International Journal of Engineering Research and Development
e-ISSN: 2278-067X, p-ISSN: 2278-800X, www.ijerd.com
Volume 11, Issue 07 (July 2015), PP.42-55

A Generalized Multistage Economic Planning Model for Distribution System Containing DG Units

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Abstract:- Distributed generation (DG) has gained a lot of attractions in the power sector due to its ability in power loss reduction, increased reliability, low investment cost, and most significantly, to exploit renewable energy resources like wind, photo-voltaic and micro-turbines, which produce power with minimum greenhouse-gas emissions. The installation of DG units into distribution system requires efficient expansion planning technique to minimize the investment and operation cost of the system.. In this paper, a new mixed integer nonlinear model for solving the multistage distribution system network planning problem including DG has been developed. The model is able to deal with different planning scenarios such as buying energy from a nearby electric distribution company through an intertie, upgrading substations, upgrading feeders or investing in DG units. The model takes into account the operational constraints of equipment capacities and voltage limits as well as the dynamic load growth. Finally, the developed mathematical mixed integer model was applied to minimize the planning cost of the studied distribution network including DG units. The implemented mixed integer nonlinear planning model is coded using LINGO V14 optimization software.

Keywords:- Distributed Generation, Distribution System, Mixed Integer non-linear Model, Expansion planning, System Optimization.

NOMENCLATURE

LB	Total number of system load buses.
NCP(t)	Number of cable paths existing at year t.
$NCS(i)$	Number of cable sizes considered at path *i*.
NDG	Maximum number of added DG units at any load bus.
NS	Number of existing and proposed substation sites.
$NSU(i)$	Number of installed transformer units in the substation at site *i*.
NTS	Number of tie-line power steps.

T	**Horizon planning year (in years).**
CE^t	Electricity market energy price at year *t* in ($/MWh).
CT_{ij}^t	Capital cost of proposed transformer unit *j* at substation site i at start of planning interval *t*.
$C_{DG_{ij}}^{t,fixed}$	DG investment of unit *j* added at load bus i at the start of year *t* (in $).
$C_{DG_{ij}}^{t,operating}$	DG operating cost of unit *j* added at load bus i at the start of year *t* (in $/MWh).
$C_{intertie_{ij}}^t$	Intertie electricity market price of imported power for step *j* of tie-line number *i* in year *t*.
C_j^t	Cost per unit length for cable size *j* when added at year *t*.
D_i^t	Apparent load demand in (MVA) at bus *i* and year *t*.
DR	Discount rate.
FC	The capital cost of distribution cables (in $)
FG	The total capital cost of the DG units
VG	The total running cost of all DG units (in $).
FS	Total capital cost of substations (in $).
VS	Total variable running cost of substations in LE or $.
Vtie	Running cost of inter-tie in LE or $.

$K1(i)$	Set of paths feeding power to substation site *i*.
$K2(i)$	Set of paths taking power from substation site *i*.
$K3(i)$	Set of paths feeding apparent power to load bus *i*.
$K4(i)$	Set of paths taking apparent power from load bus *i*.
L_F^t	Load factor at year *t*.
l_i^t	Length of added feeder of path *i* in year *t*.
n	Electrical equipment life time in years.
PF^t	Power factor considered at year *t*.
SCM_{ij}	Thermal limit of feeder path *i* with cross section *j* (in MVA).
SC_{ij}^t	Power flow on feeder of path *i* with cross section *j* (in MVA) at time *t*.
$S_{DG_{ij}}^t$	Generated by DG unit *j* at site *i* in year *t* in (MVA).
$S_{DG_{ij}}^+$	DG capacity limit (MVA) for unit *j* at bus *i*.
$S_{int_{ij}}^t$	Power flow on tie-line *i* in MVA for step *j* in year *t*.
ST_{ij}^t	Transformer j in substation i dispatched apparent power in (MVA) at year t.
ST_{ij}^+	Maximum apparent power thermal limit of the transformer unit j inside the substation located at bus *i*.
STM_{ij}	Maximum apparent power drown from tie-line existing at bus *i* and power step *j*.
V_i^t	Bus voltage at bus *i* and year *t*.
V_i^-	Lower voltage limit.
V_i^+	Maximum voltage limit.
ΔV_{ij}^t	Voltage drop on path *i* with cable size *j* in year *t*.
W^t	Present worth factor of annual cost paid at year t.
Y_h	Total hours in a year (8760 hours).
$\lvert zl_{ij}\rvert$	Series impedance of path i with cross section *j*.
σC_{ij}^t	Zero-one integer variable of path i with cross section j in time t.
$\sigma_{DG_{ij}}^t$	DG binary decision variable of unit *j* in bus *i* at start of year *t*.
$\sigma_{int_{ij}}^t$	Intertie binary decision variable for tie-line number *i* for purchased power with step *j* of in year *t*.
σT_{ij}^t	Decision binary variable for transformer unit *j* at substation i when in interval *t*.

