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Distributed Generation Expansion Planning Considering Load Growth Uncertainty: A Novel Multi-period Stochastic Model

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ABSTRACT

Distributed generation (DG) technology is known as an efficient solution for applying in distribution system planning (DSP) problems. Load growth uncertainty associated with distribution network is a significant source of uncertainty which highly affects optimal operation of DGs. In order to handle this problem, a novel model is proposed in this paper based on DG solution, considering load uncertainty. The proposed model is designed to minimize network costs including operation and losses. Genetic algorithm (GA) is used with the purpose of finding the optimal places, sizes as well as times for DGs. Load uncertainty is also modeled through Markov tree. To illustrate the effectiveness of the proposed model, it is tested in different scenarios considering the effects of the purchased electricity price, DG penetration factor (PF) and DG operation intervals. These scenarios are conducted in two different phases, with and without uncertainty, and the results are then compared and discussed. Moreover, by considering load uncertainty, planning models would be robust against network future load variations.

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NOMENCLATURE

Indices		**Parameters**		**Decision Variables**	
l	Substation bus	$AC_{l,u}$	Annual investment cost of transformer u	$IY_{l,u}$	Installation year of transformer u in substation l
t	Time (year)	C_{DGi}	DG (O&M) cost ($/MWh)	$IY_{f,ij}$	Upgrading year for feeder i-j
k	Load-level	C_{ssk}	Electricity price for load level k ($/MWh)	BK	Back up DG capacity (MVA)
u	Substation transformers	C_{ij}	Reinforcement cost of feeder i-j	I_{ij}	Current of feeder i-j (A)
DG	Distributed generation	S_{ij}^{Max}	Capacity of feeder i-j	S_{ij}	Flow of feeder i-j (MVA)
LB	Load buses	N_{LB}	No. of load buses	$S_{l,u}$	Power supplied by transformer u in substation l (MVA)
LL	Load levels	N_T	No. of system buses	S_{DGi}^{M}	DG maximum capacity in bus i (MVA)
SS	Substation	N_{ss}	No. of substations	$S_{DG\,tki}$	Power supplied by DG in year t, at load level k and bus i (MVA)
u	Substation transformers	N_U	No. of transformers	S_{SSl}	Power delivered by substation l (MVA)
ΔV	Acceptable voltage deviation (KV)	N_{LL}	No. of load levels	β	Present value conversion factor
T	Planning horizon	LD_k	Duration of load level k (h)	V_i	Voltage of bus i (KV)
pf	Power factor	$S_{SS\,l}^{Max}$	Capacity of substation l.	σ_{DGit}	Decision variable representing existence of DG at bus i in year t
		Z_{ij}	Impedance of feeder i-j	σ_{lut}	Decision variable representing the existence of transformer u at substation l in year t
		V_n	Nominal bus voltage (KV).	$\sigma_{ij,t}$	Decision variable representing the need for reinforcement of feeder i-j

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1. INTRODUCTION

The main aim of a power system is to provide the customer with a reliable power supply. Indeed, generation, transmission, and distribution tasks must be accomplished in a cost effective way. For this purpose, future system installations and equipment needs in production, transmission and distribution processes must be planned properly considering the load growth prediction. In addition, power system improvements in terms of efficiency increase, cost reduction, economic benefits, high reliability and quality would not be achieved without efficient distribution system planning (DSP). Also, with a proper DSP plan system operation would not be violated by load growth. Thus, DSP is an important issue in electric power systems industry and several technologies are being adopted for better planning of distribution systems.

Distribution system plans which are developed based on novel strategies have features different from DSPs based on traditional techniques. In conventional distribution networks, the energy flow is just in one direction from the distribution substation transformer through distribution feeders to load-point transformers. So, in traditional DSP programs, the network load growth could be compensated by expanding a substation through installing new transformers or building new substations. Moreover, if this additional equipment and load result in overloaded feeders, investing in reinforcement or construction of feeders may be required. Consequently, traditional DSP methods may not be economical, and this happens mainly because load uncertainty may not been considered properly in these approaches.

Distributed Generation (DG) technology has been introduced as an attractive innovation for DSP problem in power networks. With the increasing demand on electrical energy, it can offer important support to the conventional centralized power sources [1]. DG is defined as any small-scale electricity generation unit installed in a distribution network that provides electric power at a site close to consumers. Today, DG applications are growing widely due to its economic, environmental, and technical advantages. If DGs are placed appropriately in a power grid considering future system load growth, some benefits including higher reliability, flexibility, loss reduction, and lower delivery and installation costs would be obtained. Moreover, in the case of a load variation, it can be installed quickly and easily almost everywhere due to its small size and low investment cost. However, DG optimal operation depends on two significant factors, its placement and network load growth.

