ASSESSMENT OF DISTRIBUTION SYSTEM PERFORMANCE WITH CONSIDERABLE DISTRIBUTED GENERATION PENETRATION

Eman Kaddah, Yasser G. Hegazy, Soliman El-Dobeikey
Ain Shams University –Egypt
Y_hegazy@yahoo.com

ABSTRACT

A novel algorithm to evaluate the reliability of electric distribution systems including distributed generation is proposed. This algorithm addresses the stochastic nature of the operation of these systems. The proposed algorithm integrates Monte Carlo simulation to estimate the random operating cycles of the installed distributed generators and the ability of the system power capacity to meet the total demand. A typical case study is presented in which several distributed generation units are running in parallel within a distribution system and both the system margins and the average amount of unsupplied loads are estimated. The results obtained are presented and discussed.

INTRODUCTION

Due to the major changes in the legislative framework for the electric sector and the fast move toward liberalization of the electricity markets, generating units were introduced to distribution systems. These generating units are referred to as *distributed generation (DG).* DG is defined as the integrated or stand-alone use of small, modular electric generation close to the point of consumption [1]. It differs fundamentally from the traditional model of central generation and delivery insofar as it can be located near end-users within an industrial area, inside a building, or in a community. The small size and the modularity of DG support a potentially broad range of customer and grid sited applications where central plants would prove impractical.

As a result of deregulation in the power market, saturation of existing networks, the continuous growth of the demand, the new modern technology achieved in the generation industry and the benefits expected from this technology implementation, a wide spread of use of these DG units operated in the system has become a fact [4]. Recent studies have predicted that by year 2010, distributed generation will account for up to 25% of all new generation [2], [3].

Due to that wide spread use of DG, several system operating issues have come into sight. These concerns involve both the benefits of using DGs and the problems associated with the wide implementation of DG units in a well established system. The premise of DG is to provide electricity to customers at a reduced cost and a higher efficiency, especially if the proper technology is implemented for its application, such as the use of combined heat and power technologies. Other benefits that DG could potentially provide are: voltage support; reduction of the system power loss; increase of utility system reliability; reduced emissions; improved power quality; and deferral of transmission or distribution upgrades [5]. DG promises to significantly alter the design and operation of the power delivery system and the nature of the electric utility industry.

On the other hand, DG integration into the system created a lot of complex problems and many related aspects that have to be studied thoroughly. Among these aspects are the parallel operation of DG with the existing system, DG impact on the distribution system performance and the difficulties in the operation and control of the different types of DG which are still the main challenges associated with the use of DG in distribution systems [6].

An attempt to address the adequacy assessment of DG system is done using a Monte Carlo – based method, which has been investigated by Hegazy et.al. using DG random state (on or off) [7]. The research in all these directions was based on the assumption that the DG units have known locations and are running all the time with their full capacity. In the real life systems, the operation of these DG units undergoes different scenarios according to the strategies of the electricity producers, the needs of the consumers and the zonal load time variation characteristics. Therefore, some uncertainties are introduced in the operation of such units and thus, stochastic modeling of systems involving DG units becomes of great interest [5]. The sources of uncertainty in the operation of DG connected systems at a certain hour of the day include: the number of the running DG units at this hour, the locations of these units and the power exported to the system by these units. These uncertainties affect the modeling and evaluation of the system capacity, generation scheduling, power losses, buses' voltages, and feeders' power flow. Knowing these steady state system parameters helps greatly in predicting the electric system's behavior and its impact on system planning, design, operation and the electricity market at all levels: generation companies (Genco), Independent Market/System Operator (IMO/ISO), local distribution companies (LDC) and even the customer.

In this paper, the uncertainties of the operation of the DG units with the power flow solution of the new structured distributed generation systems are incorporated.

POWER FLOW ANALYSIS

The distribution system under consideration is the IEEE 34 node test feeder. Data of the test feeder is so extensive; it is available at [8]. The structure of the system is given in Figure 1. This feeder is an actual feeder located in Arizona.

