Consumers' Price Elasticity of Demand Modeling With Economic Effects on Electricity Markets Using an Agent-Based Model

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***Abstract*—Automated Metering Infrastructure (AMI) is a technology that would allow consumers to exhibit price elasticity of demand under smart-grid environments. The market power of the generation and transmission companies can be mitigated when consumers respond to price signals. Such responses by consumers can also result in reductions in price spikes, consumer energy bills, and emissions of greenhouse gases and other pollutants. In this paper, we use the Electricity Market Complex Adaptive System (EMCAS), an agent-based model that simulates restructured electricity markets, to explore the impact of consumers' price elasticity of demand on the performance of the electricity market. An 11-node test network with eight generation companies and five aggregated consumers is simulated for a period of one month. Results are provided and discussed for a case study based on the Korean power system.**

***Index Terms*—Agent-based modeling, automated metering infrastructure, price elasticity of demand, smart grid.**

I. Introduction

In deregulated electricity markets, market power and/or imbalances in the supply and demand associated with the marginal cost of the last unit dispatched have resulted in large fluctuations in wholesale electricity prices. In many of the existing electricity markets, only generation companies (GenCos) can respond to the price signals through supply-side offers to the independent system and/or market operator (ISO). The majority of consumers in deregulated markets have contracts with load aggregators or load-serving entities who, in turn, submit demand bids to the market operator. If the contract is a pass-through contract (i.e., the load aggregator charges the market price with some fixed profit margin), there is no incentive for the load aggregator to provide a mechanism for consumers to respond to prices. On the other hand, if it is a fixed price contract, consumers do not see the market prices and will not respond to price signals.

Moreover, because most consumers do not have access to hourly or daily electricity price information, their responses to price changes may lag behind. One potential consumer response, reducing consumption, occurs when consumers receive their monthly electricity bills. Another potential response, switching suppliers, usually occurs on an approximately monthly or annual basis, depending on the terms and conditions of supply contracts.

There has been considerable research on consumer response to electricity prices [1]. In addition, efforts have been undertaken recently to model and simulate the price elasticity in electricity markets [2], [3]. Such studies have shown that reductions in electricity consumption in response to prices, particularly by residential customers, are relatively inelastic in the short term; even high price increases produce fairly small changes in electricity usage. Large consumers, on the other hand, are relatively price sensitive.

Recently, AMI and smart grid have become widely accepted as promising technologies to provide increased awareness of electricity usage and cost to consumers. As a result, those technologies could enable consumers to overcome the technical and market barriers to participating in electricity markets through improved price elasticity.

In this paper, we have set up a model for exploring consumers' price elasticity of demand (via demand-side bidding) using EMCAS, an agent-based model that simulates the deregulated markets.

The remainder of this paper is organized as follows: Section II presents demand-side response modeling with price elasticity. Section III describes the experimental investigation and provides results and discussion. Section IV offers a real-world case study based on Korean electricity markets. Section V presents our conclusions.

II. Demand-Side Response Modeling With Price Elasticity

In economics literature, price elasticity (ε) is defined as the percentage change in demand or load (L) resulting from a percent change in price (P). For infinitely small changes in price, this can be expressed mathematically as:

$$\varepsilon = \frac{\delta L/L}{\delta P/P} = \frac{\delta L}{\delta P} \cdot \frac{P}{L} \tag{1}$$

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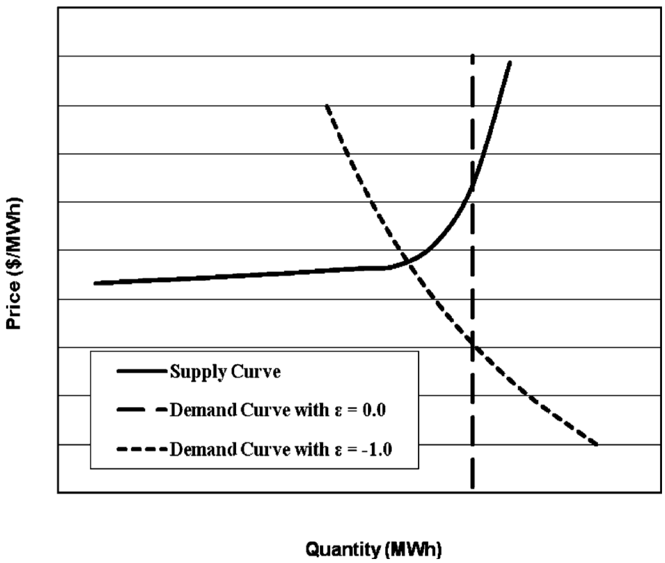

Fig. 1. Typical demand and supply curves.

TABLE I
ESTIMATES OF ELECTRICITY PRICE ELASTICITY

	Price Elasticity	
	Short-Run	Long-Run
Residential	-0.06 to -0.49	-0.45 to -1.89
Commercial	-0.17 to -0.25	-1.00 to -1.60
Industrial	-0.04 to -0.22	-0.51 to -1.82

where ε is the consumer's price elasticity of demand, δL is the consumer's change in load, δP is the price change, P is the forecasted energy price ($/MWh), and L is the consumer's base load (MWh).

