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Determining the guaranteed energy purchase price for Distributed Generation in electricity distribution networks

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ABSTRACT

With widespread installation of Distributed Generation (DG) in distribution networks and considering their impact on the network, distribution companies (DisCos) have the option of supplying loads from these resources as well as the wholesale market. In the presence of DG, an incentive scheme is required to determine the reasonable purchasing price of energy from DG owners based on benefits to the DisCos. These prices should be determined in such a way that the risk to the DisCo can be controlled. Considering the guaranteed energy purchase price (GEPP) of DG as a risk-management option, this paper addresses the GEPP for a specified future period. The proposed methodology determines the GEPP based on expected loss reduction and reliability improvement achieved by DG. Due to uncertainties associated with load, market price, and future investment, Monte-Carlo simulation is used to determine the GEPP. The performance of the proposed methodology is evaluated for a 33-bus distribution test system and results are discussed for different cases. The obtained GEPP guides investors and planners toward an optimum place and size for installation of DG, which leads to maximum network benefits as well as profits.

1. Introduction

Today, environmental issues, the high price of fossil fuels, and deregulation of power systems have drawn attention to the widespread use of DG near loads in distribution networks. In addition, developments in micro-generation, power electronics, and storage, have enhanced Distributed Generation (DG) utilization in power distribution systems (El-Khattam et al., 2004; LIANG et al., 2003; Ackermann et al., 2001).

In recent years, assessing the technical and economic effects of DG on distribution networks has been a topic of great interest in power-system research (Senjyu et al., 2008; Guerrero et al., 2010; Coster et al., 2011; Boutsika and Papathanassiou, 2008; Manfren et al., 2011; Martinez and Martin-Arnedo, 2009; QIAN et al., 2008; Balaguer et al., 2011; Ochoa and Harrison, 2011; Keane et al., 2011; Dash et al., 2012; Wang et al., 2014; Abu-Mouti and El-Hawary, 2011; Wolsink, 2012). Implementation of DG close to end users in electricity distribution systems can bring integral benefits to both customers and utilities. The most important benefit is reduction in bulk generation and transmission investments, including expansion costs. Some other benefits are lower investment risks, faster installation time, less power loss, reduced carbon emissions, and improved reliability, power quality, and voltage profiles (Algarni and Bhattacharya, 2009; Brown and Rowlands, 2009; Siano et al., 2009).

Thus, DG can be an economical and cost-effective solution for power generation in distribution networks. Motivating investors to further develop DG in distribution networks is a priority for some electricity distribution companies (DisCos). In this regard, incentive-based regulatory rules and financial (pricing) mechanisms are the main policies aimed at DG development. In Iran and in other countries, the DisCo is the retailer, and manager of the electricity distribution system (Williams and Ghanadan, 2006). Under this structure, the DisCo can supply the electricity demand of its network by purchasing power (energy) from any DG unit owned by an investor and/or directly from the wholesale electricity market at prices λ_n^h and λ_{DG}^h, respectively; this financial and energy transaction is shown in Fig. 1.

The DisCo must decide the amount of energy to be bought in the wholesale electricity market and from the DG units. The amount of power and the DisCo's purchasing price are related to the DG's impact on active loss reduction and the wholesale market price (López-Lezama et al., 2011). The DisCo must weigh the DG power price against the potential benefits obtained from dispatching these

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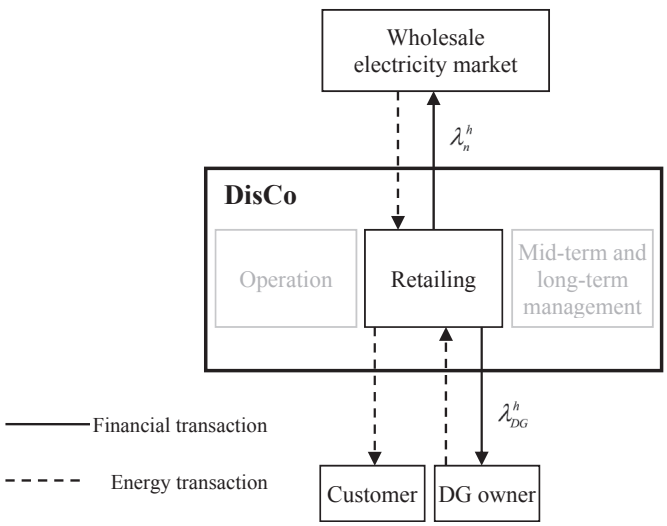

Fig. 1. Distribution Company retailing model in Iran.

units. For instance, if the power production of a DG unit has a positive impact, then the DG energy price should be slightly higher than the wholesale market price. Conversely, if the DG unit has a negative impact, its energy price should be lower than the wholesale market price (López-Lezama et al., 2011). These prices provide a mechanism to reward the DG investor who installs DG in optimal locations (López-Lezama et al., 2011; Sotkiewicz and Vignolo, 2006a, 2006b; Shaloudegi et al., 2012).

Appropriate nodal prices can encourage investors to connect their DG units at buses that lead to the most positive effects for the system. Sotkiewicz (Sotkiewicz and Vignolo, 2006a) proposed applying locational marginal pricing (LMP) in distribution systems. Other researchers (Shaloudegi et al., 2012; Sotkiewicz and Vignolo, 2007; MiriLarimi and Haghifam, 2012; Farsani et al., Hosseinian) have proposed alternative methods for applying this concept.

In all previous studies of which we are aware, real-time nodal prices were calculated considering existing DG at a certain place and size (operation capacity). However, it may be important for investors to know the energy price ($/kWh) that DisCo will pay to them for their energy production in the specified period and in the specified bus. One way that the DisCo can reduce investment risk is to effectively guarantee prices at each bus of the network. In other words, investors would be encouraged to install DG in predetermined buses in the distribution network. We propose a methodology for determining the guaranteed price for purchasing energy from DG owners for a given future period. The proposed methodology considers the effect of each DG on reliability improvement and loss reduction.

