Journal of Zhejiang University-SCIENCE C (Computers & Electronics)
ISSN 1869-1951 (Print); ISSN 1869-196X (Online)
www.zju.edu.cn/jzus; www.springerlink.com
E-mail: jzus@zju.edu.cn

Modeling the effects of demand response on generation expansion planning in restructured power systems

Mahdi SAMADI[†1], Mohammad Hossein JAVIDI[1], Mohammad Sadegh GHAZIZADEH[1,2]
([1]Department of Electrical Engineering, Ferdowsi University of Mashhad, Mashhad, Iran)
([2]Department of Electrical Engineering, Power and Water University of Technology, Tehran, Iran)
[†]E-mail: mahdi.samadi@stu-mail.um.ac.ir

Received Jan. 8, 2013; Revision accepted June 28, 2013; Crosschecked Nov. 18, 2013

Abstract: Demand response is becoming a promising field of study in operation and planning of restructured power systems. More attention has recently been paid to demand response programs. Customers can contribute to the operation of power systems by deployment demand response. The growth of customers' participation in such programs may affect the planning of power systems. Therefore, it seems necessary to consider the effects of demand response in planning approaches. In this paper, the impact of demand responsiveness on decision making in generation expansion planning is modeled. Avoidance or deferment in installation of new generating units is comprehensively investigated and evaluated by introducing a new simple index. The effects of demand responsiveness are studied from the points of view of both customers and generation companies. The proposed model has been applied to a modified IEEE 30-bus system and the results of the study are discussed. Simulation results show that reducing just 3% of the customers' demand (due to price elasticity) may result in a benefit of about 10% for customers in the long term.

Key words: Demand response, Generation expansion planning, Responsive demand
doi:10.1631/jzus.C1300008 **Document code:** A **CLC number:** TM715

1 Introduction

Volatility in fuel prices and environmental concerns have resulted in more attention being paid to research focusing on demand response (DR) (Kowli and Gross, 2009; Aalami *et al.*, 2010a). The Federal Energy Regulatory Commission (FERC) defines DR as "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" (Wight, 2009). Reduction of electricity price and its volatility, increase in the performance of the power market, improvement of reliability and security, and also reduction or deferment in new capacity requirements, may be considered as the main results obtained through DR implementation (Aalami *et al.*, 2010b).

By deployment of DR, customers can contribute to the operation and therefore influence the planning of power systems. With the growth of customer participation, planning models need to be modified (Widergren, 2009).

Generation expansion planning (GEP) is one of the main modules in power system planning. In GEP, planners try to determine which generating units should be added to the system, and when they should be installed over the planning horizon (Murugan *et al.*, 2009). Expanding DR programs unavoidably affects expansion plans. Therefore, modifying GEP models seems necessary. Evaluation of the impacts of DR on investment decisions in GEP is considered important for regulators and policy makers (Widergren, 2009).

While in many studies DR has been addressed in the short term (Tanaka, 2006; Su and Kirschen, 2009; Aalami *et al.*, 2010a; 2010b), the influences of

DR on power system planning in the long term were rarely investigated. Kowli and Gross (2009) have proposed a framework for evaluation of resource investment options such as conventional generation resources and demand response resources (DRRs). They believed that this framework is useful for analyzing resource investment options on both the supply side and the demand side. Kazerooni and Mutale (2010) incorporated a price-based DR program into the transmission expansion planning problem. Deferment of the need for more transmission capacity is the main result of their work.

Choi and Thomas (2012) developed an optimization model to determine the lowest cost investment and operation plan for the generating capacity incorporating DR, and investigated the demand moderating effects as well as the generation mix changing effects of different policy designs.

Black (2005) analyzed the technical, regulatory, and market issues to determine a system structure that provides incentives for some DR programs. The presented simulations show the potential benefits of policies, which provide incentives for adopting load control technologies.

An important aim of DR may be to reduce the necessity of installing new generating units (Aalami *et al*., 2010b; Greening, 2010), which may avoid or defer the need for installing and upgrading the transmission and distribution facilities (Albadi and El-Saadany, 2008).

However, in none of the abovementioned work, reductions in the need for installing new generating units have been studied quantitatively. In this paper we intend to model and analyze the effects of DR on generation resource planning for restructured power systems. Avoidance or deferment of the need for new generating units is comprehensively investigated and a new index for quantifying and comparing the deferment is proposed. Also, we study the changes in total investment costs, total capacity payment, and total customer payment, due to responsiveness of elastic demand and customer participation. The change in elastic demands due to the change in price is considered as the DR.

Expansion planning in a restructured environment is almost decentralized. While generation companies (Gencos) decide on investments for new generating units based on their profits, the objective of the regulatory body or independent system operator is to have the system operate in a reliable and secure manner and supply the load economically (Shahidehpour *et al*., 2002). Therefore, a rational coordination between these objectives is necessary in decentralized GEP.