The equation indicates that: a) a price elasticity of -1.0 means that a 1 percent increase in price will result in a 1 percent decrease in load, b) that zero price elasticity means that the consumers are insensitive to the price of electricity and that the load is unaffected by the price. In the latter case, the demand curve is a vertical line, as shown in Fig. 1. However, in electricity markets, the supply curve is more like a hockey stick, in which prices increase moderately for most of the supply curve except at the end, where prices increase dramatically with a steep slope. The demand responsiveness provides the greatest benefit in this region [4].

A. Estimates of Price Elasticity of Demand for Electricity

In general, measuring price elasticity is a complex task, and estimated elasticity coefficients usually have a wide range of uncertainty attached to them. It is common to differentiate between short- and long-run elasticity. Short-run elasticity describes the price-response from the system with its current infrastructure and equipment; long-run elasticity takes into account the investments that can be made (e.g., in energy conservation or alternative energy supply) in response to higher prices.

Table I lists examples of ranges of estimates for short- and long-run elasticity based on several studies [4]–[6]. However, because the studies were carried out in regulated systems, they might have limited validity for restructured markets. In general, one would expect the price elasticity of demand to increase with implementation of AMI and smart grid.

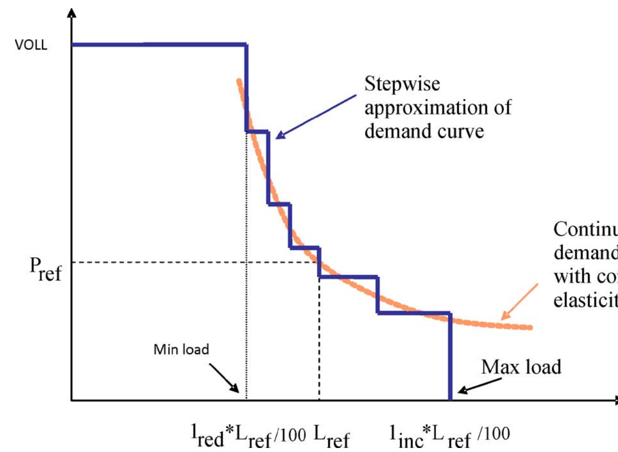

Fig. 2. Price elastic demand modeling.

B. Demand-Side Bidding and Market Clearing in the Day-Ahead Market

In the agent-based EMCAS model, consumers submit their demand to load aggregators who, in turn, submit the day-ahead hourly demand bid to the ISO. Similarly, the GenCos submit their day-ahead hourly offers to the ISO. The ISO runs the optimal load dispatch, optimal power flow, considering the transmission network, and determines the hourly locational marginal prices (LMPs) for every hour and for each bus in the system [7]. (The agent-based modeling framework is described in detail elsewhere [8], [9].) EMCAS offers an option to allow consumers/load aggregators to submit either inelastic or elastic demand bids. The shape of the demand curve that is bid into the day-ahead market is modeled by adjusting the following parameters for each individual consumer:

$\mathrm{P_{ref}}$	Reference price
$\mathrm{l_{red}}$	Limit for load reduction (percentage)
$\mathrm{l_{inc}}$	Limit for load increase (percentage)
$\mathrm{N_{red}}$	Number of steps on demand curve for load reduction
$\mathrm{N_{inc}}$	Number of steps on demand curve for load increase

Fig. 2 shows a typical demand curve. The reference price, $\mathrm{P_{ref}}$, is user input and is fixed for all hours, whereas $\mathrm{L_{ref}}$ is equal to the hourly loads and therefore changes from hour to hour. The minimum and maximum loads are determined by the parameters for the lower and upper limits.

If the price elasticity is constant for the entire demand curve, then (1) can be written as:

$$L = a \cdot P^{\varepsilon} \tag{2}$$

where a and ε (the elasticity) are constants, ε is a user input, and a can easily be calculated for each hour from L_{ref} and P_{ref}. Equation (2) is used to represent the demand-side bidding in the model. However, the continuous curve in Fig. 2 cannot be bid directly into the market; a stepwise approximation is necessary to calculate the market clearing as a linear programming (LP)

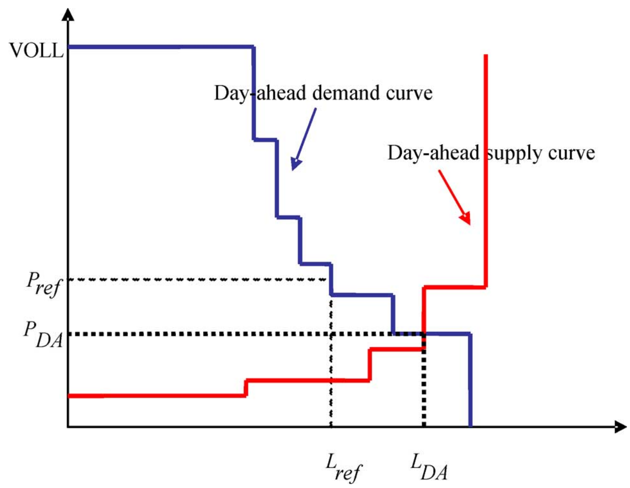

Fig. 3. Day-ahead market clearing modeling.

problem. Therefore, the continuous curve is approximated with a number of steps, as shown in Fig. 2.