In these regards, another important issue is investment dynamics. Due to the temporal and spatial intermittency of DG, different investment scenarios lead to different guaranteed prices for DG units. Monte-Carlo simulation modeling handles this intermittency challenge to GEPP determination.

The rest of the paper is organized as follows. In section 2 and 3 the structure of GEPP and , the proposed methodology for GEPP determination is discussed respectively. It is applied to GEPP determination for a standard 33-bus IEEE distribution test system and the results are discussed in section 4 and 5. Conclusions are provided in section 6.

2. The energy guaranteed purchasing price (GEPP) for Distribute Generation (DG)

Determination of a guaranteed price for purchasing electric energy from DG owners for a specified future period is a challenging issue for DisCo. From the viewpoint of the DisCo, the GEPP of each DG unit is determined based on its positive effects on the network. In addition, the effects of each DG unit on the distribution network depend on the DG place and its size. Therefore, depending on location and operating capacity, the GEPPs for DG units differ. Differential pricing will encourage DG investors to locate DG resources at appropriate places in the network.

To determine the GEPP, the DisCo must weigh the wholesale market price against the potential benefits obtained from dispatching these units. In other words, the DisCo must determine GEPP of each DG in order to send incentive signals to promote DG investment that have a positive impact on the network. For this purpose, the GEPP is determined based on DG effects on loss reduction and reliability improvement. Therefore, the GEPP is calculated according to the equation given by equation (1):

$$\lambda_i^g = \lambda^e + \lambda_i^{loss} + \lambda_i^{re} \tag{1}$$

where λ_i^g is the GEPP of the DG unit connected to ith bus, λ^e is the wholesale market price, λ_i^{loss} and λ_i^{re} are the price terms related to loss reduction and reliability improvement, respectively.

2.1. Reflecting loss-reduction value in price

Sotkiewicz et al. (Sotkiewicz and Vignolo, 2006a) used marginal active loss to determine active power nodal prices considering the DG impact on active loss. It has also been shown (Sotkiewicz and Vignolo, 2007) that this methodology leads to non-zero merchandising. Some researchers (Shaloudegi et al., 2012; Sotkiewicz and Vignolo, 2007) tried to solve this problem, but others (Larimi and Haghifam, 2013) have shown that these methods are inappropriate in distribution network, proposing instead a DG active price based on the value of loss reduction. According to this method, the negative impact of DG units on their nodal price is also considered. The actual value of DG in loss reduction can be determined based on average marginal cost according to the equation given by equation (2) (Majid Miri Larimi et al., 2015).

$$\lambda_i^{loss} = \frac{1}{2}\left(\lambda_{DG,i}^0 + \lambda_{DG,i}^p\right) \tag{2}$$

where, $\lambda_{DG,i}^0$ is the marginal loss cost with the assumption that the ith DG unit is the only one connected to the feeder, and $\lambda_{DG,i}^p$ is the marginal loss cost of the ith DG unit, with the assumption that all network DG units are connected to the feeder and are in operation mode.

2.2. Reflecting reliability improvement value in price

DG units also vary in terms of their contribution to reliability improvement. In the case of presence of several DG units in a distribution network, the contribution of each DG unit toward reliability improvement might be different based on its place and size. Determining each DG unit's share in reliability improvement is calculated by game theory from equations (3)–(6) (Larimi et al., 2013).

$$RII_i = \beta W_i + (1-\beta) w_i \tag{3}$$

where RII_i is the ith DG contribution in reliability index improvement, w_i and W_i are the minimum and maximum contribution of each DG in reliability index improvement which are determined by equation (4):

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$$w_i = V(\{1,2\ldots,N\}) - V(\{1,2\ldots,N\} - \{i\})$$
$$W_i = \max(\mathrm{V}(z_i) - \sum_{\substack{m\in z_i \\ m\neq i}} V(m)\Big) \tag{4}$$

where $N$is the number of DG units and V(s) is the reliability index improvement due to subset s, which represents the DG units that are assumed to be connected to the network. For example, subset (Ackermann et al., 2001) means that DG units 1, 2 and 3 are connected to the grid. The term z_i represents all of the subsets containing the ith DG unit. Also β is the weighting factor, which is determined by solving equation (5):

$$\sum_{j=1}^{N} \beta W_j + (1-\beta) w_j = v(\{1,2\ldots,N\}) \tag{5}$$

Finally, finding β leads to the calculation of *RII* for each DG unit from equation (3). After determining the contribution of each DG unit to improvement in the reliability index, the reliability improvement price is calculated by equation (6).

$$\lambda_i^{re} = \frac{RII_i}{P_{DG,i}} \tag{6}$$

where P_{DGi} and λ_i^{re} are the ith DG capacity and reliability improvement price.

3. Proposed methodology

As mentioned, to reduce investment risk, the DisCo may be willing to guarantee the purchasing prices of DG energy at the desired buses for specified future time periods. In this section, the proposed methodology for determining the GEPP for DG is described. For this purpose, the load profile and market energy price for the decision period are assumed. We also assume that an investor intends to invest in distribution system by installing a DG unit in a specified place and at a specified size. The DisCo intends to calculate the DG unit's GEPP for the future year considering its contribution to loss reduction and reliability improvement. The effects of each DG unit on loss reduction and reliability improvement depend on the place and size of other DG connected to the network and those may be connected to the network in a future year. Due to their non-specified location, capacity, and installation time, the contribution of the DG in loss reduction and reliability improvement and, consequently, GEPP is stochastic. In other words, uncertain investments lead to uncertainty in the GEPP calculation. We use Monte-Carlo simulation to model these investment uncertainties. For this purpose, for an investor willing to install a DG unit at the ith bus with the size of P_{inv}, the GEPP is determined according to the following steps and summarized in Fig. 2.

