Distribution System Expansion Planning In A Deregulated Environment Under System Uncertainties

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Abstract: This paper presents a long-term distribution system planning model considering technical and economical constraints using Monte Carlo simulation. A proposed optimization model is applied to distribution system planning in a competitive environment. All network equipments including feeders, substation, intertie and DISCO-owned or SPP (Small Power Producer)-owned DGs in different technologies are included in this long term distribution system planning. Moreover, the planner experimental decisions are also considered in this planing. The proposed planning method considers not-supplied energy costs also. The uncertain availability of the system components and uncertainty for demand forecast are seen as uncertain parameters. To manage uncertaininty, reliability requirments of the system is also considered in this method. Monte Carlo simulation is used to generate numerous scenarios based on the uncertainties in distribution system. To evaluate the ability of the proposed method, a typical 32 buses distribution system is used for two environmental scenarios. Comparative results confirm the effectiveness of the proposed model and investigate the impact of existence of different energy sources in system operation and economics.

Keywords: Distribution System long-term planning, Distributed Generation, intertie, not-supplied energy, Monte-Carlo simulation

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1. Introduction

The main objectives of the deregulation are to improve efficiency of the electric power industry and to reduce electricity prices. Electric utility distribution companies (DISCOs) endeavour to improve their profits and minimize the investment risk to meet the growth demands in their territories while keeping their customers' bills affordable [1]. The aim of the DSP (distribution system planning) is to assure that the growing load demand can be fulfilled technically and economically by optimal distribution system expansion. The new DSP problem has to be formulated and introduced to obtain the win–win case for all players by introducing non-traditional capacity investment options [2,3]. Distribution company (DISCO) planners continually endeavour to develop new planning strategies for their network in order to serve the load growth, provide their customers a reliable electricity supply and survive in the competitive electricity market [1]. Traditionally, the first step in long term distribution system design is load forecasting. Then, based on load forcast, distribution system investment planning studies are carried out considering the addition of new substations or expanding the existing substations. Expanding subatations may be down by extending the capacity and associated new feeder requirements for serving the forecasted load demands in distribution systems.

There are many published papers in literature, present models and algorithms for distribution system planning. Until 90s, distribution system expansion planning literature just included the options of adding new substations and connecting feeders [4,5]. In the most of them, only one or two objects and constraints had been considered. Fletcher and Strunz formulated a primary and secondary distribution system planning model. They emphasis on substation and feeder numbering, selection of appropriate voltage level, and sizing of feeder length and capacity in [4,5].

In recent years, it has been observed that with the advent of deregulation in power system, traditional distribution planning models have undergone a paradigm change to address the various arising issues. DSP models have introduced new resource options such as interties and distributed generators (DGs), driven by technological developments and the competitive structure of electricity markets [6-10]. The proposed optimization model in [11] allows minimizing total system planning costs for DG investment, operation, maintenance, purchase of power by the DISCOs from transmission companies (TRANSCOs) and system power losses. The proposed model provides not only the DG size and site but also the new market price as well. Elkhattam et al. in [7] propose a new heuristic approach for DG capacity investment planning from the perspective of a DISCO through a cost-benefit analysis approach based on a new optimization model. Bus-wise cost-benefit analysis is carried out on an hourly basis for different forecasted peak demand and market price scenarios. In [12] a model is presented for optimal sizing and siting of DG in distribution system that allows planner to make the best compromise between the cost of network upgrade, power losses, not supplied energy and the energy needed to supply the load. In all above menshened papers, the size and location of DGs are considered as decision variables while feeders and substations of the distribution network are supposed to be as constant parameters. In [8] the proposed model for solving the DSP, integrates a comprehensive optimization model and planner's experience to achieve optimal sizing and siting of distributed generation. In this model, improvement of substation and feeders are not considered as variables but they were studied according to the available alternative scenarios. A hierarchical dynamic optimization model is proposed for distribution system long-term planning from the DISCO's perspective in [13,14] that incorporates various energy supply options for DISCOs such as DGs (SPP-ownd and DISCO-owned) and interties. Some scenarios are extended to predict the impact of different energy policies on distribution system operation and economics. These papers have presened a comprehensive model for DSP but have not incorporated the not supplied energy in the problem. In [15], a risk-based optimization approach is proposed to model a multistage distribution expansion planning problem. This research considers return-per-risk index as reliability index of DISCO. This index achieves an efficient synergy between the expected return and the risk of investments by performing Monte Carlo simulations.

