Toward the Value-Based Generation Investments and Utilization: Stratum Electricity Market

Zhiyong Wu and Marija Ilic, *Fellow, IEEE*

Abstract—**In this paper we model and analyze the dependence of electricity market outcomes on the market structures and rules. Market attributes such as electricity prices and their volatility, profits and revenues by the market participants and system cost are assessed. Of particular concerns are the effects of market structures on the long-term generation investments needed to meet long-term uncertain demand. The paper builds upon an earlier introduction of electricity market modeling resulting from the dynamics of fundamental market drivers, such as demand, supply and market clearing processes. This approach is employed to model and simulate the outcomes in the short-term spot markets, and compare these with the potential outcomes in a newly proposed Stratum Electricity Market (SEM) structure comprising both spot and long-term sub-markets. The performance of the newly proposed SEM is illustrated using Monte Carlo simulations on a simple power system in which the only uncertainties come from the load forecasts and fuel prices.**

***Index Terms*—Forward Markets for Electricity, Energy Capacity Markets, Investments, Stratum Electricity Market (SEM).**

I. INTRODUCTION

This work is motivated by the on-going problems with sustainable value-based investments in the evolving electricity markets. Even the best functioning spot markets are challenged by the lack of signals for investment in generation and transmission capacity. While the reasons for this situation are multifold, one of the obvious questions concerns the management of physical uncertainties, such as demand variations and physical failures of equipment in the evolving electricity markets. Given that these are highly uncertain and multi-temporal, this brings up the basic question of managing and valuing physical uncertainties in these markets. It is our premise that failure to systematically manage these uncertainties is one of the major shortcomings and problems of current spot market structure. This should also be the starting point for enhancing such setups with well-defined and value-based performance.

While the overall problem of designing well-functioning electricity markets is very broad [1], in this paper we start by recognizing that different electricity market structures result in qualitatively different outcomes. However, this common-sense observation is hardly documented in the existing literature through systematic modeling and simulations. The paper illustrates the effects of different market structures in the electricity industry on the new generation and transmission capacity expansions as well as on the efficiency of using the existing resources. Of particular interests are monetary incentives for inducing near-optimal capacity by means of long-term market mechanisms. We also investigate how these new investment decisions affect the economic performance of the long-run social welfare of the system as a whole. This paper focuses mainly on planning and investing in new generation capacity.

So far, the main emphasis of electricity market designs has been solely on optimizing wholesale electricity spot markets with the objective of inducing efficient day-ahead use and pricing of electricity. At present there are no liquid longer-term electricity markets, which are essential for ensuring both reliable service and sufficient capacity reserve to avoid boom-and-bust cycles in generation capacity. Determining near-optimal investments for long-run efficiency requires transparent signals for decision making under various physical and financial uncertainties. In this paper we introduce a set of coordinated sub-markets, each defined for a specific time horizon, ranging across day-, month-, season-, year-, five year-horizons, referred to as a Stratum Electricity Market (SEM). We evaluate the long-term effects of the SEM on the system reliability and efficiency. We also provide initial exploration of different market and regulatory rules which are essential for the long-term investments.

In Section II we briefly review generation planning problem and propose a generic dynamic modeling approach based on fundamental physical and economic drivers in the markets. In Section III a simplified realization of the generic model with a stochastic load and deterministic fuel price are introduced. Six different scenarios are studied. The effect of centralized and decentralized decision makers, different fuel price profiles and interactions between various decision makers through the repeated auctions are analyzed for both

This work was supported in part by the U.S. National Science Foundation EPNES Program.

Zhiyong Wu received his B.S. and M.S. degrees in electrical engineering from Tsinghua University, Beijing, China, in 1999 and 2002 respectively. Currently, he is a Ph.D. student in the Engineering and Public Policy Department at the Carnegie Mellon University. He is presently engaged in designing, modeling and evaluating new electricity market structure. (e-mail: richardwu@ cmu.edu).

Marija Ilic is a Professor in the Departments of Electrical and Computer Engineering and Engineering Public Policy at Carnegie Mellon University (e-mail: milic@ece.cmu.edu).

spot market only structure and our newly proposed Stratum Electricity Market (SEM) structure. Section IV offers preliminary results concerning six different scenarios. Conclusions and further studies are summarized in Section V.

II. Problem Formulation

A. Decision criteria

The investment problem in physical electricity generation assets can be treated as an example of a more general asset investment and valuation problem. The conventional method of asset valuation is the net present value (NPV) approach [2]. The NPV is calculated by integrating the expected payoff ψ from the market, which is a spread between revenue received in the market and the cost of providing electricity, adjusted by the discount rate ρ over the period of evaluation T.

$$NPV = \int_t e^{-\rho t} E\{\psi_t\} dt$$

The NPV rule states that the firm should choose the investment option with the highest positive NPV. The revenue received in the market depends on the market rules and price predictions. One big challenge is to determine the appropriate discount rate, which must reflect the time value of money and the level of risk evolved in the investment.

The second approach is based on the mean-variance criteria. The firm can define its risk preference by stating its utility in terms of the tradeoff between the expectation and variance of the future return on the investment. Given the risk preference r of each firm, the investment option with the highest mean-variance utility would be chosen.

$$U(\sum_t \psi_t) = E\{\sum_t \psi_t\} - r \times Var\{\sum_t \psi_t\}$$

The third approach is based on concept of value-at-risk (VAR) [3]. VAR estimates the amount of the capital at risk of being lost during a given period of time. Capital is defined to be at risk if the probability of loss is greater than a threshold acceptable by the management.

$$Max(E\{\sum_t \psi_t\})$$
$$s.t. \Pr ob(\sum_t \psi_t \le V) \le x\%$$

The results in this paper are based on the conventional NPV method. Further extensions to other criteria are possible.

B. Modeling electricity prices

The expected payoff of the investment depends on the electricity market prices. Currently, there are a number of methods to model the price process.

