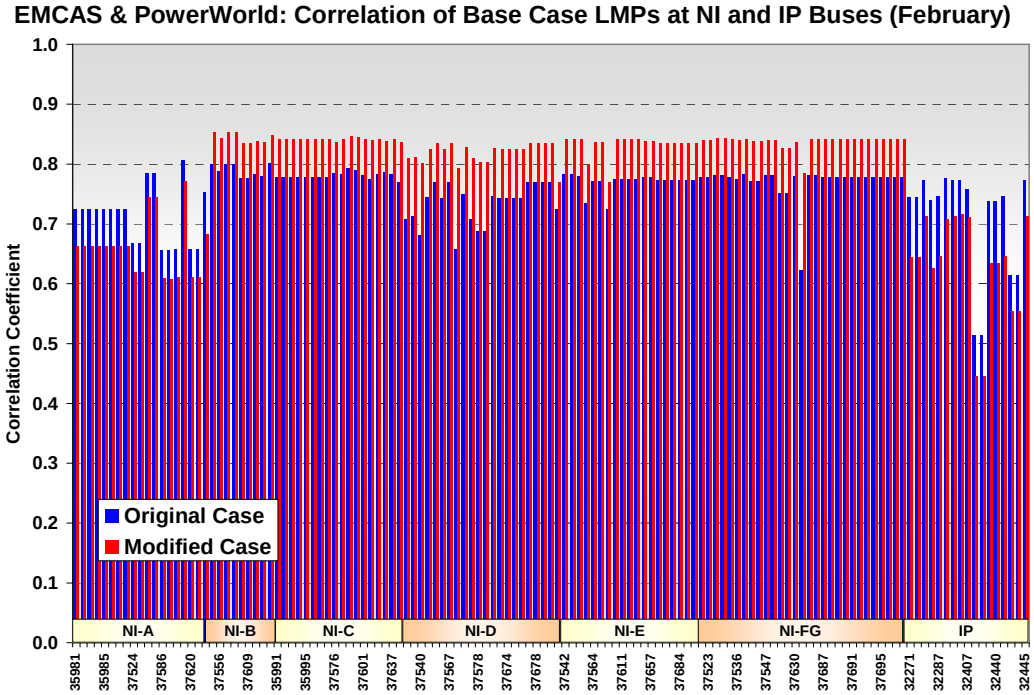

Figure C-4 Correlations between EMCAS and PowerWorld Results (February)

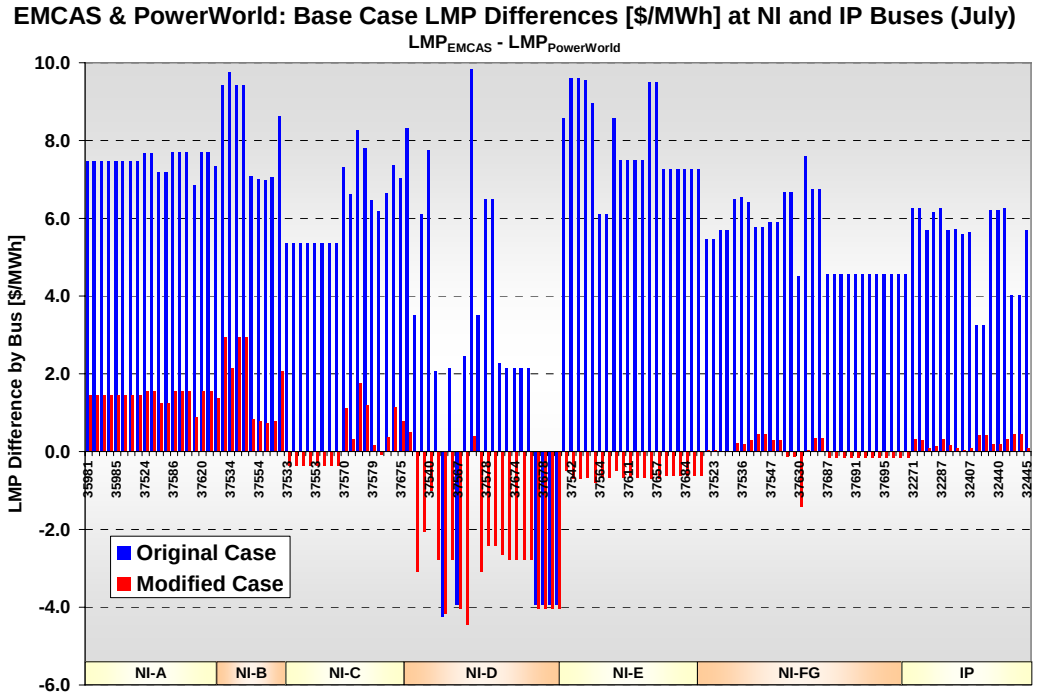

Figure C-5 Average Monthly Differences (July) by Bus for All IP and NI Buses

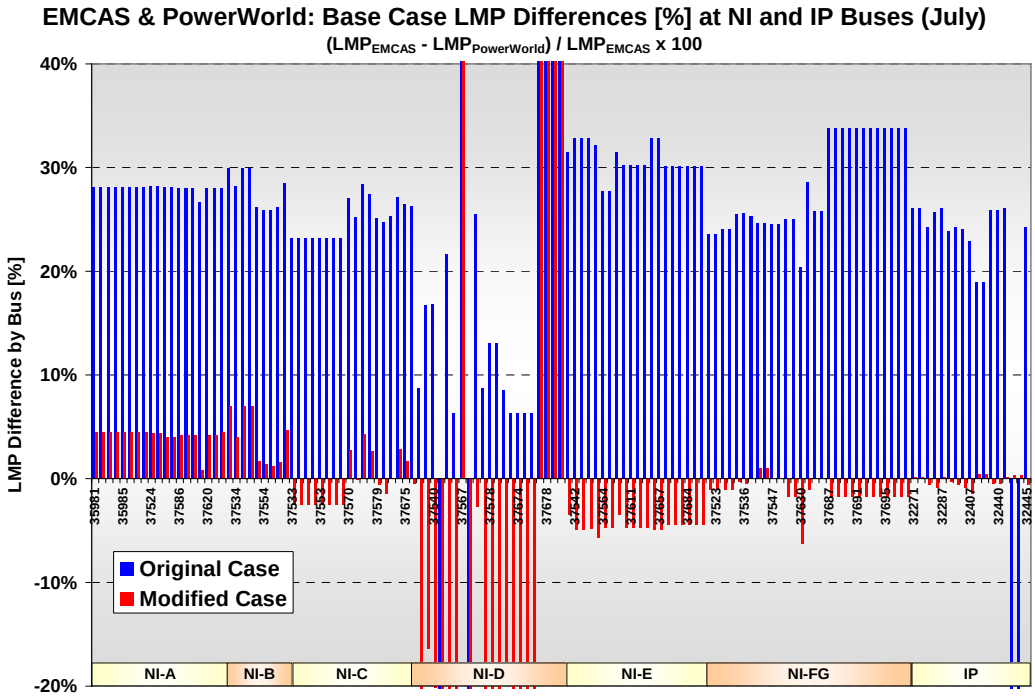

Figure C-6 Average Monthly Differences (July) by Bus for All IP and NI Buses, in Percent

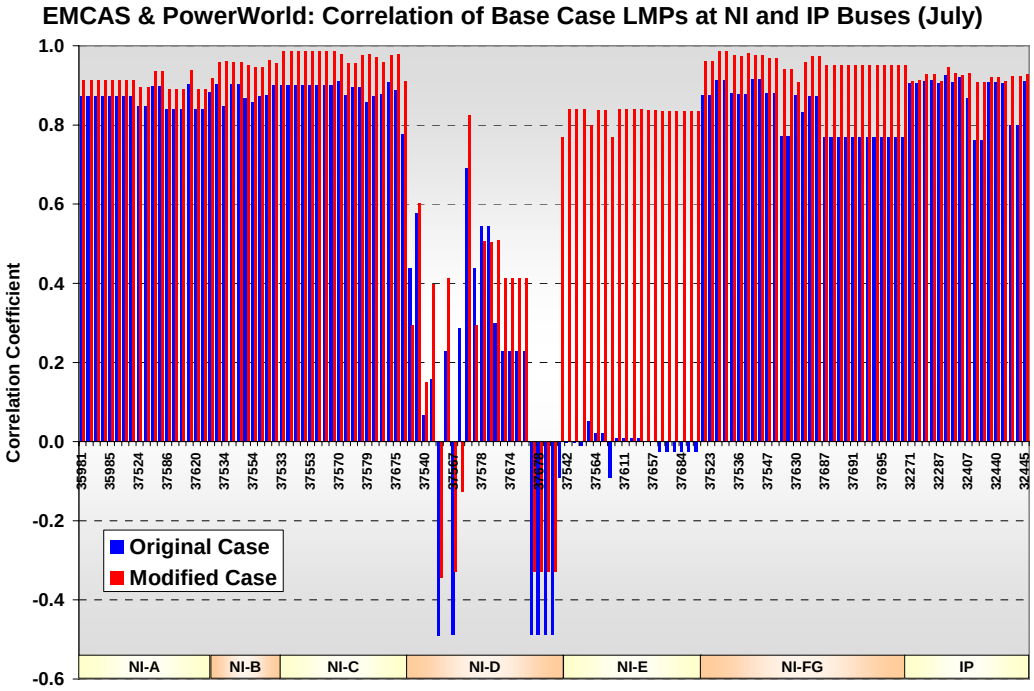

Figure C-7 Correlations between EMCAS and PowerWorld Results (July)

APPENDIX D
MODELING OF OUT-OF-STATE GENERATION AND LOAD

This appendix contains information on the modeling of generation capacity and electric loads in the areas outside of Illinois. In the EMCAS model, the representation of generation capacity and loads outside of Illinois was simplified. While all generating units operating within Illinois were modeled individually, out-of-state generation was modeled using aggregate production cost curves. These production cost curves, or so-called supply curves, represent generating units independent of ownership and show the cost of electricity generation as a function of the total power output. The electricity generation cost from out-of-state suppliers can be directly determined from the production cost curve as a value that corresponds to the level of power output.

The equivalent network of out-of-state areas (see Section 3.3 of the main report) included a number of control areas ranging from the Northern States Power Company (NSP – now Xcel Energy) in the northwest, to the Associated Electric Cooperative (AECI) in the southwest, to the Tennessee Valley Authority (TVA) in the southeast, to the Consumers Energy (CSU) and American Electric Power (AEP) areas in the east, and all of the large Wisconsin utilities in the north. A total of 24 out-of-state generation companies and their corresponding supply curves were included in the EMCAS simulation. The names and abbreviations of out-of-state generation companies are as follows:

1.	AECI	Associated Electric Cooperative
2.	AEP	American Electric Power
3.	ALTE	Alliant Energy (East)
4.	ALTW	Alliant Energy (West)
5.	Ameren-Out	Ameren (areas outside of Illinois)
6.	BREC	Big Rivers Electric Corporation
7.	CIN	Cinergy Corporation
8.	CONS	Consumers Energy
9.	DPC	Dairyland Power Cooperative
10.	DPL	Dayton Power & Light
11.	HE	Hoosier Energy
12.	IPL	Indianapolis Power & Light Company
13.	LGEE	LG&E Energy
14.	MEC	MidAmerican Energy Company
15.	MGE	Madison Gas and Electric Company
16.	MPW	Muscatine Power and Water
17.	NIPS	Northern Indiana Public Service Company
18.	NSP	Northern States Power Company (Xcel Energy)
19.	OVEC	Ohio Valley Electric Corporation
20.	SIGE	Southern Indiana Gas & Electric Company
21.	TVA	Tennessee Valley Authority
22.	UPPC	Upper Peninsula Power Company
23.	WEC	Wisconsin Energy Corporation
24.	WPS	Wisconsin Public Service Corporation

Hourly load profiles for the analysis year for the out-of-state areas were developed based on the same FERC Form 714 projections used for the Illinois companies. The load forecasts, developed on a control area basis, were aggregated into the same nodes used for the generation

companies. Thus, each out-of-state connection point had both load and generation associated with it.

One of the assumptions for the PowerWorld and EMCAS analyses was that out-of-state companies would actively participate in the same electricity market as the in-state companies. This included both sales and purchases of electric power. For the production cost case, it was assumed that electric power in out-of-state areas was generated on a production cost basis, according to the supply curves for out-of-state generation companies. In other scenarios, out-of-state companies were allowed to deviate from the production cost-based bidding and, in some cases, to apply strategic bidding.

In principle, an excess of available power in the out-of-state areas could be offered and sold in the Illinois electricity market if the price was lower than that of other competitors. In the same manner, the out-of-state demand companies were allowed to purchase power from the Illinois market if the price was lower than what was available from other sources. In both cases, the constraints imposed by the available transfer capabilities of transmission lines connecting Illinois with the out-of-state areas were strictly observed.

The following figures show the generation supply curves and the hourly load curves used for each of the out-of-state areas.

