

Fault Current Issues for Market Driven Power Systems with Distributed Generation

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Abstract—This paper presents the consequences and operating limitations of installing distributed generation (DG) to electric power systems. The proliferation of new generators creates new operating conditions, some not seen before, that are limited by fault interruption capability. Increased system fault currents resulting from DG installation and the effects of increased fault currents are discussed. A technique used to evaluate fault current in the system after installing DGs is analyzed, and an example is given. The responsibility for the system change and safety degradation is discussed.

Index Terms—Distributed / dispersed generation, power distribution, power system protection, fault calculation.

I. FAULT ANALYSIS OF POWER SYSTEMS

PROTECTION system planning is one of the indispensable parts of electric power system design. Analysis of fault level, pre-fault condition, and post-fault condition are required for the selection of interruption devices, protective relays, and their coordination. Systems must be able to withstand a certain limit of faults which also affects reliability indices. Many classical references have been written on this topic, such as [1] - [4]. This paper relates to a new aspect of fault analysis of power systems: the appearance of distributed generation (DG), perhaps at high levels of penetration, and the effect of DG on fault currents.

II. DISTRIBUTED GENERATION

The definition of distributed generation according to [5] is: “Electric generation facilities connected to an electric power system (EPS) through point of coupling common (PCC) that are not directly connected to a bulk power transmission system”. Since the 1990s, reciprocating engines and gas turbines have been rapidly placed into service. Perhaps this deployment is a result of problems in dealing with transmission issues, and problems in siting conventional generation – but, for whatever reason, protection engineers as well as transmission and distribution engineers have increasingly had to deal with problems relating to added DG in systems. Reference [5] indicates that the standby DG application continues to grow at approximately 7% per year. Other DG applications, base load and peak load, are growing faster at 11% and 17%, respectively. The market size of these three sectors is about 5 GW in 2004. Figure 1 shows the applications for reciprocating engines and gas turbines (less than 20 MW).

The emergence of small and medium size DG arises from two major necessities: inadequacy of efficient power production (both economy and environment friendly) and re-

quirement of high reliability from industrial or commercial customers with a very high value product.

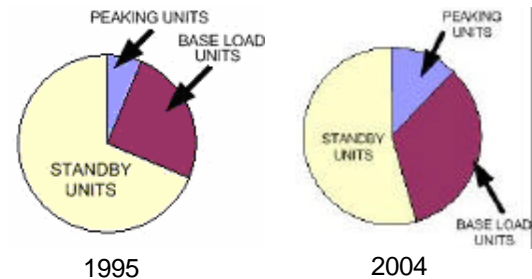


Fig. 1 Reciprocating engines and gas turbines less than 20 MW (data from [5]) in 1995 and 2004

Distributed generation can appear in different forms, both renewable and nonrenewable. Renewable technologies include fuel cells, wind turbine, solar cell, and geothermal. Nonrenewable technologies include combined cycles, cogeneration, combustion turbine and microturbines. Increasing of non-utility generators (NUGs) rapidly increases consideration of effects of distributed generations to the grid. Statistics show that by the end of the decade, the proportion of total capacity and DG capacity will grow to 20 percent or approximately from 40 GW to more than 150 GW [7].

Installing DG at a customer site enhances certain aspects of the power quality of the owners significantly by mitigating the voltage sag during a fault. Moreover, DG improves the owner reliability markedly as the back up generator can be started up within 2 minutes.

Although there are many advantages of installing DGs, a few operating conflicts cannot be ignored. During a fault, DGs can help mitigate voltage sags at the load site. Further, if there is a high penetration of DGs, the conventional utility supply may not be able to serve the load if the DGs drop off-line [10]. Installing a small or medium DG may not have a significant impact on the power quality indices at the feeder-level. The main reason for this observation is that IEEE Standard 1547 requires that the load be disconnected from the supply feeder after a specified period of time (a rather short time, measured in cycles). The DG will, after the cited disconnection, have no impact on the supply feeder. The DG has a local impact. That is, the local load may be served properly, but others on the common feeder will not experience improvement in voltage regulation.