The basic framework of our proposed model for GEP is based on the model proposed by Roh *et al*. (2007). In this framework, competition among Gencos and coordination between the independent system operator and Gencos are modeled simultaneously. Transmission constraints are considered and Gencos will decide on investments based on locational marginal prices (LMPs) and capacity payment signals. Unlike Roh *et al*. (2007), in which demand was assumed to be inelastic, in our study elastic demand is investigated. The capacity payment mechanism is assumed to be necessary as an incentive for investment in new generating units. Some experts believe that the lack of capacity payment mechanisms may lead to jeopardizing system security or rising prices.

One of the important drivers for GEP is load demand (Wang and McDonald, 1994). As shown in Fig. 1, if demand elasticity is noticeable, the price affects the demand. Furthermore, changes in future demand will affect the installations of new generating units. On the other hand, newly installed units affect LMPs in the future. This means that a closed loop between GEP and the price (LMPs) exists.

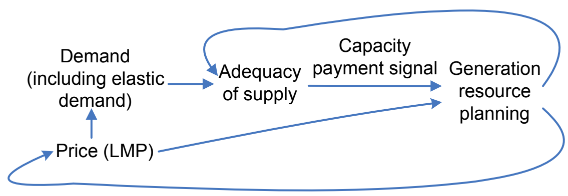

Fig. 1 A simple causal diagram for generation expansion planning considering elastic demand

Therefore, it seems essential to have a framework to analyze decisions for investments in new units, and for systems including responsive demands. The framework should be able to properly consider the causal relationships among demand, price, and expansion plans. In this paper, this concept is appropriately modeled.

2 Model description

The objective of the independent system operator is to minimize its own cost for administering the load such that security constraints of the system are not violated. To perform this optimization, the independent system operator uses the information about bids by Gencos, forecasted demand and network conditions and other available information. Then, the independent system operator will run optimal power flow (OPF) equations to provide price signals to the Gencos. Note that all of this information may not be available to the Gencos.

In this section, the framework of the proposed model for GEP is described in detail. Within this framework, each Genco submits its proposed plan for expansion to the coordinator, which could be the independent system operator. Then the independent system operator aggregates the plans and checks the essential constraints of the system by running OPF equations. If the constraints are satisfied, the plan with minimum payment to the Gencos is selected as the optimal plan. The independent system operator evaluates the optimal plan and then determines the capacity payment and LMP signals for the proposed plans and declares them to the Gencos, who revise their plans based on these signals and send revised plans to the independent system operator. This iterative and dynamic process continues until two consecutive plans are the same. The initial plans are provided based on the estimated prices. The initial value for capacity payment in the first iteration of this method is assumed to be zero. In the proposed model, part of the demand is considered price responsive. This, in turn, affects the LMPs and then the plans. The procedure of the proposed model (Fig. 2) is described in detail as follows:

Step 1: Gencos prepare their plans for expansion independent of each other and only based on signals they have received from LMPs and the capacity payment (CP), and declare the plans to the independent system operator (initial values are taken as CP=0, LMPs=estimated LMPs).

Step 2: The independent system operator aggregates the plans submitted by the Gencos and runs an OPF. If essential constraints are satisfied and there is no load curtailment, go to step 4; otherwise, go to step 3.

Step 3: The amount of load curtailment is evaluated and the locational capacity payment for new candidate units is determined based on the load curtailment for each year. Then, go to step 1. If the constraints are not satisfied in an iteration, the value of CP increases in the next iteration.

Step 4: The plan with minimum payment to the Gencos is selected as the optimal plan. When two consecutive iterations result in the same plan, the algorithm stops; otherwise, go to step 5.

Step 5: The OPF for the obtained plan is run and the LMPs are declared to the Gencos.

Step 6: The final CP is set to be proportional to the amount of capacity of new units (accepted plan) and their LMPs. If the determined CP is not sufficient, its value will be increased. Then, go to step 1.