The degree of match between the continuous curve and the stepwise approximation depends on the number of steps on the demand curve, as defined for each of the consumers. Step size is constant for all the load-reduction steps and also for all the load-increase steps. The corresponding prices are calculated for the load at the midpoint of each step by using the following formula, which is easily derived from (2):

$$P = Max(a^{-1/\varepsilon} \cdot L^{1/\varepsilon}, VOLL) \tag{3}$$

Note that a maximum demand bid price is equal to the value of lost load (VOLL).

The market clears where the supply curve intersects with the demand curve, and the resulting price and load are set accordingly. The actual load in the day-ahead market can therefore be higher than, lower than, or equal to the reference load. Fig. 3 shows an example in which the market clears at a price lower than P_{ref}, so that the actual load, L_{DA}, is higher than L_{ref}.

In the real-time market, there is no price elasticity of demand. This is because we assume that consumers cannot respond to prices in real time. Therefore, the resulting load from the clearing of the day-ahead market, $\mathrm{L_{DA}}$, is used as an inelastic load in the real-time market. This is illustrated in Fig. 4, where the demand curve is represented as a vertical line with a price equal to VOLL.

Note that in Fig. 4, we assume that some of the generators are on forced outage, causing the real-time price, $\mathrm{P_{RT}}$, to be higher than the day-ahead price, $\mathrm{P_{DA}}$, although the load is the same in the two markets.

III. Experimental Study

A. Experimental System

In the experimental simulations, we use an 11-node transmission network configuration; this approach is based on the method described in [10]. The technical specifications and the topology for the transmission lines are listed in Table II and shown in Fig. 5.

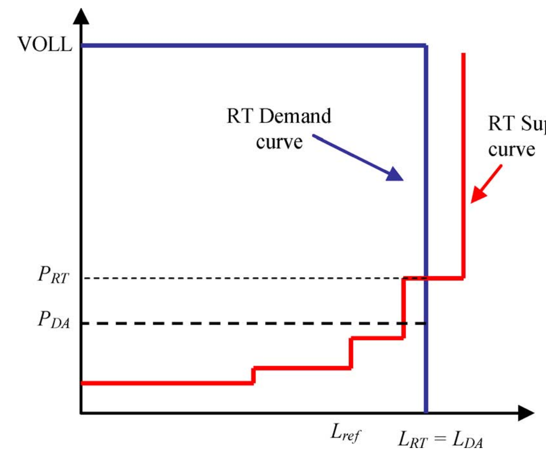

Fig. 4. Real-time market clearing modeling.

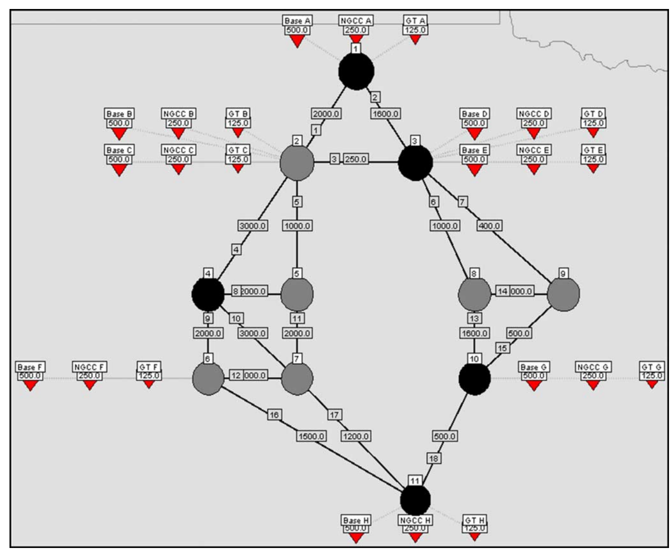
Fig. 5. 11-Node network.

TABLE II
Transmission Lines in 11-Node Network

Line No.	From Node	To Node	Circuit Reactance (per unit)	Line Capacity (MW)
1	1	2	0.02	2,000
2	1	3	0.025	1,600
3	2	3	0.08	250
4	2	4	0.01	3,000
5	2	5	0.02	1,000
6	3	8	0.04	1,000
7	3	9	0.05	400
8	4	5	0.01	2,000
9	4	6	0.02	2,000
10	4	7	0.01	3,000
11	5	7	0.015	2,000
12	6	7	0.01	2,000
13	8	10	0.025	1,600
14	8	9	0.03	1,000
15	9	10	0.04	500
16	6	11	0.02	1,500
17	7	11	0.025	1,200
18	10	11	0.04	500

TABLE III
GENERATING UNITS IN 11-NODE SYSTEM

Parameter/Plant	Unit	Base Coal	Combined Cycle	Gas Turbine
Capacity	MW	500	250	125
Fuel		Coal	Natural Gas	Natural Gas
Fuel price	$/MMBtu	1.5	5	5
Variable O&M	$/MWh	1.75	2.8	8
Fixed O&M	$/kW-m	2.1	0.6	0.7
Start-up time	Min	720	180	0
Mi. down time	Min	480	120	0
Warm start-up cost	$	7,000	2,000	50
Cold start-up cost	$	20,000	5,000	15