3.1. *Step 1: determine the maximum allowable penetration of DG units as of the end of the year*

A high penetration rate of DG may lead to problems such as protection challenges, feeder congestion, and undetectable islands. Utilities often limit penetration level of DG to a specified value. The maximum penetration of DG is calculated by equation (7).

$$PR^{\max} = \frac{P_{DG}^{total}}{P_L^{total}} \tag{7}$$

where P_{DG}^{total} and P_L^{total} are the total allowable capacity of DG connected to the network and total load respectively. For a given value of penetration level, the GEPP is determined through the next steps.

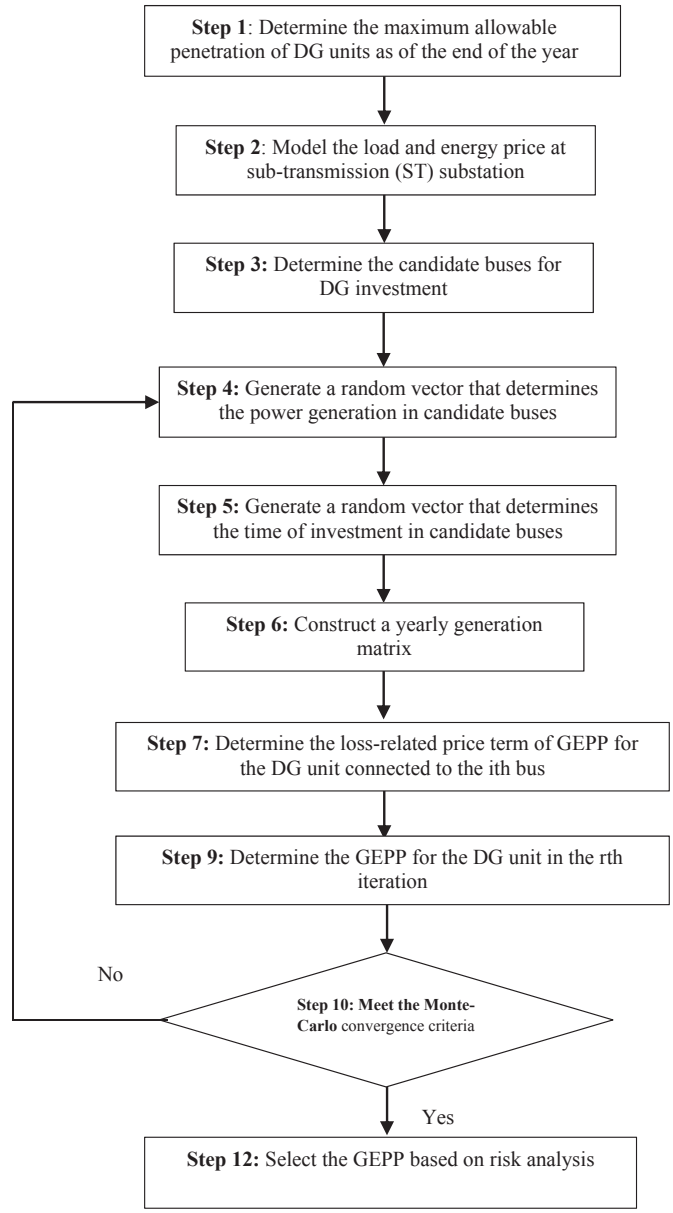

Fig. 2. GEPP calculation flowchart.

3.2. *Step 2: model the load and energy price at the sub-transmission (ST) substation*

As mentioned, it is assumed that the annual load curve is available for the ST substation, as shown in Fig. 3. It is also assumed that the energy price for the ST substation is determined with respect to the load level, as shown in Fig. 4 In order to accelerate the algorithm, the load and price curves are divided into 52 parts based on the weeks of the year. Considering the annual load curve at ST substation and the contribution factor of each bus, the active and reactive power at each bus are calculated by equations (8) and (9).

$$P_{L,i}^{j} = CF_i^j \times P_{sub}^{j} \tag{8}$$

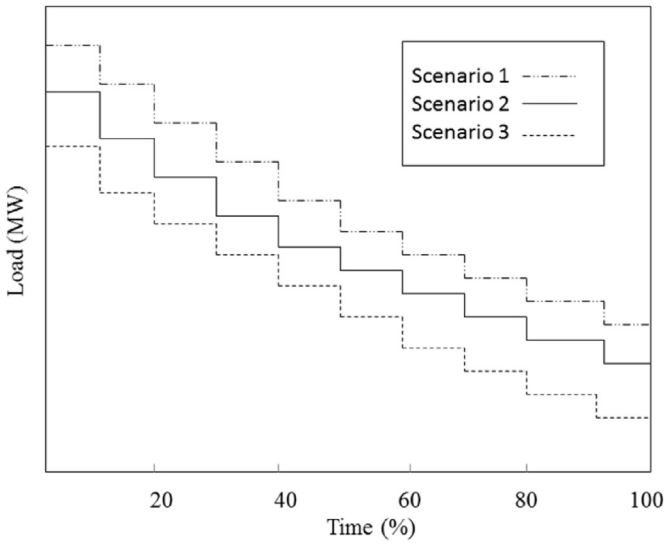

Fig. 3. Annual load curve for the ST substation.

