Evaluation of Regulatory Impacts on Dynamic Behavior of Investments in Electricity Markets: A New Hybrid DP/GAME Framework

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***Abstract*—A new hybrid framework based on game theory and dynamic programming (DP) with random demands and prices is proposed for studying the impacts of regulatory interventions on the dynamics of investment in power generation in electricity markets. In our approach, using Markov chains, the electric demand and growth of fuel prices have been modeled. DP has been used for solving the generation expansion planning (GEP) problem. Investment strategies of other investors in the market are modeled as constraints. The income of the investor is calculated by modeling strategic interactions among market players in the spot energy market. The Cournot game concept has been applied and the Nash equilibrium is calculated for each state and stage of DP. Simulation results confirm that the proposed framework is an appropriate decision-support tool that provides useful information about dynamics of investment.**

***Index Terms*—Electricity markets, game theory, generation expansion planning, investment dynamics, stochastic dynamic programming.**

NOMENCLATURE

A. Indices

e	Generation firms.
h	Hydro units.
k	Time step (years).
l	Load levels.
s	Seasons.
t	Thermal units.

B. Parameters

af_i	Availability factor of generating unit i.
B_k	Expected net profit in year k [$].
$B_{capacity,k}$	Income from capacity payment in year k [$].
$B_{e,energy,k}$	Profit of firm e in spot market in year k [$].
$C_{inv,k,i}$	Adjusted investment cost of unit i in year k [$].
$CI_{k,i}$	Investment cost of technology i in year k [$/MW].
CF_{ksl}	Capacity factor in year k, season s, and load level l.
CPF_k	Capacity payment factor in year k [$/MWh].
CP_{ksl}	Capacity payment in ksl [$/MW].
CPg	Annual growth of contractual price (%).
$C_{trasm,k}$	Transmission usage cost in year k [$].
$C_{inv,k}$	Investment cost in year k [$].
$C_{share,e}$	Capacity share of firm e [%].
D_{0ksl}	Total demand at zero prices in ksl [MW].
D_{1ksl}	Slope of demand function in ksl [MW/$/MWh].
$D_{base,ksl}$	Forecasted demand in ksl [MW].
D_{ksl}	Total demand in ksl [MW].
d_{ksl}	Duration of ksl [h].
dc	Demand coefficient introducing demand intercept.
E_{hks}	Hydro energy reserve of ks [MWh].
$EM_{e,t}$	CO_2 produced by unit t of firm e [lb/MMBtu].
F_k	Fuel price in year k [$/MBtu].
J_0	Total profit over the planning period [$].
H_t	Heat rate function of thermal unit t [MBtu/h].
L_k	N_l by N_s demand matrix in year k [MW].
LF_l	Load factor for load level l.
l_t	Construction delay of new technologies [year].
N_s	Number of seasons.
N_l	Number of load levels in each season.
$N_{e,t}$	Number of thermal units belonging to firm e.
$N_{U_{k-lt+1}}$	Number of thermal units added by investor.

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$N_{e,h}$	Number of hydro units belonging to firm e.
$NGOI_k$	Number of units constructed by other firms in year k.
$n_{t,i}$	Lifetime for new technology i [years].
$p_{t\min}$, $p_{t\max}$	Minimum and maximum generation capacity of thermal unit t [MW].
$p_{h\min}$, $p_{h\max}$	Minimum and maximum generation capacity of hydro unit h [MW].
pc	Price coefficient introducing price intercept.
$q_{e,ksl}$	Total generation contracted by firm e in ksl [MW].
r	Discount rate [%].
SF_s	Seasonal factor in s.
T	Planning period [years].
$TR_{t,k}$	CO_2 tax rate of unit t in year k [\$/lb CO_2].
TRC_{base}	Base rate for transmission cost [\$].
X_k	System installed capacity in year k [MW].
$\omega_{L,k}$	Stochastic change in demand in year k.
$\omega_{F,k}$	Stochastic change in fuel price in year k.
ω_s	Short-term strategic uncertainty.
π'_{ksl}	Contracted electricity price in ksl [\$/MWh].
$\pi_{base,ksl}$	Competitive electricity price in ksl [MW].
$\pi_{eq,entry}$	Threshold entry price [\$/MWh].
$\Delta\pi_k$	Difference between market and entry price.

C. Decision Variables

$p_{t,ksl}$	Power produced by thermal unit t in ksl [MW].
$p_{h,ksl}$	Power produced by hydro unit h in ksl [MW].
U_k	Nonnegative capacity addition in year k [MW].

D. Auxiliary Variables

$g_{e,ksl}$	Total power generation of firm e in ksl [MW].
π_{ksl}	Electricity price in ksl [\$/MWh].