I. INTRODUCTION

Over the last few years, an increased interest in the use of small-scale generation, connected to local distribution systems, which is commonly called 'Distributed Generation' (DG). This is attributed to the fact that most of DG's are environmentally friendly, electricity market liberalization, postponement of the construction of new feeders, increasing demand on highly reliable electricity supply, and reduction of the required fossil fuel resources. DGs from renewable or non-renewable energy resources include internal combustion engines, small gas turbines, wind turbines, small combined cycle gas turbines, micro-turbines, solar photovoltaic, fuel cells, biomass and small geothermal generating plants. Integration of DG will alter the power flow in the distribution system, and the distribution system can no longer be considered as a system with unidirectional power flow. It is therefore deemed necessary to evaluate the impact of increased DG on the design requirements of distribution systems.

DG systems can assist in improving voltage regulation by injecting also reactive power close to the load, thus reducing the transmission losses. [1]. DG units make positive contributions to the reliability [2] and security of distribution systems from the perspective of loads [3-5] The objective function of the optimal distribution generation placement problem can be single or multiobjective. Multiobjective functions can be transformed into a single objective function by using the weighted sum of the individual objectives. Moradi and Abdini, [6], were able to find the optimal capacity and location of DG units for an existing distribution network by hybrid GA genetic algorithm and Particle Swarm Optimization (PSO). Thereby the genetic algorithm searches for the optimal site of DG and PSO optimizes the size of DG, the load model taken was constant power, the objective function is of weighted type to minimize network power losses, improve the voltage stability and voltage regulation.

Another example is [7] were Ochoa et el, aimed to apply a single objective function which is to evaluate the maximum DG capacity for variable (renewable) generation under a range of active network management schemes that include coordinated voltage control, adaptive power factor control and energy curtailment. The method used in this optimization process was optimal power flow. The load level taken is a multi-load level and the load model is constant power. A third example, El-Zonkoly in [8] who used particle swarm optimization technique for optimal placement of multiple DG units with variable power load models. Apart from expansion of existing substations, building new substations or installing new feeders in the distribution network. DG can be used to accommodate new load growth and relieve overloaded components [9-15].

Traditionally, distribution system planning is solved in two ways, [16]: Static approach, which considers only one planning horizon and determines the capacity, type and location of new equipment that should be expanded and/or added to the system.. Multistage approach, "that defines not only optimal location, type and capacity of investment, but also the most appropriate times to carry out such investments, so that the continuing growth of the demand is always assimilated by the system in an optimal way" [16]. Different solution techniques used are: branch and bound [11,12], genetic algorithm [15-17,19], Hybrid Tribe-Particle Swarm Optimization and ordinal optimization [18], mixed integer programming [10,13].

A pseudo-dynamic procedure for multi-stage planning is provided in [16]. A combined genetic algorithm and optimal power flow is developed as an optimization tool to solve the problem. Load variation and reliability improvement are considered in the planning. The method of optimization is a metaheuristic method, it suffers from its inability to find the global optimum but indeed, it is very likely to find a reasonable solution [20]. Also there is no guarantee of exactly how good this solution is and multiple runs are often used to counter this. Metaheuristic algorithms allow the planning engineer to find not only a single optimum point, but a family of near-optimum planning alternatives [20]. The multistage planning model in this paper for solving the distribution system planning problem is mixed integer nonlinear which provides the most accurate, dynamic, and most complex, way to represent the planning problem with discrete control elements which are the most difficult type of optimization problems [21]. This document is a template. An electronic copy can be downloaded from the conference website. For questions on paper guidelines, please contact the publications committee as indicated on the website. Information about final paper submission is available from the website.

II. GENERAL DYNAMIC PLANNING ALGORITHM

A general planning problem should consider all system alternatives including distributed DG units, purchasing energy from neighbouring distribution companies. In the dynamic planning mode, the increase of load with time is correctly considered as well as the addition of equipment with time. The objective function is to determine the least cost plan for the distribution system which is required to feed the given set of load points while satisfying the different set of constraints imposed on the distribution system and its equipment as all loads should be fed.

II.1 Cost function

The cost objective function is divided into two main parts, namely, fixed and variable costs. The system fixed cost is the summation of the substations (FS), cables (FC) and DGs (FG) fixed cost given by:

$$FS = \sum_{t=1}^{T}\sum_{i=1}^{NS}\sum_{j=1}^{NSU(i)} \gamma^t . CT_{ij}^t . \sigma T_{ij}^t \tag{1}$$

Where:

$$\gamma^t = \frac{[(1+DR)^{T-t+1}-1](1+DR)^{n-T}}{[(1+DR)^n - 1]}$$

$$Fc = \sum_{t=1}^{T}\gamma^t \sum_{i=1}^{NCP(t)}\sum_{j=1}^{NCS(i)} l_i^t . C_j^t . \sigma C_{ij}^t \tag{2}$$

$$FG = \sum_{t=1}^{T}\gamma^t \sum_{i=NS+1}^{NS+LB}\sum_{j=1}^{NDG} C_{DG_{ij}}^{t,fixed} . \sigma_{DG_{ij}}^t \tag{3}$$