Installation of DGs has been discussed in many research papers, such as those dealing with the reliability of the dis-

tribution system, coordination of protective devices, ferroresonance, and consequences of increased fault current, [8]-[10].

III. CONFLICTS RELATED TO INCREASED FAULT CURRENT

In general, addition of generation capacity causes fault currents to increase. This is a simple consequence of the reduction of the Thevenin equivalent impedance seen at system busses when generation is added to the system. The consequences of increased fault current from proliferation of distributed generation is discussed as follows:

- Change in coordination of protective devices:* Fig. 2. shows a sample distribution system. This system is a primary distribution system that is offered as an example of a distribution system with three DGs. The system is purely radial, three-phase, 4160 V, and served from a 69 kV subtransmission system at a substation. In the depicted configuration, the protection system may lose coordination upon installation of a DG. This point is illustrated as follows: before installing distributed generation DG1, if a fault occurs at point 1, fuse A should operate before fuse B. This is due to the upstream fault on the sub-feeder. When DG1 is included on sub-feeder, the fault current flows from DG1 to fault point 1 and fuse B might open before fuse A if the difference between I_{FA} and I_{FB} is less than the margin shown in Fig. 3. The difference between I_{FA} and I_{FB} is proportional to characteristics of DG1. Thus, these fuses lose coordination for the case of installed DG1 [8]-[9].
- Nuisance trip:* The increase in of fault current in the grid changes the way that protection system manages faults (relay settings, reclosers, interrupting capability of circuit breakers and fuses). Fig. 2 shows a relatively large DG3 installed near the substation. In case a fault occurs on feeders other than that where DG3 is located, breaker BB might also trip due to the fault current flowing from DG3 to the fault point. The solution for this problem is to implement a directional relay instead of an overcurrent relay. This is a total reconfiguration of the protective relaying.
- Recloser settings:* A DG on the feeder normally requires that the utility to readjust their recloser settings. Normally, a DG must detect the fault and disconnect from the system within the recloser interval and leave some duration for the fault to clear. Failure to follow this step might cause a persistent fault rather than a temporary one. Reference [11] recommends a reclosure interval of 1 second or more. The IEEE Standard 1547 [6] requires a much shorter time for reclosure.
- Safety:* Safety degradation from the failure of protection system may occur because a new DG increases the fault current. If the fault current is higher than the previous levels, that is higher than the interrupting capability of circuit breaker, the fault current might persist and cause damage to personnel and equipment.
- Changing the reach of protective relays:* A DG may reduce the reach of power system protective relaying

under certain circumstances. Consider a resistance fault occurring at fault point 2 during the peak load as shown in Fig. 2. The presence of DG2 in between the fault point might cause a lower fault current to be seen by the protective relay. The DG effectively reduces the reach (i.e., zone) of the relay. This increases the risk of high resistive faults to go undetected. In such a case, backup protection may operate to interrupt a fault.

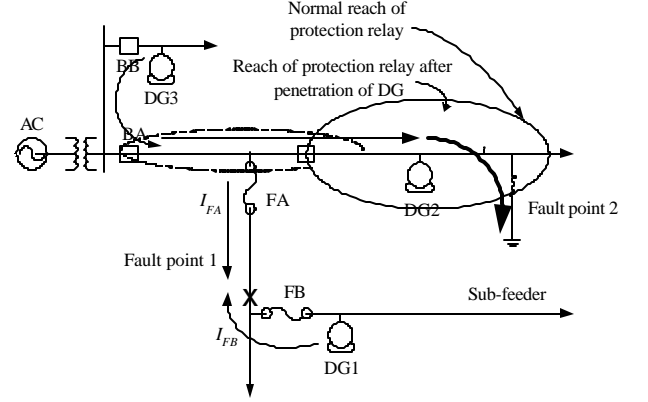


Fig. 2 The reach of a protective relay for a small sample distribution system with DGs