1. Statistical modeling [4], [5]. The user attempts to find the lowest order model possible to describe the stochastic properties of the prices. The parameters are derived from historic data.
2. Economic equilibrium based modeling [6]. Game theory based economic models like Cournot pricing are employed to solve the equilibrium solution.
3. Agent based modeling [7], [8]. Depending on the objective function of each agent and observation of current price levels, agent updates his strategy using artificial intelligence methods. The market prices are the output of individual bids.

However, electricity markets are constantly evolving, driven by the physical demands, supply and market rules. All the above methods are static in the sense that they only apply to certain market setup and neglect the underlying drivers in the system.

C. The basic of the fundamental modeling approach

A fundamental modeling approach for the electricity markets is based on starting by modeling the dynamics of physical variables, such as load demand, generation capacity and fuel prices. This is followed by defining the economic variables, such as bidding strategies of market participants; and, finally, by defining the public policy variables, such as market structures and rules. Based on the dynamic interactions among all physical, economic and public policy variables, financial outcomes such as electricity prices, individual participant's profits as well as total social welfares and their associated risks become the outputs of the overall model. This should be contrasted with the priori postulated models such as Black-Sholes [9].

Examples of this approach can be found in [10] where electricity price was modeled for a spot market only structure with the aggregated system supply and demand processes. The applications of such approach on valuing generation assets are introduced in [11], [12].

The basic market participants are generators, Load Serving Entities (LSEs), and the market administrators/policy makers, the (Independent) System Operators (ISOs). A system diagram depicting these participants and their interactions is illustrated in Fig II.1. Depending on how detailed models are used, and on which component is exogenous or endogenous within the diagram, the actual electricity market process can be captured at different level of accuracy. The main objective of fundamental-drivers-based electricity market modeling is to retain variables and parameters that shape the market outcomes to the greatest extent.

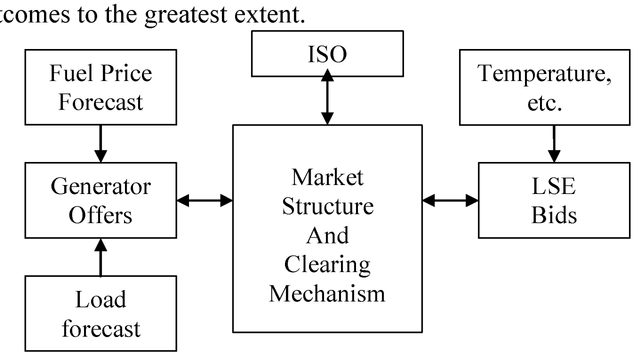

Fig. II.1 System Diagram of Market Participants and Their Interactions

In this paper, the fundamental modeling approach from [10]-[12] is further generalized by combining the i) decision making by the generators; ii) decision making by the LSEs or those responsible to serve the load; and iii) decision making by ISOs with the market clearing mechanisms that are more complex than spot only markets. Using this modeling approach, the financial outcomes seen by various market participants and the system as a whole become results of interactions within this complex decision making process. This modeling extension is critical for managing and valuing physical and financial risks over a variety of time horizons. When the approach is extended to a very long time period, it can be applied as a means of evaluating and making the investment decisions for a given market design. It can be further used to evaluate the effects of market structures and rules on various market attributes.

III. Simulation Model Setup

In the remainder of this paper we illustrate the models and the decision-making process for assessing long-term electricity market performance with an inelastic stochastic load model, which was introduced in [10] and briefly reviewed in the next sub-section.

A. A brief review of the stochastic load model

The key characters for electricity demand which we want to capture in the model are: seasonality, mean reversion and stochastic growth. To simplify the problem, weekend loads are eliminated from the model and the load is assumed price inelastic. The daily load is modeled as a 24 hours vector L_d where each row represents an hourly load. This vector is defined as :

$$\vec{L}_d = \vec{\mu}_m + \vec{r}_d$$

where μ_m ([24*1] vector) is the monthly average hourly load and the stochastic component r_d is the deviation from the monthly mean and it has 24 hourly random variables. However, because of high intra-daily correlations between these hours, we applied Principal Component Analysis (PCA) on r_d. Although some information may be lost, PCA enables us to reduce the number of variables. We keep only the first Principle Component (PC) and its associated weight w_d. Statistical results show that the first PC could explain more than 90% of the total variance of the demand.

$$\vec{L}_d = \vec{\mu}_m + w_d \vec{v}_m \qquad (1)$$

New vector v_m is the new Principle Components in each month m and w_d is its daily evolving score, which incorporates all the stochastic uncertainties. We choose a two factor mean reverting model to describe the w_d process.

$$\begin{aligned} & w_d = \delta_m + e_d \\ & e_{d+1} - e_d = -\alpha e_d + \sigma_m z_d, z_d = N(0,1) \\ & \delta_{m+1} - \delta_m = \kappa + \sigma\ z_m, z_m = N(0,1) \end{aligned} \qquad (2)$$

w_d is represents by the long-term growth component δ_m and short-term mean-reverse deviation component e_d. The δ_m process characterizes the long-term growth trend with expected value κ and stochastic component σ on a monthly basis. The e_d process represents the daily short-term deviation from the monthly mean, which is mean-reverting at the rate α with stochastic component σ_m. Both stochastic factors are assumed to be normally distributed white noise.

Using the historic hourly load data from 1993 to 2003 on ISO New England website [13], the parameters [δ_m α κ σ_m σ] in the load model can be obtained using the following procedure:

1. Construct a time series vector of scores of the first Principle Component, w_d, by applying the PCA to the historic load data. δ_m is calculated by the monthly average of w_d.
2. The mean reversion factor α is determined using linear regression between (w_{d+1}-w_d) series and (δ_m-w_d) series.
3. The short-term process stochastic component σ_m is calculated as standard deviation between the estimated and actual values of w_d.
4. The long-term drift parameter κ is calculated from the increase trend of δ_m.
5. The long-term process stochastic component σ is measured by the standard deviation between the estimated and actual values of δ_m

For a more detailed description, please refer to [10].

After all parameters are calculated, the load model is run 100 times to generate the forecasted load samples used in the simulations. Each series lasts for a 10 year period. The annual average and standard deviation of hourly load are shown in Fig III.1 and Fig III.2.

