Simulating Strategic Market Behavior Using an Agent-Based Modeling Approach

Results of a Power Market Analysis for the Midwestern United States

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This paper presents the use of a novel approach that combines detailed engineering and load-flow analysis with an agent-based power market modeling framework to simulate restructured power markets and identify the potential for individual market participants to use strategic behavior to profitably influence electricity prices in the mid-western United States. As power markets continue to evolve, there is a growing need for advanced modeling approaches that simulate how electricity markets may evolve over time and how participants in these markets may act and react to the changing economic, financial, and regulatory environments in which they operate. This is equally crucial for market monitoring purposes of already established markets as well as in the market design process for developing new markets.

The Electricity Market Complex Adaptive System (EMCAS) model is a tool specifically designed to gain new insights into today's dynamic electricity markets. The model uses agent-based modeling techniques to represent multiple and diverse market participants or "agents," each with their own unique set of business strategies, risk preferences, objectives, and decision rules and the ability to learn from past experience and change and adapt their behavior when future opportunities arise. This new approach is currently used to analyze a future power market in the mid-western U.S. The analysis was conducted for all 8,760 hours of the year when restructuring is presumed to be completed. A "Production-Cost" case, where all agents are presumed to offer power at production cost, was established as a benchmark or reference point.

The future transmission grid configuration was constructed using data from the North American Electric Reliability Council (NERC). All busses and branches in the study area are represented in the model. Under the Production-Cost case, prices increase during high-load periods as more expensive generators are brought on-line to meet the load. Prices vary by up to a factor of four across zones as a result of transmission congestion, particularly in the summer months. In addition, transmission congestion was found to create higher prices even during nonpeak hours. Several zones, and particularly the largest metropolitan region in the study area, begin to exhibit typical signs of load pockets.

Subsequent model runs tried to identify the potential for generation companies to exploit their strategic position to profitably raise prices above marginal production cost. The analysis takes into account a variety of strategies (e.g., physical and economic withholding) and a host of aspects that drive the ability to successfully exert strategic behavior, including *temporal* (ability to influence prices may be limited to certain hours), *spatial* (not all busses may be susceptible to strategic behavior), and *technological* (not all types of generators equally lend themselves to gaming). The paper presents results for various strategic behavior runs.

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Introduction

Despite the uncertainties surrounding the potential market design and the on-going debate between the various potential market operators, the Federal Energy Regulatory Commission (FERC), and a number of state legislatures, the power industry in the midwestern United States. is poised to undergo further changes and restructuring. Given these uncertainties, though, there are concerns that the envisioned electricity restructuring warrants a more detailed analysis, particularly after the recent problems experienced by power markets elsewhere. To address these concerns, a midwestern public utility commission requested an analysis to evaluate the potential future restructuring of the area's power industry. The study is specifically designed to make an initial determination if the transmission system in the 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. In addition, the analysis tries to identify conditions under which companies may be in a position to exercise market power in one or more portions of the study area and estimate the frequency and extent of these situations. The intent is not to predict whether or not such market power would be exercised by any company. Rather, the analysis is aimed at determining if a set of reasonably expected conditions could allow any company to do so.

As market power is not just simply a function of market share as often measured by indices like the Herfindahl-Hirschman Index (HHI), Residual Supply Index (RSI), and Lerner Index, a comprehensive and thorough analysis of market power has to go well beyond these traditional tests and incorporate key market dynamics, including locational and timing issues. Market power may arise in less obvious but equally consequential situations where smaller, less-dominant, generation owners happen to have a locational advantage and are able to exploit the unique characteristics and physical limitations of the transmission grid (load pocket) and/or weaknesses in market rules by developing bidding strategies that successfully drive up prices beyond competitive levels in that particular part of the grid. In this case, both the intensity and the frequency of the location-specific load pocket or transmission bottleneck are crucial. A large price spike may be of less concern if it occurs only during a few hours per year, whereas a moderate price spike may have much larger impacts if it can be sustained for a sizeable number of hours per year. This type of situation can only be captured in models that reflect the transmission grid in detail, simulate the market operation chronologically on an hourly basis, and incorporate some degree of learning among market participants based on previous experiences that can be used to adapt market behavior and bidding strategies to new situations.

Agent-Based Modeling and Simulation Concept

The complex interactions and interdependencies among participants in today's deregulated, decentralized electricity markets are much like those studied in game theory (Picker, 1997). However, the strategies used by many power market participants are often too complex to be conveniently modeled by 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 offers appealing extensions to traditional game theory.

Computational social science involves the use of agent-based modeling and simulation (ABMS) to study complex social systems (Epstein and Axtell, 1996). ABMS 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 by its focus on finding the set of basic decision rules and behavioral interactions that can produce the complex results experienced in the real world (Sallach and Macal, 2001). ABMS tools are designed to simulate the interactions of large numbers of individuals so as to study the macro-scale consequences of these interactions (Tesfatsion, 2002). Each entity in the system under investigation is represented by an agent in the model. An agent is thus a software representation of a decision-making unit. Agents are self-directed objects with specific traits and typically exhibit bounded rationality, that is, they make decisions by using limited internal decision rules that depend only on imperfect local information. In practice, each agent has only partial knowledge of other agents and each agent makes its own decisions based on the partial knowledge about other agents in the system.

The purpose of an ABMS model is not necessarily to predict the outcome of a system, rather it is to reveal and understand the complex and aggregate system behaviors that emerge from the interactions of the heterogeneous individuals. 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 (Bonabeau et al., 1999).

Several electricity market ABMS tools have been constructed, including those created by Bower and Bunn (2000), Petrov and Sheblé (2000), Lai et al. (2000), Skoulidas et al. (2002), Veselka et al. (2002), and North et al. (2002). ABMS has been applied to analyzing the new electricity trading arrangements for England and Wales (Bunn and Oliveira, 2001). Bunn and Oliveira (2003) also applied ABMS to analyze market power in electricity markets. North (2001a, 2001b, 2001c) applied ABMS to identify infrastructure factors in electric power generation and transmission leading to local price spikes and demonstrated the feasibility of applying agent simulation to quantify the extent of interdependencies between the electric power and natural gas infrastructures. Thomas et al. (2002) present a conceptual modeling framework for examining infrastructure interdependencies. These models have demonstrated the potential of agent simulations to act as electronic laboratories, or "e-laboratories," suitable for repeated experimentation under controlled conditions.

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).

EMCAS Approach

While planning and operation of traditional electric utility systems used to be strongly driven by least-cost and reliability concerns, recent trends toward restructuring and unbundling are creating opportunities for new participants with new business models to enter the markets and are creating diverse and dynamic markets. Centralized, monopolistic decision-making organizations are giving way to heterogeneous, decentralized decision structures. The “single” decision-maker is replaced by a host of decision entities each with their own, unique business strategies, risk preferences, and decision models.

The implicit assumption of a centralized decision-making process built into many of the global optimization and equilibrium-based power systems analysis tools developed over the last two decades limits their ability to adequately analyze the forces prevalent in today’s emerging markets. This is amplified by recent experiences that have shown the difficulties of understanding the operation of these markets.