The running and variable (operation and maintenance) costs of substations VS including the cost of energy supply from the grid and DG units variable cost VG are expressed as

$$VS = Y_h \sum_{t=1}^{T} W^t \sum_{i=1}^{NS} \sum_{j=1}^{NSU(i)} L_F^t . CE^t . ST_{ij}^t . PF^t \quad (4)$$

Where:

$$W^t = \frac{1}{(1+DR)^t}$$

$$VG = Y_h \sum_{t=1}^{T} W^t \sum_{i=NS+1}^{NS+LB} \sum_{j=1}^{NDG} S_{DG_{ij}}^t . C_{DG_{ij}}^{t,operating} . L_F^t . PF^t \quad (5)$$

Cost of energy purchased through inter-tie (Vtie) is as follows:

$$Vtie = Y_h \sum_{t=1}^{T} W^t \sum_{i=1}^{NS} \sum_{j=1}^{NTS} L_F^t . PF^t . C_{intertie_{ij}}^t . S_{int_{ij}}^t \quad (6)$$

The feeder losses are treated in the proposed model as an additional load.

II.2 Constraints Equations

The following set of constraints should be written for all periods starting from the first period to period T.

For substation bus, this constraint is given for year t and substation site i as:

$$\sum_{j=1}^{NSU(i)} ST_{ij}^t + \sum_{j=1}^{NTS} S_{int_{ij}}^t + \sum_{l=1}^{K1(i)} \sum_{j=1}^{NCS(l)} \left(SC_{lj}^t - \frac{{\Delta V_{lj}^t}^2}{|zl_{lj}|} . \sum_{m=1}^{t} \sigma C_{lj}^m\right) - \sum_{l=1}^{K2(i)} \sum_{j=1}^{NCS(l)} SC_{lj}^t = D_i^t , \quad (7)$$
$$i = 1,2, \ldots, NS$$

For load bus i at year t, this constraint is given as

$$\sum_{l=1}^{K3(i)} \sum_{j=1}^{NCS(l)} \left(SC_{lj}^t - \frac{{\Delta V_{lj}^t}^2}{|zl_{lj}|} . \sum_{m=1}^{t} \sigma C_{lj}^m\right) - \sum_{l=1}^{K4(i)} \sum_{j=1}^{NCS(l)} SC_{lj}^t + \sum_{j=1}^{NDG} S_{DG_{ij}}^t = D_i^t \quad (8)$$
$$i = NS+1, \ldots, NS+LB$$

Relation between power flow and bus voltages for each path *i*

Assuming that the power flow on path i and step j is from bus l to bus k, then this constraint becomes for year t,

$$SC_{lj}^t = \left(\frac{V_l^t . \Delta V_{lj}^t}{|zl_{lj}|}\right) . \sum_{m=1}^{t} \sigma C_{lj}^m \quad (9)$$
$$\Delta V_{lj}^t = (V_l^t - V_k^t)$$
$$V_l^- \le V_l^t \le V_l^+$$

Capacity limit constraint

The power flow on substation at site or bus i and transformer unit j at year t,

$$ST_{ij}^{t} \leq ST_{ij}^{+} * \left(\sum_{l=1}^{t} \sigma T_{ij}^{l}\right), \tag{10}$$
$$i = 1,2, \ldots, NS \text{ and } j = 1,2, \ldots, NSU$$

For feeder path *i* and cable size *j* at year *t*,

$$|SC_{ij}^{t}| \leq SCM_{ij} \tag{11}$$
Or
$$i = 1,2, \ldots, NCP(t), j = 1,2, \ldots, NCS(i)$$

For DG units existing at bus *i* for unit *j* at year *t*

$$SG_{ij}^{t} \leq S_{DG_{ij}}^{+} * \left(\sum_{l=1}^{t} \sigma_{DG_{ij}}^{l}\right), \tag{12}$$
$$i = NS + 1, \ldots, NS + LB, \quad j = 1,2, \ldots, NDG$$

For power drawn from tie-line existing at bus *i* and power step *j* in year *t*

$$S_{int_{ij}}^{t} \leq STM_{ij} * \sigma_{int_{ij}}^{t} \tag{13}$$
$$i = 1,2, \ldots, NS, \quad j = 1,2, \ldots, NTS$$

This last constraint guarantees that the tie-line power purchased at any year could not be purchased at further or coming years.

Logical constraints in each period

a. Logical constraint related to substation.

Due to the fact that the capital cost of a new substation having one transformer unit is higher in cost than when a second or third unit is added, i.e.

$$CT_{i1}^{t} > CT_{i2}^{t} \text{ and } CT_{i1}^{t} > CT_{i3}^{t} \tag{14}$$

So, the second state (unit) and the third state (unit) should not be added until the first state (unit) is added, so, for a period t and assuming that maximum number of transformer units is three

$$2 * \sum_{k=1}^{t} \sigma T_{i1}^{k} \geq \sigma T_{i2}^{t} + \sigma T_{i3}^{t} \tag{15}$$

b. Logical constraint related to DG units

If one DG unit only is added, then another DG unit should be added for system security. If a second state (DG unit) or a third state is to be added, no further DG unit is required. This means that:

$$C_{DG_{i1}}^{t,fixed} > C_{DG_{i2}}^{t,fixed} \text{ and } C_{DG_{i1}}^{t,fixed} > C_{DG_{i3}}^{t,fixed} \tag{16}$$