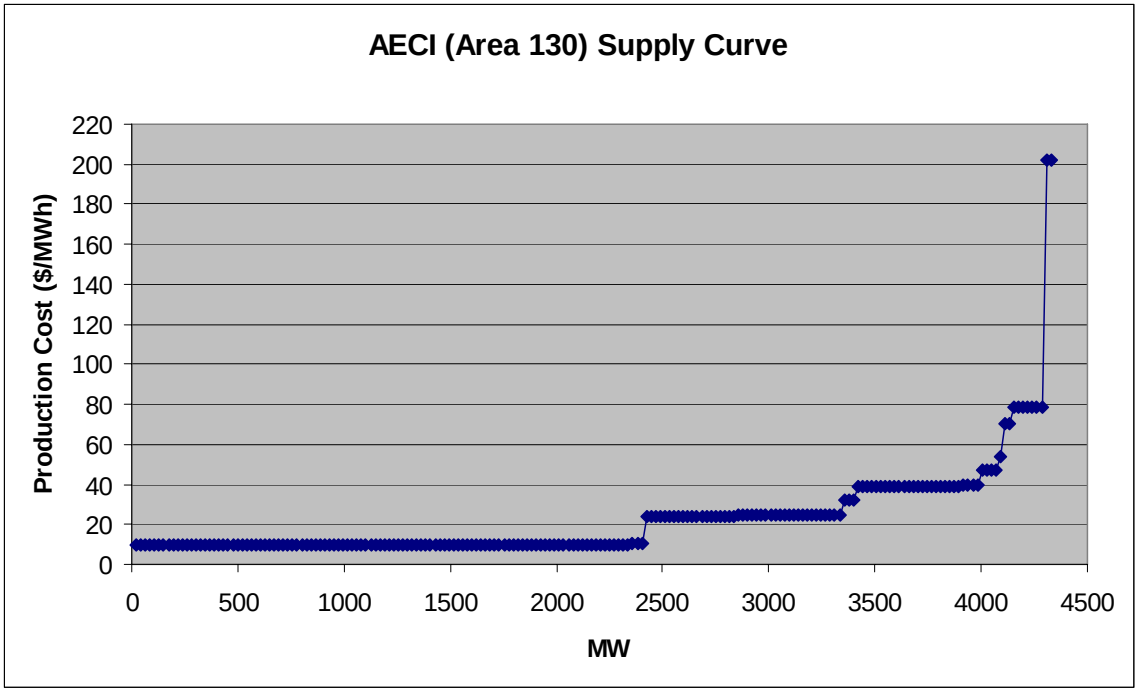

Figure D-1 AECI Generation Supply Curve

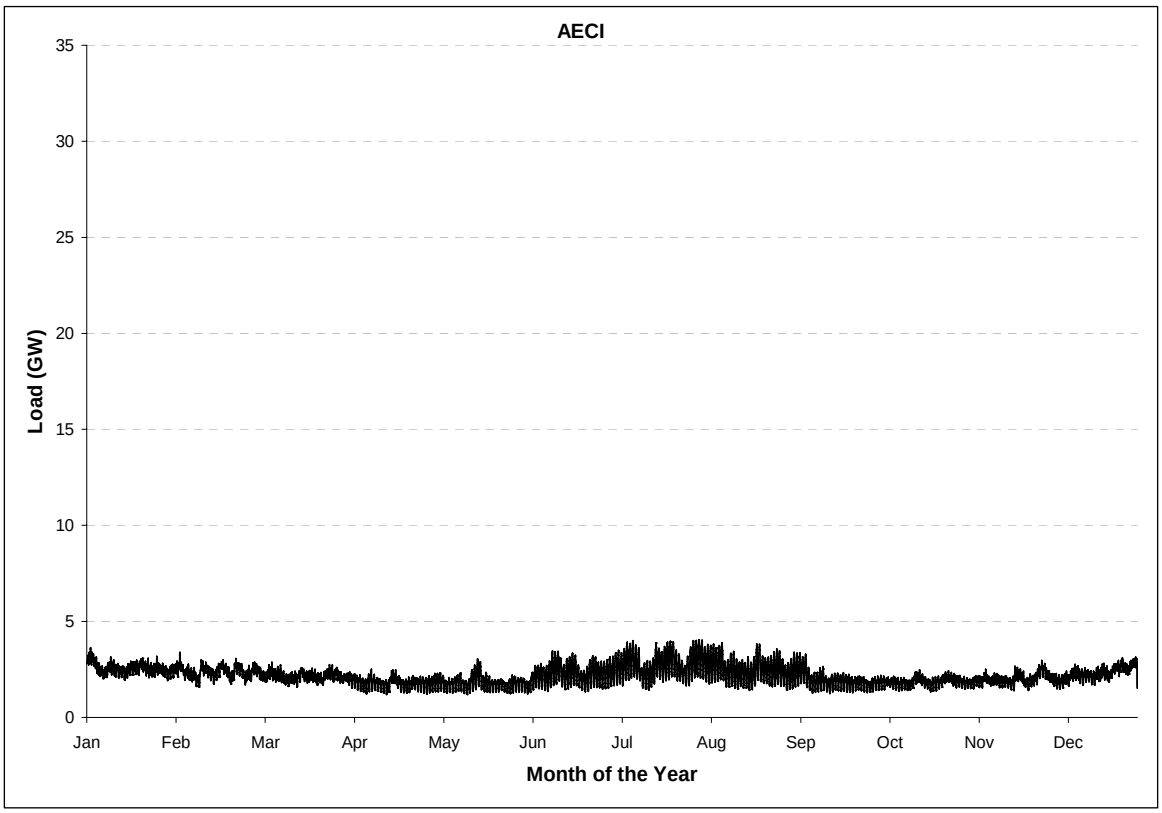

Figure D-2 AECI Load Curve

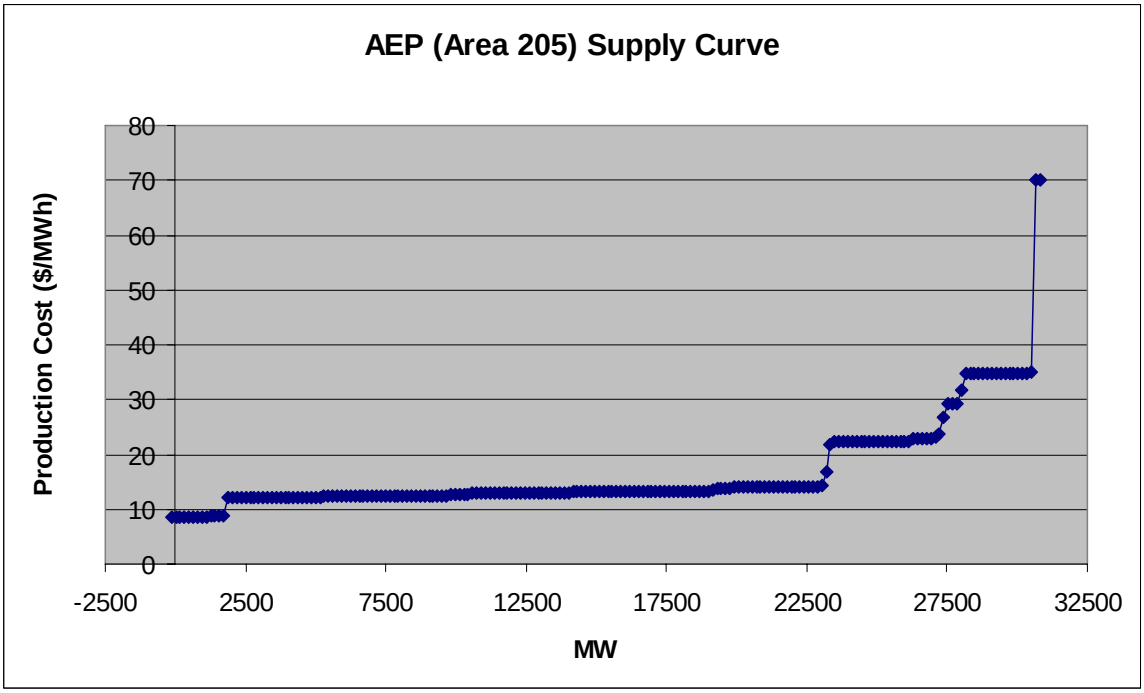

Figure D-3 AEP Generation Supply Curve

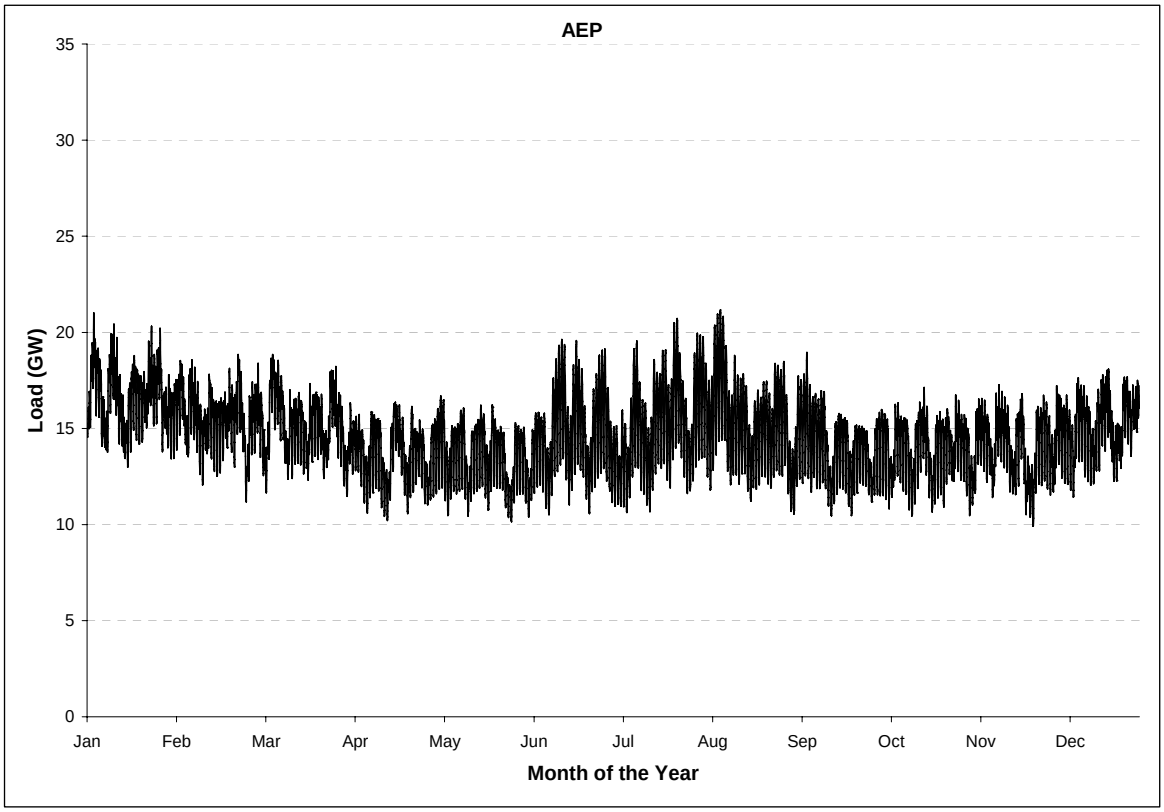

Figure D-4 AEP Load Curve

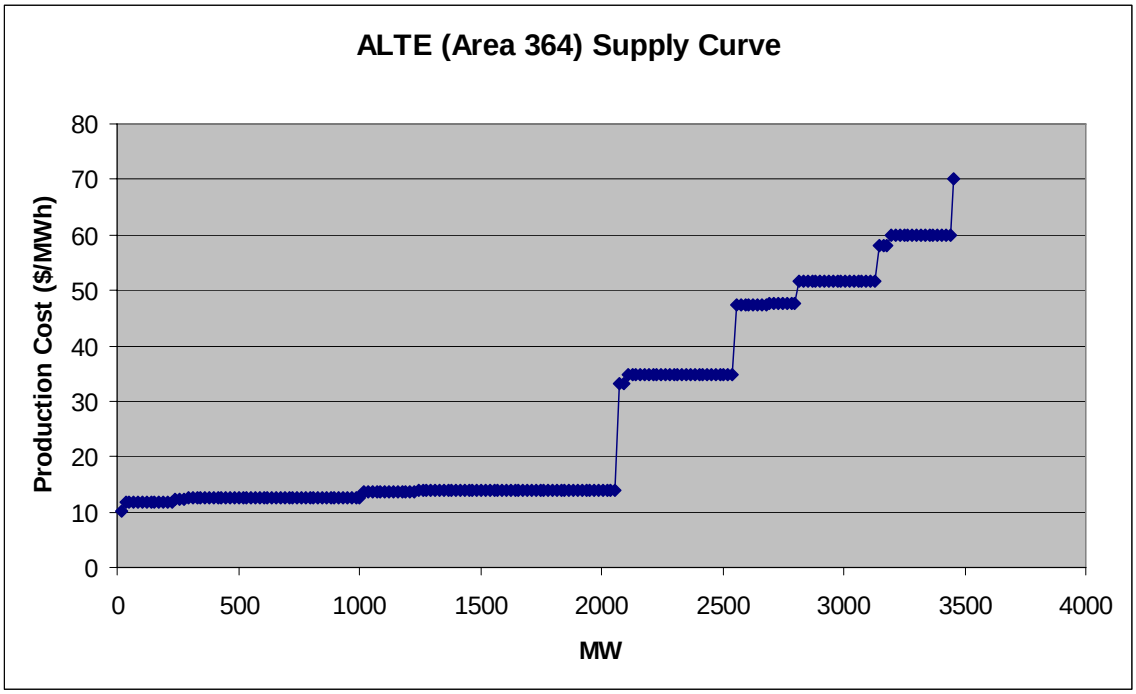

Figure D-5 ALTE Generation Supply Curve

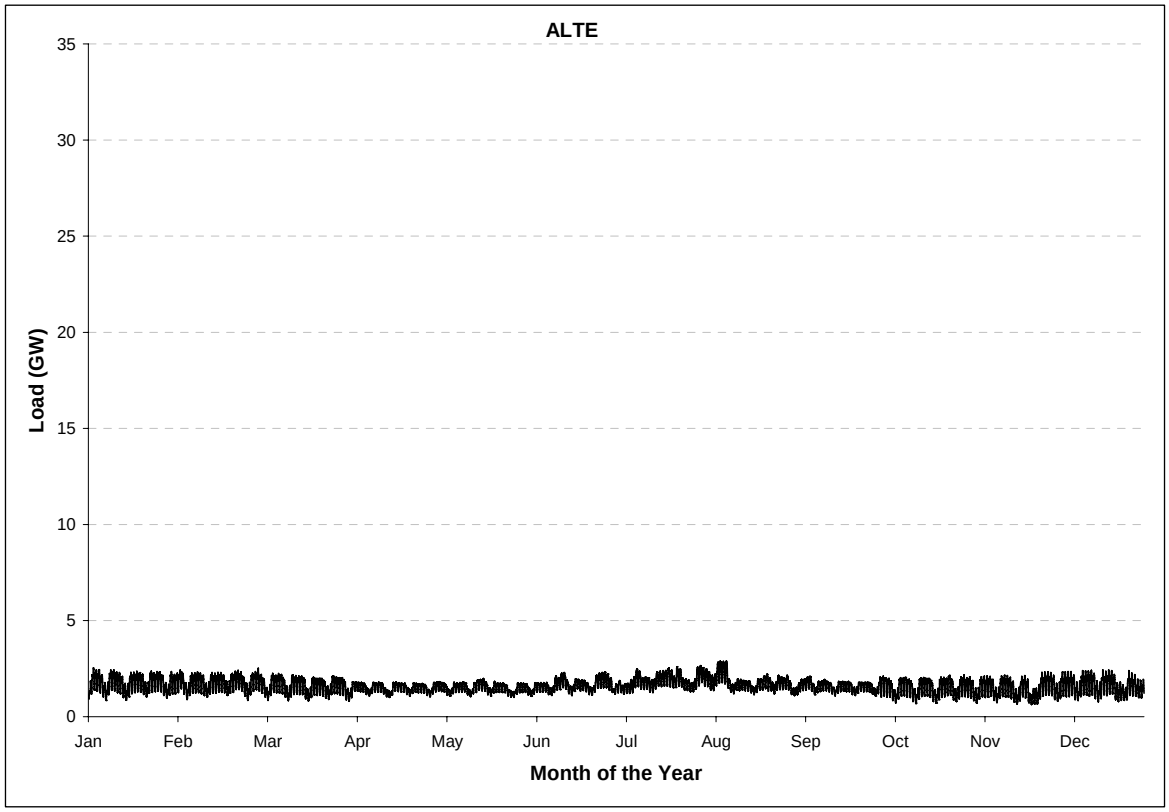

Figure D-6 ALTE Load Curve

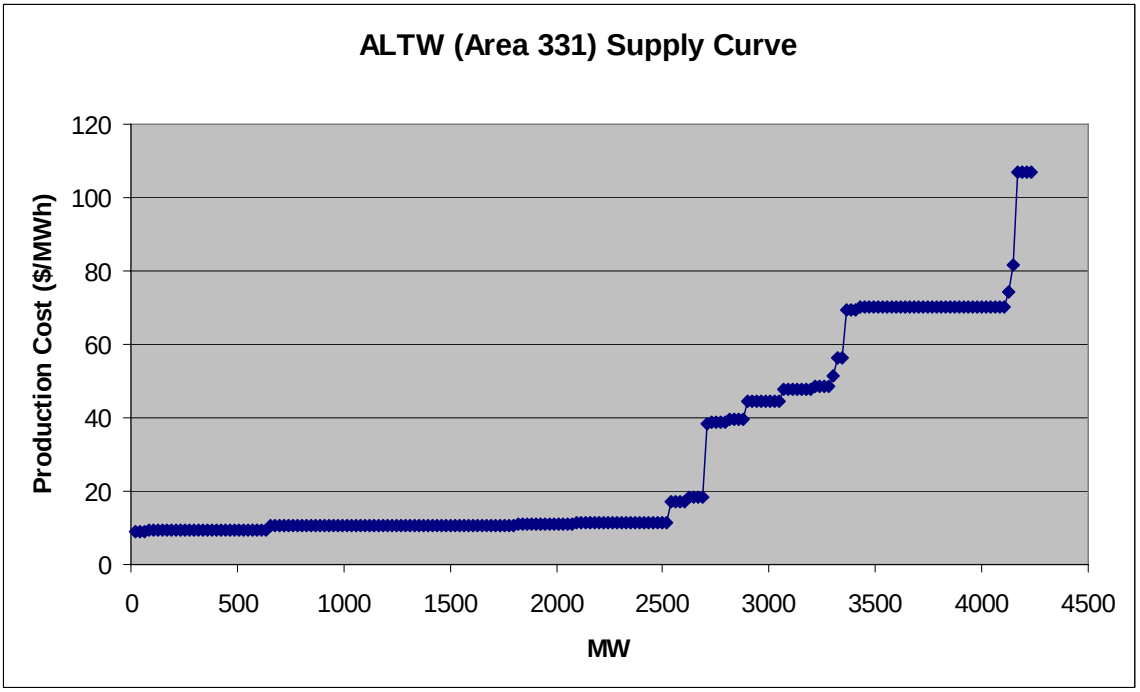

Figure D-7 ALTW Generation Supply Curve

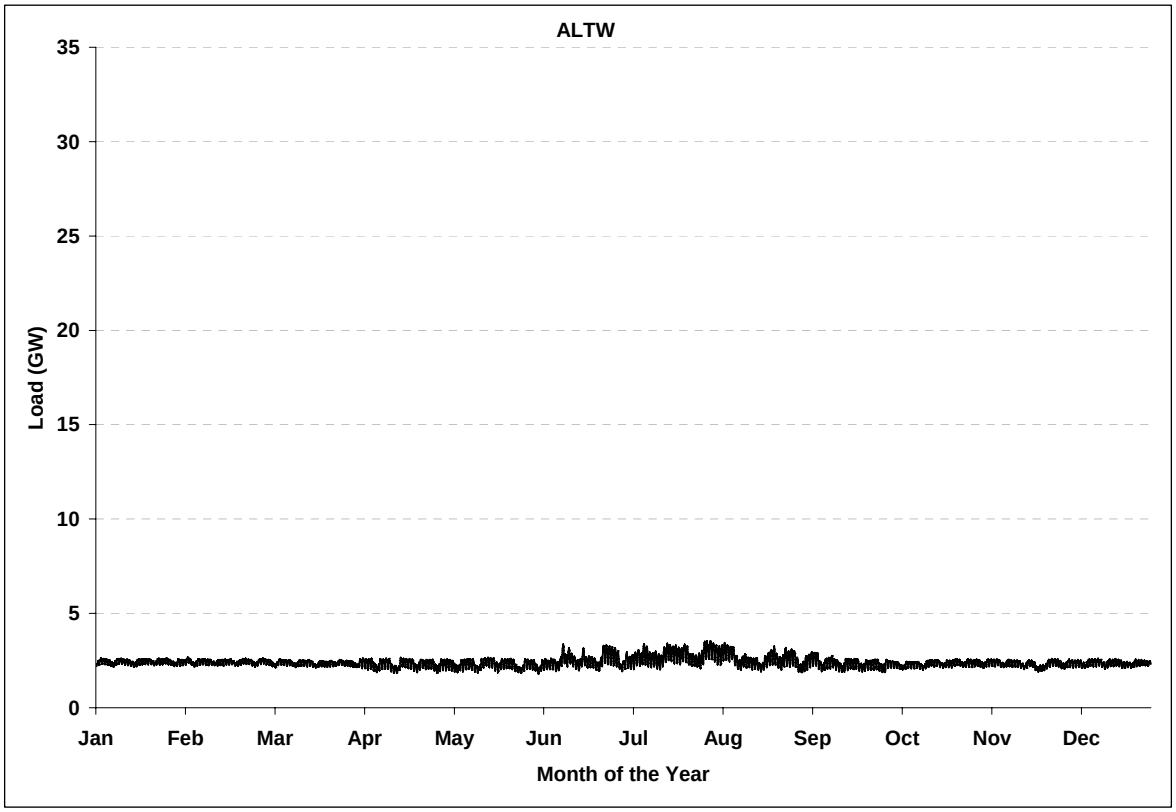

Figure D-8 ALTW Load Curve

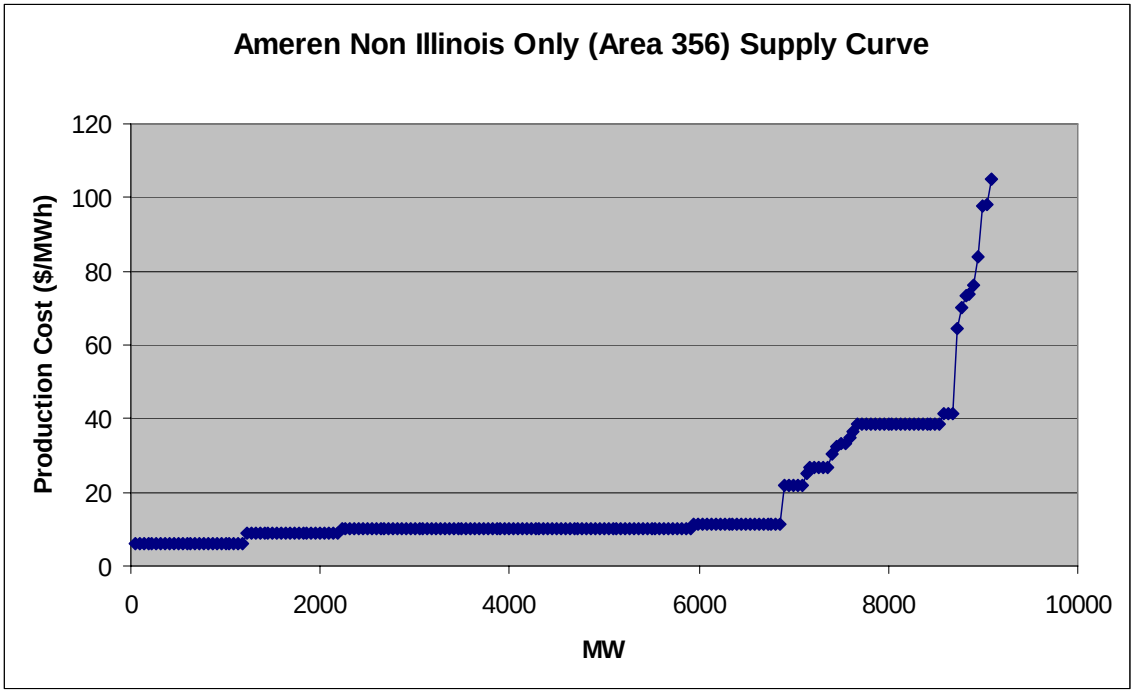

Figure D-9 Ameren Out Generation Supply Curve

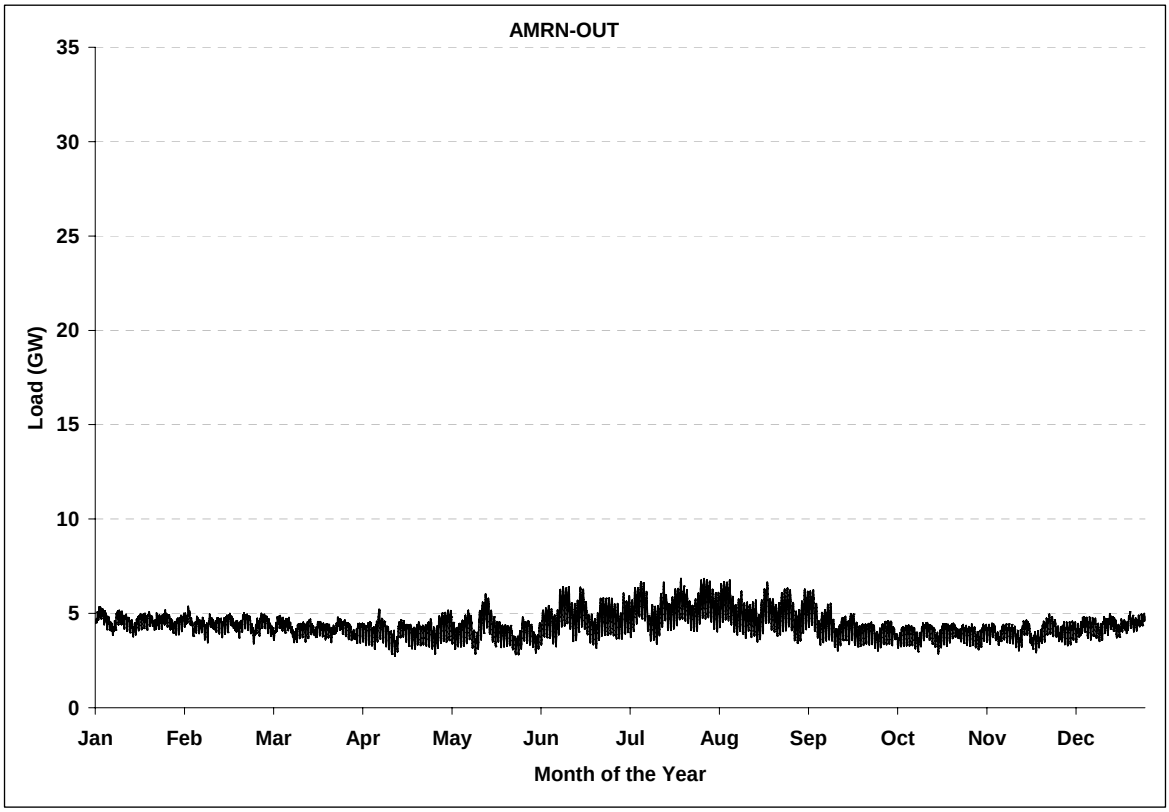

Figure D-10 Ameren Out Load Curve

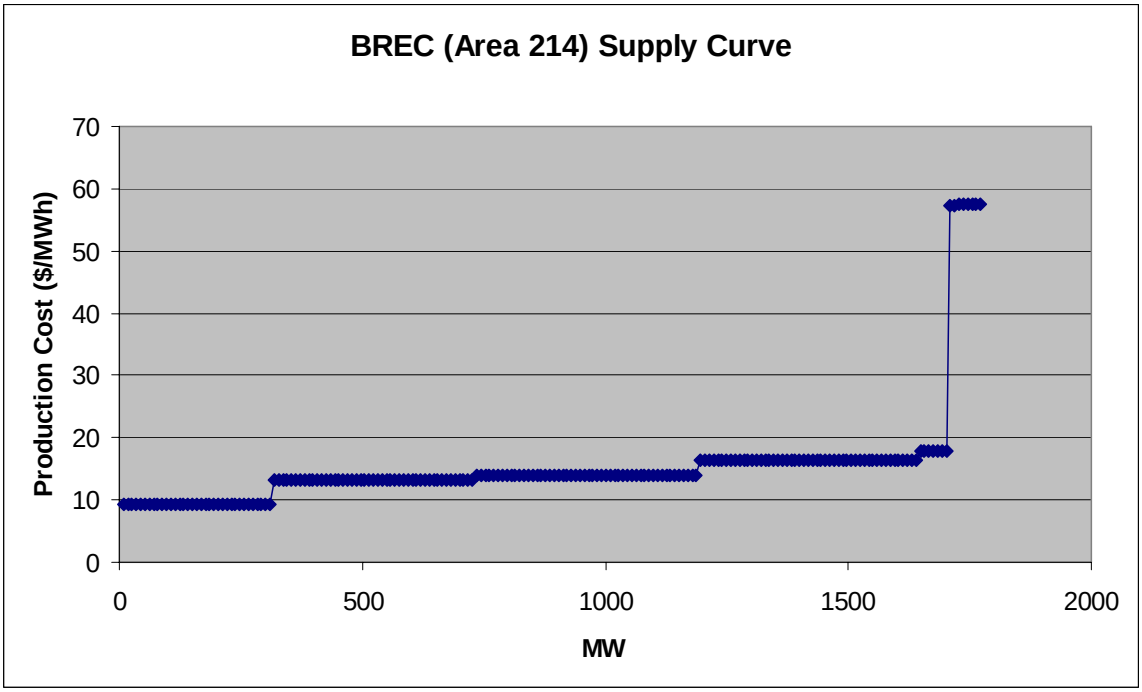

Figure D-11 BREC Generation Supply Curve

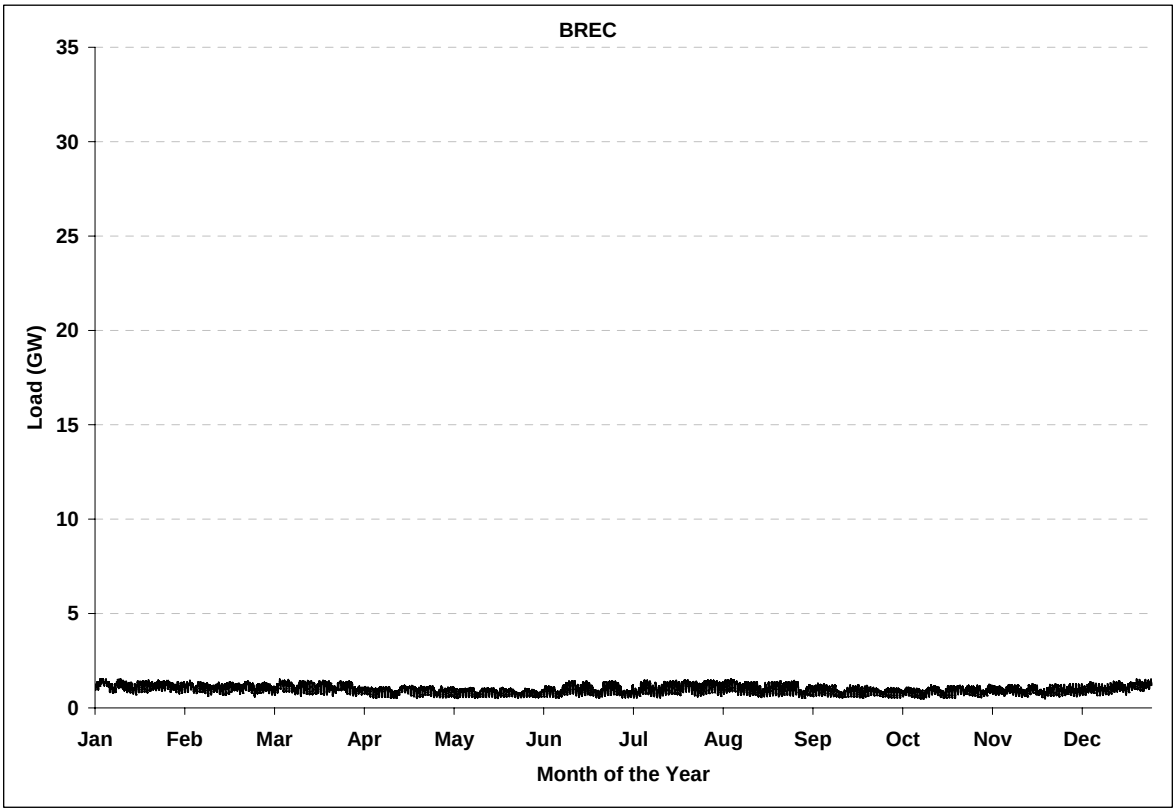

Figure D-12 BREC Load Curve

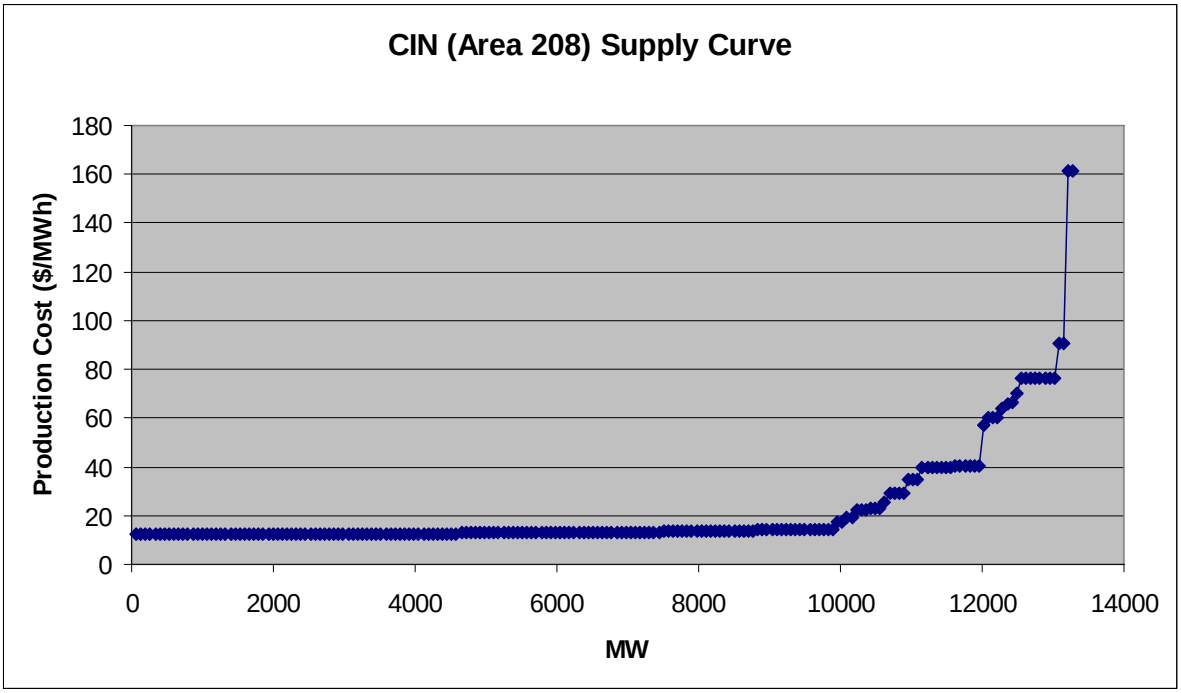

Figure D-13 CIN Generation Supply Curve

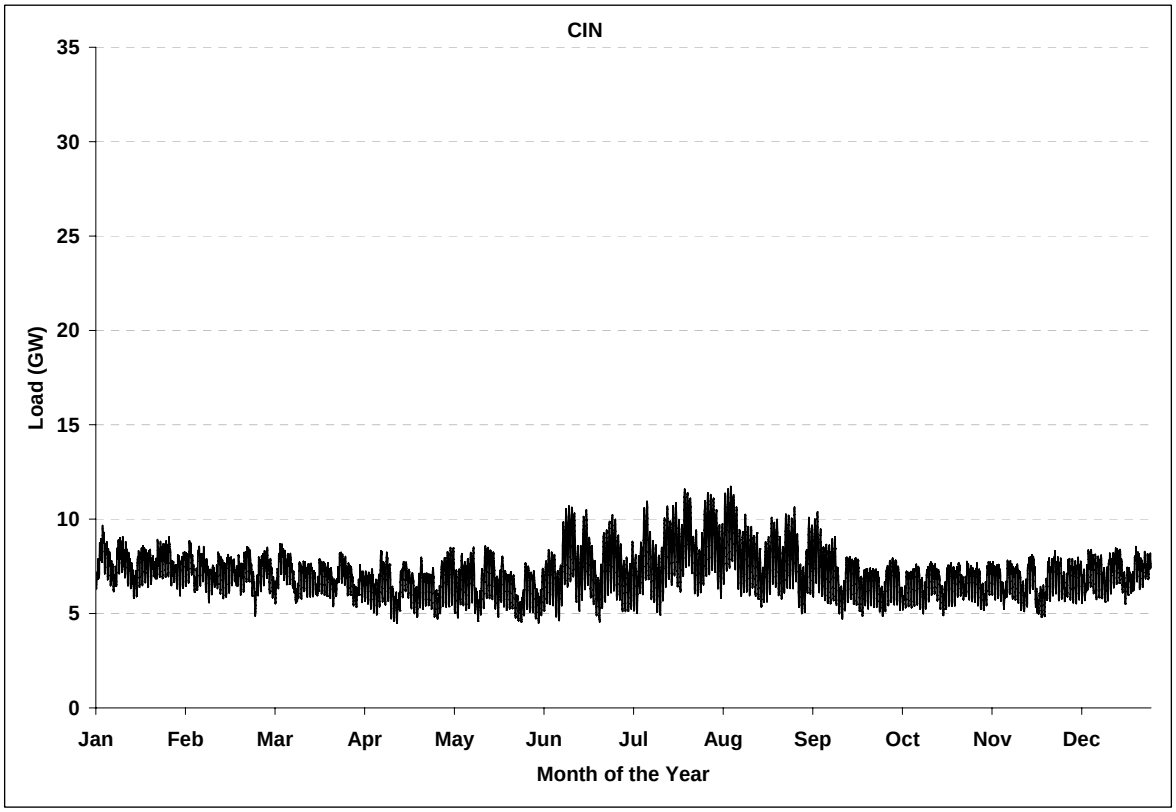

Figure D-14 CIN Load Curve

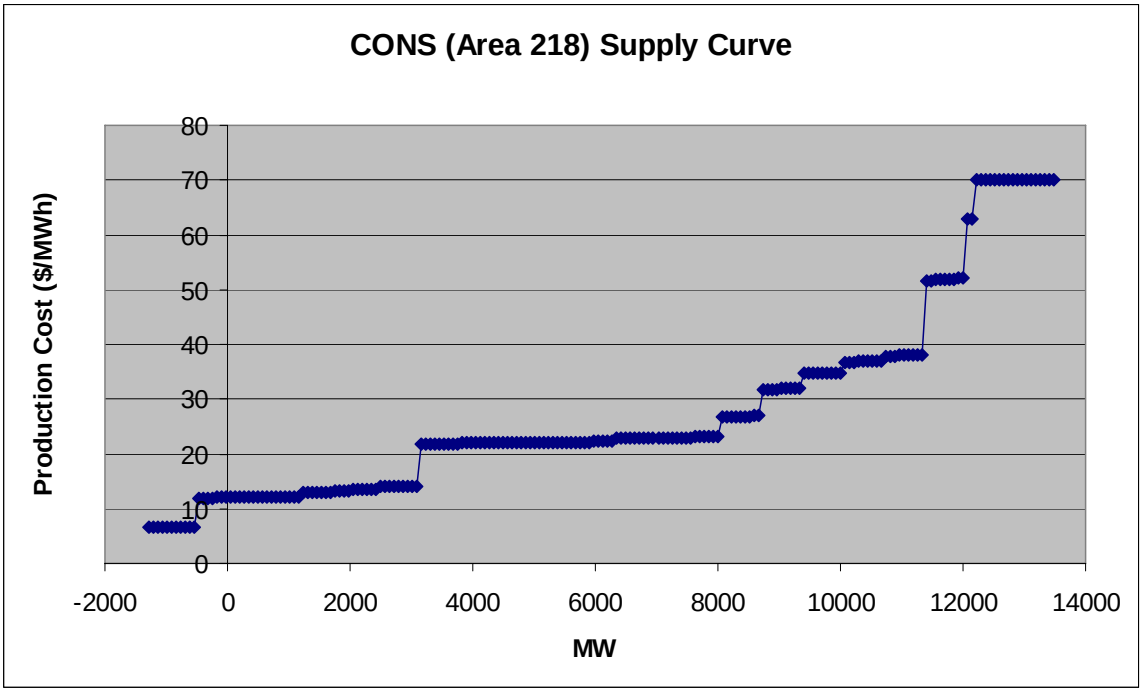

Figure D-15 CONS Generation Supply Curve

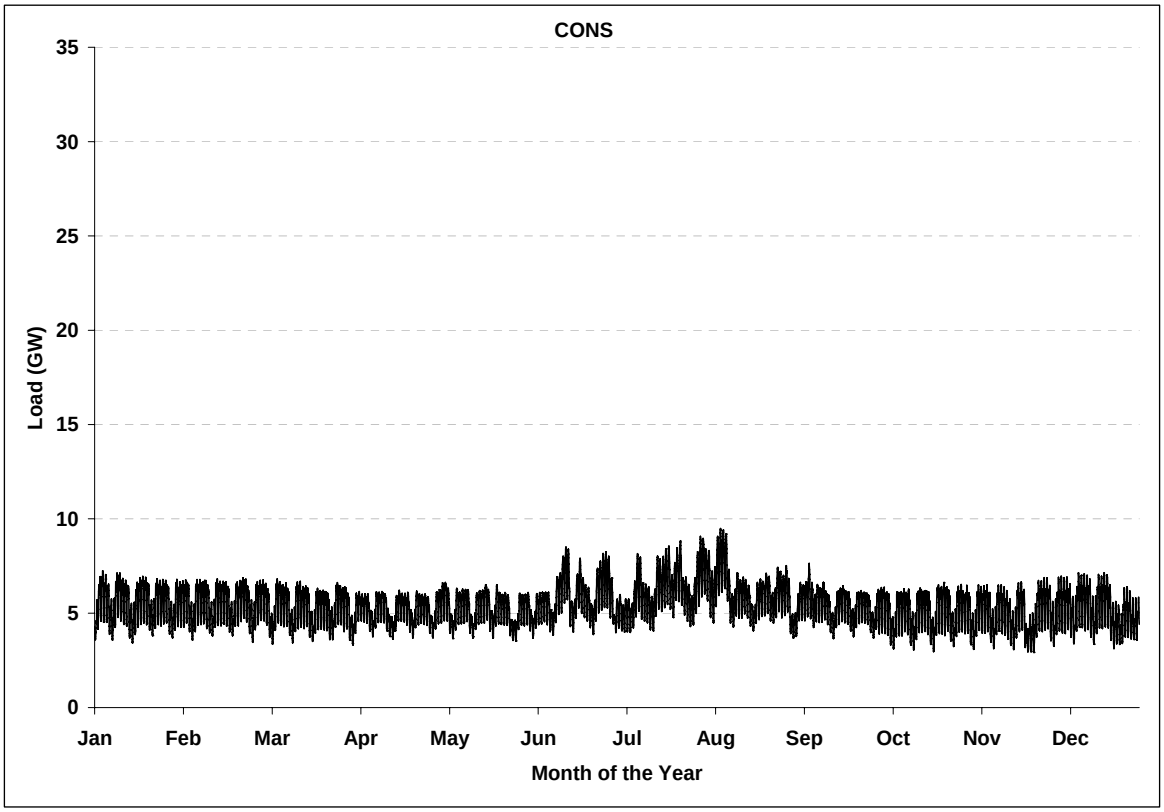

Figure D-16 CONS Load Curve

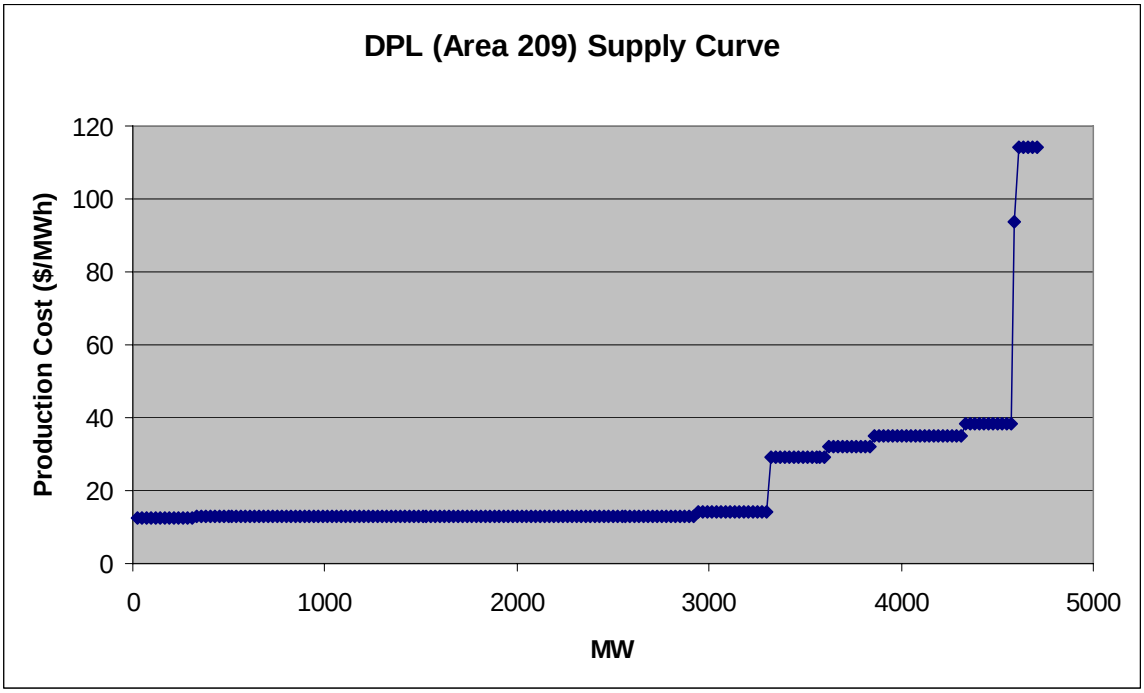

Figure D-17 DPL Generation Supply Curve

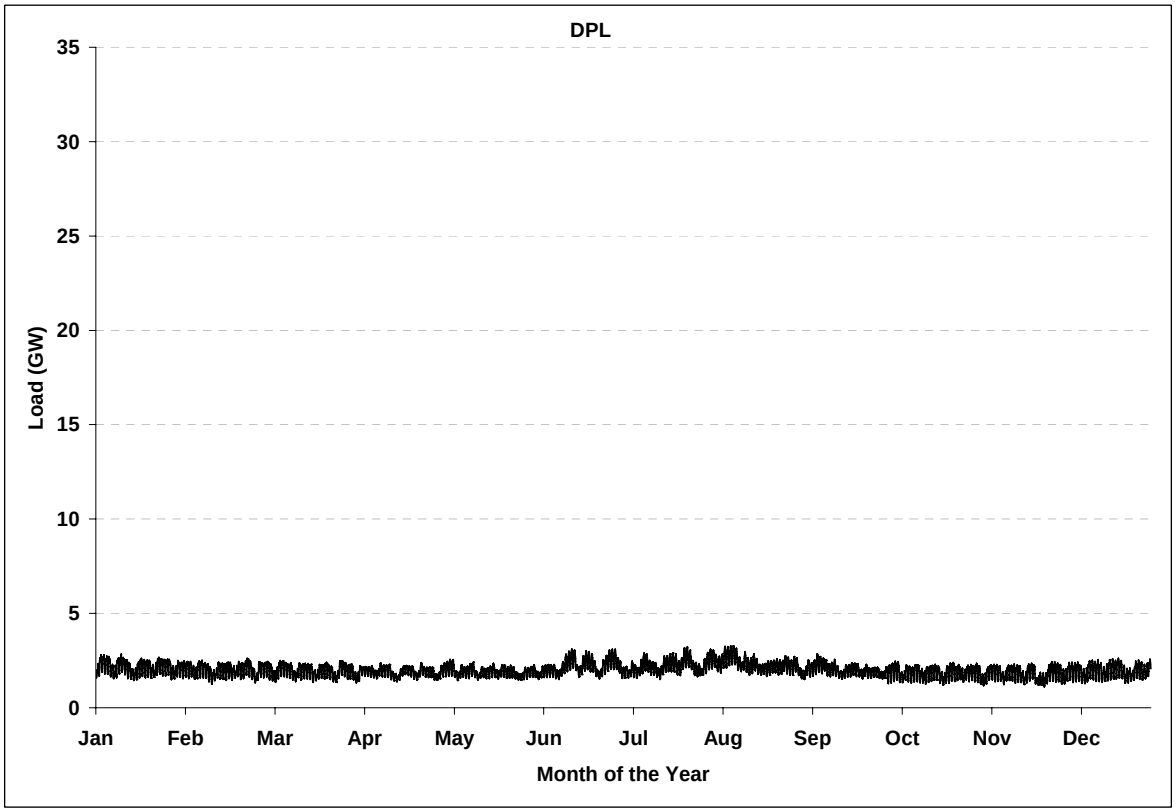

Figure D-18 DPL Load Curve

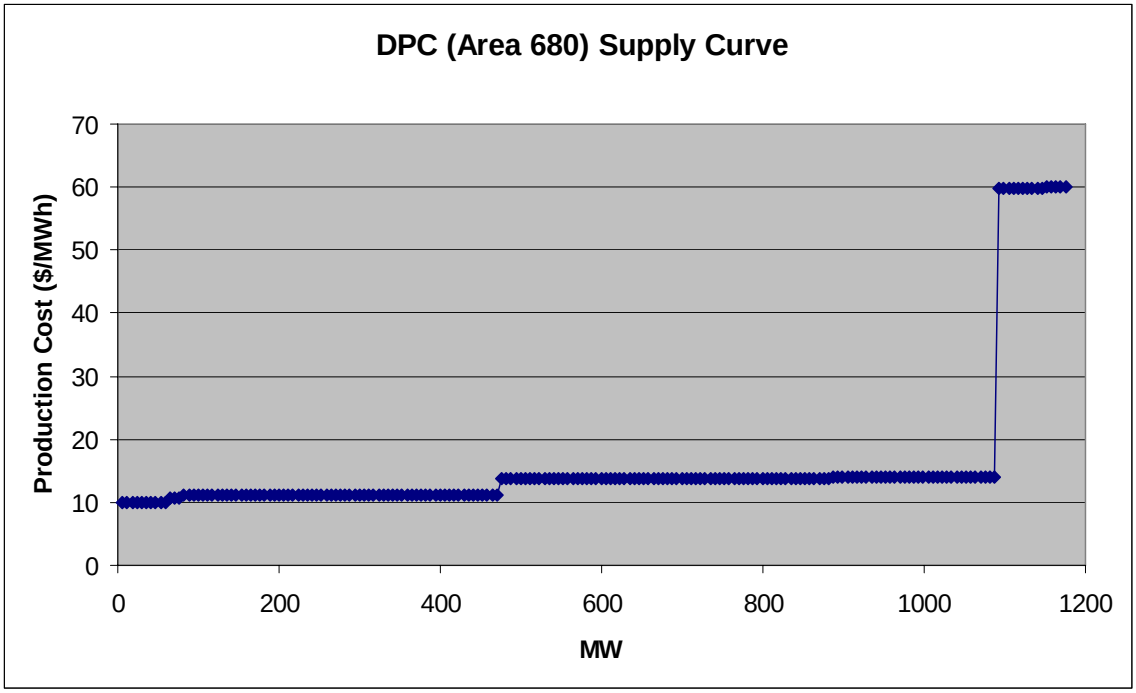

Figure D-19 DPC Generation Supply Curve

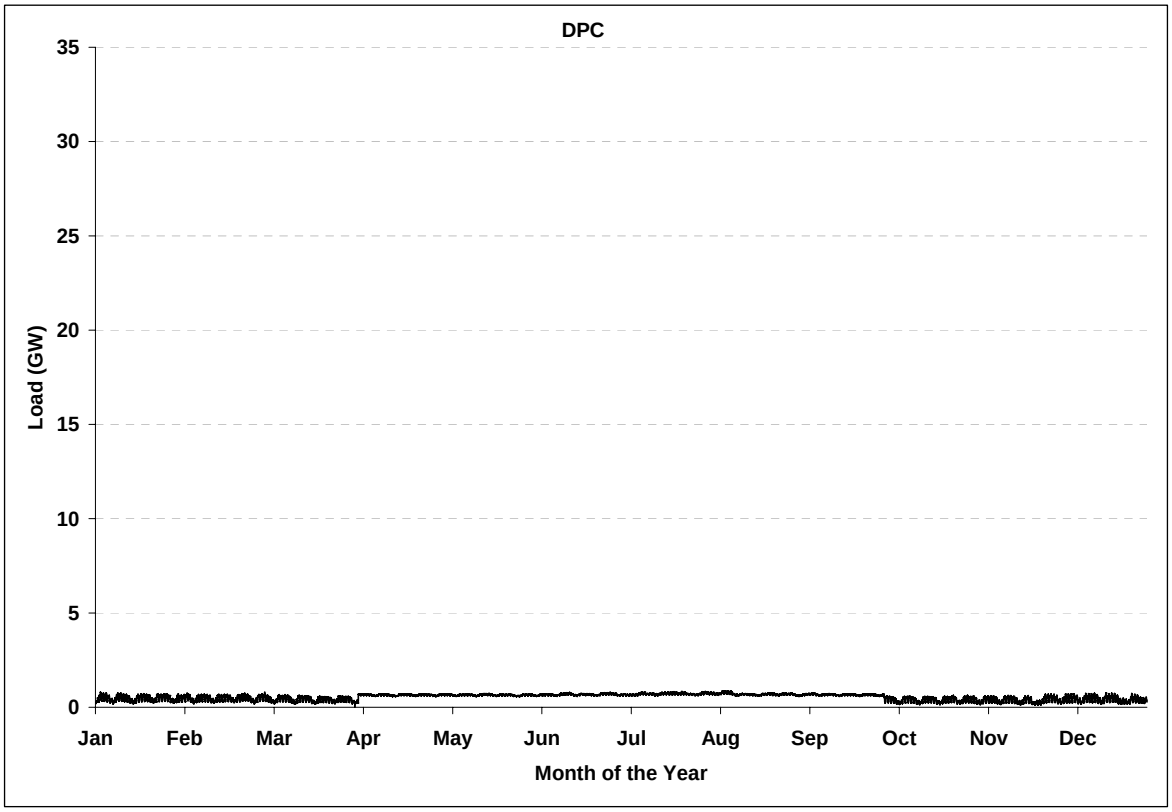

Figure D-20 DPC Load Curve

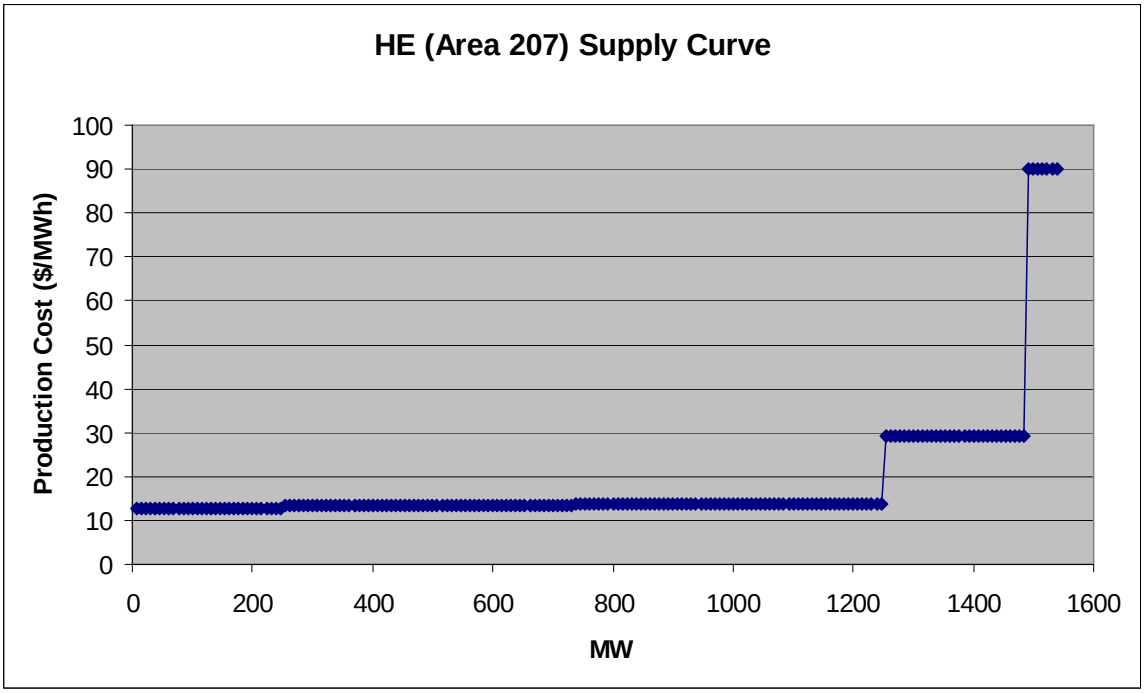

Figure D-21 HE Generation Supply Curve

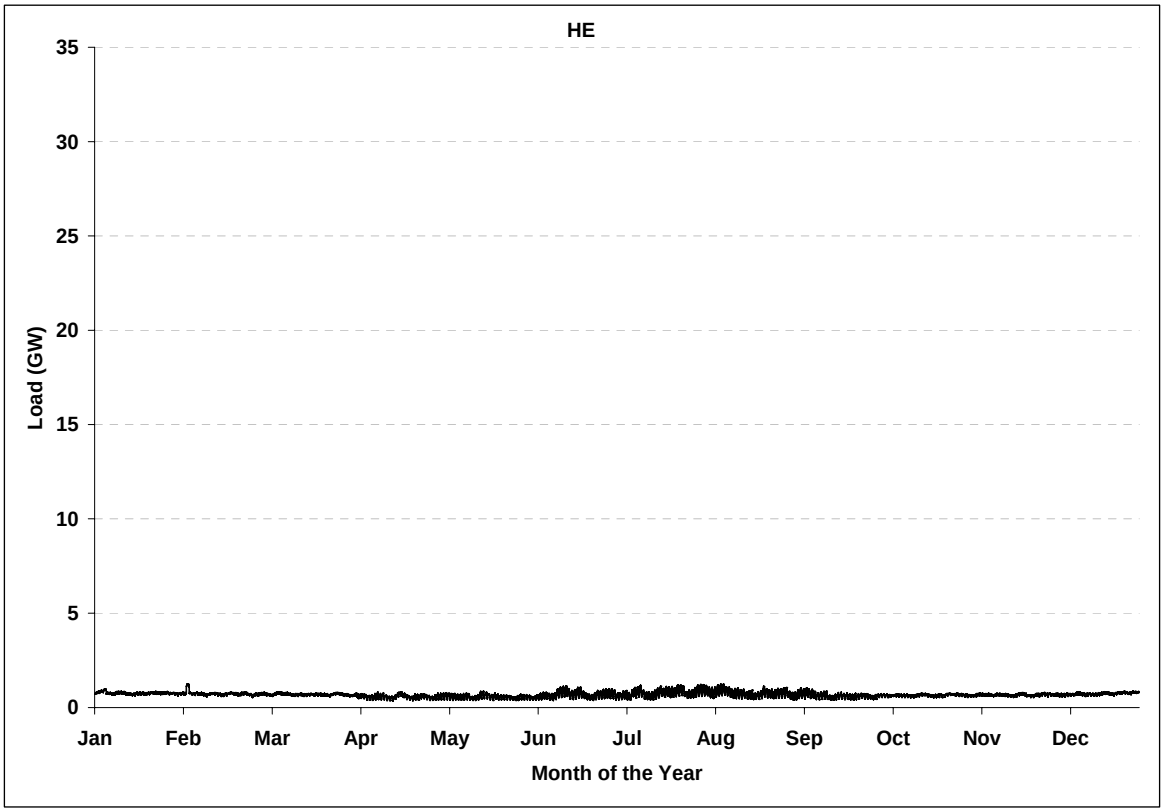

Figure D-22 HE Load Curve

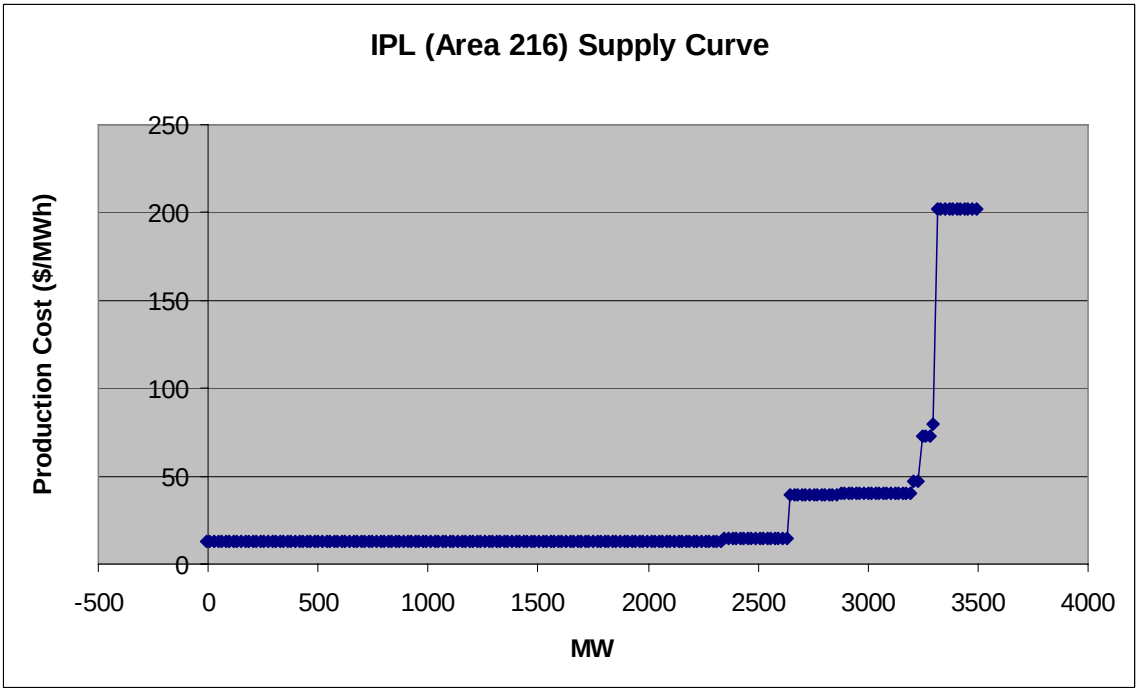

Figure D-23 IPL Generation Supply Curve

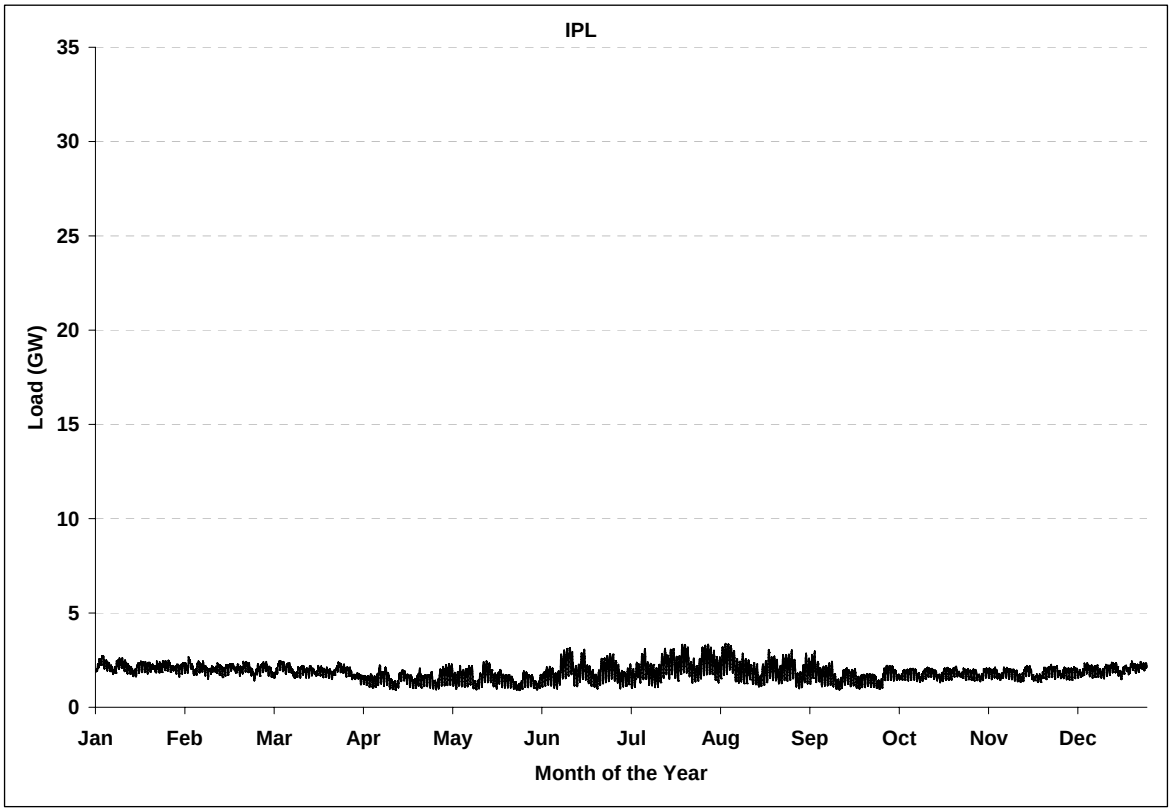

Figure D-24 IPL Load Curve

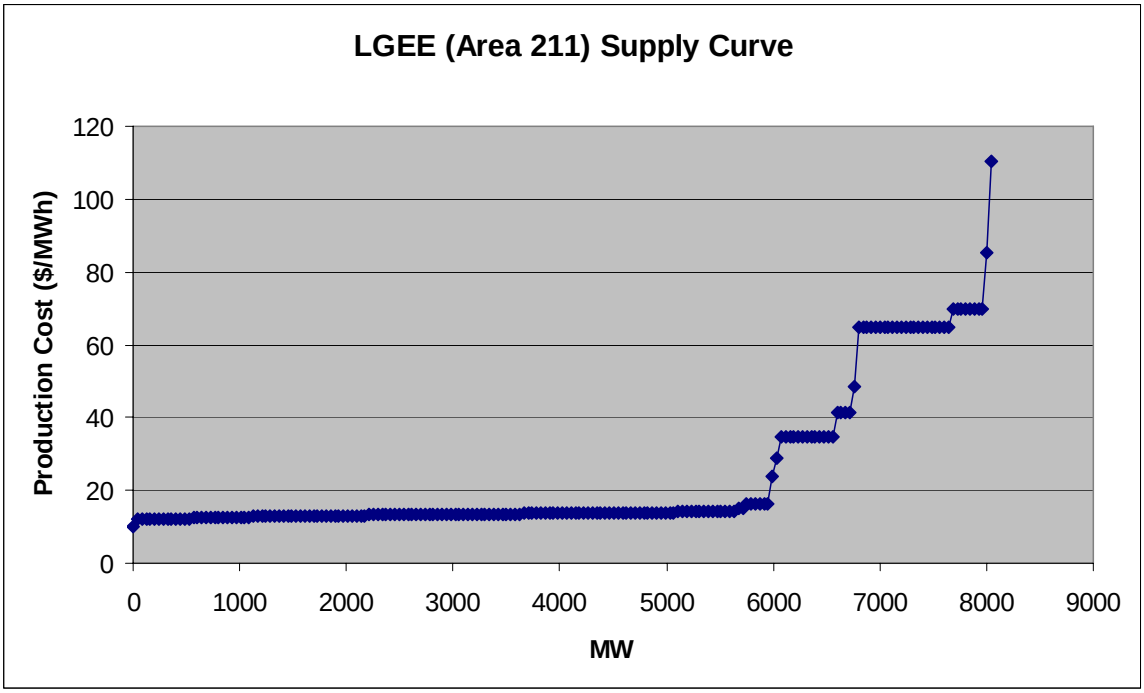

Figure D-25 LGEE Generation Supply Curve

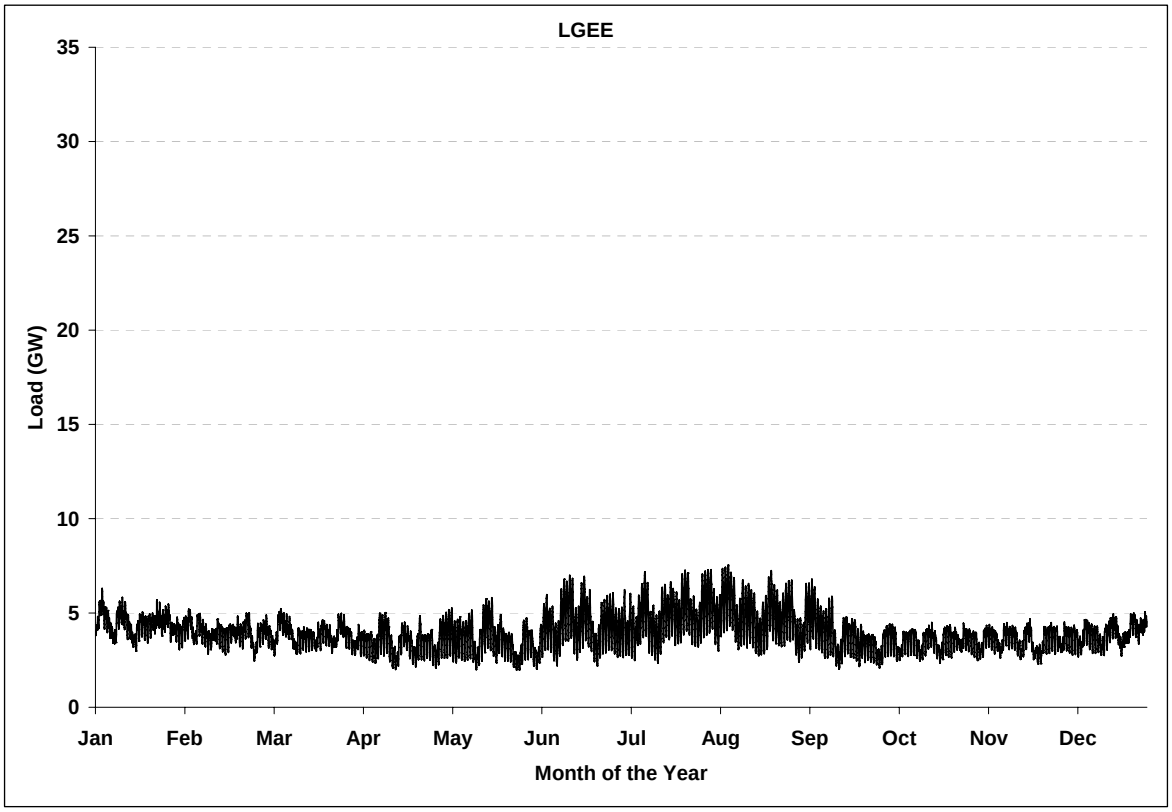

Figure D-26 LGEE Load Curve

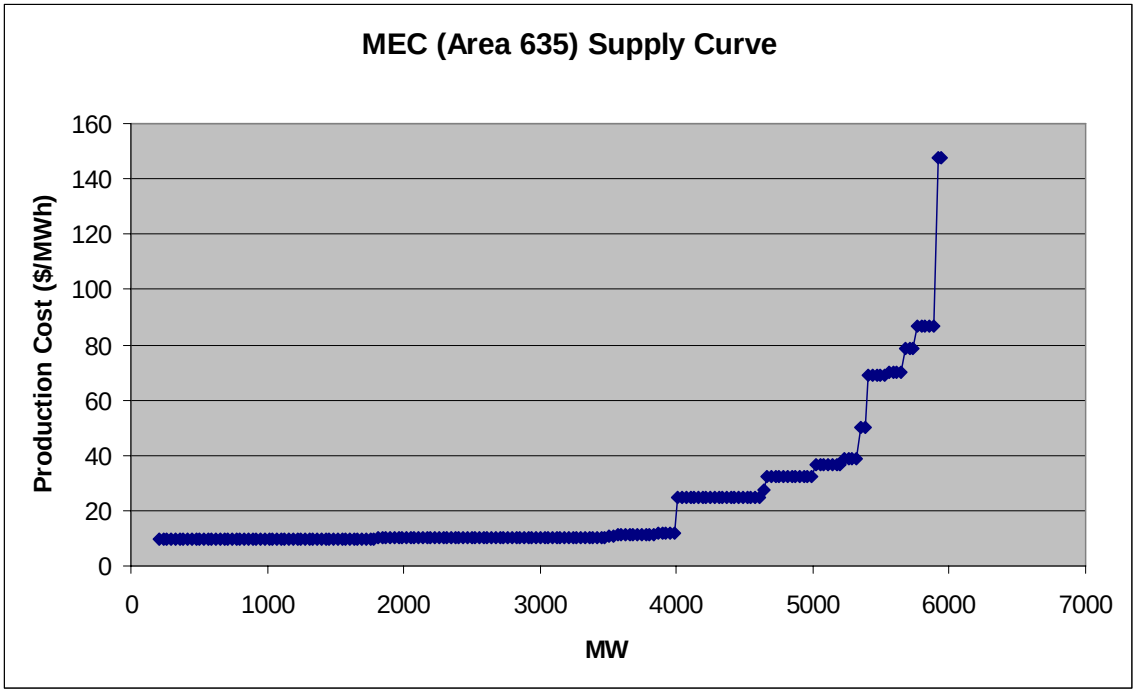

Figure D-27 MEC Generation Supply Curve

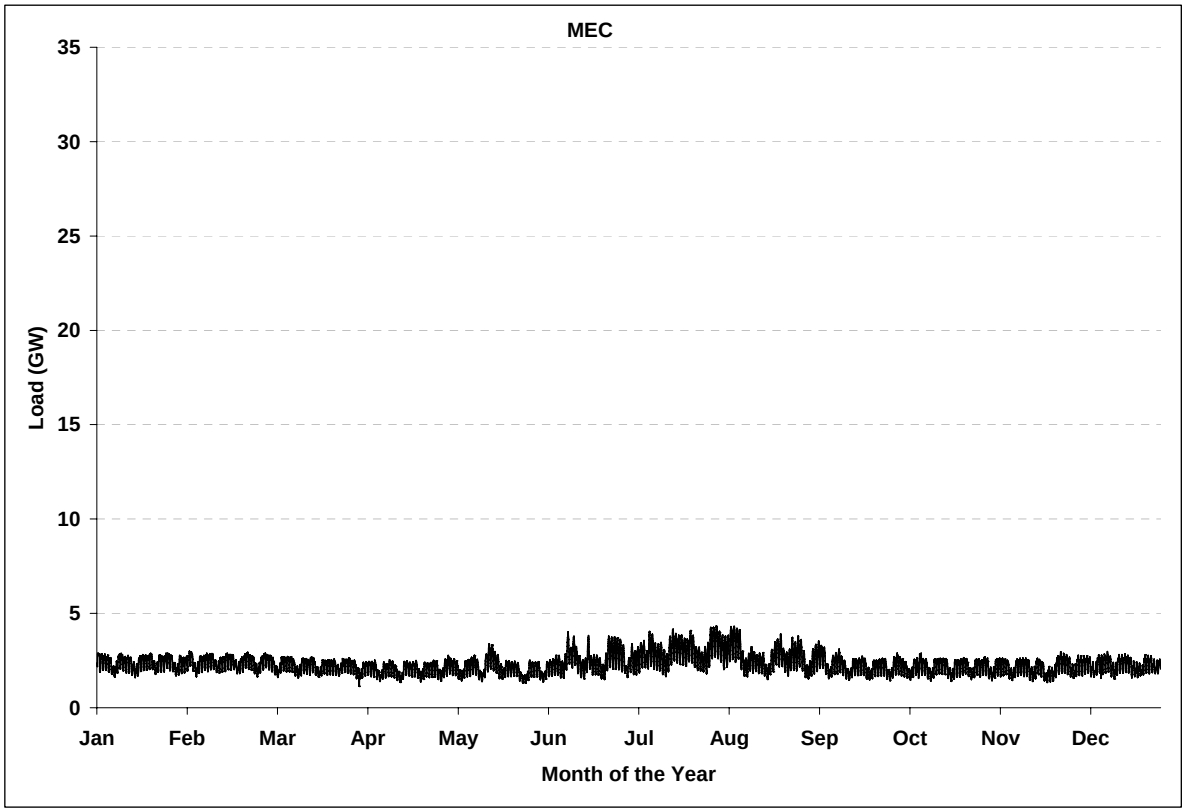

Figure D-28 MEC Load Curve

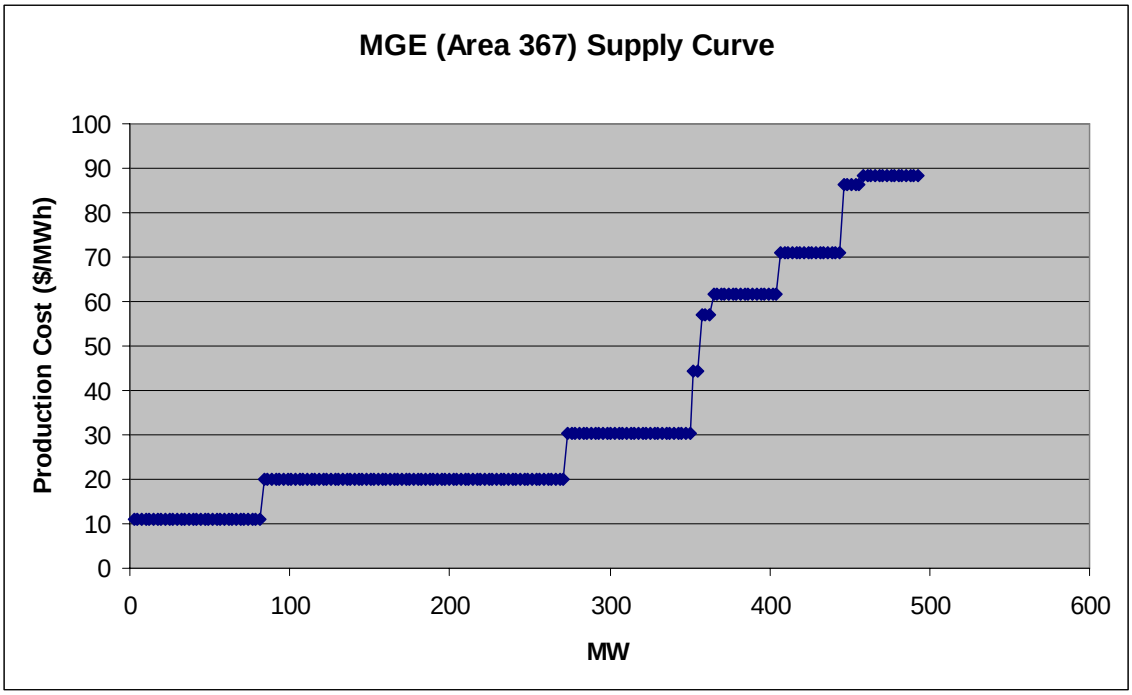

Figure D-29 MGE Generation Supply Curve

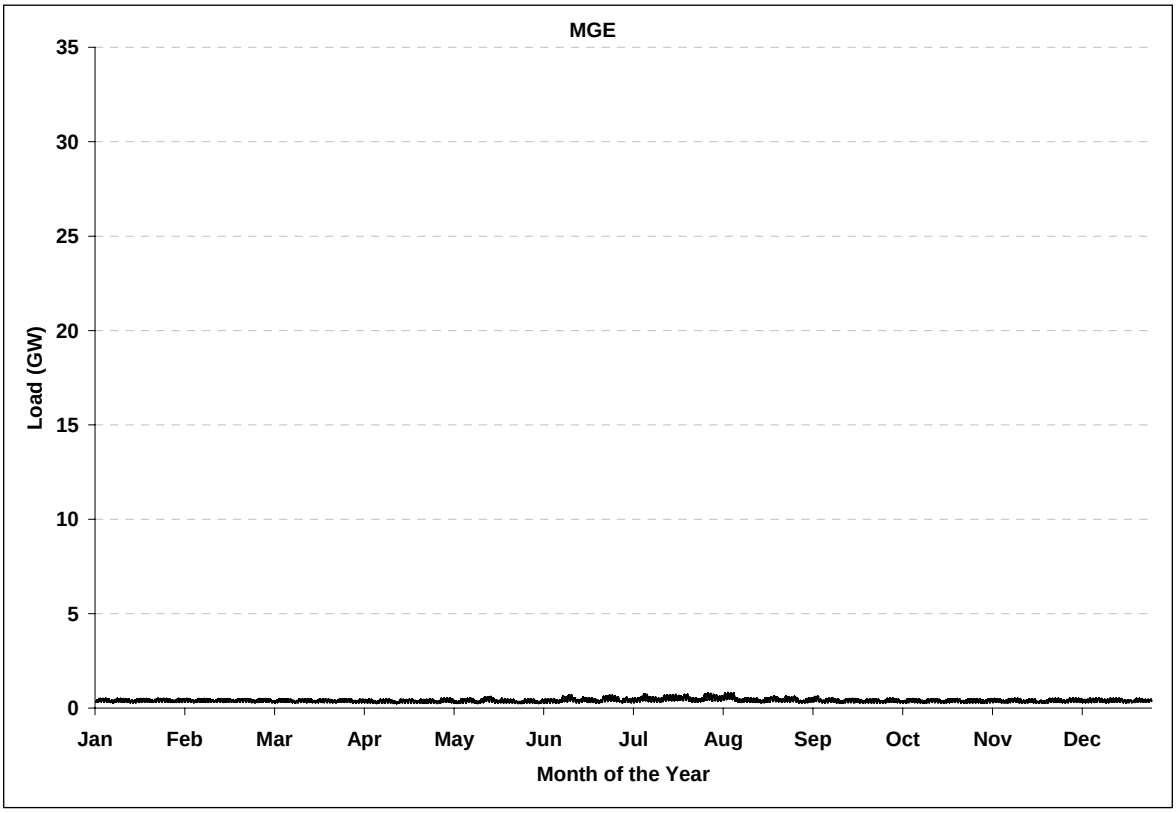

Figure D-30 MGE Load Curve

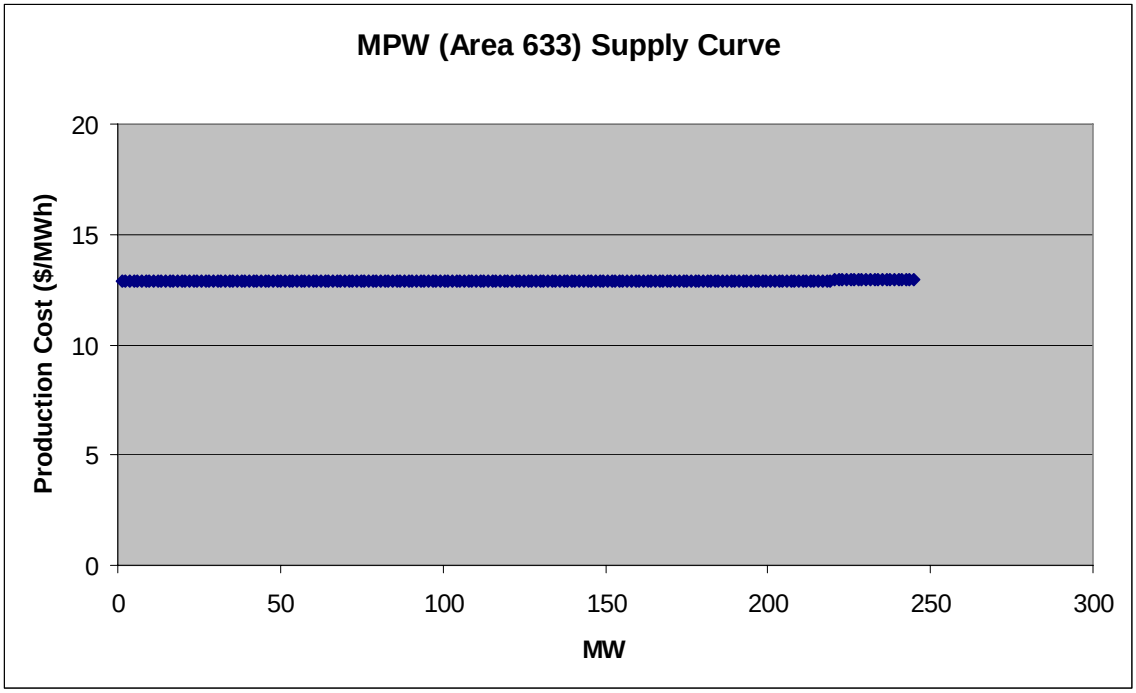

Figure D-31 MPW Generation Supply Curve

No loads projected in this area

Figure D-32 MPW Load Curve

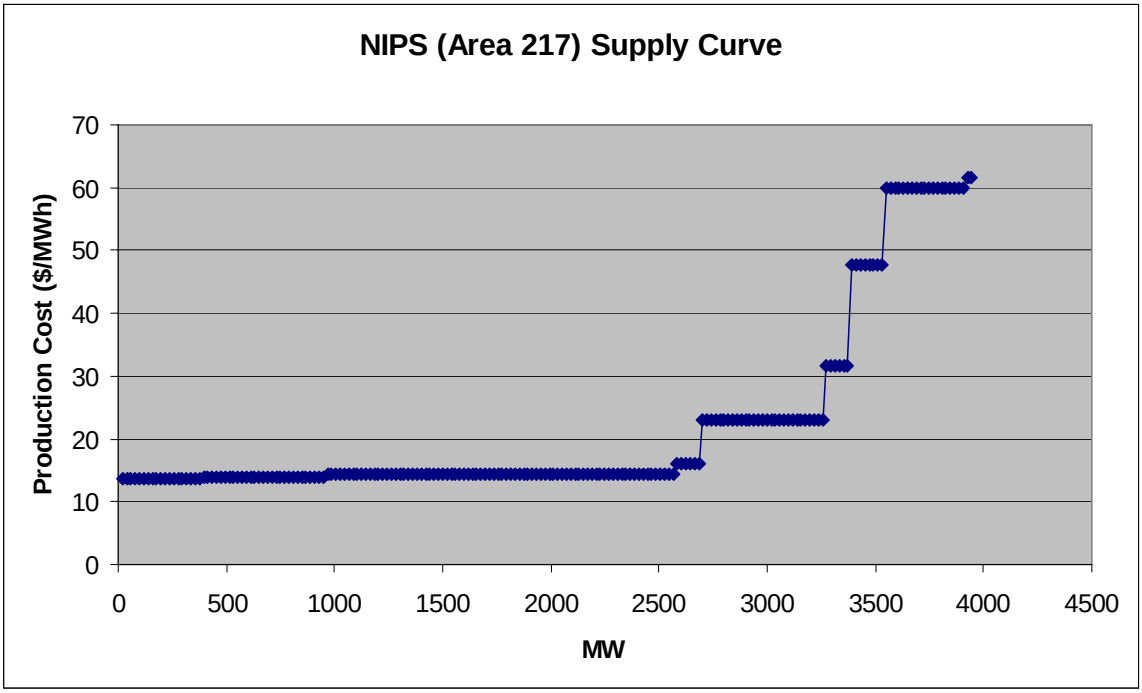

Figure D-33 NIPS Generation Supply Curve

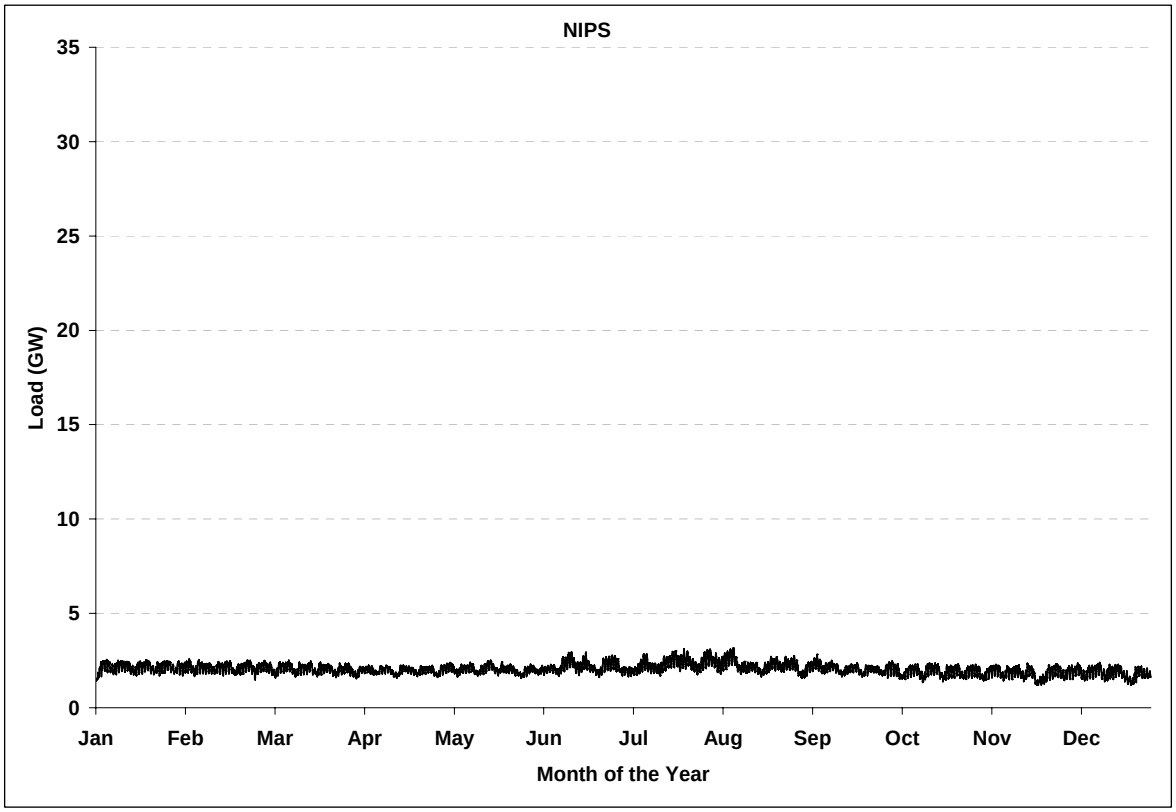

Figure D-34 NIPS Load Curve

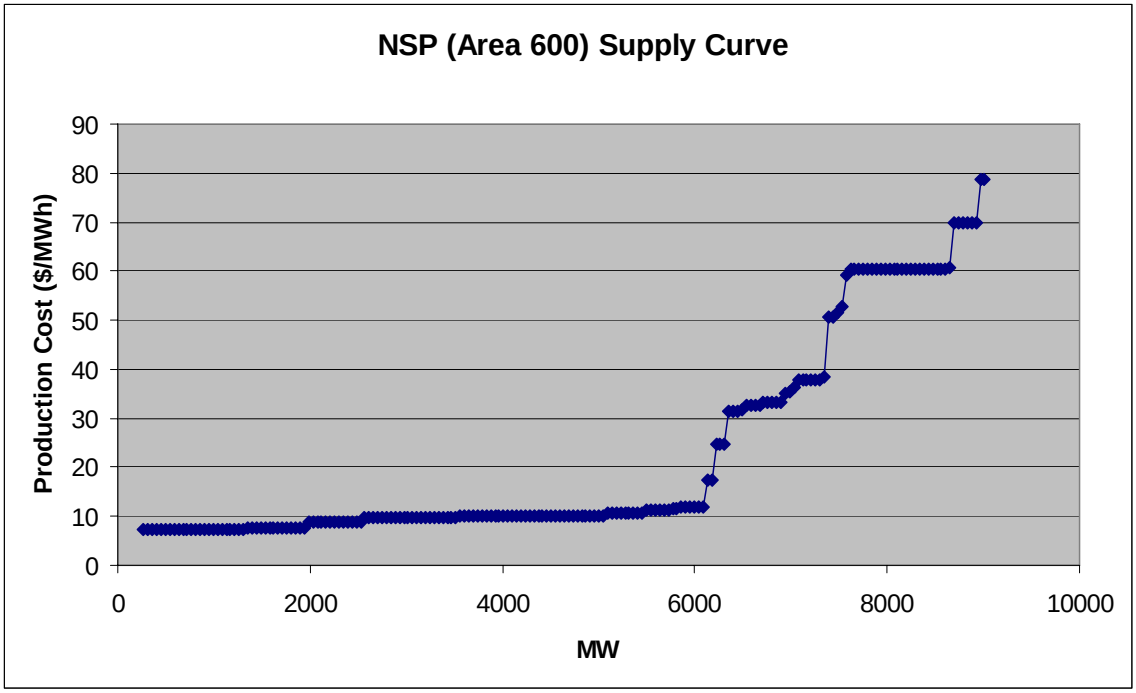

Figure D-35 NSP Generation Supply Curve

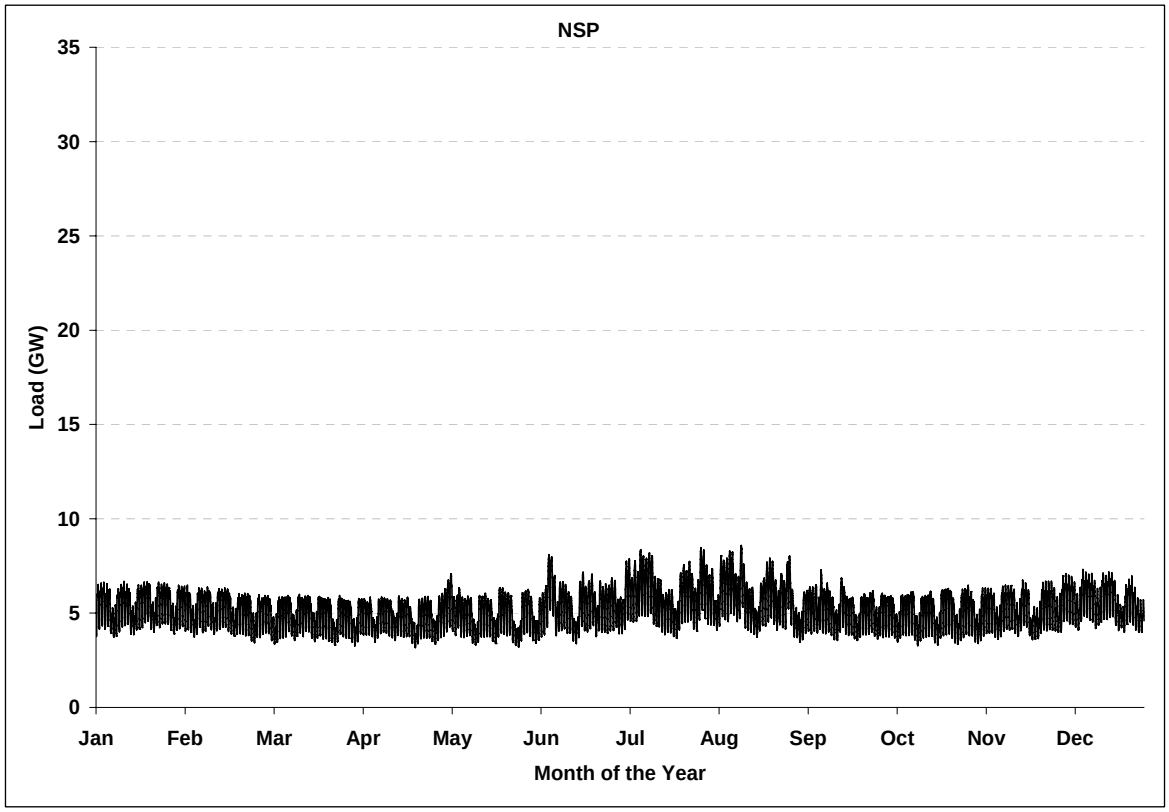

Figure D-36 NSP Load Curve

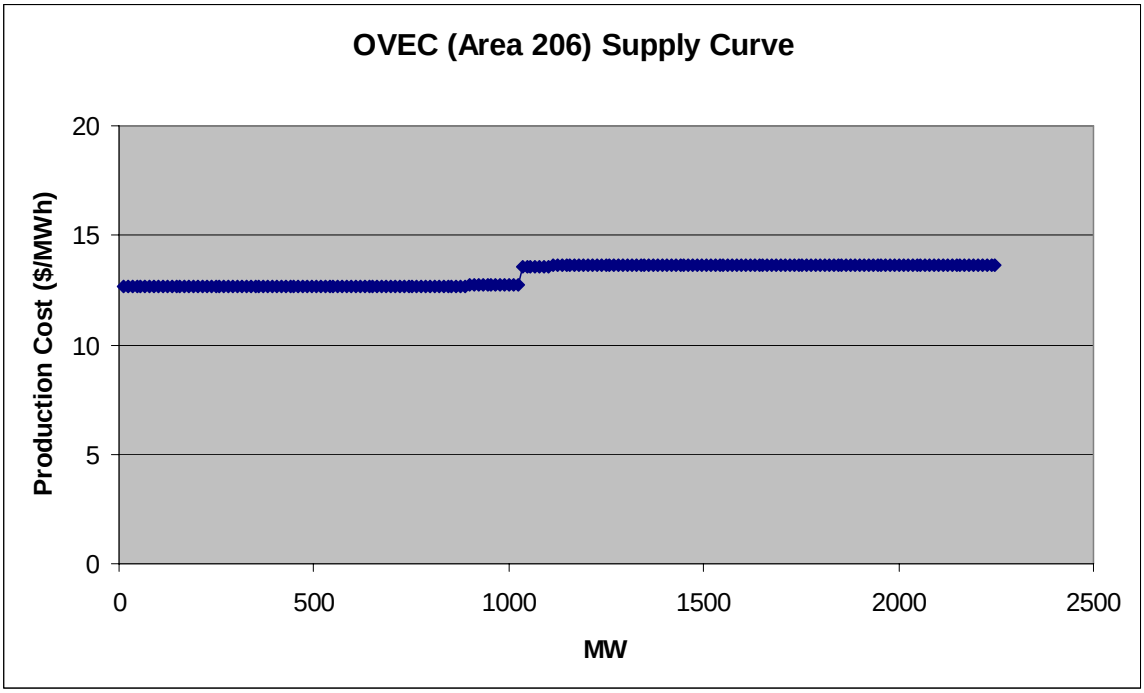

Figure D-37 OVEC Generation Supply Curve

No loads projected in this area

Figure D-38 OVEC Load Curve

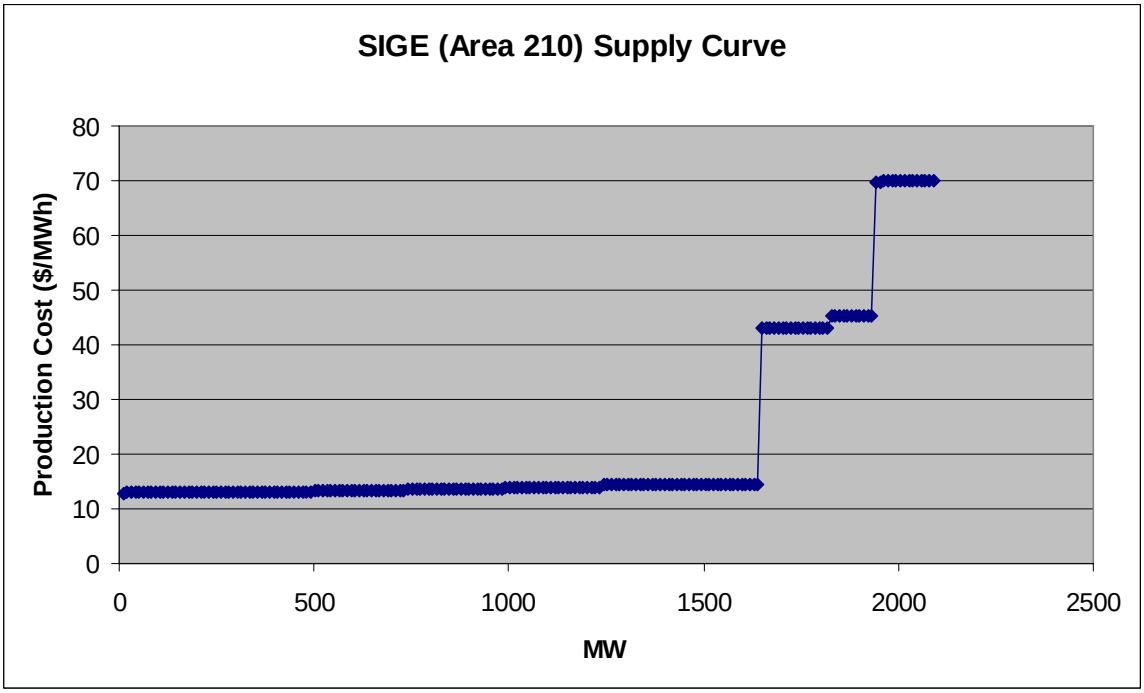

Figure D-39 SIGE Generation Supply Curve

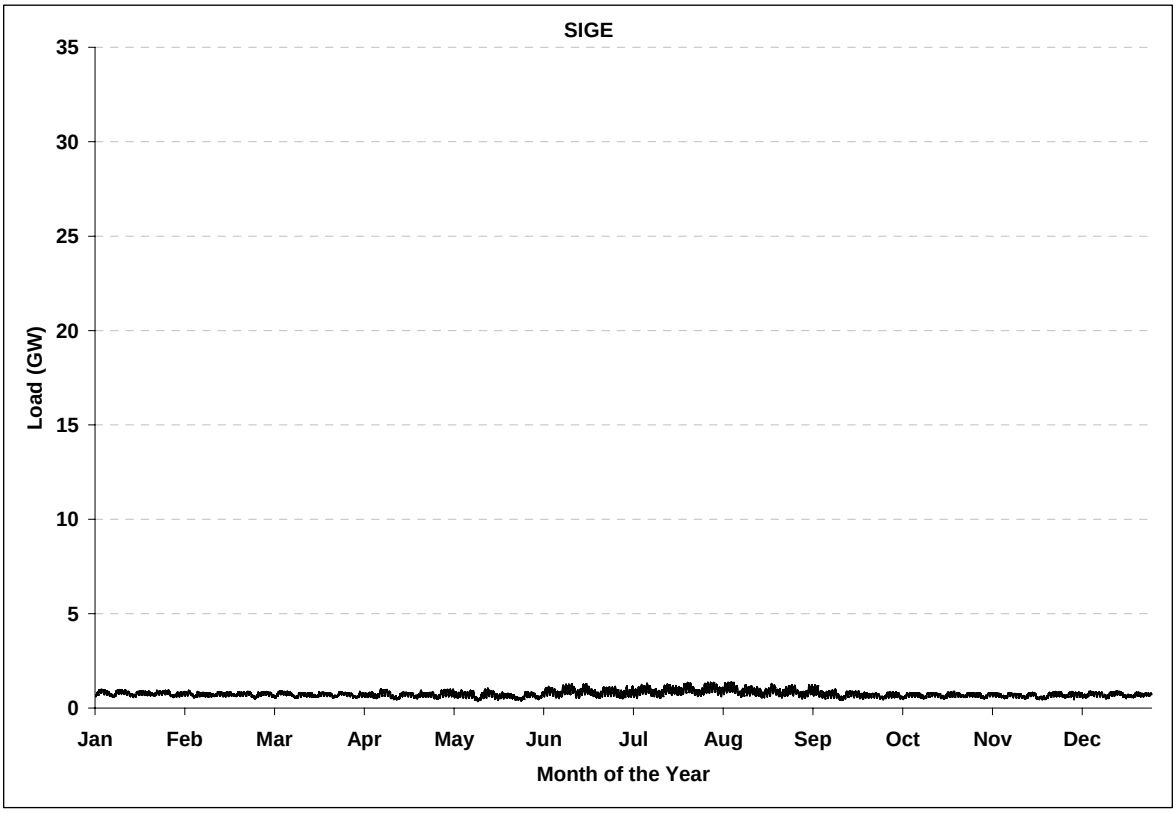

Figure D-40 SIGE Load Curve

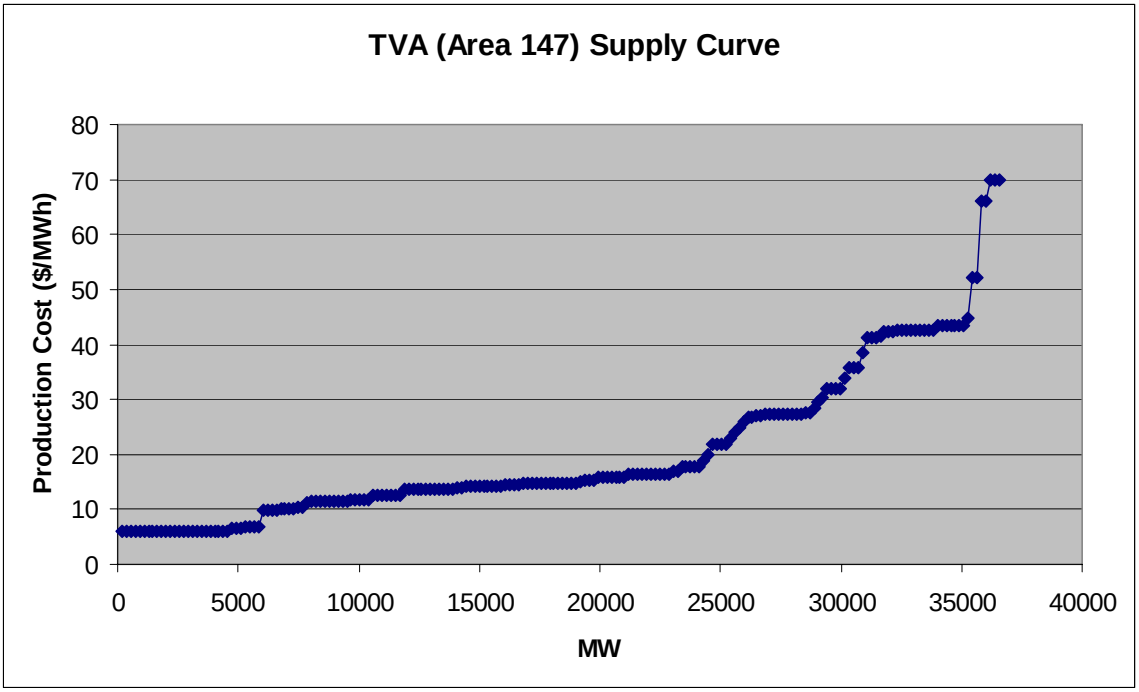

Figure D-41 TVA Generation Supply Curve

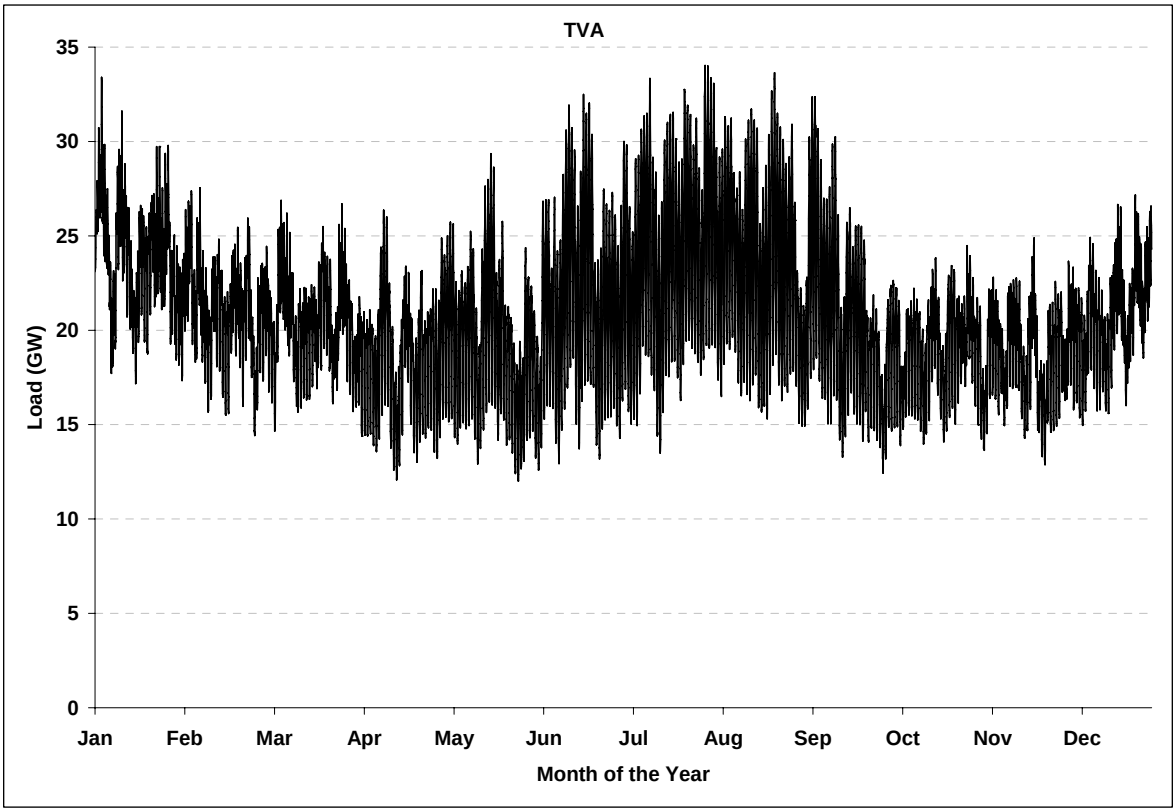

Figure D-42 TVA Load Curve

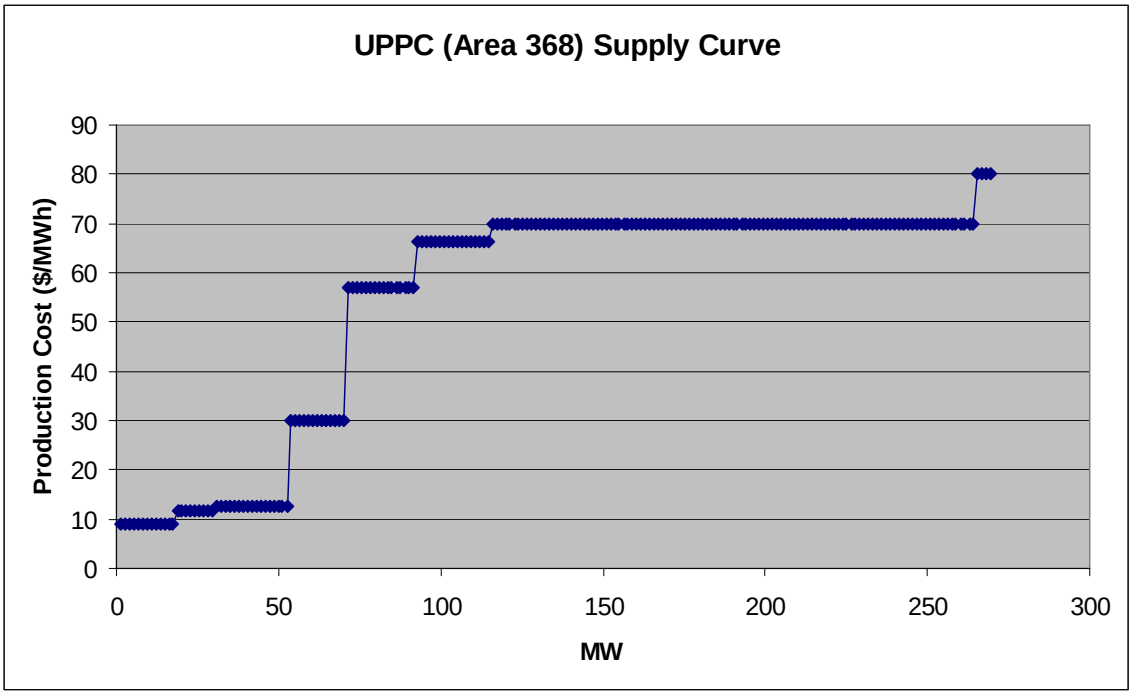

Figure D-43 UPPC Generation Supply Curve

No loads projected in this area

Figure D-44 UPPC Load Curve

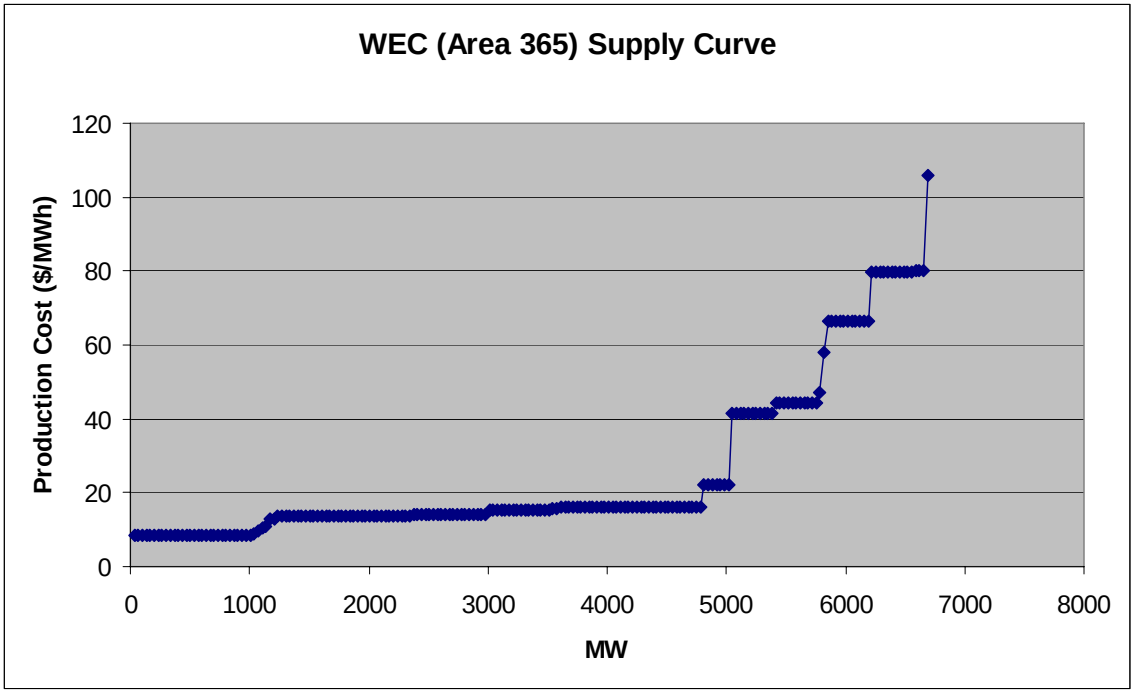

Figure D-45 WEC Generation Supply Curve

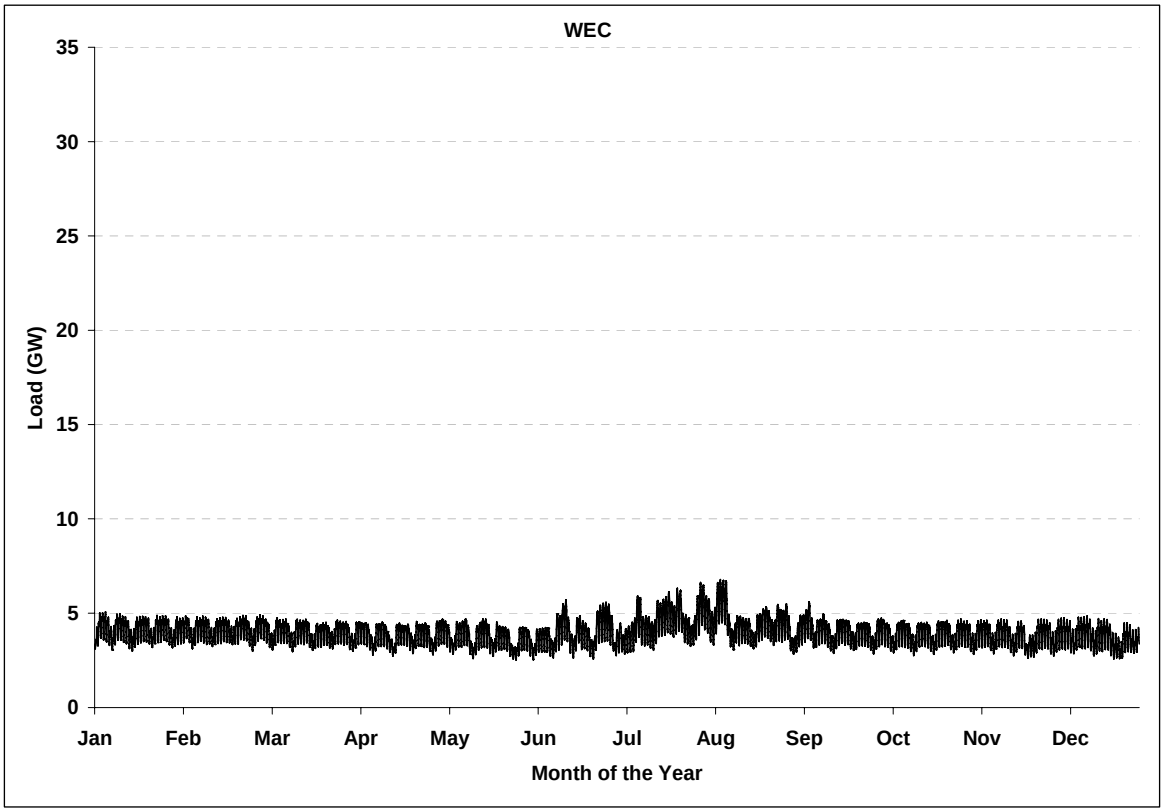

Figure D-46 WEC Load Curve

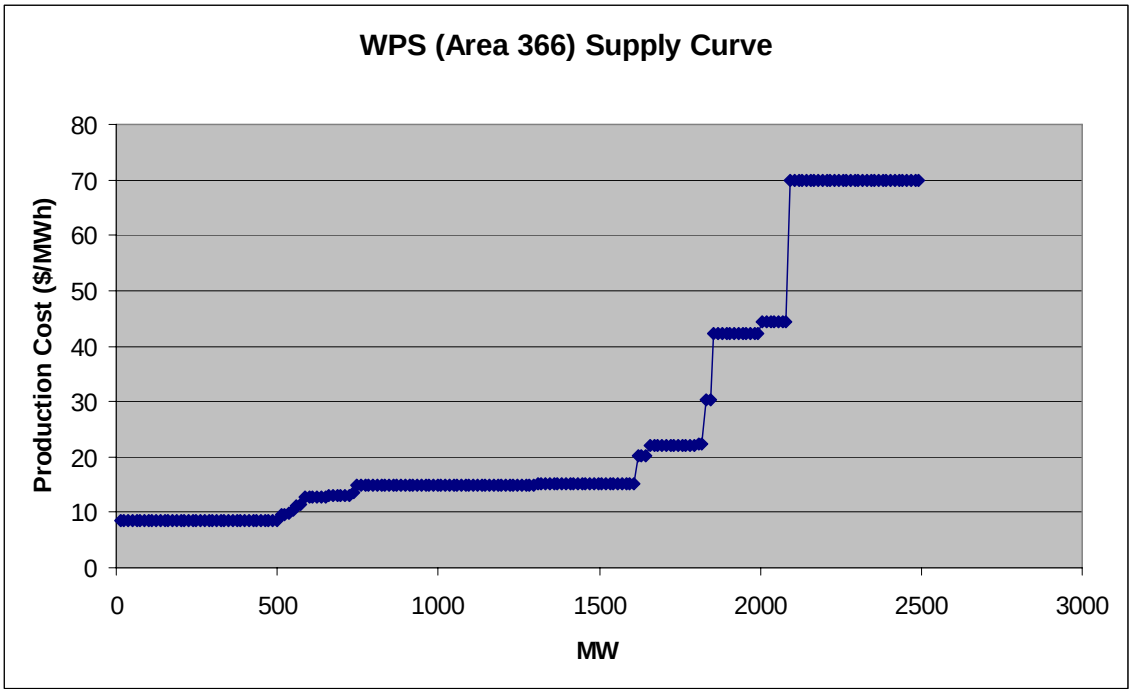

Figure D-47 WPS Generation Supply Curve

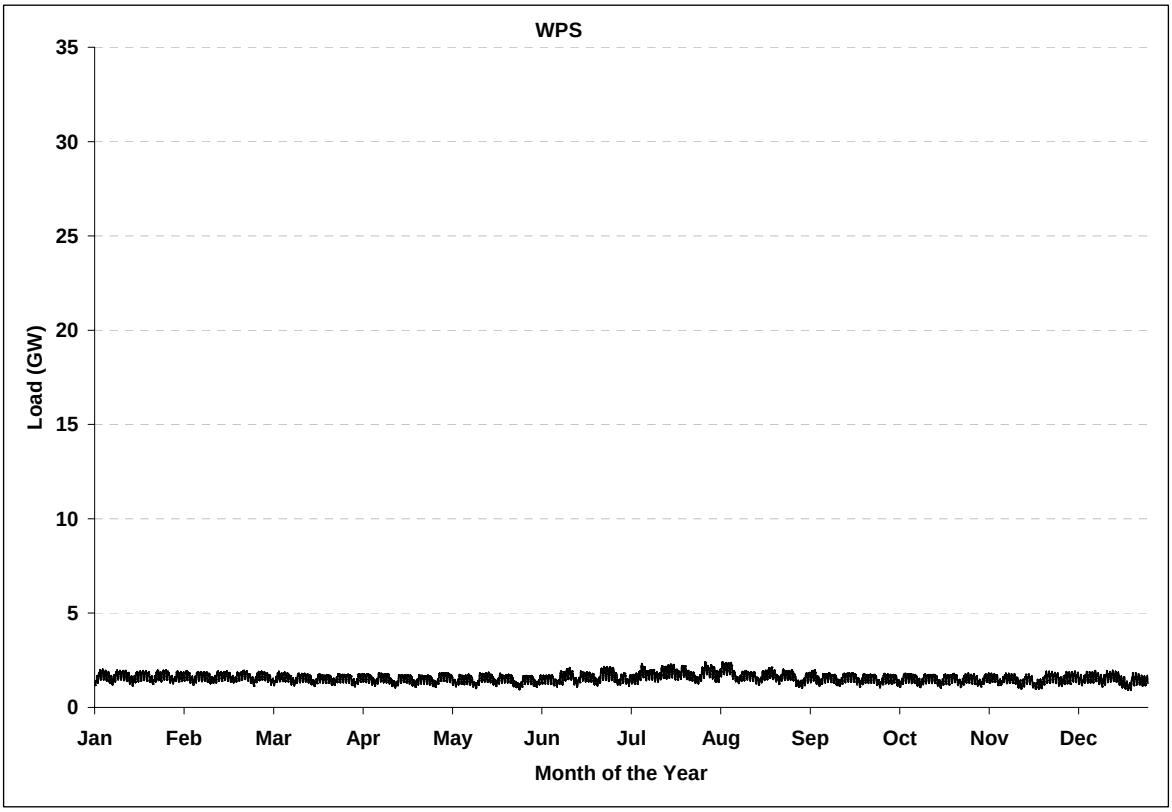

Figure D-48 WPS Load Curve

APPENDIX E
POWERWORLD® SUMMARY RESULTS

E.1 INTRODUCTION

E.1.1 PURPOSE OF THE STUDY

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

The Illinois Commerce Commission (ICC) commissioned this study to be undertaken as a joint effort by the University of Illinois at Urbana-Champaign (UIUC) and Argonne National Laboratory to evaluate the Illinois situation in the 2007 period when restructuring is scheduled to be fully implemented in the State. The purpose of this study is to make an initial determination if the transmission system in Illinois and the surrounding region would be able to support a competitive electricity market, would allow for effective competition to keep prices in check, and would allow for new market participants to effectively compete for market share. The study seeks to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power in one or more portions of the State and thereby create undue pressure on the prices charged to customers and/or inhibit new market participants from entering the market. It should be noted that the intent of the study is not to predict whether or not such market power would be exercised by any company. Rather, it is designed to determine if a set of reasonably expected conditions could allow any company to do so.

It should also be emphasized that this study is not intended to be a comprehensive evaluation of the electric power system in the State. Rather, it is intended to identify some issues that may impact the effective functioning of a competitive market.

E.1.2 PURPOSE OF THIS APPENDIX

This purpose of this appendix is to provide supplemental information on the portion of this study performed by researchers at UIUC.

E.1.3 METHODOLOGY

The full study used two analytical tools in tandem: the Electricity Market Complex Adaptive Systems (EMCAS)©, developed by Argonne, and PowerWorld® Simulator. EMCAS is used to calculate the behavior of the agents participating in an electricity market. It focuses on the manner in which the market participants make decisions and on how they adapt their behavior to

market changes and to their own success or failure in the marketplace. PowerWorld is used to calculate the detailed operation of the physical power system. It provides a detailed look at generator dispatching, transmission loading, and contingency conditions for the various behavior patterns of the market participants. The use of both models provides the ability to look at the details of the market and the details of the physical power system in an integrated fashion. This appendix focuses on the results obtained at UIUC with PowerWorld using a model of the Midwest electricity system jointly developed by Argonne and UIUC.

E.1.3.1 PowerWorld Model

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

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

E.1.3.2 UIUC Methodology

The overall methodology used in this study was to perform time-domain simulations (with a step size of one hour) of the anticipated 2007 Illinois region electricity market, using varying assumptions on the behavior of market participants. The UIUC portion of the study focused on doing the hourly SCOPF solutions using PowerWorld Simulator. Results from this portion of the study provide detailed information about the behavior of the power network, including power flow patterns, locations of congestion, and bus LMPs. In order to perform the simulations in a timely fashion, a dc power flow model was used for all the results presented in this report.

E.2 SCOPF MODEL

The key information needed for the hourly SCOPF analysis are: (1) the transmission network configuration including the electrical characteristics of the attached generators and loads, (2) the set of contingencies, (3) cost information for all the generators in the system, and (4) hourly changes to the system including variation in the load and the assumed on-line generators.

E.2.1 TRANSMISSION NETWORK CONFIGURATION (POWER FLOW MODEL)

The transmission network configuration was constructed from the 2003 summer peak power flow case prepared by the North American Electric Reliability Council (NERC) in November 2002, supplemented by slightly more up-to-date models provided by the Illinois utilities. The NERC model covered the entire North American Eastern Interconnect, a region stretching from the Atlantic to the Rockies (almost). Since the focus area of this study was the Midwest in general and Illinois in particular, this original 42,700-bus, 6,800-generator, 57,000-line/transformer NERC case modeled was equivalenced to reduce its size.

Determining the amount of detail to explicitly retain in an equivalent is a judgment call. Retaining more buses results in a potentially more accurate model (provided one has detailed cost information for the vast majority of the retained generators!) but the model takes longer to solve. Eliminating more buses results in improved solution times, but with a potential loss of accuracy. Given the study's focus on Illinois, all of the electric devices within Illinois were retained. Then, in order to provide a sufficiently large market for the Illinois generators and load yet one that was still manageable from a computational and data gathering viewpoint, the system was reduced to one covering the region roughly bounded by Minnesota, Missouri, Tennessee, Ohio, and Michigan.

Overall, the equivalent had 12,925 buses, 1,790 generators, and 17,647 lines and transformers. The total generation capacity was reduced from about 780 GW in the original NERC case to about 216 GW. While the reduced case had only about one-quarter the generation capacity of the original case, it still contained more than four times the total Illinois generation capacity (171 GW out-of-state and 45 GW in-state). Hence, the reduced case provided the desired "large" generation and load market. The breakdown of the 12,925 buses by NERC region was 2,207 in SERC, 4,052 in ECAR, 1,929 in MAPP, and 4,737 in MAIN (1,847 in-state and 2,890 out-of-state). During the study, the limits on all in-state transmission lines were enforced, but limits were only enforced for out-of-state lines with nominal voltage levels above 200 kV. This allowed direct consideration of the major transmission constraints on Illinois power imports/exports. Figure E.2-1 shows a one-line of the Illinois portion of this model, while Table E.2-1 shows a breakdown of the out-of-state generation and load.

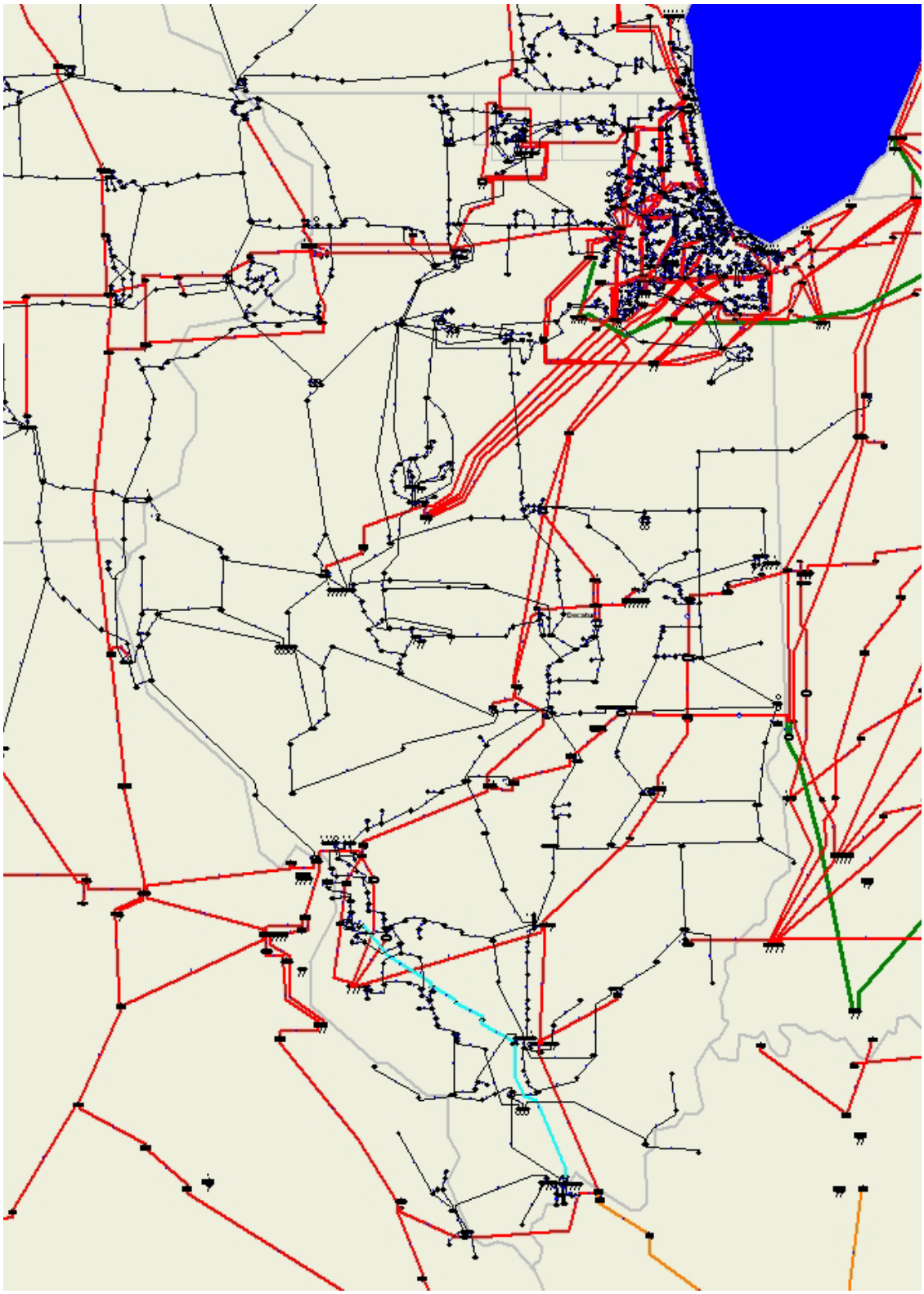

Figure E.2-1 Detailed PowerWorld Simulator One-line of Illinois Transmission, along with High Voltage Transmission in Other States

Table E.2-1 Out-of-State Generation and Load Modeled in PowerWorld Simulator

Control Area	Load (MW)	Generation Capacity by Fuel Type (MW)				
		Coal	Nuclear	Gas	Hydro/ Pumped	Other or Unknown
AECI (SERC)	4,415	2,412	0	1,614	58	249
TVA (SERC)	30,435	16,256	5,902	7,363	6,581	560
DOE (SERC0	500	0	0	0	0	0
AEP (ECAR)	23,094	21,300	2,060	6,455	731	292
OVEC (ECAR)	2,251	2,251	0	0	0	0
HE (ECAR)	1,250	1,250	0	240	0	50
CIN (ECAR)	11,775	10,171	0	1,831	75	1,220