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Autours of [16] presented a distribution system expansion planning method focused on three thecnologies of DG (wind, photovoltaic and biomass resources) and their reactive power limits. In [17,18] the DSP is formulated as a multi level mixed integer nonlinear model, where the objective function includes the investments, operation and reliability costs in probabilistic condition. Unserved energy is studied as reliability index in this paper.

This paper proposes a DSP model to make the optimal technical and economical choice in the sense of DISCO. The addressed problem in this paper is a long-term planning problem with the objective of maximizing DISCO profit considering concepts of regulations, DG technologies, intertie and subtransmission substation expansion and penalty for not-supplied energy to develop a comprehensive method for DSP. The proposed model decides the sizing and siting of all facilities include feeders, substations and interties. Both types of DG (DISCO-owned and SPP-owned) in different technologies as well as the required power to be imported from the main grid through DISCO's substations or an existing intertie are also considered to meet the demand in an optimal way. The aim of the proposed framework is minimizing the total planning cost including investment, operating, emissions and not-supplied energy costs. In this study, the unmet demand is used as a metric to represent the reliability of the system. Availability of the system components is uncertain which implies to incorporate system reliability. Hence, the availability of the system components is explicitly considered as a part of expansion planning problem. Another important uncertain parameter is load demand. Demand used in DSP problems are usually forecasted numbers, which are uncertain. Including this uncertainty into the model provides a more realistic model of the system. Monte Carlo simulation (MCS) is a technique used to understand the impact of risk and uncertainty in financial, project management, cost, and other forecasting models. MCS is used to generate scenarios based on the uncertainty in availability of the system components and uncertainty in load blocks. A two stages optimization model is used to solve the proposed model. The first stage is a mixed integer linear programming (MILP) and second one is a nonlinear programming (NLP). The proposed model has been programmed and executed in GAMS software area. The impact of existence of intertie and DGs are investigated in a 32 buses DSP final plan.

The Monte Carlo simulation is explained in Section 2. In section 3, principles of DSP and the mathematical modelling of the associated optimisation models are explained. Section 4, implementes the detailed plan studies and investigates results considering a 32 buses radial DS. Finally, conclusions are summarized in Section 5.

2. Monte Carlo Simulation

The objective of this research is to integrate uncertainity based reliability analysis with expansion planning and dispatching decisions. To achieve this objective, a stochastic simulation based optimization approach is proposed. Numerous scenarios considering the availability of the system components are generated. In each scenario, MCS is used to randomly assign whether the system assets (feeders) are available or not and also determine the load block in every time and every load level based on their probability. Uncertaine parameters used in mathematical model are scenario based; that is, they are obtained from MCS. In each scenario, uniform distributed random numbers between 0 and 1 are selected for each load block l in time t. Predefined probability rate is assigned for each uncertain parameter. The unavailable feeder is chosen randomly between all feeders based on a uniformly distributed random generator.

3. Mathematical modeling of Monte Carlo simulation methode

Ideally, a mixed-integer non-linear programming (MINLP) seems proper to solve the DSP problem. However, such a formulation is computationally very intensive and practically often failed to converge to a feasible and nearly optimal solution because of complexities. This complexity arises from nonlinearities and presence of binary variables in the model.

To overcome to this problem, a two-stage hierarchical scheme of inter-related models is proposed that imitates the decision making process of the real-world planning: first stage is a MILP that determines the optimal period and location of resource installation over the planning horizon of 10 years. Second stage is a NLP that determines the optimal unit capacities and production/contract schedules and makes any necessary modifications to the first stage recommendations.

3.1. First stage: Mixed Integer Linear Programming (MILP)

The goal of this stage is to determine the optimum level of future DS investments over a 10 years period. Inputs of MILP are; the demand at each bus, load estimate/forecast for each year, information on available resources and their characteristics such as their unit investment and energy costs as well as their market prices. Decision outputs of this stage are used as inputs to the second stage. Moreover, the planner expert knowledge may also be involved to predetermine parameters.