In case of maximum number of DG units allowed at the load bus is 5 units:

$$4 * \sum_{k=1}^{t} \sigma_{DG_{i1}}^{k} \geq \sigma_{DG_{i2}}^{t} + \sigma_{DG_{i3}}^{t} + \sigma_{DG_{i4}}^{t} + \sigma_{DG_{i5}}^{t} \tag{17}$$

c. Logical constraint for cables

As no more than one cable size is to be erected on any path, so for path *i:*

$$\sum_{t=1}^{T}\sum_{j=1}^{NCS(i)} \sigma C_{ij}^{t} \leq 1 \quad (18)$$

d. To get radial configuration.

If a radial configuration is to be required on year t, so for load bus *i*, the summation of all the paths feeding that bus should be equal to one:

$$\sum_{m=1}^{t}\sum_{l\epsilon K3(i)}\sum_{j=1}^{NCS(l)} \sigma C_{lj}^{m} = 1 \quad (19)$$

Logical constraint relating all planning periods to each other

a. With respect to transformer units and for each site *i*, state or transformer *j*

$$\sum_{t=1}^{T} \sigma T_{ij}^{t} \leq 1, \quad i = 1, \dots, NSU \quad (20)$$

b. With respect to DG units at bus *i* and state *j*

$$\sum_{t=1}^{T} \sigma_{DG_{ij}}^{t} \leq 1 \quad (21)$$

$$i = NS + 1, \dots, NS + LB, and\ j = 1, 2, \dots, NDG$$

c. With respect to cable sizes at path *i*

$$\sum_{t=1}^{T} \sigma C_{ij}^{t} \leq 1 \quad (22)$$

$i = 1, \dots, NCP, and\ j = 1, \dots, NCS$

The above described distribution system expansion planning model is a constrained, multi-stage nonlinear, mixed integer optimization programming. Thereby, the optimal plan that can satisfy the load at each planning period is defined and the required network elements have to be installed. The procedure of the planning algorithm can be summarized in the following steps:.

Step 1: The planning horizon is divided into different periods.
Step 2: According to the growth rate the load is added at the corresponding bus in each planning period.
Step 3: Using the proposed model of in order to determine the optimal expansion plan to cover the forecasted system load planning period.
Step 4: Repeat step 3 for all periods to obtain the overall expansion plan for the whole planning horizon

III DISTRIBUTION SYSTEM UNDER STUDY

The studied 11 kV network consists of one proposed substation, 23 new load buses and 32 new routes and is shown in Figure (1). The planning period is 4 years with 4 annual stages. The load at each bus and each stage as well as the length of each feeder route are given in tables (A1, A2) of the appendix The interest rate is considered to be 12.5%. The cost of a new substation with one 10 MVA transformer unit equals 4 MLE, while adding another 10 MVA transformer unit costs 2.5 MLE. The life time of each transformer unit is 40 years. In this paper two cable sizes are only considered. Size A has capacity of 12 MVA and costs 0.8 MLE/km and has an impedance of 0.0981 + j0.140 Ω/km. Size B has capacity of 7 MVA and costs 0.4 MLE/km and has an impedance of 0.1590 + j0.192 Ω/km. Life time of each cable size is 40 years.

The maximum size of candidate DG unit is 0.4 MVA with a power factor of 0.95. The cost of the first DG unit is 0.6 MLE and that of the second installed unit is 0.4 MLE. A maximum of two DG units are permitted at each bus with assumed life time of 15 years. The cost of unit energy purchased through substation is 0.5 LE/KWh and is fixed for the whole planning intervals. The cost of unit energy generated through DG units is 0.5LE/KWh and is fixed for the whole planning intervals. The maximum permissible voltage drop for "planning without DG units" is + 6% and -10% while for "Planning with DG units" is +6% and -6%.

The computation time to solve the problem of distribution system planning depends on the total number of integer variables. The integer variables in each planning stage (one year) are estimated as the summation of the planning candidates of 3 transformers in the main substation , 32 possible cable routes each with 2 alternative size (32x2) and 23 load bus (possible locations for DG's) with maximum 2 DG units to be installed at each bus (23x2). That means the number of integer variables for each stage is 113 with total number for whole planning period of 4 stages equals 452. The multi stage planning problem is solved using the mixed integer non-linear optimization technique. This technique is a well-known optimization method that has been widely applied to solve different optimization problems. The overall optimization problem is coded using LINGO V14 optimization software [22]. The main features of the implemented optimization routine LINGO is that it uses both successive linear programming and generalized reduced gradient algorithm to achieve the global optimum. Thereby, the LINGO routine combines a series of rang bounding and reduction techniques within branch-and-bound frame work to find the global optimum of non-convex non-linear problems. Moreover, LINGO passes data to its solving modules directly through memory rather than through intermediate files. This minimizes the execution time and compatibility problems between modeling language and solver components [22].

