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Protection of Electric Distribution Systems with Dispersed Storage and Generation (DSG) Devices

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POWER SYSTEMS TECHNOLOGY PROGRAM

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PROTECTION OF ELECTRIC DISTRIBUTION SYSTEMS WITH DISPERSED STORAGE AND GENERATION (DSG) DEVICES

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ABSTRACT

The problem of providing electrical circuit protection for dispersed storage and generation (DSG) devices interconnected with utility distribution systems is investigated. The emphasis of this report is on the technical issues but does address safety and economic issues to a limited degree.

The DSG protection problem areas are identified. Several simulations of protection problems are presented to show the nature of the various types of problems encountered. These simulations considered phenomena such as:

1. Resonance
2. Islanding
3. Fluctuating generation
4. Faults

An evaluation is made of the adequacy of present protection schemes with respect to the simulation results. Present schemes are found to be adequate in most areas except for protection against islanding. Guidelines are given to help utility distribution engineers design proper protection schemes.

A special protection package for small- and medium-sized DSG installations is recommended; this would simplify interconnection of DSG with the utility system. Specifications of the package are given. The feasibility of designing the package around a microprocessor-based relay is investigated. It is found that technical barriers have almost been overcome, and it should be practical to produce such a device soon.

1. INTRODUCTION

The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted to encourage the development of small, dispersed energy sources. This has sparked much interest on the part of electric utilities in the problems of connecting dispersed storage and generation (DSG) devices to conventional utility power systems. This report evaluates current techniques for protection of the interconnected systems. The particular emphasis of the report is on distribution systems, although many of the conclusions might also apply to DSG devices connected to transmission systems.

The major issues in DSG protection seem to be:

1. safety of personnel,
2. protection during faulted conditions, and
3. quality of service during normal or unfaulted conditions.

This report concentrates on Issues 2 and 3. Within these issues, the scope is limited to technical aspects. Other aspects, such as economics, are covered incidentally, only as they help to clarify a finding. The emphasis of this work is to evaluate existing schemes for protection and to suggest alternate schemes. For existing schemes, application guidelines are presented and the schemes are evaluated for adequacy in protecting against abnormal occurrences on the distribution system. For alternate schemes, this report concentrates on new technologies which might be exploited to provide better protection, such as microprocessors and automated control of distribution feeders.

This report is organized as follows:

Section 2 gives a brief summary of the major findings.

Section 3 defines the DSG protection problem. Several interesting simulations are recorded in this section that serve to illustrate the types and extents of problems that are expected to occur. Also, a comprehensive look-up table is provided to help applications engineers identify the protection needs for a given installation. This section serves as the basis for the remainder of the report.

Section 4 describes typical existing protection practices and evaluates them with respect to the findings of Section 3. General guidelines for DSG protection with existing hardware are presented.

Section 5 takes a look at alternate protection philosophies. In particular, the role of distribution automation in DSG protection is investigated.

Section 6 describes the requirements for a special-purpose DSG protection package. Considerations for building the package around a microprocessor-based relay are investigated.

2. SUMMARY OF FINDINGS

Our major findings are presented here in abbreviated form, in approximately the same order as they are discussed in the remainder of the report.

2.1. POINT-OF-VIEW BIASES

There are two points of view to the DSG protection problem. Although there are notable exceptions, the utility position is generally that DSG operators must conform to present utility operating procedures. This tends toward a more complicated interface than DSG operators would like. In reality, there must be cooperation and concessions on both sides if DSG devices are to be interconnected with proper protection.

2.2. VOLTAGE SENSING FOR FAULT DETECTION

The most common protective devices provided for loads on distribution systems are based on overcurrent sensing. However, it appears that voltage sensing devices are more appropriate for DSG protection.

2.3. NUISANCE FUSE BLOWING

Large capacity DSG devices (>1MW) or high concentrations of small DSG devices may destroy the existing coordination between reclosers and fuses. This would cause the fuse to blow, unnecessarily, for temporary faults during the first recloser operation.

2.4. RESONANT CONDITIONS

During single line-to-ground faults there is a definite possibility that high resonant voltages will appear if generators remain connected after the utility system's interrupting device opens. The voltages will affect both the utility system and the DSG device. The voltages will rise much too quickly for relays and breakers to be of any use. Surge arresters are the only means of adequate protection against this condition, and there is some question about the capability of standard distribution class arresters to withstand the discharge energy.

2.5. ISLANDING

Islanding refers to the condition that exists when a generator becomes isolated with a section of a feeder and continues to supply power to the load. It is shown in this report that islanding can occur, at least for a few seconds. This can be long enough to cause equipment damage, if not detected. There is no sure way of detecting islanding rapidly without resorting to communications between the DSG protective devices and utility protective devices.