DPL (ECAR)	3,437	3,305	0	1,410	0	0
SIGE (ECAR)	1,647	1,647	0	309	0	135
LGEE (ECAR)	7,314	5,928	0	796	71	1,259
BREC (ECAR)	1,558	1,709	0	0	0	65
IPL (ECAR)	2,971	2,664	0	742	0	100
NIPS (ECAR)	3,244	2,684	0	890	0	375
CONS (ECAR)	9,407	3,372	774	5,887	1,872	1,999
Other (ECAR)	0	0	0	1,776	0	0
ALTW (MAIN)	3,454	2,100	590	499	0	1,049
AMRN-NonIL	7,639	5,672	1,194	1,050	808	371
ALTE (MAIN)	2,505	2,034	0	1,136	26	264
WEC (MAIN)	6,792	3,640	1,012	1,032	143	868
WPS (MAIN)	2,486	1,019	500	432	131	414
Other (MAIN)	1,157	251	0	244	30	348
NSP (MAPP)	9,367	4,110	1,716	1,059	254	1,883
MEC (MAPP)	4,802	3,799	0	1,700	0	450
Other (MAPP)	939	1,257	0	84	21	60
Total	**142,439**	**98,831**	**13,748**	**36,549**	**10,801**	**12,011**

E.2.2 CONTINGENCIES

Secure power system operation requires that the system be operated both with no base case limit violations and also with no violations under a specified set of contingent conditions. Individual contingencies usually consist of the loss of one or more transmission lines/transformers or generators. When the operation of the power system is constrained due to transmission limitations, it is practically always constrained by contingent (as opposed to base case) violations. Hence, determining which contingencies to include in a study is vitally important. In this study, the impacts of 1,360 different contingencies were considered. While many of the contingencies consisted of single-line or transformer outages, others consisted of multiple-device outages (with the most complex contingency having 18 different actions). This set of 1,360 was developed using two sources. First, the in-state contingencies were developed from the list of contingencies provided by Illinois utilities. Second, the out-of-state contingencies consisted of single transmission line/transformer outages on key devices located electrically close to Illinois. Table E.2.2 shows a breakdown of the contingencies by company. During the study, contingent line flows were enforced using the power flow case "B" limit set (as indicated by the Illinois utilities). This was done using PowerWorld Simulator's security constrained optimal power flow (SCOPF).

Table E.2-2 Contingencies by Company

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

E.2.3 GENERATOR COST INFORMATION

The electrical characteristics for all the generators in the study were contained within the original NERC power flow case. These characteristics included the location of the generator on the grid and its minimum/maximum generation capacity. However, power flow cases do not include cost information for the generators, since this information tends to be viewed as more proprietary. But to perform this study, such cost information was crucial, with the necessary data including generator heat-rate, fuel type, variable O&M costs, and fixed-cost information. The initial model used here for the marginal generation costs was heat rate (MBtu/MWh) multiplied by fuel cost ($/Mbtu) plus variable O&M cost ($/MWh). For the in-state generation, all model information was provided by Argonne. For the out-of-state generation, this information was determined by UIUC using a variety of sources. The assumed fuel costs for both the in-state and out-of-state generators were provided by Argonne using DOE Energy Information Administration (EIA) data grouped by census region.

E.2.4 HOURLY SYSTEM VARIATIONS

The UIUC portion of the study consisted of doing hourly SCOPF simulations for year 2007 conditions. The hourly variation in the electric load was as provided by Argonne, with the same scaling values used for the in-state and out-of-state load. For the generator variation, all generators were assumed to be available at all times, unless they were explicitly outaged or derated. For the in-state generation, the studies were done using a generator outage schedule provided by Argonne. The purpose of this schedule was to model the planned and forced outages of individual generators that occur in actual system operation. For the out-of-state generation, the maximum real power capacities of the generators were derated to represent planned and forced outages; individual generator outages were not modeled for the out-of-state generators. The assumed derate values varied by month, representing the fact that most planned outages occur during the spring and fall when the electric loads are lower.

E.3 SCOPF RESULTS

In order to identify potential congestion regions for 2007, the full 12,925-bus, 1360-contingency model was solved using the PowerWorld SCOPF for all 8,760 hours in year 2007. The inputs to the model were essentially identical to those used in EMCAS, with the important exception that the SCOPF simulated a much larger network, and included the contingency constraints.

The hourly simulation approach, coupled with the scheduled and forced generator outages discussed in Section E.2.4, examined a wide variety of different system operating conditions. This wide variety of operating points caused a large number of constraints (i.e., contingency and line/transformer pairs) to become binding for different hours. This helped to identify the set of constraints that could be used by generators to exploit market power. However, such a detailed approach also generated a tremendous amount of data. For example, a full-year study creates over 100 million LMPs (i.e., LMPs at each of the 12,925 buses for every hour of the year) and over 50,000 binding constraint-hours. Effectively summarizing these results has been a significant challenge. This section (Appendix E) attempts to provide such a summary, with more detailed results contained in Appendix F.

E.3.1 RESULTS OVERVIEW

The initial 2007 run modeled a market in which all generators submitted bids equal to their actual production cost, that is (using the model from Section E.2.3), heat rate multiplied by fuel cost plus variable O&M cost. Table E.3.1 summaries the monthly results of this run, with the second column showing the monthly load, the third column showing the generation, the fourth showing the net exports for the month, and the last showing the average LMP (in $/MWh). Table E.3.2 shows a breakdown of the quarterly exports between Illinois and the rest of the model by direction, with the North direction, the net flow on the tie-lines with Wisconsin; East, the net flow on the tie-lines with Indiana (ECAR); South, the tie-lines with Kentucky (TVA); and West, the tie-lines with Iowa and Missouri.

Table E.3-1 Initial In-State Load, Generation, and Exports

Month	Load (GWh)	Gen. (GWh)	Exports (GWh)	Avg LMP $/MWh
January	13,588	13,541	–50	15.26
February	12,028	11,665	–365	14.57
March	12,442	12,202	–242	15.14
April	11,206	10,212	–995	15.14
May	12,062	11,406	–657	14.64
June	13,550	12,611	–941	16.21
July	15,740	15,310	–432	17.84
August	15,628	15,381	–247	18.30
September	12,155	11,586	–570	14.83
October	11,749	11,051	–699	14.95
November	11,233	10,620	–614	14.60
December	12,647	12,345	–304	14.20

Table E.3-2 Initial Exports by Quarter and Direction

Qtr.	Total (GWh)	North (GWh)	East (GWh)	South (GWh)	West (GWh)
1st	–657	1,331	–1,465	2,117	–2,640
2nd	–2,592	1,101	–2,229	1,978	–3,442
3rd	–1,249	1,992	–3,756	2,122	–1,607
4th	–1,617	1,406	–1,447	1,841	–3,417

The tables show Illinois as a net importer of electricity, a result contradicted by historical data for most recent years. However, it must be pointed out that the results are quite sensitive to the cost models used for both the in-state and the out-of-state generation. Small changes in the assumed generator cost characteristics can substantially alter the net Illinois interchange.

There appear to be several reasons for this interchange discrepancy. First, because of the scope of the study, detailed cost models were only developed for in-state generation. While significant time was spent determining the unit type and fuel type for the over 1400 out-of-state generators, the model parameters were not researched as extensively as for the in-state generators. In particular, the variable O&M costs are probably not as accurate, with the average values for the out-of-state coal units about $1/MWh less than those in-state. While this value may seem small, upping these variable O&M costs would substantially alter the interchange patterns. Second, the breakdown of the EIA fuel prices by census division resulted in the modeled prices of coal and natural gas for units immediately to the west of the Mississippi river (within the West North Central Census Division) to be substantially lower than the price in Illinois (within the East North Central Census Division). This is the primary reason for the heavy imports from the West shown in Table E.3-2, and for the low LMPs in Table E.3.3 for areas AMRN, NSP, MPW, MEC, and DPC. Third, while the 12,925 bus model contained a significant portion of the Midwest electric grid, it did not include PJM and areas further to the East, areas that tend to have higher costs than the Midwest and tend to be net importers from Illinois. Hence the impact of exports to these areas was not included in the study, somewhat skewing the results.

Table E.3-3 Initial Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
130	AECI	SERC	16.01	600
147	TVA	SERC	16.26	–4,165
148	DOE	SERC	14.52	–325
205	AEP	ECAR	15.68	2,162
206	OVEC	ECAR	15.57	1,776
207	HE	ECAR	15.52	306
208	CIN	ECAR	15.52	950
209	DPL	ECAR	15.63	415
210	SIGE	ECAR	15.30	414
211	LGEE	ECAR	15.56	708
214	BREC	ECAR	15.19	32
216	IPL	ECAR	15.37	203

Table E.3-3 Initial Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
217	NIPS	ECAR	15.59	–541
218	CONS	ECAR	15.70	–3,589
221	AEWC	ECAR	15.23	–1
222	AEWI	ECAR	15.28	–1
223	DEVI	ECAR	15.28	0
224	DEWO	ECAR	15.66	36
331	ALTW	MAIN	14.19	–424
355	CWLD	MAIN	14.70	–175
356	AMRN	MAIN	14.74	1,279
357	IP	MAIN	15.02	–162
359	CILC	MAIN	15.84	–414
360	CWLP	MAIN	15.23	–199
361	SIPC	MAIN	14.78	–144
362	EEI	MAIN	14.15	846
363	NI	MAIN	15.73	73
364	ALTE	MAIN	16.76	94
365	WEC	MAIN	16.44	–885
366	WPS	MAIN	17.29	–249
367	MGE	MAIN	16.30	–319
368	UPPC	MAIN	16.64	–51
600	NSP	MAPP	13.01	1,189
633	MPW	MAPP	14.65	49
635	MEC	MAPP	14.28	523
680	DPC	MAPP	13.71	–14

In order to assess the impact of this interchange skew on the results, a second year 2007 case was run with the generator costs altered to increase the cost of the external generation. This was done by adding an allocation of each generator's annual fixed costs to its bids, with the allocation done such that the costs of the out-of-state generators were increased slightly relative to the in-state generation (the net change was about $1/MWh). Results from this modified study are shown in Tables E.3-4 to E.3-6. More detailed results for both cases are presented in Appendix F.