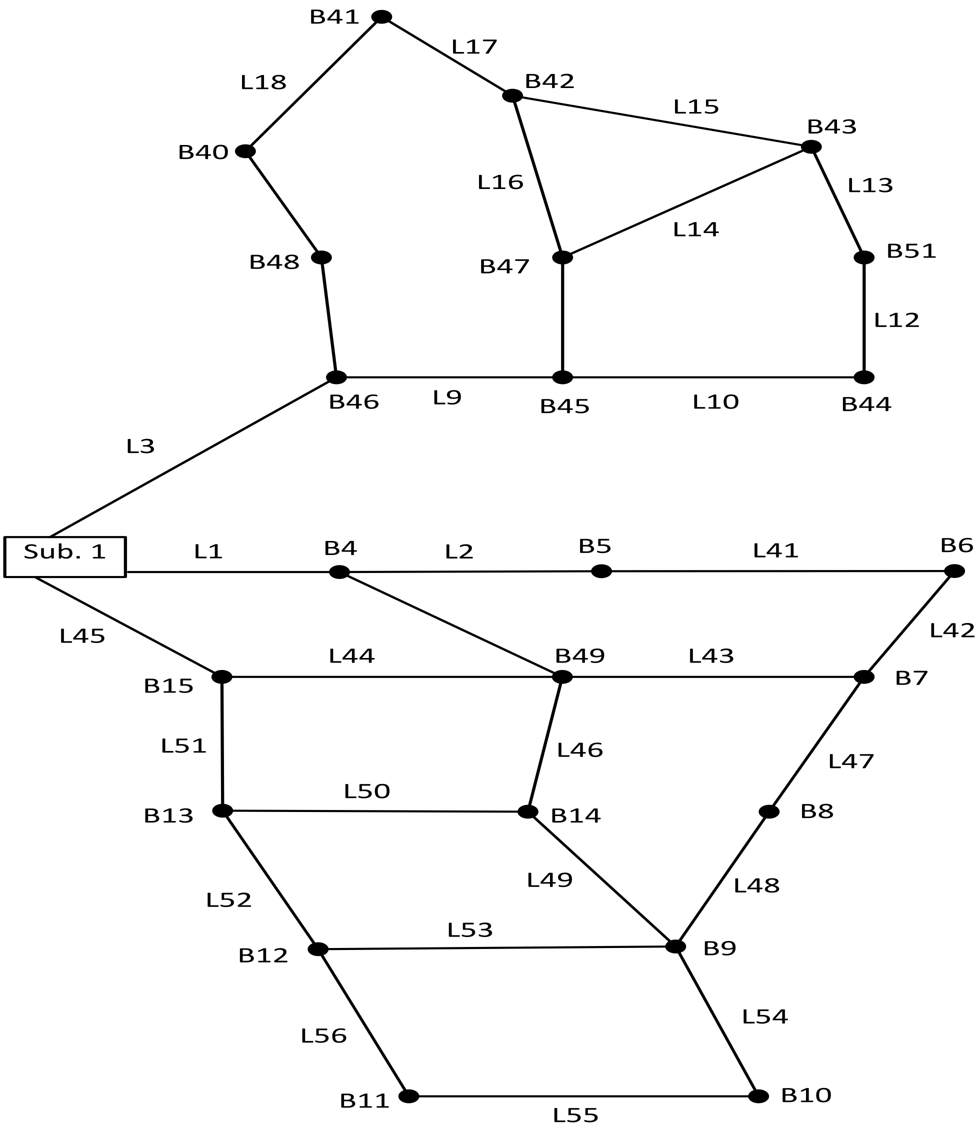

Fig 1: Proposed electric distribution network.

IV SOLUTION OF NETWRK PLANNING WITHOUT DG UNITS

For the planning of the distribution system without installing DG units, the selected cables and the direction of the power flow on each cable are shown in Figure (2), there was no change in the selection of the cables or in the direction of the power flow from period to another (first year, second year, third year and fourth year) but the lines became more loaded from year to another as the load increases by 10% each year.

The voltage at each bus and each year is shown in Table (1), from this table, it can be shown that the voltage decreases at the same bus from year to another, because as the configuration of the network did not change with time (from year to another) and as the load increases, this will result in more voltage drop on the lines as the load increases with periods resulting in voltage at each bus being lower than the voltage at the same bus in the previous year. The lowest voltage value was found to be at bus 41 with a value of 0.9048 p.u. which is still within the permissible voltage limit of (1.06 maximum and 0.9 p.u minimum).