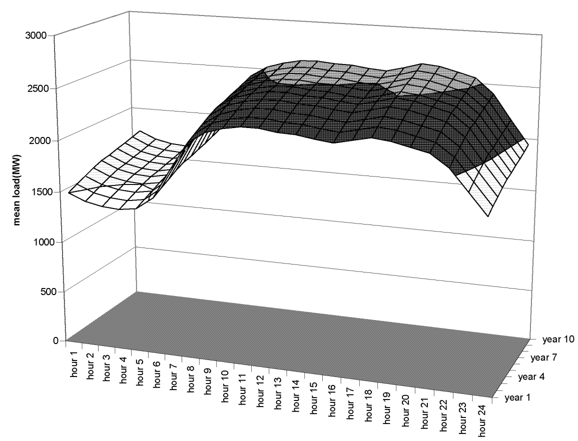

Fig. III.1 Annual average of forecasted hourly load

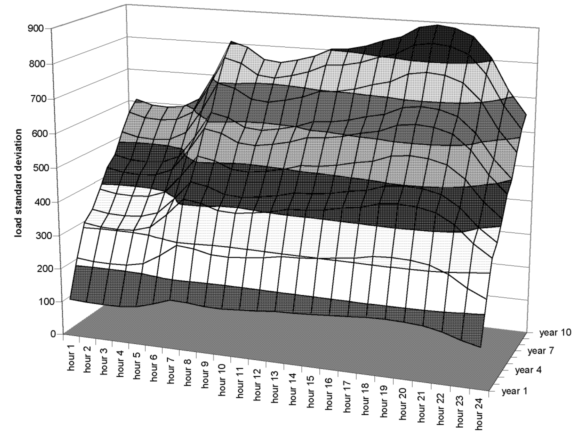

Fig. III.2 Annual standard deviation of forecasted hourly load

The average hourly load level is increasing over time. Two daily peaks, the morning peak which reaches at around hour

11 and the evening peak which reaches at hour 19, can be observed in Fig III.1. The standard deviation increases at a much faster pace than the average load on the annual basis. This shows that viewed from year zero, the uncertainties are much higher in the year 10 than year 1.

B. Fuel price forecast and generator characteristics

For illustrative purposes, a reduced generation fleet based on generation characteristics in the IEEE reliability test system described in [14] and fuel price projections from the 2005 Electricity Information Agency Annual Report [15] are used in simulations. Generator and fuel characteristics obtained from these sources are summarized in Tables III.1 and III.2, respectively. The nuclear unit variable cost is assumed as \$0.4/MWh.

Since the EIA fuel cost are based on the last year's data, the gas price prediction is relatively low. In order to illustrate the effects of high gas prices on the electricity market, a high gas price is constructed. For this case, the price is assumed starting at \$10/MMBtu with a 2% annual increase. Two fuel price forecasts, low gas profile and high gas profile, are both used in the simulations. The short term marginal cost (STMC) for generator i in year m can be defined as:

$$STMC_i^m = Heatrate_i * Fuel\ price_i^m + Variable\ O\&M_i$$

The long-run marginal cost for generator i in year m can be defined as:

$$LRMC_i^m = STMC_i^m + Levelized\ Annual\ Capitcal\ Cost_i$$

TABLE II.1
FUEL PRICE FORECASTS

Year	Coal (\$/1000btu)	Low Gas (\$/1000btu)	Oil (\$/1000btu)	High Gas (\$/1000btu)
1	1.29	5.27	5.36	10.00
2	1.28	4.83	4.96	10.21
3	1.28	4.50	4.77	10.41
4	1.27	4.39	4.61	10.63
5	1.25	4.27	4.55	10.85
6	1.24	4.31	4.58	11.07
7	1.24	4.41	4.60	11.29
8	1.24	4.54	4.66	11.53
9	1.23	4.70	4.71	11.76
10	1.23	4.81	4.77	12.00

TABLE III.2
GENERATOR TECHNOLOGY CHARACTERISTICS

unit #	Unit Type	Capacity (MW)	Capital cost (\$/KW)	Varible O&M (\$/MWh)	Heatrate (MMbtu/kw)
1	Nuclear	800	3000	10	--
2	Coal	600	1200	5	9.501
3	Coal	600	1200	5	9.504
4	Gas	300	500	10	6.501
5	Gas	300	500	10	6.504
6	Gas	300	500	10	6.507
7	Oil	200	350	10	9.501
8	Oil	200	350	10	9.504
Total	--	**3300**	--	--	--

C. Stratum Electricity Market (SEM) Structure [16]

In order to meet resource adequacy and reliability requirements, the Installed Capacity markets (ICAP) are introduced to help recover the capacity costs by ISOs in the North Eastern United States. The capacity market rules require that every load must contract enough capacity from the generators to meet the maximum forecasted demand for the future periods ranging from month to year. Since the costs to provide such capacity from the existing generators are almost zero, in the off-peak months when there is plenty of capacity around the market clearing prices are almost zero while the prices are much higher in the peak months when the capacity is scarce. Overall, recent studies found that the ability of financing capacity payments through the volatile ICAP markets is declining and that current ICAP payments alone are not sufficient to recover capital costs of power plants.

Our alternative market structure focuses on a long-term energy supply rather than on the capacity availability. The Stratum Energy Market (SEM) structure [14] proposed in this paper is motivated by the lack of transparent liquid long-term energy markets for power trading in current spot market. Although most of power is traded through long-term bilateral contracts, current rules and regulations for such trading are insufficient in terms of their ability to create liquid active trading environment. Consequently, most of the existing forward and futures markets are not transparent, and, therefore, they do not provide the right information for investments.