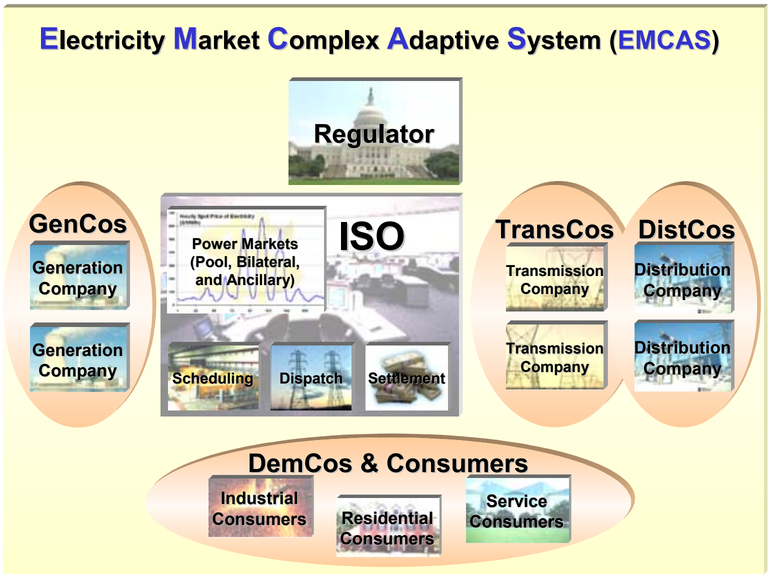

Figure 1: EMCAS Agents

Unlike conventional electric systems analysis tools, the Electricity Market Complex Adaptive System (EMCAS) model does not postulate a single decision maker with a single objective for the entire system. Rather, agents are allowed to establish their own objectives and apply their own decision rules. The complex adaptive systems (CAS) modeling approach simulates agents that learn from their previous experiences and change their behavior when future opportunities arise. That is, as the simulation progresses, agents can adapt their strategies on the basis of the success or failure of previous efforts. Genetic algorithms are used to provide a learning capability for certain agents. With its agent-based approach, EMCAS is specifically designed to analyze multi-agent markets and allow testing of regulatory structures before they are applied to real systems.

The EMCAS framework 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 signify the environment in which the agents interact with each other. The planning periods correspond to the different time horizons for which the agents make decisions regarding their participation in the market.

EMCAS Agents

EMCAS includes a large number of different agents to capture the heterogeneity of restructured markets (see Figure 1), including generation companies (GenCos), transmission companies (TransCos), distribution companies (DistCos), independent system operators (ISOs) or regional transmission organizations (RTOs), demand companies (DemCos), consumers, and regulators. EMCAS agents are highly specialized to perform diverse tasks ranging from acting as generation companies to modeling transmission lines. To support specialization, EMCAS agents include large numbers of highly specific rules. Analysts can easily define new rules and strategies to be used for EMCAS agents and then examine the marketplace consequences of these strategies.

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

Transmission Nodes and Links

The configuration of the transmission system is represented in EMCAS as a set of nodes and links that represent busses and links, respectively (Figure 2). The representation may be an aggregate of busses and links to simplify the analysis. The transmission nodes and links do not exercise any decision-making capabilities. The operation of the transmission system is governed by decisions made by the ISO/RTO agent and the transmission company that owns the facilities.

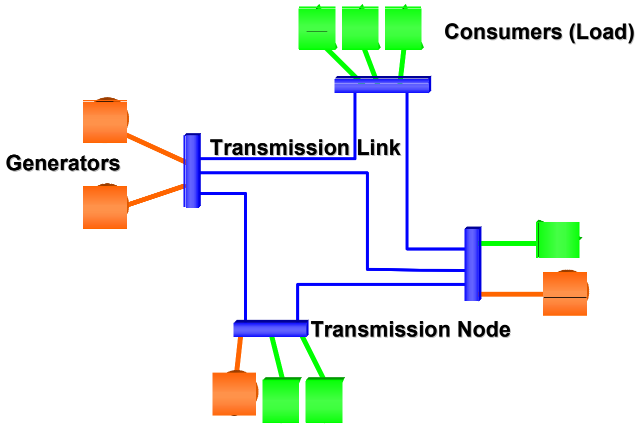

Figure 2: EMCAS Transmission Components

Consumers

An EMCAS simulation may include residential, commercial, industrial, and other electricity consumers (Figure 3). In theory, the simulation may be done for individual consumers (e.g., a single household, a single industrial facility). In practice, the number of consumers included in a simulation is limited by available data and by computational time. EMCAS consumer agents exhibit learning and adaptation by responding to the price of electricity. The consumer agent has two basic choices to respond to prices, that is, (1) reduce electricity consumption and (2) switch electricity supplier if retail choice is an option. Since most consumers do not have access to hourly or daily electricity price information, their response to price changes lags behind. For most consumers, the response of reducing consumption occurs at the time of receipt of monthly electricity bills. The response of switching suppliers usually occurs on approximately an annual basis, depending on the terms and conditions of supply contracts.

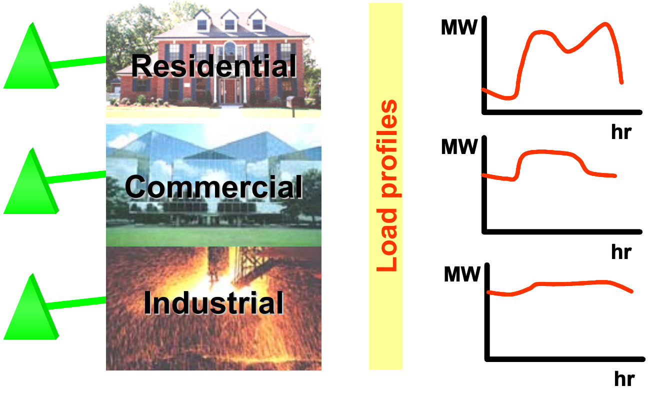

Figure 3: EMCAS Consumer Agents

Generation Companies

The generation company 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 provides other products in the electricity market (Figure 4). 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 based on the agent's business strategy. This business strategy, however, does not have to remain static. Rather, agents may change strategies as learning and adaptation occurs. In EMCAS, agents learn about market behavior and the actions of other agents using two forms of learning, that is, *observation-based learning* and *exploration-based learning*. The observation-based learning (Figure 5) goes through a structured process that includes a

- *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 choose to either (1) maintain the current business strategy, (2) adjust the current business strategy, or (3) switch to a new business strategy.

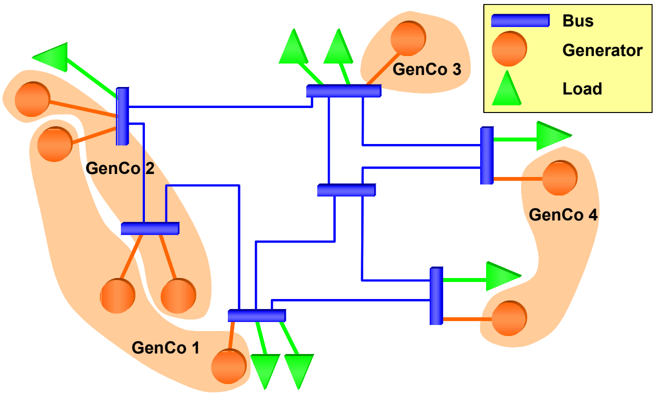

Figure 4: EMCAS Generation Company Agents

Using exploration-based learning, agents explore various marketing and bidding strategies and observe the results of their actions. Once a strategy is found that performs well, it is exercised and fine-tuned as subtle changes occur in the marketplace. When more dramatic market changes take place and a strategy begins to fail, an agent more frequently explores new strategies in an attempt to adapt to the dynamic and evolving supply and demand forces in the marketplace. Even when a strategy continues to perform well, agents periodically explore and evaluate other strategies in their search for one that performs better. Through this process, agents engage in a price discovery process and learn how they may potentially influence the market through their own actions to increase their corporate utility. Some agents may strive to exploit the physical limitations of the power system and the market rules under which they operate as a means to increase profit. For example, under the locational marginal price (LMP) market rule, if a generation company learns that under certain conditions it can frequently influence market prices, then it may decide to increase its bid prices. However, this higher bid price will increase the risk that it will be rejected. A company that has learned that it has little influence over the market or is risk-averse may decide not to increase bid prices.