Many researches have been conducted regarding DSP based on DG solution where different approaches have been implemented in these studies. In [1-3], cost function is defined based on different variables such as maintenance, investment, losses and utilization costs, and annual energy losses. Genetic algorithm (GA) is also applied for finding the best DG topology. In [4-7], dynamic approaches have been presented for solving the multi objective DG allocation problem with time varying load. The objective function in [8] is defined as benefit to cost ratio which is solved through genetic algorithm. In [9], optimal DG placement is performed using particle swarm optimization algorithm. DG type, number, sizing and sitting are the problem variables and loss minimization is the target. In [10-13], expansion plan has been formulated as a multi-stage model. In [14-19], the impact of investment deferral on DGs and various DG ownerships and its effect on DG penetration has been studied.

In the above studies, long-term uncertainty of load demand has not been considered in the dynamic DSP. Load uncertainty highly affects DSP strategies in power networks. Therefore, in the present study load uncertainty has been included in the proposed model and the objective is to minimize total expenses (investment, losses, maintenance, and utilization costs). Genetic algorithm has been applied on the optimization problem and LDC load diagram has been used for more accuracy in computing expenses. An optimum plan is firstly developed based on network constraints and DG specifications. Then, the efficiency of the DSP plan has been evaluated in different sub-periods according to DISCO costs in the LDC diagram. The model has also been tested in several scenarios with and without uncertainties.

The problem formulation is described without uncertainty in Section 2. Section 3 contains a brief description of load demand growth uncertainty and the model description with uncertainty and the procedure are introduced in Section 4. Numerical results are presented in Section 5. Finally, Section 6 presents the main conclusions.

2. PROBLEM FORMULATION WITHOUT UNCERTAINTY

Mathematical formulation of the model is presented in this section. By using Price Duration Curve (PDC) of Figure 1, at different time intervals, more accuracy is attained for expansion planning. Also, the amount of annual load growth rate is represented in the curve for each time interval.

2. 1. Objective Function

The objective function consists of costs associated to investment, operation and maintenance, and losses. Investment cost includes equipment purchasing and installations.

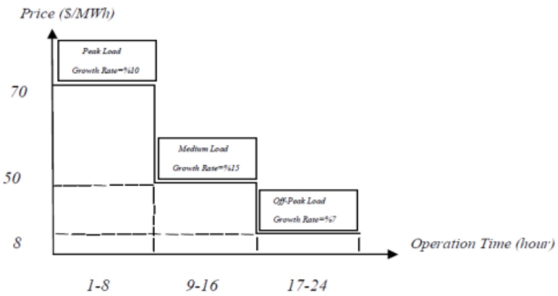

Figure 1. Price duration curve

Power purchase cost is time varying which continuously exist in the network. Assuming no uncertainty in the system, the objective function (OF) is formulated as follows:

$$OF = A + B \tag{1}$$

where,

$$A = \sum [(investment\ costs), (power\ loss\ expenses), (operation\ and\ maintenance\ costs)]$$

$$B = \sum [(cost\ of\ new\ transformers), (purchasing\ power\ cost), (feeder\ reinforcement\ cost)]$$

The equivalent annual investment cost (AC) (in \$/MVA or in \$) is also given by (2):

$$AC = \frac{d \times CC}{1 - \frac{1}{(1+d)^{LT}}} \tag{2}$$

Thus, AC can be obtained provided that total capital cost (CC), life time (LT) and discount rate (d) parameters are known. The outcome value of (2) must be then added to the objective function for each year. Details of A are given in (3).

$$\begin{aligned} A = & \sum_{t=1}^{T} \sum_{i=1}^{N_{LB}} \beta(IY_{DGi}) AC_{DGi} \times \left(S_{DGi}^{M} + BK\right) \sigma_{DGit} \\ & + \sum_{t=1}^{T} \beta(t) \sum_{k=1}^{N_{LL}} LD_k \sum_{i=1}^{N_{LB}} C_{DGi} \times S_{DGt,k\ i}\, pf\ \sigma_{DGi\ t} \\ & + \sum_{t=1}^{T} \beta(t) . \sum_{k=1}^{N_{LL}} LD_k . C_{ssk} \times \sum_{i=1}^{N_{LB}} \sum_{j=i+1}^{N_T} Re\{(V_i - V_j) I_{ij}^{*}\} \end{aligned} \tag{3}$$