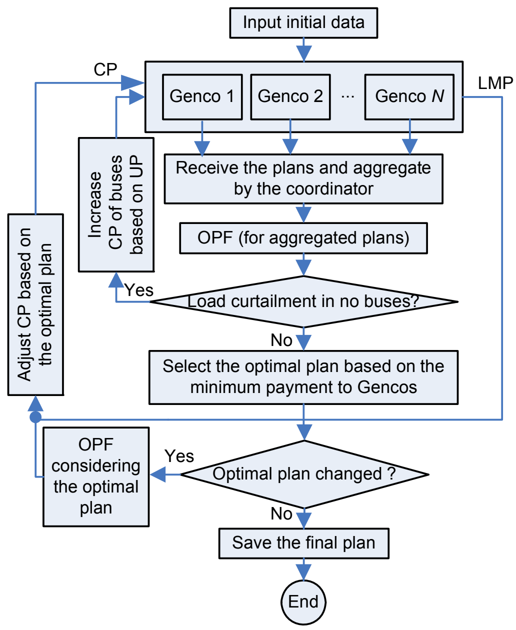

Fig. 2 The procedure of the proposed model

Adding a new unit at a bus reduces the LMP of that bus and hence, the Genco's revenue at that bus is reduced. Therefore, devoting CP to compensate for the reduction in the revenue of the Genco is essential. When such an incentive is not devoted to the Genco, the Genco may refuse to invest. Therefore, in the proposed model, CP is considered based on load curtailment before satisfying essential constraints. The amount of CP is determined only based on the capacity of new units and their LMPs, after recognizing the optimal plan. While signals are sent to the Gencos for their investment decisions, the capacity payment mechanism is considered as a mechanism for controlling the prices by regulators to maintain prices at acceptable levels in electricity markets.

The main characteristics of the proposed model are as follows:

1. The transmission network and its constraints are considered.

2. LMPs are obtained from running the OPF.

3. CP is paid to the Gencos, who then make decisions about investment based on the LMPs and CP.

4. A percentage of the demand is price responsive.

In this work the planning process is performed considering generation adequacy constraints as in Roh *et al*. (2007).

3 Mathematic formulation

3.1 Modeling of the price responsive demands

Initially, behavior of the price responsive demands is identified and then the problem is explained from the viewpoint of the independent system operator. The notations that will be used throughout the paper are given in Table 1.

As mentioned in Section 2, a portion of the demand is assumed to be elastic and responsive to the price. The total served demand is equal to the summation of both elastic and inelastic demands:

$$D_{jt} = \mathrm{De}_{jt} + \mathrm{Du}_{jt} \quad \forall j,t, \tag{1}$$

$$\mathrm{De}_{jt}^{\mathrm{Max}} = \gamma_{jt} D_{jt}^{\mathrm{Max}} \quad \forall j,t, \tag{2}$$

$$\mathrm{Du}_{jt} = (1-\gamma_{jt}) D_{jt}^{\mathrm{Max}} \quad \forall j,t. \tag{3}$$

Fig. 3 shows the elastic and inelastic demands. The price and the elastic demand are inversely proportional.

Then, assuming linear functionality, the relationship between elastic demand and price can be written as (m_{jt}>0)

$$\begin{aligned} &\mathrm{De}_{jt} - \mathrm{De}_{jt}^{\mathrm{Max}} = -m_{jt}(P_{jt} - P_0) \\ \Rightarrow\ &P_{jt} = -\mathrm{De}_{jt} / m_{jt} + P_0 + \mathrm{De}_{jt}^{\mathrm{Max}} / m_{jt} \quad \forall j,t. \end{aligned} \tag{4}$$

Table 1 Notations used in this paper

Symbol	Meaning	Symbol	Meaning
d	Discount rate	I_{it}	Capital investment cost of unit i in year t ($/year)
i	Index of unit	LMP_{it}	Locational marginal price for unit i in year t ($/(MW·h))
i'	Index of newly installed units	m_j	Responsiveness factor of the demand at bus j
j	Index of bus	MC_{it}	Marginal cost of unit i in year t ($/(MW·h))
k	Index of Genco	Obj_k	The objective function of Genco k
l	Index of line	P_{jt}	Willingness to pay for the elastic demand j in year t
t	Index of year	P_0	Initial price ($/(MW·h))
Nc_k	Number of candidate units of Genco k	PG_{it}	Dispatched capacity of unit i in year t (MW)
Ne_k	Number of existing units of Genco k	$\mathrm{PG}_i^{\mathrm{Max}}$	Capacity of unit i (MW)
Ni_k	Total number of units of Genco k	PL_{lt}	Power flow through line l in year t (MW)
NI	Total number of units	$\mathrm{PL}_l^{\mathrm{Max}}$	Capacity of line l (MW)
NJ	Total number of buses	UP_t	Unserved power in year t (MW)
NK	Total number of Gencos	VOLL_t	Value of lost load in year t ($/(MW·h))
T	Total duration of planning horizon	x_{mn}	Reactance of line mn
TCP	Total capacity payment ($)	X_{it}	Status of candidate unit i (1 if installed, otherwise 0)
TIC	Total investment cost ($)	α_i	Bidding coefficient
TPC	Total payment of customers ($)	γ_{jt}	Percentage of elastic demand with respect to the total demand of bus j in year t
TPG	Total payment to Gencos ($)		
Bid_{it}	Energy bid price by unit i in year t ($/(MW·h))	θ	Bus angle
C_{it}	Operating costs of unit i in year t ($/h)	*	Symbol for given variables
CP_{it}	Capacity payment for unit i in year t ($/h)	Λ	Set of newly installed units
D_{jt}	Total served demand at bus j in year t (MW)	$\boldsymbol{A}$	Bus-unit incidence matrix
D_{jt}^{Max}	Forecasted peak load at bus j in year t (MW)	$\boldsymbol{B}$	Bus-load incidence matrix
De_{jt}	Elastic demand at bus j in year t (MW)	$\boldsymbol{K}$	Bus-branch incidence matrix
$\mathrm{De}_{jt}^{\mathrm{Max}}$	Maximum elastic demand at bus j in year t (MW)	**PG**	Real power output vector
Du_{jt}	Inelastic demand at bus j in year t (MW)	**PD**	Load vector
DDI	Decrement and deferment index	**PL**	Real power flow vector