I. Introduction

THE power industry has experienced drastic changes in the structure, its markets, and regulations during the past three decades. This restructuring process as a transition from the traditional vertical integrated system to a new competitive framework has been adopted to promote competition, mainly in the generation sector. In the new situation, traditional approaches for expansion planning may not be appropriate any more. Therefore, new approaches, considering different time scales, need to be developed. These time scales are of the short, medium, and long terms.

One of the most important issues associated with long-term decisions is the problem of generation expansion planning (GEP), which investigates the construction of new power plants. Traditionally, GEP has been defined as determining the optimal plan for generation expansion including decisions on generating technologies, unit size, location, and timing in such a way that the total capacity of the system meets the forecasted electricity demand with a specified level of reliability or social welfare criterion [1], or represents an acceptable tradeoff among multiple objectives [2]. On the other hand, there are few incentives for regulated electric companies to incorporate uncertainty in their planning framework [3].

In competitive electricity markets, the objective of generation companies (GENCOs) for investing in new power plants is to maximize their expected profit during the operation and planning periods. The capital cost, operating cost, and revenues from the spot and contractual electricity markets are the main components affecting the GENCOs' objective functions. The expected costs resulting from uncertainties are not directly charged to the consumers. Hence, uncertainties in future demand and fuel price may seriously affect investment decisions. Furthermore, investment decisions of other investors, together with the strategic behavior of market players, affect electricity price in both the short and long terms. Consequently, it is essential to provide investors with a decision-support tool for analyzing long-term effects of regulatory interventions on investments behavior considering uncertainties.

Several studies have been performed on GEP in competitive electricity markets. Game theory has been applied for modeling a deterministic GEP problem in an oligopoly electricity market, where generating units are considered as market players competing in a Cournot model [4]. In [5], reliability criteria have been considered in a model based on game theory for solving the generation investment problem, where forecasted average market prices have been assumed to be known. A model based on the Nash-Cournot equilibrium has been proposed in [6] to solve the GEP problem that takes into account power production in the energy market. A dynamic stochastic model has been presented for describing investment, as well as production in an oligopoly market [7]. In [8], a two-stage oligopolistic game has been presented for solving the generation investment problem in electricity markets. Security of power system has been included in the resource-planning framework [9]. A game-theoretic model has been applied for handling the GEP problem by neglecting uncertainties, where particle swarm optimization (PSO) has been used to solve GENCOs' optimization problem [10]. A genetic algorithm has been applied to solve the optimal investment problem for each GENCO considering their interactions with the regulatory body [11]. To solve the GEP problem in a deregulated environment, where the participation of independent power producers (IPPs) and environmental impacts have been considered, an improved genetic algorithm has been presented in [12]. A stochastic optimization model, which considers annual average price of electricity as well as system load factor, has been proposed for studying investment behavior in electricity markets [13]. An agent-based model has been proposed for solving the generation investment problem, where interactions among agents have been represented by a conjectured variation approach in [14].

In the present article, a new hybrid DP/GAME framework is proposed for studying the impacts of regulatory interventions on the dynamic behavior of investments in new generation capacity in electricity markets. Electricity demands, as well as fuel prices, are two important long-term uncertain variables that have been modeled by Markov chains. Dynamic programming (DP) has been applied to solve the optimization investment problem. Investment strategies of other investors are modeled as constraints. In this respect, investment decisions by other investors are made according to the portfolio of existing generation capacity when the average annual electricity price exceeds a certain threshold. Generation expansion by other investors is a function of the difference between the market price and the threshold entry price. Revenues of the investor are calculated by considering interactions among generation firms in the spot market. Game theory has been used for modeling the strategic interactions among market players. The Nash equilibrium point is obtained for each stage and state of the DP. The main idea and contribution of this paper is combining the Cournot market game approach and DP in creating a new model. The approach proposed in this paper differs from the one in [13] in the following ways.

- The method for modeling the power market and therefore forecasting market price, as well as the revenue of GENCOs, is different from the approach in [13], in which electricity price is assumed to be a function of the system load factor, which is available as an input. In our proposed approach, equilibrium analysis has been used for forecasting electricity price and the revenue of GENCOs.
- In our approach, in addition to considering load uncertainty, fuel price is also considered as a stochastic uncertainty.
- Unlike [13], where backward dynamic programming is applied for solving the optimization problem, we have used forward dynamic programming. The dynamic program has stochastic elements, in particular random demands and fuel prices in each period. However, the model is not a full stochastic dynamic program in that it yields a single deterministic capacity plan over the time horizon, in which the investment decisions in each period do not depend on stochastic state variables. Therefore, this model is most appropriately referred to as a dynamic programming model with stochastic demand and fuel prices. If this was a true stochastic dynamic program, however, backward DP would need to be applied.