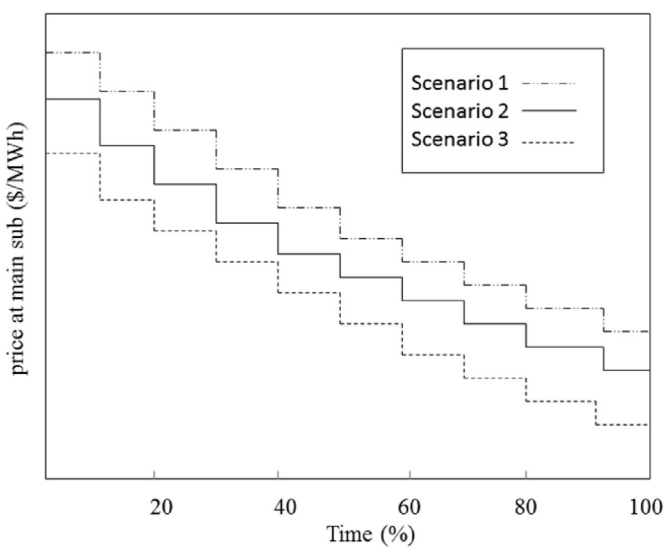

Fig. 4. Annual energy price for the ST substation.

$$Q_{L,i}^{j} = P_{L,i}^{j} \times \tan\left(\varphi_i^j\right) \quad \varphi_i^j = \cos^{-1}\left(PF_i^j\right) \tag{9}$$

where $P_{L,i}^{j}$, $Q_{L,i}^{j}$, CF_i^j andPF_i^j are the active power, reactive power, contribution factor, and power factor in the ith bus at the jth load level, respectively andP_{sub}^{j} is the ST substation load at the jth level.

3.3. ***Step 3:*** *determine the candidate buses for DG investment*

As mentioned, determining the GEPP in the ith bus for a DG with the capacity of P_{inv} is affected by the probable future investments in the other network buses. Since investment in all network buses is not possible, the buses with the possibility of investment are assumed to be the set of candidate buses (B_c). It is noted that B_c does not contain the ith bus.

3.4. ***Step 4:*** *generate a random vector that determines the power generation in candidate buses*

Considering the maximum allowable penetration of DG in the distribution system, a random number is generated for each candidate bus to represent the generation power of the bus according to equation (10).

$$P_{inv} + \sum_{k \in B_c} P_k^R \le PR^{\max} \times P_{sub}^{\max} \tag{10}$$

where P_k^R is the random power generation in the kth bus, $P_{sub}^{\max}$ is the maximum load level in ST substation.

3.5. ***Step 5:*** *generate a random vector that determines the time of investment in candidate buses*

In this step, for each candidate bus, a random number is generated to represent the time of investment in the bus during the future year.

$$2 \le t_i \le 52 \quad i \in B_c \tag{11}$$

After this step, the size of investment in each candidate bus is determined. The place, size, and time of installed DG must meet the network constraints. After the load-flow calculation, the bus voltages and line currents should be in standard ranges, as given by equations (12) and (13).

$$V_i^{\min} \le V_i \le V_i^{\max} \tag{12}$$

$$|I_i| \le I_{\max} \tag{13}$$

3.6. ***Step 6:*** *construct a yearly generation matrix*

In this step, considering the random vectors generated in steps 4 and 5, a matrix is constructed in which the rows represent the buses and columns represent the weeks of the year where each element shows the power generation of each bus in each week of the year. Fig. 5 depicts the matrix for a 4-bus network, where two investments with the size of P_2 and P_4 occur respectively in bus 2 and 4 in the second and third weeks of the year. The DisCo intends to determine the GEPP for a specific DG with capacity P in bus 3.

3.7. ***Step 7:*** *determine the loss-related price term of GEPP for the DG unit connected to the ith bus*

As discussed in part A of section II, with respect to power generation and consumption associated with the network buses at each load level, the loss-related price term of GEPP at the rth iteration of Monte-Carlo ($\lambda_{i,r}^{loss,j}$) is calculated by equation (14).

$$\begin{array}{c} \\ Bus\,1 \\ Bus\,2 \\ Bus\,3 \\ Bus\,4 \end{array} \begin{array}{c} \begin{array}{ccccccccc} 1^{st} & 2^{nd} & 3^{rd} & 4^{th} & 5^{th} & & 50^{th} & 51^{th} & 52^{th} \\ \text{week} & \text{week} & \text{week} & \text{week} & \text{week} & \cdots & \text{week} & \text{week} & \text{week} \end{array} \\ \begin{pmatrix} 0 & 0 & 0 & 0 & 0 & L & 0 & 0 & 0 \\ 0 & 0 & P_2 & P_2 & P_2 & L & P_2 & P_2 & P_2 \\ P_{inv} & P_{inv} & P_{inv} & P_{inv} & P_{inv} & L & P_{inv} & P_{inv} & P_{inv} \\ 0 & P_4 & P_4 & P_4 & P_4 & L & P_4 & P_4 & P_4 \end{pmatrix} \end{array}$$

Fig. 5. Structure of yearly generation matrix.

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$$\lambda_{i,r}^{loss,j} = \frac{1}{2}\left(\lambda_{DG,i}^{0,j} + \lambda_{DG,i}^{p,j}\right) \tag{14}$$

After determining the loss-related price for each load level, $\lambda_{i,r}^{loss}$, which is the loss-related price term of GEPP at the rth iteration, is obtained by averaging the $\lambda_{i,r}^{loss,j}$ over load levels according to equation (15).

$$\lambda_{i,r}^{loss} = \frac{\sum_j \lambda_{i,r}^{loss,j}}{52} \tag{15}$$

3.8. ***Step 8:*** *determine the reliability-related price term of the GEPP for the DG unit connected to the ith bus*

To determine the DG unit's share in reliability improvement, its effect in terms of reducing the cost of service interruption to customers is considered. The expected interruption cost is calculated by equation (16).

$$CIC = \sum_{d=1}^{NS} P_d \sum_{g=1}^{NC} CDF_g L_g \tag{16}$$

where P_d is the probability of failure in the dth network component, L_g is the gth bus interrupted load due to failure in the dth network component, and CDF_g is the customer damage function ($/kW(of the gth bus interrupted load.