2.6. RECLOSE INTERVALS

Utilities that use short reclosing intervals (0.5 s or less) may have to extend the first reclosing interval to allow time for the protection at DSG devices to detect the fault and disconnect. If feeder load and DSG generaion capacity are well matched, it may take many tens of cycles for the DSG devices to drift in frequency and voltage sufficiently for anything wrong to be detected.

2.7. HARMONICS

Harmonic problems can be made worse by the placement or presence of power factor capacitors. It is not always good to require DSG operators to correct their power factor onsite. That may drastically increase the harmonic distortion.

2.8. FLUCTUATING GENERATION

The power output of some types of DSG devices is extremely weather-dependent (e.g., wind-driven generators) and can vary widely in a matter of seconds. This will cause voltage regulation problems on a distribution feeder, if the source is sufficiently large. Results of a simulation show that the variation of wind machines is too rapid for conventional 32-step voltage regulators to be of use.

2.9. DSG PROTECTION SPECIFICATIONS

The majority of utility specifications for DSG protection are atypical of distribution protection specifications for loads of comparable size. They call for equipment which would normally be found in central generating stations and substations. In general, this equipment is too large and too expensive for small- and medium-sized (<1MW) DSG installations. A package especially for DSG protection on distribution systems is needed.

2.10. ADEQUACY OF PRESENT DSG PROTECTION SPECIFICATIONS

Present DSG protection specifications provide adequate protection in most respects. The most significant area of

inadequacy is protection against islanding. Communications between protective devices are needed to supplement present schemes.

2.11. REQUIRED RELAYING FUNCTIONS

The four basic relaying functions required by most DSG installations are:

1. Over/under voltage
2. Over/under frequency
3. Phase unbalance (if three-phase)
4. Overcurrent

2.12. DISTRIBUTION AUTOMATION

Distribution automation makes the interconnection of utility systems and DSG devices safer. It would generally enhance the operation of a distribution system with DSG, prevent DSG device islanding, and is particularly useful for restoration of service following a fault.

2.13. MICROPROCESSOR-BASED PROTECTION PACKAGE

A microprocessor-based DSG protection package appears to be technically feasible. Many technical barriers have already been overcome, as evidenced by the microprocessor-based equipment already available for DSG protection[8]. Some institutional barriers (e.g., mistrust of electronic relays) will remain for some time.

3. THE DSG PROTECTION PROBLEM

3.1 OVERVIEW OF THE PROBLEM

There are two major areas of the DSG protection problem that are addressed in this report:

1. protection during faults
2. protection during normal conditions

Each of these is addressed in detail in the following two subsections. However, it is useful at this point to give an overview of the problem.

Figure 3.1 shows a tree chart of all the areas covered in the report. This chart can be used as a "road map" to the next two subsections. The first major decomposition of the DSG protection problem on the chart yields the two areas listed above. Each of these, in turn, can be broken down into two general areas:

1. Protecting the utility from DSG
2. Protecting DSG from the utility

These areas represent the two different, sometimes opposing, viewpoints on this problem. The utility is

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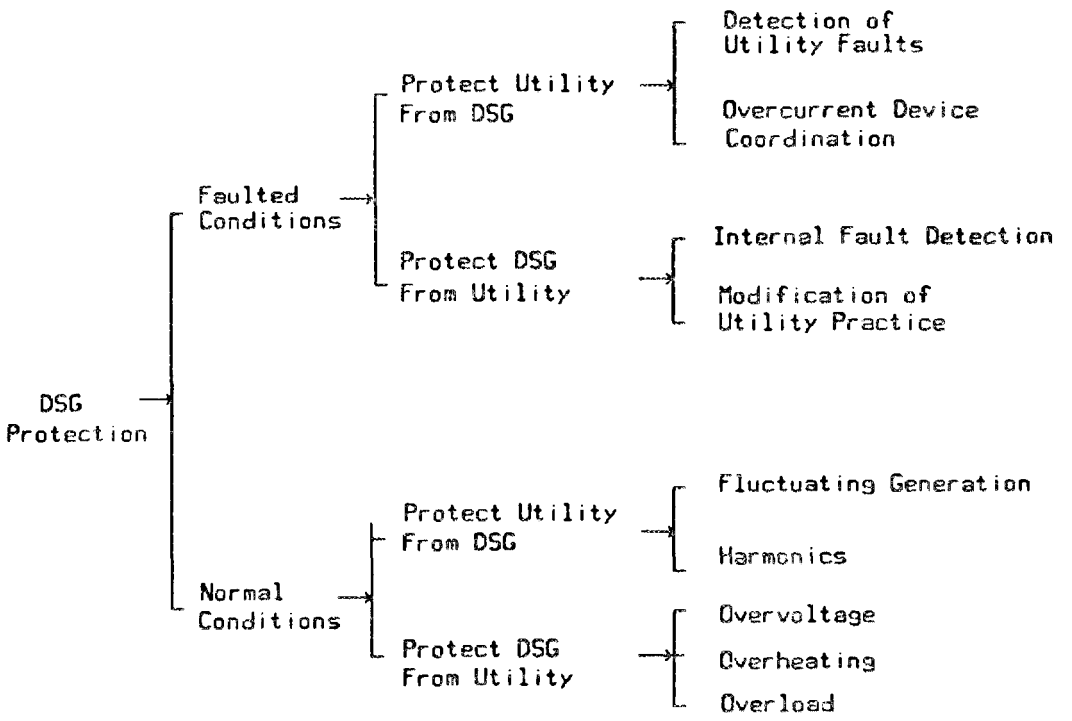