The objective function, J in (1), is the present value of the total system real time cost of DS investments and operations. This may be calculated using different discount rates of investment and different energy prices components over the planning horizon in the sense of DISCO. The objective function is as following:

$$J = \sum_t^T \left(\frac{1}{(1+IRc)^t} * (J_a + J_b + J_c + J_d) + \sum_t^T \frac{1}{(1+IRe)^t} * (J_e + J_f + J_g + J_h + J_i - J_j + J_{unmet}\right)$$

Where J_a, J_b and J_c, are the engineering, procurement and construction (EPC) costs, capacity costs of feeder, and substation and intertie placement costs respectively. J_d is the investment cost of DISCO- owned DG which varies by technology. J_e is the cost of importing energy to the DISCO from the external grid/electricity market via substations. J_f is the cost of power imported from neighbouring DISCOs via interties. J_g is the DISCO's cost of operating its own DG. J_h is the cost of energy purchased by the DISCO from SPP-owned DG assumed to be based on an apriori fixed price contract. J_i is the cost arising from emmision tax scheme that may be enforced by the government and J_j is the revenue earned by the DISCO for power exports to the grid via substations. Finally, J_{unmet} is the penalty cost of not supplied energy. Details of these costs are as:

$$J_a = \sum_{i,j} Ccffdr * G(i,j) * L(i,j) * zfdr(i,j,t) + Ccvfdr * wfdr(i,j,t) \quad (2)$$

$$J_b = \sum_i Ccfss * zss(i,t) + Ccvss * wss(i,t) \quad (3)$$

$$J_c = \sum_i Ccfint * zint(i,t) + Ccvint * wint(i,t) \quad (4)$$

$$J_d = \sum_{i,tech} (1 + CRcDGU(tech))^t * CcDGu(tech) * wDGu(tech,i,t) \quad (5)$$

$$J_e = \sum_{i,l} Psss(i,l,t) * Hrs(l) * Cess(l,t) \quad (6)$$

$$J_f = \sum_{i,l} Psint(i,l,t) * Hrs(l) * Ceint(l,t) \quad (7)$$

$$J_g = \sum_{tech,i,l} (1 + CRoDGu(tech))^t * PsDGu(tech,i,l,t) * Hrs(l) * CoDGu(tech) \quad (8)$$

$$J_h = \sum_{tech,i,l} PsDGp(tech,i,l,t) * Hrs(l) * CeDGp(tech,l,t) \quad (9)$$

$$J_i = \sum_{tech,i,l} PsDGp(tech,i,l,t) * Hrs(l) * EmP(t) * Em(tech) + \sum_{tech,i,l} PsDGu(tech,i,l,t) * Hrs(l) * EmP(t) * Em(tech) \quad (10)$$

$$J_j = \sum_{i,l} Px(i,l,t) * Hrs(l) * Cx(l,t) \quad (11)$$

$$J_{unmet} = \sum_{i,l} unmetPd(i,l,t) * Hrs(l) * Cunmet(l,t) \quad (12)$$

The constraints of DSP problem including all technical and economical constraints are represented as following:

3.1.1. Nodal power balance: the power balance equations in buses are a set of nonlinear equations. In this stage a simple linear power flow representation is used which implies less computation. Feeders' losses are approximated by loss factor of power flow:)

$$\sum_j \Big(\big(1 - \mathrm{Lsfdr}(j,i,t)\big) * \mathrm{P}(j,i,l,t) - \mathrm{P}(i,j,l,t)\Big) = \mathrm{Px}(i,l,t) + (1 + \mathrm{Rs}) * \mathrm{Pd}(i,l,t) - \mathrm{unmetPd}(i,l,t) - \mathrm{Psss}(i,l,t) - \mathrm{Psint}(i,l,t) - \sum_{\mathrm{tech}} \mathrm{PsDGu}(\mathrm{tech},i,l,t) - \sum_{\mathrm{tech}} \mathrm{PsDGp}(\mathrm{tech},i,l,t) \quad (13)$$