Table 1: Voltages in all periods for "Planning without DG units":

Bus Voltage	First period	Second Period	Third period	Fourth Period
V_1	1	1	1	1
V_4	0.9894	0.9883	0.9872	0.9861
V_5	0.9851	0.9835	0.9820	0.9804
V_6	0.9794	0.9773	0.9751	0.9730
V_7	0.9670	0.9636	0.9602	0.9567
V_8	0.9639	0.9602	0.9564	0.9526
V_9	0.9590	0.9547	0.9504	0.9460
V_{10}	0.9564	0.9519	0.9473	0.9426
V_{11}	0.9599	0.9557	0.9515	0.9472
V_{12}	0.9633	0.9595	0.9556	0.9517
V_{13}	0.9700	0.9669	0.9637	0.9605
V_{14}	0.9679	0.9646	0.9612	0.9578
V_{15}	0.9784	0.9761	0.9739	0.9716
V_{49}	0.9765	0.9741	0.9716	0.9692
V_{40}	0.9363	0.9294	0.9225	0.9154
V_{41}	0.9284	0.9206	0.9128	0.9048
V_{42}	0.9391	0.9325	0.9259	0.9192
V_{43}	0.9391	0.9325	0.9259	0.9192
V_{44}	0.9523	0.9472	0.9421	0.9369
V_{45}	0.9627	0.9587	0.9547	0.9506
V_{46}	0.9822	0.9804	0.9784	0.9765
V_{47}	0.9462	0.9404	0.9346	0.9287
V_{48}	0.9547	0.9498	0.9449	0.9399
V_{51}	0.9460	0.9403	0.9345	0.9286

The losses in MVA in case of planning without using DG units and for each period or year are shown in

Table), the table shows the losses as a percentage of the total demand during each period as well.

Table (2): Losses in all periods for "Planning without DG units":

	First period	Second Period	Third period	Fourth Period
Total Load during each period in MVA	20.260	22.286	24.312	26.338
Total Load including Losses in MVA	21.0894	23.3000	25.5315	27.7847
Losses in MVA	0.8294	1.0140	1.2195	1.4467
Losses as a percentage of total load	4.094 %	4.5501 %	5.0162 %	5.4928 %

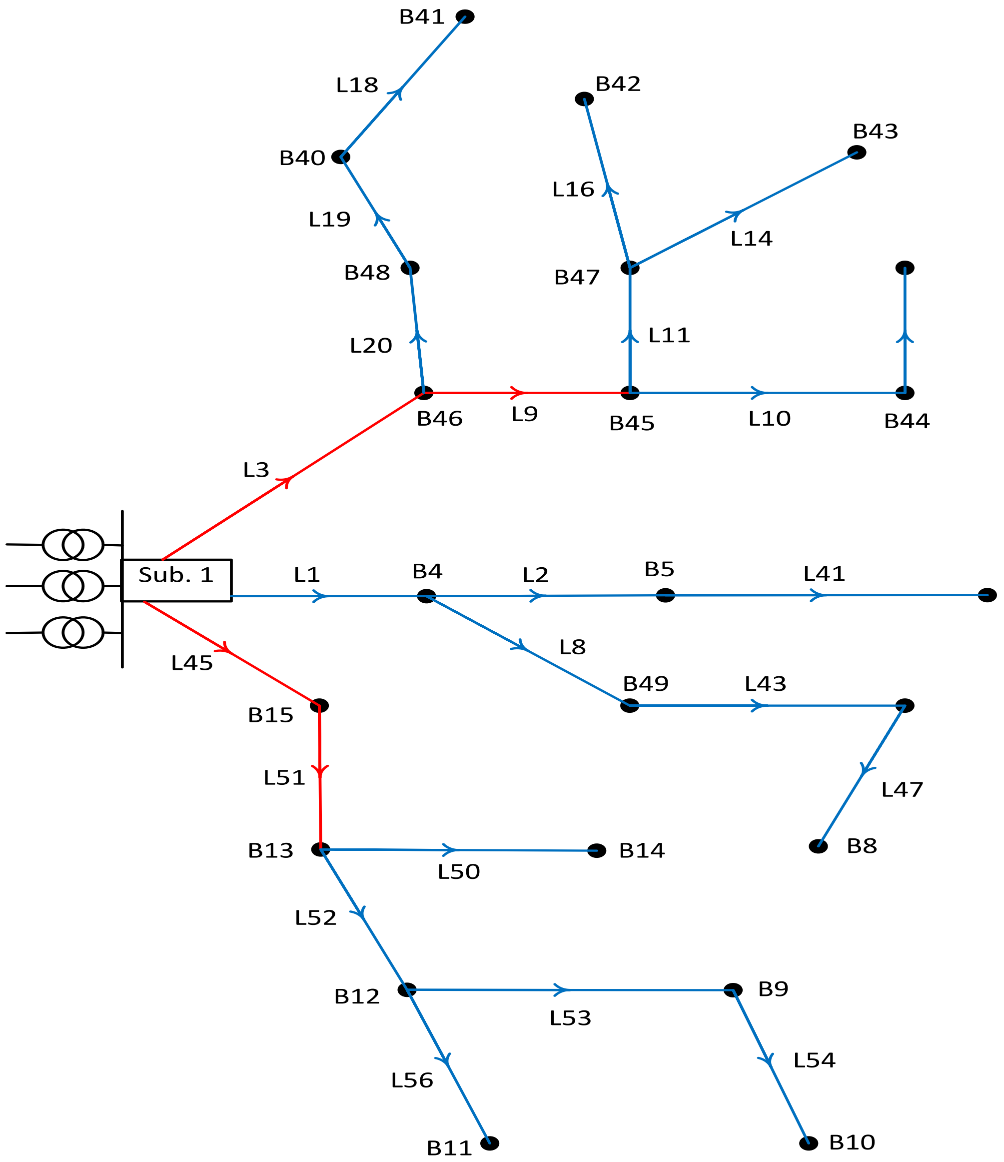

Figure (2): Solution showing the selected cables and power flow for "planning without using DG units"

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V. SOLUTION OF NETWRK PLANNING USING DG UNITS

The cost saving by using DG units was found to be more than 1.25 MLE, the selected cables and the direction of the power flow on each cable for the final planning period is shown in Figure (3), The configuration of the selected cables and their sizes remained fixed from period to another (first year, second year, third year and fourth year) and is completely different than the case of planning without using DG units.