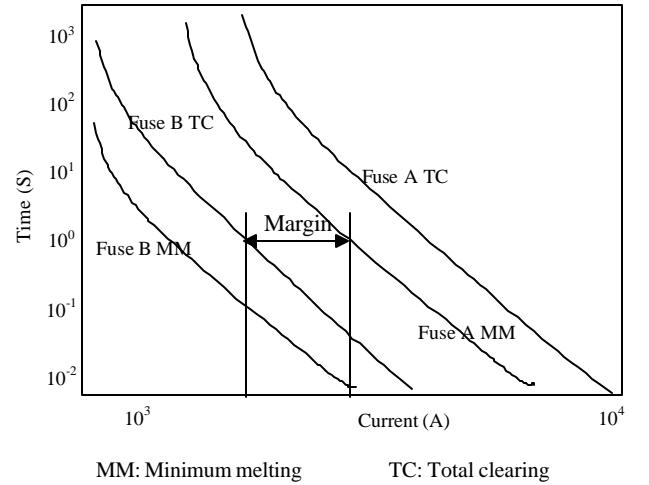


Fig. 3 Time-current characteristic of the fuse in the sample system of Fig. 2

IV. MODIFICATION OF TRADITIONAL ALGORITHMS OF FAULT CURRENT CALCULATION

As mentioned earlier, installing a DG in a distribution system could increase the fault current levels. Circuit breakers and fuses which are originally designed and coordinated for the system without the DG may have lesser capability to interrupt the fault current after the DG is installed. Note that DGs must be disconnected from the utility company supply when a fault is detected and the DG picks up the local load. The disconnection is needed because: (1) a fault near to the DG in the supply system must be interrupted and (2) the local DG can not support the power demands of the distribution system (apart from the local load). The disconnection of the DG from the network must occur rapidly: Table 1 shows the IEEE 1547 requirement for disconnection times.

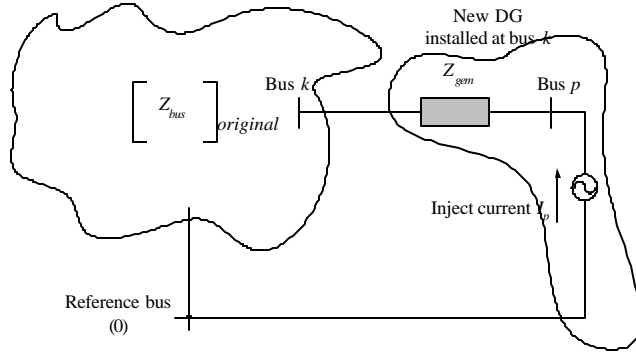
TABLE 1

Required disconnection times for DGs, from IEEE 1547 [6]

Voltage Range (percent of base voltage)	Clearing time (s)
$V < 50$	0.16
$50 \leq V < 88$	2.00
$110 < V < 120$	1.00
$V \geq 120$	0.16

In order to calculate the fault current at a system bus, a simple Thevenin model is used for the power system. That is, the system is modeled as a voltage behind a system impedance. The system impedance is the Thevenin impedance ‘seen’ at the bus that experiences the fault. The Thevenin voltage is the prefault bus voltage. The Thevenin impedance is simply the j, j entry of Z_{bus} , the bus impedance matrix when a fault occurs at bus j . The Z_{bus} matrix models the entire network (i.e., the transmission network, the sub-transmission network, the primary distribution network, and any generators that appear in the system). Generators are modeled as a transient reactance. For example, Fig. 4 shows the configuration of an unfaulted distribution system and a generator installed at bus k . Let the system without the generator at bus k be modeled as $[Z_{bus}]_{original}$. After the addition of the generator at bus k , a new bus, bus p , is added to the system.

Fault analysis by means of an impedance matrix can be applied to evaluate the incremental fault current due to new generator. Positive sequence models are adequate for some short circuit studies which determine the response of a DG [12].