A comparison of Tables E.3-1 to E.3-3 with E.3-4 to E.3-6 indicates that with the allocation of the fixed costs, Illinois has changed from being a net importer (with an average import of about 700 MW) to being a net exporter (with an average export of about 1,844 MW). This rather dramatic change is actually not unexpected, since in the second case the costs of the out-of-state generators have been increased relative to the in-state generation. A comparison of Tables E.3.2 and E.3.5 indicates most of this change is due to a dramatic increase in the Illinois exports to the east. The reason: the original cost differentials between the costs in the east and Illinois were small, partly due to both being in the same census region, and hence having the

same modeled fuel costs. Hence, even small changes in the relative costs could dramatically alter the interchange. Also, there are relatively few transmission limitations to the east.

Table E.3-4 Modified In-State Load, Generation, and Exports

Month	Load (GWh)	Gen. (GWh)	Exports (GWh)	Avg LMP $/MWh
January	13,588	15,264	1,675	17.79
February	12,028	13,575	1,547	17.23
March	12,442	13,935	1,493	17.65
April	11,206	11,713	507	17.56
May	12,062	13,511	1,449	17.28
June	13,550	14,704	1,154	18.82
July	15,740	16,878	1,138	20.54
August	15,628	16,976	1,348	21.03
September	12,155	13,825	1,670	17.53
October	11,749	12,609	860	17.39
November	11,233	12,370	1,137	17.14
December	12,647	14,825	2,178	16.84

Table E.3-5 Modified Exports by Quarter and Direction

Qtr.	Total (GWh)	North (GWh)	East (GWh)	South (GWh)	West (GWh)
1st	4,715	2,152	3,181	1,936	–2,554
2nd	3,110	2,228	2,176	1,979	–3,273
3rd	4,156	3,041	793	1,888	–1,566
4th	4,175	2,591	3,160	1,767	–3,343

Table E.3-6 Modified Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
130	AECI	SERC	18.01	562
147	TVA	SERC	18.44	–2,326
148	DOE	SERC	17.71	–321
205	AEP	ECAR	18.21	1,201
206	OVEC	ECAR	18.15	1,557
207	HE	ECAR	18.19	1,245
208	CIN	ECAR	18.16	462
209	DPL	ECAR	18.21	331
210	SIGE	ECAR	18.06	264
211	LGEE	ECAR	18.18	124
214	BREC	ECAR	18.07	-68
216	IPL	ECAR	18.05	154
217	NIPS	ECAR	18.20	–1,073
218	CONS	ECAR	18.25	–3,895
221	AEWC	ECAR	17.95	–1

Table E.3-6 Modified Average LMP and Power Exports by Operating Area for 2007

Area Number	Area Name	NERC Region	Average Bus LMP ($/MWh)	Average Exports (MW)
222	AEWI	ECAR	17.98	–1
223	DEVI	ECAR	17.98	0
224	DEWO	ECAR	18.21	26
331	ALTW	MAIN	16.97	–466
355	CWLD	MAIN	17.31	–175
356	AMRN	MAIN	17.45	1,498
357	IP	MAIN	17.66	768
359	CILC	MAIN	18.42	101
360	CWLP	MAIN	17.74	–128
361	SIPC	MAIN	17.64	–141
362	EEI	MAIN	17.64	754
363	NI	MAIN	18.33	992
364	ALTE	MAIN	19.67	40
365	WEC	MAIN	19.17	–1,261
366	WPS	MAIN	20.03	–321
367	MGE	MAIN	19.26	–322
368	UPPC	MAIN	19.41	–51
600	NSP	MAPP	15.91	1,059
633	MPW	MAPP	17.46	57
635	MEC	MAPP	17.05	513
680	DPC	MAPP	16.60	–41

In contrast, the costs in the west were originally substantially lower than Illinois's, primarily due to a lower assumed cost for coal. Hence, a slight change in the assumed generator costs will have a lower impact. Also, transmission imports from the west are more constrained.

While the differences between the two cases may seem significant, the different assumptions on the generator costs actually had little impact on the focus of this study, that is, evaluating the impact transmission constraints would have on competitive electricity markets in Illinois. The reason is that, as previously stated, the hourly simulation approach placed the system in a wide variety of different operating conditions. Over the course of a day, the hourly interchanges would swing over a wide range, with power being imported for some hours and exported for others. This is illustrated in Figures F.1-1 to F.1-4 and F.2-1 to F.2-4 (in Appendix F), which plot the hourly Illinois interchange. While the average value is higher in the Appendix F.2 cases, the wide variation means that essentially the same constraints are binding in both cases, albeit perhaps for a different number of hours. The impact of transmission constraints on the Illinois electricity market is discussed in the next section.

E.3.2 ILLINOIS TRANSMISSION SYSTEM CONSTRAINTS

Constraints are the cause of LMP variation. Without constraints, all of the LMPs in the system would be identical, with their values set each time period by the cost of the single marginal generator. Power would flow freely from any generator in the system to any load. Of course, for a real power market, such a situation seldom, if ever, occurs. The operation of the grid is constrained by the need to avoid overloading any device under either base case conditions or during one of the contingencies. Therefore, to identify potential congestion regions, the impact of the individual constraints needs to be considered.

Tables F.1-1 and F.2-1 in Appendix F list the different binding device/contingency pairs in the two studies under consideration here, including both in-state and out-of-state constraints. As was mentioned earlier, devices practically always bind for contingencies, as opposed to base case conditions. For the first case (Appendix F.1 results), there were 240 different binding device/contingency pairs, with a total of 50,844 binding device-hours for the year, or an average of about 6 per hour. Table F.1-1 lists just the 104 device-contingency pairs that were binding for 25 or more hours for the year, along with the average and maximum marginal costs (in $/MWh) of enforcing these constraints. For the second case (Appendix F.2 results), there were 206 different binding device/contingency pairs, with a total of 38,605 binding device-hours for the year, or an average of about 4.4 per hour. Table F.2-1 lists just the 88 device-contingency pairs that were binding for 25 or more hours for the year.

However, in accessing the potential for congestion to segment the Illinois electricity market, it is actually better to focus on the variation in the bus LMPs rather than on the constraints themselves. As was mentioned earlier, the variation in the LMPs is caused by the constraints. But the determination of how a particular constraint affects the bus LMPs is actually rather complicated. One of the beauties of an LMP-based market is that end users do not (usually) need to worry about the details of how a particular LMP is determined. Rather, they can just respond to the result. The remainder of this section focuses on market segmentation caused by the constraints, with the individual constraints discussed only when necessary to understand the reason for the market segmentation.

Before moving on, it is important to briefly discuss one somewhat unique characteristic of the Illinois market – the presence of ten phase-shifting transformers in the ComEd control area. Usually, the flow of power through transmission lines and transformers can only be indirectly controlled by changing the real power outputs of the generator. Indeed, LMP price variations arise because at least some generation needs to be dispatched in a non-economic manner to avoid overloading the transmission systems. With few exceptions, the flow of power through a transmission line or transformer cannot be directly controlled. Phase-shifting transformers, however, are one of those exceptions (others include HVDC transmission lines, which are not present in Illinois). By controlling the phase angle of a phase-shifting transformer, the flow of power can be directly controlled. Such control is routinely done by ComEd to avoid overloading transmission lines in the City of Chicago. The impact of this phase-shifter control was included in the PowerWorld Simulator software used for this project, with the result being that there was very little congestion seen in the City of Chicago. If the impact of the phase

shifters had not been considered, one would have expected substantial congestion, with a pronounced increase in the LMPs in northeast Illinois (Lake and northern Cook Counties).

E.3.3 ILLINOIS TRANSMISSION SYSTEM CONGESTION REGIONS

This section details the regions of Illinois in which the LMPs are unusually high. The challenge in doing this assessment has been to make sense out of the many millions of LMPs generated by the computer runs done for this study. Figures F.1-5 to F.1-16 and F.2-5 to F.2-16 in Appendix F show the hourly variation (by month) of the average bus LMPs for the various utilities in Illinois. The figures indicate several general characteristics about the LMPs. First, the LMPs for all areas tend to increase during high-load periods (e.g., daytime during the summer) and decrease during times of low load. Because the generators are submitting bids equal to their marginal costs, the lowest LMP values tend to be fairly constant, with the value dictated by the costs for the base-load units. Second, for many hours, the changes in at least the average LMPs tend to be fairly uniform between the various utilities. That is, for many hours they have the same average LMP. However, the last characteristic is that there are some hours in which the average LMPs diverge quite significantly, particularly for Ameren-CILCO (CILCO), even under non-peak conditions. Also, periods of high prices in one area can result in low prices in another (e.g., March 2007, with several days of high prices in CILCO and low prices in CWLP). These deviations in the average prices are caused by transmission system constraints, which may be aggravated by planned or unplanned generator outages. However, while useful, just looking at the variation in the average LMPs across an entire control area can mask the effects of more localized congestion. To highlight the impacts of this congestion, we need to look at metrics derived from the individual bus LMPs.

There are a number of different metrics that could be used to highlight these regions of localized congestion. For example, Figures 17 to 28 in Appendix F show bus contour plots for each quarter in 2007 of the average LMP, the highest bus LMP, and the number of times the LMPs exceed a specified threshold (either $30/MWh or $40/MWh). The average LMP has the advantage of giving an overall feel for the price a consumer would pay at a particular bus, but has the disadvantage of masking significant variations in the price, particularly if a given bus's LMP is greater than average during times of high load and less than average during times of low load. Contouring the highest LMP for a time period (quarterly, in the figures) has the advantage of clearly showing the maximum price that occurred at each location. But the disadvantage is that information about the duration of the high prices is lost. Contouring the number of hours a given point is above a threshold combines some of the advantages of both, but at the expense of not showing the impact of very high but short-duration prices.

A complementary approach is to count the number of times a bus LMP is greater than the state-wide average by a specified percentage (10% here), and then to calculate the cumulative $/MWh by which it exceeds this threshold. The results of such a ranking are given in Tables F.1-2 and F.2-2 in Appendix F, with the top 100 buses with the highest cumulative $/MWh shown. For example, the first entry in Table F.1-2, bus 33002 (RS WALL) had an LMP greater than 110% of the hourly state-wide average for 298 hours (out of 8,640) with a cumulative $/MWh value of 11,739. This means on average its LMP exceeded 110% of the

average by 11,739/298 = $39.4/MWh. Figures E.3-1 and E.3-2 below show contours of this metric for all the buses in the State, with more detailed figures shown in Appendix F (Figures F.2-30 to F.2-33). A comparison of Tables F.1-2 and F.2-2, along with Figures E.3-1 and E.3-2, indicates that the regions of congestion in the State are fairly constant. For example, about 80% of the Table F.1-2 entries also appear in Table F.2-2, albeit with different values. The remainder of this section provides a detailed look at each one of these in-state congestion zones, along with a discussion of how congestion in the zone could be used by the generation companies to increase profits.

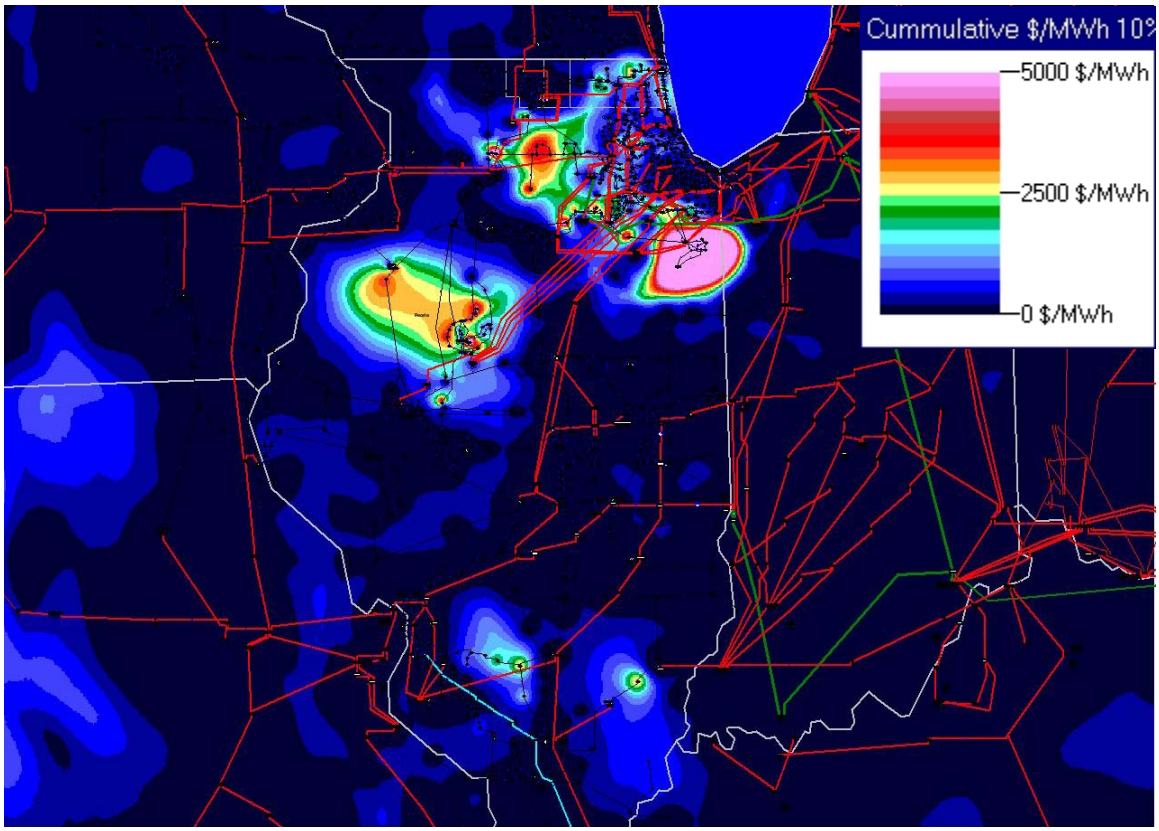

Figure E.3-1 Cumulative $/MWh 10% above Average for the Appendix F.1 Case

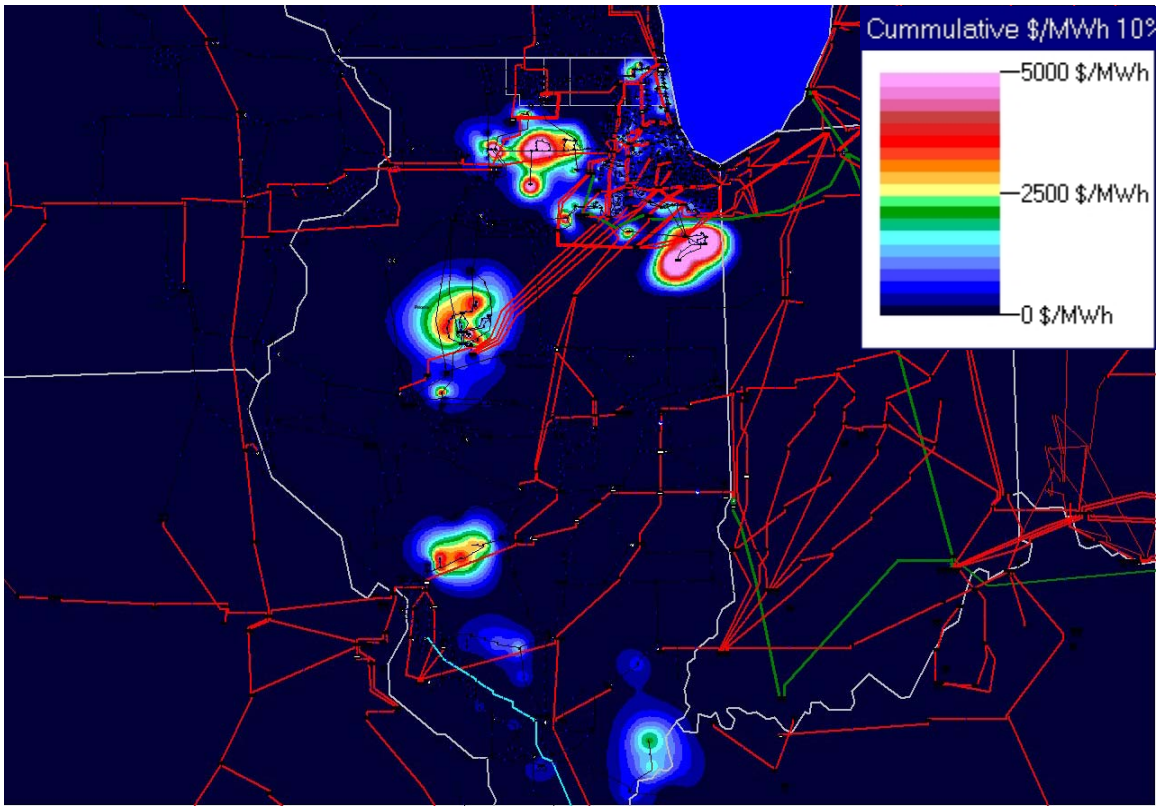

Figure E.3-2 Cumulative $/MWh 10% above Average for the Appendix F.2 Case

E.3.3.1 Peoria Congestion Region

The most significant congestion region occurred in the CILCO control area for both the Appendix F.1 and F.2 cases, with the values slightly higher in the latter. The presence of this congestion region is most evident in the control area average LMP plots for February, March, June, July, August, and November. The region also appears prominently in the highest LMP color contours for each quarter. As shown in Tables F.1-2 and F.2-2, the highest LMPs occur at the RS Wall and Edwards1 69-kV buses, followed closely by the Peoria and Pekin 138-kV buses. The complete extent of this region is shown visually in Figures F.1-31 and F.2-31.

These high LMPs are essentially due to SCOPF binding constraints on just two devices, the Holland-Mason 138-kV line (which is binding more than 80% of the time; these buses have high LMPs) and the RS Wall 138/69-kV transformer #1. The Holland-Mason 138-kV line binds for flow north from Holland to Mason (and on to Tazewell) for either the CIL-6 contingency (loss of Duck Creek-Tazewell 345 kV) or the ComEd 345-L0304_R-S contingency (loss of Tazewell-Powerton 345 kV). The RS Wall 138/69-kV transformer is binding for base case problems (due to it having a 90 MVA base case and 150 MVA contingency limit) with the flow always from the 138-kV to 69-kV buses.

The presence of above average LMPs at these buses also has good correlation with generator outages in the area. For example, for the Appendix F.1 case of the 298 hours during which the RS Wall 69-kV bus has high LMPs, 220 hours are associated with an outage of the Edwards #2 generator, 114 hours are associated with an outage of Edwards #3, 175 hours are associated with an outage of the Dresden #2 generator, and 157 hours with Quad City #2. In additional, several other ComEd generators have associates of more than 80 hours. Clearly, a localized congestion region is possible during times of generator outages either at Edwards or at electrically close ComEd generators.

The degree to which generators in the CILCO area could take advantage of this congestion to profitably increase the bus LMPs depends, of course, upon the particular system conditions, such as the load level, and which generators and/or lines are out of service. To provide more generic results, a case with load equal to 90% of system peak and no generator outages was studied using the Appendix F.2 cost characteristics. The system load should be at or above 90% of peak for about 80 hours per year.

The main generator within the congestion region is Edwards, a relatively low-cost coal plant with a total capacity of about 600 MW. To assess the ability of Edwards to profitably manipulate prices, its bids were scaled from initially being equal to its actual marginal cost (as was assumed in the Appendix F.1 and F.2 cases), to being equal to a scalar multiplier by its marginal cost. The results are shown in Table E.3-7, with the second column showing the total CILCO generation, the third column showing the relative profit (with unity corresponding to a marginal cost bid), while the last two columns show the average and maximum LMP for the CILCO area. Small increases in the Edwards bids have no impact on prices, since Edwards is initially dispatched at full capacity with bus LMPs above its marginal costs. When the bid scaling is 2.0, the share of the Edwards generation drops off, decreasing profit slightly. Then for higher bids, a situation is reached in which some Edwards generation needs to run, regardless of price. Once this point is reached, additional increases in the Edwards bids result in increased profits. For example, when the bid multiplier is 4.0, the total CILCO profits are 1.32 the initial profits. The minimum Edwards generation for the assumed 90% system load is 170 MW, with the binding constraint being the Holland-Mason 138-kV line. Hence we could conclude that under heavy system loading, even with all generators in-service, the Edwards generator has localized market power.

Table E.3-7 Variation in CILCO Profit Modified Edwards Bids (Base Case)

Edwards Bid Multiplier	Total CILCO Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	1,106	1.000	27.25	27.57
1.5	1,106	1.000	27.26	27.57
2.0	777	0.952	31.23	39.67
2.5	583	0.964	37.44	58.52
3.0	579	1.136	44.42	70.24
3.5	578	1.226	50.86	76.97
4.0	578	1.320	56.46	83.22

However, this binding constraint is currently in the process of being upgraded, with the changes affecting the entire Tazwell-Holland-Mason-East Springfield 138-kV line. The study results reported here were done using the original limits. Also, during the process of doing this analysis, it was noticed that the 138-kV ties between CILCO and IP at Richland (north side of CILCO) were modeled as being normally open in the base case. Subsequent checking indicates that these two lines should be modeled as closed. If these two changes are considered (with the most significant being the line upgrade), the Table E.3-7 results change substantially, with the new values given in Table E.3-8. The Edwards generator still has market power, but with its required generation decreased from 170 MW to 120 MW, requiring that its bid be about 6 times marginal cost for an increased profit. The binding constraint is now the Tazwell-East Peoria 138-kV line.

Table E.3-8 Variation in CILCO Profit Modified Edwards Bids with Upgraded Tazwell to East Springfield 138 kV Line

Edwards Bid Multiplier	Total CILCO Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	1,106	1.000	27.20	27.56
1.5	1,106	1.000	27.20	27.56
2.0	529	0.538	31.90	38.01
2.5	527	0.609	36.64	55.02
3.0	524	0.642	42.32	72.13
3.5	529	0.683	41.00	72.75
4.0	529	0.780	41.30	85.30
5.0	532	0.918	43.94	110.38
6.0	532	1.094	47.75	135.47

E.3.3.2 Kankakee Area Congestion Region

The second most significant congestion region occurs in the Kankakee area (ComEd operating area), with the most significant buses in the pocket listed in the second to twelfth entries in Table F.1-2, as well as the Wilmington 138 kV bus, and to a lesser extent the red Dresden 138-kV bus. This congestion region also is shown visually in Figures E.3-1, E.3-2, and in the bottom right of Figures F.1-32 and F.2-32. These high LMPs are due to an SCOPF binding constraint on the blue Davis Creek 345/138-kV transformer for the ComEd 345-L17704_R-S contingency (loss of the red Davis Creek transformer and several other devices). These high LMPs mostly occur on high-load days. The total peak load in this region is between 300 and 400 MW.

The higher marginal costs in the Kankakee area arise from needing to do a constrained dispatch to avoid the contingent overload of the 345/138-kV transformer at Davis Creek. For the 90% of peak case mentioned earlier, this constrained dispatch involves using the University Park natural gas turbine generators owned by Constellation Power. University Park has a total of six 50-MW turbines. For this case, the highest LMP in the Kankakee region is $54.18/MWh. Since the University Park generators are “marginal units,” changes to their bids will directly affect the bus LMPs, with the potential that such changes could increase Constellation’s total Illinois profit. The results of this analysis, which are shown in Table E.3-9, indicate that increases in the bids for the University Park generators could indeed increase Constellation’s profit, with the

tradeoff again between lower market share and higher prices. If the bids were increased to the profit maximizing value of 1.7 times marginal cost (assumed here to be $35.26/MWh), the highest LMP in the Kankakee region almost triples to $147.66/MWh.

Table E.3-9 Variation in Constellation Power Profit for Modified University Park Bids

University Park Bid Multiplier	Total University Park Gen. (MW)	University Park LMP	Relative Profit
1.0	104	35.26	1.000
1.1	103	38.79	1.128
1.2	45	42.31	1.193
1.3	42	45.83	1.171
1.4	42	49.35	1.204
1.5	33	52.89	1.192
1.6	29	56.42	1.201
1.7	29	59.94	1.232
1.8	0	63.22	1.008

E.3.3.3 Dixon Area Congestion Region

The next most significant congestion region appears in the vicinity of the ComEd Dixon 138-kV bus extending to the east to include Mendota and Steward. This congestion region is shown visually in the upper center of Figures E.3-1 and E.3-2, and in more detail in the left center of Figures F.1-32 and F.2-32 in Appendix F. The high prices at these buses are often caused by a binding constraint on one of the 138-kV lines going from Nelson to Dixon. These lines bind for the ComEd 138-L15507_B-R contingency (loss of the blue Nelson to Dixon 138-kV line) and the 138-L15508_B-R contingency (loss of the Nelson red 138 kV bus) (essentially the loss of the parallel line). These high LMPs mostly occur on high-load days, particularly with generator outages in the Rockford area.

There are no generators in the direct area of the constraint, so exploiting this constraint to maximize generation profit seems unlikely unless there is an outage of a large generator, such as one of the Byron units. Then the NRG units at Rockford may be able to increase their profit by submitting bids above marginal cost. For example, in the 90% of peak case with one of the Byron units outaged (and all other units in-service), if the NRG Rockford units bid 20% above marginal cost, their dispatch falls from 421 to 147 MW, but their profit increases by about 13%. Bidding 40% above marginal cost results in a 0 MW dispatch.

E.3.3.4 Mazon Area Congestion Region

The next congestion region appears in the vicinity of the ComEd Mazon 138-kV bus, extending towards the J-375, J-371, and J-339 buses. This congestion region is best seen visually on Figures F.1-32 and F.2-32 in Appendix F, to the southeast of the Dixon area. The high prices here are practically always caused by a binding constraint on the Oglesby-Mazon 138-kV line, with the binding constraint flow always going from Oglesby to Mazon. This constraint is usually caused by the ComEd 345-L15502_B-R contingency (loss of the Nelson-Electric Junction 345-kV line), with a significant minority caused by the ComEd 345-L2101-S

contingency (loss of a Brokaw 345-kV bus – also IP contingency IP108). The LMPs at Mazon are more than 10% above the state-wide average for more than 700 hours in the year, although usually they are not significantly above the average. A wide variety of generators are capable of helping to mitigate this constrain, so it is unlikely to be exploited for profit maximization.

E.3.3.5 Lombard Congestion Region

The next most severe congestion region appears for just 25 hours at the blue Lombard 138-kV bus and several surrounding blue buses (e.g., Glen Ellyn, Glendale, Nordic, Butte, Addison). The high LMPs are always caused by a binding constraint on the blue Lombard 345/138-kV transformer due to ComEd contingency 345-L12001_B-N (loss of the blue Itasca 345/138-kV transformer and the blue Lombard-Itasca 345-kV line). This constraint is only binding at the times of highest loading.

The most sensitive generators for controlling the flow on the constrained transformer, and hence with the best potential for inducing or enhancing the congestion, are all owned by Midwest Generation. The generating plants are Will County Unit 4, Joliet Unit 9, Crawford 7 and 8, Fisk 9, and Waukegan 6 and 8. Analysis of the 90% load case indicates that no single generator, or group of two or three generators, can benefit from this congestion (however, see Section E.3.4.2 for a discussion of a more company-wide strategy for Midwest Generation).

E.3.3.6 Galesburg Congestion Region

The LMPs at the Galesburg 138-kV bus and several surrounding buses are more than 10% above the state-wide average for about 1,700 hours in the Appendix F.1 case; they are much less problematic in the Appendix F.2 case. This congestion zone is shown visually in Figure E.3-1 and Figures F.1-30 and F.1-31. These high prices are caused by a binding constraint on the Galesburg 161/138-kV transformers (there are two, each with a rating of 100 MVA), with the flow direction always from the 161-kV to the 138-kV. Most of the time, these transformers are binding for ComEd contingency 345-L15502_B-R (loss of the Nelson-Electric Junction 345-kV line), but they are sometimes binding for contingency L0304-A (loss of the Tazewell-Powerton 345-kV line and the Tazewell-Mason 138-kV line), or contingency 345-L0404_R (loss of the Quad City-H471 [NW Steel] 345-kV line). This constraint occurs when there are high imports from Iowa. Since there is little generation in the immediate vicinity of the constrained buses, it is unlikely that this constraint could be exploited for profit maximization.

E.3.3.7 Wilson/Round Lake/Antioch Congestion Region

The next congestion zone is associated with the red 138-kV buses at Wilson, Round Lake, Antioch, and, to a lesser extent, Gurnee. It is shown visually in Figures E.3-1 and E.3-2 in the far northeast part of the State, and in more detail in Figures F.1-32 and F.2.32. These high prices are always caused by a binding constraint on the Marengo-Pleasant Valley 138-kV line (with flow from Marengo to Pleasant Valley) for the ComEd 345-L15616-R contingency (loss of the Cherry Valley-Silver Lake 345-kV line).

The generators with the most sensitivity for controlling this constraint (on the constrained side) are Rocky Road owned by Dynegy, Elgin owned by Ameren-UE, Waukegan owned by

Midwest Generation, and Aurora owned by Reliant. Given the diversity of ownership, it is unlikely that this constraint could be exploited by a single company for profit maximization.

E.3.3.8 Gillespie Congestion Region

The Gillespie congestion zone, which is only significant for the Appendix F.2 case, is associated with the 138 kV buses at the Gillespie, N. Staunton, and to a lesser extent, the Litchfield substation. It is shown visually in Figures E.3-2 and F.2-33, immediately to the northeast of St. Louis. These high prices are always caused by a binding constraint on the N. Lac-Gillespie 138 kV line with the binding flow always from N. Lac to Gillespie. Most of the time (> 90%) this congestion is due to the Ameren AMRNMTL71A contingency (loss of the Coffeen-Roxford 345 kV line; this is also the IP95 contingency), with most of the other times due to the IP96 contingency (loss of the West Frankfort-Mt. Vernon 345 kV line).

This constraint tends to occur during lower load periods, when sensitive generators on the constrained side of the line are either on an outage, or not dispatched because of low system LMPs. These generators include Coffeen owned by Ameren-CIPS, the Holland Energy Center owned by Constellation Power, and Kincaid owned by Dominion Energy. Given the diversity of ownership, and the associated low load conditions, it is unlikely that this constraint could by exploited by a single company for profit maximization.

E.3.3.9 Northbrook Congestion Region

The Northbrook congestion zone is a localized problem that occurs for just a handful of hours. It is caused by an overload on the Northbrook-Dearfield 138-kV line (with flow going from Northbrook to Dearfield) during the 138-L15912_B_N contingency (loss of the parallel line from Northbrook to Dearfield) under very heavy load situations (> 30 GW) with a simultaneous outage of one of large Waukegan units. This results in very high LMPs on the Waukegan buses, greatly increasing total profits. During the few hours, this constraint that is binding Midwest Generation could probably increase profits by submitting high bids for the non-outaged Waukegan units.

To examine the extend to which Midwest Generation could increase its profits under high but not peak load conditions, the 90% of peak case was examined (again with the assumption that all Illinois units are in-service). The results of bid manipulation at Waukegan are shown in Table E.3-10. Once their bids exceed their existing bus LMP (multiplier equal 2), their net generation at Waukegan rapidly decreases, resulting in a reduced overall profit. For a range of bids, they seem to have about 45 MW of must-run generation at Waukegan, but there is a limit. For high enough bids, their net generation drops to zero, with overall decreased profits. So in general just modifying the Waukegan bids would not be profitable under the 90% of peak scenario. But the presence of the Northbrook Congestion region in the marginal cost studies indicates that for extremely high loads, coupled perhaps with other generator outages, Midwest Generation could profitably benefit from high bids at Waukegan.

Table E.3-10 Variation in Midwest Power's Profit for Modified Waukegan Bids

Waukegan Bid Multiplier	Total Waukegan Generation (MW)	Waukegan LMP	Midwest's Relative Profit
1.0	789	28.9	1.000
1.5	789	28.9	1.004
2.0	65	31.8	0.891
3.0	44	37.5	0.908
4.0	49	38.7	0.904
6.0	43	53.5	0.921
8.0	0	69.2	0.875

E.3.3.10 Gallatin Congestion Region

The LMPs at the Carmel and Gallatin 69-kV buses are occasionally high due to congestion on an electrical equivalent 69-kV line from Hamilton to Carmel. Since the high LMPs are due to congestion only on an equivalent line (i.e., mathematically the line represents the aggregate impedance of several lines), this congestion may not actually occur in actual operation.

E.3.4 PROFIT MAXIMIZATION BY INDUCING NEW CONGESTION

The previous section examined the major congestion regions that would be expected if all generators submitted marginal cost bids, and discussed how different companies might exploit this congestion to increase their profits. This section discusses the potential for profit maximization by inducing new congestion. Examples are given using the 90% loading case from the previous section, which assumes all in-state generation is in-service. This case models a total load of about 30 GW of Illinois load. As was mentioned earlier, the system load should be at or above 90% of peak for about 80 hours per year.

E.3.4.1 Exelon Generation

In year 2007, Exelon Generation will own the largest percentage of the in-state generation, with a just over 20% market share. However, even with such a large percentage, no profit maximization potential was observed with its nuclear plants for the 90% of peak case. Attempts to increase profits by upping the bids resulted in a rapid loss of market share. Since the nuclear plants have costs well below their bus LMPs during the high-load condition, loss of market share resulted in substantial loss of revenue. Initially the Exelon Generation plants were producing 9,764 MW. With bids equal to 2 times marginal cost, their generation was reduced to 8,064 MW and their net profit to about 89% of that obtained with marginal cost bids. When bids are increased to 3 times marginal cost, the generation falls to 2,771 MW and the profit to 40% of marginal cost bids. Increasing the bids to 4 times marginal cost results in a dispatch of only 200 MW and profits well below 10% of marginal cost bids. Of course, unusual situations, such as the outage of several large coal units, could result in profit maximization opportunities. However, given the costs associated with starting/restarting and cycling nuclear plants, it is

doubtful that a strategy of trying to maximize profits by submitting bids significantly above marginal costs would be beneficial.

E.3.4.2 Midwest Generation

In year 2007, Midwest Generation will own approximately 20% of the total in-state generation. The analysis presented here first looked at the 90% of peak loading case, which assumes all in-state generation is available. Figure E.3-3 shows a contour of the northern Illinois LMPs for this case assuming all generators submit marginal cost bids. Midwest Generation is producing 5,328 MW, with an average bus LMP of $28.0/MWh and a maximum LMP of $32.9/MWh. If any of their generators or even a small number try to increase profits by submitting higher than marginal costs bids (assuming all other companies do not), then the result will be a decreased profit.

However, if a large number of their units submit bids substantially above their marginal costs, they can increase their profit. Table E.3-11 provides results for the case in which generators at Collins, Powerton, and Waukegan submit bids equal to their marginal cost, while all the other Midwest Generation plants submit bids equal to a bid multiplier times their marginal cost. As indicated in the table, for small values above marginal cost, there is an initial slight increase in their profit. This increase would be expected, since initially some of the Midwest Generation units are marginal units (that is, they are not dispatched at their limits, and hence are being used to set prices). Then, there is a rapid decrease in profit as Midwest Generation loses market share. Eventually, however, their market share stabilizes as the other available generators become fully dispatched and lines begin to congest. For high enough values, they have several units reduced to must-run status, allowing them to arbitrarily set the LMPs at these buses. In this example, this situation occurs at Will County, Crawford, and Fisk. This situation then allows them to increase their profit substantially above the marginal cost value. The LMP contours for the ten times marginal cost case are shown in Figure E.3-4. Note that while the presence of an extremely high cost band stretching across the southern part of the Chicago metro area, prices throughout the entire Chicago metro region have increased but those further west have actually decreased.

Next, this profit maximization approach was tested for an 85% of peak load case, again with all units in-service. The system load should be at or above this value for about 150 hours per year. For this level of loadings, Midwest Generation could raise the average bus LMPs, but could not do so profitably. As their bid multiplier was increased, their total generation and relative profit both rapidly decreased, until eventually none of their generation with non-marginal costs bids was being dispatched.

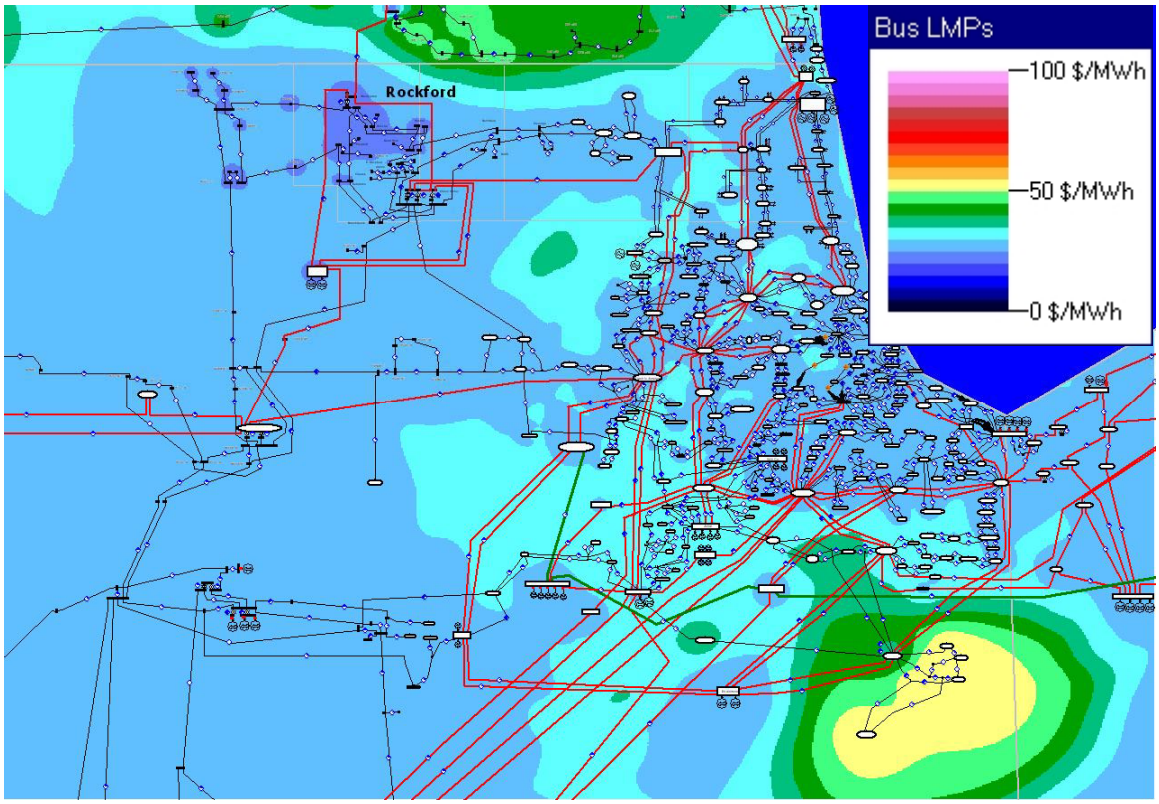

Figure E.3-3 Northern Illinois LMP Contours for 90% of Peak Case with Marginal Cost Bids

Table E.3-11 Variation in Midwest Generation Relative Profit

Bid Multiplier	Total Midwest Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	5,330	1.000	28.0	32.9
1.5	5,330	1.033	28.3	32.9
2.0	4,587	0.985	30.3	35.2
3.0	2,981	0.75	36.6	55.1
4.0	2,935	0.89	43.3	73.4
5.0	2,860	0.98	49.7	91.7
6.0	2,851	1.12	42.32	110
8.0	2,831	1.37	41.00	147
10.0	2,717	1.46	41.30	183
12.0	2,683	1.57	98.2	200
14.0	2,673	1.73	110.0	257

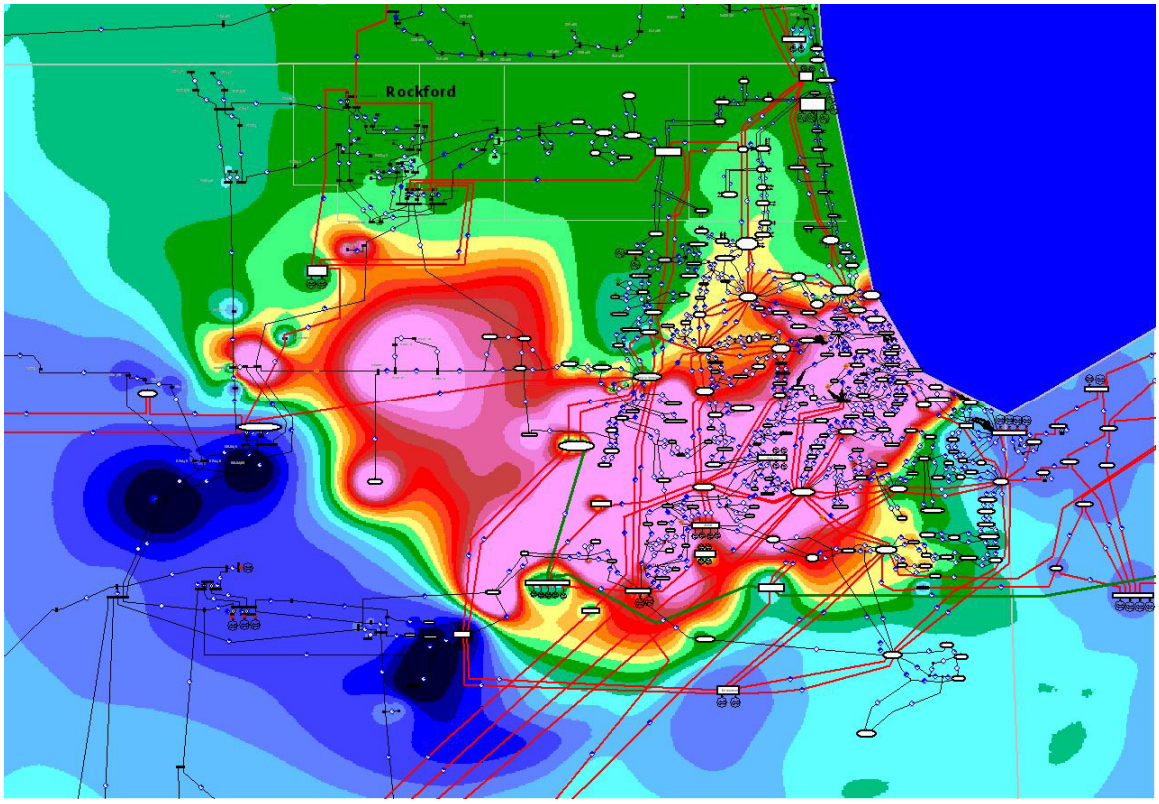

Figure E.3-4 Northern Illinois LMP Contours for 90% of Peak Case with Select Midwest Generation Units Bidding 10 Times Marginal Cost

E.3.4.3 Ameren – CIPS and Ameren – UE

In year 2007, Ameren CIPS and Ameren UE will own slightly more than 10% of the in-state generation. No profit maximization potential was observed for their combined generation portfolio for the 90% of peak case. This is probably due to the generators being more geographically dispersed, located near plants from other companies (such as Dynegy), and located in portions of the State with a relatively low load density. Of course, unusual situations may result in profit maximization opportunities.

E.3.4.4 Dynegy

In year 2007, Dynegy will own about 8 or 9 percent of the in-state generation. As with Ameren, no profit maximization potential was observed for the Dynegy generators for the 90% of peak case. The Dynegy generators are also geographically dispersed with significant amounts of generation from other companies (such as Ameren) sharing the same footprint. Of course, unusual situations may result in profit maximization opportunities.

E.3.4.5 Ameren – CILCO

Results for CILCO are discussed in Section E.3.3.1, the Peoria Congestion Region.

E.3.4.6 CWLP

CWLP is a municipally owned utility, so it would seem unlikely that they would seek profit maximization. Nevertheless, for completeness, results for CWLP are included here. Bid increases for the CWLP generators initially result in loss of market share and decreased profit. However, eventually a situation is reached in which some generation becomes must-run. For CWLP, this generation is at the Dallman 69-kV bus (Dallman 1 and 2). The binding constraint is the Auburn-Chatham 138-kV line (with flow from Auburn to Chatham) for contingency IP109 (the loss of the entire Latham 345 kV and some 138 kV). Full results are given in Table E.3-12.

Table E.3-12 Variation in CWLP Relative Profit

Bid Multiplier	Total CWLP Generation (MW)	Relative Profit	Avg LMP	Max LMP
1.0	448	1.000	28.6	26.6
2.0	143	0.612	35.0	39.8
3.0	121	1.001	53.5	65.6
4.0	121	1.503	72.6	114.8

APPENDIX F
POWERWORLD® DETAILED RESULTS

APPENDIX F.1

Appendix F.1 provides additional results for the original case with all generators bidding their marginal costs with no inclusion of their fixed costs.