Furthermore, for analyzing the impact of other investors on the expansion strategies of the investor, a new index, so-called "rival investors presence factor (RIPF)," has been introduced. Using the proposed framework, it becomes possible to analyze the investment behavior of market participants for different regulatory interventions or alternative values of demand growth or other parameters. Consequently, the proposed framework can be a useful planning tool providing information about long-term dynamics of electricity price and investment behavior.

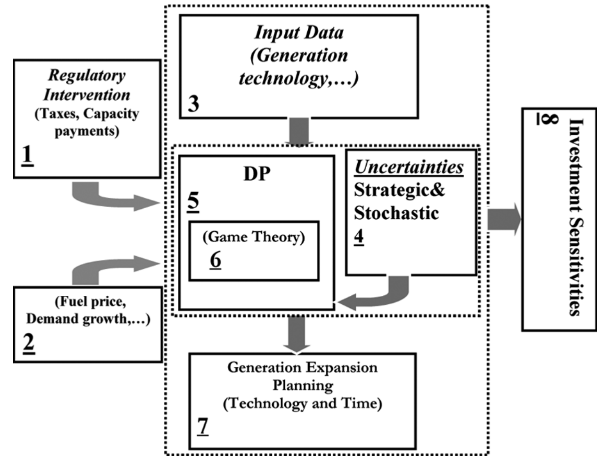

Fig. 1. General description of the proposed framework.

II. Description of the Proposed Framework

The proposed framework is generally depicted in Fig. 1. The framework is presented in eight blocks, which are explained as follows.

Exogenous variables of the considered system are addressed first. Annual demand and fuel price growth, as well as variables describing regulatory interventions in the market, are considered as exogenous variables from an investor point of view. Capacity payments, emission taxes, demand growth, fuel price, discount rate, and the fraction of system capacity traded in a contractual market, which are indicated in blocks 1 and 2, are also considered exogenous variables. Data required for solving the optimization problem (e.g., data of existing and candidate generating technologies being selected for expansion planning) are indicated in block 3.

One of the most important impacts of deregulation is the creation of new sorts of uncertainties [15]. Therefore, incorporating such uncertainties in operation and investment decisions is required. The uncertainties that an investor may be faced with are shown in block 4. Both short-term and long-term uncertainties are considered in the proposed framework.

Generally, in different time scales, attention should be paid to two types of uncertainties, referred to as stochastic and strategic uncertainties. Electricity demand is a basic variable, which can directly affect electricity price. Furthermore, changes in fuel price of existing and new generation units are clearly reflected in their operating costs and consequently in spot price. The profit of the investor will then be affected by fluctuation of the spot price resulting from fuel price uncertainty. These uncertainties, considered as long-term stochastic uncertainties, are modeled by the binomial Markov chain. Representation of uncertainties of the demand and fuel price by the Markov chain makes it possible to apply DP for solving the investment optimization problem, as indicated in block 5.

The strategies of other investors in the market can affect electricity prices. From an investor point of view, these are considered as a main source of profit uncertainty. Here, such uncertainties, which are referred to as long-term strategic uncertainties, are represented as the threshold entry price. In this respect, other investors will construct a number of generation facilities when the market price exceeds the reference entry price. Therefore, the annual electricity price should be calculated to clarify whether or not other investors would enter the market.

Since the objective of an investor is to maximize profit, the revenue of the investor from spot market must be calculated during the operation period. This requires the calculation of electricity price at each stage and state of DP. The way the electricity price is forecasted is also important. To forecast the spot price for electricity, equilibrium analysis [16] has been applied, where game theory is used for modeling the strategic behavior of market players (block 6). Game theory is an appropriate tool that has been extensively used to analyze the problems of conflict among competing decision makers [17]. It is also considered as a generalization of decision theory that includes multiple players or decision makers [18].

Among various game models, supply function equilibrium (SFE) and Cournot model are two of the most popular categories for modeling strategic interactions among market players [19]. Simplicity, computational tractability, flexibility in modeling bilateral contracts and technical limits, as well as compatibility with traditional operational planning in power systems, are features that cause Cournot model to be a popular game concept [20], [21]. This model is used to calculate electricity price together with operational profits of generation companies in spot market. Expansion strategies of investors and the dynamics of market prices, together with investment sensitivity to regulatory interventions, are outputs of the framework (blocks 7 and 8).