As discussed in part B of section II, with respect to the power generation and consumption of the network buses at each load level, the contribution of the DG connected to the ith bus in CIC reduction at the rth iteration of the Monte-Carlo simulation is calculated by equations (17) and (20).

$$RII_{i,r}^{j} = \beta_r^j W_{i,r}^j + \left(1 - \beta_r^j\right) w_{i,r}^j \tag{17}$$

$$\begin{aligned} w_{i,r}^j &= V(\{1,2\ldots,N\}) - V(\{1,2\ldots,N\} - \{i\}) \\ W_{i,r}^j &= \max\left(V(z_i) - \sum_{\substack{m \in z_i \\ m \neq i}} V(m)\right) \end{aligned} \tag{18}$$

$$\sum_{n=1}^{N} \beta_r^j W_{n,r}^j + \left(1 - \beta_r^j\right) w_{n,r}^j = v(\{1,2\ldots,N\}) \tag{19}$$

$$\lambda_{i,r}^{re,j} = \frac{RII_{i,r}^j}{P_{DG,i}} \tag{20}$$

After determining the reliability-related price in each load level, $\lambda_{i,r}^{re}$, which is the reliability-related price term of the GEPP at the rth iteration, is obtained by averaging the $\lambda_{i,r}^{loss,j}$ over load levels according to equation (21).

$$\lambda_{i,r}^{re} = \frac{\sum_j \lambda_{i,r}^{re,j}}{52} \tag{21}$$

3.9. ***Step 9:*** *determine the GEPP for the DG unit in the rth iteration*

After determining the loss and reliability related terms of GEPP for DG unit, the GEPP in the rth iteration of algorithm is calculated by equation (23)

$$\lambda_i^r + \lambda_{avg}^e + \lambda_{i,r}^{re} + \lambda_{i,r}^{loss} \tag{22}$$

In which λ_{avg}^e is the annual average energy price in ST substation and is calculated by equation (23).

$$\lambda_{avg}^e = \frac{\sum_j \lambda_j^h}{52} \tag{23}$$

3.10. ***Step 10:*** *meet the Monte-Carlo convergence criteria*

The Monte-Carlo simulation output is a Probability Distribution Function (PDF) for GEPP. The convergence criteria for this simulation is checked by equation (24), in which σ and λ_i^{avg} are the standard deviation and average of the GEPP calculated by equations (25) and (26), respectively.

$$\frac{\sigma}{\sqrt{r}\lambda_i^{avg}} \leq \varepsilon \tag{24}$$

$$\sigma = \frac{1}{2}\sum_{h=1}^{r}\left(\lambda_i^h - \lambda_i^{avg}\right)^2 \tag{25}$$

$$\lambda_i^{avg} = \frac{\sum_{h=1}^{r} \lambda_k^h}{r} \tag{26}$$

where ε is a small value that specifies the algorithm's accuracy; the smaller the ε, the more accurate the solution.

3.11. ***Step 11:*** *select the GEPP based on risk analysis*

Probabilistic methods provide a set of probable values instead of a deterministic value. The DisCo must select the GEPP from the PDF obtained by Monte-Carlo simulation. In this paper, risk analysis is proposed for selecting the final value of the GEPP based on the Cumulative Distribution Function (CDF). As shown in Fig. 6, the vertical and horizontal axes of the CDF represent the risk level and GEPP, respectively. Based on acceptable risk, the DisCo can choose the corresponding GEPP for the DG unit; selecting higher values for the GEPP translates to less risk for the DG investor but higher risk for the DisCo.

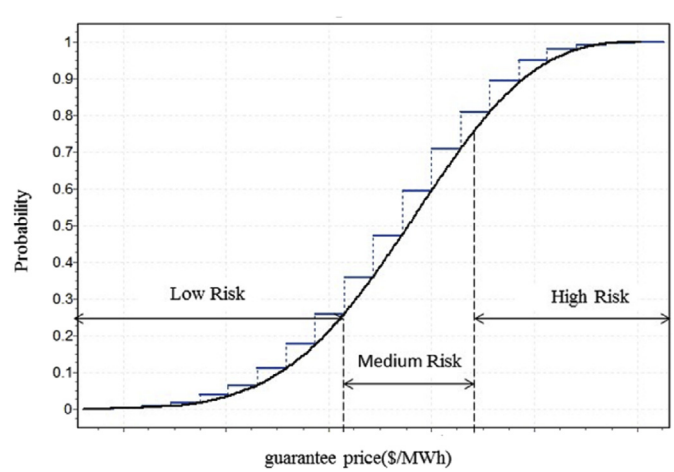

Fig. 6. The cumulative distribution function of GEPP.

4. Simulation results

The proposed methodology is tested using the 33-bus distribution system shown in Fig. 7 (Baran and Wu, 1989) and Figs. 8 and 9 depicts the average weekly load of the future year and the corresponding energy price at the ST substation, respectively. The power factor of all buses is assumed to be 0.85 and the contribution factor of each bus is shown in Table 1. The place of sectionalizer switches, which is important in reliability evaluation, is shown in Table 2. The contract duration between the investor and the DisCo is assumed to be one year. Base on our assumptions, the GEPP for each DG unit is calculated for the following different cases.