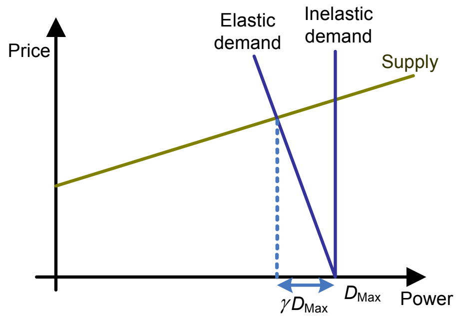

Fig. 3 Elastic and inelastic demands

A higher value of m_{jt} is corresponding to a greater response of elastic demand. Defining

$$a_{jt} \equiv 1/m_{jt},\ \ b_{jt} \equiv P_0 + \mathrm{De}_{jt}^{\mathrm{Max}}/m_{jt}, \tag{5}$$

then we have

$$P_{jt} = -a_{jt} \cdot \mathrm{De}_{jt} + b_{jt} \quad \forall j,t. \tag{6}$$

3.2 Optimal power flow problem considering price responsive demands

When the plans of the Gencos are determined, the independent system operator gathers the plans and performs an OPF for each year of the planning horizon. During this step, newly proposed candidate units are evaluated. It is assumed that each Genco submits a bid in a linear supply function form as shown in Eq. (7), to the independent system operator. It is supposed that the bid of each generating unit is the multiple of the bidding coefficient and the marginal cost. The marginal cost is given by the first derivative of the generation cost function, which is expressed in the form of a quadratic function as Eq. (8).

$$\mathrm{Bid}_{it} = \alpha_i \cdot \mathrm{MC}_{it} = \alpha_i (a_{it} \cdot \mathrm{PG}_{it} + b_{it}) \quad \forall i, \tag{7}$$

$$C_{it} = \frac{1}{2} a_{it} (\mathrm{PG}_{it})^2 + b_{it} \cdot \mathrm{PG}_{it} \quad \forall i,t. \tag{8}$$

The objective of the independent system operator is to maximize social welfare, which is given by the consumer benefit minus the bid based generation cost. Then, the optimization problem for the independent system operator can be formulated as follows (Wang *et al*., 2004):

$$\max \left(\sum_{j=1}^{\mathrm{NJ}} \left(-\frac{1}{2} a_{jt} \mathrm{De}_{jt}^2 + b_{jt} \mathrm{De}_{jt} \right) - \sum_{i=1}^{\mathrm{NI}} \alpha_i \left(\frac{1}{2} a_{it} \mathrm{PG}_{it}^2 + b_{it} \mathrm{PG}_{it} \right) \right),\ t = 1,2,\ldots,T \tag{9}$$

subject to

$$\boldsymbol{K} \cdot \mathbf{PL} = \boldsymbol{A} \cdot \mathbf{PG} - \boldsymbol{B} \cdot \mathbf{PD}/\mathrm{LMP}, \tag{10}$$

$$\mathrm{PL}_{lt} = \frac{\theta_{mt} - \theta_{nt}}{x_{mn}} \quad \forall l, \tag{11}$$

$$\theta_{\mathrm{ref}} = 0, \tag{12}$$

$$0 \le \mathrm{PG}_{it} \le \mathrm{PG}_{it}^{\mathrm{Max}} \quad \forall i, \tag{13}$$

$$0 \le \mathrm{De}_{jt} \le \mathrm{De}_{jt}^{\mathrm{Max}} \quad \forall j, \tag{14}$$

$$|\mathrm{PL}_{lt}| \le \mathrm{PL}_l^{\mathrm{Max}} \quad \forall l. \tag{15}$$

The constraints (10) and (11) stand for DC power flow equations. According to the LMP definition, the Lagrangian multiplier of the constraints in Eq. (10) is the LMP. In this optimization, the LMPs are determined regarding the bids received from the supply side and the willingness to pay for the elastic demand. The constraints (13) and (14) represent the limits for generation and the elastic demand, respectively. The inequality (15) represents the limits of line flows for the network.

When this problem is solved, the dispatched power for all units (existing and newly proposed candidates), the value of the elastic demand that will be served at each bus, the LMPs at all buses, and the power flows of the lines are specified. In addition, when there exists any load curtailment in the system, its quantity at any bus of the system and in any year of the time horizon will be specified. This information will be used for determining the capacity payment signal.