The SEM structure comprises a sequentially clearing series of forward sub-markets of different duration. Forward sub-markets are designed for physical or financial energy trading with periodic bidding and clearing processes on daily, weekly, monthly, seasonal, annual and multi-annual basis. The short-term spot sub-market is designed to balance the deviations from real load pattern and forecasted load pattern. The SEM structure resembles ways in which the electric power capacity was planned and used in the regulated industry: large, base-load power plants were built and dispatched to supply a large portion of the base load; medium-size plants were turned on and off according to the seasonal variations, and small peaking plants were used to follow short-term high load demands. Fig.III.3 is an illustration of load partition for various sub-markets within the SEM.

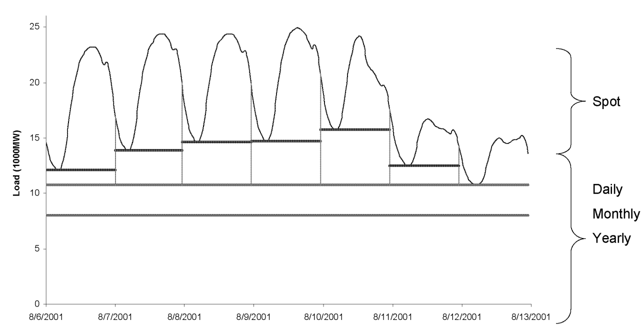

Fig.III.3 SEM structure

The forward markets can be subdivided into annual, seasonal, monthly, weekly or even daily markets according to the load cycles. All forward markets are cleared sequentially from longer-term to shorter-term. For example, at the end of 2005 an annual forward auction for 2006 would be held and annual forward position and price are determined before January 1st 2006. Then the monthly forward auction for January 2006 would be held successively. The quantity for trading in each forward market can be decided in two ways.

- The market clearing entity could use the forecasted minimum load (or a portion of it) as the demand quantity.
- Both supply and demand sides can submit bids/offer for the forward markets and the price is determined where supply meets demand.

The forward markets are organized and monitored by the ISOs. The price in each sub-market is determined by the uniform auction rule: The last offer that meets the demand if supply side opens only or by the equilibrium point of supply and demand if both sides are open. The market clearing quantities of these forward markets are not necessarily physical. For example if the expected market clearing price in spot market is lower than the already cleared forward price in the annual market, then the generator may choose to buy from the spot market instead of generating by itself to fulfill the annual market quantity. Bidding strategies for such multi-layered market are currently being investigated.

The SEM model has the following features.

- Well-defined products and quality of service. Because of little storage, the values for the same amount of energy at different time and different location are disparate. This is reflected by hourly spot market dynamics. Moreover, for the same hour, the values for the same amount of power at base load or at peak load are different due to the different generation technologies used. The multiple forward submarkets are designed to reflect more realistic demand and supply conditions for different strata.
- Market stability. A good market structure should provide sufficient risk management tools to reduce short-term volatility and hedging physical and financial uncertainties. Multiple forward markets are perfectly designed instruments to hedge the spot market risks.
- Means of capital cost recovery. Annual or five years long-term forward energy markets may be tools to recover the capital costs since generators should bid long-term marginal cost into these markets.
- Natural solution to accounting for unit commitment (UC) constraints. The UC problem [17] is straightforward in the SEM market because the on/off decisions are made implicitly by individual units when they compete in the sub-markets. All the units may easily include startup and shutdown costs into their single bids due to the known hours for each sub-market. Only the units that are within the physical unit commitment constraints, such as must run hours, minimum startup and shutdown time, can submit their bids into the corresponding forward market. In this way, a system operator need not maintain these constraints explicitly as in a pure spot market.

D. Assumptions and simulation methods

Two market structures are investigated in this paper. The hourly spot market where price is set by the offer of the last unit that meets the demand at each hour and the newly proposed SEM model. Transmission network constraints are neglected.

Two kinds of decision makers, central planner (ISO/RTO) and individual generator, are both explored in the paper. The evaluation period for new investment decision is set for the next 10 years. At the beginning of year one, decision makers try to make their optimal investment decisions for given scenarios.

To simplify the problem, several assumptions are made throughout the simulations:

1. Two submarkets for SEM setup: hourly spot market and long-term annual market.
2. Bidding strategies: In spot only market generators submit their short term marginal costs (STMC). In SEM setup, generators first submit their full capacity at the long run marginal costs (LRMC) for long-term markets and then submit the left over capacity at short run marginal costs (SRMC) for spot markets.
3. Simple linear cost function is adopted and marginal cost curve is a scalar.
4. Uniform auction mechanism for both markets.
5. Auction quantity for long-term markets set by minimum annual forecast.

To simulate the new capacity expansion results in different scenarios, Monte Carlo technique are adopted. Since the only uncertainty in the simplified problem comes from the load, for a given load forecast series and fuel price profile, a deterministic nonlinear optimization problem can be solved by simulations. The average and standard deviation of all the deterministic results are calculated as final results.

E. Scenarios under investigation

All together six scenarios are studies in this paper. The only decision variables are the new capacity investment of the generator i in the system k_i^m.

Scenario 1 Central min cost. In this setup, a system planner (ISO) makes coordinated investment decisions for all units facing the uncertain demand in the future under a spot market only setup.

The problem can be posed as an optimization problem with the system-wide objective of minimizing the total expected cost. Total cost includes production cost, investment cost and blackout cost. Blackout hour variable at hour n u^n is defined as 1 if system demand is larger than total capacity and 0 otherwise.

$$u^n = \begin{cases} 0, \sum_i K_i^m \geq L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

The blackout cost in this industry structure is defined as the social costs of the value of lost load (VOLL). The VOLL is calculated as the product of total demand and the penalty factor $\mu_{blackout}$, which is set at $1000/MWh in the simulations.

$$VOLL^n = D^n \mu_{blackout}$$

The objective function of central planner can be represented as following:

$$\min_{(k_i^m),1\le i\le G,1\le m\le M} \mathrm{E}(\sum_i \sum_{m=1}^{M} e^{-\rho mTm}(\sum_{n=(m-1)Tm}^{mTm} e^{-\rho n}((1-u^n)\underbrace{\sum_i STMC_i^n(P_i^n)}_{\text{short-term production costs}} + \underbrace{u^n VOLL^n}_{\text{blackout costs}}) + \underbrace{\mathrm{CC}_i^m(K_i^m)}_{\text{long-term capital costs}}))$$

subject to

(a) The stochastic load demand process governed by equations (1)-(2)