In EMCAS, the business profile of a GenCo is described using multi-attribute utility theory. The business profile consists of objectives, risk preference, and a utility function. The business objectives are the parameters that the company uses to determine the desirability of the various options it has available. The most commonly used business objective is profit. Other objectives, such as market share, can be included. The GenCo's risk preference is determined by a parameter that characterizes the company as risk-neutral, risk-prone, or risk-averse. The objectives and risk prefer-

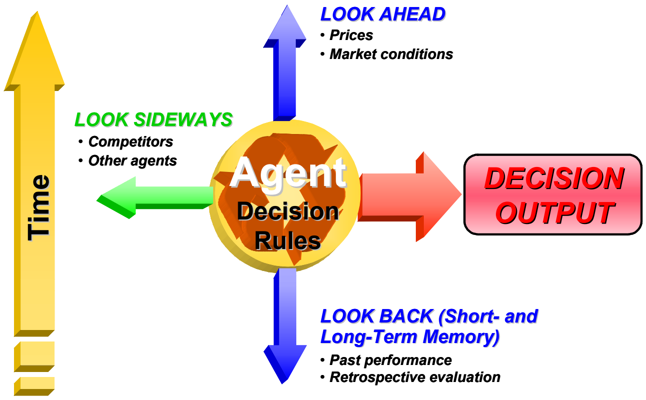

Figure 5: Agent Learning Process

ence are combined to form a company utility function. Each GenCo seeks to maximize its expected utility throughout the simulation, and each GenCo can have a different business profile in order to test the effects of different company business styles. The utility function represents the primary measure of how well the GenCo agent is performing. In the terminology of agent-based modeling, it is the “fitness function” that determines if the agent should continue in its current course of action or should seek to adapt.

Demand Companies

Demand company (DemCo) agents represent the business units that sell electricity to consumers. DemCos purchase this electricity either by entering into bilateral contracts with GenCos or by buying electricity from the pool market. An EMCAS demand company does not need to have a specific service territory and may serve consumers from anywhere in the study area (Figure 6). DemCos make decisions on how much electricity to buy, what price they are willing to pay, and what to charge their consumers.

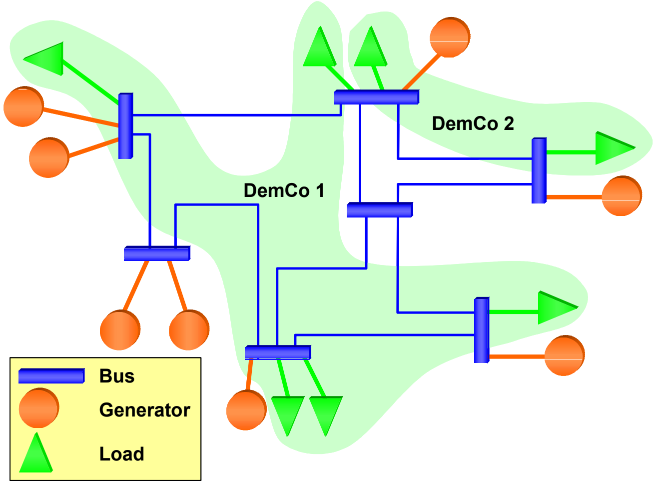

Figure 6: EMCAS Demand Company Agents

A DemCo’s business profile is described in the same manner as that of a GenCo. That is, the profile consists of objectives, risk preferences, 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. Learning and adaptation by DemCo agents occurs in a manner analogous to what is experienced by GenCo agents.

Transmission Companies

In EMCAS the transmission companies (TransCos) own the transmission lines but do not operate the system. Operation is left to the ISO/RTO. Transmission companies also do not engage in strategic business practices. Instead, they charge a fee for the use of their transmission assets. By convention in EMCAS, the transmission use fee is collected from DemCos and is added to the price they charge consumers. Multiple TransCos can be included in a simulation run. Each transmission line and bus in the network is assigned to a TransCo owner. Some busses/nodes may have lines attached to them that belong to different TransCos. Consumers pay an implicit *transmission congestion charge* by paying a locational marginal price. This charge is calculated for each hour and node based on the differences in LMPs, collected by the ISO/RTO, and distributed to the TransCos based on the distribution of load at the nodes owned by each TransCo.

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. Multiple DistCos can be included in EMCAS, each with a specific service territory. To identify the service territory of each DistCo, each bus in the network where load is attached is identified as belonging to a specific DistCo. All consumer agents at that bus are identified as being served by that DistCo. The user inputs the distribution fee structure. The fee may vary by DistCo and, for a given DistCo, may vary by network node and consumer type. The distribution fee is paid by consumers and is accounted as revenue to the DistCo.

ISO/RTO

This agent represents an independent system operator (ISO), regional transmission organization (RTO), or independent transmission provider, depending on what organizational structure is in place. The ISO/RTO exercises several functions in an EMCAS simulation including the following:

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

The ISO/RTO 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. It does this by running a security-constrained, direct-current optimal power flow model (DC-OPF). The ISO/RTO sets system reliability parameters that will be used for system operation, such as various reserve margins. It also sets the procedures used to operate the day-ahead market as well as bilateral contract treatment.

Regulators

The regulator agent sets the market rules. In its current implementation, the EMCAS regulator does not adapt or change its behavior. Rather, it relies on user input. Parameters that can be set include (1) the type of valid markets, that is, bilateral contracts, pool energy, or ancillary services markets; (2) pricing and settlement rules, including uniform versus discriminatory auction as well as price caps; and (3) taxes and end user tariffs.

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 in the planning levels. Currently, the special event generator can be used to inject unplanned incidents at the hourly dispatch level, including unexpected variations in load, generator outages, and transmission link outages.

EMCAS Interaction Layers

The interaction layers provide the environment for the agents to operate in. This environment is typically multi-dimensional, that is, agents operate within several interconnected layers, including a physical layer, several business layers, and a regulatory layer as shown in Figure 7.

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. Consumers, generators, and transmission nodes and links together make up the physical part of the electricity market. Typically, though, the distribution system is not modeled in detail to keep the analysis and computing requirements within reasonable limits.

The ISO/RTO operates both the transmission system and the electricity markets. In the physical layer, the ISO/RTO exercises its dispatch function to operate the system to match load and generation and to adjust to changes in load, generator or transmission outages, and other unplanned events.

Business Layers

Figure 7 also shows three business layers that represent the business side of the electricity market. Here, the GenCo agents that own the generators make the decisions regarding how to operate the equipment to meet company objectives. The DemCos participate in the electricity market by buying electricity from GenCos and selling it to their consumers. EMCAS can account for situations where a GenCo and a DemCo are part of the same corporate parent. *Pool markets* (or spot markets) for energy and ancillary services serve as central clearing houses for buyers and sellers and are operated in EMCAS by the ISO/RTO. GenCos and DemCos can engage in *bilateral contract markets* for the sale and purchase of electricity. These contracts are negotiated privately between two agents. In some market structures, the ISO/RTO is involved in these contracts only to the extent of determining that there is adequate transmission capacity to accommodate the contractual power transfers. The *transmission and distribution company* 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 TransCos and DistCos may be part of a single corporate parent, along with a GenCo and DemCo. EMCAS can account for this corporate connection while maintaining a separate accounting of each business unit.