TABLE IV
PRODUCTION AND INCREMENTAL BLOCK COSTS

Capacity	Bid Block (MW)	Heat Rate (MMBtu/ MWh)	Inc. Heat Rate (MMBtu/ MWh)	Prod. Cost ($/MWh)	Inc. Cost ($/MWh)
Base Coal					
250	n/a	12,000	n/a	19.8	n/a
350	350	10,500	6,750	17.5	11.9
400	50	10,080	7,140	16.9	12.5
450	50	9,770	7,290	16.4	12.7
500	50	9,550	7,570	16.1	13.1
Combined Cycle					
100	n/a	9,000	n/a	47.8	n/a
150	150	7,800	5,400	41.8	29.8
200	50	7,200	5,400	38.8	29.8
225	25	7,010	5,490	37.9	30.3
250	25	6,880	5,710	37.2	31.4
Gas Turbine					
50	n/a	14,000	n/a	78.0	n/a
100	100	10,600	7,200	61.0	44.0
110	10	10,330	7,630	59.7	46.2
120	10	10,150	8,170	58.8	48.9
125	5	10,100	8,900	58.5	52.5

We assume that there is only one transmission company (TransCo) in the system, which owns the entire transmission network. The transmission network is operated by an ISO.

There are eight GenCos in the system, located at various nodes in the grid (Fig. 5). All of the GenCos have the same set of generating units: one base load coal plant (CO), one combined-cycle plant (CC) to cover intermediary load, and one gas turbine (GT) peaking unit. For each GenCo, all three generating units (CO, CC, and GT) are connected to the same node. The parameters for the plants are listed in Tables III and IV. These performance and cost parameters are only representative of the technology and are not actual plant data.

Note that the bidding blocks for each generating unit are based on the blocking of the heat rate curves described in Table III. In the base scenario, the GenCos bid according to their incremental production costs, as listed in Table IV. Forced outages are not included in the simulations, making it is easy to compare the profits for each of the GenCos.

We use an aggregate representation of the demand side of the market. Five aggregate consumers are included, representing total demand in the node where they are connected. The loads are connected to nodes 1, 3, 4, 10, and 11. We are simulating the month of July, which is assumed to be the peak-load month of the year. The five hourly load series are shown in Fig. 6. The highest load is clearly in node 11.

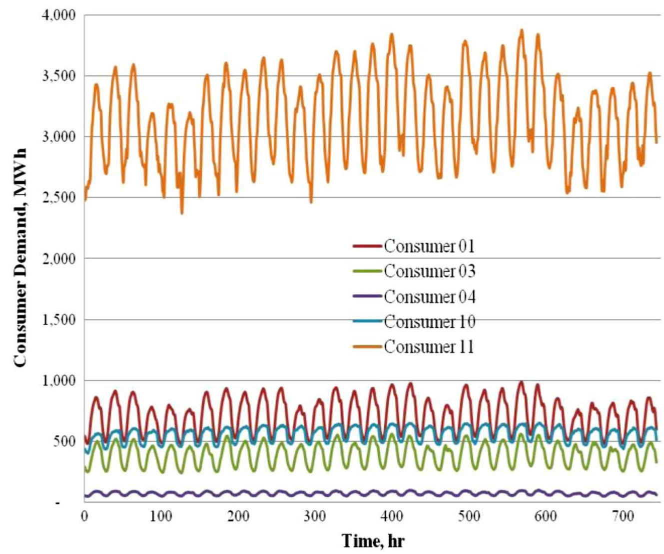

Fig. 6. Hourly consumer load in 11-node case study.

All of the consumers buy their electricity from a demand company (DemCo). The transmission network is split into four zones: A (nodes 1–3), B (nodes 4–7), C (nodes 8–10), and D (node 11). We assumed that there is one DemCo in each of the zones. Note that the consumers pay all charges to the DemCo, including energy, as well as transmission and distribution (T&D), charges.

The DemCo, in turn, passes the respective charges on to the GenCos and T&D companies. A markup can be added to the price paid by the consumers to represent DemCo profits. However, in this study, we focus on the GenCos and consumers and set the DemCo markup to zero. Fixed costs, $10/MWh and $18/MWh, are assumed for transmission and distribution, respectively.

B. Scenarios and Price Elasticity Parameters

For the sake of simplicity, we assumed that all five consumers exhibited price elasticity. A number of scenarios were run to analyze the impact of price elasticity and the reference price of consumers.

In all of these scenarios, we assumed that the GenCos bid the incremental production cost of their units (as listed in Table IV). In demand-side bidding, the consumers had a reference price of $25/MWh or $30/MWh and various price-elastic coefficients. In addition, the lower and upper load decrease and increase limits were set at 90% and 105% of the base load, respectively. These scenarios are summarized in Table V. The loads served in the base case and in other scenarios for a typical day are shown in Fig. 7, which shows that consumers increase their load when prices are lower and decrease their load when prices are higher.

C. Results and Discussion

Tables VI, VII, and VIII, respectively, present the reductions in peak load, total load served, and total energy cost under various scenarios. The overall peak load reduction is in the range

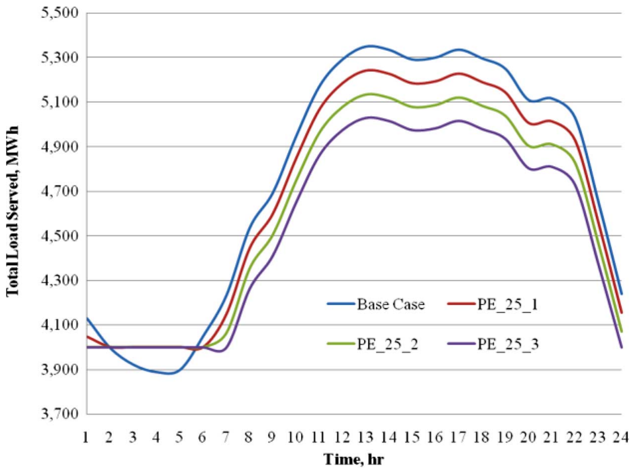

Fig. 7. Change in consumer load under various scenarios.