Fig. 3.1. The DSG protection problem as addressed in the report.

often reluctant to support independently owned DSG because of fears that the utility's system will be damaged. They want to require DSG sites to have protection schemes with considerable redundancy that can adapt to existing utility practices.

The DSG owners are often faced with marginal return on investment and want to make a minimum investment in protection equipment. They would prefer that the utility modify its practices to reduce the chances that

disturbances on the utility system will inflict damage to their equipment. Therefore, people holding each viewpoint tend to concentrate on the issues listed under the area that represents their viewpoint.

The purpose of the chart in Fig. 3.1 is to show that the DSG protection problem cannot be viewed entirely from either perspective alone. It encompasses both the utility and DSG owner perspectives and must be solved with an integrated approach. The DSG owners may have to install more protection equipment than they feel necessary. The utility may have to modify long-established practices. Both sides may have to bend a little so that dispersed sources can be safely connected to utility distribution systems.

The next two subsections (3.2 and 3.3) address the areas listed on the chart and give specific examples of the major protection problems. The last subsection (3.4) presents a procedure that should help utility engineers and DSG owners understand the protection problem and determine what kind of equipment is available to solve each problem that arises.

3.2 PROTECTION DURING FAULTED CONDITIONS

The area of the protection problem that seems to cause the greatest concern is protection during faulted conditions, when both the utility system and DSG devices are the most vulnerable to damage. Utilities have decades of experience through which they have established procedures to minimize fault damage on their distribution systems. Most of these systems are radial, and the protection schemes take advantage of the fact that power flow is in one direction. However, the addition of dispersed generation essentially transforms the radial feeder into a looped feeder, forcing changes in the traditional feeder protection procedures.

The simplest approach to handling faults when DSG is present is to force the feeder into a purely radial configuration. Then the standard procedures for dealing with the fault can be utilized. This means that DSG devices will be disconnected from the circuit at the first sign of a fault and remain disconnected until the fault is removed and normal service is restored. The DSG devices must be able to detect faults on the utility system and the utility system must wait for the feeder to revert to radial form.

There are other problems during faulted conditions. The presence of DSG might destroy the overcurrent protection device coordination, resulting in more numerous extended outages. Some investigators have suggested that during ground faults resonant conditions can develop that will damage DSG devices and line devices before the protection circuits can operate. Also, there is the problem of islanding, where a generator becomes isolated on a section of feeder and continues to supply power to the load on that section of feeder. In the future, with better controls, this might be desirable. However, it is generally

considered dangerous today, considering the safety of line repair personnel and the consequences of out-of-phase reclosing.

Another area of concern is faults within the DSG device. In this case, the protection objective would be to interrupt current flow from both the utility source and local dispersed generator before damage is done. The utility source is often able to contribute more current to a secondary fault than the local generator contributes. Therefore, the protection at the DSG site must be able to detect internal faults from the utility side as well as from the generator side.

Methods for accomplishing these protection objectives are presented in the subsections which follow. The issues dealing with protecting the utility from DSG are discussed first, followed by the issues which deal with protecting DSG from the utility source.

3.2.1 Protecting the Utility from DSG

Fault Detection

It is critical for each DSG site to be able to quickly detect faults that occur on the utility system. Then the generating device can be disconnected so that the feeder reverts to radial form and the standard fault-clearing procedures can be used. When service is restored (however that is defined), the generator can be reconnected.

The usual utility practice for handling faults is:

1. Interrupt the fault current.
2. Reclose.
3. Repeat steps 1 and 2 as many as 3 times if necessary.

The utility's philosophy is that most faults are temporary and that they will clear themselves when the fault current is interrupted; then service can be restored quickly without human intervention. If the fault is permanent, the reclosing is continued until the feeder is sectionalized by fuse operation, sectionalizer operation, or recloser lockout. In most applications, a fuse should not operate before the fault current is interrupted for the first time.

If a DSG device were to remain on line, it could:

1. continue to feed the fault, making it appear permanent,
2. cause premature fuse blowing, or
3. be damaged by the reclosing operation.

Therefore, a fast and reliable method is needed for detecting faults.