The added DG units and their sizes in each planning period are summarized as follows:

First period: Installing DG units with capacity of 2x0.4 MVA at bus B8, B41, B43 and B45
Feeder L14 is deleted, adding feeder L13, changing feeders L9,45,51 to second type and L1 to the first type

Second period: Adding extra DG units with capacity of 2x0.4 MVA at bus B10 B51

Third period: Adding extra DG units with capacity of 0.4 MVA at bus B11

Fourth period: Adding another extra DG unit of 0.4 MVA at bus B11 plus 2x0.4 MVA at bus B12 and B42.

The bus voltage for each year is shown in Table (3), the lowest voltage value was found to be at bus 41 with a value of 0.9402 p.u. which is still within the permissible voltage limit of (1.06 maximum and 0.94 p.u minimum).Thus planning with DG units improves the voltage profile.

Table (3): Voltages in all periods for "Planning using DG units":

Bus Voltage	First period	Second Period	Third period	Fourth Period
V_1	1	1	1	1
V_4	0.9927	0.9920	0.9913	0.9905
V_5	0.9861	0.9847	0.9833	0.9819
V_6	0.9747	0.9721	0.9695	0.9668
V_7	0.9693	0.9662	0.9630	0.9598
V_8	0.9502	0.9529	0.9501	0.9546
V_9	0.9502	0.9532	0.9507	0.9554
V_{10}	0.9476	0.9524	0.9497	0.9542
V_{11}	0.9511	0.9526	0.9518	0.9582
V_{12}	0.9546	0.9564	0.9546	0.9599
V_{13}	0.9614	0.9626	0.9609	0.9649
V_{14}	0.9812	0.9793	0.9773	0.9754
V_{15}	0.9720	0.9727	0.9714	0.9740
V_{49}	0.9846	0.9830	0.9814	0.9799
V_{40}	0.9588	0.9540	0.9475	0.9426
V_{41}	0.9587	0.9532	0.9458	0.9402
V_{42}	0.9506	0.9505	0.9438	0.9560
V_{43}	0.9495	0.9581	0.9497	0.9479
V_{44}	0.9572	0.9621	0.9557	0.9558
V_{45}	0.9681	0.9697	0.9650	0.9666
V_{46}	0.9874	0.9873	0.9855	0.9854
V_{47}	0.9576	0.9582	0.9523	0.9582
V_{48}	0.9687	0.9659	0.9612	0.9582
V_{51}	0.9502	0.9595	0.9519	0.9506

The losses in MVA in case of planning using DG units for each period are shown in Table), the table shows as well the losses as a percentage of the total demand during each period.

Table (4): Losses in all periods for "Planning using DG units":

	First period	Second Period	Third period	Fourth Period
Total Load during each period in MVA	20.2600	22.2860	24.3120	26.3380
Total Load including Losses in MVA	20.8762	22.8919	25.0397	27.0329
Losses in MVA	0.6162	0.6059	0.7277	0.6949
Losses as a percentage of total load	3.0415	2.7186	2.9933	2.638

The simulation results indicated that the application of DGs reduces the fixed cost of added feeders and substations by 0.6369 MLE and 0.9478 MLE, respectively. Besides, DGs reduce the cost of purchased grid energy by 33.5287MLE. On the other side, the installation and operating cost of the DGs equal 33.5550MLE .Consequently the net saving of the distribution planning with DGs is more than 1.5847MLE.
.