(b) Capacity expansion process:

$$K_i^{m+T_i} = K_i^m + k_i^m$$

(c) Blackout variable for hour n:

$$u^n = \begin{cases} 0, \sum_i K_i^m \ge L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

(d) ISO economic dispatch process for hour n:

$$\forall u^n = 1 \begin{cases} \lambda^n = 0 \\ P_i^n = 0 \end{cases}$$

$$\forall u^n = 0 \begin{cases} \min_{P_i^n} \sum_i STMC_i^n(P_i^n) \\ s.t. \sum_i P_i^n = L^n : \lambda^n \\ P_i^n \le K_i^m \end{cases}$$

Scenario 2 Central min revenue. Central planner makes coordinated investment decisions in spot only market to minimize total costs of electricity to consumers, investment costs and blackout costs. The costs of electricity to consumers are determined by the hourly spot market clearing prices.

The objective function of ISO can be represented as follows:

$$\min_{(k_i^m),1\le i\le G,1\le m\le M} \mathrm{E}(\sum_i \sum_{m=1}^{M} e^{-\rho mTm}(\sum_{n=(m-1)Tm}^{mTm} e^{-\rho n}(\underbrace{\lambda_i^n P_i^n}_{\text{short-term production costs}} - \underbrace{u^n VOLL^n}_{\text{blackout costs}} - \underbrace{\mathrm{CC}_i^m(k_i^m)}_{\text{long-term capital costs}}))$$

subject to

(a) The stochastic load demand process governed by equations (1)-(2)

(b) Capacity expansion process:

$$K_i^{m+T_i} = K_i^m + k_i^m$$

(c) Blackout variable for hour n:

$$u^n = \begin{cases} 0, \sum_i K_i^m \ge L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

(d) ISO economic dispatch process for hour n:

$$\forall u^n = 1 \begin{cases} \lambda^n = 0 \\ P_i^n = 0 \end{cases}$$

$$\forall u^n = 0 \begin{cases} \min_{P_i^n} \sum_i STMC_i^n(P_i^n) \\ s.t. \sum_i P_i^n = L^n : \lambda^n \\ P_i^n \le K_i^m \end{cases}$$

Scenario 3 Spot. Generators make their own investment decisions in spot market only setup to maximize their expected profits. The profits are defined as total revenue minus total production cost, investment cost and possible blackout costs. Here we assume ISO may introduce a market rule to charge individual generators if there is a blackout due to the resource inadequacy. The blackout costs are defined as the product of total capacity K_i^m and the penalty factor $\mu_{blackout}$, which is set at \$1000/MWh in the simulations.

$$BC_i^n = K_i^m \mu_{blackout}$$

To test the effect of such rule, two cases with or without such rule, SpotA and SpotB respectively, are both simulated. The SpotA case is illustrate as an example in the following model. Furthermore, we make the assumption that each generator make their own decision assuming the others would not expand at all.

The objective function of generator i can be expressed as

$$\max_{(k_i^m),1\le m\le M} \mathrm{E}(\sum_{m=1}^{M} e^{-\rho mTm}(\sum_{n=(m-1)Tm}^{mTm} e^{-\rho n}((1-u^n)(\underbrace{\lambda^n P_i^n}_{\text{short-term revenue}} - \underbrace{STMC_i^m(P_i^n)}_{\text{short-term production costs}}) - \underbrace{u^n BC_i^n}_{\text{blackout costs}}) - \underbrace{\mathrm{CC}_i^m(K_i^m)}_{\text{long-term capital costs}}))$$

subject to

(a) The stochastic load demand process governed by equations (1)-(2)

(b) Capacity expansion process:

$$K_i^{m+T_i} = K_i^m + k_i^m$$

(c) Blackout variable for hour n:

$$u^n = \begin{cases} 0, \sum_i K_i^m \ge L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

(d) ISO economic dispatch process for hour n:

$$\forall u^n = 1 \begin{cases} \lambda^n = 0 \\ P_i^n = 0 \end{cases}$$

$$\forall u^n = 0 \begin{cases} \min_{P_j^n} \sum_j STMC_j^n(P_j^n) \\ s.t. \sum_j P_j^n = L^n : \lambda^n \\ P_j^n \le K_j^m \end{cases}$$

Scenario 4 Stratum. In this scenario generators make their own investment decisions in the newly proposed SEM market to maximize their expected profits. The profits are defined as total revenue from both long-term and short-term markets minus total production cost, investment cost and possible blackout costs. Similar to Scenario 3, we also introduce a market rule to charge the individual generators if there is a blackout due to the resource inadequacy. The blackout costs are defined as the product of total capacity K_i^m and the penalty factor $\mu_{blackout}$, which is set at \$1000/MWh in the simulations.

$$BC_i^n = K_i^m \mu_{blackout}$$

To test the effect of such rule, two cases with or without such rule, StratumA and StratumB respectively, are both simulated. We use StratumA case as an example in the following problem description. Furthermore, we make the assumption that each generator make their own decision assuming the others would not expand at all.