3.3 Genco's planning problem

It is assumed that each Genco owns some existing units and will plan for investment on some new candidate units. Then, the overall formulation of the long term discounted generation investment problem for an arbitrary Genco$_k$ can be written as

$$\max \mathrm{Obj}_k = \sum_{i}^{\mathrm{Ni}_k} \sum_{t=1}^{T} \frac{8760\mathrm{LMP}_{it} \cdot \mathrm{PG}_{it}}{(1+d)^{t-1}} - \sum_{i=1}^{\mathrm{Nc}_k} \sum_{t=1}^{T} \frac{8760 C_{it}}{(1+d)^{t-1}} + \sum_{i=1}^{\mathrm{Nc}_k} \sum_{t=1}^{T} \frac{8760\mathrm{CP}_{it}}{(1+d)^{t-1}} - \sum_{i=1}^{\mathrm{Nc}_k} \sum_{t=1}^{T} \frac{I_{it} X_{it}}{(1+d)^{t-1}},\ \ k = 1,2,\ldots,\mathrm{NK} \tag{16}$$

subject to

$$0 \le \mathrm{PG}_{it} \le \mathrm{PG}_{it}^{\mathrm{Max}} \quad \forall t, i=1,2,\ldots,\mathrm{Ne}_k, \tag{17}$$

$$0 \le \mathrm{PG}_{it} \le \mathrm{PG}_{it}^{\mathrm{Max}} X_{it} \quad \forall t, i=1,2,\ldots,\mathrm{Nc}_k. \tag{18}$$

In fact, using the discount rate, the net present values for different times can be determined. In this study, for simplicity, the discount rate is assumed to be the same for all Gencos. In this formulation, the first term of the objective function (16) refers to the revenue earned from energy sales, the second term expresses the operating costs, the third item represents the revenue obtained from CP, and the last term stands for the investment cost of new generating units. Other planning constraints such as the restriction in the number or site or type of generating units could also be considered. This formulation forms a constrained, mixed integer, nonlinear optimization problem. The number of distinct problems equals the number of Gencos. Since every Genco maximizes its own profit independently, the decentralized nature of the planning in the competitive market will be preserved.

3.4 Criterion for selecting the optimal plan

As expressed in Section 2, the independent system operator selects the optimal plan based on the minimum total payment to the Gencos. The value of the total payment to the Gencos is then obtained:

$$\mathrm{TPG} = 8760\left(\sum_{i=1}^{\mathrm{NI}}\sum_{t=1}^{T}\frac{\mathrm{LMP}_{it}^{*}\cdot\mathrm{PG}_{it}^{*}}{(1+d)^{t-1}} + \sum_{i'\in A}\sum_{t=1}^{T}\frac{\mathrm{CP}_{i't}^{*}X_{i't}^{*}}{(1+d)^{t-1}}\right). \tag{19}$$

4 Numerical example and analysis

The proposed GEP model has been applied to a modified IEEE 30-bus system. This system is assumed to include a total of 29 existing and candidate generating units owned by five Gencos. The whole network includes 44 lines. The capacity of each line is assumed to be 250 MW. Detailed data of demands and generating units is given in the Appendix. The planning horizon is considered to be 10 years. Although many GEP models use different sub-periods for forecasted load (e.g., Roh *et al.* (2007)), to avoid unnecessary complexity, the planning is performed based on the peak load of each year (Kannan *et al.*, 2005; Kannan and Murugan, 2008; Murugan *et al.*, 2009). The discount rate is assumed to be 5%. For simplicity, the values of m_{jt}'s are assumed to be equal for all j's. Also, the value of γ is assumed to be the same at all buses. The value of m_t over the planning horizon is considered to be constant, similar to Choi and Thomas (2012) in which the elasticity was assumed to be a constant value for the long term. Hereafter the values of these two parameters are represented by m and γ, respectively.

The proposed method for GEP is essentially an optimization problem composed of several constrained, mixed integer, nonlinear optimization sub-problems and one constrained nonlinear optimization sub-problem. A designed interface between GAMS and MATLAB is used to solve the problem.

4.1 Simulation results for γ=0.15 and m=1

As an example, the results achieved from performing the proposed model for γ=0.15 and m=1 are presented. Table 2 shows new units and the installation year of units of the finalized plan.

Fig. 4 shows the average value of LMPs at each year over the planning horizon.

Table 2 The proposed plan for γ=0.15 and m=1

Installation years	New unit
4	U17 (300 MW)
5	U8 (300 MW)

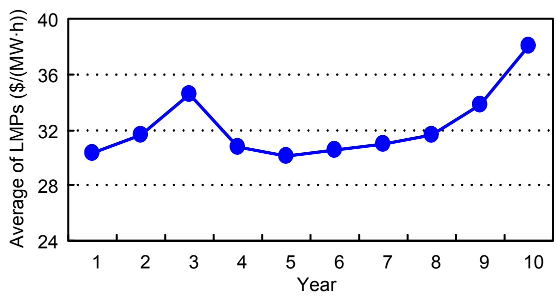

Fig. 4 Average of LMPs over the planning horizon

As can been seen, prices have an ascending trend in the first three years of the planning horizon. This is due to the fact that the demand is increasing yearly. However, no new unit has been installed in those years. On the other hand, due to installation of new units in the fourth and fifth years, prices experience a descending trend. The sixth year, however, sees an ascending trend. As expressed in Section 2, installation of a new unit leads to decrease in the value of LMP. Table 3 shows the amount of capacity payment allocated for newly installed units. This will be paid only to new units after their installation until the end of the planning horizon.