3.1.2. Feeder capacity limits: Feeder thermal limits impose limits on loading of feeders;

$$\mathrm{P}(i,j,l,t) \le \mathrm{wfdr}(i,j,t0) + \sum_t \mathrm{wfdr}(i,j,t) \quad (14)$$

$$\mathrm{wfdr}(i,j,t) \le \mathrm{wfdrmax}(i,j) \quad (15)$$

3.1.3. Capacity adequacy limits: This constraint ensures that 80% of substation, DG and intertie capacities are adequate to meet peak demand plus reserve for any given year.

$$0.8 * \sum_i \{(\mathrm{wss}(i,t0) + \sum_t \mathrm{wss}(i,t) + \mathrm{wint}(i,t0) + \sum_t \mathrm{wint}(i,t)\} + \sum_{\mathrm{tech},i,t} \mathrm{wDGu}(\mathrm{tech},i,t) + \sum_t \mathrm{wDGp}(\mathrm{tech},i) * \mathrm{zDGp}(\mathrm{tech},i) \ge \sum_i (1 + \mathrm{Rs}) * \mathrm{Pd}(i,'\mathrm{peak}',t) \quad (16)$$

3.1.4. Substation capacity limits: Energy purchased from external grid/electricity market is transferred to the DS via substations. Hence, it is limited by the capacity limits of substation:

$$\mathrm{Psss}(i,l,t) \le \mathrm{wss}(i,t0) + \sum_t \mathrm{wss}(i,t) \quad (17)$$

$$\mathrm{wss}(i,t) \le \mathrm{wssmax} \quad (18)$$

$$\mathrm{wss}(i,t) \ge \mathrm{wssmin} * \mathrm{zss}(i,t) \quad (19)$$

3.1.5. Intertie capacity limits: It is assumed the DS is connected via interties have the same nominal voltage. Thus, transformers are not required. The power transferred via intertie is limited by entertie capacity.

$$\mathrm{Psint}(i,l,t) \le \mathrm{wint}(i,j,t0) + \textstyle\sum_t \mathrm{wint}(i,t) \quad (20)$$

$$\mathrm{wint}(i,t) \le \mathrm{wintmax} \quad (21)$$

3.1.6. DISCO-owned DG capacity limits: DSP recommends technology, size and placement of DISCO's DG units, whose energies are limited by their capacities.

$$\mathrm{PsDGu}(tech,i,l,t) \le \mathrm{wDGu}(tech,i,t0) + \textstyle\sum_t \mathrm{wDGu}(tech,i,t) \quad (22)$$

$$\mathrm{wDGu}(tech,i,t) \le \mathrm{wDGumax}(tech) \quad (23)$$

$$\mathrm{wDGu}(tech,i,t)\mathrm{wDGumin}(tech) * \mathrm{zDGu}(tech,i,t) \quad (24)$$

3.1.7. SPP-owned DG capacity limits: The planner may have no control over the size, location, or time of SPP-owned DG investments. Nevertheless, generation from SPP-owned DG must be limited by their capacities. Under special circumstances, planner may preset the location(s).

$$\textstyle\sum_i \mathrm{zDGp}(tech,i) = 1 \quad (25)$$

$$\mathrm{PsDGp}(tech,i,l,t) \le \mathrm{wDGp}(tech) * \mathrm{zDGp}(tech,i) \quad (26)$$

3.1.8. Total DG capacity limits: this constraint determine Minimum and/or maximum DG penetration.

$$\textstyle\sum_{tech,i} \mathrm{PsDGu}(tech,i,l,t) + \sum_{tech,i} \mathrm{PsDGp}(tech,i,l,t) \le \mathrm{FDGmax}(\sum_i (1+Rs) * \mathrm{Pd}(i,l,t) + \sum_i \mathrm{Px}(i,l,t)) \quad (27)$$

$$\textstyle\sum_{tech,i} \mathrm{PsDGu}(tech,i,l,t) + \sum_{tech,i} \mathrm{PsDGp}(tech,i,l,t) \ge \mathrm{FDGmin}(\sum_i (1+Rs) * \mathrm{Pd}(i,l,t) + \sum_i \mathrm{Px}(i,l,t)) \quad (28)$$