In the first term of (3) [1]:

- The investment cost is obtained by adding annual investment over the planning period.
- An extra backup DG would be considered at the buses which DGs have been installed (for emergency conditions)
- The DGi investment cost value could be converted to the present value by (4).

$$\beta(IY_{DGi}) = \frac{1}{(1+d)^{IY_{DGi}}} \tag{4}$$

The second term of (3) represents DG's operation and maintenance (O&M) cost [1]. This cost is not considered for backup units so that they are assumed to be O&M cost free. Operation cost of each candidate DG unit would be compared to other available power sources, such as power purchasing and other available DGs. With $C_{DG\,i}$ (in \$/MWh), LD_k is used to calculate the cost over each load-level period by solving an OPF problem. Besides, $\beta(t)$is used to calculate present values.

$$\beta(t) = \frac{1}{(1+d)^{t}} \tag{5}$$

The third term of (3) represents the cost of system losses, which is calculated for various load levels. $LD_{t,k}$ is related to hours and actual load level is accounted for in the calculation of $V_{t,k.i}$, $V_{t,k,j}$, and $I_{t,k,ij}^{*}$. B is given by (6).

$$\begin{aligned} B = & \sum_{t=1}^{T} \{ \sum_{l=1}^{N_{ss}} \sum_{u=1}^{N_U} \beta(IY_{l,u}) AC_{l,u} \sigma_{lut} \\ & + \sum_{I=1}^{N_{LB}} \sum_{J=i+1}^{N_T} \beta(IY_{f,ij}) C_{ij}\, \sigma_{i\ t} \} \\ & + \sum_{t=1}^{T} \beta(t) \sum_{k=1}^{N_{LL}} LD_k C_{ss\,k} \sum_{l=1}^{N_{ss}} \sum_{u=1}^{N_U} S_{l,u} Pf\ \sigma_{l\,u\,t} \end{aligned} \tag{6}$$

The following variables are calculated by minimizing the objective function in (1).

- Location, installation year and the capacity of DG units
- Installation year of new transformer and its capacity
- The feeder reinforcement; load growth and new installations may require feeders reinforcement

2. 2. Constraints

1. Power balance: Power consumption and production should be balanced. This constraint can be considered by load flow equations and O&M costs. DGs are assumed as negative loads [1].
2. Voltage constraints: The voltage at each bus should remain between two constraints as follows.

$$|V_i - V_n| \leq \Delta V \tag{7}$$

3. DG Penetration: Total DG capacity must be less than a specific percentage of the total load.
4. Feeders' thermal limit: As load grows, network may require additional investment for feeder capacity reinforcement.

$$S_{ij} \le S_{ij}^{Max} \sigma_{i,u,t} \tag{8}$$

5. Maximum DG capacity: DG capacities vary from a few kilowatts to several megawatts.
6. DG annual operation time limit: DG generation would be performed for limited hours in each year. In this paper, it is assumed that DGs can be operated in all durations.
7. Distribution substation capacity limit: The power transferred by substation should stay within its normal capacity.

3. CONSIDERING THE UNCERTAINTY

Here, a mathematical model is presented considering load uncertainty. In this respect, uncertainty modeling, the objective function and optimization procedure are described.

3. 1. Load Growth Uncertainty In this study, load uncertainty is modeled by Markov Tree. In Markov modeling, 7% and 5% load growth rates correspond to 60% and 40% probabilities, respectively. For five-year horizon, there are 6 scenarios. Markov Tree modeling scheme is presented in Figure 2.

3. 2. Objective Function The objective function is somewhat similar to the objective function in the case of deterministic case. Load uncertainty is applied on LD_k, C_{DGi}, $S_{DGt,k,i}$, V_i, V_j, I_{ij}^*, $\sigma_{ij.t}$, and $S_{l.u,t}$; and these are replaced with $LD_{k,\omega}$, $C_{DGi,\omega}$, $S_{DGt,k,i,\omega}$, $V_{i,\omega}$, $V_{j,\omega}$, $I_{ij,\omega}^*$, $\sigma_{ij.t,\omega}$, $S_{l.u,t,\omega}$. ω is the number of scenarios. Considering uncertainty, probability function $\varphi_{\omega,t}$ is included in the objective function as an additional term. The number of scenarios at year t ($N_{\omega,t}$) is obtained by (9).