Table 3 Capacity payment for new units

Year	Payment ($\times10^6$ \$)		Year	Payment ($\times10^6$ \$)	
	U17	U8		U17	U8
1	0	0	6	45.6	44.5
2	0	0	7	45.6	44.5
3	0	0	8	45.6	44.5
4	45.6	0	9	45.6	44.5
5	45.6	44.5	10	45.6	44.5

4.2 Investigating the effect of demand responsiveness

To investigate the effects of responsiveness of the elastic demand on GEP, the algorithm has been run for eight different values of the responsiveness factor. The results indicate that for m=0.001 almost the maximum demand is served ($\sum_t\sum_j \mathrm{De}_{jt} \cong \sum_t\sum_j \mathrm{De}_{jt}^{\mathrm{Max}}$). This means that for this value, the load is almost inelastic. The upper bound of the responsiveness parameter m is set to three. The selected values are scaled on a semi-logarithmic axis. Table 4 shows different values of m for simulations.

Table 4 Values of parameter *m* in next simulations

m	0.001	0.003	0.01	0.03	0.1	0.3	1	3
$\lg m$	−3	−2.5	−2	−1.5	−1	−0.5	0	0.5

Table 5 shows the simulation results for different m values. Increasing demand responsiveness results in postponing the necessity for installing new units and/or decrement in the capacity that should be installed.

To quantify the deferment and decrement, a new simple index called DDI is proposed:

$$\mathrm{DDI} = \sum_{i'\in A} \frac{\mathrm{PG}_{i'}^{\mathrm{Max}}}{\mathrm{year}_{i'}}, \tag{20}$$

where $\mathrm{year}_{i'}$ stands for the installation year of new unit i'. As an example for the case in Table 2, the proposed index is calculated as DDI=300/4+300/5=135. Table 6 depicts the values of the proposed index calculated for plans in Table 5.

Table 5 New units and their installation year

Year	New unit(s)							
	m=0.001	0.003	0.01	0.03	0.1	0.3	1	3
1								
2	U9	U12	U9	U12	U17			
3	U8, U17	U8, U17	U8, U17	U17	U8	U8, U17		
4		U4		U8			U17	U12
5	U7						U8	U8
6			U4	U4				
7	U4							
8								
9					U4			
10								

Table 6 The values of the proposed index DDI

m	0.001	0.003	0.01	0.03	0.1	0.3	1	3
DDI	432	425	400	375	283	200	135	135

As expected, more responsiveness of the demand results in reduction of the DDI index. A lower value of this parameter indicates that less capacity needs to be installed or that the installation can be postponed.

To investigate the economical aspects of the results, we may calculate the total investment cost (TIC), as follows:

$$\mathrm{TIC} = \sum_{i'\in A}\sum_{t=1}^{T} \frac{I_{i't}}{(1+d)^{t-1}}. \tag{21}$$

In addition, the total served demand during the planning horizon (which is obtained from summation for all buses and during all years, i.e., $\sum_t\sum_j D_{jt}$) is computed. Fig. 5 shows the normalized TIC and the normalized total served demand over the planning horizon.

The base values of TIC and the total served demand are 1.74×10^9 \$ and 26025 MW, respectively. Fig. 5 shows that TIC decreases intensely when responsiveness of the demand increases. For example, when m increases from 0.001 to 0.1, TIC reduces to almost 55% of its initial value.

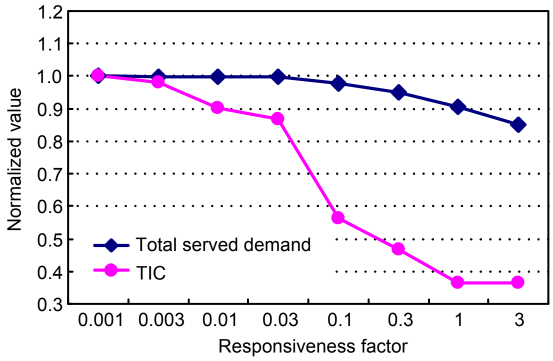

Fig. 5 Normalized TIC and total served demand (γ=0.15)

4.3 Investigating the effect of customers' participation level

The percentage of the price responsive demand with respect to the total demand could be interpreted as the customer participation level in DR. This parameter can significantly affect decisions in GEP. To investigate this issue, three different values for γ are examined. All these cases are analyzed by running simulations with four different values of m. After specifying the new units and their installation years for all cases, the DDI index of the achieved plans is calculated. Fig. 6 presents the results.