The objective function for generator i can be expressed as:

$$\max_{(k_i^m),1\le m\le M} \mathrm{E}\Big(\sum_{m=1}^{M} e^{-\rho m Tm}\Big(\sum_{n=(m-1)Tm}^{mTm} e^{-\rho n}\big(\underbrace{\lambda_i^m P_i^m}_{\text{long-term revenue}} + \underbrace{\lambda_i^n P_i^n}_{\text{short-term revenue}} - \underbrace{(1-u^n)STMC_i^n(P_i^m + P_i^n)}_{\text{short-term production costs}} - \underbrace{u^n BC_i^n}_{\text{blackout costs}}\big) - \underbrace{\mathrm{CC}_i^m(k_i^m)}_{\text{long-term capital costs}}\Big)\Big)$$

subject to

(a) The stochastic load demand process governed by equations (1)-(2)

(b) Capacity expansion process:

$$K_i^{m+T_i} = K_i^m + k_i^m$$

(c) Blackout variable for hour n:

$$u^n = \begin{cases} 0, \sum_i K_i^m \ge L^n \\ 1, \sum_i K_i^m < L^n \end{cases}$$

(d) The auction quantity. The load demand for long-term market in year m D^m is determined by the minimum load level within that year for a given load forecast series and the remaining load belongs to the load demand to be supplied by the short-term market D^n.

$$D^m = \min(L^n), n \in [(m-1)Tm, mTm]$$

$$D^n = L^n - D^m, n \in [(m-1)Tm, mTm]$$

(e1) ISO economic dispatch process for long-term market at year m assuming current capacity will cover the long-term market demand D^m:

$$\min_{P_j^n} \sum_j LRMC_j^m(P_j^m)$$

$$s.t. \sum_j P_j^m = D^m : \lambda^m$$

$$P_j^m \le K_j^m$$

(e2) ISO economic dispatch process for short-term market at hour n:

$$\forall u^n = 0 \begin{cases} \min_{P_j^n} \sum_j STMC_j^n(P_j^n) \\ s.t. \sum_j P_j^n = D^n : \lambda^n \\ P_j^n \le K_j^m \end{cases}$$

$$\forall u^n = 1 \begin{cases} \lambda^n = 0 \\ P_i^n = 0 \end{cases}$$

Scenario 5. Repeated spot. In this case new market rules are introduced to allow information gathering by those making investment decisions about what the others intend to do. This is done iteratively as follows:

1) Each generator makes optimal investment decisions assuming the some initial values of the others' decisions. The decision making process is the same as in SpotA. Here we set the initial value to zero.

2) The market maker will publish the market clearing prices and quantities of every unit at the end of each bidding round *r*. Then from these results each unit could estimate the optimal expansion decisions made by the others for round *r*, $\bar{k}_{i,r}^m$.

3) Using the $\bar{k}_{i,r}^m$ as the updated decisions about the others, each unit re-evaluates the expansion problem and chooses its updated best response $k_{i,r+1}^m$ for round *(r+1)*. If the difference of decision variables between round *n* and *(n+1)* is smaller than some value ε, iteration stops and it is assumed that the bidding process had reached the market equilibrium. Otherwise, the process is repeated starting from Step 2).

Scenario 6. Repeated stratum. In this case new market rules are introduced to allow repeated bidding and results feedback on top of the scenario stratumA setup. The iteration follows the same logic as in Scenario 5.

IV. Numerical Results

Altogether, eight scenarios are simulated. The results under low gas price forecast are shown in Figures IV.1-IV.4. The resulting generator investment decisions for this case are shown in Fig IV.1. The resulting market attributes of interest, such as costs and revenues, are shown in Fig IV.2. The expected average electricity prices and associated standard deviations are shown in Fig IV.3. The expected average blackout hours and associated standard deviations are shown in Fig IV.4.

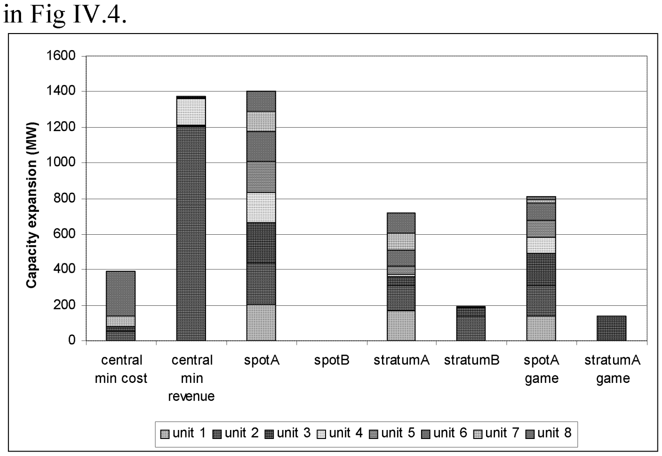

Fig. VI.1 Generation capacity expansion under low gas price profile

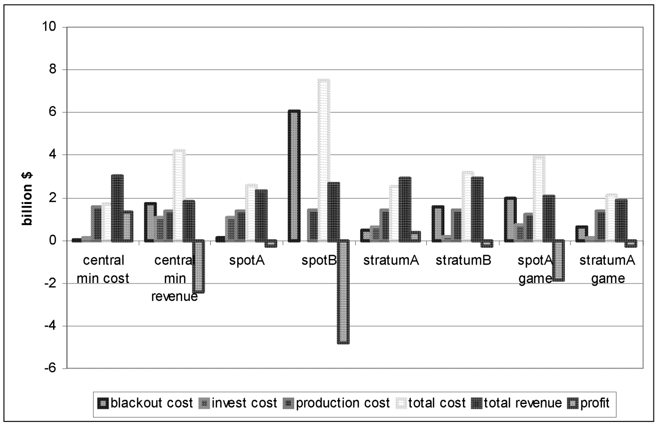

Fig. VI.2 Revenue, production costs and profits under low gas price profile

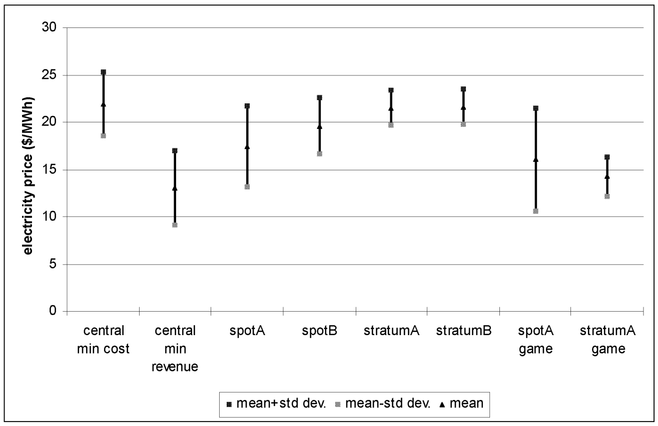

Fig. VI.3 Average and standard deviation of electricity price under low gas price profile