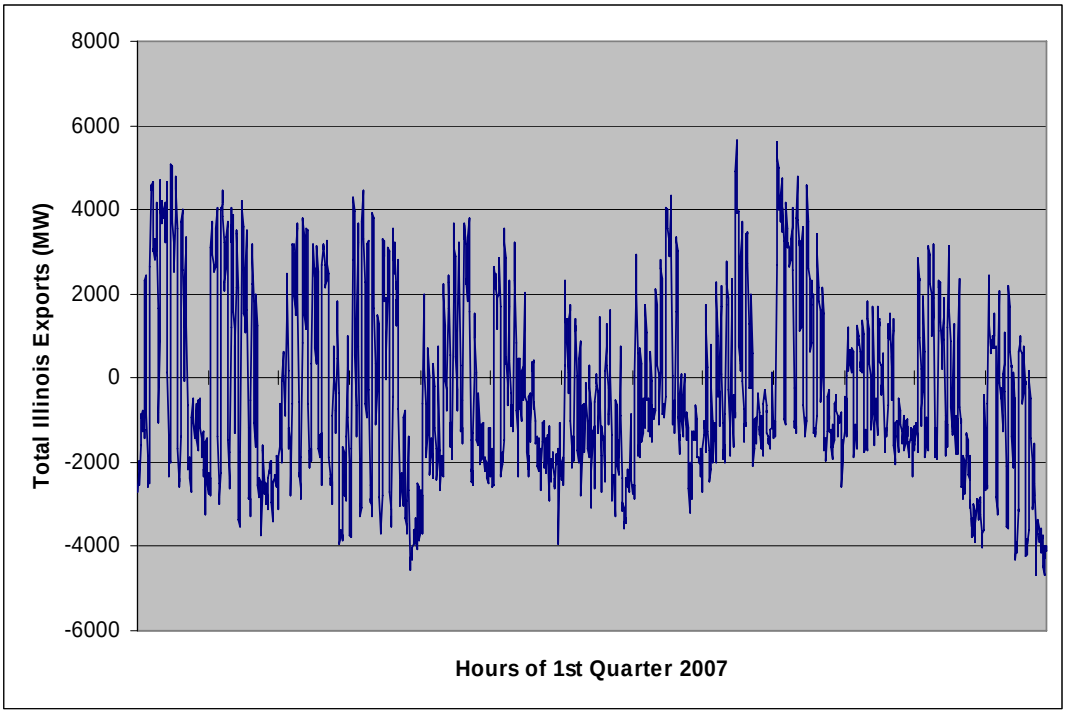

Figure F.1-1 Hourly Power Exports for Illinois during the 1st Quarter 2007

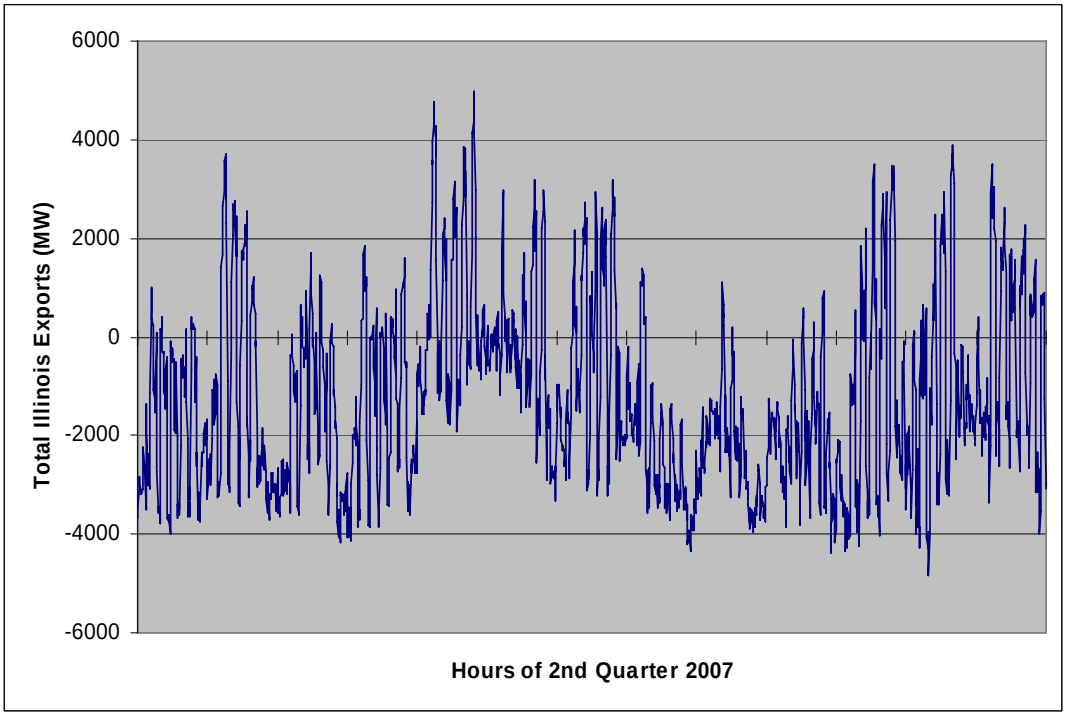

Figure F.1-2 Hourly Power Exports for Illinois during the 2nd Quarter 2007

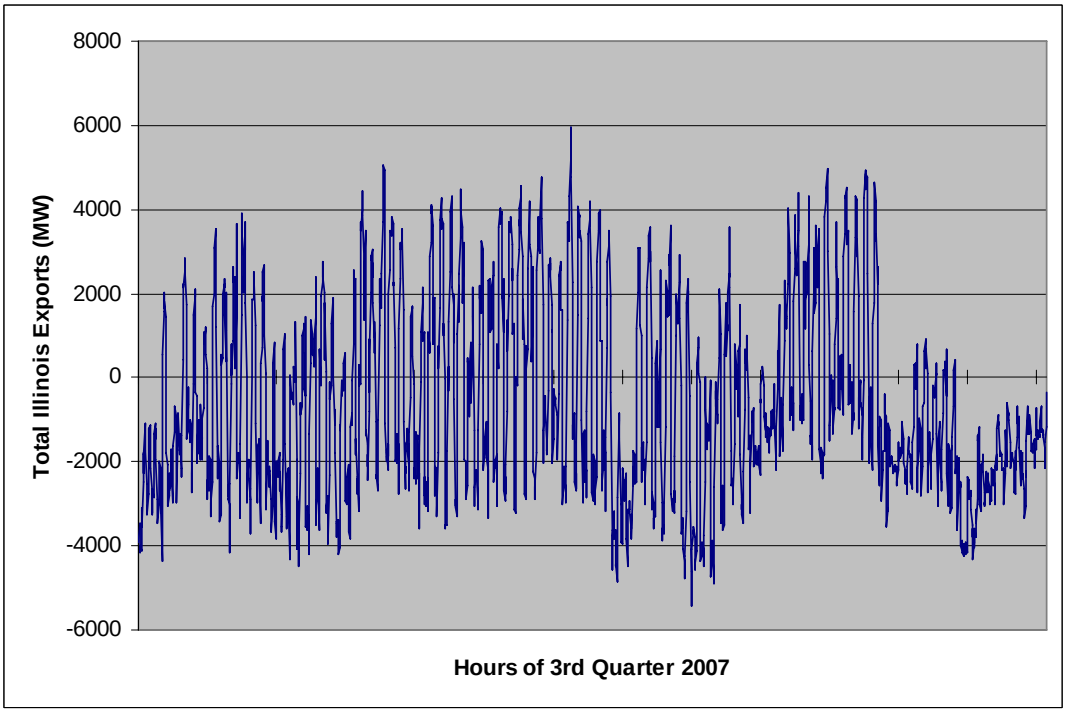

Figure F.1-3 Hourly Power Exports for Illinois during the 3rd Quarter 2007

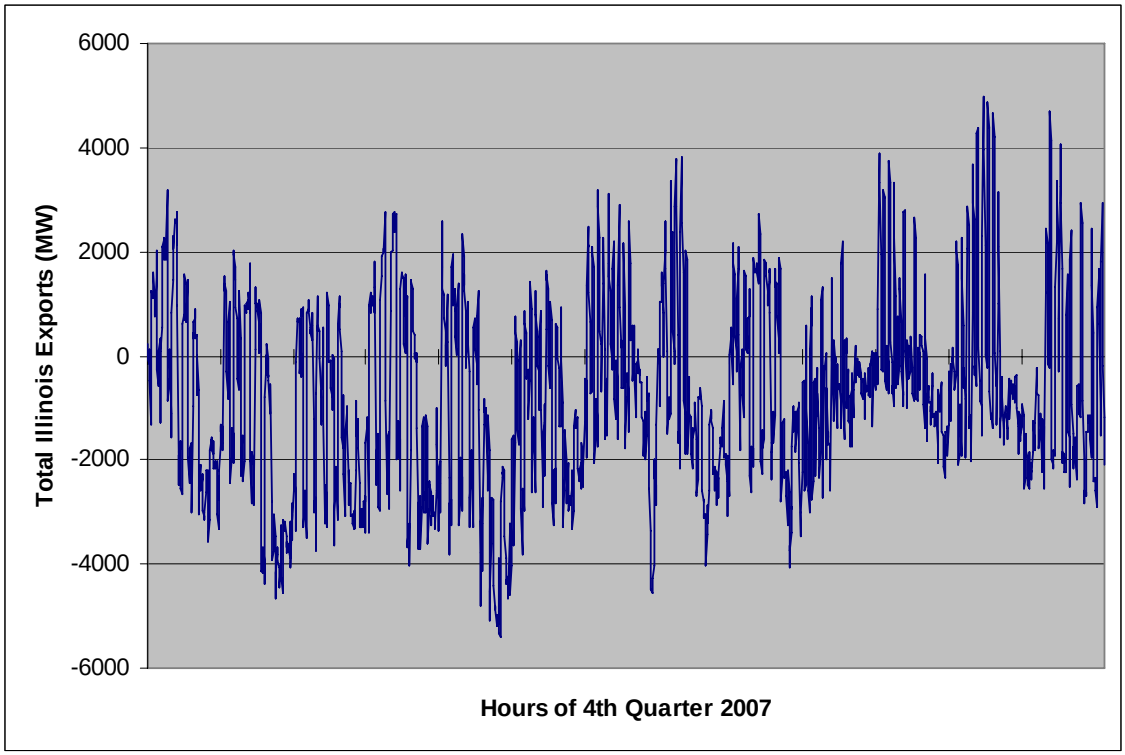

Figure F.1-4 Hourly Power Exports for Illinois during the 4th Quarter 2007

Table F.1-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
WI	ARP 138	ARP 345	1	WIS39244ARP345-39785ROCKYRNC1	7580	21.64	129.65
Ameren-MO	ORAN	STODDARD	1	AMRNMTL51	5705	54.56	383.3
EEI	JOPPA S	JOPTAPY	3	EEIDOE33392JOPPAS-33395JOPTAPXC2	4980	1.74	16.28
IP-MEC	GALESBRG	GALESBR5	2	345-L15502_B-R	2708	10.25	33.47
Ameren-MO	FRED TAP	FREDTOWN	1	AMRNMTL73	2393	19.05	167.75
WI	OK CRK9	OC CRK6	1	WIS38857OCCRK8-39367OKCRKC1	2374	1.04	12.87
WI	EDG 345	CEDRSAUK	1	WIS38870GRANVL2-39433PTBCH1C1	1985	2.47	5.58
TN (TVA)	8JVILLE	8CUMBERL	1	TVA184258CUMBERL-184308DAVIDSOC1	1984	9.24	36.29
ComEd	MAREN;RT	P VAL; R	1	345-L15616-R	1866	9.65	119.49
WI	BAIN 5	PLS PR4	2	WIS38850PLSPR3-38851PLSPR4C1	1807	4.97	45.85
TN (TVA)	8CUMBERL	8DAVIDSO	1	TVA184228JVILLE-184258CUMBERLC1	1175	1.93	21.58
WI	PAD 345	PAD 138	1	WIS39058PAD345-39119ROE345C1	903	14.78	61.82
WI	DEAD RVR	DR NEU1	1	WIS39917DEADRVR-39898DRNEU1AC1	896	0.51	2.8
IN	08KOK HP	08KO IN5	1	AEP2266505GRNTWN-2266705JEFRSOC1	880	80.61	413.34
Ameren	ALBION	CROSSVL	1	IP98	650	9.63	95.02
ComEd	MAZON; R	OGLES; T	1	345-L15502_B-R	633	16.72	79.55
MO	MARIES	5MARIES	1	AMRNVSS17	629	67.84	180.62
Ameren-MO	CEE TAP	CENTRAL	1	Basecase	611	12.25	19.14
Ameren-MO	CEE TAP	CENTRAL	1	AMRNMTL55	510	10.65	14.98
IN	08WEBSTE	08NEWLON	1	AEP2266505GRNTWN-2266705JEFRSOC1	477	3.74	64.39
ComEd	FISK ; R	FISK STR	19	TR81_TAYLR_R-C	430	12.5	159.36

Table F.1-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
IA (MEC)	DAVNPRT3	WALCOTT3	1	MEC64402LOUISA3-64403EMOLIN3C1	361	1.69	3.67
CILCO	HOLLAND	MASON	1	CIL-6	349	16.66	92.19
Ameren-CWLP	AUBURN N	CHATHAM	1	IP109	347	4.9	43.16
ComEd	HILLC;6B	WILL ;BT	1	Basecase	332	3.76	9.36
IP-CILCO	1346A TP	KICKAPOO	1	345-L0304_R-S	289	2.87	20.47
ComEd	FISK ; B	FISK STR	19	TR82_TAYLR_B-C	258	8.39	18.86
ComEd	SLINE;5S	WASHI; R	1	345-L17723_B-C	232	7.48	141.32
IP-MEC	GALESBRG	GALESBR5	2	L0304-A	231	5.02	19.97
ComEd	LASCO; B	MAZON; B	1	345-L1223_R-S	218	37.42	104.26
Ameren	HAMLTNAM	HAMLTNAM	1	AMRNMTL32	198	5.19	11.97
ComEd	CLYBO; B	CROSB; B	1	138-L4018_R-C	184	0.53	8.89
CILCO	RS WALL	RSW EAST	1	Basecase	184	197.49	1000
CILCO	HOLLAND	MASON	1	345-L0304_R-S	180	14.29	139.47
MI	05BENTON	05COOK	1	AEP2265405COOK-2853818PALISAC1	179	8.48	14.76
ComEd	ELECT;3R	ELECT;3M	1	TR84_ELECT_R-N	177	5.36	35.99
ComEd	CLYBO; B	CROSB; B	1	345-L4621_B-N	167	1.73	35.92
SIPC-BREC	14MORGAN	2GALTN_S	1	IP98	167	24.73	113.49
IP-MEC	GALESBRG	GALESBR5	2	345-L0404-R	162	9.76	22.88
ComEd	BARTL;BT	SPAUL; B	1	345-L14402_B-N	157	8.17	17.82
IP	SPRTA TP	ARCH TAP	1	IP96	156	11.64	46.63
ComEd	ELMHU;3I	F PAR; B	1	TR81_ELMHU_R-N	156	4.44	103.21
ComEd	JEFFE; B	KINGS; B	1	138-L1110_B-C	145	6.72	121.8
ComEd	DAVIS; B	DAVIS;3M	1	345-L17704_R-S	145	72.36	511.77
Ameren-MO	MARBHD N	PALMYRA	1	AMRNMTL58	137	5.91	15.55
WI	EDG 345	CEDRSAUK	1	WIS38898PTBCH2-39433PTBCH1C1	132	2.64	5.44
IP	MT VRNON	ASHLEY	1	IP96	132	49.24	166.79
ComEd	MAZON; R	OGLES; T	1	345-L2101-S	129	20.54	61.22
ComEd	CLYBO; B	DIVER; B	1	138-L4018_R-C	129	0.25	0.35
ComEd	SLINE;2S	WASHI; B	1	138-L0708_B-C	123	2.4	29.3
ComEd	MAZON; R	OGLES; T	1	IP108	123	22.33	62.23
Ameren	HAMLTNAM	KH2 XFMR	1	AMRNMTL32	118	18.29	29.93
Ameren	E.QUINCY	S.QUINCY	1	AMRNVSS112	106	4.34	11.27
Ameren	KINMUNDY	LOUISVL	1	IP98	105	7.66	20.23
IP-ComEd	PWR JCTB	POWER;	1	CIL-6A	97	36.76	94.55
ComEd	RIDGE; B	RIDGE;BS	1	138-L5118_B-S	95	9.85	210.56
ComEd	DIXON; R	NELSO;RT	1	138-L15507_B-R	92	80.81	300.08
Ameren-AEP	05BREED	CASEY	1	AEP2266705JEFRSO-2267105ROCKPTC1	89	0.91	2.68
ComEd	HARBO;8S	UNIVE; B	1	345-L17723_B-C	89	1.68	14.15
IA	HAZLTON5	HAZLTON3	1	ALTW34020HAZLS5-34018HAZLTON3C2	86	43.8	71.76
WI	OC CRK8	OK CRK	1	WIS39367OKCRK-39369OKCRK9C1	84	1.1	5.25
Ameren	RNTOUL J	SIDNYCPS	1	IP45	83	5.99	14.71
IN	07RAMSEY	07RAMSY5	2	CIN2518107RAMSY5-2538808SPEEDC1	81	557.74	1000

Table F.1-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
SIPC-BREC	14MORGAN	2GALTN_S	1	AMRNVSS76	76	8.91	42.41
ComEd	DAVIS;3M	DAVIS; B	1	345-L17704_R-S	74	65.09	352.35
CWLP	EASTDALE	EASTDALE	1	CWLPDALLMAN-DALLMANC1	70	3.57	6.87
WI	EDG 138	EDG 345	1	WIS39215EDG138-39214EDG345C2	67	223.54	372.49
Ameren	ROXFORD	SIOUX	1	Basecase	67	2.17	4.78
ComEd	Y450 ; R	CONGR; R	1	Basecase	63	1.37	17.32
Ameren	ALBION	CROSSVL	1	IP96	60	21.53	78.89
ComEd	HANOV; B	SPAUL; B	1	345-L14402_B-N	59	2.82	14.17
IP-Ameren	LANSVILL	LANSVILL	1	CWLPILLOPTP-INTERSTAC1	59	22.48	43.46
ComEd	CROSB; R	ROCKW; R	1	138-L6721_B-C	58	0.46	1.5
ComEd	ELECT;3M	ELECT;3R	1	TR84_ELECT_R-N	57	4.74	22.74
ComEd	TOLLW; B	TOLLW;3M	1	138-L7910_B-R	56	8.42	26.75
IP	SPRTA TP	ARCH TAP	1	IP30	55	8.84	25.04
SIPC	5MRN_PLN	5RNSHW_S	1	TVA184018SHAWNEE-184068MARSHALC1	50	8.82	28.31
OH	08BUFTN1	08BUFTN1	1	CIN2496206PIERC2-2602908FOSTERC1	47	98.03	181.51
ComEd	E FRA; B	GOODI;3B	1	Basecase	46	7.33	24.82
ComEd	ELWOO; R	GOODI;1R	1	345-L1223_R-S	45	6.97	28.56
ComEd	HILLC;6B	WILL ;BT	1	138-L0907_B-S	43	6.64	9.63
ComEd	CROSB; R	DIVER; R	1	138-L4013_B-C	43	0.08	0.17
ComEd	MAZON; R	OGLES; T	1	CIL-6A	42	13.4	34.13
ComEd	D799 ;6B	RIDGE; B	1	138-L1321_G-C	42	40.14	176.92
ComEd	CORDO; B	NELSO; B	1	345-L0404-R	40	1.78	14.28
ComEd	DEVON;3R	ROSEH;RT	1	138-L11416_R-C	39	35.93	329.23
IP-AEP	05EUGENE	BUNSONVL	1	AMRNVSS1	36	1.09	3.08
ComEd	WAYNE; B	WAYNE;1M	1	345-L14402_B-N	35	8.14	19.28
Ameren-IP	MAZON CY	1346A TP	1	CIL-6	33	8.94	32.63
IN	08GALAGH	08GALAGH	1	AEP2266705JEFRSO-2267105ROCKPTC1	33	0.58	1.34
ComEd	DIXON; B	NELSO; B	1	138-L15508_R-R	33	101.3	295.12
ComEd	MAZON; R	OGLES; T	1	345-L0302_B-S	32	10.88	39.5
SIPC-BREC	14MORGAN	2GALTN_S	1	SIPC333515MRN_PLN-333525RNSHW_SC1	31	40.94	83.52
ComEd	RIDGE; B	RIDGE;BS	1	138-L3705_B-C	31	2.16	43.42
ComEd	NELSO;RT	NELSO; R	1	138-L15507_B-R	31	7.68	26.98
IP-CILCO	1346A TP	KICKAPOO	1	CIL-6	31	17.41	49.4
ComEd	ELECT; B	ELECT;1M	1	TR82_ELECT_B-N	30	3.36	8.38
ComEd	UNIVE; B	WASHI; B	1	138-L13701_R-C	30	0.29	0.33
Ameren	COFFEEN	PANA	1	AMRNVSS36	29	0.9	2.19
ComEd	F PAR;5S	NATOM; B	1	138-L19209_B-C	27	0.36	0.78
ComEd	Y450 ; R	CRAWF;YS	1	Basecase	27	4.87	41.58
ComEd	Y450 ; R	CONGR; R	1	138-L6721_B-C	27	17.82	196.85
CWLP	WESTCHES	WESTCHES	1	CWLPPALOMINO-PALOMINOC1	27	4.59	9.29
ComEd	F PAR;0S	NATOM; R	1	Basecase	25	0.3	1.91