$$N_{\omega,t} = t + 1 \tag{9}$$

Probability function $\varphi_{\omega,t}$ is defined as:

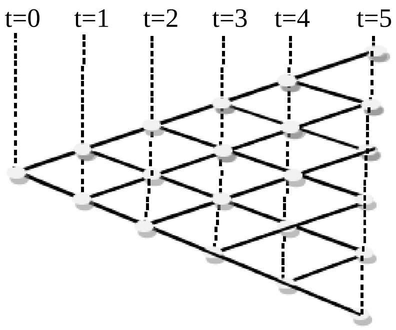

Figure 2. Markov Tree for a five-year horizon

$$\varphi_{\omega,t} = \begin{cases} \%60 & \omega = \omega_{i,i} \quad , i = 1,2,\ldots,N_{\omega,t} \\ \%40 & \omega = \omega_{j,j+1} \ , j = 1,2,\ldots,N_{\omega,t} \end{cases} \tag{10}$$

In (10), $\varphi_{\omega,t}$ is the probability of scenario ω at year t.
The objective function under load uncertainty is composed of two main terms X and Y.

$$OF = X + Y \tag{11}$$

where,

$$\begin{aligned} X &= \sum \big(investment\ costs\big), \\ &\quad \big(operation\ and\ maintenance\ costs\big), \\ &\quad \big(power\ loss\ expenses\big)] \\ Y &= \sum [\big(cost\ of\ new\ transformers\big), \\ &\quad \big(feeder\ reinforcement\ cost\big), \\ &\quad \big(purchasing\ power\ cost\big)] \end{aligned}$$

$$\begin{aligned} X &= \sum_{t=1}^{T} \sum_{i=1}^{N_{LB}} \beta(IY_{DGi}) AC_{DGi} \times \left(S_{DGi}^{M} + BK\right) \sigma_{DGit} \\ &+ \sum_{t=1}^{T} \beta(t) \sum_{\omega=1}^{N_{\omega,t}} \varphi_{\omega,t} \sum_{k=1}^{N_{LL}} LD_{k,\omega} \sum_{i=1}^{N_{LB}} C_{DGi,\omega} \\ &\times S_{DGt,k\,i\,\omega} pf\ \sigma_{DGi\,t} + \sum_{t=1}^{T} \beta(t) \sum_{\omega=1}^{N_{\omega,t}} \varphi_{\omega t} \sum_{k=1}^{N_{LL}} LD_{k\,\omega} C_{ssk} \\ &\times \sum_{i=1}^{N_{LB}} \sum_{j=i+1}^{N_T} Re\{(V_{i,\omega} - V_{j,\omega}) I_{ij,\omega}^*\} \end{aligned} \tag{12}$$

$$\begin{aligned} Y &= \sum_{t=1}^{T} \{ \sum_{l=1}^{N_{ss}} \sum_{u=1}^{N_U} \beta\left(IY_{l,u}\right) AC_{l,u} \sigma_{l,u,t} \\ &+ \sum_{i=1}^{N_{LB}} \sum_{j=i+1}^{N_T} \sum_{\omega=1}^{N_{\omega,t}} \varphi_{\omega,t}\ \beta(IY_{f,ij,}) C_{ij}\, \sigma_{i\ t\ \omega} \} \\ &+ \sum_{t=1}^{T} \beta(t) \sum_{\omega=1}^{N_{\omega,t}} \varphi_{\omega,t} \sum_{k=1}^{N_{LL}} LD_k C_{ss\,k} \sum_{l=1}^{N_{ss}} \sum_{u=1}^{N_U} S_{l,u,t\ \omega} Pf\ \sigma_{l\,u\,t} \end{aligned} \tag{13}$$

Each term of (12) and (13) is also related to the same as mentioned in Section 2 (equations 3 and 4). Equation (12) is composed of three terms. The first term represents the investment cost of DGs, which is not dependent on uncertainties. The second term of (12) represents the expected cost of the operation costs of GDs and the third term is the expected cost of energy loss. Furthermore, equation (13) consists of three terms, where the first term represents the capital cost of upstream substation expansion, which is independent of uncertainty. The second term is the expected cost of needing for distribution lines reinforcement and the third term represents the expected cost for purchasing energy from upstream substation. It should be noted that due to uncertainty of demand and its modeling by sets of scenarios, decision variables relating to the operation period (short term variables) are dependent to scenarios, while the long-term variables (investment cost of DGs and substations) are independent to scenarios.