III. Mathematical Formulation

Because of the dynamic nature of investment problem and its multistage decision-making feature, a dynamic programming technique has been used. Given the existence of long-term uncertainties, the investment problem is of a stochastic nature, and DP is a suitable tool for solving such problems. Stochastic DP has been also applied for solving a variety of investment problems in regulated power industries [22]. A mathematical formulation of the problem is presented in this section.

A. Optimization of the Investment Problem

The investment optimization problem is formulated in (1) to (5). The objective function represented by (1) indicates total discounted profits over the planning period. Equation (2) represents the system capacity vector for time step k. Equation (3) is included as a constraint to consider the effects of investment decisions for thermal units, which the investor owns for every year of ownership. Constraints (4) and (5) represent demand and fuel prices:

$$J_0(.) = Max \underset{\omega_{L,k},\omega_{F,k}}{E} \left\{ \sum_{k=0}^{T} \left[(1+r)^{-k}.B_k(X_k, L_k, F_k, U_k) \right] \right\} \quad (1)$$

$$s.t.: \quad X_{k+1} = X_k + U_{k-lt+1} \quad (2)$$

$$N_{e,t,k+1} = N_{e,t,k} + N_{U_{k-lt+1}} \quad (3)$$

$$L_{k+1} = L_k + \omega_{L,k} \quad (4)$$

$$F_{k+1} = F_k + \omega_{F,k}. \quad (5)$$

To solve the investment problem in (1)–(5), the forward DP algorithm is used as shown in (6) at the bottom of the page. The total expected profit of the investor for time step is represented by (7):

$$B_k(.) = \underset{\omega_s}{E}[B_{e,energy,k}(.)] + B_{capacity,k,i}(U_{k,i}, L_k) - C_{inv,k,i}(U_{k,i}) - C_{trasm,k}. \quad (7)$$

The first and second terms in (7) represent an investor's revenues from energy sales in spot market and capacity payment, respectively. Investment cost is expressed by the third term. Transmission charge, expressed by the fourth term, is assumed to be a function of the capacity share of the GENCO, as given in (8):

$$C_{trasm,k} = C_{share,e}.TRC_{base}. \quad (8)$$

B. Profits Obtained in Spot Market

The short-run optimization problem for each GENCO at any stage and state of DP is represented by (9)–(15) at the bottom of the next page.

The first and second components of (9) represent investor's revenues obtained in spot and contractual markets, respectively. The third and fourth components represent fuel cost and CO_2 taxes, respectively. As rational forward prices of electricity may not deviate much from the expected spot price, the forward contract price denoted by (9) is endogenously determined. The contractual price in each year is assumed to be a function of spot price in the earlier stage with specified annual growth, as in (10). Equation (11) represents constraints imposed by limitations of available energy for hydro units, whereas (12) denotes the demand constraint, because generation firms are not responsible for meeting the whole demand of market. Constraints (13) and (14) are the bounds upon the decision variables. Finally, (15) is

$$J_k(.) = Max \left\{ B_k(.) + (1+r)^{-1}. \underset{\omega_{L,k},\omega_{F,k}}{E} [J_{k-1}(f_k(X_k, L_k, F_k, U_k, \omega_{L,k}, \omega_{F,k}))] \right\} \quad (6)$$

an auxiliary constraint that represents total generation of each GENCO for each season and load level.

According to the property of Cournot game, the above optimization problem should simultaneously be solved by GENCOs. The method for calculating Nash equilibrium of the game is described as follows.

Step 1) Each generation firm calculates its production by solving the optimization problem expressed in (9)–(15). Here, it is assumed that the rivals' productions are fixed.

Step 2) Electricity price is updated by the demand curve. To do this, the total power produced by generation firms is used instead of D_{ksl} in (16), because balancing between demand and supply is essential in the market. Therefore, electricity price will be affected by the total output of all generation firms. As a result, the optimization problems of all GENCOs are mutually linked through the market price [23]:

$$D_{ksl}(\pi_{ksl}) = -D_{1ksl}.\pi_{ksl} + D_{0ksl}. \tag{16}$$

Step 3) Steps 1 and 2 are repeated until no generation company benefits from changing its production. In such a situation, the Nash equilibrium of the game is obtained.

To find constants D_{0ksl} and D_{1ksl}, the forecasted demand $D_{base,ksl}$ and the reference price $\pi_{base,ksl}$ are used (17) and (18):

$$D_{0ksl} = dc.D_{base,ksl} \tag{17}$$

$$D_{1ksl} = \frac{D_{0ksl}}{pc.\pi_{base,ksl}} \tag{18}$$

where $\pi_{base,ksl}$ is calculated using traditional hydrothermal unit commitment program [24] for state of Markov chain having maximum forecasted demand for each year, season, and load level. Detailed implementation procedures for clearing the power markets are explained in [25].