Fig. 4. New DG added to bus k through its internal impedance creating a new bus p

The new bus p of the system is connected to the existing bus k through the impedance Z_{gen} which, for a synchronous generator, is simply jx' . The current from the DG injected to the system results in a change of voltage at every bus. The relationship between the new voltages, the injected current, I_p , and the off-diagonal elements of bus impedance matrix is given as,

$$\begin{aligned} V_1 &= V_1^0 + I_p Z_{1k} \\ V_2 &= V_2^0 + I_p Z_{2k} \end{aligned}$$

$$\begin{aligned} &\vdots \\ V_k &= V_k^0 + I_p Z_{kk} \\ V_p &= V_k^0 + I_p (Z_{kk} + Z_{gen}). \end{aligned}$$

In these expressions, the notation Z_{ij} is used to denote elements of the bus impedance matrix referenced to ground. This matrix, Z_{bus} , includes generators represented as ground ties which are the transient reactances of those generators (for the case of usual synchronous machines). All other ground ties (e.g., capacitors) are modeled in Z_{bus} as well. All the usual faulted power system assumptions are made in constructing Z_{bus} [1]. These model equations can be written in matrix form as,

$$\begin{bmatrix} V_1 \\ V_2 \\ \dots \\ V_n \\ V_p \end{bmatrix} = \begin{bmatrix} & & & & & \\ & & & & & \\ & & & & & \\ & & & & & \\ & & & & & \\ Z_{k1} & Z_{k2} & \dots & Z_{kn} & Z_{kk} + Z_b \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \\ \dots \\ I_N \\ I_p \end{bmatrix}$$

or,

$$\begin{bmatrix} V_{orig} \\ V_p \end{bmatrix} = \begin{bmatrix} Z_{orig} & col_k(Z_{orig}) \\ row_k(Z_{orig}) & Z_{kk} + Z_{gen} \end{bmatrix} \begin{bmatrix} I_{orig} \\ I_p \end{bmatrix} \quad (1)$$

where N is the row and column dimensions of the original bus impedance matrix, Z_{orig} is the original impedance matrix before installing the generator, Z_{gen} is the transient impedance of the added generator, k is the bus where the generator is installed, p is newly added bus to the system.

The model of the added generation used above is the conventional model of a synchronous generator. Not all DGs are conventional generators. Many DGs are energy sources that produce DC which is used as the input to an inverter which ultimately interfaces with the AC system. The controls of that inverter determine how the inverter is ‘seen’ by the network. In many cases, the inverter plus its controls appears as a voltage source and reactance as shown in Fig. 4. For some inverters, a constant current or constant power control may be used. The constant current model shall be considered below after dealing with the model shown in Fig. 4.

Applying the Kron reduction formula to (1), each element of the new bus impedance matrix is

$$Z_{ij,new} = Z_{ij,orig} - \frac{Z_{ik,orig} Z_{kj,orig}}{Z_{kk,orig} + Z_{gen}}. \quad (2)$$

Equation (2) gives a new bus impedance matrix model for the DG.

If there is a fault occurs at bus j , as shown in Fig. 5, the ‘injected current’ at bus j is $-I_j$ (i.e., this is the fault current). From the definition of the bus impedance matrix,

$$I_j = \frac{V_j}{Z_{jj,new}} = -I_{fj}. \quad (3)$$

The voltage at bus j is

$$V_j = Z_{jf} I_{fj} - V_f. \quad (4)$$

The three phase fault current at bus j can be evaluated by substituting (4) into (3),

$$I_{fj} = \frac{V_f}{\left(Z_{jj,orig} - \frac{Z_{jk,orig}^2}{Z_{kk,orig} + Z_{gen}} \right) + Z_f} \quad (5)$$

where Z_f is the fault impedance and V_f is the pre-fault voltage from a load flow calculation. The diagonal elements of the new bus impedance matrix are used to calculate the fault current at the faulted bus, and the off-diagonal elements are required to calculate the change in voltage and current flows in the system during the fault.