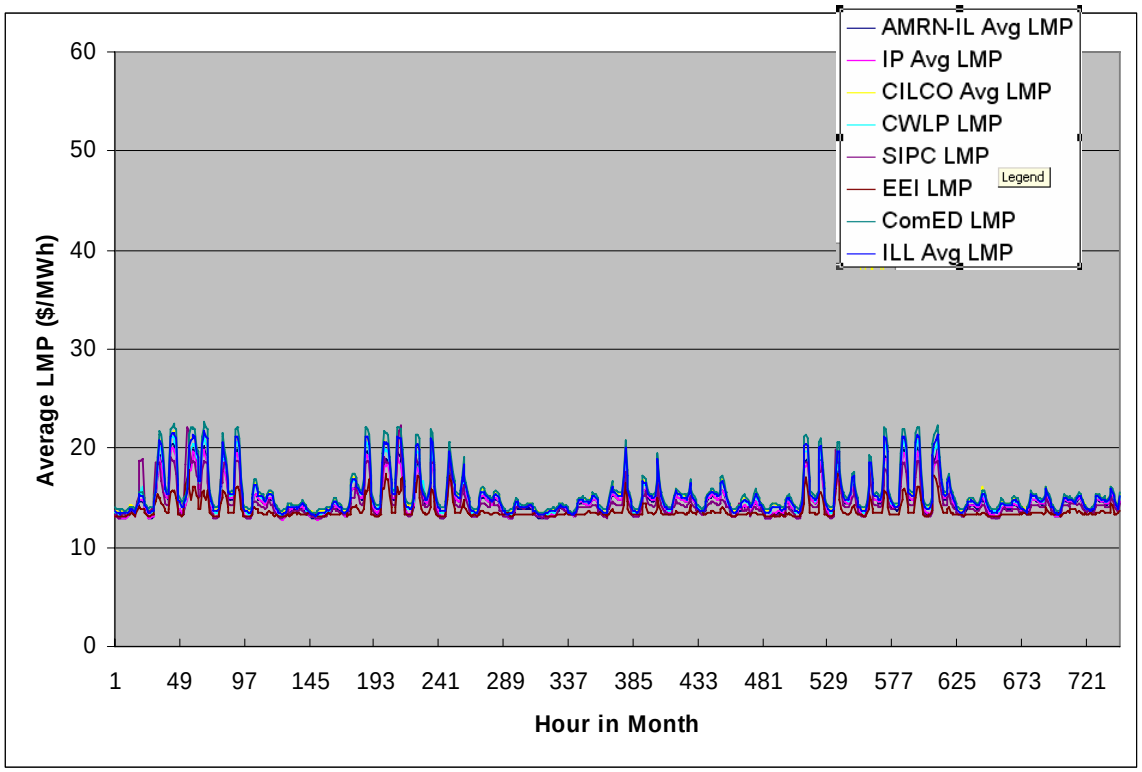

Figure F.1-5 Average LMPs for January 2007

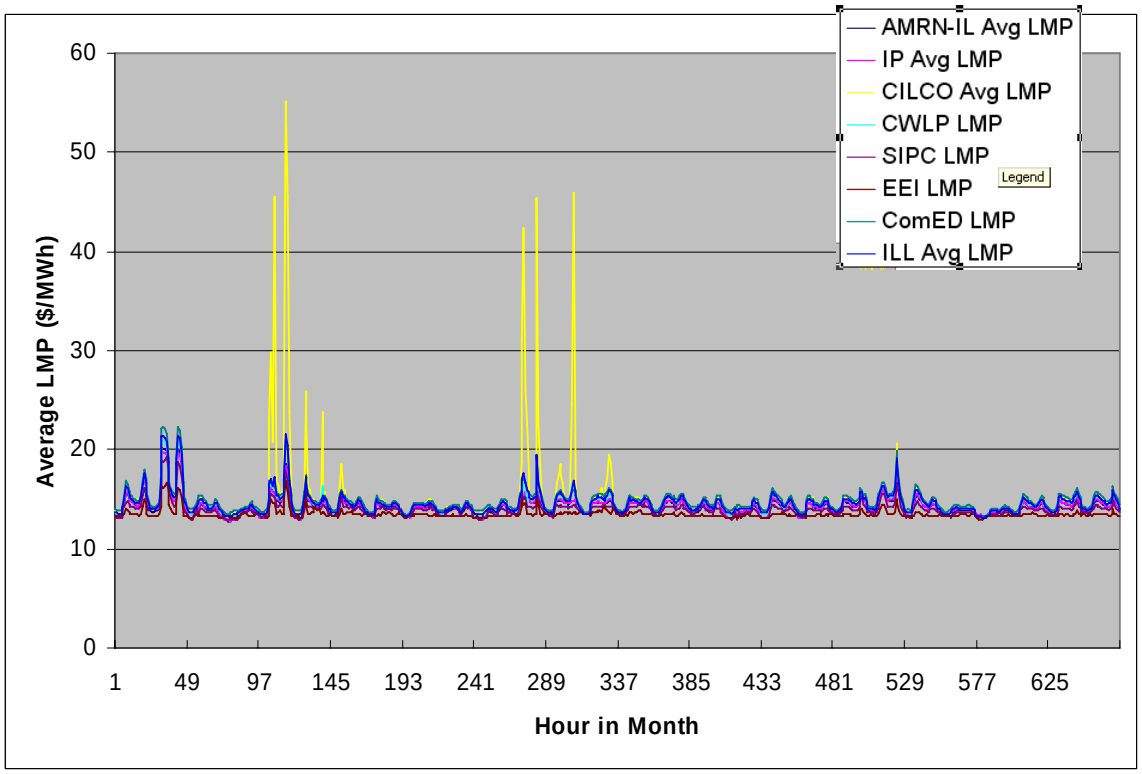

Figure F.1-6 Average LMPs for February 2007

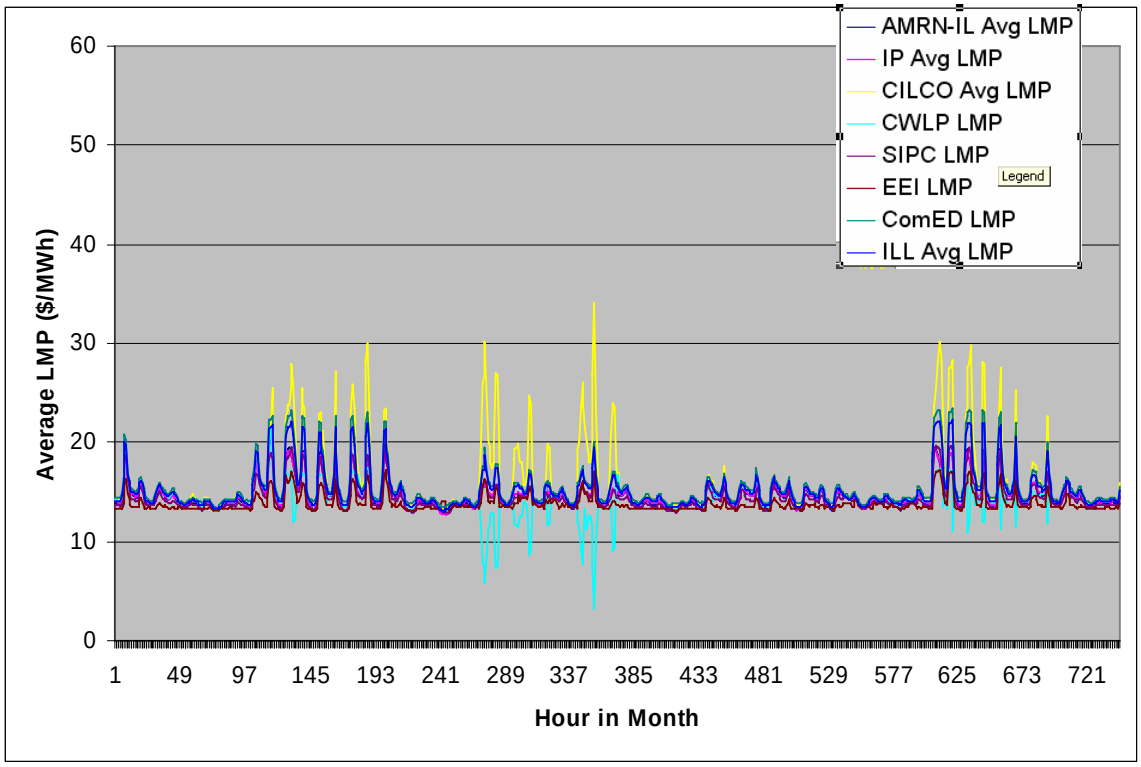

Figure F.1-7 Average LMPs for March 2007

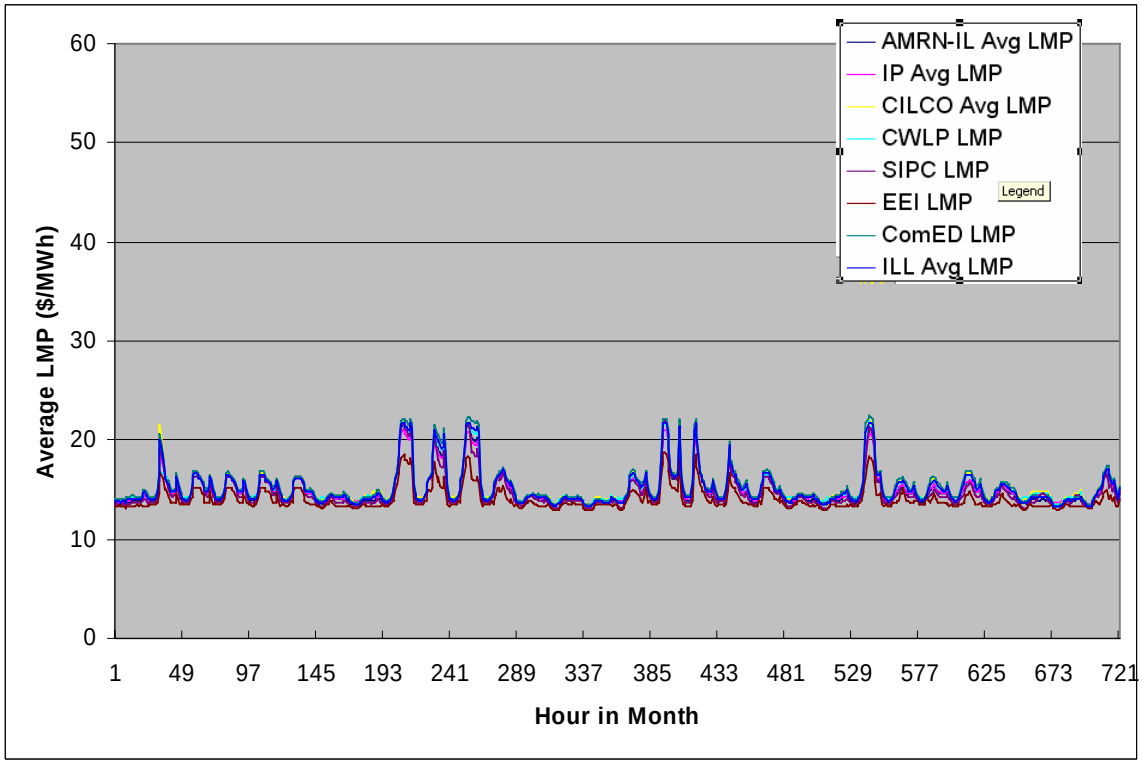

Figure F.1-8 Average LMPs for April 2007

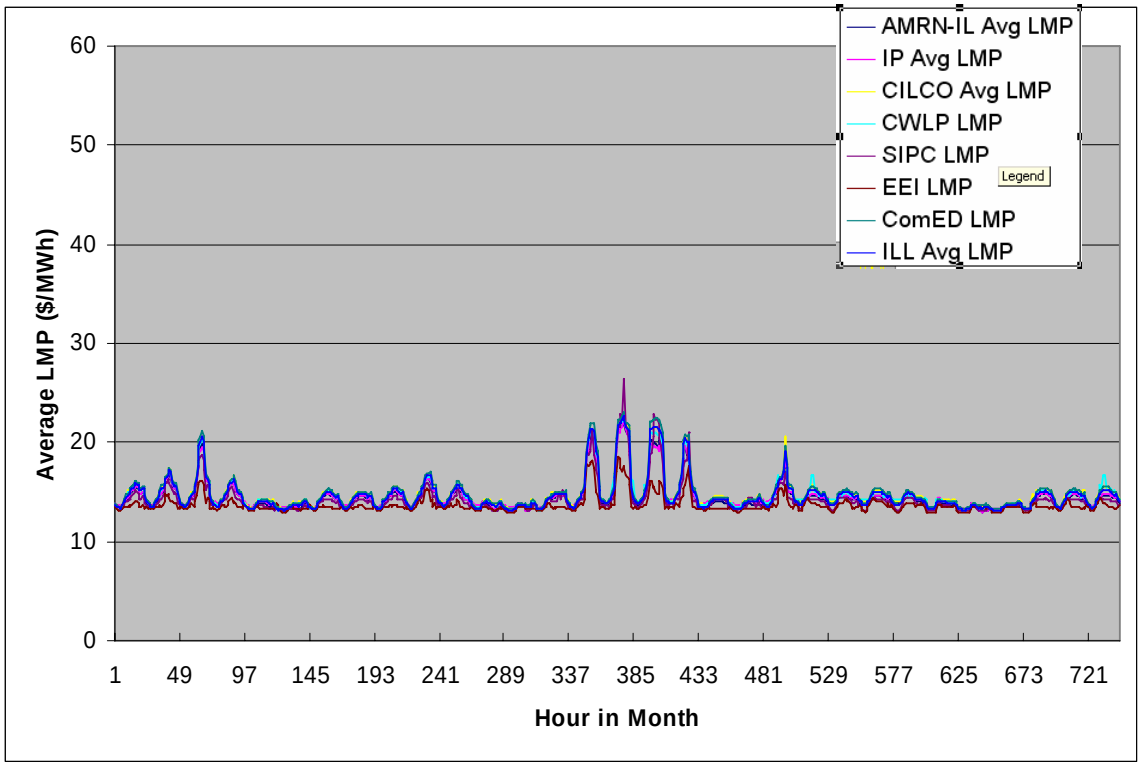

Figure F.1-9 Average LMPs for May 2007

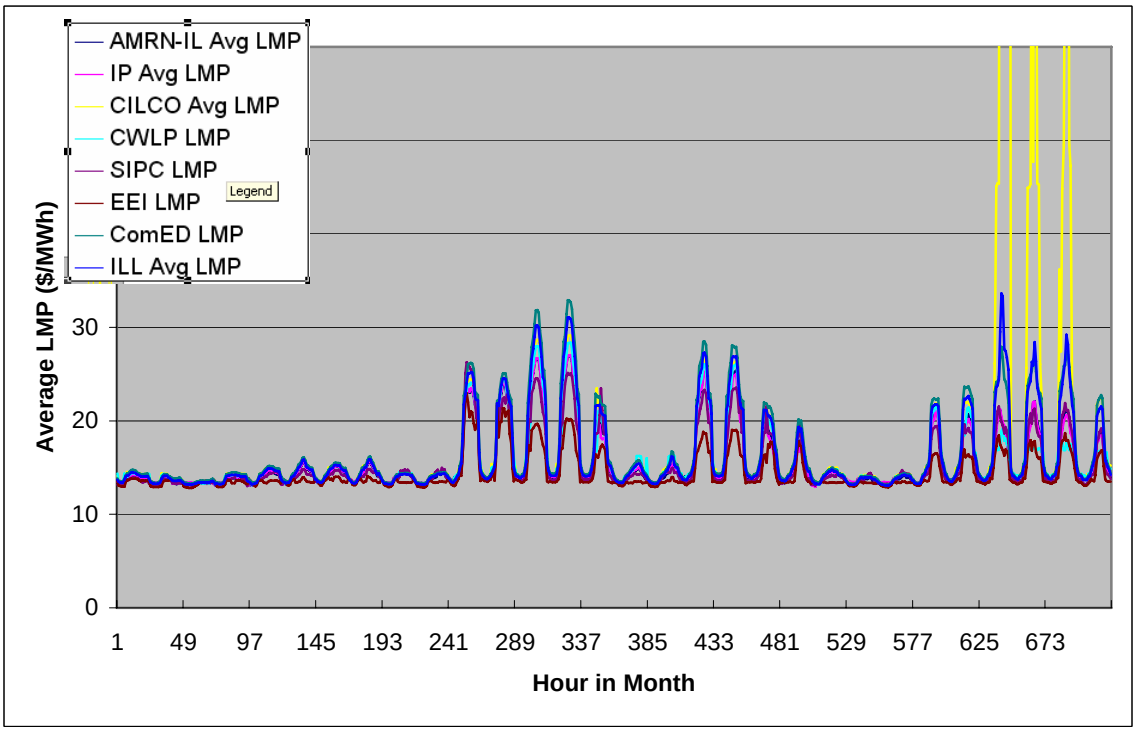

Figure F.1-10 Average LMPs for June 2007

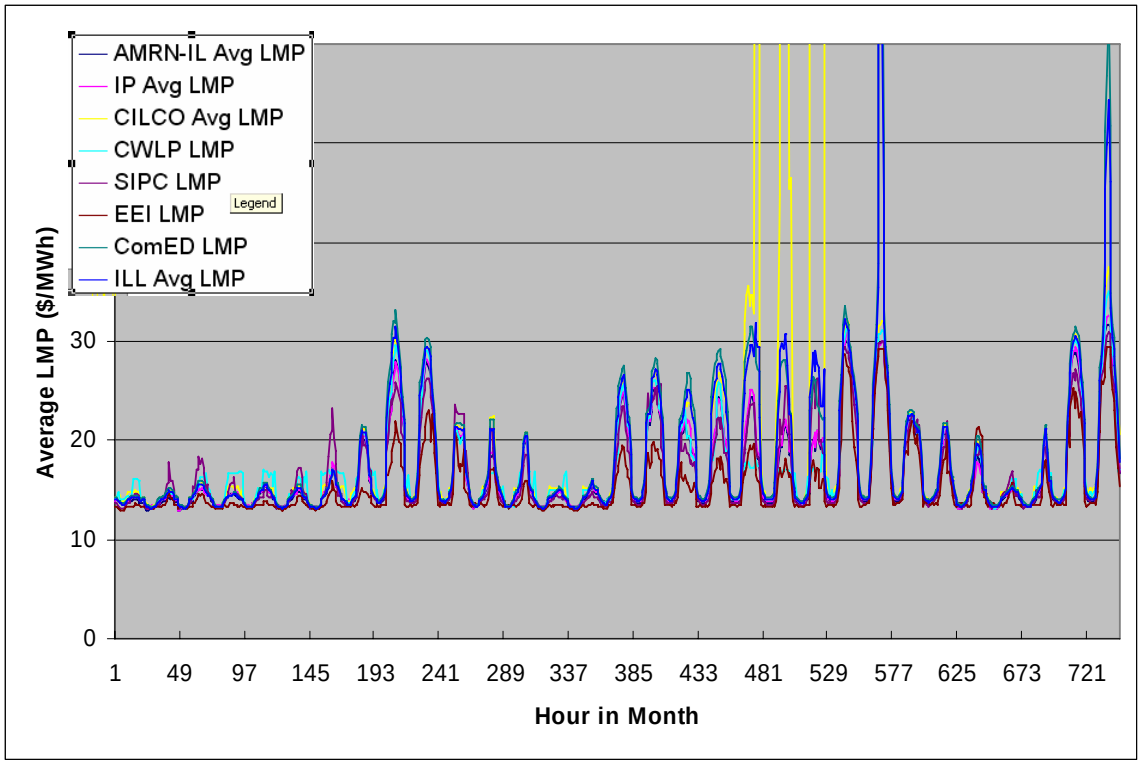

Figure F.1-11 Average LMPs for July 2007

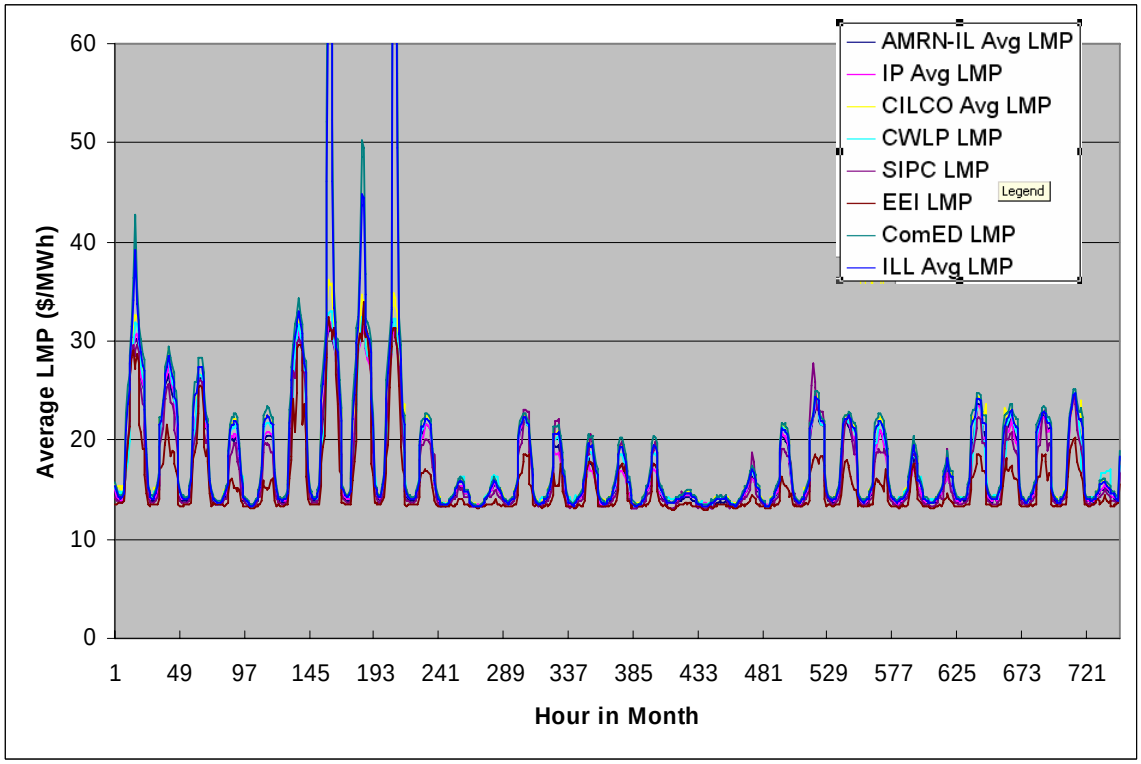

Figure F.1-12 Average LMPs for August 2007

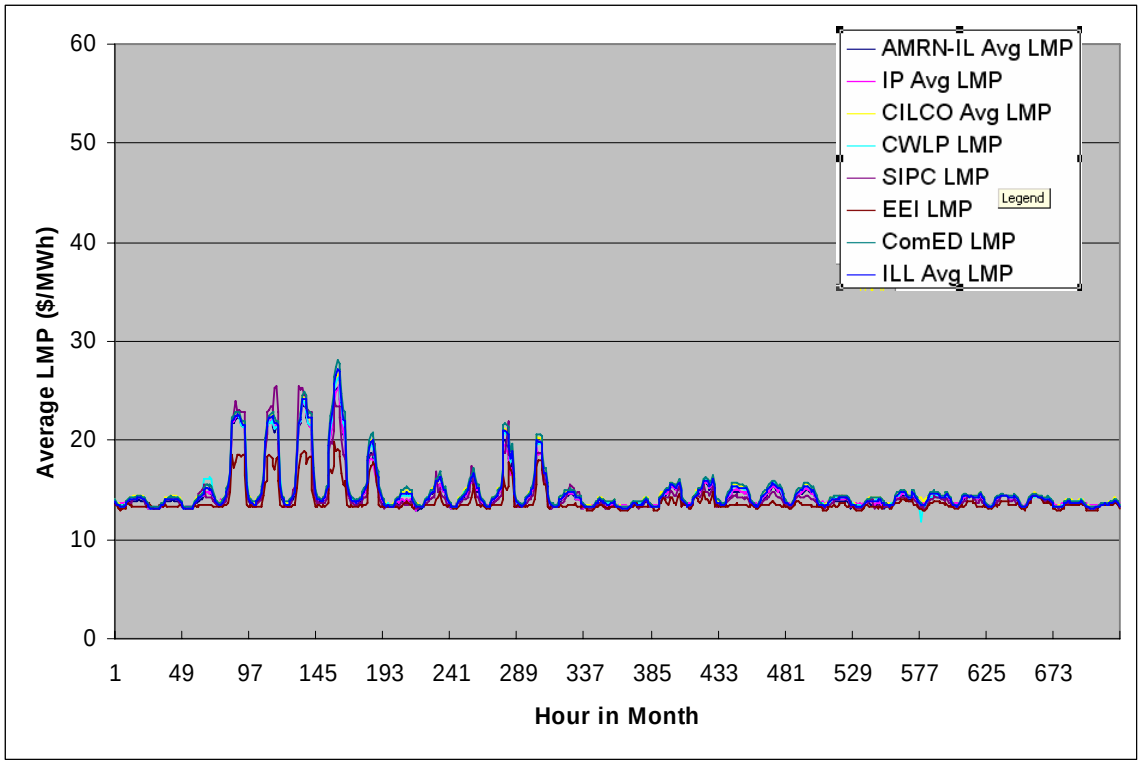

Figure F.1-13 Average LMPs for September 2007

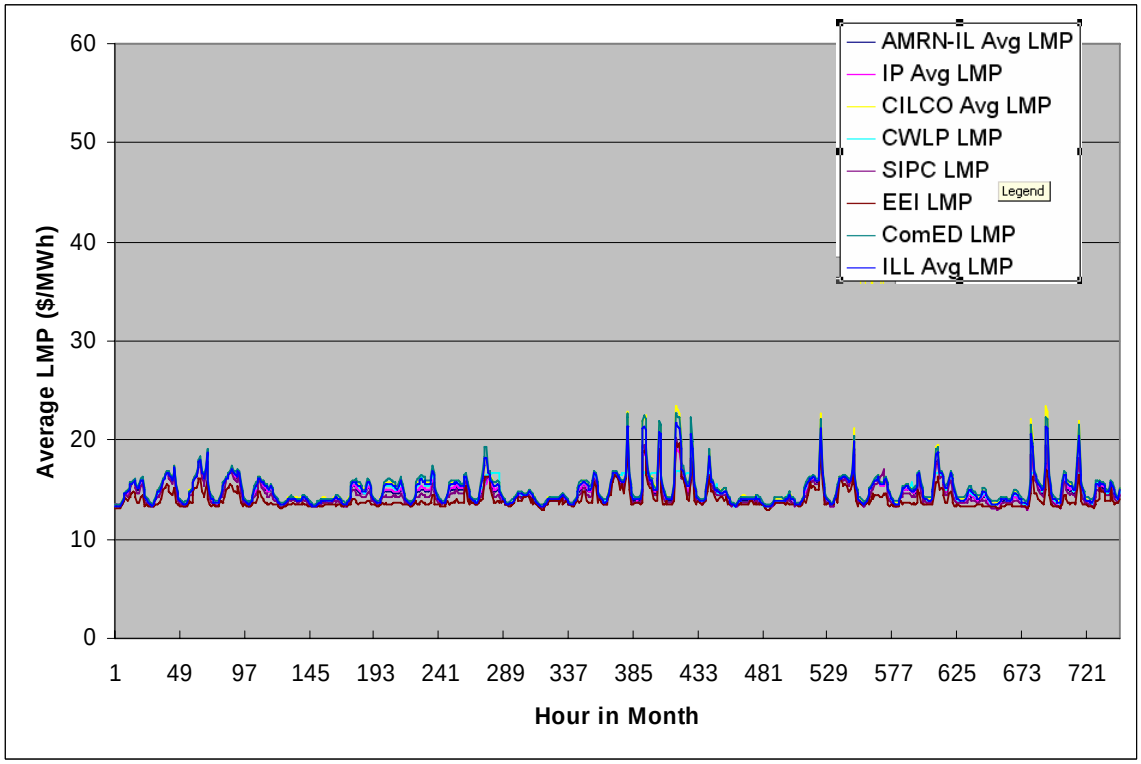

Figure F.1-14 Average LMPs for October 2007

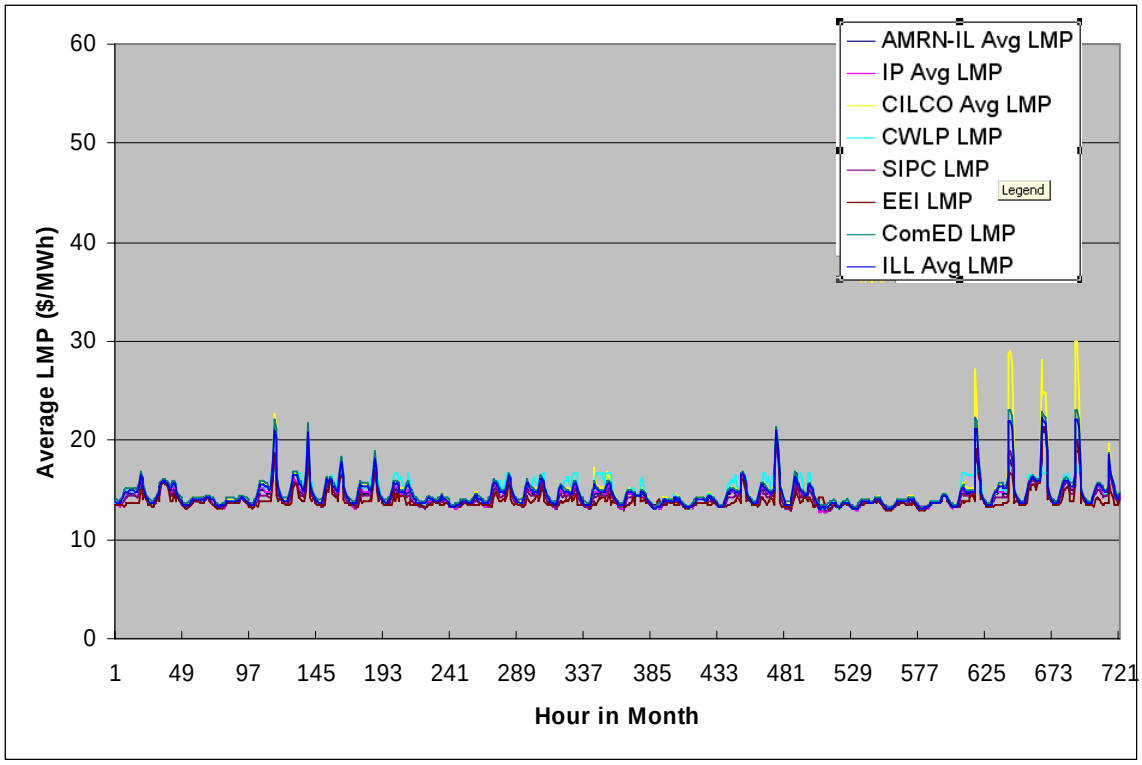

Figure F.1-15 Average LMPs for November 2007

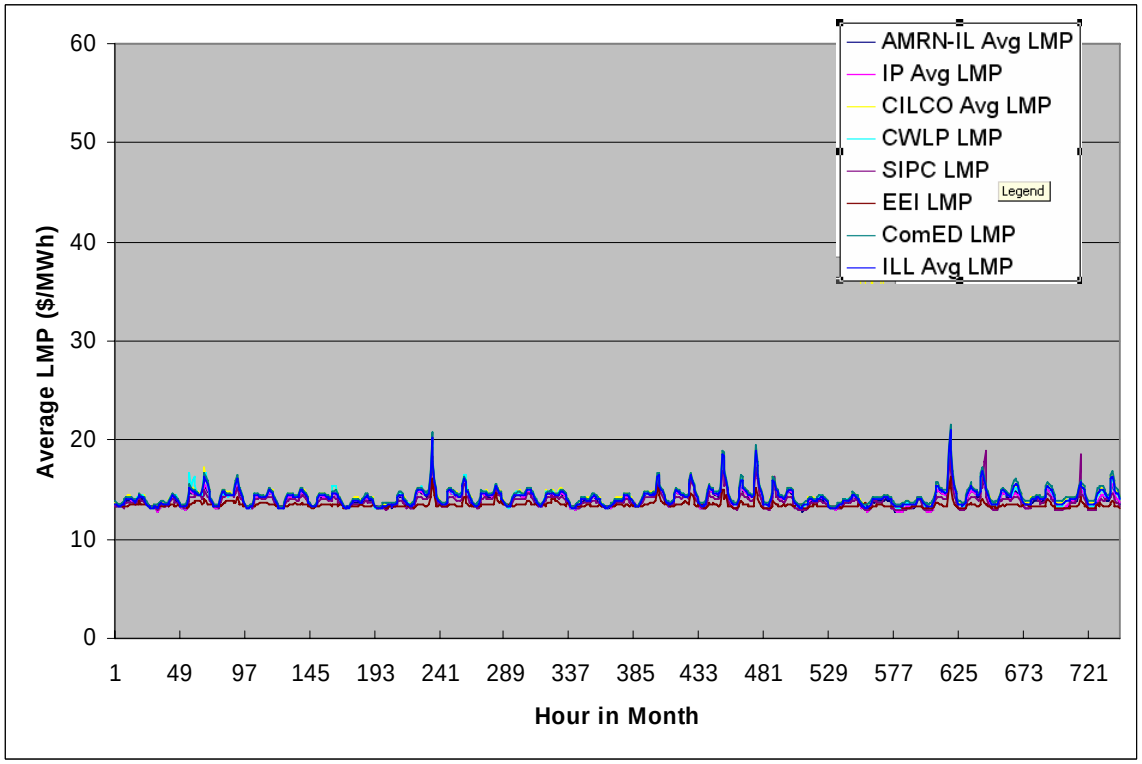

Figure F.1-16 Average LMPs for December 2007

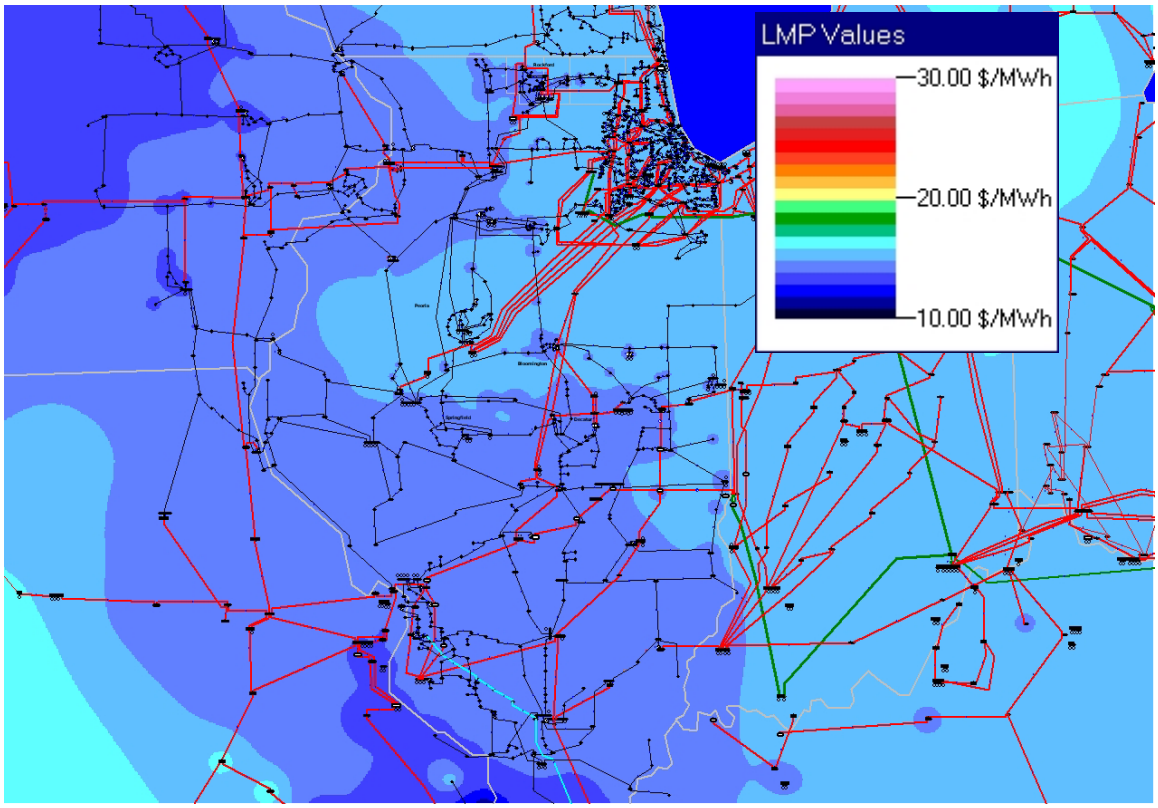

Figure F.1-17 Average LMPs for January to March 2007

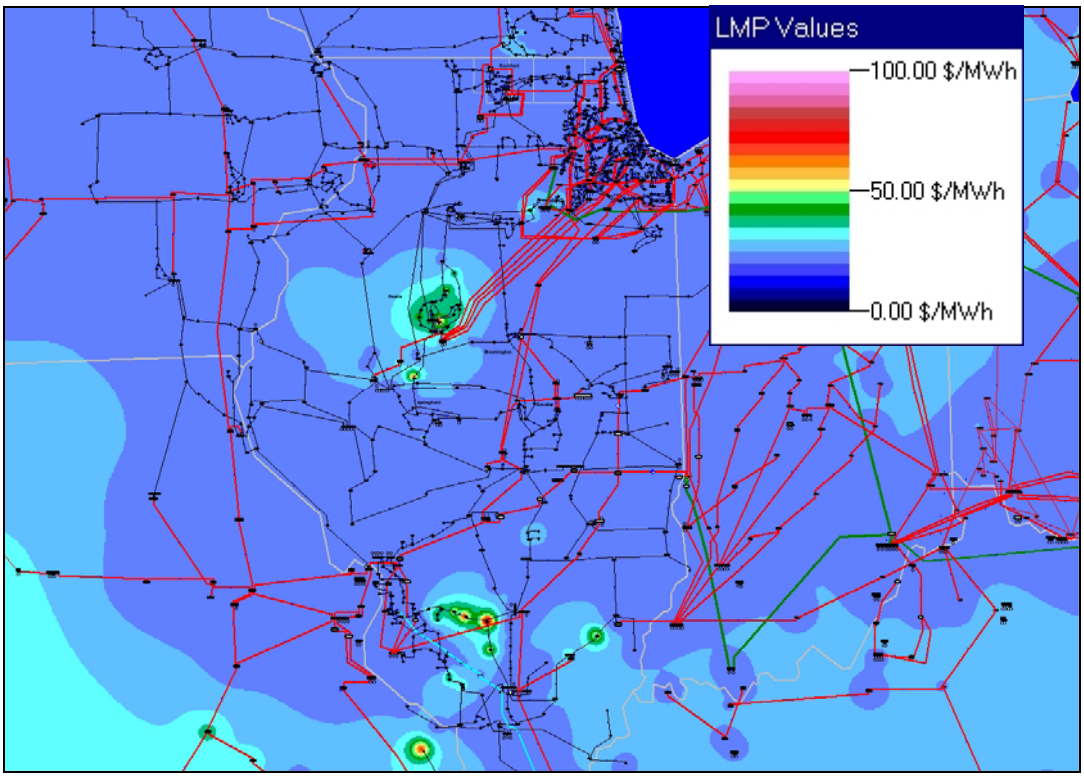

Figure F.1-18 Highest LMPs for January to March 2007

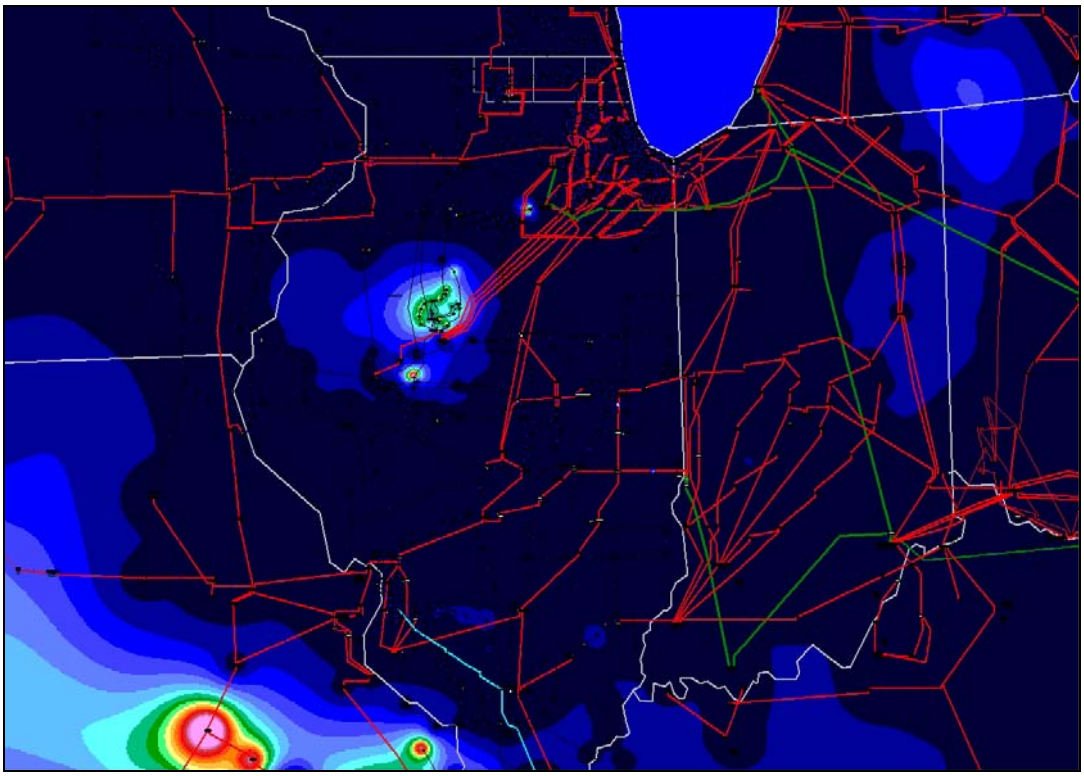

Figure F.1-19 Hours LMP Exceed $30/MWh for January to March 2007

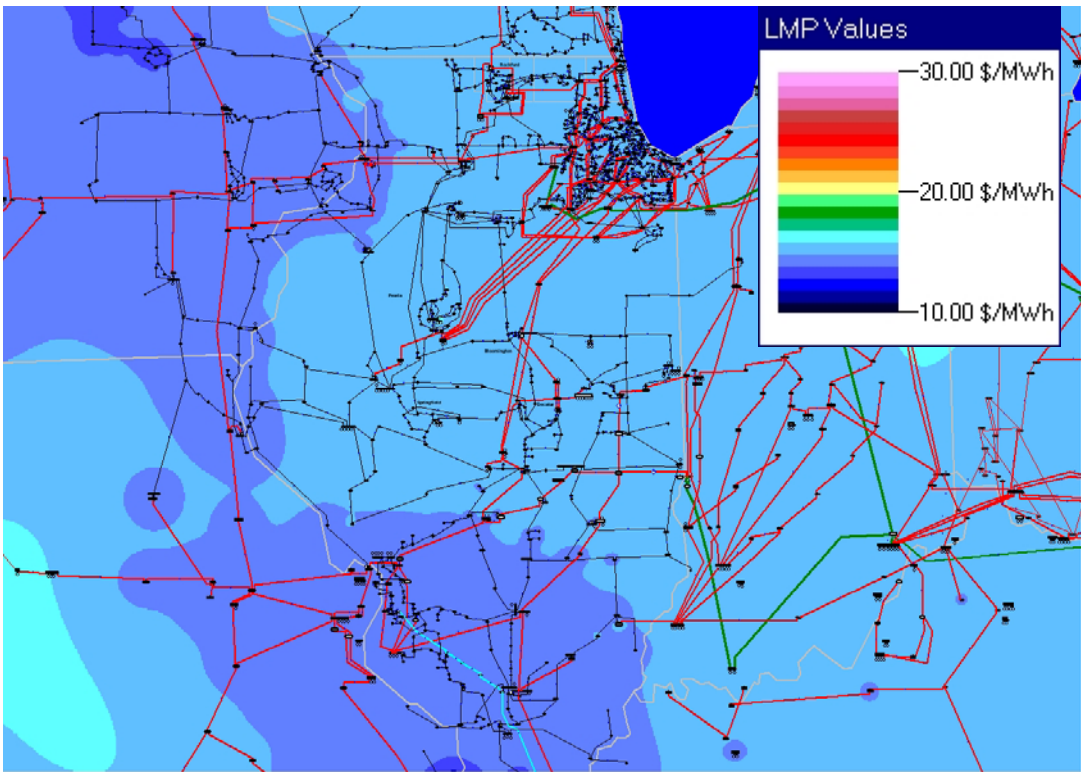

Figure F.1-20 Average LMPs for April to June 2007

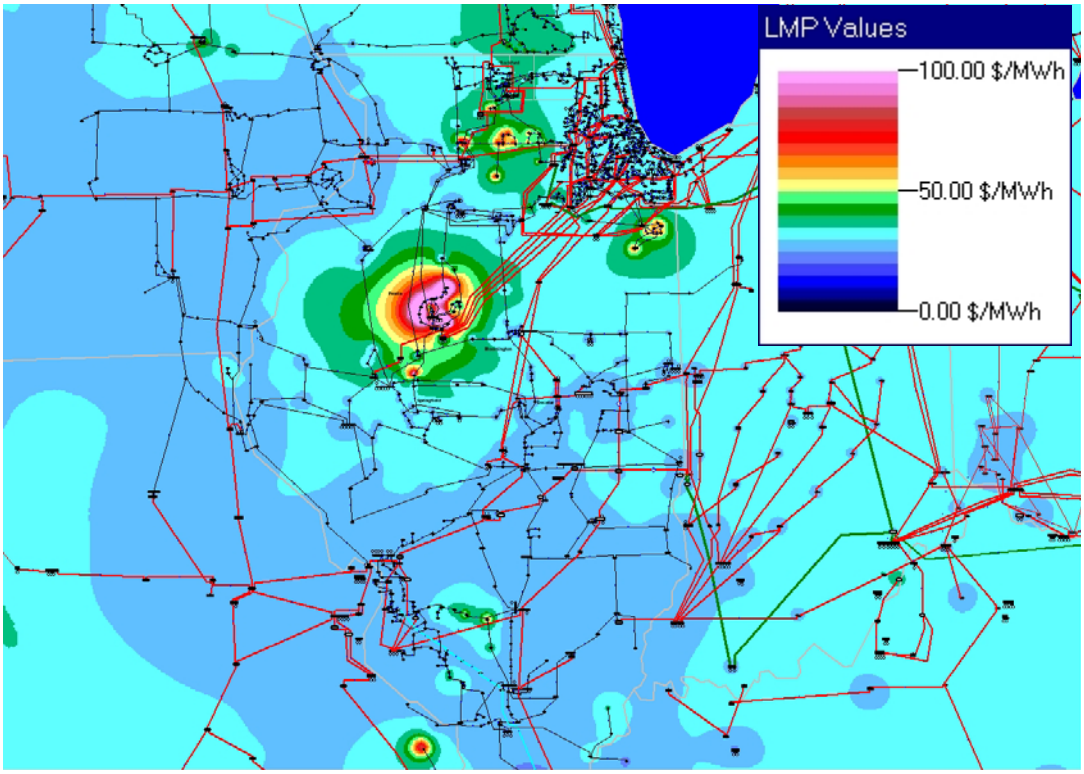

Figure F.1-21 Highest LMPs for April to June 2007

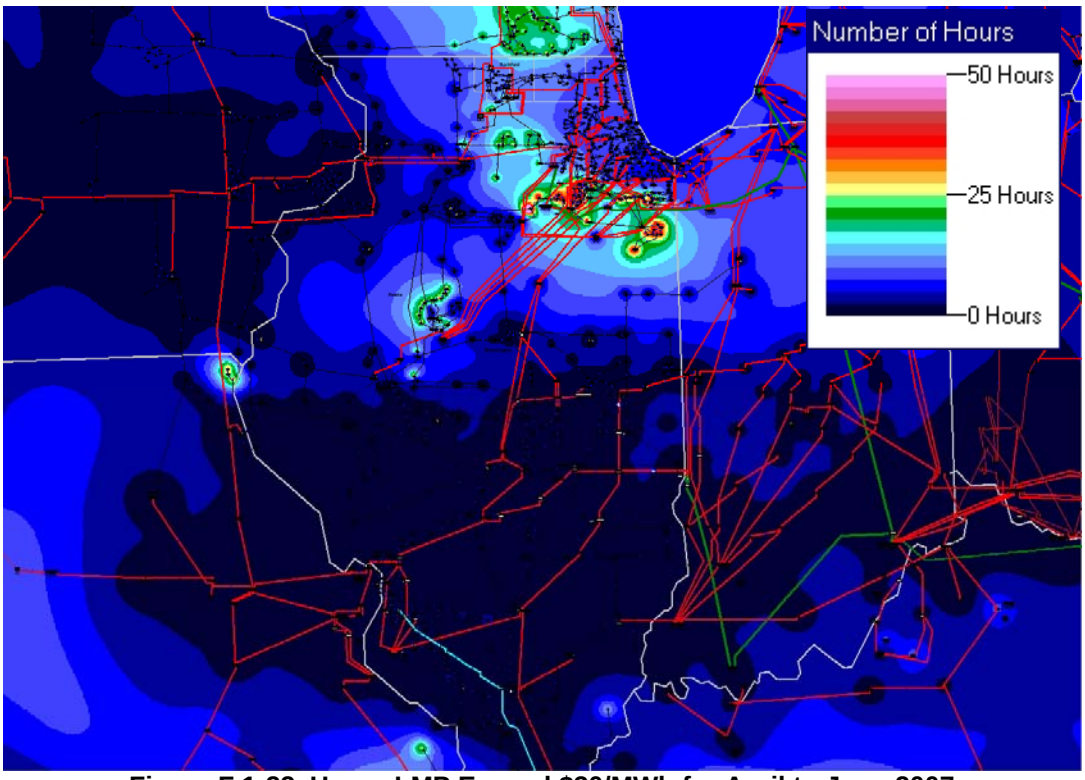

Figure F.1-22 Hours LMP Exceed $30/MWh for April to June 2007

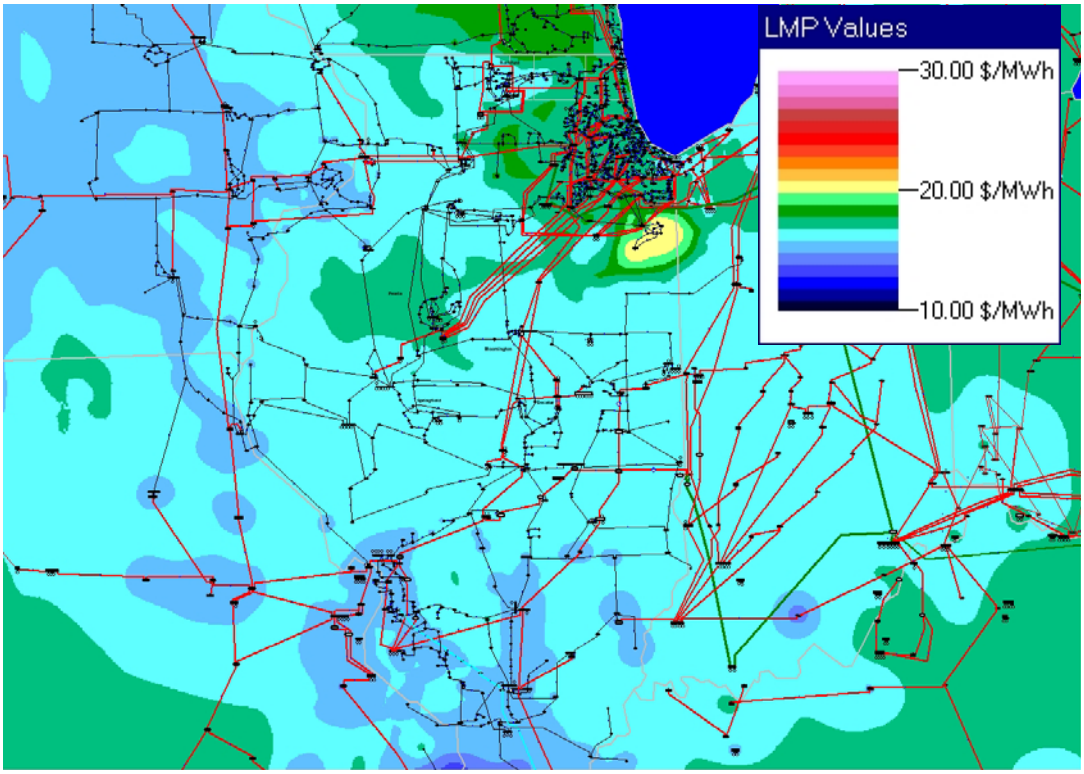

Figure F.1-23 Average LMPs for July to September 2007

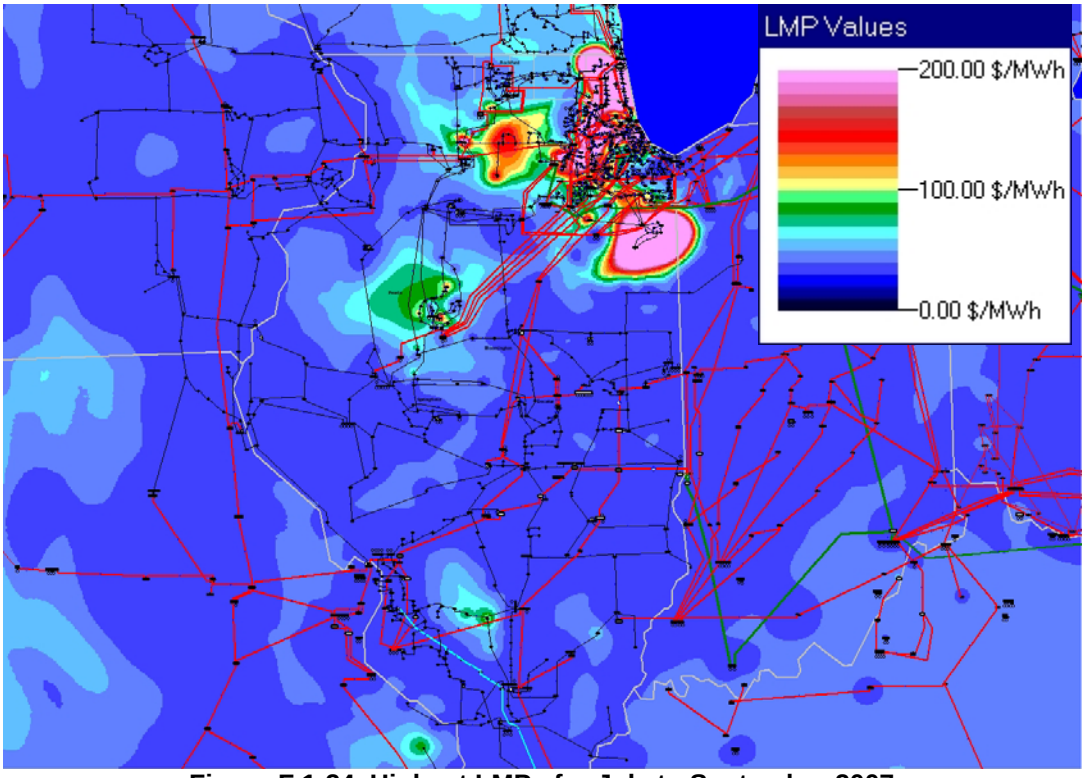

Figure F.1-24 Highest LMPs for July to September 2007

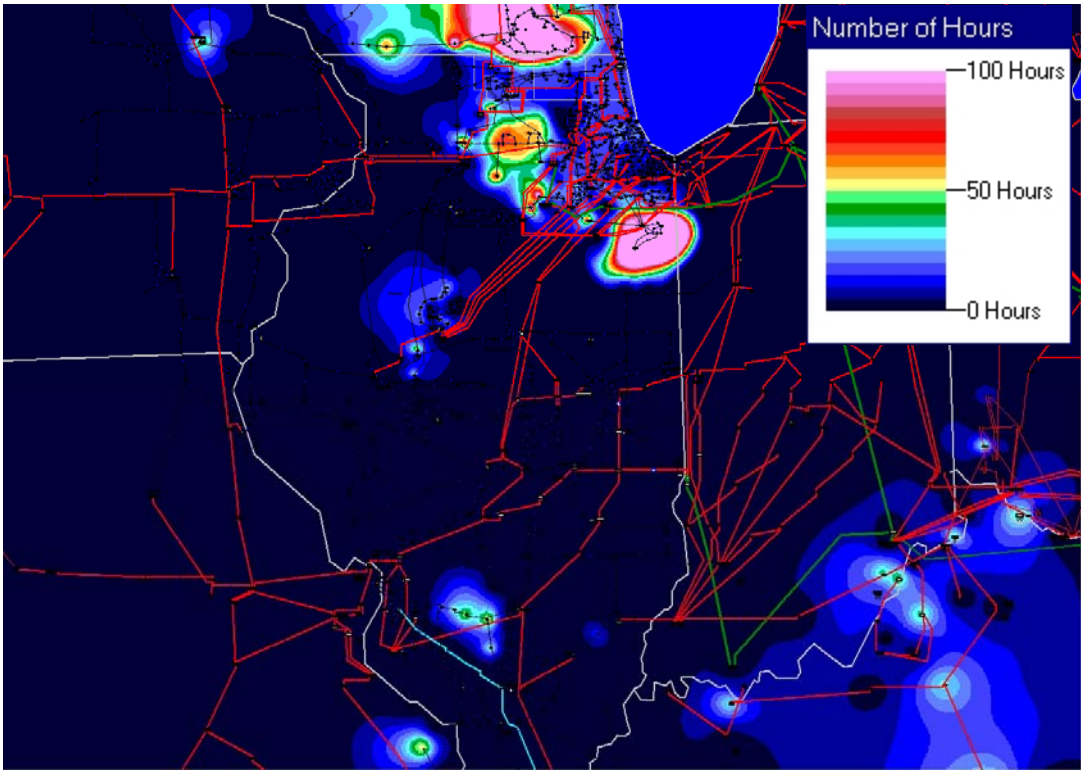

Figure F.1-25 Hours LMP Exceed $40/MWh for July to September 2007

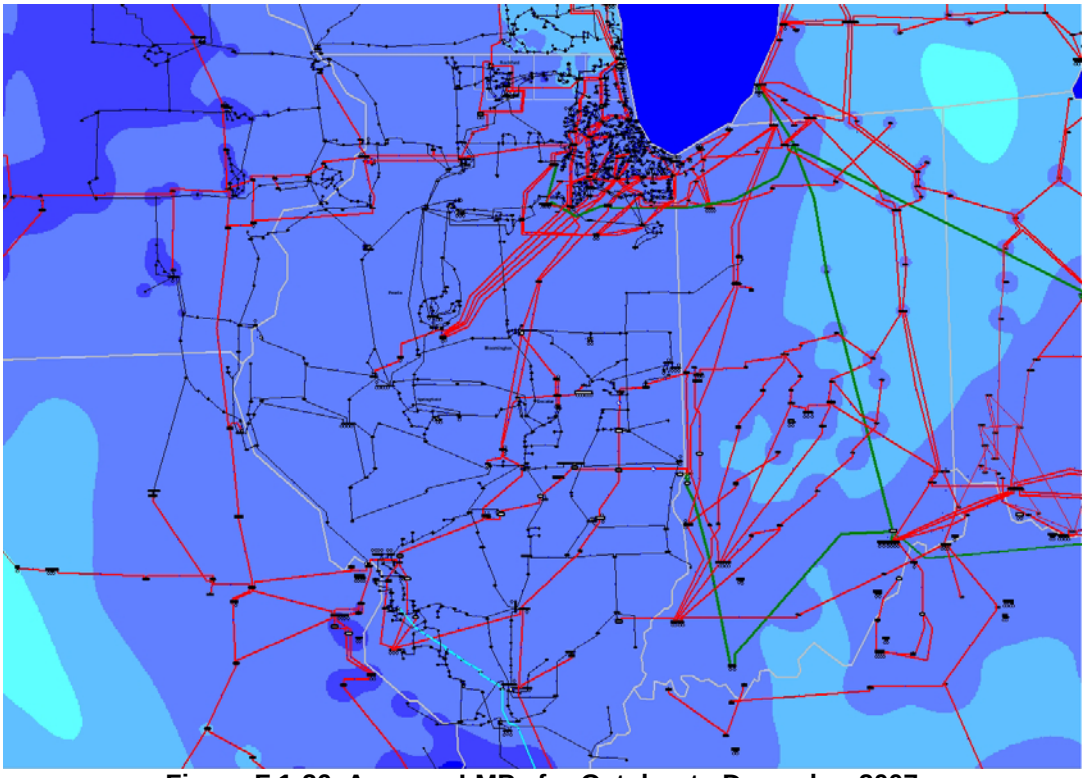

Figure F.1-26 Average LMPs for October to December 2007

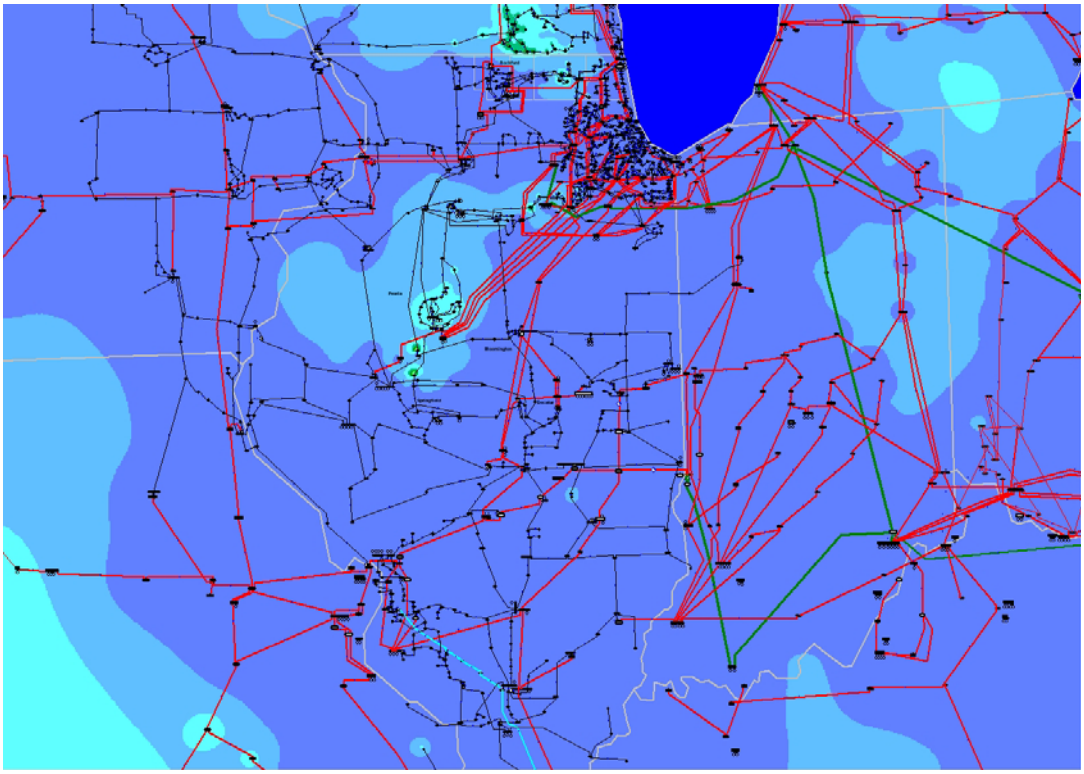

Figure F.1-27 Highest LMPs for October to December 2007

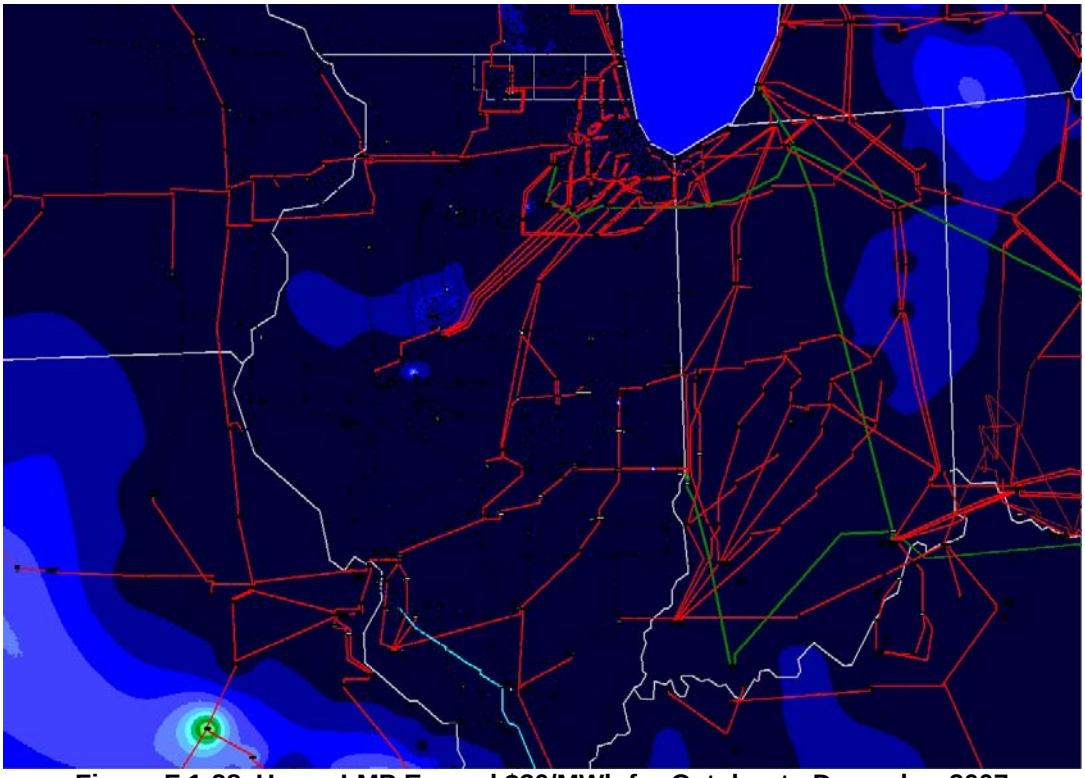

Figure F.1-28 Hours LMP Exceed $30/MWh for October to December 2007

Table F.1-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
33002	RS WALL	CILC	69	298	11,739
36544	K3192;4T	NI	138	218	8,847
36546	K3191;4T	NI	138	218	8,847
36548	K3192;4B	NI	138	218	8,847
36660	DAVIS; B	NI	138	218	8,847
36670	K3192;5T	NI	138	218	8,839
36874	K3192;5B	NI	138	218	8,839
36882	KANKE;BT	NI	138	218	8,837
36884	KANKE; B	NI	138	218	8,837
36562	BRADL; B	NI	138	218	8,837
36883	KANKE;RT	NI	138	218	8,837
36885	KANKE; R	NI	138	218	8,837
36661	DAVIS; R	NI	138	218	8,829
33001	EDWARDS1	CILC	69	282	8,217
33299	PEORIA	CILC	138	281	8,107
33300	PEKIN	CILC	138	279	7,714
33073	MIDWEST	CILC	69	278	7,700
36688	DIXON; B	NI	138	139	7,074
36689	DIXON; R	NI	138	139	7,071
33040	EASTERN	CILC	69	275	6,424
33023	HINES	CILC	69	273	6,192
33029	NORTHWST	CILC	69	273	5,970
36969	MAZON; R	NI	138	737	5,635
36027	DAVIS;3M	NI	138	147	5,475
36127	DAVIS;3C	NI	34.5	147	5,475
36968	MAZON; B	NI	138	235	5,273
36942	LOMBA; B	NI	138	25	5,141
37582	LOMBA;BP	NI	138	25	5,141
37114	PLEAS;BT	NI	138	25	5,116
37116	PLEAS; B	NI	138	25	5,116
33108	FARGO	CILC	69	267	4,913
36778	GLEND;BT	NI	138	25	4,501
36780	GLEND; B	NI	138	25	4,501
33088	HALLOCK	CILC	69	263	4,482
37369	WILMI;	NI	138	468	4,480
33175	MASON	CILC	138	337	4,403
32415	GALESBRG	IP	138	1,865	4,359
33144	HINES	CILC	138	262	4,209
37371	WILSO; R	NI	138	176	4,161
33146	EASTERN	CILC	138	264	3,994
32603	EGAL #1	IP	69	1,777	3,945

Table F.1-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
32602	EGAL #2	IP	69	1,774	3,934
36776	G ELL; B	NI	138	25	3,923
37048	NORDI; B	NI	138	25	3,911
37195	ROUND; R	NI	138	145	3,892
36981	MENDO;	NI	138	130	3,848
36982	MENDO; T	NI	138	130	3,848
37167	H440 ;RT	NI	138	130	3,823
37169	H440 ; R	NI	138	130	3,776
37168	H445 ;3B	NI	138	130	3,776
33152	PIONEERC	CILC	138	262	3,759
32601	MONB #5	IP	69	1,728	3,746
33155	HALLOCK	CILC	138	260	3,715
33084	TAZEWELL	CILC	69	264	3,708
32600	MONB #4	IP	69	1,713	3,700
37166	STEWA; B	NI	138	130	3,679
36483	ANTIO;RT	NI	138	104	3,602
36485	ANTIO; R	NI	138	104	3,602
32416	MONMOUTH	IP	138	1,656	3,488
33154	CAT MOSS	CILC	138	256	3,430
33151	RADNOR	CILC	138	256	3,426
37063	NB212; R	NI	138	25	3,270
36667	DEERF;RT	NI	138	25	3,225
36669	DEERF; R	NI	138	25	3,225
37141	J375 ; R	NI	138	682	3,222
37631	EQUIS; R	NI	13.8	682	3,222
36813	GURNE; R	NI	138	50	3,218
36578	BUTTE; B	NI	138	25	3,211
36794	GRACE; B	NI	138	22	3,203
37140	J375 ; B	NI	138	235	3,176
37630	EQUIS; B	NI	13.8	235	3,176
36843	HIGHL; R	NI	138	26	3,130
36658	DAVIS;1T	NI	138	231	3,094
37091	O ELM; R	NI	138	26	3,075
36471	J371 ; R	NI	138	669	3,071
36473	J371 ;RT	NI	138	669	3,071
36470	J371 ; B	NI	138	236	3,066
36472	J371 ;BT	NI	138	236	3,066
33150	FARGO	CILC	138	254	3,015
37066	J339 ; B	NI	138	236	2,987
37040	N LEN; B	NI	138	238	2,982
33143	CAT SUB2	CILC	138	257	2,979

Table F.1-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
37067	J339 ; R	NI	138	662	2,974
36448	ADDIS; B	NI	138	22	2,954
32334	ASHLEY	IP	138	119	2,941
36045	ITASC;1M	NI	138	27	2,937
36145	ITASC;1C	NI	34.5	27	2,937
36864	ITASC; B	NI	138	27	2,933
30439	CROSSVL	AMRN	138	528	2,888
36807	A450 ; R	NI	138	26	2,881
36433	1A431; R	NI	138	26	2,867
36439	1A431;5T	NI	138	26	2,867
37061	N CHI; R	NI	138	26	2,840
36754	FFORT; B	NI	138	230	2,785
36909	LAKEH; R	NI	138	29	2,782
36032	DRESD;1M	NI	138	613	2,722
36132	DRESD;1C	NI	34.5	613	2,722
36050	LISLE;2M	NI	138	26	2,709
36150	LISLE;2C	NI	34.5	26	2,709
36659	DAVIS;2T	NI	138	229	2,691

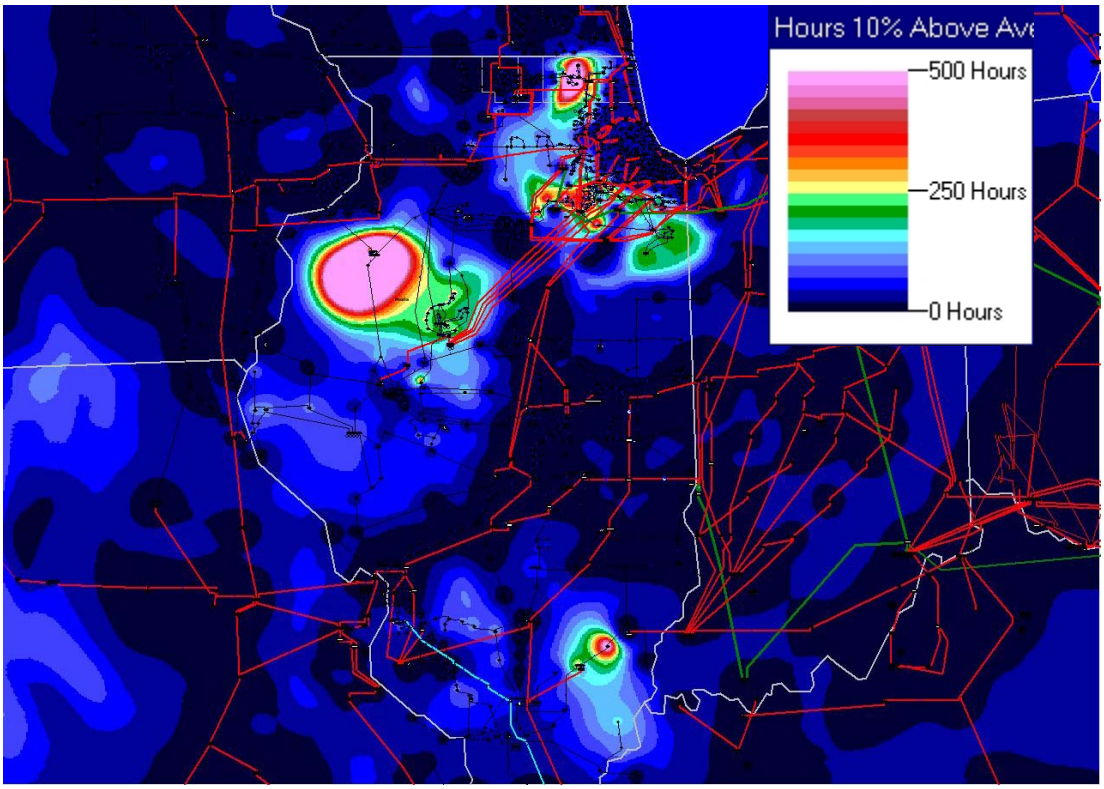

Figure F.1-29 Number of Hours Bus LMPs at Least 10% above the State Average

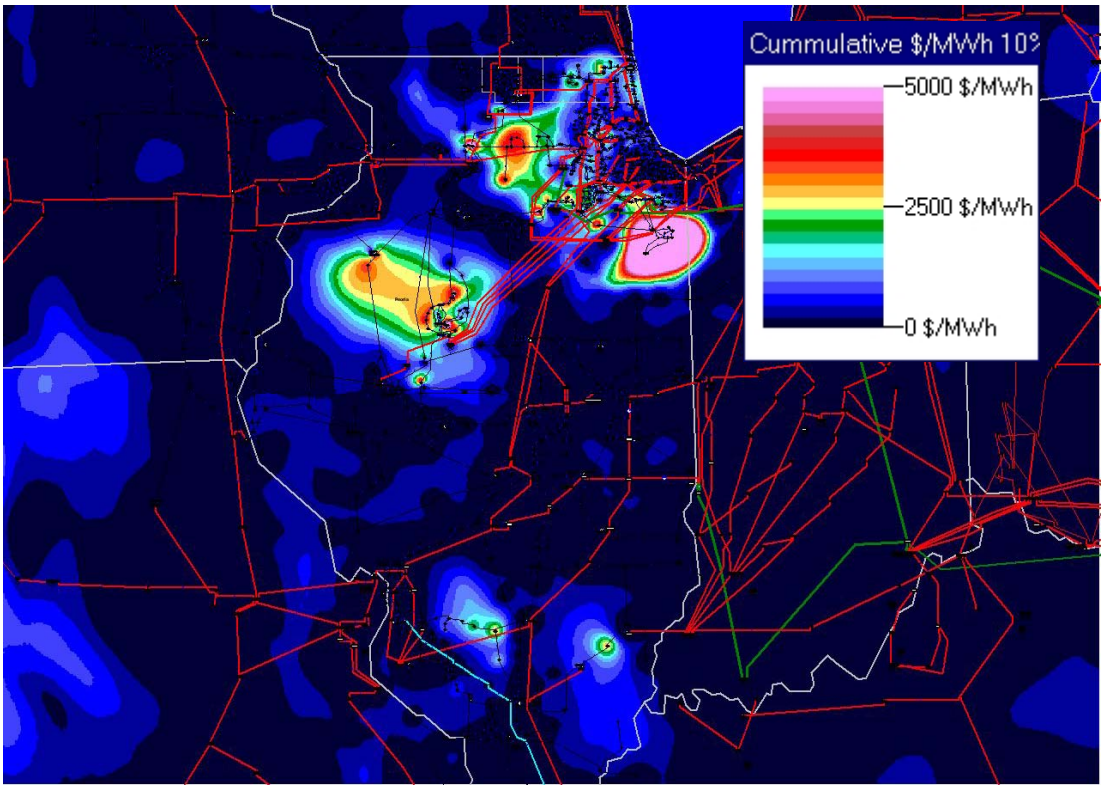

Figure F.1-30 Cumulative $/MWh 10% above the State Average

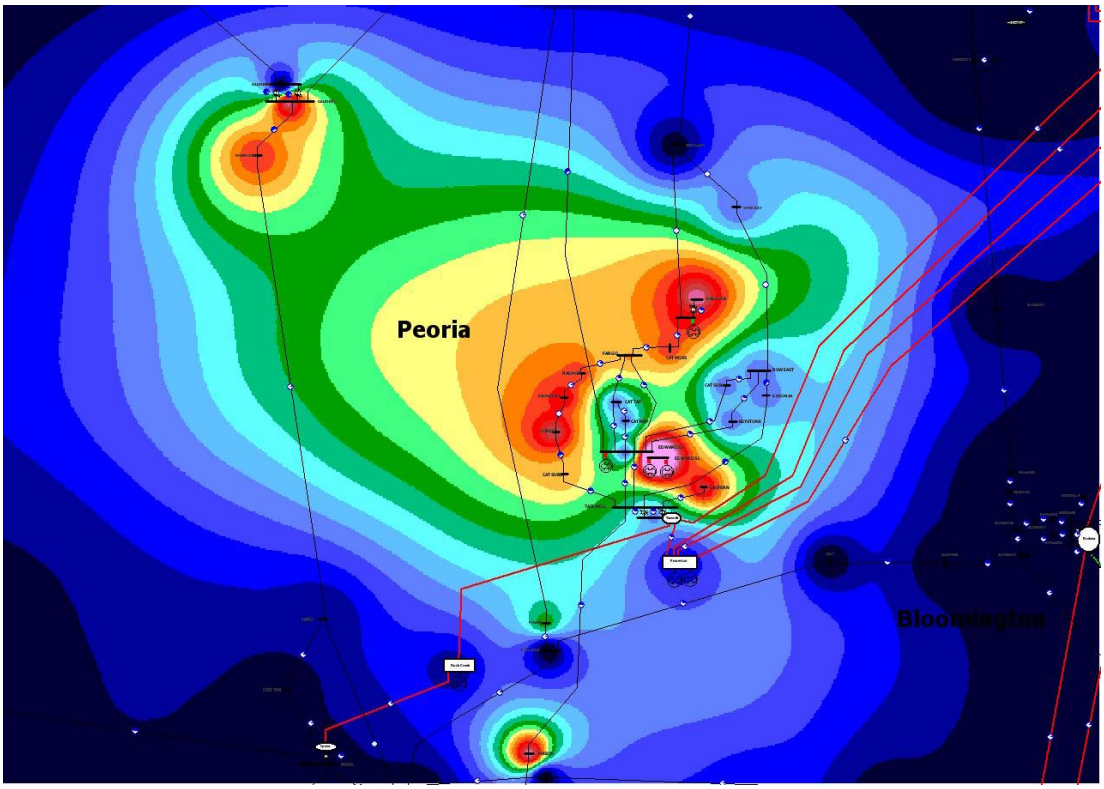

Figure F.1-31 Figure F.1-30 with Zoomed View of Peoria Area

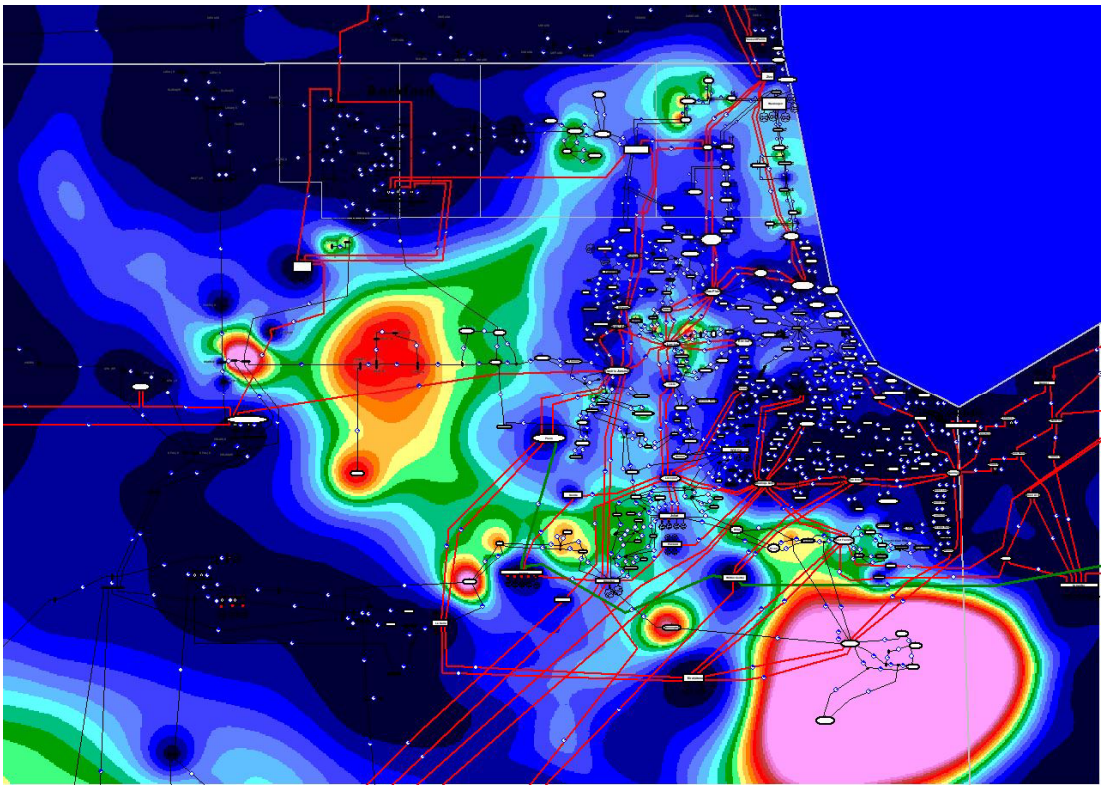

Figure F.1-32 Figure F.1-30 with Zoomed View of Northern Illinois

APPENDIX F.2

Appendix F.2 provides additional results for the modified case. The modified case is the same as the original case, except the generator cost curves have been modified to include a component that includes the impact of fixed costs in the generator bids. In general, higher fixed costs were added to out-of-state generators, causing Illinois to switch from being a net importer to being a net exporter.