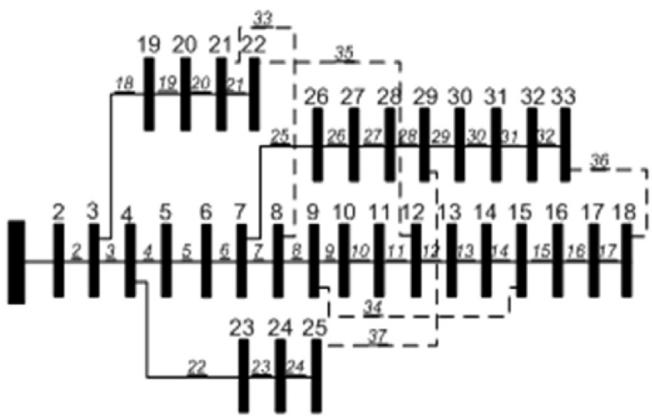

Fig. 7. 33-bus distribution test system (Baran and Wu, 1989).

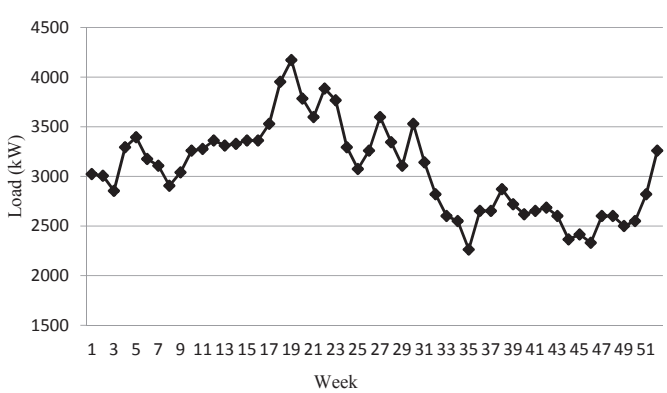

Fig. 8. Weekly load curve at ST substation.

Table 1
Bus load contribution factor.

Bus no	*CF*	Bus no	*CF*
1	0	18	0.022
2	0.066	19	0.06
3	0.06	20	0.022
4	0.08	21	0.022
5	0.015	22	0.022
6	0.015	23	0.017
7	0.05	24	0.077
8	0.05	25	0.077
9	0.015	26	0.011
10	0.015	27	0.011
11	0.03	28	0.011
12	0.04	29	0.022
13	0.015	30	0.037
14	0.03	31	0.027
15	0.015	32	0.039
16	0.015	33	0.011
17	0.015		

Table 2
Place of sectionalizer switches.

Send bus	Receive bus
1	2
3	4
4	5
7	8
12	13
3	19
4	23
7	26
29	30

4.1. Case 1: the impact of DG on loss reduction and reliability

In this case, it is assumed that an investor intends to install a DG unit with the capacity of 300 kW and a power factor of 0.95 at bus 4. With this assumption, and given load and energy prices in ST substation for the year ahead and considering the maximum penetration equal to 30%, the PDF of the GEPP is calculated. It is also assumed that the investment is possible in all buses except bus 1. The PDF of loss and reliability related price and the final GEPP for the DG unit are depicted in Figs. 10–12. As shown in Fig. 12, the minimum and maximum GEPP for the DG connected at bus 4 is equal to 26.82 and 27.25 ($/MWh), respectively. The lower GEPP corresponds to lower risk for the DisCo. Fig. 13 depicts the CDF of the GEPP for the low-risk (56%), medium-risk (14%), and high-risk (30%) scenarios. In other words, 56% of the obtained GEPP from the Monte-Carlo simulations fell into low-risk area. Thus, the DisCo can determine the GEPP based on its assessment of risk relative to the importance of the investment in bus 4. Although, selecting the higher GEPP persuades investors to install DG at that bus, it shifts more risk to the DisCo.

4.2. Case 2: the impact of DG location on the GEPP

To assess the impact of DG placement, the GEPP is determined for different DG locations considering its capacity equal to 300 kW. As shown in Table 3, by increasing the distance of DG units from the ST substation, the maximum GEPP is increased while the minimum

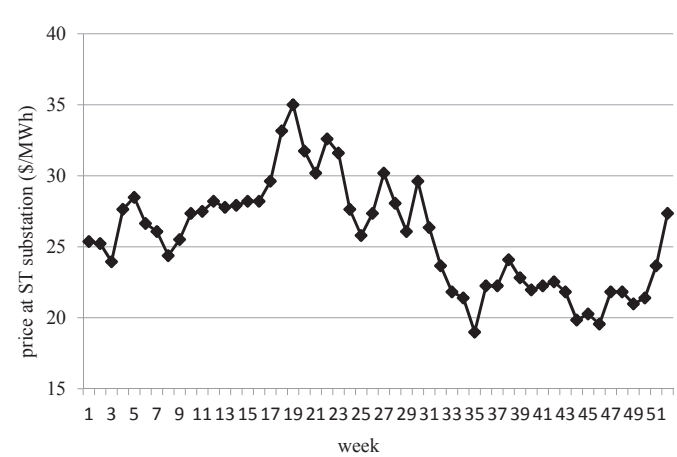

Fig. 9. Weekly price at ST substation.

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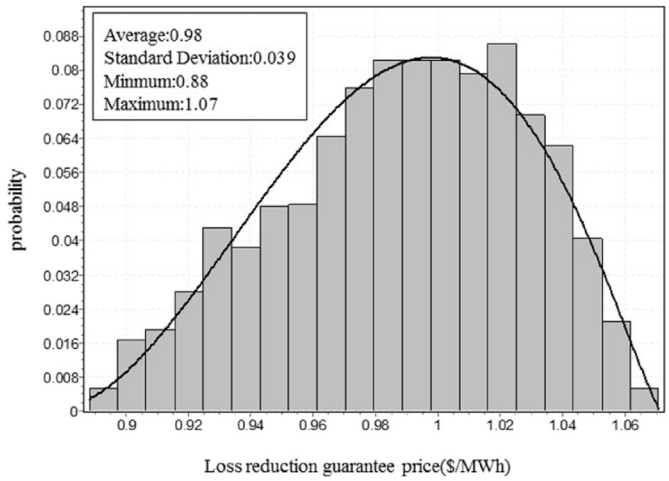

Fig. 10. PDF of the GEPP for the DG unit connected at bus 4 due to loss reduction.