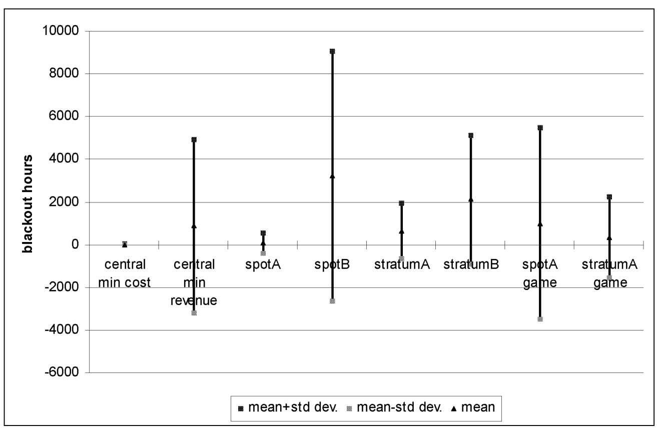

Fig. VI.3 Average and standard deviation of blackout hours under low gas price profile

It can be concluded based on these simulations that If the investment decisions are made by a coordinating planner like ISO, the results are very sensitive to the objective chosen by the ISO. As shown in Fig IV.1, if the objective is to minimize total costs of electricity generation (central min cost), more peak-load generators should be built, which would lead to a higher market price. On the other hand more base-load generators should be built if the objective is to minimize total electricity charges to the consumers (central min revenue).

On the other hand, if the decisions are left to generators themselves, market structure and market rules will affect results dramatically. In particular, the blackout cost rule has a substantial effect. No one would expand anything in spot only market with no blackout costs charge in place (SpotB) since they would never recover the investment; a much larger investment decision is made when considering the blackout cost (SpotA). As expected, a market rule explicitly charging market participants for lack of service may encourage more investments to avoid a bigger loss even under low fuel price profile. Similar effect can be drawn for the SEM structure.

However, the solution under spot market only setup is not sustainable since generators would lose money no matter whether they invest or not. Under the SEM setup, generators can make reasonable profits if the blackout rule is applied and the average electricity prices are much less volatile comparing to the spot market only setup.

The gaming between generators will reduce the investment immensely for both market structures, which will jeopardize generator's financial viability and expose the system to higher blackout risks. This can be seen by comparing the corresponding scenarios with and without the repeated bidding.

The simulation results under the high gas price forecast are shown in Fig IV5-IV.8, respectively.

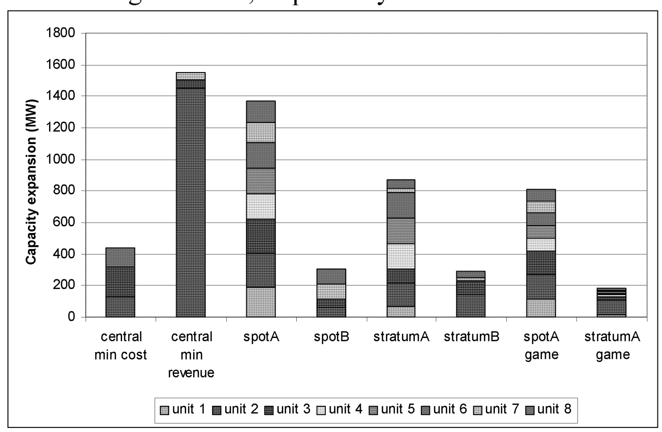

Fig. VI.5 Generation capacity expansion under high gas price profile

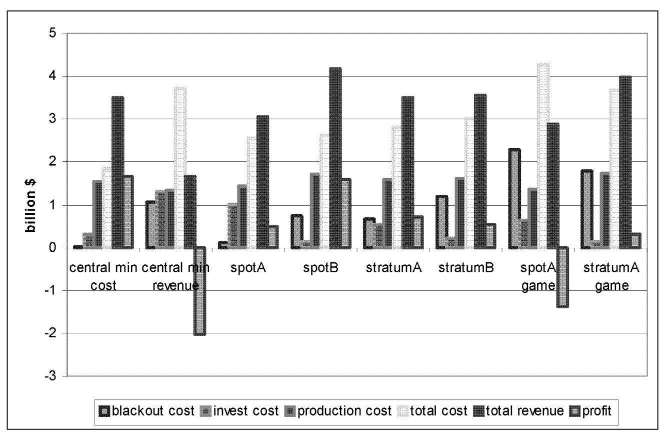

Fig. VI.6 Revenue, production costs and profits under high gas price profile

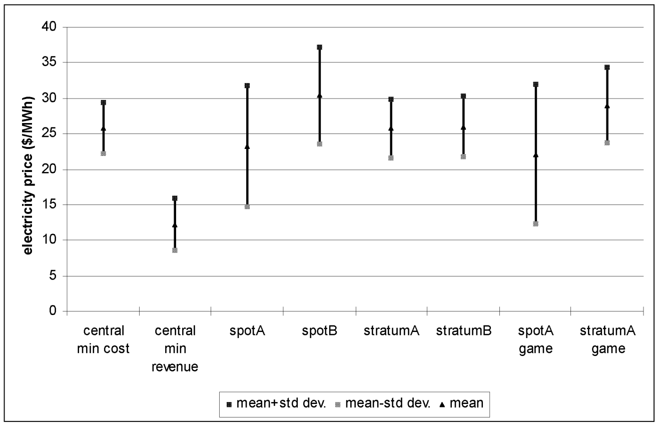

Fig. VI.7 Average and standard deviation of electricity price under high gas profile