3.1.9. Budget limits: The annual investment expenditures on feeders, substations, intertie and DISCO-owned DG is limited by allowable budget.

$$J_a + J_b + J_c + J_d \le \mathrm{Budget}(t) \quad (29)$$

3.1.10. Emission limits: Based on CO_2 emission caused by DGs, there are different policy sets by government. In this paper exceeded emission encountered more than maximum allowable emission limit is penelized by addition cost;

$$\textstyle\sum_{tech,i,l} \mathrm{PsDGu}(tech,i,l,t) * \mathrm{Hrs}(l) * \mathrm{Em}(tech) + \sum_{tech,i,l} \mathrm{PsDGp}(tech,i,l,t) * \mathrm{Hrs}(l) * \mathrm{Em}(tech) \le \mathrm{Emmax} + \mathrm{Emx}(t) \quad (30)$$

3.2. Second stage: Non-Linear Programming (NLP)

The DS resource upgrades/installations, their locations and build dates obtained from previous stage are used as inputs to this stage. This stage determines the capacity (within pre-defined bounds) with accurate power flow representation, including losses and voltage drop constraints. The equation of objective function is the same as first stage but this stage uses nonlinear power flow equations. Hence, the dynamic-NLP is used to optimize these equations. Note that, nonlinear power flow equations need some additional data included feeder's impedances and allowable voltage limits. Based on results earned from first stage, network impedance matrix is perfomed and enters as input to second stage.

$$P(i,j,l,t) = v(i,l,t) * \frac{v(i,l,t) - v(j,l,t)}{|Z(i,j,t)|} \quad (31)$$

$$\textstyle\sum_j \mathrm{AvailFdr}(i,j,l,t) * \{P(j,i,l,t) - \frac{(v(j,l,t)-v(i,l,t))^2}{|Z(i,j,t)|}\} = \mathrm{Px}(i,l,t) + (1+Rs) * \mathrm{Pd}(i,l,t) - \mathrm{Psss}(i,l,t) - \mathrm{Psint}(i,l,t) - \sum_{tech} \sum \mathrm{PsDGu}(tech,i,l,t) - \sum_{tech} \mathrm{PsDGp}(tech,i,l,t) \quad (32)$$

And the voltage profile must be maintained within specified limits.

$$\mathrm{Vmin} \le V(i,l,t) \le \mathrm{Vmax} \quad (33)$$

Other constraints in this stage are the same as in MILP. Moreover, final capacity of all resources may be restricted in a nighberhood MILP resuls.

4. Numerical examples

4.1. Description of distribution test system

The testbed is a 32 buses system as shown in Figure 1. This system is connected to grid via bus 1. There is a candidate intertie site at bus 30. The total system peak demand is 37 MW (including reserve) in year 0 and it grows 3% annually. Power factor is assumed unity in this distribution system.

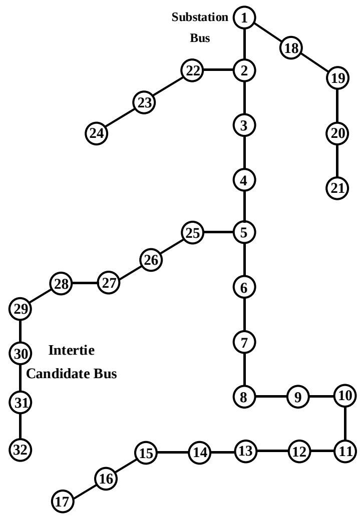

Fig 1. 32 buses distribution system

Each feeder segment length is 1 km with geographic facor of 0.4, and a loss factor of 2%. Three DGs are contracted between DISCO and SPP as; SPPDG1, a 1.5 MW photovoltaic system at year 3 in one of the

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buses 17, 29, 30, 31 or 32, SPPDG2, a 1 MW gas turbine at year 3 in bus 23 and SPPDG3, a 2 MW wind turbine at year 5 in bus no.19 or 20, to be installed. Feeder, substation and intertie fixed investment costs are 150000 $/Km, 200000 $ and 200000 $ respectively. Feeder, substation and intertie variable costs are 1000 $/Km, 50000 $ and 1000 $ respectively. Maximum allowable penetration of DGs is 20%. Generation cost and emission of DGs are given in table 1. Energy price of different resources at year 0 is given in table 2 and inflation rate of energy and investment costs is 8%. The load model is divided into demand intervals and is calculated the probabilities for each interval. The demand intervals and corresponding probabilities are presented in table 3.