TABLE V
OVERVIEW OF SIMULATED SCENARIOS FOR 11-NODE SYSTEM

Scenario	Consumer Price Elasticity
Base Case	No price elasticity
PE_25_1	Ref. price: 25 $/MWh; Price elasticity: -0.1
PE_25_2	Ref. price: 25 $/MWh; Price elasticity: -0.2
PE_25_2	Ref. price: 25 $/MWh; Price elasticity: -0.3
PE_30_1	Ref. price: 30 $/MWh; Price elasticity: -0.1
PE_30_2	Ref. price: 30 $/MWh; Price elasticity: -0.2
PE_30_2	Ref. price: 30 $/MWh; Price elasticity: -0.3

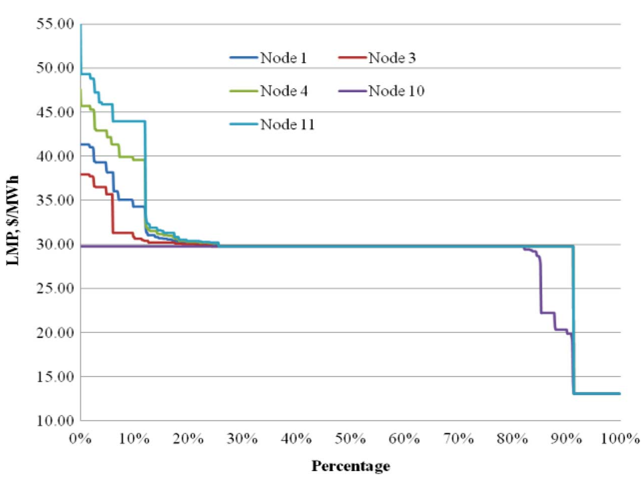

Fig. 8. Price (LMP) exceeding curve in base case.

TABLE VI
PEAK LOAD AND ITS REDUCTION IN 11-NODE SYSTEM (MW)

Scenario	Base Case	PE_25_1	PE_25_2	PE_25_3
Consumer 1	990	950 (4%)	939 (5%)	931 (6%)
Consumer 3	563	544 (3%)	540 (4%)	529 (6%)
Consumer 4	104	100 (4%)	99 (5%)	98 (6%)
Consumer 10	650	642 (1%)	632 (3%)	616 (5%)
Consumer 11	3,879	3,646 (6%)	3,591 (7%)	3,569 (8%)
Total	6,167	5,856 (5%)	5,750 (7%)	5,702 (8%)

TABLE VII
TOTAL LOAD SERVED IN 11-NODE SYSTEM (GWH)

Scenario	Base Case	PE_25_1	PE_25_2	PE_25_3
Consumer 1	530	521 (2%)	512 (3%)	503 (5%)
Consumer 3	291	286 (2%)	282 (3%)	277 (5%)
Consumer 4	57	56 (2%)	55 (3%)	54 (5%)
Consumer 10	418	412 (2%)	404 (3%)	398 (5%)
Consumer 11	2,347	2,303 (2%)	2,264 (4%)	2,227 (5%)
Total	3,643	3,578 (2%)	3,518 (3%)	3,459 (5%)

TABLE VIII
TOTAL ENERGY COST IN 11-NODE SYSTEM (MM$)

Scenario	Base Case	PE_25_1	PE_25_2	PE25_3
Consumer 1	15.95	15.43	15.00	14.67
Consumer 3	8.62	8.44	8.24	8.07
Consumer 4	1.76	1.68	1.62	1.58
Consumer 10	11.70	11.86	11.71	11.50
Consumer 11	72.91	68.84	66.36	64.74
Total	110.94	106.25	102.94	100.56

TABLE IX
IMPACT OF CONSUMER PRICE ELASTICITY IN 11-NODE SYSTEM

	Base Case	PE_25_1	PE_25_2	PE_25_3
GenCos				
Total revenue, MM$	109.26	105.67	102.75	100.48
Fuel cost, MM$	67.71	65.14	63.11	61.10
Startup costs, MM$	1.22	1.24	1.22	1.20
Fixed O&M, MM$	10.30	10.30	10.30	10.30
Variable O&M, MM$	7.14	6.90	6.73	6.56
Operating profit, MM$	22.89	22.09	21.39	21.32
Profit increase, %	n/a	-3.50	-6.57	-6.87
TransCo				
Line use revenue, MM$	36.43	35.78	35.18	34.59
Congestion rev., MM$	1.68	0.59	0.19	0.08
Congestion rev. inc., %	n/a	-65.12	-88.79	-95.49

of 5% to 8%. However, the peak load reduction for Consumer 10 is only in the range of 1% to 5%. The lower peak load reduction for Consumer 10 can be attributed to the LMPs at node 10. The LMPs at node 10 exceed the consumers' reference price 85% of the time; at other nodes, it exceeds the reference price 91% of the time (Fig. 8). Therefore, the peak load reduction for Consumer 10 is much less than that of the other consumers.