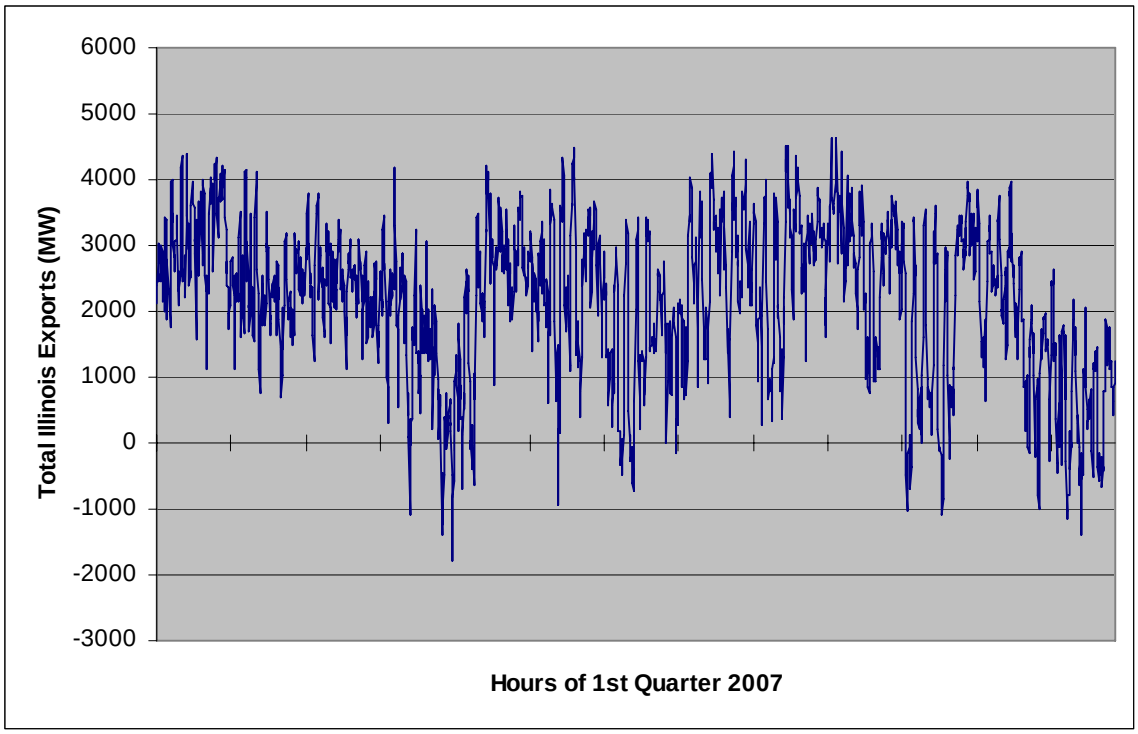

Figure F.2-1 Hourly Power Exports for Illinois during the 1st Quarter 2007

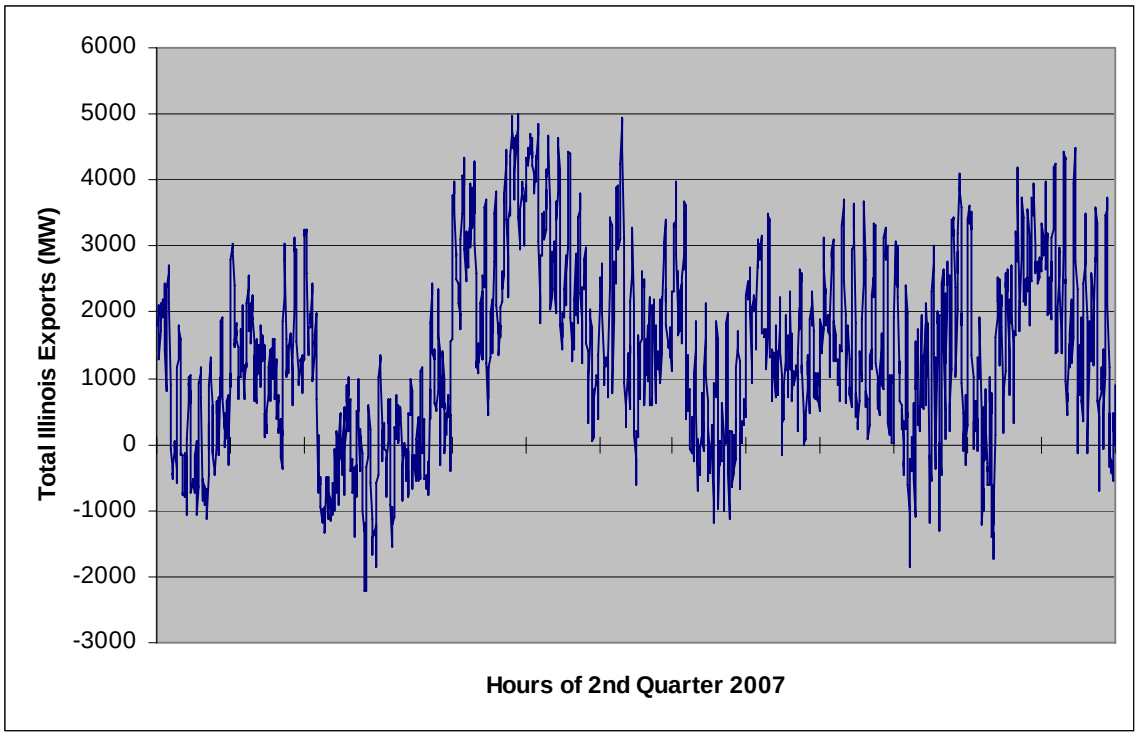

Figure F.2-2 Hourly Power Exports for Illinois in 2nd Quarter 2007

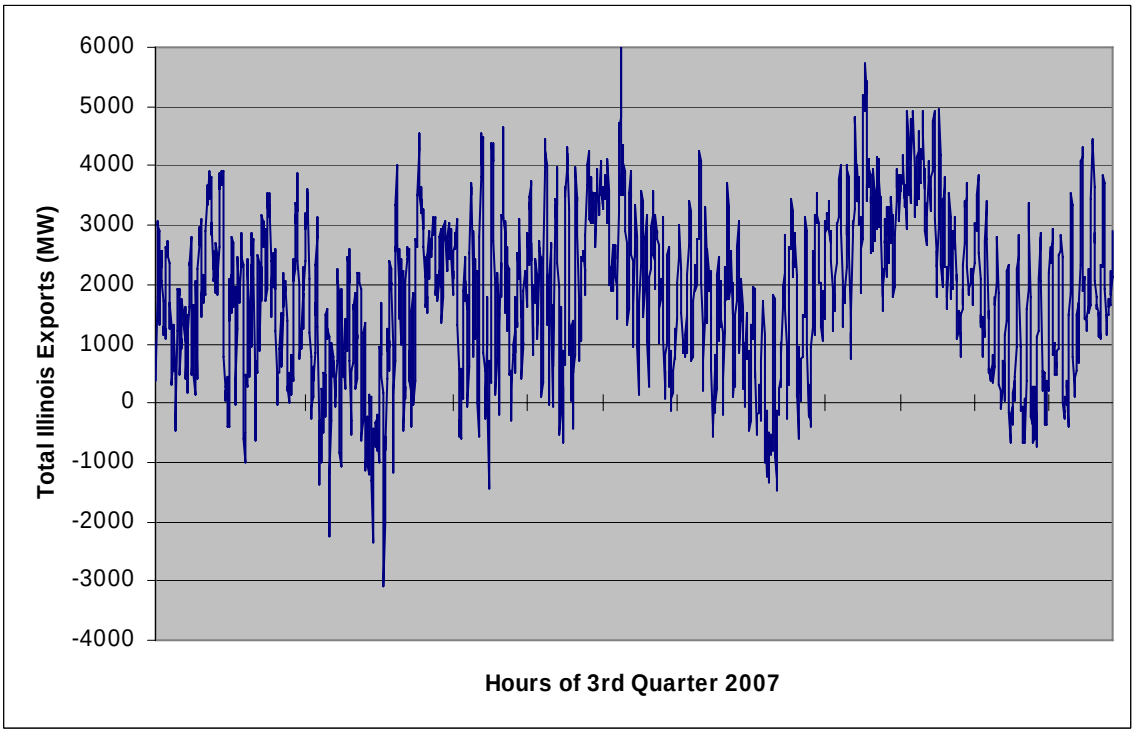

Figure F.2-3 Hourly Power Exports for Illinois in 3rd Quarter 2007

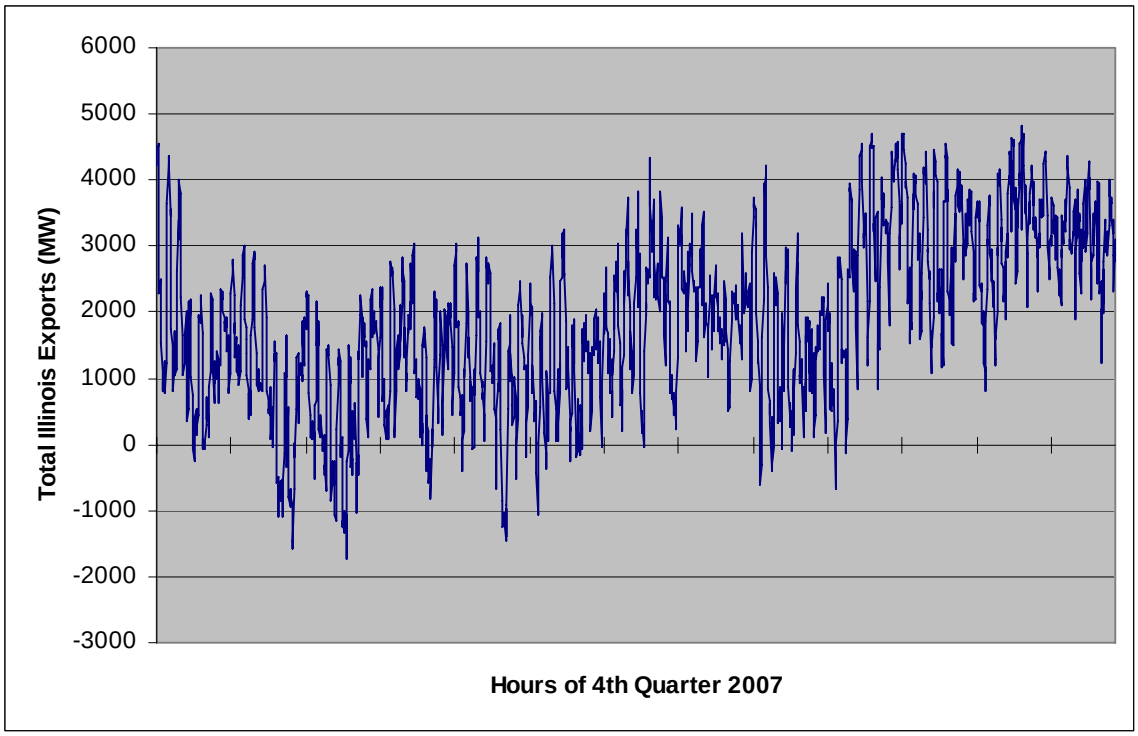

Figure F.2-4 Hourly Power Exports for Illinois in 4th Quarter 2007

Table F.2-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
WI	ARP 138	ARP 345	1	WIS39244ARP345-39785ROCKYRNC1	7,939	19.28	129.52
Ameren-MO	FRED TAP	FREDTOWN	1	AMRNMTL73	3,666	16.97	150.72
Ameren-MO	ORAN	STODDARD	1	AMRNMTL51	2,873	38.65	206.72
Brec-SIPC	14MORGAN	2GALTN_S	1	SIPC2761814LIVIN5-333525RNSHW_SC1	1,782	7.5	36.31
ComEd	MAZON; R	OGLES; T	1	345-L15502_B-R	1,750	10.78	60.49
WI	PAD 345	PAD 138	1	WIS39058PAD345-39119ROE345C1	1,727	12.5	70.12
IP	LAC N TP	GILSP TP	1	AMRNMTL71A	1,489	7.38	15.06
WI	BAIN 5	PLS PR4	2	WIS38850PLSPR3-38851PLSPR4C1	1,228	6.33	49.53
Ameren-IP	MASON CY	1346A TP	1	CIL-6	798	4.6	30.33
CILCO	HOLLAND	MASON	1	CIL-6	736	9.35	65.59
WI	EDG 345	CEDRSAUK	1	WIS38870GRANVL2-39433PTBCH1C1	734	0.98	4.92
IA (MEC)	DAVNPRT3	WALCOTT3	1	MEC64402LOUISA3-64403EMOLIN3C1	713	2.89	5.6
TVA	8CUMBERL	8DAVIDSO	1	TVA184228JVILLE-184258CUMBERLC1	677	0.83	13.47
ComEd	MAZON; R	OGLES; T	1	345-L2101-S	661	6.43	61.86
TVA	8JVILLE	8CUMBERL	1	TVA184258CUMBERL-184308DAVIDSOC1	641	14.07	37.76
Cinergy	08WEBSTE	08NEWLON	1	AEP2266505GRNTWN-2266705JEFRSOC1	595	3.43	57.91
Cinergy	08KOK HP	08KO IN5	1	AEP2266505GRNTWN-2266705JEFRSOC1	530	76.38	466.63
ComEd	MAZON; R	OGLES; T	1	CIL-6A	512	6.2	51.03
WI	OK CRK9	OC CRK6	1	WIS38857OCCRK8-39367OKCRKC1	502	0.53	14.96
Ameren-MO	MARIES	5MARIES	1	AMRNVSS17	483	78.58	201.72

Table F.2-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
ComEd	MAZON; R	OGLES; T	1	IP108	472	6.21	62.76
ComEd	MAREN;RT	P VAL; R	1	345-L15616-R	467	5.72	31.72
ComEd	MAZON; R	OGLES; T	1	345-L0302_B-S	345	3.83	54.56
SIPC	2CARML_S	2HMLTN_S	99	AMRNVSS76	322	35.02	88.57
ComEd	FISK ; R	FISK STR	19	TR81_TAYLR_R-C	305	16.43	155.7
Ameren-MO	CEE TAP	CENTRAL	1	AMRNMTL55	262	2.71	12.01
WI	DEAD RVR	DR NEU1	1	WIS39917DEADRVR-39898DRNEU1AC1	242	0.14	1.05
ComEd	FISK ; B	FISK STR	19	TR82_TAYLR_B-C	192	9.31	28.46
ComEd-WI	ZION ; R	PLS PR2	1	345-L17101-R	189	0.17	1.37
ComEd	SLINE;5S	WASHI; R	1	345-L17723_B-C	182	10.74	141.11
CILCO	RS WALL	RSW EAST	1	Basecase	178	205.88	1000
ComEd	LASCO; B	MAZON; B	1	345-L1223_R-S	171	13.27	47.54
ComEd	CLYBO; B	CROSB; B	1	138-L4018_R-C	157	0.67	14.32
ComEd	CLYBO; B	CROSB; B	1	345-L4621_B-N	145	1.83	31.42
Ameren-MO	HAMLTNAM	HAMLTNAM	1	AMRNMTL32	144	6.49	14.83
ComEd	HILLC;6B	WILL ;BT	1	138-L0907_B-S	143	9.31	12.73
IP	SPRTA TP	ARCH TAP	1	IP30	142	4.25	23.74
ComEd	DAVIS; B	DAVIS;3M	1	345-L17704_R-S	139	74.69	546.83
ComEd	WAUKE; B	ZION ;	1	345-L2221_R-N	132	1.36	4.29
ComEd	ELMHU;3I	F PAR; B	1	TR81_ELMHU_R-N	127	8.11	140.69
IP	LAC N TP	GILSP TP	1	IP95	124	7.83	12.21
Cinergy	08GALAGH	08GALAGH	1	AEP2266705JEFRSO-2267105ROCKPTC1	118	0.66	1.5
BREC-SIPC	14MORGAN	2GALTN_S	1	IP98	118	48.92	134.34
SIPC	2CARML_S	2HMLTN_S	99	SIPC31023MARIONS-333515MRN_PLNC1	117	41.74	84.74
ComEd	DIXON; R	NELSO;RT	1	138-L15507_B-R	108	101.67	494.23
ComEd	BARTL;BT	SPAUL; B	1	345-L14402_B-N	103	5.15	23.63
CILCO	HOLLAND	MASON	1	345-L0304_R-S	98	28.46	91.04
IP-ComEd	PWR JCTB	POWER;	1	CIL-6A	89	13.84	92.51
Ameren-CWLP	AUBURN N	CHATHAM	1	IP109	88	2.59	27.04
ComEd	ELECT;3R	ELECT;3M	1	TR84_ELECT_R-N	87	3.44	16.38
ComEd	SLINE;2S	WASHI; B	1	138-L0708_B-C	84	3.62	24.11
ComEd	TOLLW; B	TOLLW;3M	1	138-L7910_B-R	84	4.26	21.6
Ameren-IP	MASON CY	1346A TP	1	CIL-6A	83	4.58	23.67
ComEd	JEFFE; B	KINGS; B	1	138-L1110_B-C	82	14.12	137.33
ComEd	RIDGE; B	RIDGE;BS	1	138-L5118_B-S	79	18.69	215.76
IA (ALTW)	HAZLTON5	HAZLTON3	1	ALTW34020HAZLS5-34018HAZLTON3C2	79	47.41	73.64
AEP	05BENTON	05COOK	1	AEP2265405COOK-2853818PALISAC1	79	3.34	16.54
IP	MT VRNON	ASHLEY	1	IP96	78	40.63	133.72
Ameren-MO	CEE TAP	CENTRAL	1	Basecase	73	4.16	12.95
IN	07RAMSEY	07RAMSY5	2	CIN2518107RAMSY5-2538808SPEEDC1	72	549	1000
WI	EDG 345	CEDRSAUK	1	WIS38898PTBCH2-39433PTBCH1C1	69	1.07	3.86

Table F.2-1 Congested Transmission Lines 2007

Area	From Bus	To Bus	Cir-cuit	Contingency Name	Hours Binding	Avg MC	Max MC
ComEd	HILLC;6B	WILL ;BT	1	Basecase	69	9.25	17.28
WI	EDG 138	EDG 345	1	WIS39215EDG138-39214EDG345C2	66	228.55	389.86
ComEd	Y450 ; R	CONGR; R	1	Basecase	66	12.52	200.55
Ameren	ALBION	CROSSVL	1	IP96	65	12.41	56.18
ComEd	MAZON; R	OGLES; T	1	TR81_DRESD_B-S	60	12.54	46.73
ComEd	HARBO;8S	UNIVE; B	1	345-L17723_B-C	57	2.47	11.48
Cinergy	08BUFTN1	08BUFTN1	1	CIN2496206PIERC2-2602908FOSTERC1	55	111.11	224.67
Ameren	EFFINGHM	NEWTON	1	AMRNVSS35	53	3.4	27.03
Ameren	HAMLTNAM	KH2 XFMR	1	AMRNMTL32	52	15.36	22.46
ComEd	UNIVE; B	WASHI; B	1	138-L13701_R-C	51	0.26	0.34
WI	WESTONWP	WESTON	1	WIS39245ARP138-39244ARP345C1	51	0.95	1.71
ComEd	D799 ;6B	RIDGE; B	1	138-L1321_G-C	50	48.38	230.38
ComEd	CROSB; R	ROCKW; R	1	138-L6721_B-C	47	0.49	1.37
ComEd	DIXON; B	NELSO; B	1	138-L15508_R-R	45	88.71	463.33
ComEd	O PAR; B	RIDGE;9I	1	Basecase	41	0.59	1.9
ComEd	ELWOO; R	GOODI;1R	1	345-L1223_R-S	39	8.23	36.39
ComEd	DEVON;3R	ROSEH;RT	1	138-L11416_R-C	38	49.92	331.8
Ameren	ALBION	CROSSVL	1	IP98	36	25.31	93.9
ComEd	SLINE;2S	WASHI; B	1	345-L17723_B-C	36	0.25	0.45
Cinergy	08M.FTHS	08MFTM9	1	Basecase	35	48.08	109.45
WI	WESTONWP	WESTON	1	Basecase	35	1.19	2.06
ComEd-WI	ZION ; R	PLS PR2	1	WIS36406WEMPL;B-39058PAD345C1	31	0.16	0.43
ComEd	F PAR;0S	NATOM; R	1	345-L12002_R-N	31	0.48	3.06
CILCO	HOLLAND	MASON	1	345-L2101-S	31	3.42	7.12
ComEd	DAVIS;3M	DAVIS; B	1	345-L17704_R-S	27	65.3	313.8
ComEd	E FRA; R	GOODI;1R	1	Basecase	26	6.82	27.49
ComEd	TAYLO; R	TAYLO;1M	1	TR82_TAYLR_B-C	26	64.32	215.94