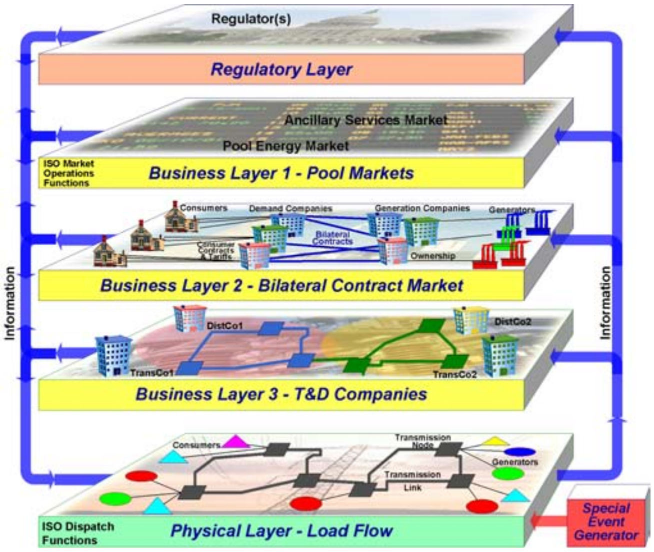

Figure 7: EMCAS Interaction Layers

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.

EMCAS Planning Periods

The underlying structure of EMCAS is that of a time continuum ranging from hours to decades. Modeling over this range of time scales is necessary to understand the complex operation of electricity marketplaces. The model operates at six distinct time scales or decision levels that include an hourly dispatch as well as several forward markets, such as day-ahead, week-ahead, month-ahead, year-ahead, and multi-year (Figure 8). At each decision level, GenCo agents make decisions regarding the operation of the generating resources they manage and formulate marketing strategies. User-defined rules make different types of markets are available to players at each time scale. The types of markets available and the specific rules under which each operates influence decisions made by market participants. The focus of agent rules in EMCAS varies to match the time continuum.

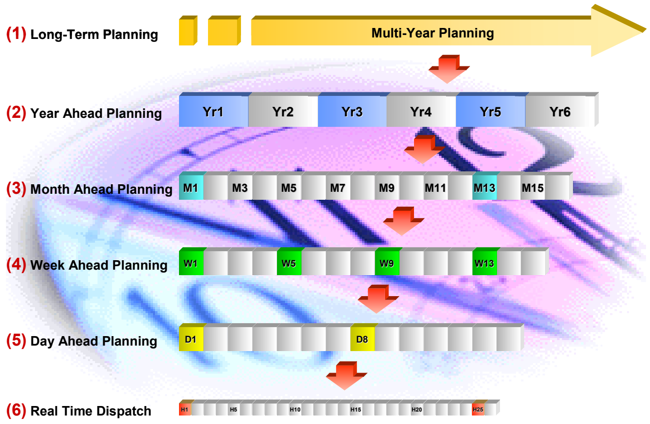

Figure 8: EMCAS Planning Periods

EMCAS Forward Markets

Currently, EMCAS simulates three types of markets that include bilateral contract, pool energy, and ancillary services (Figure 9). Generally, bilateral contracts are agreements between a single GenCo agent and a single DemCo agent. These contracts have time scales that range from hours to several years. In the pool energy market, EMCAS agents submit buy and sell bids to the auction clearinghouse—in this case, the ISO. On the basis of bid prices, transmission constraints, and energy security considerations, the clearinghouse determines which bids are accepted and rejected and

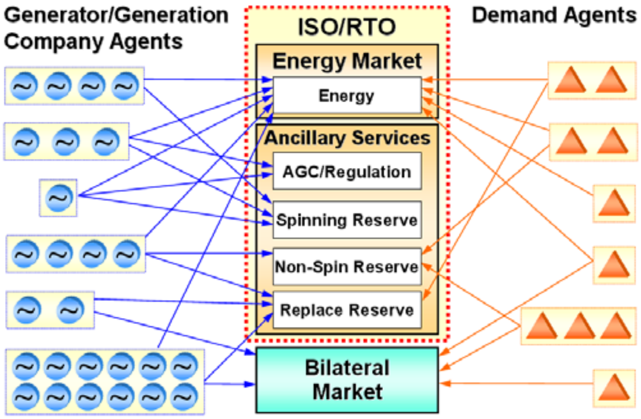

Figure 9: EMCAS Forward Markets

calculates the price of electricity. Pool energy markets are typically conducted at the day-ahead time scale. Ancillary services markets, such as spinning and non-spinning reserves, automatic generation control (AGC), and replacement reserves, maintain electric quality and reliability. The ancillary services markets are usually conducted at the day-ahead and hour-ahead time scales.

EMCAS Bilateral Contract Markets

EMCAS simulates bilateral contracts among generation company and demand agents through a series of requests for proposals (RFPs) that are initiated by the DemCo agents. A DemCo agent formulates an RFP for capacity and energy on the basis of the anticipated needs of its customers and its risk tolerance for exposure to pool market price volatility. This process is performed independently by each agent and is subject to uncertainty. If a DemCo agent chooses to participate in the bilateral market, one or more RFPs are sent to select GenCo agents. RFPs can be issued for energy deliveries that are constant over all hours of the contract term and energy deliveries that vary over time. GenCo agents analyze RFPs, formulate responses, and send these responses to DemCo agents. The response includes prices for all or some portion of the requested capacity and energy. DemCo agents evaluate the responses that they receive and either accept or reject the offers. On the basis of the bilateral agreements forged among market players and lessons learned from previous bid rounds, both DemCo and GenCo agents revise their marketing strategies for the next round. The user controls the number of bidding rounds simulated by EMCAS.

EMCAS Pool Markets

Pool markets are typically conducted at the day-ahead and hour-ahead time scales. The ISO conducting the market is responsible for posting public information that is available to all agents, including unit outage data, historical pool clearing prices and system-level loads, and load projections. Each agent in the market submits bids independently, without any information regarding the bids placed by its competitors. This can be modified to examine effects of collusion. EMCAS has two pool market options. The first is the locational marginal price option in which all agents get paid the marginal bid to serve loads at a specific location. The LMP is paid to all GenCos that sell power (accepted bid) at a specific location regardless of the agent's bid price (uniform auction). The second pool market option is referred to as "Pay-as-Bid" in which each GenCo gets paid the price that it bids (discriminatory auction).

In the day-ahead pool market, GenCos' bidding strategies are formulated for the entire day, not for individual hours. GenCos use public information as well as private information to formulate their bidding strategies. On the basis of bid prices, transmission constraints, and energy security considerations, the ISO accepts or rejects the bids it receives and computes the LMPs. On the basis of this decision, GenCos develop unit commitment schedules and formulate plans for the ancillary services markets.

EMCAS Ancillary Services Markets

EMCAS models three ancillary services markets after the pool market closes. Spinning reserve markets are simulated first followed by the AGC and replacement reserves markets. The amount of these services that is purchased by the ISO is a function of system reliability and security parameters that are entered into EMCAS by the user.

The ISO selects ancillary services bids based solely on price, not location. The lowest-priced bids are accepted such that all ancillary services requirements are fulfilled. Total transfer capabilities on transmission lines include security constraints. Therefore, it is assumed that the transmission system can reliably accommodate ancillary services functions under all but the most severe situations.