Except for Consumer 10, all of the other consumers reduced their total energy cost by reducing their total load. For Consumer 10, higher price elasticity and higher load reduction were required for a reduction in the total energy cost. In fact, the LMPs that Consumer 10 pays are higher when exhibiting price elasticity than in the base case; therefore, the reduction in total energy cost comes solely from a reduction in the load. However, other consumers benefit from a reduction in both load and prices. Table IX presents the impact of the consumers' price elasticity on GenCos and TransCos. When consumers exhibit price elasticities in the range of -0.1 to -0.3, the GenCos' profits are reduced by 3.50% to 6.87% and the TransCo's congestion revenues are almost eliminated.

We also studied the impact of the consumers' reference prices [Tables X and XI(a), (b), and (c)].

As expected, when the reference price increases from \$25/MWh to \$30/MWh, the load reduction is only 0.11% to 0.27%—for price elasticity in the range of -0.1 to -0.3. The small change in load is because the reference price is now close to the average price in the base case. Also, there is a slight

TABLE X
IMPACT OF CONSUMER PRICE ELASTICITY AND REFERENCE PRICE

	Base Case	PE_30_1	PE_30_2	PE_30_3
Consumers				
Total load served, GWh	3,643	3,639	3,635	3,634
Total energy cost, MM$	110.94	110.88	109.96	109.39
Avg. energy price, $/MWh	30.45	30.46	30.25	30.11
GenCos				
Total revenue, MM$	109.26	109.98	109.40	109.90
Fuel cost, MM$	67.71	67.26	67.08	67.04
Startup costs, MM$	1.22	1.20	1.20	1.18
Fixed O&M, MM$	10.30	10.30	10.30	10.30
Variable O&M, MM$	7.14	7.08	7.05	7.05
Operating profit, MM$	22.89	24.15	23.77	23.42
Profit increase, %	n/a	5.5	3.82	2.32
TransCo				
Line use revenue, MM$	36.43	36.39	36.35	36.34
Congestion rev., MM$	1.68	0.89	0.56	0.40
Congestion rev. inc., %	n/a	-47.05	-66.52	-76.47

TABLE XI
(A) GENCO PROFITS WITH HIGHER CONSUMER REFERENCE PRICE (MM$), (B) CONSUMERS' LOAD SERVED WITH HIGHER CONSUMER REFERENCE PRICE (GWH), (C) CONSUMERS' TOTAL COSTS WITH HIGHER CONSUMER REFERENCE PRICE (MM$)

a

GenCo	Base Case	PE_30_1	PE_30_2	PE_30_3
GenCo A	2.93	3.08	3.03	2.99
GenCo B	3.03	3.09	3.00	2.94
GenCo C	3.01	3.08	2.99	2.93
GenCo D	2.80	3.07	3.07	3.06
GenCo E	2.75	3.02	3.03	3.01
GenCo F	3.03	3.02	2.90	2.81
GenCo G	2.27	2.76	2.86	2.91
GenCo H	3.08	3.02	2.89	2.78

b

Consumer	Base Case	PE_30_1	PE_30_2	PE_30_3
Consumer 1	530.10	530.06	529.50	529.24
Consumer 3	291.45	291.55	291.43	291.30
Consumer 4	57.22	57.15	57.11	57.06
Consumer 10	418.07	418.99	418.93	418.92
Consumer 11	2,346.62	2,341.71	2,338.20	2,337.76

c

Consumer	Base Case	BS_1.5	BS_2.0	BS_2.5
Consumer 1	30.79	30.89	30.78	30.71
Consumer 3	16.78	16.91	16.90	16.87
Consumer 4	3.36	3.35	3.33	3.32
Consumer 10	23.41	23.96	24.06	24.10
Consumer 11	138.62	137.67	136.67	136.13

increase in the GenCos' profits, because even though they are generating less energy compared with the base case, the startup costs decrease; whereas there is a significant reduction in the congestion charges. Tables XI(a), (b), and (c) present the profits of each GenCos, individual consumers' load served, and total cost, respectively, when consumers have a higher reference price. When the price response is reduced because of a higher reference price, the total cost for consumers at nodes 3 and 10 increases compared with the base case. This shows that all consumers do not benefit equally, and some of them may actually face a higher cost.

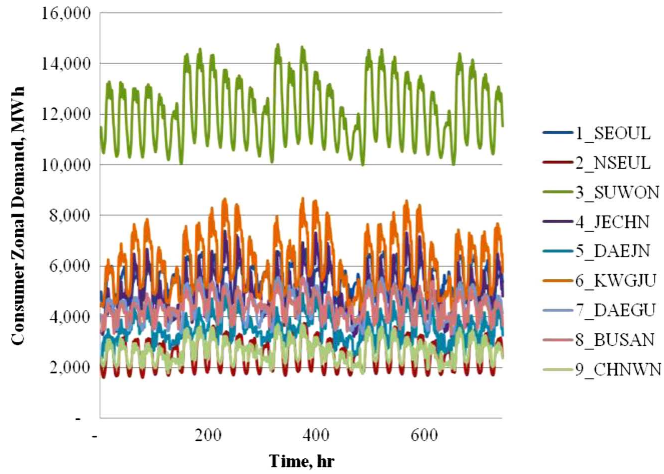

Fig. 9. Hourly consumer load in Korean power system (2006).