The feeder's nominal voltage is 24.9 kV. It is characterized by:
1. Three phase 4 wire and single phase, 2 wire overhead lines arranged in different configurations.
2. Very long and lightly loaded.
3. Two in-line regulators required to maintain a good voltage profile.
4. An in-line transformer reducing the voltage to 4.16 kV for a short section of the feeder.
5. Unbalanced loading with both "spot" and "distributed" loads. Distributed loads are assumed to be connected at the center of the line segment.
6. Shunt capacitors modeled as constant susceptance.
Loads are three-phase (balanced or unbalanced) or single-phase. Three-phase loads are connected in wye or delta while single-phase loads are connected line-to-ground or line-to-line. All loads can be modeled as constant kW and kVAR (PQ), constant impedance (Z) or constant current (I) [9].

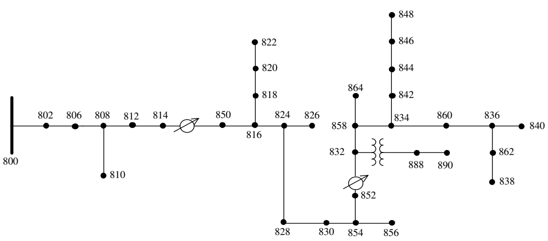

Figure 1: The system under study

ANALYSIS AND RESULTS

The solution of the power flow is performed using the Electrical Transient Analyzer Program (ETAP). The power flow equation is employing Newton-Raphson method with 99 maximum no. of iterations.
This study starts with performing the load flow calculation for the IEEE 34 system as it is. The calculation is performed again based on some case studies to examine the system performance when inserting DGs in the system at different scenarios. All DG units are considered as PV units, which will cause a load reduction at their connected buses. At each case study, the system kW, kVAR losses, the minimum voltage percentage buses, the branch of maximum voltage drop percentage and XFM-1(24.9/4.16kV) loading percentage are triggered.
The power flow results of the original IEEE 34 system are analyzed as follows:

- The minimum bus voltages are at bus 20 (exists between bus 812&814), bus 890, bus 812 & bus 21(exists between bus 852&854) of 85.311%, 87.913%, 88.855% & 91.726% in order.
- The branch of the maximum voltage drop percentage is 888-890 (the branch connecting XFM-1 and L890) of 8.02 % drop in V magnitude.
- The total system losses are 424.4 kW & 324.2 kVAR.
- XFM-1 loading percentage is 96.7%.

Case Study I
Load Flow runs are performed by inserting DG1 of 5%, 7% &10% of system KVA at the worst bus voltage magnitude (Bus 20). Figure 2 summarizes the results obtained for this case study. The voltage profile of the buses of minimum voltages is improved, the system kW & kVAR losses reduces, while XFM-1 loading percentage increases and branch 888-890 remains the highest voltage drop percentage branch of 8.02%.Case I results emphasize that inserting DG into the system of ratings going forward to higher percentages of system kVA is preferable.

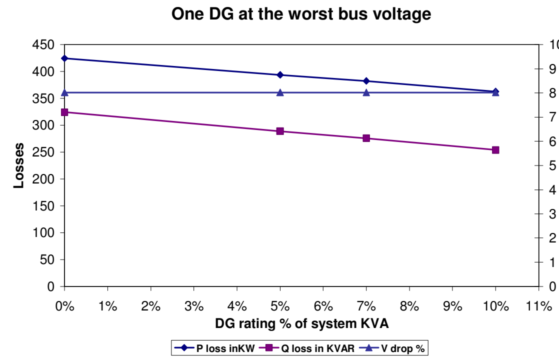

Figure 2: Summary of Case I results

Case Study II
Two runs of load flow are performed by inserting two equally rated DGs of 2.5% & 5% of system KVA in each run. One DG at the 1st. worst bus voltage magnitude (Bus 20) & the other one at the 2nd. worst bus voltage magnitude (Bus 890). The results are presented in Figures 3. These results show that the voltage profile of the buses of minimum voltages is improved, the system kW & kVAR losses are reduced and branch 888-890 remains the highest voltage drop percentage branch but its percentage decreased than its value at the original case & case study I.