C. Income From Capacity Payment

In competitive power markets, where GENCOs' incomes are only obtained from energy sales, the risk of revenues would be high, especially in periods with tight conditions. The total installed capacity of the system may be reduced as a result of decreased investors' willingness to construct new generation capacity. Therefore, the system's reliability may be reduced, which is unacceptable for both regulators and consumers.

One possible regulatory intervention that may be applied in the market is the capacity payment. The impact of capacity payment on investment strategy is highly dependent on the method applied. Here, revenue from capacity payments is assumed to be a function of total installed capacity and the forecasted demand. Equations (19)–(21) represent the method for calculating the investor's profit based on the capacity payment policy. The associated coefficients are defined according to seasonal and load level conditions for electricity demand. In addition, all generating units in the system receive capacity payments during the whole planning period. See equations (19)–(21) at the bottom of the page.

$$\begin{aligned} B_{e,energy,k} = &\sum_{s=1}^{N_s}\sum_{l=1}^{N_l} d_{ksl}.(g_{e,ksl} - q_{e,ksl}).\pi_{ksl} + \sum_{s=1}^{N_s}\sum_{l=1}^{N_l} d_{ksl}.q_{e,ksl}.\pi'_{ksl} \\ &- \sum_{s=1}^{N_s}\sum_{l=1}^{N_l} d_{ksl}\left(\sum_{t=1}^{N_{e,t}} F_{t,k}.H_t(p_{t,ksl})\right) - \sum_{s=1}^{N_s}\sum_{l=1}^{N_l} d_{ksl}\left(\sum_{t=1}^{N_{e,t}} TR_{t,k}.H_t(p_{t,ksl}).EM_{e,t}\right) \end{aligned} \tag{9}$$

$$s.t.: \quad \pi'_{ksl} = (1. + CPg*\pi_{eq,k-1}) \tag{10}$$

$$\sum_{l=1}^{N_l} d_{ksl}.p_{h,ksl} \le E_{hks} for h = 1, \ldots, N_h \tag{11}$$

$$g_{e,ksl} \le D_{ksl} \tag{12}$$

$$p_{t\min} \le p_{t,ksl} \le p_{t\max} \tag{13}$$

$$p_{h\min} \le p_{h,ksl} \le p_{h\max} \tag{14}$$

$$g_{e,ksl} = \sum_{t=1}^{N_t} p_{t,ksl} + \sum_{h=1}^{N_{e,h}} p_{h,ksl} \tag{15}$$

$$B_{capacity,k,i}(U_{k,i}, L_k) = af_i.U_{k,i}.\sum_{s=1}^{N_s}\sum_{l=1}^{N_l} CP_{ksl}.SF_s.LF_l \tag{19}$$

$$CP_{ksl} = \begin{cases} (CPF_k + 4*BRCP_k(1 - CF_{ksl}))*d_{ksl}, & 0 < CF_{ksl} \le 1.25 \\ 0, & \text{otherwise.} \end{cases} \tag{20}$$

$$CF_{ksl} = \frac{X_k}{L_{ksl}} \tag{21}$$

D. Representation of Investment Cost

Representation of the investment cost is as in (22). The proportion of the new plant's lifetime remaining in the planning period and fixed annuity for all time steps in the planning period were considered for adjusting the investment cost [13]. Assuming that the total investment payment was made halfway into the construction period, the investment cost is also adjusted according to the new technology's construction time:

$$C_{inv,k,i}(U_{k,i}) = (1+r)^{(-l_t/2)}.CI_{k,i}.U_{k,i}.\frac{\sum_{m=1}^{T-k}(1+r)^{-m}}{\sum_{n=1}^{nt,i}(1+r)^{-n}}. \tag{22}$$

E. Modeling of the Impact of Other Investors

In an actual situation, there may be many investors who want to make decisions for investing in new power plants. Thus, it is vital for investors to take other investors' strategies into consideration in modeling their own investment. A threshold entry price is considered at which other investors construct new generating units according to their portfolio of existing units. To distinguish between situations where the price is just a bit higher, or much higher than the threshold price, the number of generation units is also calculated. It depends on the percentage of increase in the market price with respect to the entry price. This dependency is assumed to follow (23) and (24):

$$\Delta\pi_k = \left(\frac{\pi_{eq,k} - \pi_{eq,entry}}{\pi_{eq,k}}\right) * 100 \tag{23}$$

$$NGOI_k = \begin{cases} 1 & 0 \prec \Delta\pi_k \leq 20 \\ 2 & 20 \prec \Delta\pi_k \leq 40 \\ 3 & 40 \prec \Delta\pi_k \leq 60 \\ 4 & 60 \prec \Delta\pi_k \leq 80 \\ 5 & \Delta\pi_k \succ 80. \end{cases} \tag{24}$$