The programming of test system is carried out in the GAMS software area. The first stage programing is a MILP using CPLEX solver while the second stage is a DNLP using MINOS solver.

4.2. Case studies

In this section two cases are examinined based on maximum emission rate in a comparative study to evaluate the capability of the proposed methodology under future uncertainties. There may be different government based policy sets for DG CO2 emission control. In this paper, impact of two different policy sets in DS planning and design are evaluted. In every case, MCS method with 1000 samples is applied using predefined uncertain parameters.

4.2.1. Case study A: fixed cost for emission produced by DGs

In this case, a cost is evaluated for DISCO and DGs based on their emission. It is assumed that emission cost is 10 $/ton. The test distribution system was planned under this regulation. The corresponding results of DS expansion plan are given in table 4.

Results show that the 10-years plan emphasises on gas turbine and diesel engine investments in first three years. It is justifiable because of their low investment and operating costs. In two next years, investment in fossil fuel DGs is not justifiable because of increased operating costs. Hence, investments in wind turbines are recommended in next three years. Investment in intertie connection is recommended at the start of the planning period at its maximum permited capacity; while substation upgrade are recommended in third year.

4.2.2. Case study B: threshold limiting of emission

In this case, exceeded emission encountered more than maximum allowable emission limit is penelized by additional cost.

Table 1. Generation cost and emission of DGs

DG technology	Investment cost (M$)	Operating cost ($/MWh)	Annual change in operating cost (%)	CO_2 emission (tonnes/MWh)
Diesel engine	0.4	90	+3	0.65
Gas turbine	0.825	75	+4	0.63
PV system	7.5	4	-4	0
Wind turbine	2.5	10	-1	0

Table 2. Energy cost for different power rsesources

Energy prices	**Price ($/MWh)**		
	Base load	**Intermediate load**	**Peak load**
import via subtransmission substation	110	92	75
import via intertie	100	70	50
Export to the transmission system via substation	108	90	73
Power purchased from SPP-owned DG	90	72	55
Not-supplied energy	200	280	500

Table 3. Load block and their intervals

Load block	% of peak load	Probability %	Load block	% of peak load	Probability %

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Peak1	100	1	Intermediate3	0.6	23
Peak2	0.95	1	Base1	0.5	21
Peak3	0.9	2	Base2	0.4	22
Intermediate1	0.8	11	Base3	0.3	3
Intermediate2	0.7	16			

Maximum allowable emission is 30000 tonnes/year. It is assumed that emission tax for additional emission is 50 $/ton. The corresponding DS expansion plan is given in table 5.

4.2.3. Case study B: threshold limiting of emission

In this case, exceeded emission encountered more than maximum allowable emission limit is penelized by additional cost. Maximum allowable emission is 30000 tonnes/year. It is assumed that emission tax for additional emission is 50 $/ton. The corresponding DS expansion plan is given in table 5.

It can be shown that in this case unlike the case A, there is not high tendency to install diesel engine and gas turbine; while the 10-years plan emphasises on wind turbine investments in years 2 to 7. This is because of high operating costs of fossil fuell DGs and specially imposed emission limit and high cost of emission in this case. Intertie connection is also recommended at the start of the planning period at its maximum permited capacity. While substation is not upgraded in this scenario, three feeders are recommended to be upgraded as the table.

It can be seen that in both cases diesel engine, gas turbine and wind turbine are recommended DGs to be installed in the DS (installation of gas turbine and diesel engine in caseA is very low in comparison with case B), while any photovoltaeic system connection is not recommended. It is because of very high investment cost of PV in comparison with the other DGs. Hence, for increasing the penetration level of PV, governments may either force or pay subsidies to DISCOs. It is more noticeable that in both cases, most of DG resource investments have been recommended for near ends of branchs where they have the most impact on reducing feeder losses.