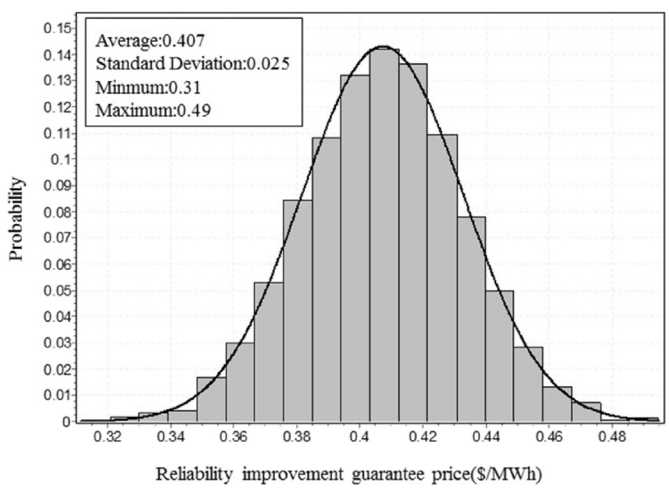

Fig. 11. PDF of the GEPP for the DG unit connected at bus 4 due to reliability improvement.

GEPP is decreased. The increase in the maximum GEPP is due to the increased effect of the DG on loss reduction and reliability improvement by increasing DG distance from ST substation. The decrease in the minimum GEPP is due to the increasing influence of other DG units on the considered DG unit associated with increasing the DG distance from the ST substation. Moreover, the standard deviation grows as distance from the ST substation increases, indicating increasing uncertainty associated with the GEPP. This means that the DisCo is faces lower risk when DG is installed closer to the ST substation.

4.3. Case 3: the impact of DG penetration on the GEPP

In this case, the impact of DG penetration on GEPP is investigated. For this purpose, the maximum allowable penetration is increased from 30% to 50%. As shown in Table 4, increasing DG penetration rate leads to growth in the standard deviation and thus the uncertainty associated with the GEPP. In addition, the minimum GEPP decreases with increasing DG penetration. The impacts of DG on loss reduction and reliability improvement fall with rising DG penetration rates.

4.4. Case 4: the impact of DG size on the GEPP

In this case, to assess the effect of DG size on GEPP, the capacity of DG is increased from 300 to 500 kW. As shown in Table 5, the standard deviation decreases as DG size increases. The reason is that for a given DG penetration rate, the number of investment scenarios falls as the DG size grows, which leads to lower uncertainty in the GEPP. It can also be seen that the minimum GEPP is increased while the average and maximum GEPP are decreased due to reductions of other DG units and unit size growth, respectively.

4.5. Case 5: the impact of candidate bus numbers on the GEPP

In this case, the effect of the number of candidate buses on GEPP is investigated. For this purpose, it is assumed that the investment in buses 1, 2, 5, 8, 16, and 23 is not possible. As shown in Table 6, the standard deviation, which represents GEPP uncertainty, decreases when the number of candidate buses is decreased. The reason in this case is that the number of investment scenarios is decreased.

4.6. Case 6: the effect of sectionalizer switch numbers on GEPP

In this case, we assumed that the sectionalizer switches shown

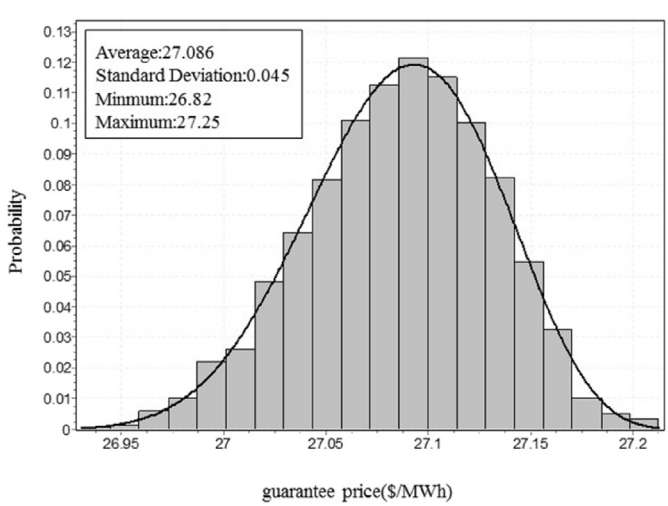

Fig. 12. PDF of the GEPP for the DG unit connected at bus 4.

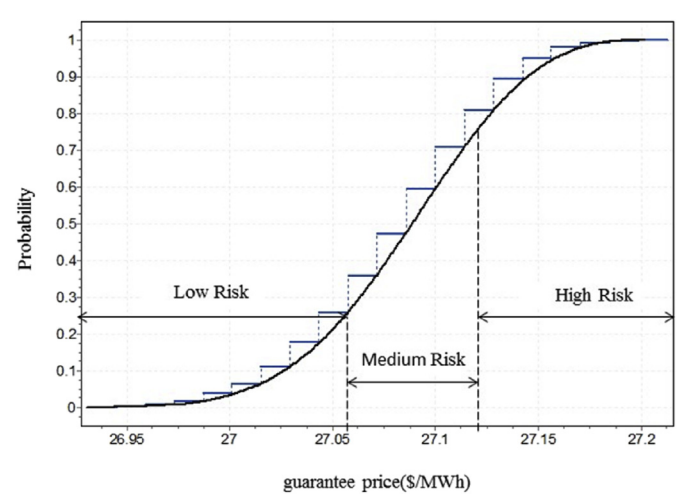

Fig. 13. The CDF of GEPP of the DG connected at bus 4.