RIPF, which is used to describe interactions between the investor and his competitors, is defined by (25):

$$\text{RIPF} = \frac{\sum_{i=1}^{N_{rival}} p_{i,rival}}{T} \tag{25}$$

where N_{rival} and $p_{i,rival}$ are the number of stages in which the rival investors construct new power plants and its probability, respectively.

IV. Numerical Study

A. Description of the Test System

The proposed framework has been tested by using IEEE RTS [26]. The study system has 2595 MW as total installed capacity and 2072 MW as peak demand at the beginning of the planning period. The planning horizon is assumed to be ten years, while each year is specified with four different hydro seasons. Each season is composed of three subperiods (off-peak, medium, and peak). The available hydro energy is 200 GWh for each year in the planning period. Table I shows the data of the forecasted demands and durations in year 1. The upper and lower bounds of the demand growth associated with Markov chain are assumed to be 7.0% and 4.0%, respectively. The bounds for fuel price are assumed to be 6.0% and 4.0%, respectively. The transition probabilities in the Markov chain are assumed to be 0.5 for both the upper and lower bounds.

The electricity market considered here consists of five price-maker GENCOs, owning four, six, eight, three, and eight units, respectively. Data regarding the ownership of the units by GENCOs are shown in Table II. Fuel prices of the thermal units are according to data available in [20]. Data of new candidate plants are shown in Table III. The discount rate is assumed to be 5%. The demand and price coefficients are assumed to be 1.8

TABLE I
FORECASTED DEMANDS AND DURATIONS IN THE FIRST STAGE

Season	Load level and Duration MW (hrs.)		
	Off-peak (Duration)	Medium (Duration)	Peak (Duration)
1	1280(876)	1680(985.5)	1920(328.5)
2	1400(876)	1760(985.5)	2000(328.5)
3	1600(766.5)	1920(876)	2072(547.5)
4	1200(876)	1600(985.5)	1880(328.5)

TABLE II
UNITS OWNED BY EACH FIRM

	Generation Firm				
Capacity [MW]	1	2	3	4	5
12	2	1	4	1	-
50	-	-	-	-	6
76	1	2	2	1	1
100	-	1	-	-	-
155	1	1	1	-	1
197	-	-	1	-	-
350	-	-	-	1	-
400	-	1	-	-	-
Total	4	6	8	3	8

TABLE III
DATA FOR NEW CANDIDATE PLANTS

Technology	Coal	GT
Capacity [MW]	650	200
Capital Cost[$/KW]	800	400
Operating Cost [$/MWh]	10.0	40.0
CO_2 Emission Data [lb/MMBTU]	180	120
F.O.R	0.04	0.01
Construction Delay(yr)	3	1
Life time (yr)	40	30

TABLE IV
SCENARIO DEFINITION

	Strategic uncertainty	Stochastic Uncertainties		Regulatory Interventions	
No.	Rival Investors Strategies	Demand Uncertaint y	Fuel Uncertainty	Capacity Payment	CO_2 Tax
1	YES	YES	YES	NO	NO
2	YES	YES	YES	YES	NO
3	YES	YES	YES	YES	NO
4	YES	YES	YES	NO	YES

TABLE V
EXPANSION STRATEGIES AND MARKET VARIABLES

Sc. No	Invested Capacity by Investor MW (yr)	Total Profit of the Investor [M$]	Invested Capacity by Others (MW), (yr)	RIPF	HHI	AAMP [$/MWh]	SDAP [$/MWh]	LRCP [$/MWh]
1	650(3), 200(5)	4645.7	(1472,736) (9,10) [1.0,1.0]*	0.20	2272	69.68	27.29	32.56
2	650(3), 200(5)	4793.2	(1472,736) (9,10) [1.0,1.0]	0.20	2272	69.68	27.29	32.56
3	650(3), 200(4)	7413.6	(1472,736) (9,10) [1.0,1.0]	0.20	2272	69.40	27.37	32.55
4	650(3), 200(6)	3137.7	(736,736) (9,10)[1.0,1.0]	0.20	2356	71.17	29.03	32.80