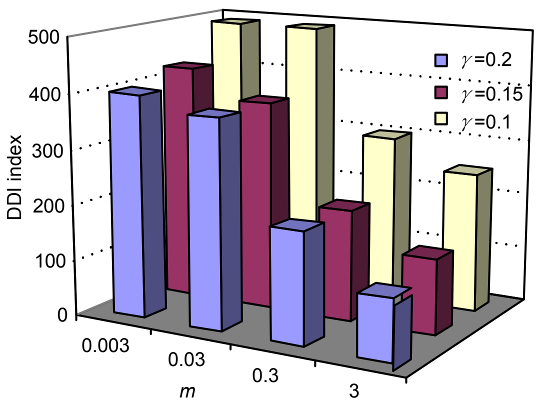

Fig. 6 DDI values under different m and γ

Fig. 6 shows that increasing the customer participation results in a reduction of the proposed index. It can be concluded that higher levels of customer participation and higher sensitivity to the price result in smaller values of the DDI index. This means that less capacity is required to be installed when customers respond to prices. This is a quite reasonable conclusion.

TIC values for these 12 cases are calculated (Table 7). The trend of reduction is sharper for $m \geq 0.3$.

Table 7 Total investment cost

γ	Investment cost ($\times 10^6$ \$)			
	m=0.003	0.03	0.3	3
0.10	2030	2030	1220	1100
0.15	1700	1510	813	636
0.20	1570	1510	813	524

4.4 Analysis of customers' cost

Any expenditure from the supply side will be imposed indirectly on customers. In this subsection, we will show that increase in m leads to significant reduction of total capacity payment (TCP) and total payment by customers (TPC). TCP and TPC are calculated as follows:

$$\mathrm{TCP} = 8760 \sum_{i' \in A} \sum_{t=1}^{T} \frac{\mathrm{CP}_{i't}^* X_{i't}^*}{(1+d)^{t-1}}, \tag{22}$$

$$\mathrm{TPC} = 8760 \left(\sum_{j=1}^{\mathrm{NJ}} \sum_{t=1}^{T} \frac{\mathrm{LMP}_{jt}^* D_{jt}^*}{(1+d)^{t-1}} + \sum_{i' \in A} \sum_{t=1}^{T} \frac{\mathrm{CP}_{i't}^* X_{i't}^*}{(1+d)^{t-1}} \right). \tag{23}$$

As shown in Eq. (23), TPC equals the summation of total payment for energy costs and total payment for capacity. TCP and TPC are calculated for minimum participation of customers (γ=0.1) and different values of m. Also, the total served demand for the planning horizon is computed. The values of TCP, TPC, and the total demand are calculated and normalized with respect to their maximum values (Fig. 7). The maximum values of TCP, TPC, and the total demand are 1.95×10^9 \$, 7.41×10^9 \$, and 26 025 MW·h, respectively.

Fig. 7 shows that increasing the responsiveness factor from 0.03 to 0.3 corresponds to a 3% reduction in the total demand and an almost 47% reduction in TCP. However, TPC experiences only a 10% decrease. This is a remarkable conclusion, implying that the responsiveness of customers efficiently reduces their cost, even when the minimum participation occurs. In other words, if the customers reduce their demand by only 3%, their cost will be reduced by 10%. The reduction in customers' cost may reach 22% for m=3.

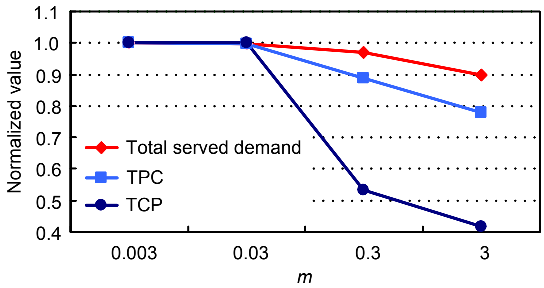

Fig. 7 Normalized TCP, TPC, and total demand under different *m*

4.5 Analysis of Gencos' profits

For Gencos, profit is the most important objective that should be maximized. On the other hand, it is expected that the more the elastic demand, the more the reduction that will occur in the profits of generating companies (Su and Kirschen, 2009). Figs. 8 and 9 depict the profit of individual Gencos and the total profit of all Gencos, respectively.