3. 3. Optimization Procedure The problem formulation is a kind of mixed-integer nonlinear programming problem which is solved by genetic algorithm (GA). Each GA chromosome consists of 20 variables. As illustrated in Figure 2, the first 8 integer bits of each chromosome represent the DG installation year and place at 8 load buses. In a 4-year horizon, each of these eight bits is an integer between 0 and 4, while in a 5-year horizon; they are an integer between 0 and 5. The ninth and tenth bits are binary which indicate 10 MVA transformer additions. The other eight variables (11^{th} to 18^{th}) indicate DG capacity between 1 to 4 MVA. The last two bits of each chromosome are equal to 10 which is the rated capacity of DGs through the planning period. The algorithm begins by a series of random decision variables.

In the first three scenarios of the network, transformers work at full capacity at all load levels. However in the fourth scenario, full capacity performance occurs at peak load level. At low and medium levels of load, this value decreases to 25% and 50% of rated power respectively. Newton-Raphson (NR) method has been used for solving load flow problem. In fact NR is applied on each chromosome. If the obtained variables (buses voltages, currents, transferred power …) meet the problem constraints, the fitness function will be calculated by these values for each chromosome. Then, the chromosomes would be ranked according to their fitness values (minimum fitness value) and the best solutions would be selected in this step. This procedure would continue until the best answer is obtained at the last iteration and minimum DSP cost achieved.

4. NUMERICAL STUDIES

To assess the effectiveness of the proposed model, it has been used to solve DSP problem on a radial distribution network. This problem has been analyzed in different scenarios in two different cases, existence and non-existence of uncertainty.

4. 1. Test Network The network is shown in Figure 3 [1]. This system includes a 132 KV/33 KV substation with 40 MVA capacity and 8 load buses. Data of load demand are given in Table 1.

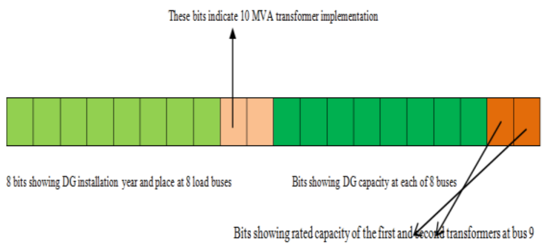

Figure 3. Contents of each decision variable

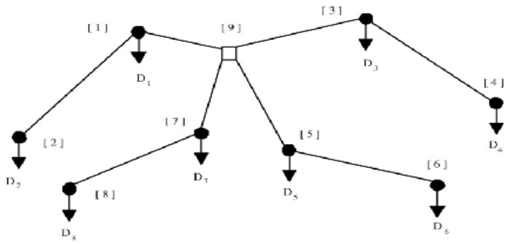

Figure 4. Network of study

TABLE 1. Data of load demand (MVA)

Bus	Medium	Off-peak	Peak
1	4	3	6
2	4	3	6
3	4	3	6
4	2.66	2	4
5	2.66	2	4
6	2.66	2	4
7	2.66	2	4
8	4	2	6

It is assumed that the three load levels have the same durations. Assuming no uncertainty in the system, each of these load levels has its own rate of annual growth and electricity price. However, the price value is the same considering load uncertainty. Load buses are connected to the grid by 33 KV/11KV transformers. Thermal capacity of the network feeders is 12 MVA with 0.15M$/Km of reinforcement cost. Gas-fired generators are also used as DGs, which requires low space for installation. The capacity of DGs is assumed 4 MVA with 1 MVA steps. The Investment and O&M costs of DGs are 0.89 M$/MVA and 10 $/MWh, respectively. A 1 MVA backup DG is also provided for each DG unit. In addition, it is assumed that there is no limitation for accessing to natural gas at all load buses. Two available 10 MVA transformers can be installed in the substation each with a cost of $ 0.2 M. The discount rate is 12.5% for all cases and the system power factor is 0.9. The problem is solved in a 4-year for validating the results, and then extended for 5-year planning horizon. The annual load growth rates are assumed to be 15%, 7% and 10% for medium, off-peak and peak load, respectively. Table 2 illustrates the details of different scenarios tested on this network. These scenarios have been considered to study the effects of some special conditions on DSP. In the first step of simulations, DSP problem has been analyzed at peak hours with constant PF (30% of full load). The test has been performed in a 4-year and 5-year horizon with and without load uncertainty. Secondly, the problem has been studied in some scenarios with different constraints.