*Probability of investing by other investors

and 2.0, respectively. Annual growth of the contractual price is assumed to be 2%. Contractual volume is assumed to be 10% of total installed capacity, which is constant over the planning period. The seasonal factors are assumed to be 1.0, 1.2, 1.2, and 0.9 for the four seasons, respectively. Load coefficients are assumed to be 1.0, 1.5, and 2.5 for off-peak, medium, and peak load subperiods. GENCO 2 is considered to be the investor in our study. Because of financial limitations, it is assumed that the investor could construct at most two new power plants in the planning period. The candidate generation capacities to be constructed by other investors (i.e., 1, 3, 4, and 5) are 76, 155, 350, and 155 MW, respectively. Fuel prices of these thermal units have been taken according to data available in [20]. Four scenarios, summarized in Table IV, have been defined for this study. The base rate for transmission cost is assumed to be $20 M per year.

B. Simulation Results

Table V shows the expansion strategies of generation firms, the total profit of the investor, RIPF, Herfindahl-Hirschman index (HHI) [27] as an index of market power, the average annual market price (AAMP), and the standard deviation of the annual price (SDAP), which indicates the long-term volatility of the price. The long-run competitive price (LRCP) is the average of the annual system marginal cost, which is calculated by traditional hydrothermal unit commitment.

1) Scenario 1 (Base Scenario): In this scenario, the impact of uncertainties associated with both demand and fuel price on expansion strategies of generation firms, as well as market variables, have been investigated. The threshold entry market price is assumed to be 100 $/MWh. The results show that the investor will decide to expand the generation capacity by 650 MW and 200 MW in years 3 and 5 of the planning period, respectively. AAMP is shown to be greater than the LRCP. It should be mentioned that AAMP was firstly calculated to be 131.65 and 108.06 $/MWh for the 1st state of Markov chains, respectively, in the 9th and 10th year of the planning period. Since they are greater than the threshold entry price, other investors have constructed new generation capacity in the mentioned year and therefore reduced the market price. Thus, AAMP has been calculated again for those years. The annual market price and the competitive price during the planning period are depicted in Fig. 2. As the annual spot price is greater than the competitive price, market players experienced market power in the spot market. Furthermore, the competitive characteristics of the market have not improved during the planning period, since the obtained HHI is 2249 and 2272 for the beginning and the end of the planning period, respectively.

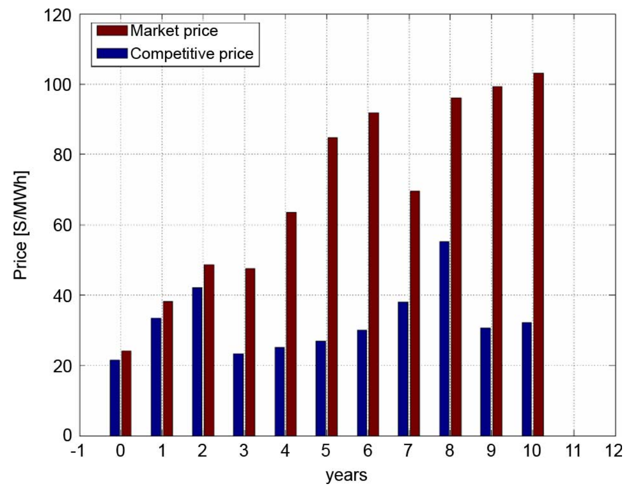

Fig. 2. Market and competitive price in scenario 1.

Investment in peak technology has taken place in later years than the base-load technology. The reason is that the peak load technologies (i.e., 200-MW units) are operated for limited durations where the market price is significantly high. This is the case for year 5 of the planning period, which the difference between the annual market price and the annual competitive price is high.

2) Impacts of Regulatory Interventions: In a liberalized market, when revenues are only obtained through energy and ancillary services, consumers may be exposed to price volatility and unacceptable risks. Capacity payments, which are normally considered by the regulatory body at the stage of market design, may reduce those risks. The impact of capacity payment on electricity price and investment strategies of generation companies is examined in scenarios 2 and 3.

Scenario 2 (Variable Capacity Payment): The simulations have been carried out assuming that $CPF_k = 20$ $/MWh for all the time steps of the planning period. A variable capacity payment has been also considered for calculating investor's revenues. The results show that the investor's strategy has not been changed with respect to scenario 1. The reason is that when the method for calculating the capacity payment depends on the capacity factor, which itself is a function of installed capacity and demand, the investor will not earn much through capacity payment. Moreover, in the presence of demand uncertainty, the investor's income will also be uncertain. Therefore, the investment strategy of the investor will not change with respect to the case where capacity payment is not included. In addition, total profit of the investor has been increased by 3.17% with respect to scenario 1. In such circumstances, the base capacity payment may need to be selected sufficiently high to encourage investors. However, this may not be acceptable from a regulatory and consumers' point of view. Consequently, it seems that capacity payment should be independent of the capacity factor.