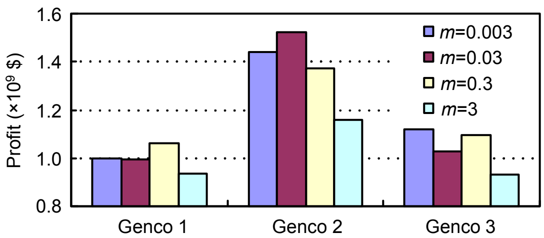

Fig. 8 Profit of individual Gencos

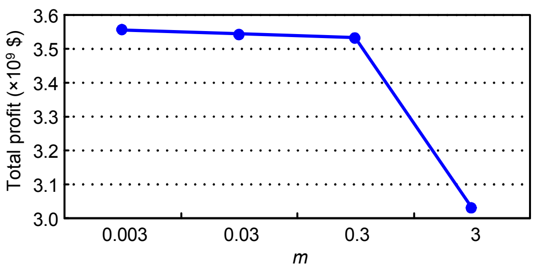

Fig. 9 Total profit of all the Gencos

The profit of Genco$_k$ is calculated as

$$\text{Profit}_k = \text{total\_payment\_to\_Genco}_k + \text{generation\_cost}_k - \text{investment\_cost}_k. \quad (24)$$

Note that the terms in Eq. (24) are net present values (i.e., the discount rate is considered). In these simulations, Genco 4 and Genco 5 have not committed in supplying the demands. While the profit of the individual Genco may vary (go up or down), with the increase of the responsiveness factor, the total profit of all Gencos decreases. This is due to the decrement and deferment in need for investment in new generating units.

5 Conclusions

Demand response is becoming a promising field of study in operation and planning of restructured power systems. Customers can contribute to the operation of power systems by deployment demand response. In this paper, a model is proposed to analyze the demand response effects on decentralized generation resource planning. Demand responsiveness impacts on reduction in need for installing new generating units are comprehensively investigated. Also, a new simple index has been introduced by which deferment and/or decrement of the expansion can be numerically identified. The proposed model has been applied to a modified IEEE 30-bus system. In the simulations, various values of the responsiveness factor and customer participation level have been tested in a case study, and changes in the total investment cost, total capacity payment, and total customer payment have been investigated.

The results confirm that the demand responsiveness results in postponing the necessity for installing new units and/or decrement in the capacity that should be installed. It was also shown that reducing just 3% of the customers' demand (due to price elasticity) may result in a good benefit of more than 10% for customers in the long term. Using the proposed model, the regulatory body can investigate the economic effects of demand response on Gencos' investment decisions, and on the total cost imposed on the customers.

However, comprehensive investigation of all impacts of demand response on investment planning needs more research. The effect of demand response on generation expansion planning, from a reliability point of view, will be investigated in our next work.

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Appendix: Data of demands and generating units

Table A1 lists the load distribution of the system, and Table A2 lists the forecasted load for 10 years of the planning horizon. Characteristics of generating units are gathered in Table A3.

Table A1 Load distribution

Bus	Load	Bus	Load
1	0	16	0.04
2	0.07	17	0.02
3	0.06	18	0.06
4	0.07	19	0.05
5	0.05	20	0.04
6	0	21	0.04
7	0.06	22	0
8	0.06	23	0.04
9	0	24	0.03
10	0.05	25	0
11	0	26	0.07
12	0.06	27	0
13	0	28	0
14	0.04	29	0.02
15	0.04	30	0.03

Table A2 Forecasted load

Year	Peak load (MW)
1	1950
2	2130
3	2250
4	2400
5	2550
6	2680
7	2815
8	2950
9	3100
10	3200

Table A3 Characteristics of generating units

Genco	Unit	Status	Capacity (MW)	Bus	Generation cost		Investment cost ($\times 10^6$ \$/year)
					a (\$/(MW^2·h))	b (\$/(MW·h))	
1	U1	1	400	1	0.02	18.67	0
	U2	1	200	2	0.02	24.26	0
	U3	1	350	5	0.02	19.35	0
	U4	0	300	4	0.02	20.69	80
2	U5	1	400	8	0.02	18.43	0
	U6	1	300	11	0.02	20.23	0
	U7	0	200	12	0.02	20.69	53.2
	U8	0	300	16	0.02	19.66	66
	U9	0	300	17	0.02	19.66	66
	U10	0	200	20	0.02	22.16	60
	U11	0	200	20	0.02	22.16	66
	U12	0	300	20	0.02	19.66	66
3	U13	1	400	13	0.02	18.16	0
	U14	1	300	19	0.02	20.38	0
	U15	0	200	18	0.02	22.16	72
	U16	0	200	18	0.02	22.16	60
	U17	0	300	18	0.02	19.66	66
4	U18	0	100	23	0.02	26.88	32
	U19	0	100	23	0.02	26.88	32
	U20	0	200	23	0.02	24.16	60
	U21	0	100	24	0.02	26.88	35.2
	U22	0	100	24	0.02	26.88	35.2
	U23	0	200	24	0.02	24.16	60
	U24	0	100	25	0.02	26.88	38.4
	U25	0	100	25	0.02	26.88	38.4
	U26	0	200	25	0.02	24.16	60
5	U27	0	100	27	0.02	26.88	32
	U28	0	100	27	0.02	26.88	32
	U29	0	200	27	0.02	22.16	60