TABLE 2. Definition of scenarios

	DG operation hours		Load growth uncertainty		Scenario topics
Scenario number	**Peak hours**	**All hours**			
1	✓	×	✓	×	PF effects
2	✓	×	✓	×	market price effects
3	✓	×	✓	×	PF and market price effects
4	✓	✓	✓	×	Operation of DGs in all period

4. 2. Results in a 4-year Horizon To demonstrate the effectiveness of the model, the last scenario of the [1] is analyzed here as the first test. The outcomes have been then compared. The results are almost the same except for some small differences (Table 3). The slight differences could be due to differences in optimization procedures and limited access to full data.

4. 3. Results for 5-year Horizon Load demand depends on some factors such as population growth which varies unsteadily. Therefore, it is not fully reasonable to consider a constant pattern for load growth rate. In this section, DSP problem has been solved in a 5-year horizon with and without load uncertainty. The amount of the increase in the demand with the probability of 60% and 40% are 7% and 5%, respectively. Results are given in Tables 4 and 5. Indeed, by including load uncertainty in the model, load growth and DG O&M will be calculated more precisely for the future years. The five-year horizon problem has been also tested in different scenarios with some parameters variations. These tests have been illustrated in the next sections.

4. 3. 1. Impacts of PF (scenario 1) In this scenario, impacts of PF on DSP without and with uncertainty are considered, and the results are shown on Tables 6 and 7.

TABLE 3. Comparing results for a 4-years horizon with [1]

	Ref. [1]	**Base Case**
Total capacity of DGs (MVA)	15	13
DG investment cost (M$)	11.146	7.0196
Transformer expansion cost (M$)	0	0
Cost of losses (M$)	1.106	1.2407
Purchased power cost (M$)	30.081	33.961
DG O&M cost (M$)	2.425	1.0744
Feeder cost (M$)	0	0
Total expansion cost(M$)	44.759	43.296

TABLE 4. Results for 5-years horizon (no uncertainty)

Total capacity of DGs (MVA)	16
DG investment cost (M$)	8.6271
Transformer expansion substation cost (M$)	1.1099
Cost of losses(M$)	1.4769
Purchased power cost (M$)	42.9957
DG O&M cost (M$)	1.178
Feeder cost (M$)	4.4394
Total expansion cost (M$)	59.827

TABLE 5. Results for 5-years horizon (with uncertainty)

Total capacity of DGs (MVA)	14
DG investment cost (M$)	7.3589
Transformer expansion substation cost (M$)	0
Cost of losses (M$)	1.8164
Purchased power cost (M$)	36.688
DG O&M cost (M$)	1.571
Feeder cost (M$)	0
Total Expansion Cost (M$)	47.4343

TABLE 6. Impact of PF (scenario 1-no uncertainty)

	PF=%30	PF=%20	PF=%10
Total capacity of DGs (MVA)	16	11	10
DG investment cost (M$)	8.6271	7.5197	6.0379
Transformer expansion cost (M$)	1.1099	1.2486	1.2486
Cost of losses (M$)	1.4769	1.8264	2.936
Purchased power cost (M$)	42.9957	43.403	45.05
DG O&M cost (M$)	1.178	1.071	0.482
Feeder cost (M$)	4.4394	4.9944	4.9944
Total expansionCost (M$)	59.827	60.0631	60.7489

TABLE 7. Impacts of PF (scenario 1-with uncertainty)

	PF=%30	PF=%20	PF=%10
Total capacity of DGs (MVA)	14	14	11
DG investment cost (M$)	7.358	6.751	5.8057
Transformer expansion Cost (M$)	0	0	1.7778
Cost of losses (M$)	1.816	2.150	2.226
Purchased power cost (M$)	36.688	37.198	38.922
DG O&M cost (M$)	1.571	1.24	0.997
Feeder cost (M$)	0	0	7.111
Total expansion cost (M$)	47.434	47.539	56.840

It can be seen that decreasing the PF resulted in power purchase growth and decreasing DG costs. Since there is a specified limit for DGs operation, PF reduction should be compensated by increasing of power from market. However, the total costs increases due to the growth of purchased power cost.