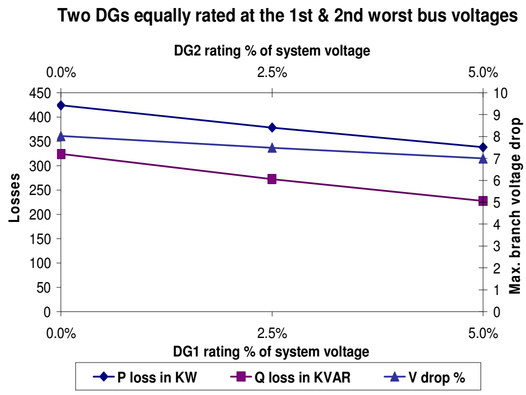

Figure 3: Case II results

From case II concludes that the DG MVA shall be distributed in order to decrease transformer loading and branch voltage drop.

Case Study III

Three runs of load flow are comparing the capacitor banks existence versus DGs by inserting DG3 of rating equivalent to the 450 kVAR capacitor bank & instead of it at bus 848 at the1$^{st.}$ run. DG4 of rating equivalent to the 300 kVAR capacitor bank & instead of it at bus 844 at the2$^{nd.}$ run. Then replacing the two capacitor banks by those two DGs at the 3$^{rd.}$ run. These results show that replacing the capacitor banks by DGs improves the voltage profile of the buses of minimum voltages, reduces the system kW& kVAR losses, while branch 888-890 remains the highest voltage drop percentage branch at the same percentage of the original case of 8.02% and XFM-1 loading percentage increases than its original case value.

Case III results emphasize that replacing the capacitor banks by DGs have a good impact in improving the bus voltages & reducing the system kW & kVAR losses while it increases the system transformer loading percentage and doesn't improve the voltage drop in the system.

Case Study IV

In this case, the idea of inserting DGs of ratings equivalent to the capacitor banks ratings at the buses of the minimum voltages is discussed. This is mainly to gain the benefits of bus voltage profile improvement & system kW & kVAR losses reduction with the benefits of reducing the voltage drop in the system and reducing the system transformer loading percentage.

At the1$^{st.}$ run, the two capacitor banks of the system are kept connected with DG-3 of rating equivalent to the 450 kVAR capacitor bank added at the worst bus voltage magnitude (Bus 20). At the 2$^{nd.}$ run, the two capacitor banks &DG-3 remain exist plus adding DG-4 of rating equivalent to the 300 kVAR capacitor bank at the 2nd worst bus voltage magnitude (Bus 890). At the 3$^{rd.}$ run, DG-3& DG-4 are kept connected but this time without the capacitor banks.

These results show that the best improvement of the bus voltages & the minimum system kW & kVAR losses occur at the 2$^{nd.}$ run. While the minimum XFM-1 loading percentage occurs at the 3$^{rd.}$ run of a value close to its result at the 2$^{nd.}$ run. At the 2$^{nd.}$ & 3$^{rd.}$ runs, branch 888-890 voltage drop percentage drops to nearly half of its original case value while new branches appear to have the highest voltage drop percentage branch of values around 5% at XFM-1 & Regulator2 with the best readings at the 2$^{nd.}$ run. Figure 4 shows that the 2$^{nd.}$ Run (X12) is considered the best improvement for the all items grouped together at the same time compared to the runs of case III (X6, X7&X8) & case IV(X11, X12&X13). Case IV results emphasize that if the DGs inserted in the system have ratings equivalent to the system capacitor banks and distributed at the lowest bus voltages, this will have the best impact on the bus voltages, system kW & kVAR losses, system voltage drop and the system transformer loading percentage.