Spinning reserve services are called upon by EMCAS when scheduled generation cannot meet load because of an unplanned event, such as a generator failure or a line outage. Spinning units that were previously called into generation service are eventually put back into a spin state, and, if required, generation from replacement reserve units fulfills the shortfalls. Since ancillary services markets are cleared last, GenCo agents must anticipate the costs, benefits, and risks associated with these markets in their overall marketing strategy. If all of a GenCo agent's resources are committed in other markets, then the opportunity to participate in ancillary services markets is lost. On the other hand, if generating capabilities are reserved for these markets and ancillary services bids are not accepted, potential profits that could have been made in other markets are lost. When making spinning and ancillary services marketing decisions, GenCo agents must also consider the probability that they will be called upon and the profits or losses associated with generating power from the unit.

Midwest Market Power Analysis—Modeling Assumptions

The analysis of the midwest power system started with the development of a Production-Cost Case. Under this case, the power system and electricity markets were simulated for all 8,760 hours of a year when restructuring is presumed to be completed, that is, the *analysis year*. This case is used as a point of comparison and is not intended to be a prediction of what will happen in the region. Rather, the results reflect a situation where companies do not engage in any strategic market behavior which can be used as a benchmark for a set of alternative conditions and scenarios.

Grid Configuration

The future transmission grid configuration for the analysis year was constructed from the 2003 summer case prepared by the North American Electric Reliability Council (NERC). All busses and branches in the study area are represented in the model. For ease in presenting results, the approximately 2,000 busses in the study area were grouped into zones based on current ownership. Data on load growth, generator additions and retirements, and transmission system changes were added to bring the system up to what might be expected in the analysis year. The case contains eight TransCo agents for the region under investigation. A reduced out-of-area transmission network was developed to account for power transfer capabilities into and out of the study area. In this process, all of the tie lines between the study area and the surrounding systems were identified and aggregated into a small set of interconnection points. Note that the aggregated lines were only used for flows from out-of-area to out-of-area nodes. For flows among study-area nodes and from out-of-area to study-area nodes, the actual branch data were used.

Electricity Demand

Hourly control-area loads for the analysis year were developed based on total control area loads for all hours in the year 2000 combined with 10-year forecasts of seasonal peak loads and total annual loads given in FERC Form 714. Bus-level loads were estimated using bus distribution factors (BDF) that indicate the portion of the total control area load that is assigned to that specific bus. BDFs are assumed to remain constant throughout the simulation year. The load shows the typical seasonal variation for the northern United States. Peak loads are seen in the summer months (June, July, and August) as air conditioning use increases. Some unusually warm days in the spring and fall also appear in these data. April and October are the months with the lowest loads. Daily and weekly variations in load are evident from the data.

The EMCAS case includes a total of 27 DemCo agents consisting of electric utility affiliates and alternative retail electric suppliers. Some of these DemCos already have begun selling electricity; others are only certified suppliers but have not begun service to their customers. The EMCAS analysis also includes about 10 DistCo agents expected to be operating in the analysis year.

Generation Capacity

In the analysis year, the case contains 200-300 individual generating units with up to five blocks. This was compiled from detailed unit-by-unit information available from FERC, the Energy Information Administration (EIA), and various state agencies.

Fuel Prices

Projected fuel prices are based on regional forecasts produced by the EIA's National Energy Modeling System (NEMS) model that are reported in its Annual Energy Outlook (AEO). Price projections for the NEMS East-North-Central region were used to develop fuel prices for the analysis year for all major fuels contained in the EMCAS runs.

Scheduled and Forced Outages

The analysis includes representation of both scheduled and forced outages. All outages used in this study are based on information contained in the NERC Generation Availability Data System (GADS). Planned outage lengths are assigned to individual units based on their fuel type and primary mover. It is assumed that planned outages are coordinated among all GenCos such that the highest hourly reserve margin (not including unplanned outages) during the year is at the lowest possible level. Planned outages are therefore scheduled to occur during low-load periods, that is spring and fall, when reserve margins are at a peak. The simulation schedules planned outages sequentially, one unit at a time, in a prespecified order based on average production costs. The end result is to "valley-fill" low-load period with maintenance, thus reducing variability in hourly reserve margins among seasons of the year.

Forced outages occur at random as the result of component failures. Outage durations range from a few hours to several days as a function of the cause of the failure. Consistent with GADS statistics, the forced outage algorithm determines the number of outages as well as the duration of the outage for each unit. As a result, there is always adequate generation capacity to meet the load and the hourly generation reserve margin never falls below 22%, even with scheduled and forced outages.

Out-of-area System Representation

For a simplified representation of the out-of-area power system, the loads and generation were represented by aggregated supply and demand curves. While generating units within the study area were represented in the EMCAS model with their individual characteristics, the out-of-area generation capacity was aggregated by interconnection point and modeled with their respective cumulative supply curves. The supply curves for out-of-area generators were constructed on the basis of their variable production costs. A similar approach was applied for the modeling of out-of-area loads that were also aggregated by interconnection point. In the Production-Cost Case, the out-of-area generation was assumed to be offered at production-cost-based prices. The out-of-area loads were assumed to be firm and not price-responsive.

Market Rules

Respective regulatory bodies have not specifically defined the configuration of the future power markets. In addition, FERC's proposed standard market design (SMD) is still undergoing review and revision and is far from being finalized. In the absence of any clearly defined market designs, there is a great deal of uncertainty regarding the shape and form of the area's future electricity market. For the purposes of the Production-Cost Case analysis, the following market rules were assumed for the analysis year:

- Locational marginal prices are paid to GenCos;
- DemCos pay the load-weighted average zonal price;
- There is a day-ahead market (DAM) for both energy and ancillary services;
- DAM allows GenCos and DemCos to bid for their participation in the market;
- DAM bidding is administered by the ISO/RTO;
- Bids are unregulated;
- Bilateral contracts between suppliers (GenCos) and purchasers (DemCos) are not allowed; all power is purchased in the spot markets;
- There is a single independent system operator with a single set of markets for electricity in the area;
- All companies in the study area and the out-of-area interconnected systems buy and sell electricity in the same marketplace;
- Generation companies sell electricity based entirely on the production costs of the generators including fixed costs;

- Demand companies serve firm uninterruptible load. Unserved energy is due only to forced outage conditions and not to any market considerations. DemCos charge consumers a flat markup of their costs to purchase electricity of 10%;
- Consumers are assumed to have no response to electricity prices;
- Distribution companies collect revenues for the use of their distribution lines using an average distribution use charge of $18/MWh; and
- Transmission companies do not employ any strategic business behavior. Their revenue comes in two forms: a transmission use charge of $3/MWh and a transmission congestion payment.

Production-Cost Case Results

Generation and Sales

Results show that throughout the year, there is sufficient generation to meet the study-area load. In fact, on an annual basis the study area will export about 13% of its generation as study-area GenCos can effectively compete with surrounding-area suppliers. One company captures almost 40% of the study area's annual generation. The largest five companies account for about 97% of the study area's generation. On the sales side, one company captures approximately 70% of the study area's annual electricity sales. The largest three companies account for almost 95% of the study area's electricity sales.