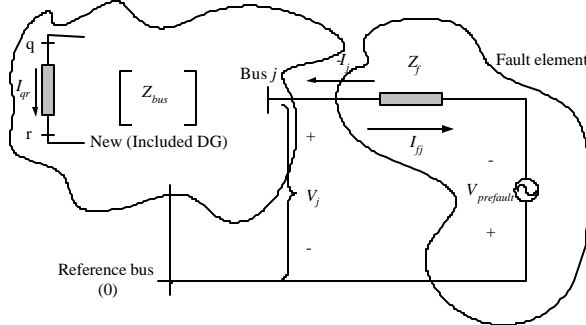


Fig. 5 Fault occurs at bus j in the system including the new DG

During the fault at bus j , the change in voltage ($\Delta|V|$) can be calculated by the bus impedance matrix equations,

$$\begin{bmatrix} \Delta V_1 \\ \Delta V_2 \\ \Delta V_j \\ \vdots \\ \Delta V_n \end{bmatrix} = \begin{bmatrix} -\frac{Z_{1j}}{Z_{jj,new}} V_f \\ -\frac{Z_{2j}}{Z_{jj,new}} V_f \\ -\frac{Z_{jj}}{Z_{jj,new} + Z_f} V_f \\ \vdots \\ -\frac{Z_{nj}}{Z_{jj,new}} V_f \end{bmatrix} \quad (6)$$

or the voltage during a fault can be obtained as,

$$V_i = \begin{bmatrix} V_f - \frac{Z_{1j}}{Z_{jj,new}} V_f \\ V_f - \frac{Z_{2j}}{Z_{jj,new}} V_f \\ V_f - \frac{Z_{jj}}{Z_{jj,new} + Z_f} V_f \\ \vdots \\ V_f - \frac{Z_{nj}}{Z_{jj,new}} V_f \end{bmatrix} \quad i = 1, 2, \dots, n.$$

The current flowing from bus q to r , as shown in Fig. 5, is

$$I_{qr} = \frac{V_q - V_r}{l_{qr}} = \frac{V_f (Z_{qk} - Z_{rk})}{l_{qr} (Z_{jj,new} + Z_f)} \quad (7)$$

where l_{qr} is the primitive line impedance from bus q to bus r , and Z_f is the fault impedance.

Equation (5) can be applied to examine the fault current consequences of installing a new DG. In order to calculate the new impedance matrix, a model of the DG should be known. These models may be complicated due to complex controls, or may be unknown. Some degree of engineering

judgment may be needed to obtain an approximate model. There are many technologies for distributed generation beyond conventional synchronous generators. Analysis of the fault current in the case of a new DG in the system requires knowledge of the model such as indicated by [13]-[16].

References [16]-[18] propose an application of ANNs to analyze faults from system waveforms. The applicability in the case of the presence of DGs in the system is unknown, and the concept is offered as a point of interest only.

V. A CONSTANT CURRENT MODEL FOR A DG

The foregoing was an analysis of the addition of a DG at a bus k in which the DG model is a Thevenin equivalent circuit (i.e., impedance plus voltage source, as seen in Fig. 4). If the DG model were a constant current source, with amplitude I_k , then the contribution of the DG to the fault current at bus j is

$$I_{f,withDG} = I_{f,noDG} + \frac{Z_{jk}}{Z_{jj}} I_k \quad (8)$$

where j is the faulted bus, k is the bus where the DG is installed, Z_{jk} is element jk from the original impedance matrix, Z_{jj} is the diagonal element from the original matrix, $I_{f,withDG}$ is the fault current after installing the DG, $I_{f,noDG}$ is the fault current before installing DG, and I_k is the injected current from current model. From (8), change of fault currents relates to:

- Influence of the bus where DG is installed to the faulted bus. This relation is shown in element jk of impedance matrix.
- Size of the DG, namely I_k .

VI. AN EXAMPLE OF FAULT ANALYSIS

The distribution system as shown in Fig. 6 is offered as an example of calculating fault current in the presence of a DG. The system is connected to transmission system at 230 kV. Substation transformers at bus 2 and 7 step down the voltage to 69 kV and serve the primary distribution system. A DG, 10 MVA, with transient impedance 17% is installed at bus 10. The DG model to be used is a transient reactance and series voltage source. Table 2 shows the result of the calculations before and after the DG is installed. As shown in Table 2, there are changes of fault current in every bus after installing the DG. However, the fault current is significantly changed at buses close to the DG.