Case Study V

In this case we circulate one DG rated at 250 KVA (10% of system KVA) on each loaded bus to search the most sensitive node in the system. The results in all runs compared to the original case show an improvement in the voltage profile at the buses with minimum voltages (Bus20, Bus 890, Bus 812 & Bus 21). The best results triggered were at the run where the DG is added at bus 890. Then the system kW & kVAR losses were the minimum of 297.5 kW &178.9 kVAR, the system transformer loading percentage was the minimum of 52.1%, branch 888-890 voltage drop percentage drops to 3.94% instead of 8.02% at the original case. While a new branch appears to have the highest voltage drop percentage branch of 4.91% at Regulator2 branch. Looking at bus 890, we realized that it is the nearest bus following XFM-1. From the results of case V, we can deduce that there are some sensitive nodes in the system at which the insertion of the DG will reduce the system kW & kVAR losses, system transformer loading percentage and the voltage drop in the system. These sensitive nodes are the nodes following the system main transformers.

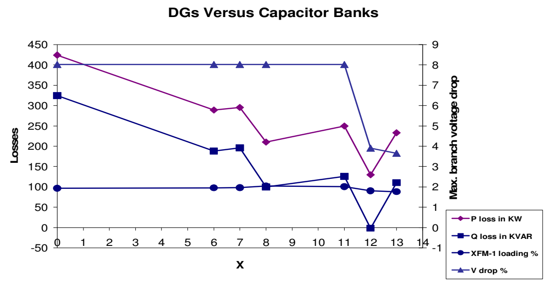

Figure 4: Results of case study III &IV

STOCHASTIC LOAD FLOW

Consider a distributed generation system with N *DG* units. Each unit is either on or off. The two states for each unit give rise to 2^N possible states or cable loading conditions. These states include loading conditions due to 1, 2, 3…N units being "on" at a time. In addition, each unit injects a current I_G during its on time (T_{on}) and is idle during its off period (T_{off}). The duty cycle "*d*" of the i $^{th.}$ unit can be defined as follows:

$$d_i = \frac{T_{on}}{T_{on} + T_{off}} \tag{1}$$

This duty cycle is a random variable since the process of switching on and off of each unit is a customer-controlled process. The basic philosophy of the proposed method is to transform the random switching states of all DG units into random injected currents variables. The range of the injected current of each unit is adjusted to reflect the duty cycle of this *DG*. To illustrate how the duty cycle of the *DG* determines the characteristics of the random current injected by this DG into the system the following example is given. Consider a DG unit with a 50% duty cycle and a known rated current. This unit is represented by a current source with a magnitude obtained by generating a random number between [0,1] and then, converting this random number into a random variable following a uniform distribution with a mean of 1 and a mean of 1 and a variance of 0.5 "other distributions could be used". Then, this variable is multiplied by the value of the rated current of the generator to scale it into actual generator current. A 70% duty cycle unit will require a variance of 0.7 to allow more contribution of its random current to the system. Figure 5 shows an example of the implemented probability distribution functions to represent two different units. G1 is rated 35 kVA, 11 kV, with a 50% duty cycle and G2 is rated 30 kVA, 11kV, with a 70% duty cycle. Table I includes some numerical values for the random sequence of the *DG* currents of I_{G1} and I_{G2} to illustrate how the duty cycle controls the range of variation of these currents. To perform the simulation, the distributed generation system is modeled in terms of its equivalent circuit. In this circuit, each distributed generator is represented by a current source injecting its output current into the network.

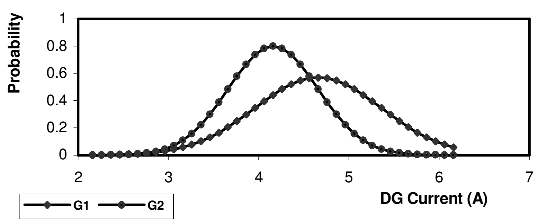

Figure 5: Random injected DG currents distribution

The magnitude of the source current is a random number generated according to the duty cycle of this generator and the phase angle of this current source is determined by knowing the phase angle of the node voltage where this generator is connected and the generator equivalent impedance. To complete the modeling of the system, the central substation is modeled as an ideal voltage source with its phase angle considered the reference angle for the system. The system loads are modeled as in terms of the P, Q ratings of the load.