Electricity Prices (LMPs)

Results of the day-ahead market show that in low-load hours it is possible to use the least-cost generation since transmission congestion does not occur. However, in intermediate-load hours and, even more pronounced, in peak-load hours, some of the lower-cost units must be bypassed and more expensive units need to be dispatched out of economic merit. When this occurs, generators with relatively low bids remain idle while generators with more expensive bids are put into operation. These high-priced bids are accepted as power injection into the grid at the units' specific interconnection points or busses will serve loads, often locally, without overloading transmission lines. On the other hand, accepting the lower-cost bid would have resulted in a violation of transmission system line limitations and/or security safeguards. This congestion-related dispatch of units in out-of-bid merit order leads to LMP differences across the system. Figure 10 shows the projected monthly minimum and maximum values of the load-weighted LMPs in each zone. Bus-level prices can show even greater variation than what is shown for the zones. The following conclusions can be drawn:

LMPs increase during high-load periods as more expensive generators are brought on-line to meet the load. This is seen as an increase in the maximum LMP in all the zones in the June, July, and August periods. Even under the Production-Cost Case where GenCos do not engage in strategic behavior to exercise market power, LMPs can be more than four times higher in high-load periods than during low-load periods.

LMPs vary across zones as a result of transmission congestion. During high-load periods, the spread in LMPs across the zones in the study area increases noticeably. Were the LMPs to rise and fall together at the same rate, the indication would be that there is no significant transmission congestion as all zones would have nearly the same price at all times. However, in the June, July, and August periods, the spread in the LMPs across the zones becomes significant. Transmission congestion forces the prices higher in some areas than in others. The variation across the study area results in LMPs in some parts reaching almost four times higher levels than elsewhere. This is an indication of higher levels of transmission congestion in parts of the network. This can be also observed in Figure 11, which displays the projected hourly load-weighted LMPs for three select zones. Zone 1 exhibits substantial price volatility whereas prices in Zones 2 and 3 show much less variation.

Transmission congestion can create higher LMPs even during non-peak hours. Figure 10 shows several zones where the LMPs become significantly higher or lower than elsewhere in the study area, even in the lower-load months of March, May, and November. This is the result of the scheduled and forced outage scenario where some generators in these zones are assumed to be out of service. In these zones, this loss of generation capacity cannot be readily made up by other, less expensive units due to transmission limits. Significantly more expensive units in these zones must be brought on-line to meet the load.

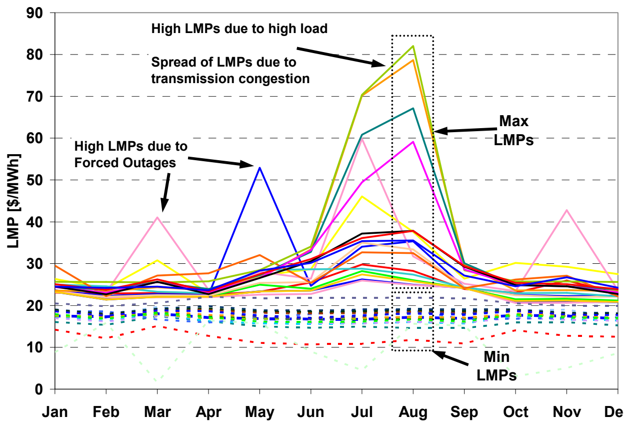

Figure 10: Projected Monthly Minimum and Maximum Hourly LMPs for All Zones

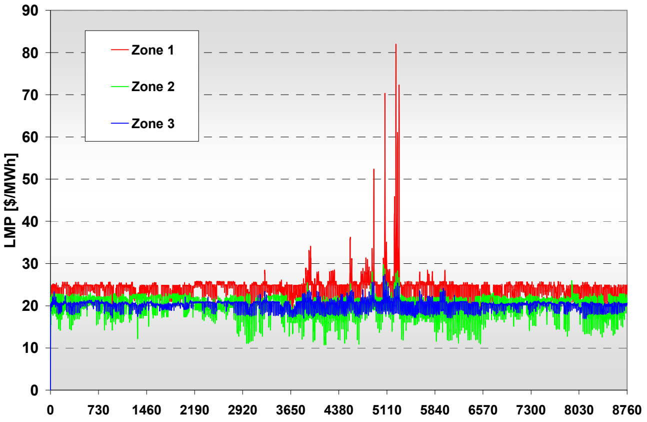

Figure 11: Projected Hourly LMPs for 3 Zones

Figure 12 provides a more detailed look at the occurrence of higher LMPs by presenting a frequency distribution of load-weighted LMPs for 3 select zones. While in most zones, LMPs are in the range of $20–25 per MWh for 90% of the time, higher loads combined with grid congestion cause LMPs to rise for about 5% of the time. For about 1% of the time (about 88 hours per year), the increasing transmission congestion causes LMPs to rise considerably and to vary significantly from zone to zone. As shown in the graph, LMPs across the study area rise above $80 per MWh in some areas (e.g., in Zone 1). Generally, the price distribution under the Production-Cost Case shows that prices will spike during relatively few hours; however, during these hours the LMPs can be significantly higher and can show greater variability across the study area.

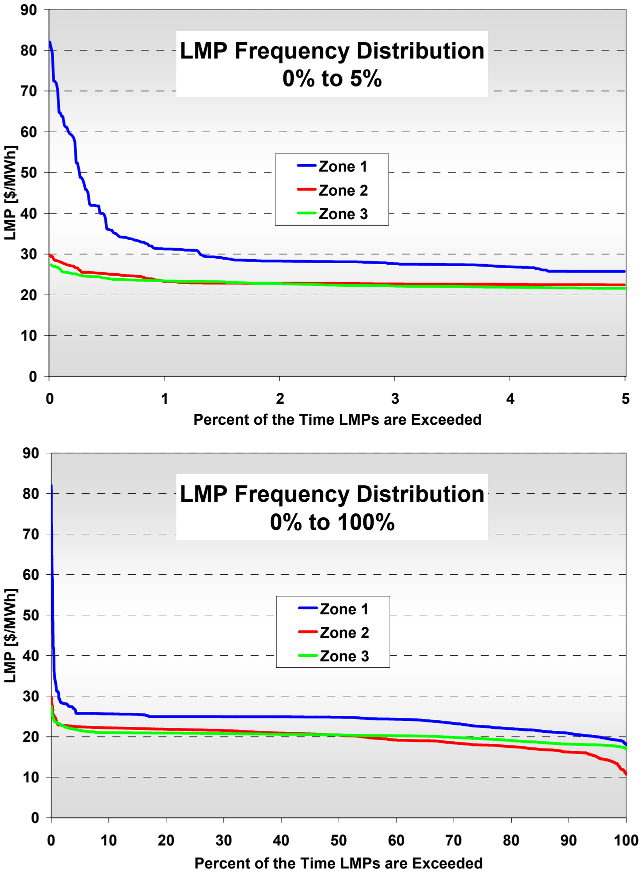

Figure 12: LMP Frequency Distribution 3 Zones

Load Pockets

The term “load pocket” is used to refer to a geographic area where the limitations of the transmission network prohibit the import of additional power. The area must rely primarily on generation that is located within the area to meet demand. If the generation in the area is owned by only a few companies (usually one or two), there is an opportunity for these companies to exercise market power and manipulate prices within the load pocket. If, on the other hand, there are a sufficient number of competitors operating in the area, none may be able to exercise market power in the load pocket.

As there is no universally agreed upon method to map load pockets, the following method is adopted: A *load pocket* is a set of transmission network nodes that have LMPs above a reference LMP for more than a reference number of hours. The reference LMP is chosen based on the average LMP for the study area. The reference number of hours is chosen based on the frequency distribution of LMPs across the study area.