TABLE XII
OVERVIEW OF SIMULATED SCENARIOS FOR KOREA POWER SYSTEM

Scenario	Consumer Price Elasticity
Base Case	No price elasticity
PE_50_1	Ref. price: 50 kWon/MWh; Price elasticity: -0.1
PE_50_2	Ref. price: 50 kWon/MWh; Price elasticity: -0.2
PE_50_3	Ref. price: 50 kWon/MWh; Price elasticity: -0.3
PE_55_1	Ref. price: 55 kWon/MWh; Price elasticity: -0.1
PE_55_2	Ref. price: 55 kWon/MWh; Price elasticity: -0.2
PE_55_3	Ref. price: 55 kWon/MWh; Price elasticity: -0.3

IV. KOREAN POWER SYSTEM

A. Korean Power System

An aggregated representation of the Korean electricity transmission network developed in 2006 is used to perform an economic study on this power system. The Korean power system has a total capacity of 72 000 MW, and it includes 126 transmission lines, 97 busses, 9 zones, and 152 generators. The zones are Seoul, Nam Seoul, Suwon, Jechun, Deajon, Kwangju, Daegu, Busan, and Changwon. There are five pumped-storage hydro plants in the system. KEPCO is the only transmission and distribution company.

The hourly consumer loads by zone for the month of August 2006 are shown in Fig. 9. Zone Suwon has the highest load; zone Nam Seoul has the lowest load in the system.

B. Scenarios and Price Elasticity Parameters

We assumed that all consumers exhibit price elasticity. A number of scenarios were run to analyze the impact of price elasticity and the reference price of consumers. In all of these scenarios, GenCos bid the incremental production cost of their units. In demand-side bidding, the consumers had a reference price of 50 kWon/MWh or 55 kWon/MWh (1 kWon is approximately equivalent to U.S. $1) and various price elastic coefficients. In addition, the lower- and upper-load decrease and increase limits were set at 90% and 110% of base load, respectively. These scenarios are summarized in Table XII.

C. Results and Discussion

Because there are several consumers in the system, the results are presented here at the zonal level. Tables XIII, XIV, and

TABLE XIII
PEAK LOAD AND ITS REDUCTION IN KOREA POWER SYSTEM (MW)

Scenario / Zone	Base Case	PE_50_1	PE_50_2	PE_50_3
1_SEOUL	6,689	6,555	6,555	6,421
2_NSEUL	3,746	3,652	3,652	3,596
3_SUWON	14,764	14,469	14,469	14,174
4_JECHN	7,384	7,237	7,168	7,089
5_DAEJN	4,941	4,842	4,798	4,743
6_KWGJU	8,672	8,498	8,433	8,325
7_DAEGU	5,569	5,458	5,458	5,347
8_BUSAN	5,556	5,445	5,445	5,288
9_CHNWN	3,710	3,636	3,636	3,561
Total	58,997	57,502	56,637	56,637

TABLE XIV
TOTAL LOAD SERVED IN KOREA POWER SYSTEM (GWH)

Scenario / Zone	Base Case	PE_50_1	PE_50_2	PE_50_3
1_SEOUL	4,078	4,034	4,020	3,978
2_NSEUL	1,956	1,934	1,929	1,908
3_SUWON	9,039	8,941	8,916	8,823
4_JECHN	3,766	3,727	3,722	3,682
5_DAEJN	2,664	2,635	2,629	2,603
6_KWGJU	4,612	4,561	4,552	4,504
7_DAEGU	3,274	3,240	3,235	3,202
8_BUSAN	3,283	3,250	3,243	3,213
9_CHNWN	1,989	1,969	1,966	1,947
Total	34,660	34,290	34,212	33,859

TABLE XV
TOTAL CONSUMER ENERGY COST IN KOREA POWER SYSTEM (MILLION WON)

Scenario / Zone	Base Case	PE_50_1	PE_50_2	PE_50_3
1_SEOUL	225	220	218	215
2_NSEUL	108	106	105	103
3_SUWON	496	486	483	476
4_JECHN	207	203	202	199
5_DAEJN	146	143	142	140
6_KWGJU	254	248	247	244
7_DAEGU	179	176	175	173
8_BUSAN	179	176	175	173
9_CHNWN	109	107	107	105
Total	1,902	1,864	1,854	1,827

XV, respectively, present the reduction in peak load, total load served, and total energy cost under various scenarios. There is a 2% to 4% reduction in the peak load in all zones as the consumers increase their price elasticity from −0.1 to −0.3. Similarly, there is a 1% to 2.5% reduction in the total load. By exhibiting price elasticity, consumers were also able to reduce their total cost in the range of 2.0% to 4.4%.

Fig. 10 shows the price-exceeding curve in the base case. In all zones, prices exceed the reference price (50 kWon/MWh) nearly 80% of the time, which means that, on the average, consumers decreased their load 80% of the time and increased their load only 20% of the time during the simulation period.