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Table 3
GEPP PDF parameters in different buses.

Bus.no	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Length of GEPP range ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)	Minimum risk (%)	Medium risk (%)	Maximum risk (%)
4	26.82	27.25	0.43	27.086	0.045	56	14	30
7	27.66	28.47	0.81	28.21	0.16	54	30	16
12	27.63	29.85	2.22	29.3	0.38	63	25	12
18	27.29	30.8	3.51	29.54	0.49	56	19	25
32	26.95	31.63	4.68	31.26	0.5	88	11	1

Table 4
GEPP PDF parameters with the increase in DG penetration.

Bus.no	DG penetration: 30%				DG penetration: 50%			
	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)
4	26.82	27.25	27.086	0.045	26.62	27.19	26.94	0.11
7	27.66	28.47	28.21	0.16	27.052	28.49	27.94	0.305
12	27.63	29.85	29.3	0.38	26.72	29.86	28.93	0.59
18	27.29	30.8	29.54	0.49	26.23	30.25	29.13	0.7
32	26.95	31.63	31.26	0.5	26.95	31.84	30.84	0.78

Table 5
GEPP PDF parameters with the increase in DG size.

Bus.no	DG size: 300 kW				DG size: 500 kW			
	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)
4	26.82	27.25	27.086	0.045	26.94	27.17	27.068	0.0389
7	27.66	28.47	28.21	0.16	27.78	28.42	28.15	0.13
12	27.63	29.85	29.3	0.38	27.88	29.46	29	0.3
18	27.29	30.8	29.54	0.49	27.49	29.5	28.9	0.33
32	26.95	31.63	31.26	0.5	28.34	31.44	30.81	0.45

Table 6
GEPP PDF parameters with the decrease in candidate buses.

Bus.no	Forbidden buses: 1				Forbidden buses:1,2,5,8,16,23			
	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)
4	26.82	27.25	27.086	0.045	26.95	27.22	27.088	0.044
7	27.66	28.47	28.21	0.16	27.72	28.53	28.21	0.14
12	27.63	29.85	29.3	0.38	27.8	29.9	29.28	0.34
18	27.29	30.8	29.54	0.49	27.54	30.22	29.54	0.46
32	26.95	31.63	31.26	0.5	28.1	31.87	31.2	0.48

in Table 7 are in the network (in addition to the existing ones). As can be seen in this Table 8, the average GEPP increases with the increase in the number of sectionalizer switches. The higher GEPP is obtained because increasing the number of switches enhances the effect of DG the maneuverability and thus the reliability of the distribution system. Moreover, the growth of GEPP in downstream buses is much more than the upstream buses. This is because downstream DG can be used in more distribution system failure modes for load restoration.

4.7. Case 7: the impact of annual load on the GEPP

In this case, the impact of a 20% increase in annual load, on the GEPP is investigated. As seen in Table 9, load level growth is associated with an increase in the GEPP because the effect of DG on loss reduction and reliability improvement is increased. The results also show that the standard deviation of GEPP increases with increasing investment associated with load growth.

Table 7
Place of new sectionalizer switches.

Sent bus	Receive bus
16	17
9	10
31	32
27	28
24	25
20	21

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Table 8
GEPP PDF parameters with the increase in sectionalizer switches.

Bus.no	Number of sectionalizer switches:9				Number of sectionalizer switches:15			
	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)
4	26.82	27.25	27.086	0.045	26.92	27.21	27.086	0.045
7	27.66	28.47	28.21	0.16	27.73	28.52	28.22	0.16
12	27.63	29.85	29.3	0.38	27.9	30.1	29.44	0.41
18	27.29	30.8	29.54	0.49	27.66	30.46	29.74	0.52
32	26.95	31.63	31.26	0.5	28	31.86	31.45	0.54

Table 9
GEPP PDF parameters with the increase in load level.

Bus.no	Load level: normal load				Load level: 120% normal load			
	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)	Minimum GEPP ($/MWh)	Maximum GEPP ($/MWh)	Average GEPP ($/MWh)	Standard deviation ($/MWh)
4	26.82	27.25	27.086	0.045	27.2	27.49	27.34	0.047
7	27.66	28.47	28.21	0.16	28.26	29.02	28.74	0.19
12	27.63	29.85	29.3	0.38	28.62	30.69	30.1	0.41
18	27.29	30.8	29.54	0.49	31.28	31.21	30.48	0.5
32	26.95	31.63	31.26	0.5	28.83	32.6	32.05	0.48

5. Comparison of case studies results

Comparing the results of seven cases shows that the DG penetration rate has the most significant impact on the GEPP and deviation, or GEPP uncertainty. In addition, after the penetration rate, the results indicate that increasing the distance of DG from the ST substation increases the GEPP. In our simulations, DG size and annual load have a moderate impact on the GEPP. However, the number of candidate buses and switches do not affect the GEPP and deviation as much as other factors.

6. Conclusion

We presented a methodology for determining the energy guaranteed purchasing price (GEPP) for DG units. The proposed methodology determined the GEPP for each DG unit based on its contribution to loss reduction and reliability improvement. Due to the dependency of the GEPP on future investments and the uncertainty during decision period, Monte-Carlo simulation was used for obtaining the probability and cumulative distribution functions (PDF and CDF) of GEPP. Finally, the obtained PDF and CDF were used to extract the final value of the GEPP by considering the DisCo's acceptable risk. Simulation results showed the influence of different parameters on the GEPP, particularly DG penetration rates, location, size and annual loads. The findings reveal that investors can be appropriately compensated for DG, taking place and size into account, and DisCos can make use of DG to improve operations in terms of loss reduction and improved reliability to the benefit of consumers.

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