This definition captures the transmission limitation by identifying those nodes with limited ability to bring in cheaper power for a significant portion of the time. Note that the load pocket definition has no reference to market power potential. In the context of this study, the following terminology is adopted to measure a company’s ability to exercise market power: *Baseline price levels* are the LMPs when all potential suppliers or GenCos in the market offer their power at production cost (i.e., fuel costs plus fixed and variable operating and maintenance costs). *Market power* is the ability of a company to profitably increase prices (i.e., LMPs) above baseline price levels by its own actions, independent of what other companies do.

The monthly results show that the largest metropolitan region in the study area has higher LMPs for much of the year. This is not unexpected since that region has the highest loads and exerts the greatest demands on the system. There are also higher LMPs experienced through some portions of the study area while others have lower LMPs throughout the year. The cheaper generation that is available in these regions does not help relieve the higher prices in the other parts of the study area because of transmission limitations.

As the load increases in the warmer months—June, July, and August—a good part of the study area shows an increase in LMPs (Figure 13 shows an example of this situation for a hypothetical region). The fact that the LMPs are in the same range indicates that all are paying higher prices as more expensive generation must be dispatched to meet the increasing load. This is not an indication of load pockets. In contrast, the largest metropolitan region in the study area begins to show evidence of higher LMP indicators in June and this persists throughout the summer. The higher LMPs spread during July and August. These areas are exhibiting load pocket behavior. As the load decreases through the fall and early winter, the situation returns to the condition where a few portions of the study area have higher LMPs.

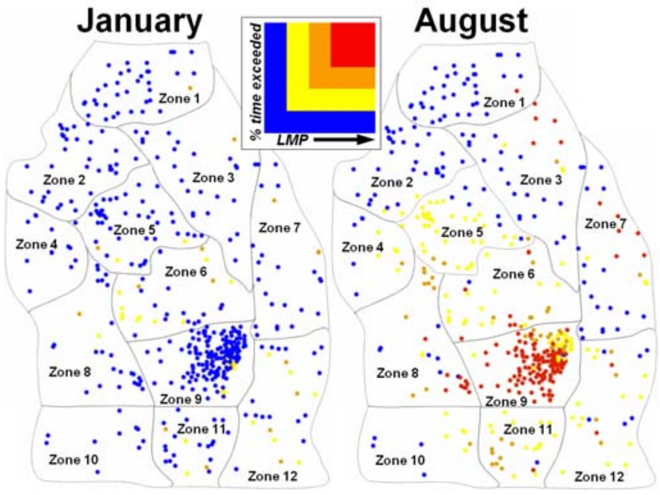

Figure 13: Potential Future Load Pockets

It should be emphasized that under Production-Cost Case conditions, there is no strategic bidding and GenCos price their power at production cost. By this assumption, no market power is being exercised. Strategic bidding could be expected to amplify price differences between load pockets and other areas.

Market Power Results

While under the Production-Cost Case GenCo agents do not engage in strategic market behavior, but rather offer their power at production cost into the pool energy market, this part of the analysis attempts to identify the potential for companies to exploit their strategic position to profitably raise prices above marginal production cost. The analysis takes into account a host of aspects that drive the ability to exert market power, including *temporal* (market power may be limited to certain hours), *spatial* (not all busses may be susceptible to market power), and *technological* (not all types of generators equally lend themselves to gaming). It is important to note that this is not intended to imply that any company participating in the study area's electricity market would use any of these techniques, nor that any would engage in any practices that could be viewed as manipulating the market. Rather, the intent is to determine if the market structure as currently envisioned would be able to function efficiently and effectively given the physical limitations of the power system and the competitive forces of the marketplace.

There are numerous business strategies that a company participating in the electricity market might pursue in order to improve its position. This may include *physical withholding* of individual or multiple units, *above-production-cost pricing* of individual or all units included in a company portfolio, pricing units such that they will not be dispatched, that is, *economic withholding*, etc. Though the strategies included in the analysis are not intended to cover all situations, but rather to illustrate the range of possibilities, a significant number of EMCAS runs were conducted to study a variety of market strategies. For example, multiple runs were performed to analyze single-unit physical withholding for approximately 70 units on peak-load days, low-load days, and days with significant unit outages. Similarly, for above-production-cost pricing and economic withholding, runs were performed for individual units as well as for companywide pricing behavior. For brevity, only a few of the strategic results are presented in this paper.

Model runs show that the ability to exercise market power varies substantially across the different GenCos, with some companies able to drive up prices substantially and others having no impact at all.

Physical withholding of individual units will increase company operating profits only when applied to a few select units. For the majority of the generating units, withholding them from service on peak-days will reduce company profitability. In addition, GenCos have no incentive to physically withhold any unit on low-load days as it will result in lower company profits across the board.

Above-production-cost pricing and economic withholding of single units in a company's portfolio results in relatively minor increases in operating profitability for a few units. For most units, it will create a loss as the unit's dispatch schedule is reduced and there is adequate generation and transmission capacity to bring cheaper units on line.

Companywide economic withholding during all 24 hours of a peak-load day is attractive to some GenCos but not to others. Figure 14 shows the impact on one generation company if it were to price all of its units in its portfolio increasingly above production cost. Results are shown for the peak day only. Under the Production-Cost Case, the output of GenCo1 was constant over the 24 hours. Portfolio generation drops, though, as bid prices increase above production cost. The reduction in output initially leads to a decrease in operating profits for the company up to about 150% above cost as less expensive generation and adequate transmission capacity is available to meet the load, both from study-area and out-of-area sources. However, as bid prices continue to increase (200% above production cost), operating profits start to grow rapidly as a certain portion of the company's capacity is needed to meet the load and transmission constraints limit the use of cheaper capacity from elsewhere.

Figure 15 compares generation and operating profits for the same company over a range of bid prices for the above strategy (bid prices increased for all 24 hours) with a strategy where units are priced higher only during the afternoon from 2 to 6 p.m., when the load is the greatest. While daily output falls substantially if GenCo1 were to apply its pricing strategy for the entire day, production remains fairly unchanged should the company try to exert its market power only in the afternoon. This appears to be a more attractive strategy for GenCo1 over most of the pricing range, particu-

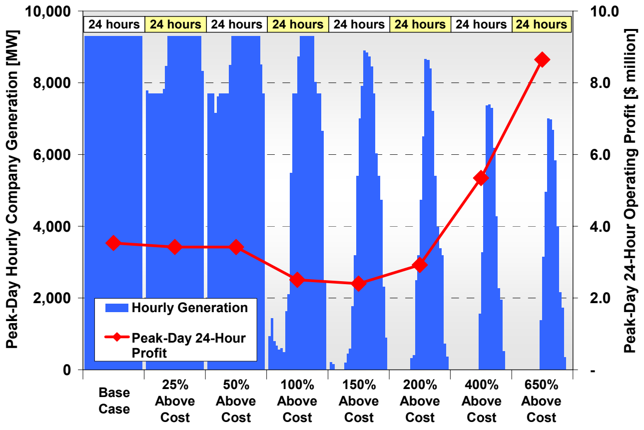

Figure 14: GenCo1 24-Hour Strategic Bidding

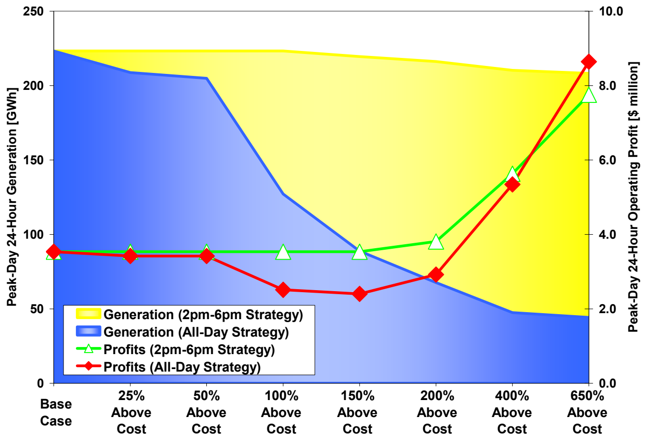

Figure 15: GenCo1 Results of Different Strategies

larly if the company is concerned with excessive cycling of its units as generation under this strategy shows little variation throughout the day even as prices are increased significantly.