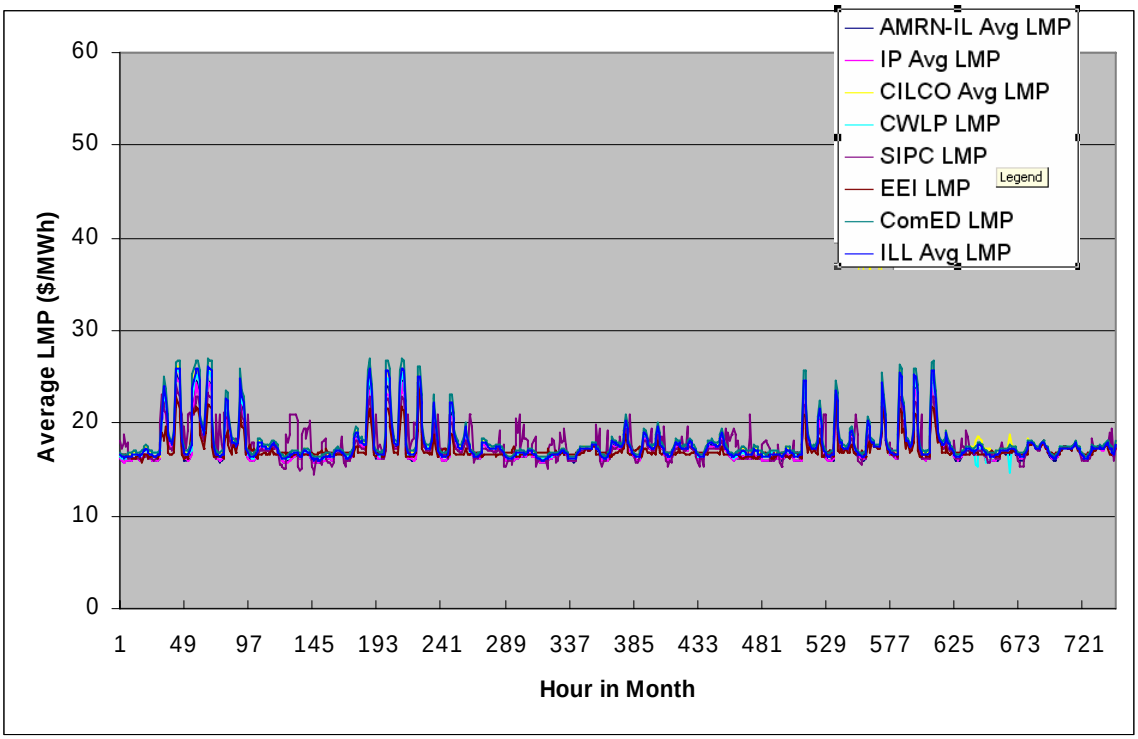

Figure F.2-5 Average LMPs for January 2007

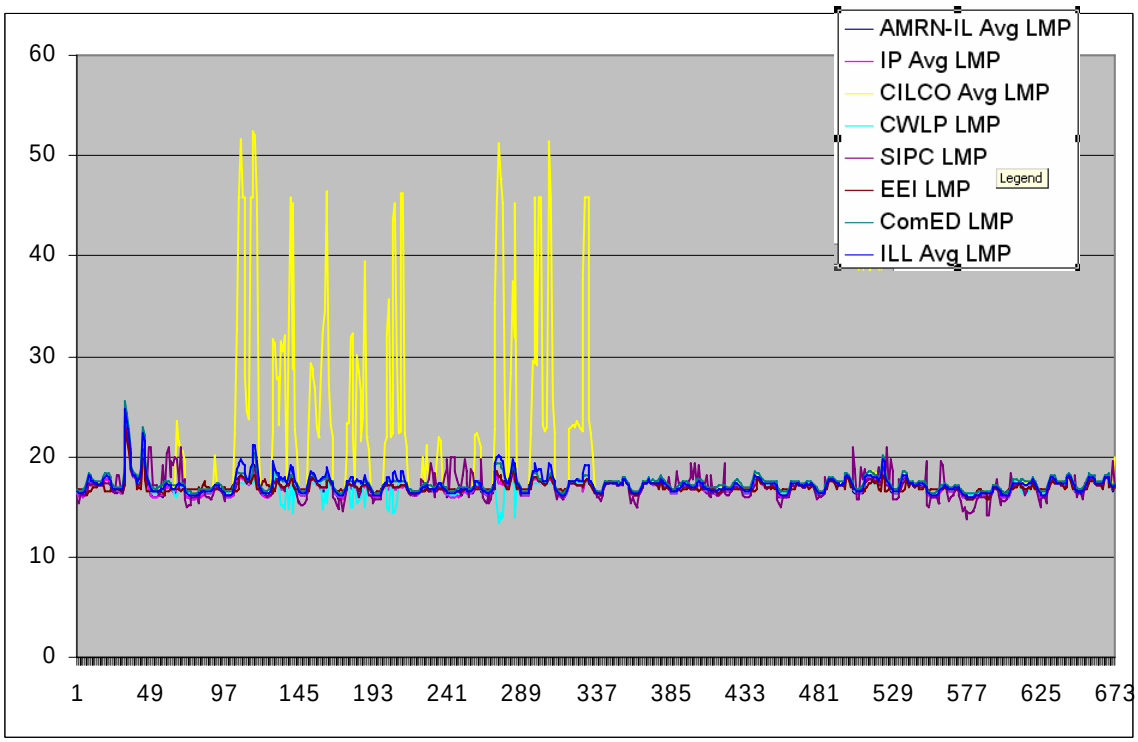

Figure F.2-6 Average LMPs for February 2007

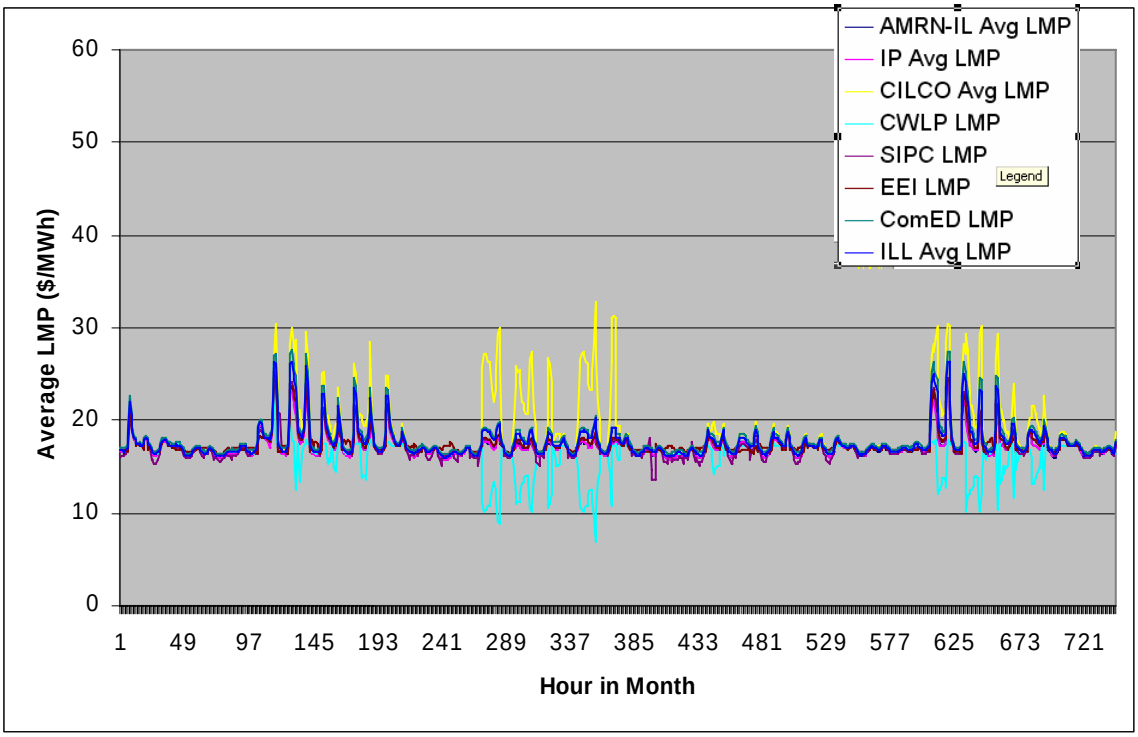

Figure F.2-7 Average LMPs for March 2007

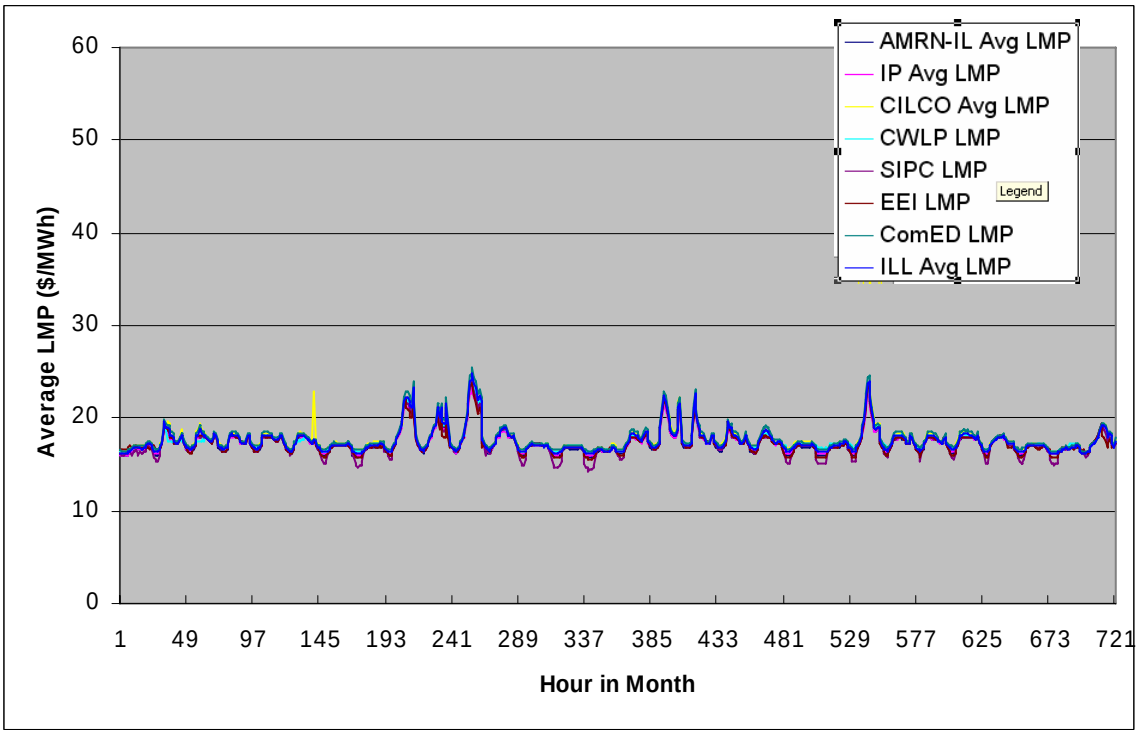

Figure F.2-8 Average LMPs for April 2007

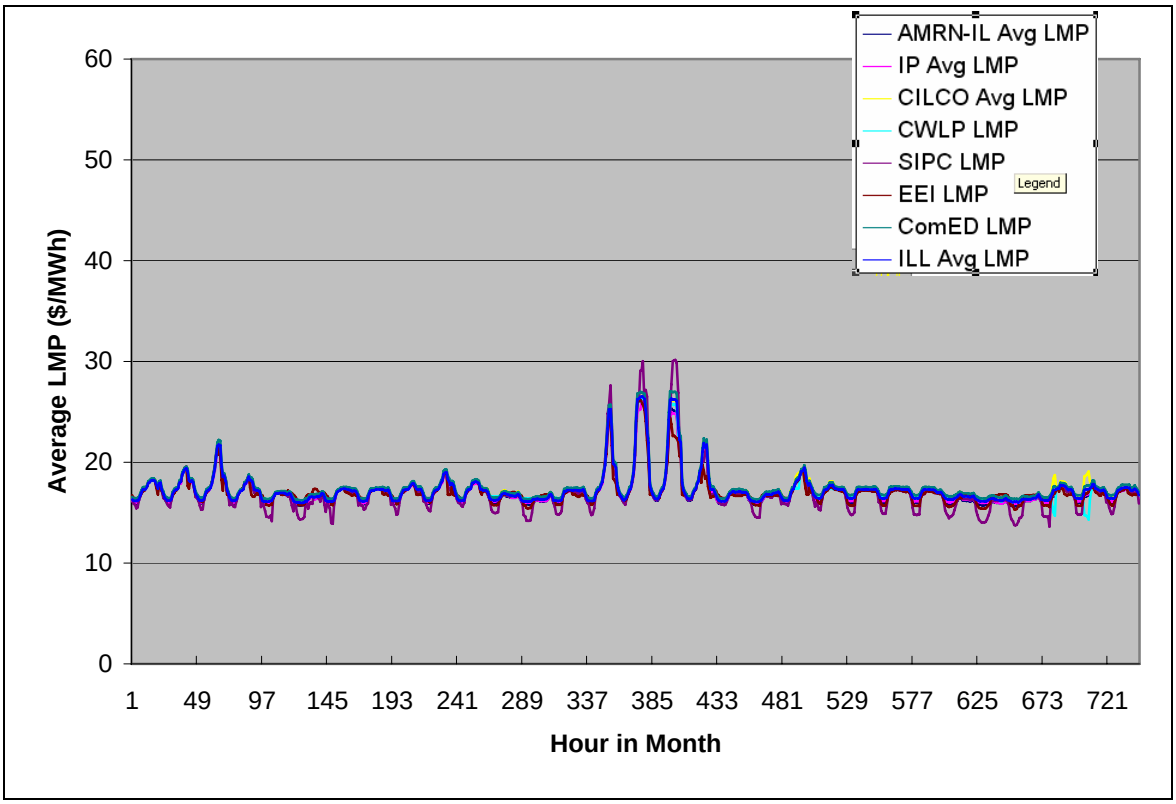

Figure F.2-9 Average LMPs for May 2007

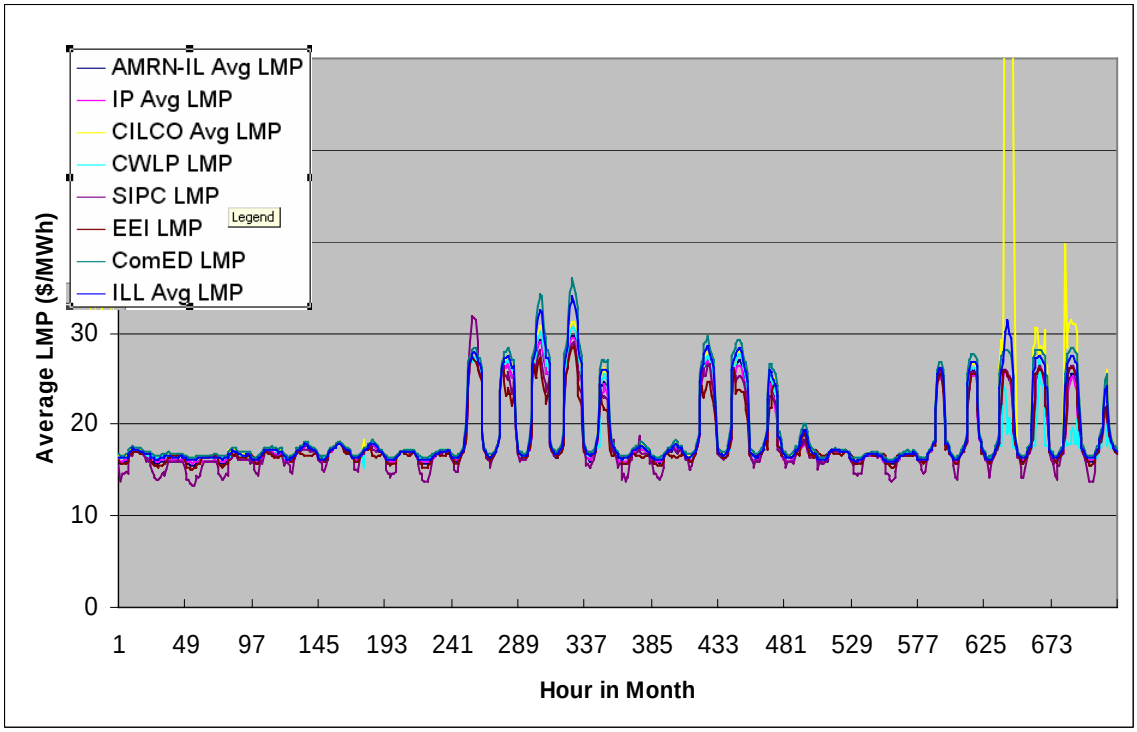

Figure F.2-10 Average LMPs for June 2007

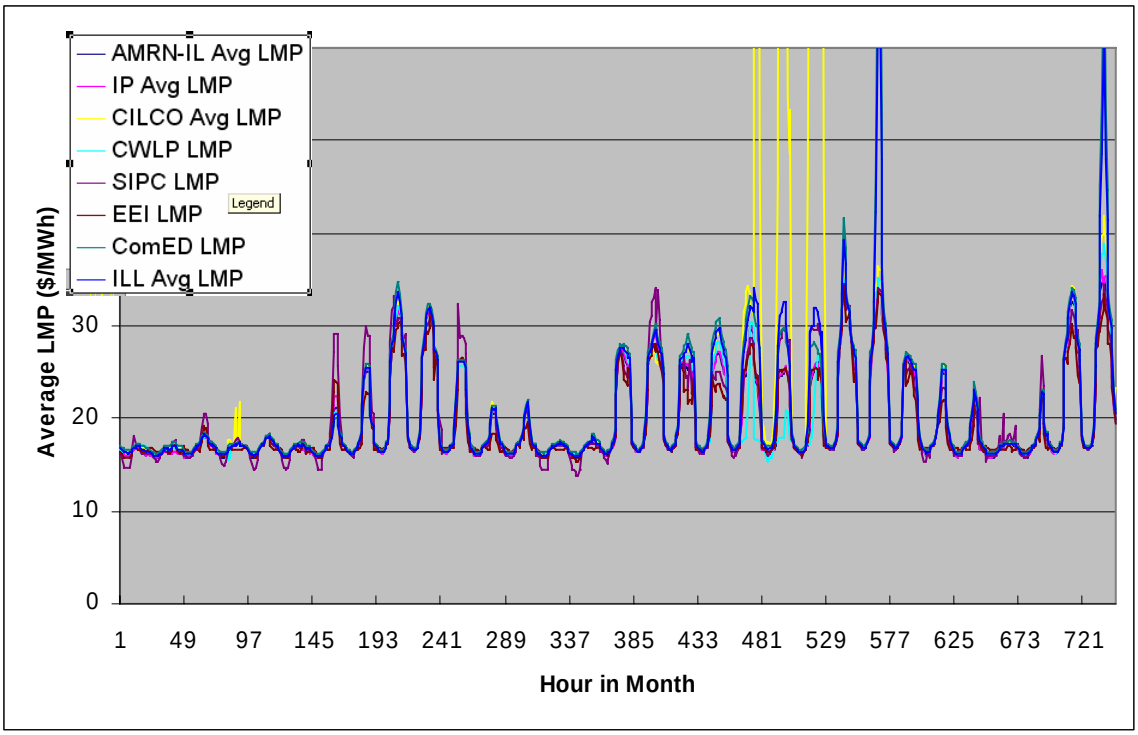

Figure F.2-11 Average LMPs for July 2007

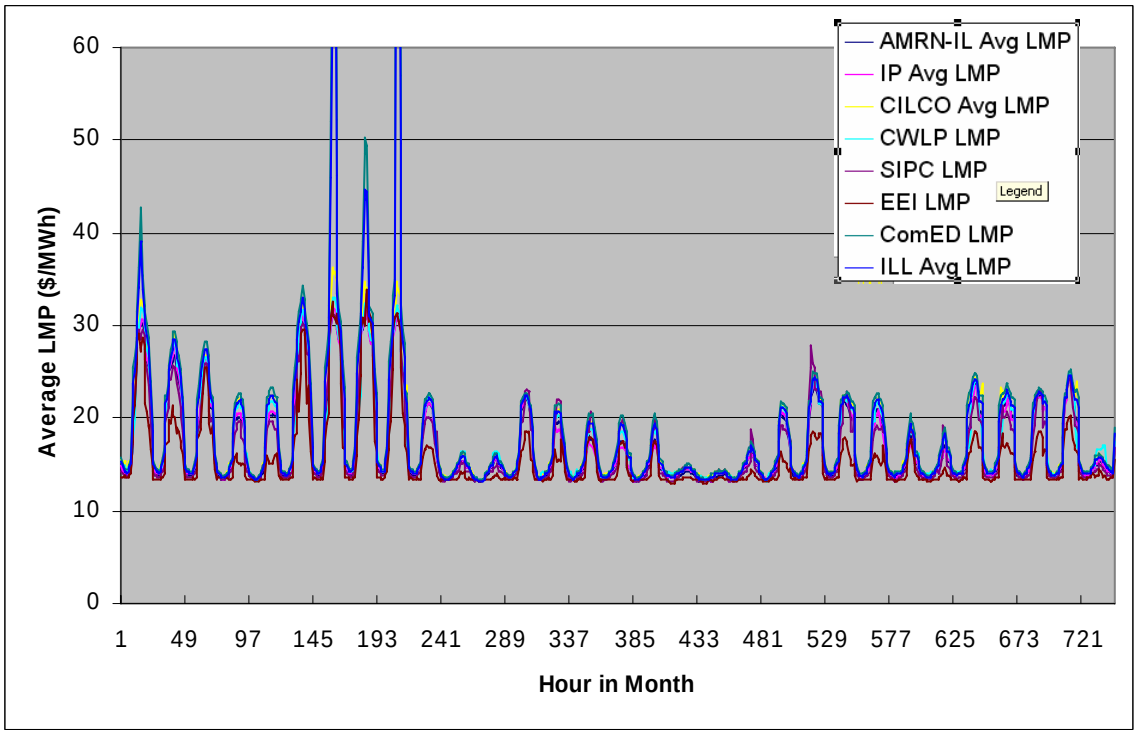

Figure F.2-12 Average LMPs for August 2007

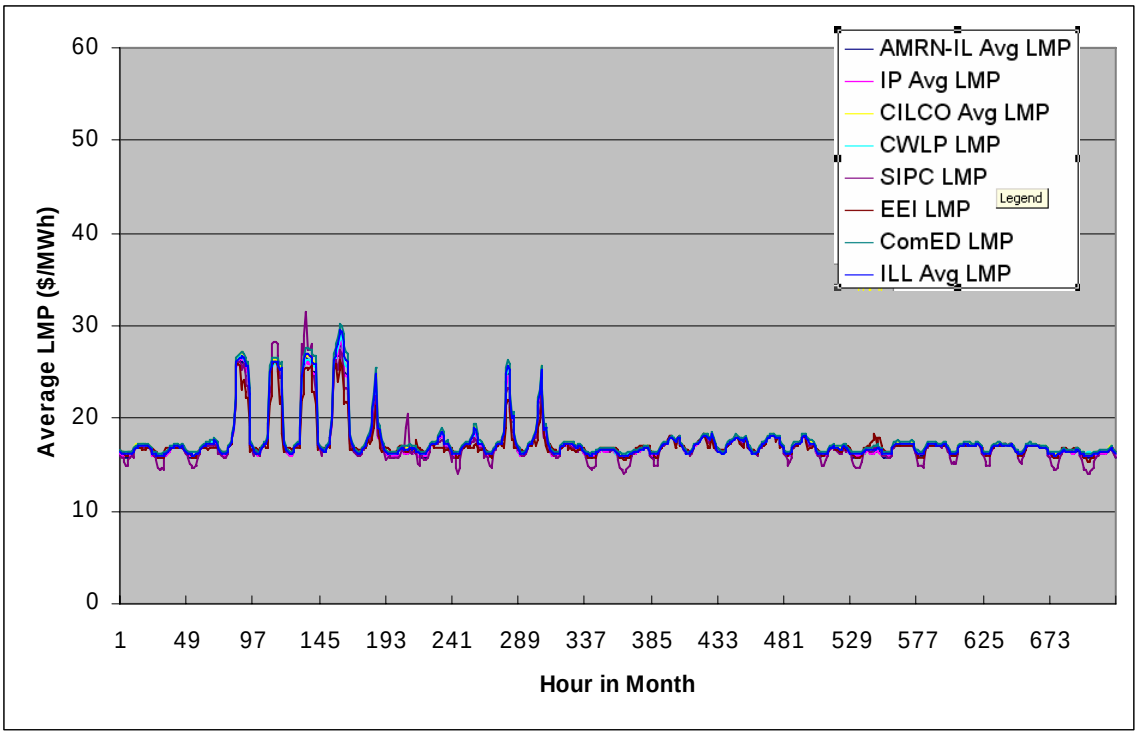

Figure F.2-13 Average LMPs for September 2007

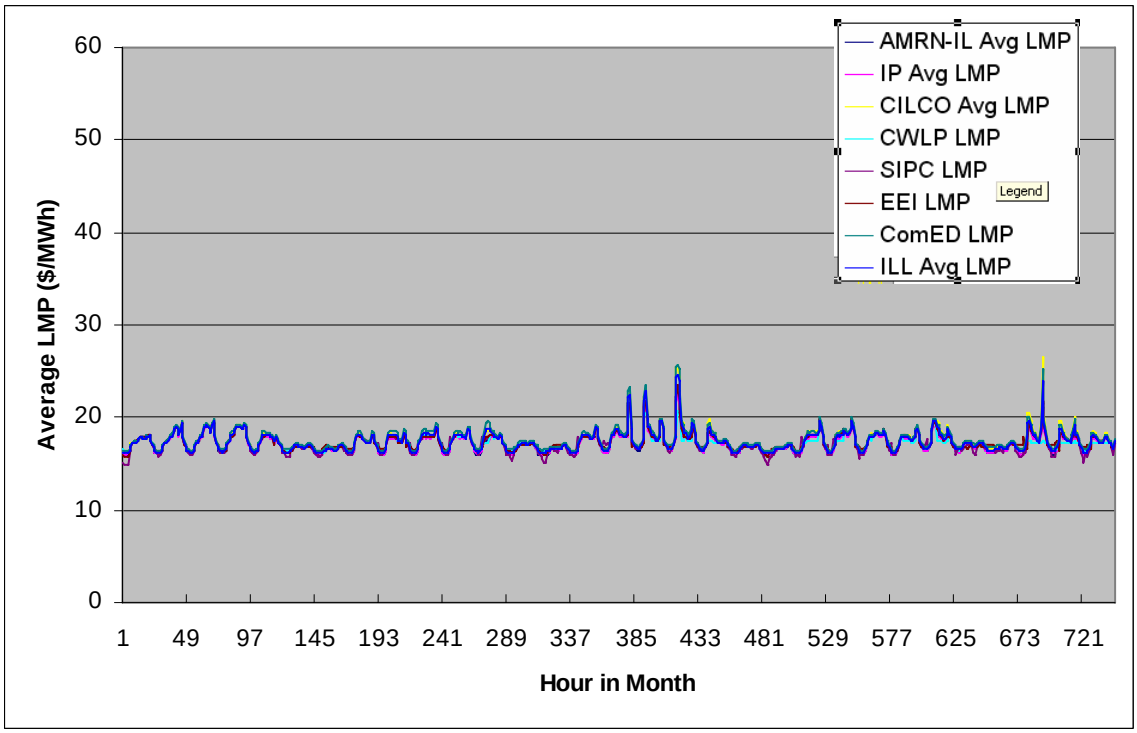

Figure F.2-14 Average LMPs for October 2007

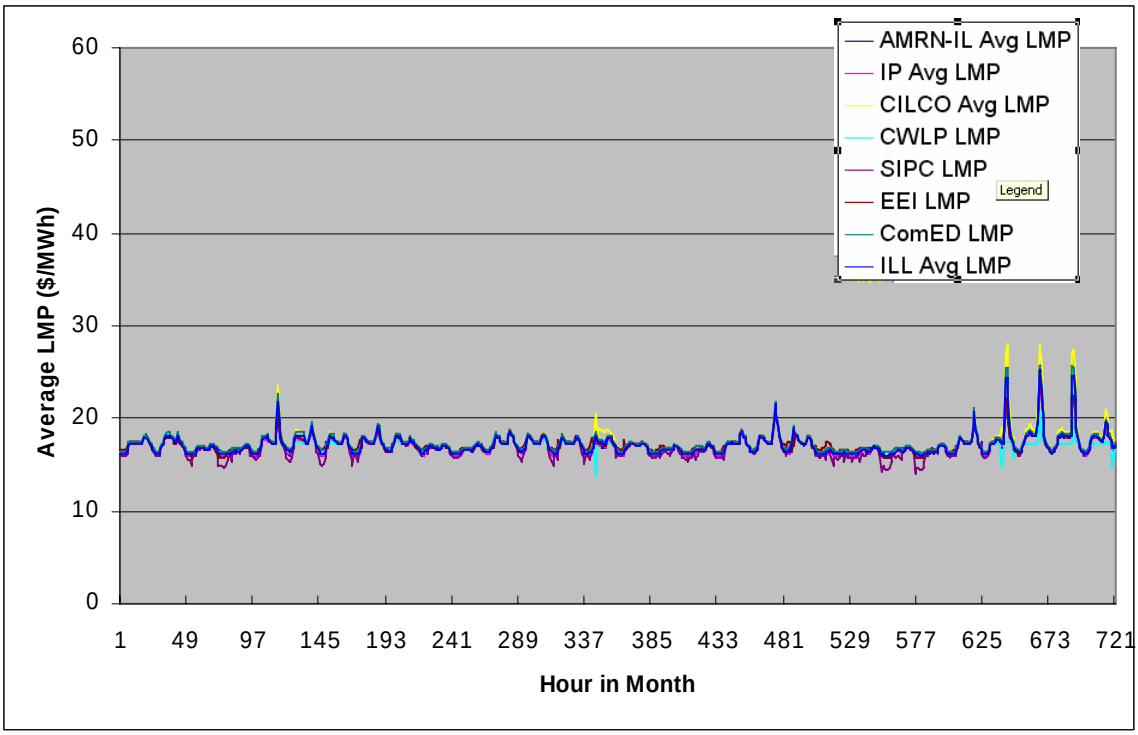

Figure F.2-15 Average LMPs for November 2007

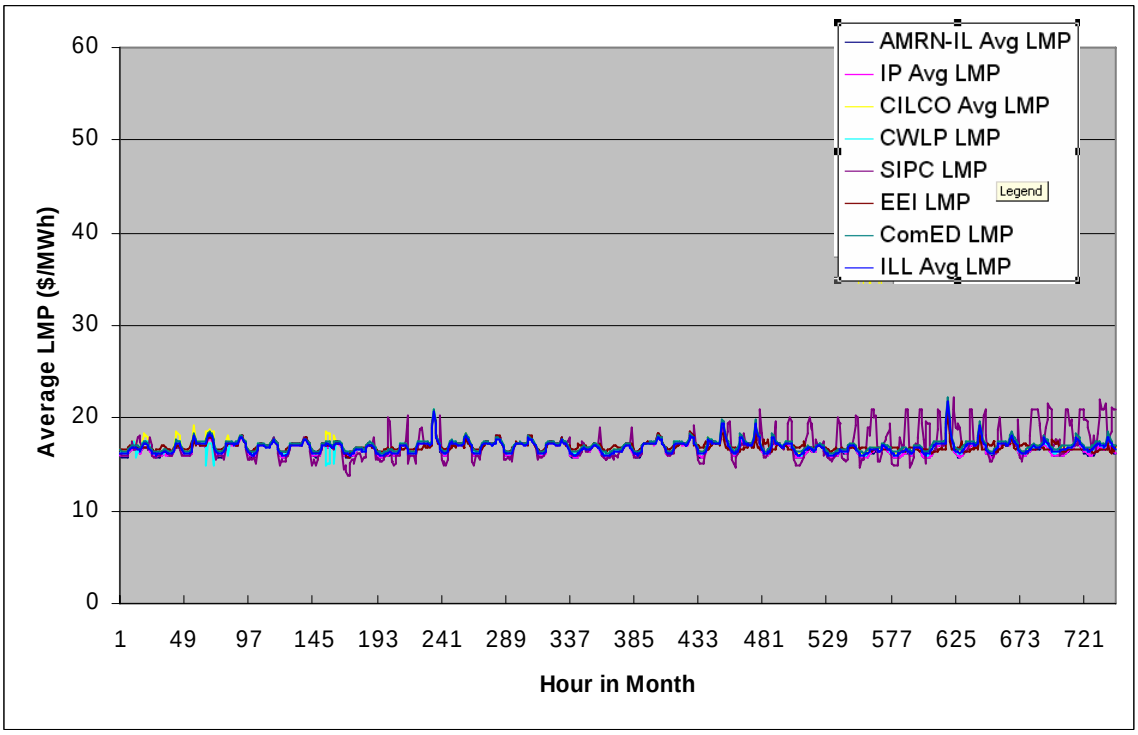

Figure F.2-16 Average LMPs for December 2007

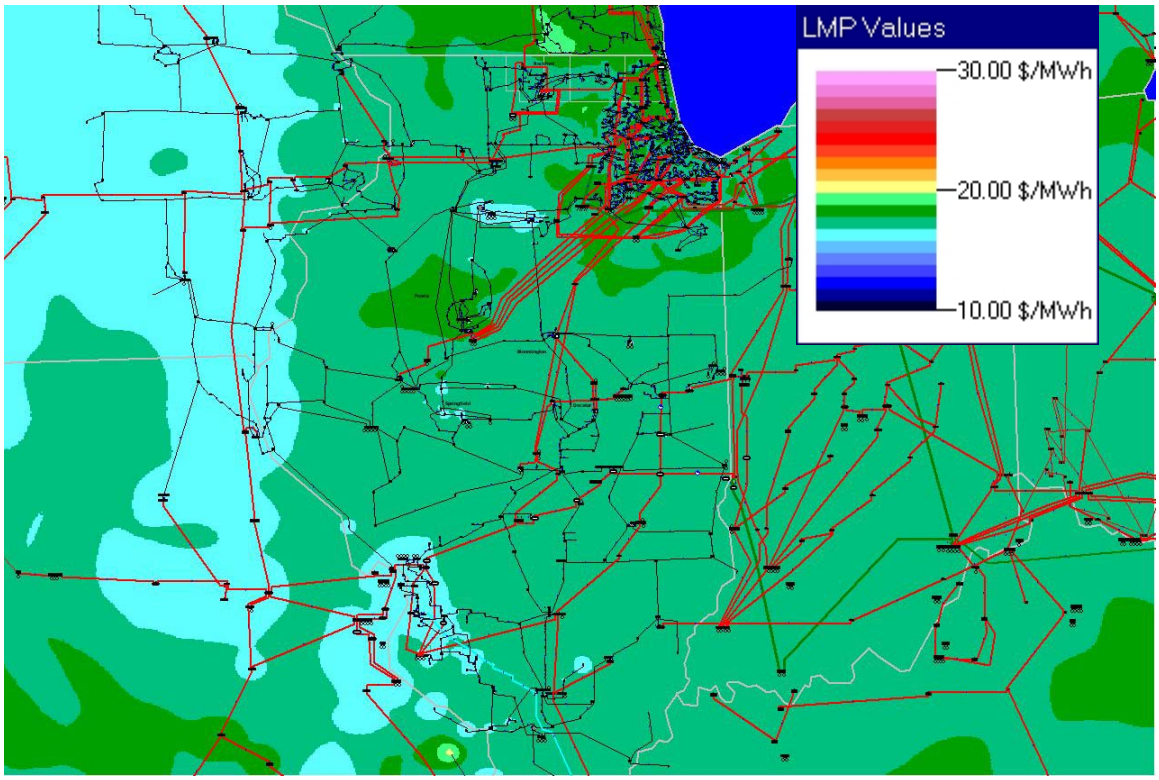

Figure F.2-17 Average LMPs for January to March 2007

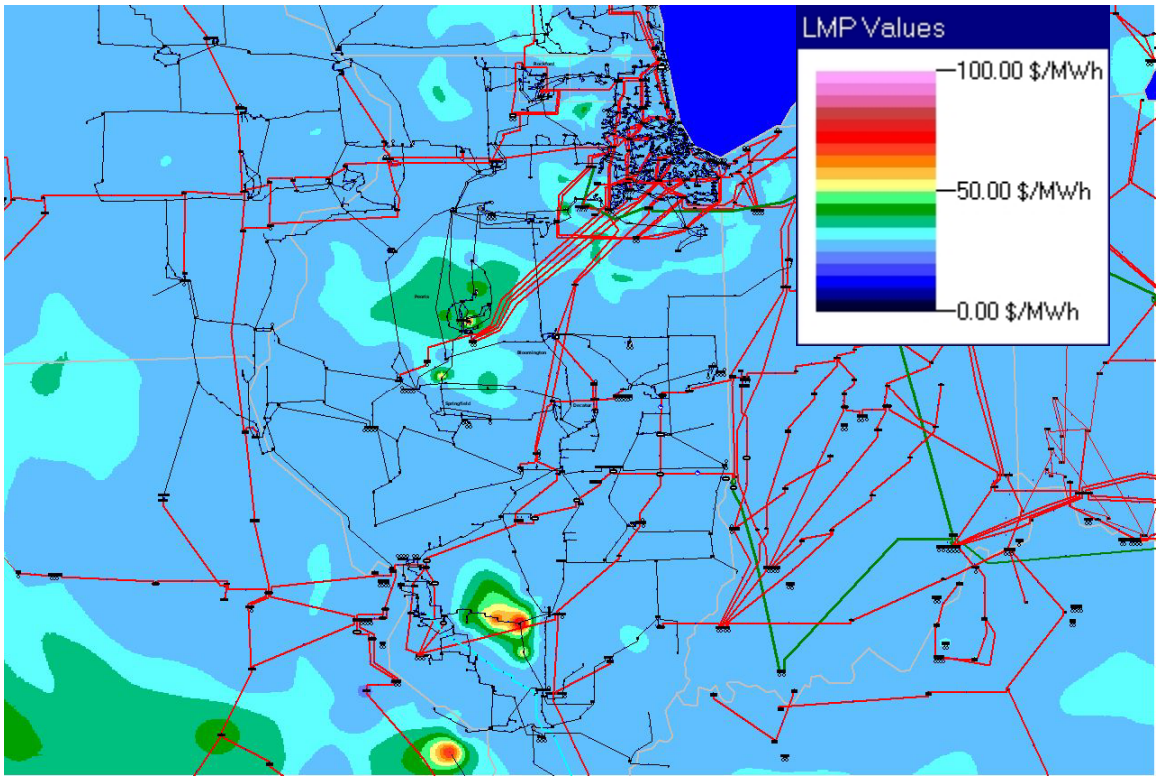

Figure F.2-18 Highest LMPs for January to March 2007

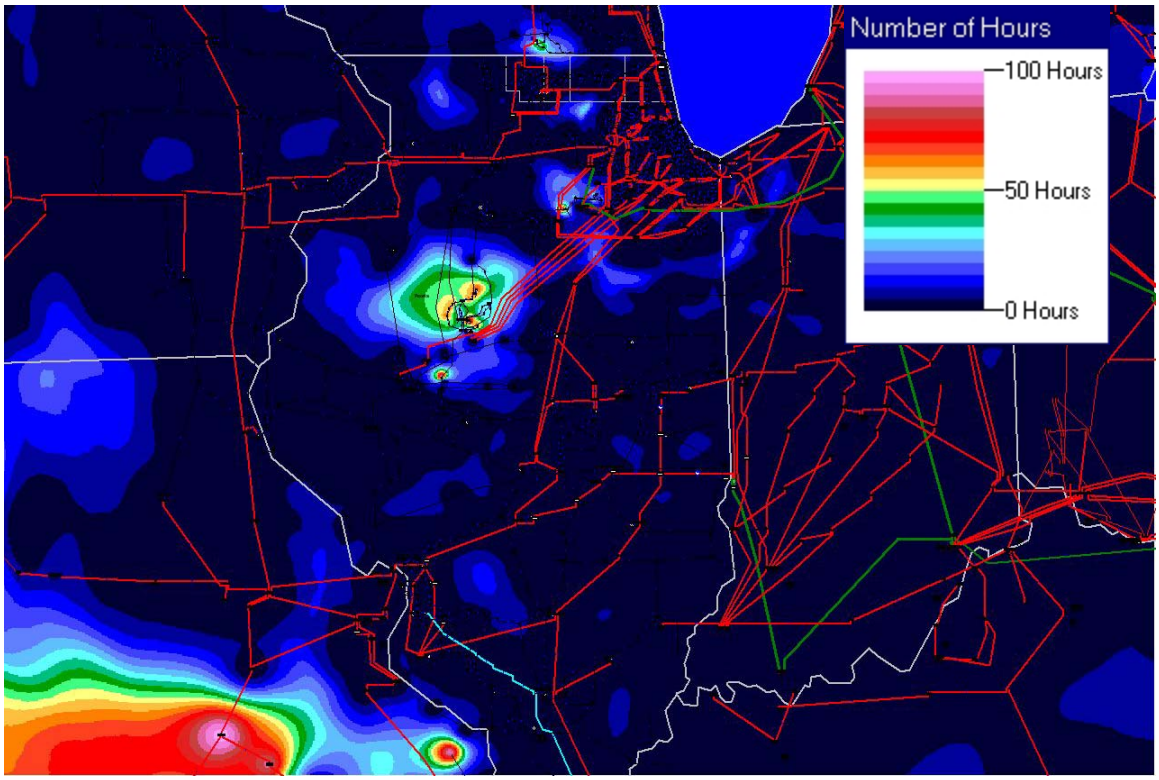

Figure F.2-19 Hours LMP Exceed $30/MWh for January to March 2007

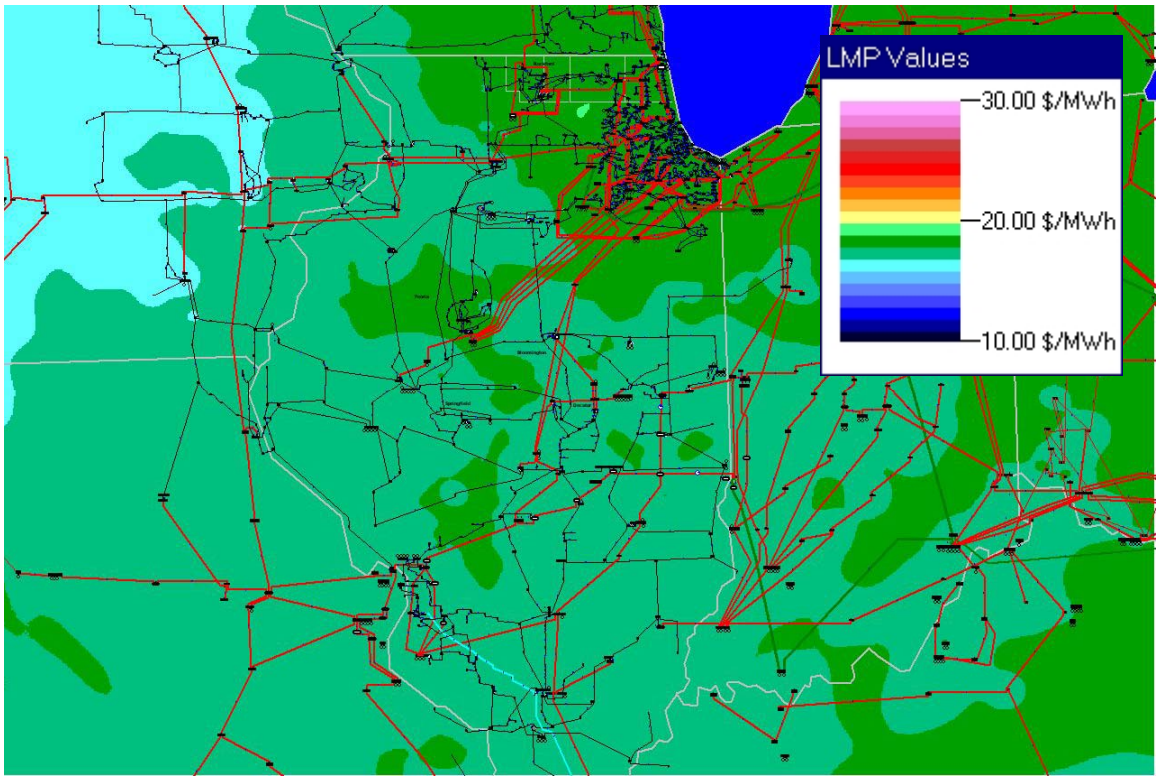

Figure F.2-20 Average LMPs for April to June 2007

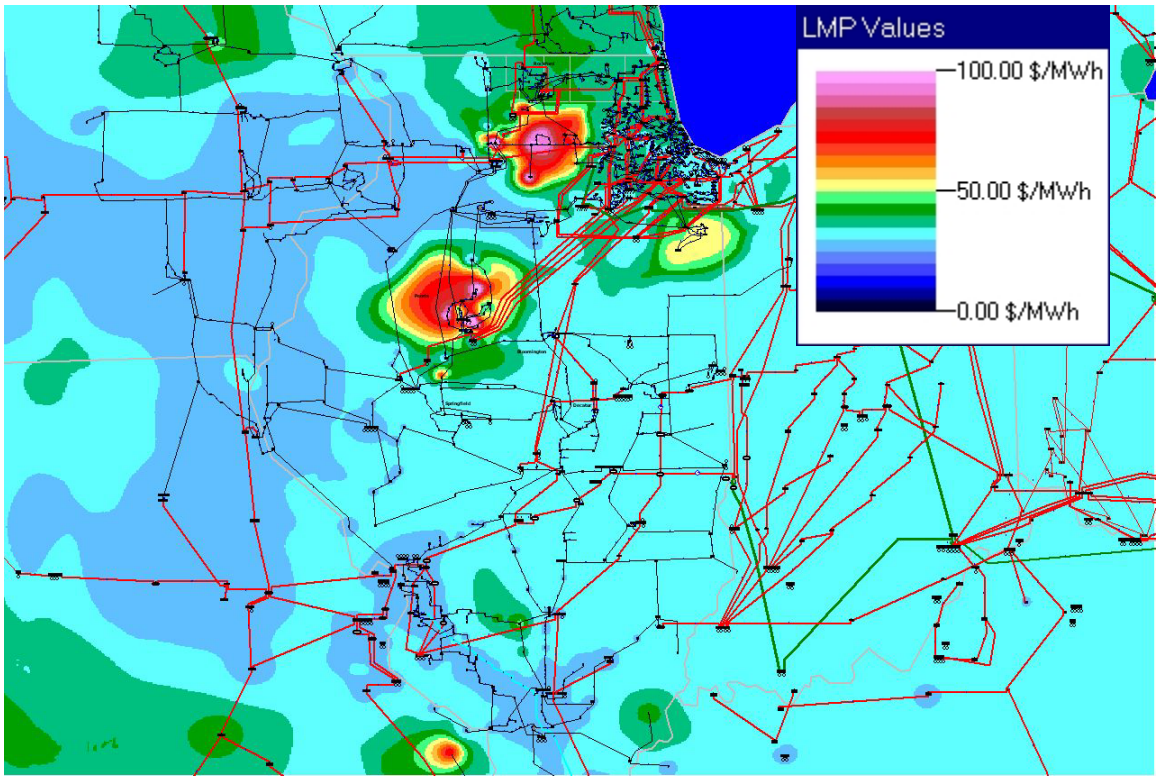

Figure F.2-21 Highest LMPs for April to June 2007

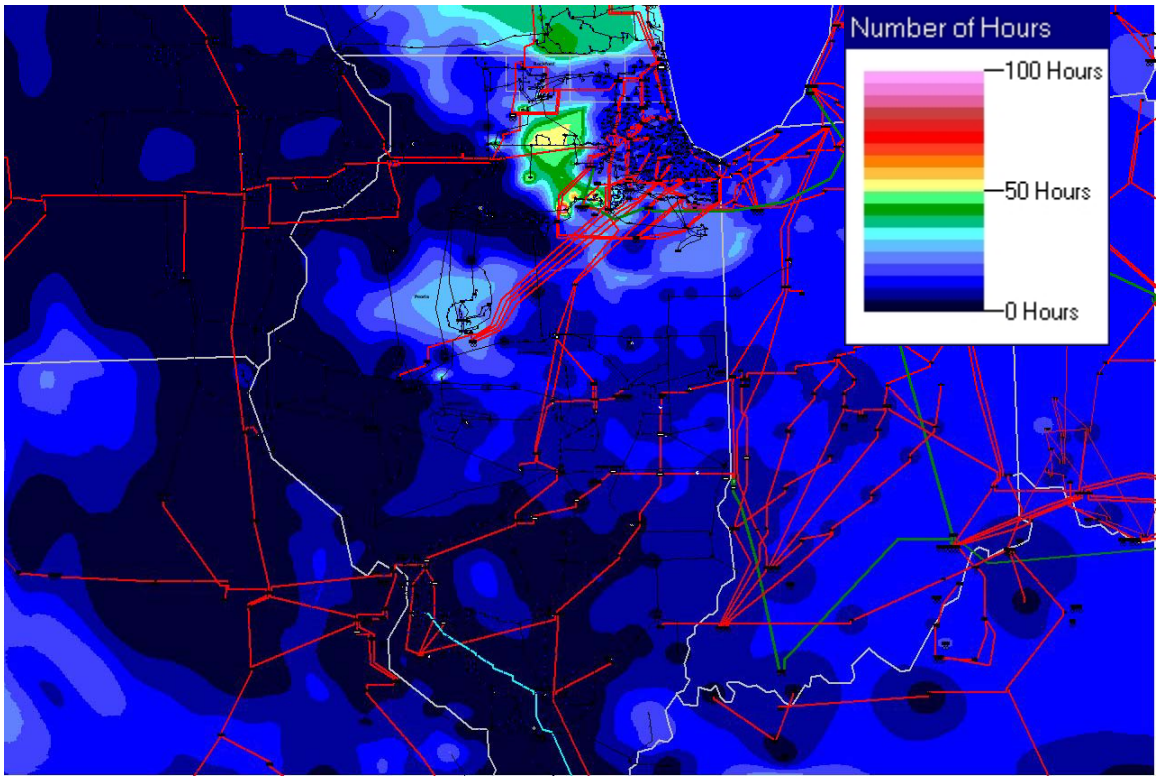

Figure F.2-22 Hours LMP Exceed $30/MWh for April to June 2007

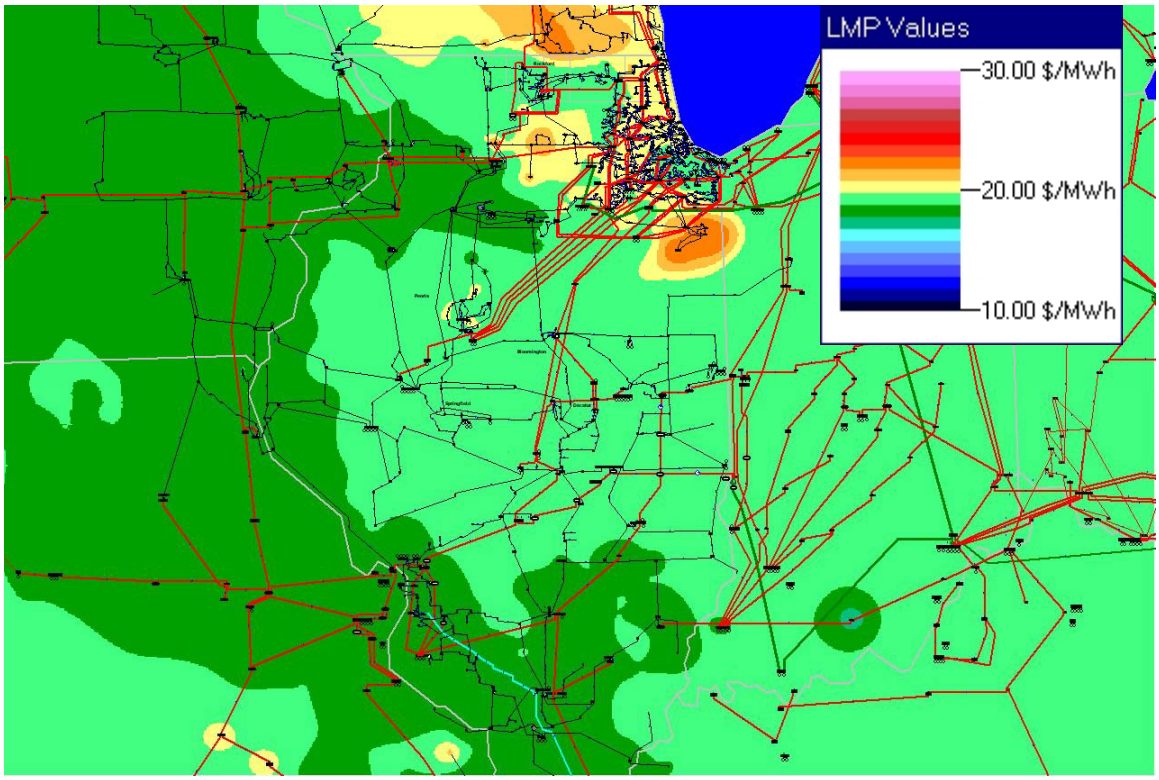

Figure F.2-23 Average LMPs for July to September 2007

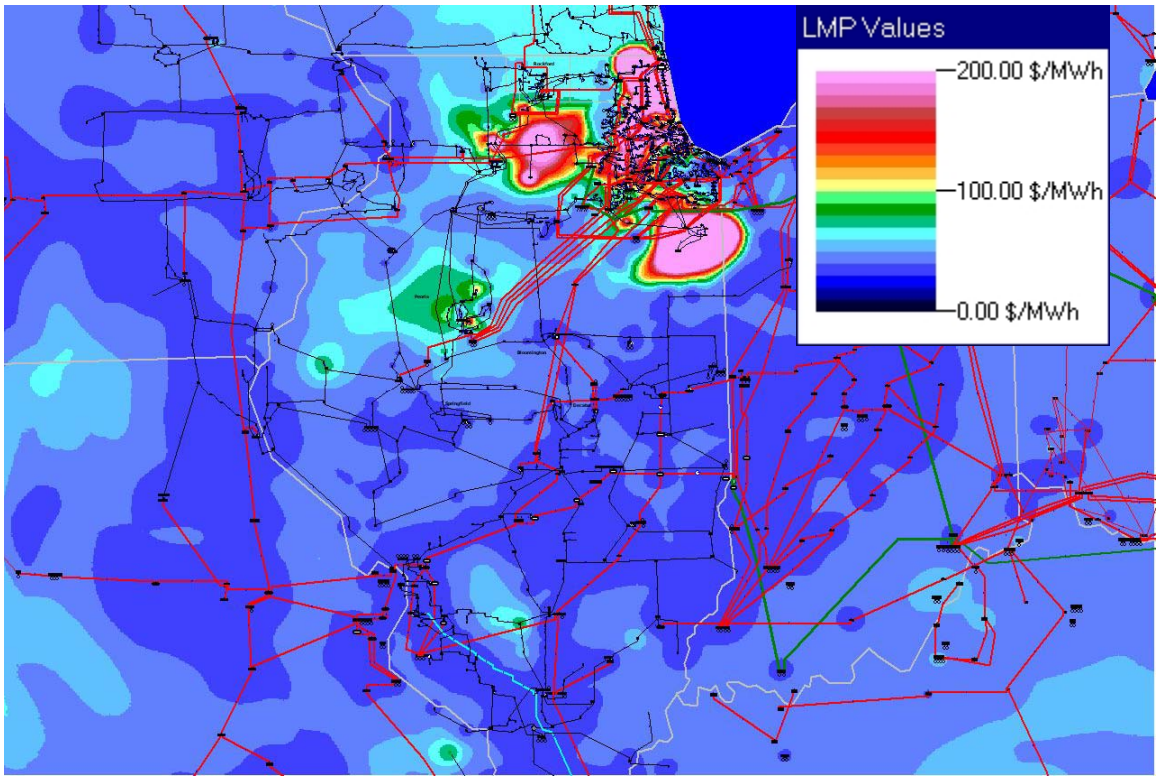

Figure F.2-24 Highest LMPs for July to September 2007

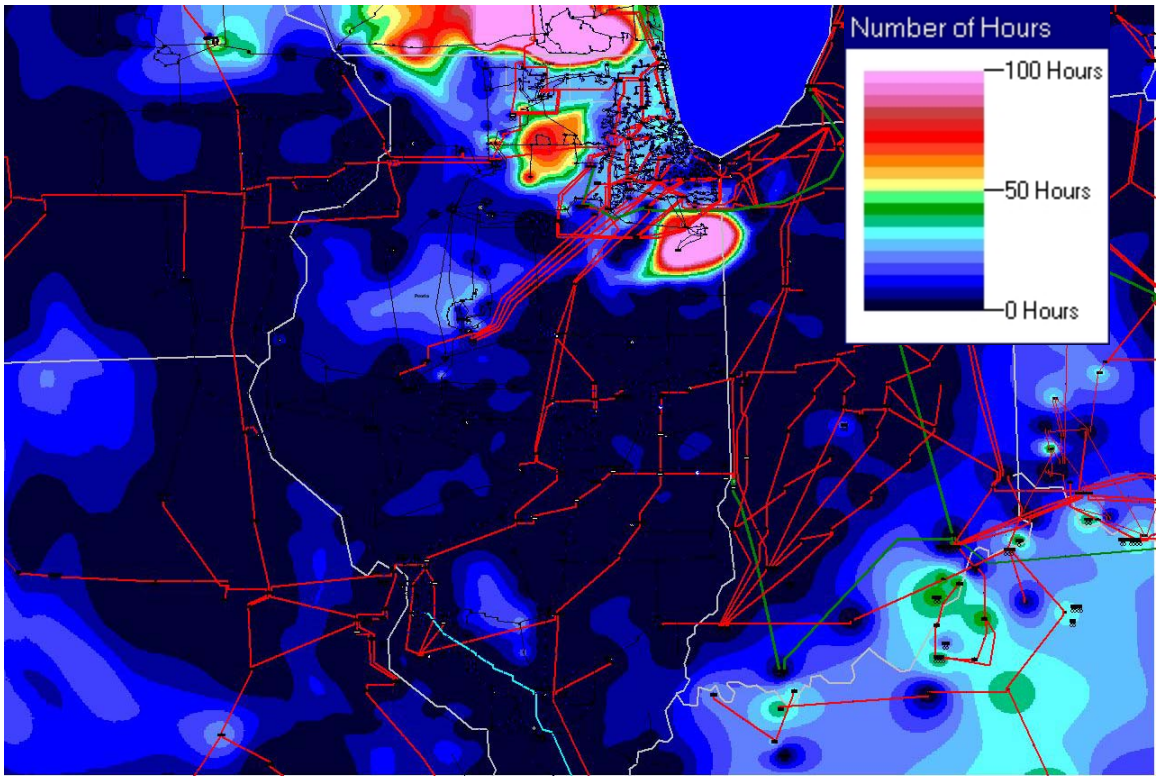

Figure F.2-25 Hours LMP Exceed $40/MWh for July to September 2007

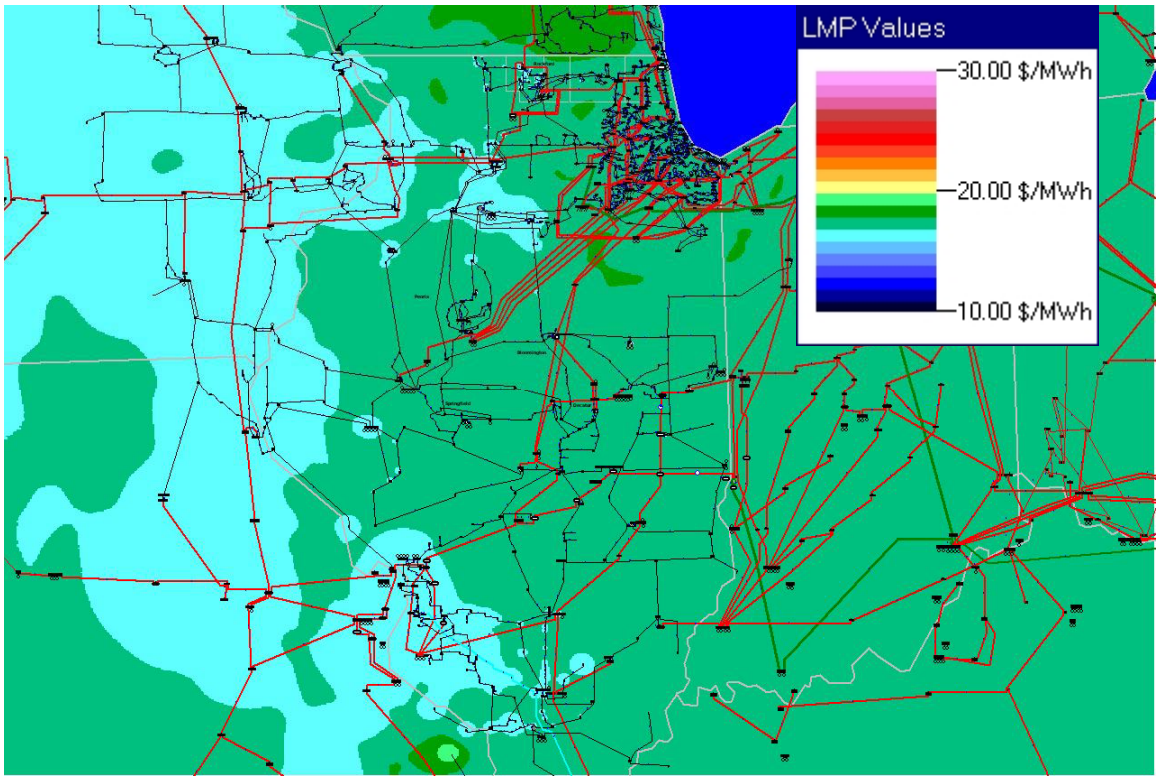

Figure F.2-26 Average LMPs for October to December 2007

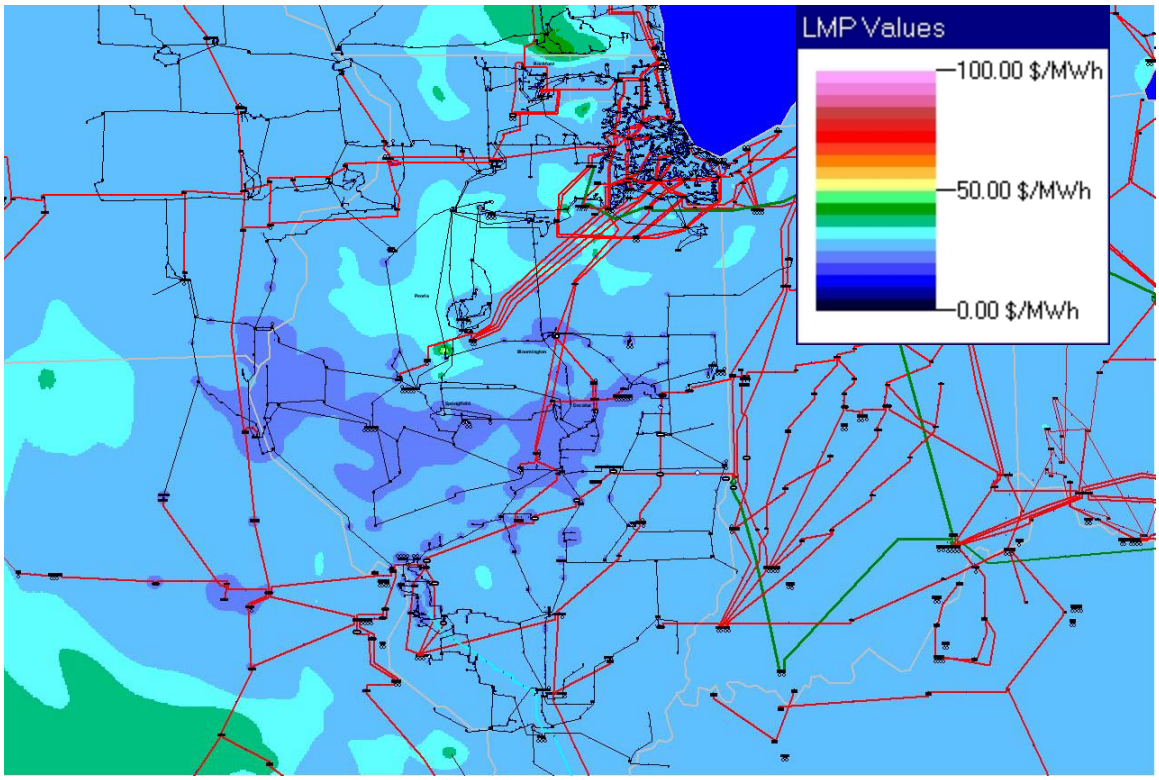

Figure F.2-27 Highest LMPs for October to December 2007

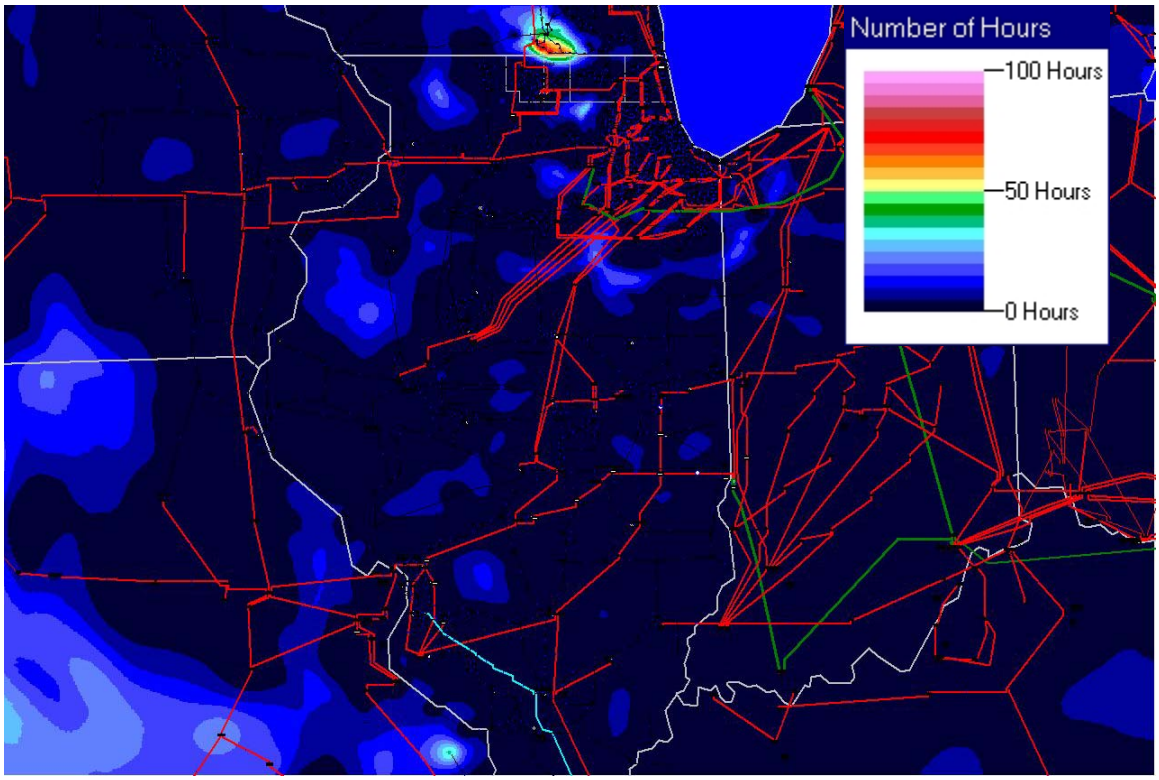

Figure F.2-28 Hours LMP Exceed $30/MWh for October to December 2007

Table F.2-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
33002	RS WALL	CILC	69	399	12,623
36688	DIXON; B	NI	138	159	9,994
36689	DIXON; R	NI	138	159	9,990
33001	EDWARDS1	CILC	69	403	8,801
33299	PEORIA	CILC	138	399	8,679
36969	MAZON; R	NI	138	1,576	8,267
33300	PEKIN	CILC	138	404	8,256
33073	MIDWEST	CILC	69	403	8,241
36548	K3192;4B	NI	138	163	6,924
36544	K3192;4T	NI	138	163	6,924
36546	K3191;4T	NI	138	163	6,924
36660	DAVIS; B	NI	138	163	6,924
36874	K3192;5B	NI	138	163	6,918
36670	K3192;5T	NI	138	163	6,918
36884	KANKE; B	NI	138	163	6,917
36882	KANKE;BT	NI	138	163	6,917
36562	BRADL; B	NI	138	163	6,917
36883	KANKE;RT	NI	138	163	6,916
36885	KANKE; R	NI	138	163	6,916
36661	DAVIS; R	NI	138	163	6,910
33040	EASTERN	CILC	69	405	6,850
33023	HINES	CILC	69	399	6,593
33029	NORTHWST	CILC	69	399	6,350
33371	2CARML_S	SIPC	69	523	5,847
36981	MENDO;	NI	138	154	5,487
36982	MENDO; T	NI	138	154	5,487
37167	H440 ;RT	NI	138	154	5,452
37169	H440 ; R	NI	138	154	5,386
37168	H445 ;3B	NI	138	154	5,386
36027	DAVIS;3M	NI	138	136	5,346
36127	DAVIS;3C	NI	34.5	136	5,346
37166	STEWA; B	NI	138	151	5,242
33108	FARGO	CILC	69	399	5,202
36942	LOMBA; B	NI	138	21	5,162
37582	LOMBA;BP	NI	138	21	5,162
37114	PLEAS;BT	NI	138	21	5,137
37116	PLEAS; B	NI	138	21	5,137
33088	HALLOCK	CILC	69	398	4,733
32298	GILSP TP	IP	138	1,327	4,590
33175	MASON	CILC	138	490	4,581
32295	GILESPIE	IP	138	1,326	4,556
36778	GLEND;BT	NI	138	21	4,525

Table F.2-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
36780	GLEND; B	NI	138	21	4,525
37371	WILSO; R	NI	138	17	4,519
33144	HINES	CILC	138	400	4,436
32654	GILESPIE	IP	34.5	1,308	4,260
37195	ROUND; R	NI	138	17	4,246
33146	EASTERN	CILC	138	406	4,198
32653	STAUNTON	IP	34.5	1,297	4,097
32296	STAUNTON	IP	138	1,289	4,025
36485	ANTIO; R	NI	138	17	3,955
36483	ANTIO;RT	NI	138	17	3,955
37048	NORDI; B	NI	138	21	3,939
36776	G ELL; B	NI	138	21	3,938
33152	PIONEERC	CILC	138	397	3,937
33155	HALLOCK	CILC	138	395	3,891
33084	TAZEWELL	CILC	69	405	3,882
37269	STILL;	NI	138	141	3,836
37267	STILL;RT	NI	138	141	3,836
37341	W DEK;4R	NI	138	141	3,612
37344	W DEK;3T	NI	138	141	3,612
33154	CAT MOSS	CILC	138	389	3,575
33151	RADNOR	CILC	138	389	3,569
36813	GURNE; R	NI	138	14	3,560
37369	WILMI;	NI	138	350	3,455
33356	2GALTN_S	SIPC	69	471	3,303
37063	NB212; R	NI	138	14	3,288
36667	DEERF;RT	NI	138	14	3,256
36669	DEERF; R	NI	138	14	3,256
36578	BUTTE; B	NI	138	21	3,222
36843	HIGHL; R	NI	138	14	3,187
36794	GRACE; B	NI	138	19	3,186
37091	O ELM; R	NI	138	14	3,148
37631	EQUIS; R	NI	13.8	700	3,147
37141	J375 ; R	NI	138	700	3,147
33150	FARGO	CILC	138	373	3,099
33143	CAT SUB2	CILC	138	376	3,050
32283	LITCH TP	IP	138	1,172	3,032
36807	A450 ; R	NI	138	15	3,018
36433	1A431; R	NI	138	16	3,010
36439	1A431;5T	NI	138	16	3,010
32297	LITCHFLD	IP	138	1,167	3,008
37061	N CHI; R	NI	138	16	2,991
36045	ITASC;1M	NI	138	22	2,969

Table F.2-2 Illinois Buses with Marginal Costs Most Often More than 10% above the State Average

Number	Name	Area Name	Nominal kV	Hours 10% above Average	Cumulative $/MWh
36145	ITASC;1C	NI	34.5	22	2,969
36864	ITASC; B	NI	138	21	2,962
36909	LAKEH; R	NI	138	16	2,946
36448	ADDIS; B	NI	138	19	2,934
37340	WATER;3B	NI	138	138	2,924
37318	WATER; B	NI	138	138	2,924
37211	SANDW; R	NI	138	138	2,924
32655	LITCHFLD	IP	34.5	1,154	2,899
36473	J371 ;RT	NI	138	646	2,890
36471	J371 ; R	NI	138	646	2,890
37556	WAUKE;7U	NI	18	16	2,840
37327	WAUKE; R	NI	138	16	2,840
36873	A418 ; R	NI	138	16	2,827
36871	A418 ;RT	NI	138	16	2,827
36429	A429 ;4R	NI	138	16	2,827
36427	A429 ;RT	NI	138	16	2,827

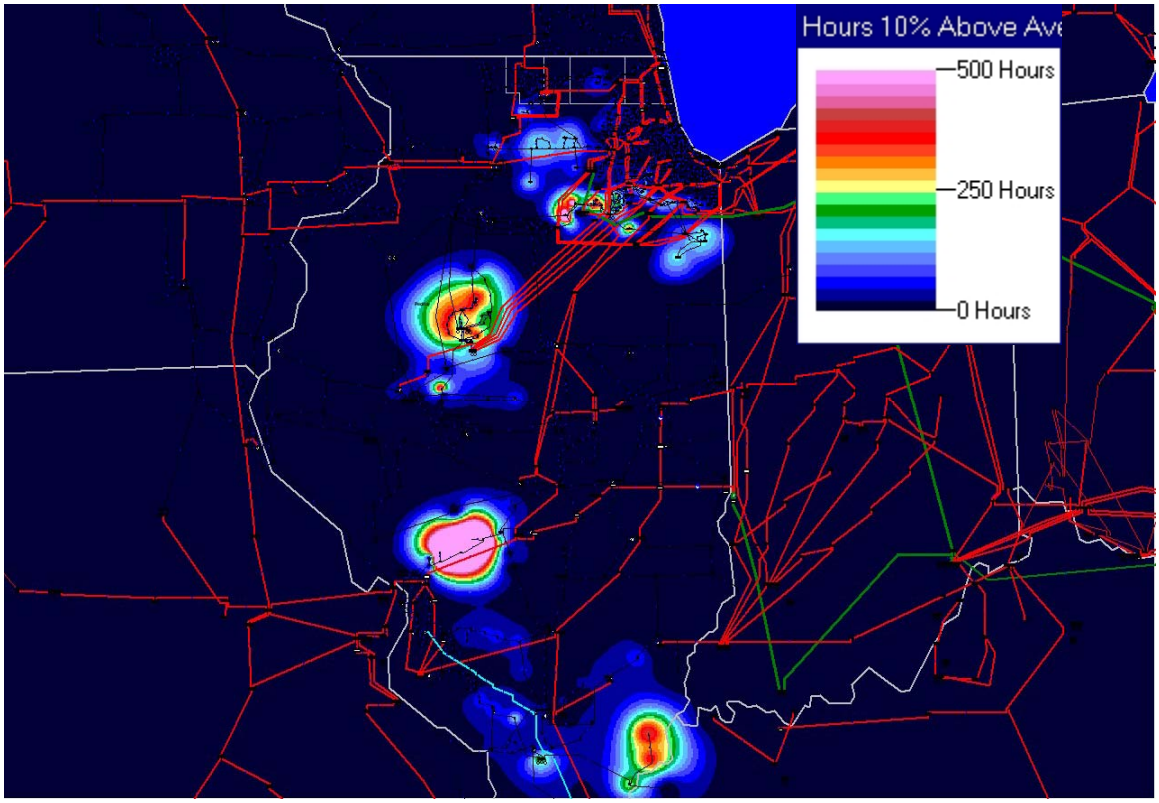

Figure F.2-29 Number of Hours Bus LMPs at Least 10% above the State Average

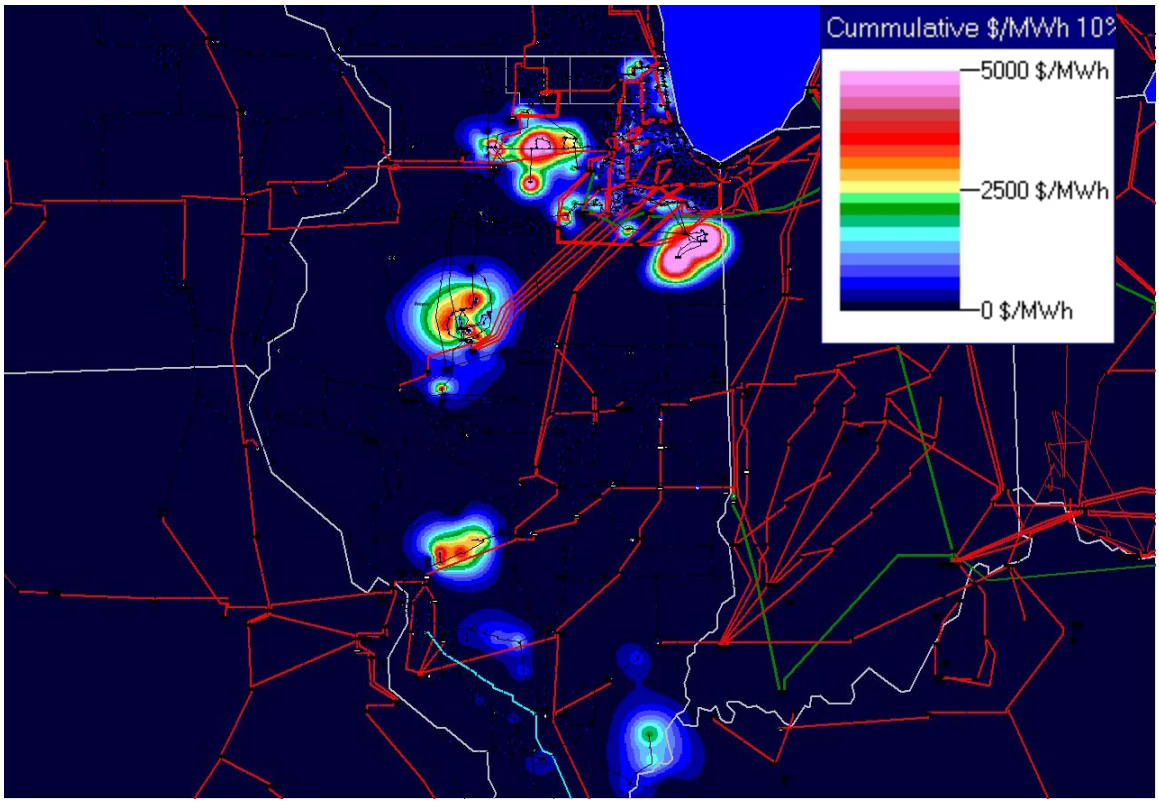

Figure F.2-30 Cumulative $/MWh 10% above the State Average

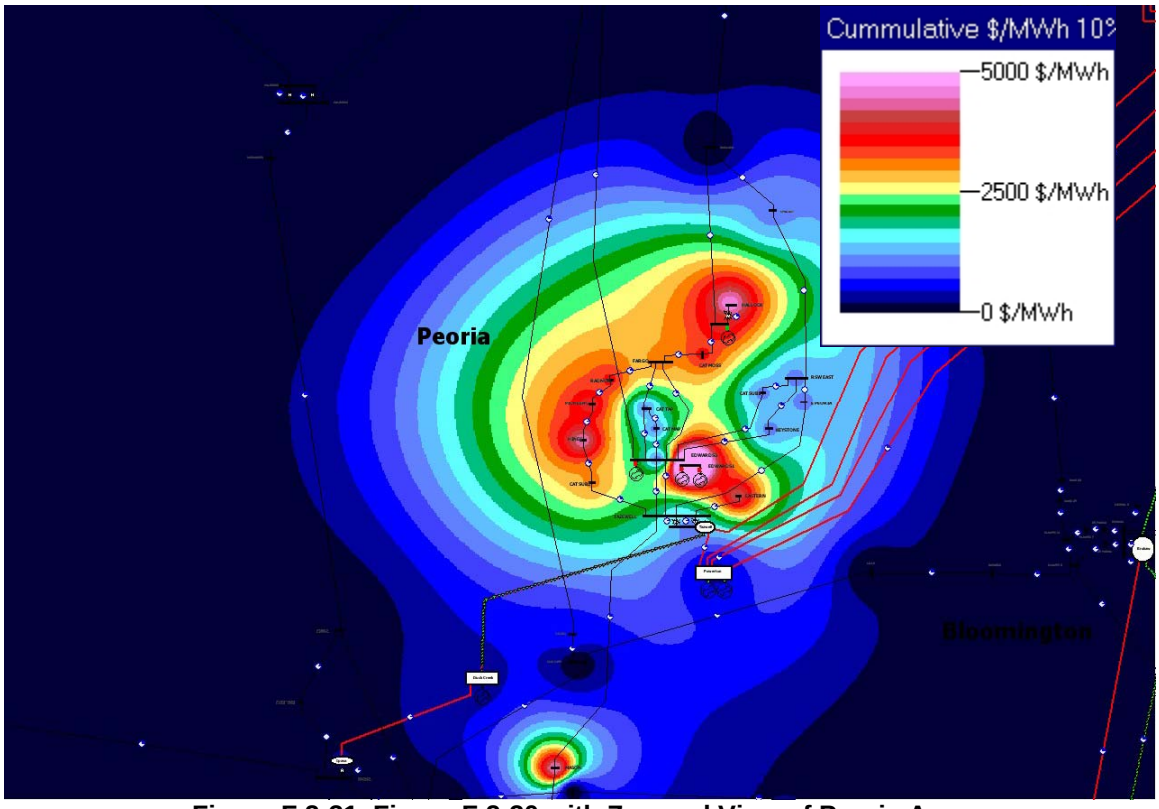

Figure F.2-31 Figure F.2-30 with Zoomed View of Peoria Area

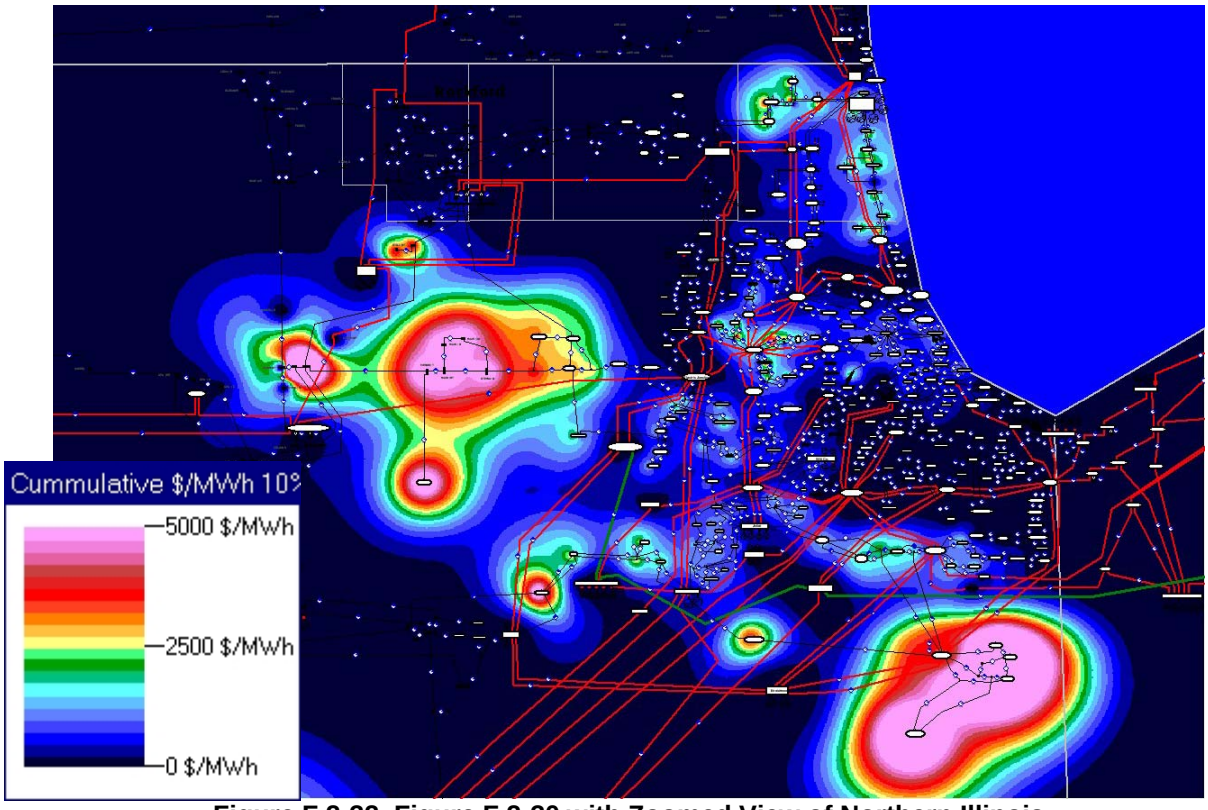

Figure F.2-32 Figure F.2-30 with Zoomed View of Northern Illinois

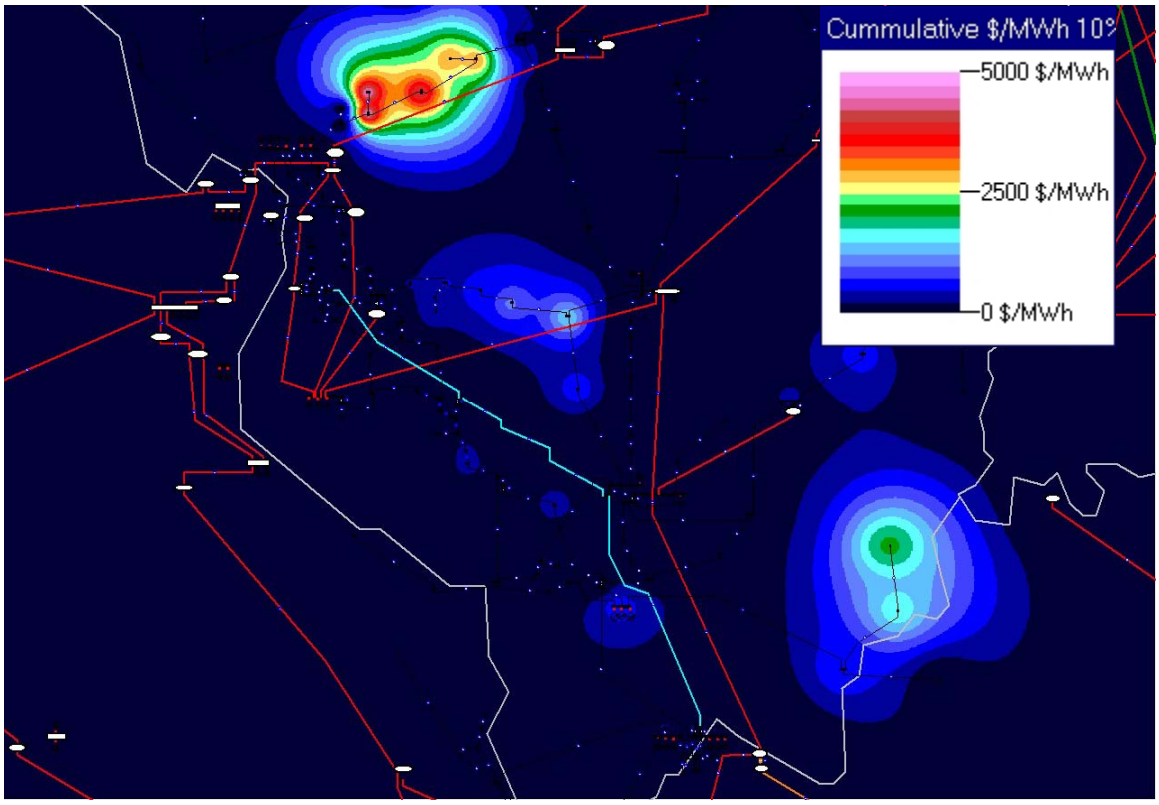

Figure F.2-33 Figure F.2-30 with Zoomed View of Southern Illinois

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