VII. CHANGES IN SYSTEMS CAUSED BY DGs

Safety degradation due to DGs is important. According to [5], A. D. Little interviews with 14 U.S. electric transmission and distribution companies with the question "What are your concerns in regards to DGs?" indicate that safety to workers comes first. If the utility company workers are not aware that there is a DG running in the system, they might be injured from electric shock while working on lines or with other equipment. Significantly more sophisticated protection systems are needed to avoid problems of energized components when de-energization is expected.

TABLE 2
Results of fault analysis before and after adding a DG

Faulted Bus	$ I_f $ before DG (pu)	$ I_f $ after DG (pu)	Percent change (%)
1	60.692	60.85	0.26
2	26.750	27.26	1.91
3	22.76	23.17	1.80
4	12.36	12.49	1.05
5	8.76	8.83	0.80
6	55.42	55.63	0.38
7	26.83	27.45	2.31
8	24.04	24.67	2.62
9	12.26	12.91	5.30
10	10.92	11.58	6.04
11	9.84	10.38	5.49
12	8.22	8.60	4.62
13	23.63	24.12	2.07
14	3.48	3.50	0.57
15	2.96	2.98	0.68
16	10.92	11.44	4.76

In case a DG is the only supplier to the distribution system, islanding effectively results after the DG is disconnected from the primary distribution supply. At an islanded load, the voltage waveform from DGs may fluctuate and may not meet voltage regulation standards. Modern DGs are often electronically controlled in voltage magnitude and frequency. However, the susceptibility to the problems cited is greater for DG supplies than networked conventional supplies. Equipment of the customer connected to the distribution system might be damaged due to low power quality arising from a DG. Moreover, the DG equipment might be

damaged due to overloading – especially in transient cases. These issues are avoidable with electronic controls. To ensure the safety of installing DGs, all of the equipment should meet the standard requirements specified by IEEE Standard C1547 [6].

VIII. RESPONSIBILITY FOR FAULT CURRENT LEVELS

Fault currents in power systems determine the ratings of circuit interruption devices and settings of power system protective relays. Once the circuit breakers are in place and relay settings have been implemented, there may be some operating and planning implications imposed by changing fault current. Fault analysis should be done prior to the appearance of a new DG which may result in the change of fault response of the system. A method should be developed for the redesign of a protection system. The objective is to minimize the need to replace (upgrade) existing equipment. In some cases, entirely new protective relay methods may be needed. This is a complicated issue which depends on the type of customer, size and type of DG equipment, and the operation intention of the DG system. All approaches to allocate the responsibility and cost of these changes must be on the basis of simple and fair market for every customer and utility. The identification of what is fair and what is simple has not been done for the case of fault currents due to added DGs. Some alternatives include:

- The owner of the DG pays for all system changes and upgrades

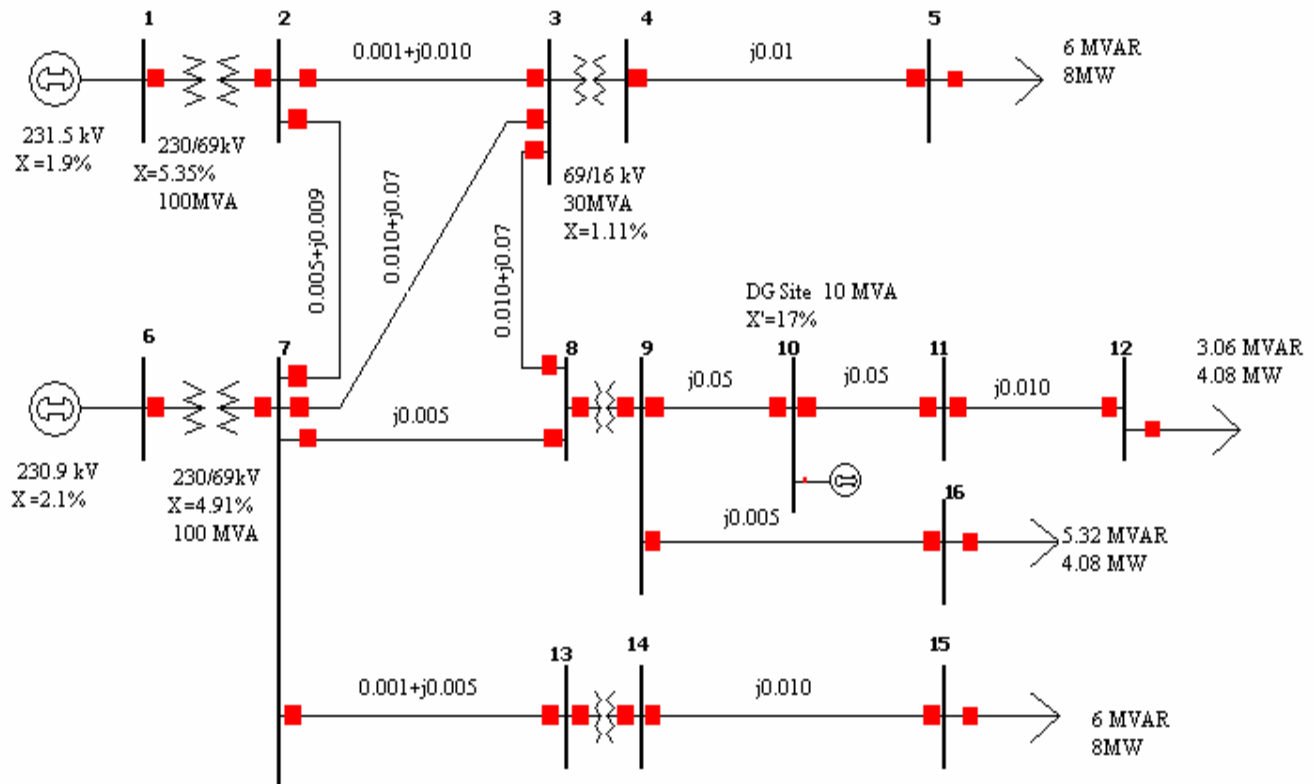


Fig. 6 A sample system for calculation of fault currents before and after installing of a DG at bus 10

- The owner of the DG shares the cost of the system changes and upgrades with the electric utility company on the basis of the system reliability prior to the installation of the DG. That is, the DG owner has installed the DG because of reliability issues due to the utility company, and therefore the utility company should share the cost of the upgrades needed. Under such a policy, if the primary distribution system reliability fell below a certain level, the cost of DG upgrades would be shared by the DG owner and the utility company – by an agreed formula.
- Special tariffs for customers with DGs should be approved to create a fund for the payment of required system upgrades.

Note that the foregoing remarks relating to the cost of added equipment and upgrades due to fault currents are separate from issues relating to commonality of technical conditions at DG sites. Most utilities utilize a common set of rules to interconnect the DG to power system, for example:

- Exchange the project information between utility and customer
- Technical analysis by the utility to evaluate the impact of DGs
- Inspection of interconnection and protective equipment by the utility.

These issues are needed to guarantee safety and reliability of the system which should be covered by the owner of the DG.

IX. CONCLUSIONS

There are advantages that arise from installing DGs in power systems, such as improving reliability, potentially improving power quality, and potentially enhancing environmental friendliness. However, a well planned system is also required to avoid problems from system generation capacity additions. Problems discussed in this paper include:

- Change in coordination of protective devices
- Nuisance trips
- Recloser settings
- Changing the reach of protective relays.

This paper presents a modification of the conventional fault current calculation in the case of addition of DGs. The impedance matrix is utilized to evaluate increased fault currents. The method accommodates bus voltage changes. Fault analysis provides important information needed to retrofit protective relaying and circuit interruption provisions.

X. ACKNOWLEDGMENTS

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XII. BIOGRAPHIES



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