Figure 16 shows results for a GenCo that is unable to exert market power. As GenCo2 increases its bid price during the entire day (24 hours) for its portfolio of units, output rapidly declines and finally reaches zero as all of its generators will eventually be replaced by cheaper units. Operating profits turn negative, that is, GenCo2 actually starts losing money under this strategy as it will continue to incur fixed operating expenses. Even if the company applies this portfolio strategy only during the afternoon peak hours, it still will face reduced profitability as some of its units drop out of the dispatch and the price increase does not compensate for the lower portfolio capacity factor.

Under this pricing strategy, almost all GenCos will cause peak-day consumer costs to rise. Some portions of the study area can experience a doubling of peak-day consumer costs if any company chooses to increase its capacity-weighted average price to $150/MWh. Larger price increases will drive this even higher.

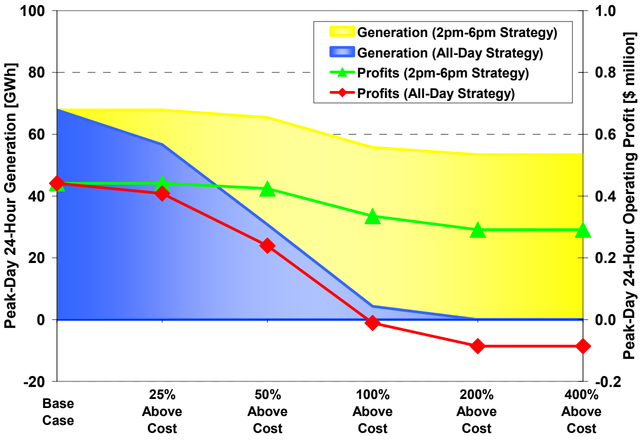

Figure 16: GenCo2 Results of Different Strategies

An illustration of the system impacts of different company behavior on projected electricity prices over a 3-month period are given in Figures 17 through 19. The first scenario in Figure 17 represents a case in which all GenCos are submitting strictly production-cost-based bids for all of their capacity blocks. For a given electricity demand pattern, this production-cost-bidding scenario establishes a reference for the assessment of LMPs resulting from different bidding strategies. For this case, no price elasticity or demand response were assumed on the part of electricity consumers. During low-load periods, the observed price spread across the state is relatively narrow indicating that there is limited congestion in the network. However, during high-load hours, prices spike to about $80/MWh in some zones because transmission congestion limits the use of cheaper outside power. Note that these price spikes are not due to strategic behavior by the generation companies but due to physical limitations of the underlying infrastructure.

The second scenario shown in Figure 18 is based on the assumption that all GenCos are applying a fixed-increment price probing strategy in which they increase their bid prices by, for example, 5% for all capacity blocks that were accepted in the previous day’s market. Similarly, GenCos decrease their bid prices by the same amount (5%) for all capacity blocks that were not accepted in the previous day’s market. The results obtained for this relatively simple bidding strategy show a clear trend of increasing LMPs during the peak hours. However, the off-peak prices tend to quickly stabilize and remain more or less constant at a level that is somewhat higher than the pure production cost level.

The third scenario (Figure 19) assumes that some GenCos still apply the same fixed-increment price probing strategy as in the second scenario, while most of the larger GenCos revert to production cost-based bidding. The results of this scenario show LMPs that are mostly higher than in the first scenario, but without the continuously increasing trend during peak hours as obtained in the

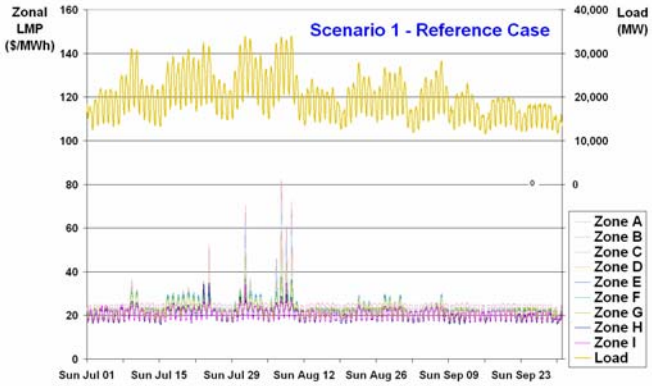

Figure 17: 3-Months LMPs for Scenario 1

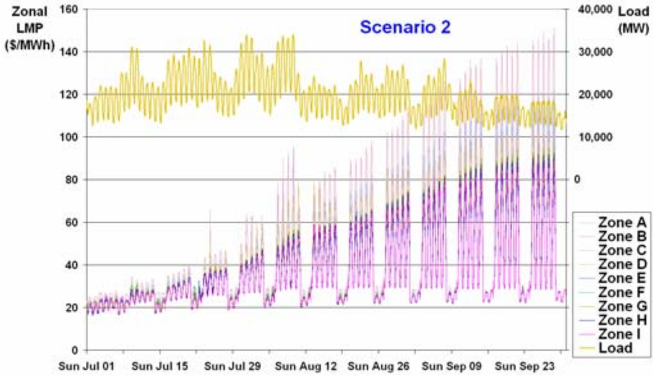

Figure 18: 3-Months LMPs for Scenario 2

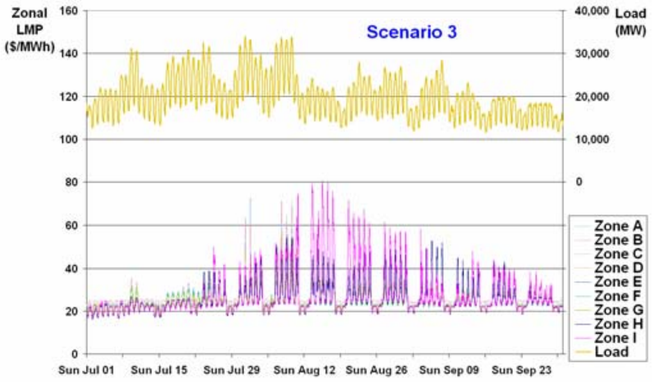

Figure 19: 3-Months LMPs for Scenario 3

second scenario. Obviously, in the third scenario, the amount of generating capacity offered by large GenCos at production cost prices was sufficient to keep the market prices in check and relatively stable. Although rather simple, these three scenarios show that different adaptation and learning strategies of market participants may result in very different market behaviors even when the same physical system is analyzed.

Current model runs are investigating more complex strategies and market behavior employed by participating companies as well as the mitigating potential that price-elastic consumer demand may have on the ability to exert market power. Also, additional model runs will focus on how much distributed generation in the form of renewable energy can contribute to market power mitigation. Results for these runs will be presented in subsequent papers.

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