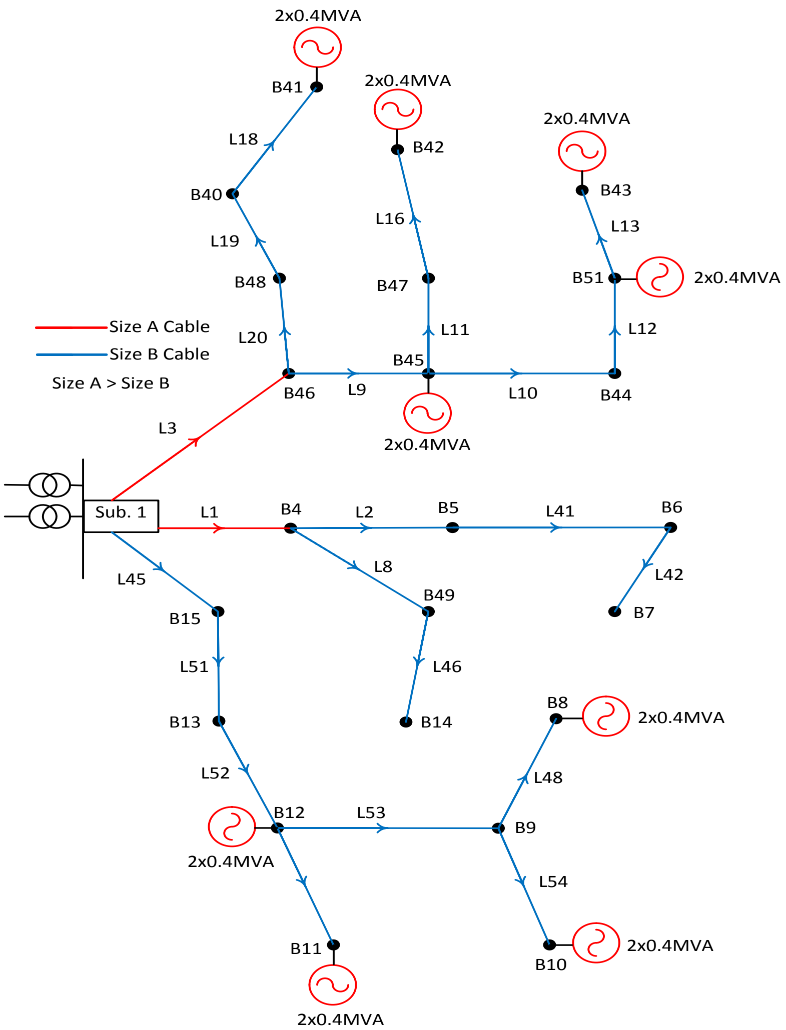

Figure (3): Fourth period solution showing the selected cables and DG units as well as power flow directions for "planning using DG units"

VI. CONCLUSION

A model for multistage distribution system planning in the presence of DG is proposed in this paper. The proposed model properly handles voltage, capacity limits and radial constraints. The capability and performance of the proposed model have been demonstrated using case study which resembles a typical distribution system. Comparison between planning with DG and planning without DG has been carried out. The obtained results show that the integrating of DG sources in multistage distribution system planning can result in a distribution plan that has lower cost and better performance.

It has been shown that the voltage profile of the buses has been improved; the voltage limits are between 0.9 p.u and 1.06 p.u for the case for planning without DG units, while in planning with DG units, the voltage range was between 0.94 p.u and 1.06 p.u. Since DG units inject power into the lines and supply part of the load, the power flow on the lines has been reduced which means longer life for the cables. Also the total losses in the distribution network have been reduced by a significant amount from 5.493 to 2.638%.

Utilizing DG units saves part of the capital costs needed for installing new substations and feeders by 1.5847 MLE. Finally, the main advantage of using the DG is due its short lead time and low investment, module installation, also the small capacity modules can track load variation more closely.

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APPENDIX

Table A-1: Length of each proposed path.

Index	From bus	To bus	Length (km)
1	1	4	1
2	4	5	1.2
8	4	49	2.4
41	5	6	3
42	7	6	2.8
43	7	49	2.6
44	15	49	2.4
45	15	1	2.2
46	14	49	2
47	7	8	1.8
48	9	8	1.6
49	9	14	1.4
50	13	14	1.2
51	13	15	1
52	13	12	0.8
53	9	12	1
54	9	10	1.2
55	11	10	1.4
56	11	12	1.6
3	1	46	1.4
9	46	45	2.6
10	45	44	2.8
11	45	47	3
12	44	51	3.2
13	51	43	3.4
14	47	43	3.6
15	42	43	3.8
16	42	47	4
17	42	41	4.2

18	40	41	4.4
19	40	48	4.6
20	46	48	4.8

Table A-2: Load at each bus and for each year.

Bus Index	First Year Load (MVA)	Second Year Load (MVA)	Third Year Load (MVA)	Fourth Year Load (MVA)
1	0	0	0	0
4	0.81	0.891	0.972	1.053
5	0.81	0.891	0.972	1.053
6	0.9	0.99	1.08	1.17
7	0.9	0.99	1.08	1.17
8	0.81	0.891	0.972	1.053
9	1	1.1	1.2	1.3
10	1	1.1	1.2	1.3
11	1	1.1	1.2	1.3
12	0.9	0.99	1.08	1.17
13	1	1.1	1.2	1.3
14	0.81	0.891	0.972	1.053
15	1	1.1	1.2	1.3
49	0.81	0.891	0.972	1.053
40	1	1.1	1.2	1.3
41	0.81	0.891	0.972	1.053
42	0.81	0.891	0.972	1.053
43	0.9	0.99	1.08	1.17
44	0.81	0.891	0.972	1.053
45	0.81	0.891	0.972	1.053
46	0.85	0.935	1.02	1.105
47	0.81	0.891	0.972	1.053
48	0.81	0.891	0.972	1.053
51	0.9	0.99	1.08	1.17
Total Load	**20.260**	**22.286**	**24.312**	**26.338**