Table 4. Distribution system expansion plan of case A

Year	New capacity/upgraded capacity in MW to be built (bus)								
	Substation	intertie	Diesel engine	Gas turbine	Wind turbine	SPP-owned DG			Feeder
						Solar	gas	Wind	
1	-	10(30)	0.11(16)	10(7) 6.197(13) 10(24)	-	-	-	-	0.243 (29, 30)
2	-	-	1.935(21)	3.247(3) 3.928(22)	-	-	-	-	-
3	55(1)	-	-	10(2)	-	1.5(17)	1(23)	-	-
4	-	-	-	-	2.367(18)	-	-	-	-
5	-	-	-	-	7.633(18)	-	-	2(20)	-
6	-	-	-	-	1.55(2)	-	-	-	-

Table 5. Distribution system expansion plan of case B

Year	New capacity/upgraded capacity in MW to be built (bus)								
	Substation	intertie	Diesel engine	Gas turbine	Wind turbine	SPP-owned DG			Feeder
						Solar	Gas	Wind	
1	-	10(30)	-	5.547(6)	-	-	-	-	2.088 (2,22)

									2.605(29,30)
2	-	-	-	-	8.104(9) 6.26(10) 5(11) 5.328(13)				
3	-	-	1.654(24)	-	9.617(21) 7.937(24)	-	-	-	-
4	-	-	-	-	0.383(21) 2.063(24)	1.5(17)	1(23)	-	-
5	-	-	-	-	6.61(7) 5(22)	-	-	-	-
6	-	-	-	-	5(22)	-	-	2(20)	-
7	-	-	-	-	5(3) 10(18)	-	-	-	-

Table 6. Calculated results for cases A and B

Average of all scenarios in MCS scenarios (standard deviation)					
Cases	Case A	Case B	Cases	Case A	Case B
Cost of plan ($)	3.69908082E+08 (2766430.531)	4.1920374E+08 (3556815.47)	Operation cost($)	3.25284E+08 (721342)	1.02583061E+08 (691501.64)
Investment cost($)	4.635311E+07 (13264.3)	3.16620671E08 (3255383.97)	Loss(MWh)	17955 (525.44)	13568.8 (398.08)
Not- supplied energy (MWh)	1144404 (18762.47)	1142935.3 (8543.5)	Emission (tonnes)	2213892 (13428.94)	387250.1 (17137.3)
Imported energy to the grid (MWh)	7738747 (37011.66)	2501158 (56217.6)			

Since intertie is a cheaper source of energy, investment in intertie connection is recommended at the start of the planning period at its maximum permited capacity in both cases. However, substation upgrades is different in two cases. Substation upgrade is recommended in third year in case A, but there is no need to upgrade the substation in case B. The export of energy via the substation is a result of the excess generation capacity available from DISCO and SPP-owned DGs, which can be sold for additional income. Both cases have revealed that feeder between buses 29 and 30 is a weak feeder; hence, both cases have recommended to upgrade it. Buses 17, 20 and 23 were selected for SPPDGs 1, 2 and 3 (solar, gas turbine and wind turbine), respectively. Note that, DISCO had only one choice for the placement of SPPDG2 (i.e. bus 20).

The other calculated results of cases A and B including total cost, investment cost and operating cost of plan, emissions, loss, not-supplied energy and exported power to subtransmition system are given in table 6. The penetration level percentage of DG technologies is presented in table 7.

It is seen that gas turbine has the largest penetration level in case A, while in case B, penetration level of gas turbine is decreased because of imposed emission limit. The WT penetration level is increased from 22% in case A to 89% in case B. This table shows that clean and renewable technologies have the highest penetration level in case B. Hence, CO_2 emission in case B is about 1/6 of emission in case A. The high penetration level of WT causes increament of total cost of plan for case B, specially investment cost to seven times biger than in case A. Since, there is no substation upgrade in case B, the exported power of DS to subtransmition system is decreased.