Table I: Numerical values for the random DG currents

Sequence	1	2	3	4	5
I_{G1}	4.12	1.07	2.92	3.74	4.51
I_{G2}	2.95	4.07	3.52	3.17	2.52

The calculations of the equivalent continuous current for each feeder and the feeder power losses are done by running Monte Carlo simulation to solve the equivalent circuit of the system and evaluating (2) and (3) until the convergence for all currents has been reached. The circuit configuration does not change during the simulation but the random injected currents are updated every run (experiment) until the convergence is reached. It is important to mention here, that unlike the deterministic approach, running Monte Carlo simulation at this step does not require any additional calculations or resolving of the circuit model. It needs only the updating of the already developed current equations.

$$I_{ec_i}^2 = \frac{1}{K}\sum_{k=1}^{M} I_i^2(k) \tag{2}$$

$$P_i = \frac{1}{K}\sum_{k=1}^{M} I_i^2 * R_i \tag{3}$$

Where $I_i(k)$ is the i^{th} feeder current at k^{th} experiment, P_i is the i^{th} feeder section power losses, R_i is the i^{th} feeder section resistance, K is the experiment number and M is the total number of experiments. The experiment in this section refers to equivalent circuit solution for each generated set of *DG* random currents.

CONCLUSIONS

From all the results obtained, it can be concluded that, the following concerns should be triggered in selecting the positions and the ratings of the DGs to be inserted in the system:

- The DGs should be distributed in the system.
- It is preferable to select the DGs ratings to be equivalent to the capacitor banks existing in the system and to be distributed at the lowest system bus voltages.
- It is preferable to add the DGs at the sensitive nodes of the system which are the buses following the main transformers of the system.

A method to study the effect of the uncertainty of the operation of distributed generators on the power flow solution is also discussed in this paper.

REFERENCES

[1] T. Ackermann, G. Andersson, and L. Soder, "Distributed generation: A definition," Elect. Power Syst. Res., vol. 57, pp. 195–204, 2001.

[2] R. H. Lasseter, "Control of distributed resources," in Proc. Bulk Power Syst. Dynamics Control IV, Santorini, Greece, Aug. 1998, pp. 323–329.

[3] T. Ackermann, G. Andersson, and L. Soder, "Electricity market regulations and their impact on distributed generation," in Proc. Int. Conf.Elect. Utility Deregulation Restructuring Power Technol., London, U.K.,Apr. 2000, pp. 608–613.

[4] N. Hadjsaid, J. Canard, and F. Dumas, "Dispersed generation increases the complexity of controlling and maintaining the distribution systems," IEEE Comput. Appl. Power, vol. 12, pp. 23–28, Apr. 1999.

[5] Walid El- khattam, Y. G. Hegazy, and M. M. A. Salama, "Investigating distributed generation systems performance using Monte Carlo simulation," IEEE Trans. Power Syst., vol. 21, no .2, pp. 524 -532, May 2006.

[6] F. V. Edwards, G. J. Dudgeon, J. R. McDonald, and W. E. Leithead, "Dynamics of distribution networks with distributed generation," Proc.IEEE Power Eng. Soc. Summer Meeting, pp. 1032–1037, 2000.

[7] Y. G. Hegazy, M. M. A. Salama, and A. Y. Chikhani,, "Adequacy assessment of distributed generation systems using Monte Carlo simulation," IEEE Trans. Power Syst., vol. 18, no. 1, pp. 48-52, Feb. 2003.

[8] http// ewh.ieee.org/soc/pes/dsacom/testfeeders.html.

[9] W. H. Kersting, "Radial distribution test feeders," distribution systems analysis subcommittee, the 2000 PES Summer Meeting.