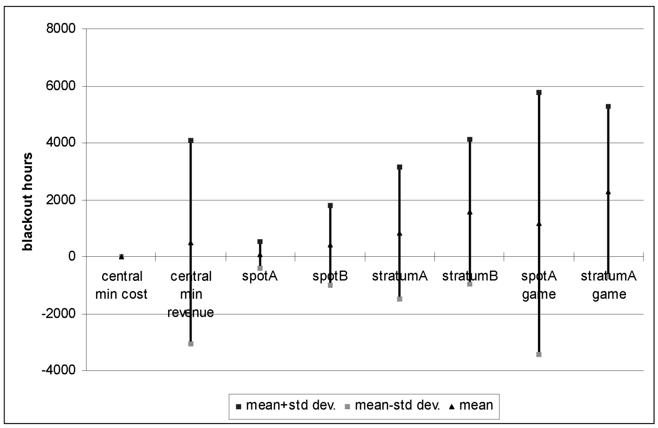

Fig. VI.8 Average and standard deviation of blackout hours under high gas price profile

The basic results remain the same under high gas price profile as in the case of low gas price scenarios. Different goal of central planners and market makers may lead to different results; in particular, the blackout risk sharing with generator will encourage more investments in both scenarios. The SEM structure will lead to smaller price volatility and gaming between players will always decrease the investment and increase the blackout risks. However, generators will continue to make good profits under most scenarios and the results are sustainable if the high fuel price continues into the future.

V. Conclusions and Future Research

Given that today's measurements of market power in the spot market classify any bids higher than the SRMC cost, we suggest that it is essential to introduce other means to provide incentives of new generation capacity installation in a timely manner to supply the long-term uncertain demand. This can be done by designing longer-term physical and/or financial mechanisms for valuing future investments. In this paper we propose a Stratum Electricity Market (SEM) structure as an enhancement to the short-term spot market. This market would eliminate the need for various installed capacity and reliability markets currently under consideration. The SEM structure consists of several sequentially clearing sub-markets, ranging from a day-ahead-market, through month-, season-, year-, five year- and even ten year-forward sub-markets.

A fundamental modeling approach is further applied to model and simulate the SEM structure and compare to the short-term only markets under different market setup. The following conclusions are reached:

1. Different market structures will affect both technical and economic performance of the power system as a whole as well as those of the individual market participants, generators in particular.
2. Short-term marginal costs based bidding rules currently implemented in the ISOs within the United States which focus on the spot market only structure do not provide sufficient signals to attract new generation investment, unless very high fuel price is forecasted for the future.
3. The newly proposed SEM structure provides long-term price signals for investments as well as short-term price signals for supply meeting demand. It has the potential of drastically reducing the price volatility risks seen by the generators and others comparing to spot market only setup.
4. Market rules which encourage risk sharing between supply and demand, such as blackout charges to generators, may lead the better system performance.
5. Gaming between players in the market can distort the market results extensively. Market monitoring rules to avoid such effects are necessary.

Future research concerns:

1. Incorporating price-sensitive consumers into the demand model.
2. Developing stochastic fuel price model.
3. Studying more complicated bidding strategies and their inter-dependence with the market structures in place.
4. Simulating long-run capacity market mechanisms like the Relaibility Provision Market (RPM) model proposed by PJM [18].
5. Including the network constraints.

Acknowledgments

The authors greatly appreciate several discussions with Porfessor Lester Lave at Carnegie Mellon University.

References

[1] M. Ilic, et al, Toward Working Electiricty Markets, Springer Verlag, 2006 (to appear)

[2] S. A. Ross, R. W. Westerfield, and J. Jaffe, "Corporate Finance", 7th edition, McGraw-Hill Higher Education, 2005

[3] G. A. Holton, "Value-at-Risk: theory and practice", Elsevier Acadamic Press, 2003

[4] E. Schwartz, "The stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging", The Journal of Finance, Vol. 7, No.3, July 1997

[5] C. Joy, "Pricing Modeling and Managing Physical Power Derivatives", Risk Publications, 1999

[6] B. F. Hobbs, C. B. Metzler, and J.S. Pang, "Strategic Gaming Analysis for Electric Power Systems: an MPEC Approach", IEEE Trans. On Power Systems, Vol. 15, No. 2, May 2000, pp 638-645

[7] P. Visudhiphan and M. Ilic, "Dynamic Game-based Modeling of Electricity Markets", 1999 IEEE PES Winter Power Meeting, New York, New York City, February 1999.

[8] P. Visudhiphan and M. Ilic, "Dependence of Generation Market Power on the Demand/Supply Ratio: Analysis and Modeling", 2000 IEEE PES Winter Meeting, Singapore, January 2000

[9] F. Black and M. Scholes, "The Pricing of Options and Corporate Liabilities", Journal of Political Economy, Vol. 81, May-June 1973, pp 637-659
[10] P. Skantze, A. Gubina and M. Ilic, "Stochastic Modeling of Electric Power Prices in a Multi-Market Environment", 2000 IEEE PES Winter Meeting, Singapore, January 2000
[11] P. Skantze, P. Visudhiphan and M. Ilic, "Valuation of Generation Assets with Unit Commitment Constraints under Uncertain Fuel Prices", MIT Energy Lab Technical Report EL 00-004, November 2000
[12] A. Botterud and M. Ilic, "Optimal Investments in Power Generation Under Centralized and Decentralized Decision Making", IEEE Transactions on Power Systems, vol. 20-1, pp. 254-263, February 2005.
[13] Hourly load data from ISO-NE website. Available: http://www.iso-ne.com/Historical_Data/eei_loads.html
[14] "The IEEE reliability test system –1996", *IEEE Trans. Power Systems*, Vol. 14, pp. 1010–1020, Aug. 1999.
[15] Annual Energy Outlook 2005 with Projections to 2025. Available: http://www.eia.doe.gov/oiaf/aeo/index.html
[16] Z. Wu, "Toward a Systematic Design of Capacity Sub-Markets for Electric Power: Stratum Electricity Market (SEM) Structure", PhD thesis, Department of Engineering Public Policy, Carnegie Mellon University, June 2006.
[17] J. A. Wood, and F. B. Wollenberg, "Power Generation, Operation, and Control," 2nd Edtion, New Jersey, John Wiley and Sons, 1996
[18] PJM Relaibility Provision Market (RPM) model. Available: http://www.pjm.com/committees/working-groups/pjmramwg/rpm-annual-meeting.html