Table XVI presents the impact of the consumers' price elasticity on GenCos and the TransCo. When consumers exhibited

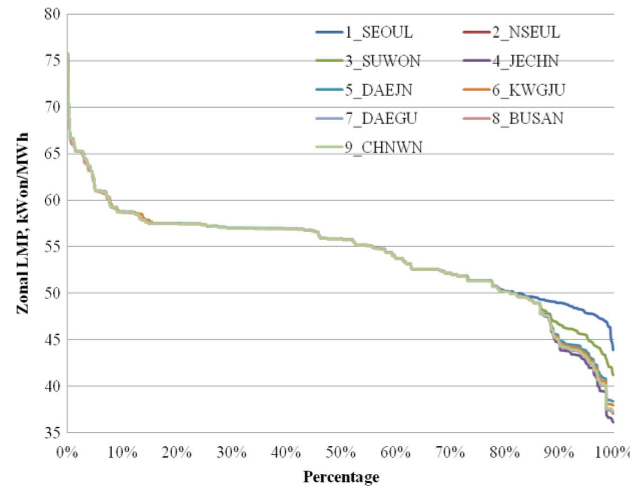

Fig. 10. Zonal price exceeding curve in base case for Korean power system.

TABLE XVI
IMPACT OF CONSUMER PRICE ELASTICITY IN KOREAN POWER SYSTEM

	Base Case	PE_50_1	PE_50_2	PE_50_3
GenCos				
Total revenue, Billion Won	1,899	1,861	1,852	1,826
Fuel cost, billion Won	799	756	751	730
Startup costs, billion Won	6.1	5.8	5.6	5.3
O&M, billion Won	368	368	368	368
Operating profit, billion Won	786	731	727	722
Profit increase, %	n/a	-1.9	-2.5	-3.2
TransCo				
Line use revenue, Billion Won	173	171	171	169
Congestion revenue, billion Won	3.7	3.0	2.1	1.6
Congestion rev. inc., %	n/a	-18.5	-42.8	-55.4

price elasticities in the range of −0.1 to −0.3, GenCos' profits were reduced by 1.9% to 3.2%, and the TransCo's congestion revenues were reduced by 18% to 55%.

To understand the impact of the reference price, simulations were run with a higher reference price of 55 kWon/MWh. As shown in Fig. 10, the zonal prices exceeded the reference price nearly 56% of the time.

It can be expected that the amount of load increase and decrease would be almost equal in these simulations. The results from the simulations are presented in Tables XVII and XVIII(a) and (b). The total system load is almost identical to the base load with a minor change—in the range of −0.04% to 0.19%. The small change in load is because the reference price is now closer to the average price in the base case.

Also, there is a slight increase in GenCos' profits, because even though they are generating less energy compared with the base case, the startup costs decreased; whereas there is a significant reduction in the congestion charges.

TABLE XVII
IMPACT OF CONSUMER PRICE ELASTICITY AND REFERENCE PRICE

	Base Case	PE_55_1	PE_55_2	PE_55_3
Consumers				
Total load served, GWh	34,660	34,673	34,736	34,592
Total energy cost, billion Won	1,902	1,902	1,906	1,899
Avg. energy price, kWon/MWh	54.9	54.8	54.9	54.9
GenCos				
Total revenue, Billion Won	1,899	1,900	1,905	1,898
Fuel cost, billion Won	799	779	783	773
Startup costs, billion Won	6.1	6.0	5.2	5.3
O&M, MM$	368	368	368	368
Operating profit, billion Won	786	747	749	751
Profit increase, %	n/a	0.1	0.4	0.7
TransCo				
Line use revenue, billion Won	173	173	174	173
Congestion revenue, billion Won	3.7	2.1	1.5	1.1
Congestion rev. inc., %	n/a	-42.0	-60.2	-69.7

TABLE XVIII
(A) CONSUMERS' LOAD SERVED WITH HIGHER CONSUMER REFERENCE PRICE (GWH), (B) CONSUMERS' TOTAL COSTS WITH HIGHER CONSUMER REFERENCE PRICE (BILLION WON)

a

Scenario / Zone	Base Case	PE_55_1	PE_55_2	PE_55_3
1_SEOUL	4,078	4,075	4,079	4,066
2_NSEUL	1,956	1,957	1,957	1,948
3_SUWON	9,039	9,038	9,051	9,017
4_JECHN	3,766	3,770	3,774	3,759
5_DAEJN	2,664	2,664	2,671	2,658
6_KWGJU	4,612	4,614	4,626	4,604
7_DAEGU	3,274	3,278	3,285	3,271
8_BUSAN	3,283	3,286	3,295	3,281
9_CHNWN	1,989	1,991	1,997	1,988
Total	34,660	34,673	34,736	34,592

b

Scenario / Zone	Base Case	PE_55_1	PE_55_2	PE_55_3
1_SEOUL	225	224	224	223
2_NSEUL	108	108	108	107
3_SUWON	496	495	496	494
4_JECHN	207	207	207	207
5_DAEJN	146	146	147	146
6_KWGJU	254	254	254	253
7_DAEGU	179	179	180	179
8_BUSAN	179	179	180	180
9_CHNWN	109	109	110	109
Total	1,902	1,902	1,906	1,899

V. CONCLUSION

This paper describes a study in which an agent-based model was used to demonstrate and quantify the economic impact of price elasticity of demand in electricity markets when consumers are well equipped with smart grid technologies to increase their awareness of responsiveness of demand. While the impact depends on the price level at which consumers exhibit price responsiveness, price-elastic consumers could benefit by a reduction in energy usages and prices. In addition, they could significantly reduce congestion charges and, potentially, reduce the market power of GenCos. While some consumers may face a higher cost because of their location in the network, most benefit by exhibiting price elasticity of demand. We will investigate these results more specifically in the next phase of the study.

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