4. 3. 2. Impacts of Market Price (scenario 2) In this section, the effect of market price variations on DSP with and without load uncertainty has been studied. In this test, it is assumed that PF is 30%. Tables 8 and 9 show the results. As the electricity costs increases, more DGs need to be installed. By increasing the price, DG installation also grows. Furthermore, there is a reduction in power flows of feeders and losses cost due to the closeness of electrical resources to demand points.

4. 3. 3. Impacts of Market Price and PF (scenario 3) In this scenario, the effects of market price and PF are considered simultaneously. As the PF and power price decrease, it is better to purchase additional power instead of extending the number of installed DGs. The results are shown in Tables 10 and 11. This choice is good in case of lower electricity price and limited DG operation rate.

TABLE 8. Impact of market price (scenario 2-no uncertainty)

Market price ($/MWh)	2,15, 35	5,30, 50	8,50,70	20,80, 100	25,90,110
Total capacity of DGs (MVA)	10	13	16	20	23
DG Investment cost (M$)	3.215	6.233	8.627	10.788	14.057
Transformer expansion cost (M$)	1.404	1.109	1.109	1.109	1.109
Cost of losses(M$)	1.045	1.540	1.4769	1.719	1.716
Purchased power cost (M$)	19.950	29.990	42.995	63.391	66.679
DG O&M cost (M$)	0.2262	0.828	1.178	1.943	3.084
Feeder cost (M$)	5.618	4.439	4.439	4.399	4.399
Total expansion cost (M$)	31.461	44.142	59.827	83.39	90.795

TABLE 9. Impact of electricity price (scenario 2-with uncertainty)

Market price ($/MWh)	2,15,35	5,30,50	8,50,70	15,70, 90	20,80,100
Total capacity of DGs (MVA)	9	12	14	15	16
DG Investment cost (M$)	6.211	7.076	7.358	12.574	14.646
Transformer expansion cost (M$)	0	0	0	0	0
Cost of losses (M$)	0.345	1.0985	1.8164	1.349	1.421
Purchased power cost (M$)	14.08	24.331	36.688	43.848	46.933
DG O&M cost (M$)	0.687	0.8156	1.571	2.121	3.062
Feeder cost (M$)	0	0	0	0	0
Total expansion cost (M$)	21.323	33.322	47.434	59.892	66.062

TABLE 10. Impacts of market price and PF (scenario 3-no uncertainty)

Market price ($/MWh) and PF	50, 170, 210, 30%	40,110,160, 25%	25,90, 110, 20%	15,70, 90, 15%	8,50, 70, 10%
Total capacity of DGs (MVA)	29	27	21	15	12
DG Investment Cost (M$)	21.845	17.361	14.13	9.0379	7.3053
Transformer expansion cost (M$)	0	0	0	0	1.1047
Cost of losses (M$)	5.712	2.297	1.793	1.562	2.5071
Purchased power cost (M$)	109.3607	84.3567	59.837	57.3367	43.7597
DG O&M cost (M$)	4.541	3.857	4.235	1.6811	1.3646
Feeder Cost (M$)	4.3994	4.3994	4.3994	4.3994	5.6186
Total expansion cost (M$)	145.9001	112.3101	86.4291	74.0571	61.96

TABLE 11. Impacts of market price and PF (scenario 3-with uncertainty)

Market price($/MWh) and PF	50,170, 210, 30%	40, 110, 160, 25%	25,90, 110, 20%	15, 70, 90, 15%	8,50, 70, 10%
Total capacity of DGs (MVA)	22	19	16	15	12
DG investment cost (M$)	20.237	17.433	12.432	10.86	10.503
Transformer expansion cost (M$)	0	0	0	0	1.1047
Cost of losses (M$)	3	2.785	2.238	2.272	2.045
Purchased power cost (M$)	89.132	68.423	56.792	45.582	33.461
DG O&M cost (M$)	4.238	3.301	1.856	1.78	1.308
Feeder cost (M$)	0	0	0	0	0
Total expansion cost (M$)	116.61	91.942	73.319	60.494	39.4217

4. 3. 4. Impacts of DG Operation Policy (scenario 4)

In this section, the influence of DG operation periods has been studied. It is assumed that at peak hours, DG operates at its full capacity, while at medium and low load levels, it operates at 50% and 25% of its rated power respectively. Considering results presented in Tables 12 and 13, it is realized that DG capacity, its investment and its O&M costs are lower at peak hours compared to all around condition. Contrary, the power and grid losses expenses at peak hours are higher than another case.