Table 7. Penetration level (%) of DG technologies for cases A and B

Cases	All DG capacity	DE	GT	WT	PV
Case A	61.5MW	3.3%	72.2%	22%	2.4%
Case B	88MW	1.9%	7.4%	89%	1.7%

5. Conclusion

This paper presents a comprehensive framework for DS design and planning considering uncertainties, in a deregulated environment. A two-stage planning method based on Monte Carlo simulation has been proposed to solve the distribution system planning problem. The proposed planning framework considers various complex issues such as those arising from uncoordinated private investments in DG, intertie, not-supplied energy, environmental emissions and uncertainties on component availability and forecasted demand. The detailed plan results have been successfully demonstrated in the sense of utility planner and policy makers. Evidently, experimental decisions of planner may also be included in the problem solution.

The proposed method has been evaluated on a 32 buses distribution system planning in GAMS software area for two cases. The effect of different emission limitation policies on final plan was investigated in these cases. Results show that gas turbine and wind turbine have the largest penetration level. Hence, when emission is limited and exceeded emission is penalized, WT penetration increases. Since PV is not economical for using in DS, the final plan doesn't have any PV except PV of SPP (without economical aspects). Finally, performed simulations confirm the ability of proposed DSP method under different economical and technical situations of network and different policies.

Appendix: list of parameter

IRc و Ire: inflation rate for investment costs and energy costs (%)

Ccffdr و Ccfss و Ccfint : fixed EPC cost of feeder/substation/intertie upgrade

Ccvfdr و Ccvss و Ccvint : variable investment cost of feeder/substation/intertie upgrade ($/MW)

CoDGu(tech): operating cost of DISCO-owned DG ($/MWh)

Cess(l,t): price of energy from external grid/market ($/MWh)

Ceint(l,t): price of energy from intertie ($/MWh)

CRcDGu(tech): annual change in investment cost of DISCO-owned DG (%)

CcDGu(tech): fixed investment cost of DISCO-owned DG ($/MW)

CRoDGu(tech): annual change in operating cost of DISCO-owned DG (%)

CeDGp(tech): price of energy from SPP-owned DG ($/MWh)

Cx(l,t): export energy price ($/year)

Cunmet(l,t): price of not-supplied energy($/MWh)

G(i,j): geographic cost factor between (i, j)

L(i,j): length between (i, j) (km)

Wfdr(i,j,t), Wss(i,t), Wint(i,t: capacity addition to feeder(i, j)/substation/intertie (MW)

wDGu(tech,i,t): capacity addition to DISCO-owned DG/feeder (i, j) (MW)

wDGp(tech,i,t): SPP-owned DG k capacity (MW)

Wfdrmax(i,j): maximum feeder(i,j) capacity (MW)

Wssmax, *Wssmin:* max/min substation capacity (MW)

Wintmax: maximum intertie capacity (MW)

wDGmax(tech), *wDGmin(tech):* max/min DISCO-owned DG unit capacity (MW)

FDGmax, *FDGmin* :max/min DG power supply w.r.t.demand (%)

zfdr(i,j,t), *zss(i,t)*, *zint(i,t)* : decision on feeder/substation/intertie upgrade (0/1)

zDGu(tech,i,t), *zDGp(tech,i)* : decision on DISCO-owned DG/SPP-owned DG upgrade (0/1)

Psint(i,l,t), *Psss(i,l,t)*, *PsDGu(tech,i,l,t)*, *PsDGp(tech,i,l,t):* power supply from intertie/substation/DISCO-owned DG/SPP-owned DG (MW)

P(i,j,l,t) : power flow on feeder between (i, j) (MW)

AvailFdr(i,j,l,t): availability of feader between buses i and j for load block l for scenario n in time t.

Px(i,l,t): power export to grid (MW)

Pd(i,l,t*):* demand at i during level l in year t (MW)

unmetPd(i,l,t): not supplied demand at i during level l in year t (MW)

Lsfdr(i,j,t): estimated line loss for (i, j) (%)

Rs: reserve margin (%)

Hrs(l:) hours per year per load level

T : overall planning horizon

EmP(t): penalty for CO2 cap ($/tonnes)

Em(tech): CO2 emissions from DG (tonnes/MWh)

Emmax: CO2 emissions cap cap (t)

Budget(t): investment expenditure budget ($)

V(i,l,t): voltage(pu)

Z(i,j,t): absolute value of impedance (i, j) (p.u.)

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