Scenario 3 (Fixed Capacity Payment): In this scenario, the investment model has been investigated considering a fixed amount of 20 \$/MWh for capacity payment factor. According to simulation results, the strategy of the investor has been changed with respect to scenario 1. Accordingly, the investor decides to construct 650 MW and 200 MW units in years 3 and 4 of the planning period. Total investor's profit has been increased by 59.58% with respect to scenario 1. In addition, AAMP has been decreased by 0.40%. It can be concluded that modifying the capacity payment mechanism to a fixed rate would encourage investors to construct new generation capacity earlier. In other words, fixed capacity payment would not provide an incentive for the investor to postpone the investment decision since the payment is not affected by the uncertain capacity factor.

Consumer surplus is considered as a measure of the effect of various scenarios of capacity payments on consumer welfare. The total consumer surplus (present worth, at an interest rate of 0.05) is 9818.07 \$M and 3311.42 \$M for the variable and fixed capacity payment mechanisms, respectively. In terms of levelized value (present worth of consumer surplus divided by present worth of consumption), these equaled 70.81 \$/MWh and 23.84 \$/MWh, respectively. As a result, it can be concluded that variable capacity payment mechanism makes consumers better off in the long term.

Scenario 4 (Impact of CO_2 *Tax Regulation):* In this scenario, the impact of CO_2 emission tax regulation on investment behavior has been investigated. Here, the CO_2 tax rate has been assumed to be 0.02 \$/lb CO_2. The investment rule for other investors, e.g., the threshold price, has been assumed to be 110 \$/MWh, a few percent higher than in the previous scenarios. This is because other investors may change their strategies if CO_2 tax regulation is included. The investor's strategy has been changed with respect to scenario 1, since he decides to expand the generation capacity by 650 MW and 200 MW in years 3 and 6 of the planning period. The total profit of the investor has been also decreased by 48.06%. This regulation results in postponing the investment decision by the investors.

3) Sensitivity of the Investment: To investigate the impacts of the load growth variations on market variables, the proposed framework has been applied to several scenarios of demand growth in the absence of long-term uncertainties and regulatory interventions. The correlation coefficient between market variables is represented in Table VI. Relatively low positive correlation coefficient between AAMP and demand growth indicates that increasing of the demand would not increase the market price in the long term, because generation companies will construct new generation capacities. Furthermore, the relatively low positive correlation coefficient between investor's profit and the demand growth indicates the effect of constructing new generation capacities in the planning period by other investors. This is because generation companies with a higher capacity market share try to obtain their profit by increasing the market price. Therefore, more investment opportunities may be provided for

TABLE VI
CORRELATION COEFFICIENT BETWEEN VARIABLES

	Investor's total profit	Demand growth	AAMP
Investor's total profit	1.0	0.4843	0.9903
Demand growth	0.4843	1.0	0.5145
AAMP	0.9903	0.5145	1.0

generation companies having smaller market share in the long term. On the other hand, a high positive correlation between total investor profit and AAMP indicates that increasing the market price often increases the investor's profit, which makes sense.

A lower elasticity of the demand, resulted by increasing the price intercept (i.e., choke price) by 1.5 times of which was considered in the above scenarios, together with a higher volume of forward contract (30%), has also been investigated in our studies. Although the strategies of companies changed, similar trends resulted for the impact of regulatory interventions. In this situation, AAMP equaled 65.60 \$/MWh.

It should be mentioned that the short time horizon considered can distort decisions because of the well-known end effects of dynamic expansion model. That is, high capital cost investments will be discriminated against in later periods. There are ways to correct this, for instance, by adjusting the discount factor for the last year so that the last year can be simulated as repeating forever.

V. CONCLUSIONS

The hybrid DP/GAME framework developed in this paper describes the long-term dynamics of investment and electricity price in liberalized electricity markets. The framework also provides a platform for analyzing investment behavior as well as the market dynamics resulting from regulatory interventions.

Numerical studies show that investment in power generation might not necessarily be encouraged by a variable capacity payment mechanism. Changing the capacity payment mechanism to a fixed high payment has encouraged investors to construct new generation capacities. Environmental protection regulations could affect both investors' profit and their investment strategies. Sensitivity analysis confirms that increasing demand growth might not increase the market price in long term. Also, more investment opportunities may be provided for generation companies that at first have less market share. Finally, the proposed framework appears to be a useful tool for analyzing long-term effects of regulatory interventions, as well as uncertainties.

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