It can be seen that as PF gets larger, more electricity has been purchased and fewer DGs are installed. However, if the purchased power exceeds the limit (40 MVA), then overall DSP costs will rise significantly. In the second scenario, the electricity price growth has been compensated by extending DG implementation and lowering power purchasing. While there is a decline in both PF and electricity price (in the 3rd scenario), increasing the rate of power purchasing with lower costs is the best alternative. Finally, in the last scenarios, it is concluded that better DSP program would be produced by considering DG operation at all load hours.

TABLE 12. Impacts of operation policy (scenario 4-no uncertainty

	Operation hours	
	Peak hours	**All hours**
Total capacity of DGs (MVA)	16	19
Additional purchased power (MVA)	0	0
DG investment cost (M$)	8.627	16.272
Transformer expansion cost (M$)	1.11	0
Cost of losses (M$)	1.476	0.497
Purchased power cost (M$)	42.996	31.103
DG O&M cost (M$)	1.178	3.133
Feeder cost (M$)	4.439	0
Total expansion cost (M$)	59.827	43.056

TABLE 13. Impacts of operation policy (scenario 4-with uncertainty

	Operation hours	
	Peak hours	**All hours**
Total capacity of DGs (MVA)	14	21
Additional peak purchased power (MVA)	0	0
DG investment cost (M$)	7.359	13.272
Transformer expansion cost (M$)	0	0
Cost of losses (M$)	1.8164	0.357
Purchased power cost (M$)	36.688	25.574
DG O&M cost (M$)	1.571	3.004
Feeder cost (M$)	0	0
Total expansion cost (M$)	47.4343	42.207

5. CONCLUSION

A novel model has been proposed for DG expansion planning considering load growth uncertainty in a multi-year horizon. Load uncertainty is modeled through Markov Tree. GA has been used to solve the problem. Impacts of penetration factor, purchased electricity price and DG operation hours have been studied.

Future load growth uncertainty is an important factor which has a significant impact on DSP. The proposed model works well in existence of load uncertainty. In fact, the grid expenses have been kept balanced by this approach. This has been shown by the results of tests with and without load uncertainty. In the case of either certainty or uncertainty in the load, reducing the DG coefficients results in a decrease in DG exploitation. As a result, there will be less investment and exploitation on DGs. In the second scenario, simulation results show that DSP shows more tendencies for DG usage. Thus, increasing electricity price leads to a decrease in the electricity usage while more DGs are being used. So, power flow of the line, loss, and loss cost decrease. In the third scenario, by reducing the penetration of the

DGs and electricity price at the same time, DG usage decrease and purchasing of power increase. This increase in the purchase will lead to the usage of transformer. Since in the fourth scenario there is no limitation for the usage of DGs in the load peaks, there is possibility of increasing in the exploiting of the units and there will be decrease in purchase.

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Distributed Generation Expansion Planning Considering Load Growth Uncertainty: A Novel Multi-period Stochastic Model

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چکیده

یکی از راهکارهای موثر در برنامه ریزی توسعه سیستم‌های توزیع انرژی الکتریکی، استفاده از تولید پراکنده می‌باشد. عدم قطعیت در رشد بار شبکه یکی از موضوعات قابل توجه است که می‌تواند مدیریت بهره‌برداری و برنامه‌ریزی توسعه منابع تولید پراکنده را تحت تاثیر قرار دهد. به این منظور، در این مقاله مدلی تصادفی جدید مبتنی بر راهکار توسعه تولید پراکنده با ملاحظه عدم قطعیت در رشد بار شبکه توزیع ارائه می‌شود. برای حل مسئله بهینه‌سازی (تعیین مکان، ظرفیت و زمان نصب مولدها) از الگوریتم ژنتیک استفاده می‌شود. همچنین، عدم قطعیت در رشد بار شبکه توسط درخت مارکوف مدل می‌شود. برای نشان دادن اثربخشی مدل پیشنهادی سناریوهای متنوعی با ملاحظه اثرات قیمت برق خریداری شده از شبکه بالادست، ضریب نفوذ مولدها و دوره های بهره برداری آنها مورد مطالعه قرار می‌گیرد. این سناریوها با ملاحظه عدم قطعیت و بدون آن مطالعه و با یکدیگر مقایسه می‌شوند. شبیه‌سازیها نشان می‌دهند که با ملاحظه عدم قطعیت، مدلهای برنامه ریزی توسعه در برابر تغییرات بار شبکه مقاوم‌تر خواهند بود.

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