Utility distribution engineers tend to think in terms of using overcurrent devices to detect faults. These devices fit into long-established practices for detecting faults on radial circuits where the fault detection devices are in series with the fault path (Fig. 3.2). It is not obvious that overcurrent is the best means to detect faults at DSG sites; in fact, voltage sensing is suggested simply on the basis that the DSG device is connected to the feeder in parallel, rather than in series (Fig. 3.3). Current sensing will work in some cases where the generator senses the fault from its terminals and produces an overcurrent. However, it is not clear that generators close to the substation and relatively remote from the fault will produce an overcurrent. Also, generators such as induction machines and dc devices with inverters may not have the ability to feed enough fault current for reliable fault detection by sensing overcurrent.

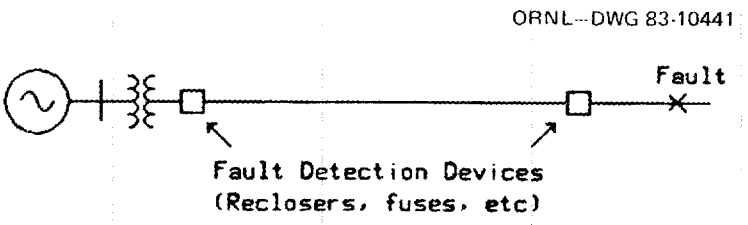

Fig. 3.2. Typical distribution feeder-fault detection scheme with devices connected in series.

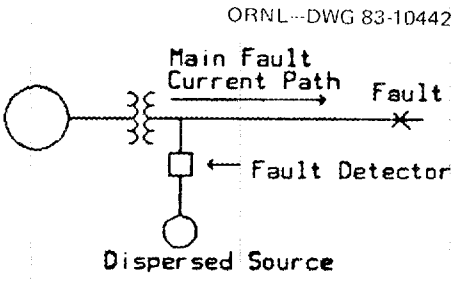

Fig. 3.3. Fault sensing from DSG site must be done by a device connected in parallel with the feeder.

These problems with current sensing and the manner in which the generator is connected (parallel) suggest that voltage sensing be used as the primary fault detection quantity. Overcurrent sensing would then be relegated to a secondary role, protecting the generator against overloads and internal faults. This represents a break with tradition for many distribution engineers, who may be reluctant to approve a voltage relaying scheme.

To determine if a fault detection scheme relying primarily on voltage sensing would be practical, an analysis was made. Although the analysis does not define all the parameters in such a scheme, it strongly suggests that a voltage sensing scheme would be feasible. There are cases where voltage sensing fails to detect faults before the utility

interrupting breaker operates. However, even in those cases, it would be expected that the voltage would deviate from normal quickly after the utility breaker operation and the abormal condition would be easily detected in time to act before the reclosing operation.

Analysis of Using Voltage Sensing Alone to Detect Feeder Faults

For this analysis, the example circuit in Fig. 3.4 was used. This is a 12.47 kV feeder (7200v line-to-ground) with available fault currents at the substation and the end of the three-phase feeder as indicated on the figure.

The phase voltages and sequence voltages were recorded at each node for various faults applied to each node. The applied faults were three-phase faults, single-line-to-ground (SLG) faults, line- to- line (LL) faults, and line-to- line-to-ground (LLG) faults. No fault impedances were used and load was neglected.

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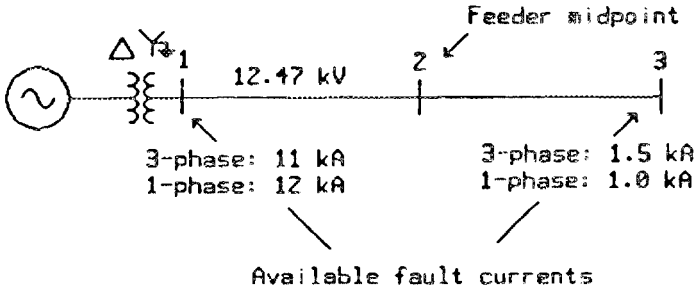

Fig. 3.4. Example circuit.

For these faults, Tables 3.1 and 3.2 record the results. Table 3.1 records the zero- and negative- sequence voltages at each node for each fault. Table 3.2 records the magnitude of the unfaulted phase voltages.

These tables give the voltage quantities available to use for fault sensing at the time of the fault. For fault detection to be reliable, the voltage quantities have to be significantly different than normal feeder voltages. To make this determination, a probabilistic load analysis was done on this feeder (Fig. 3.4). A load condition was established that would represent the typical maximum load on a feeder of this type (Fig. 3.5). This load condition gives approximately 126 volts (secondary) at the substation and 114 volts at node 3. The load is approximately 8 MW at 0.89 lagging power factor.

These loads were varied randomly, using a normal distribution around the target value specified above. Each phase was varied independently with a standard deviation of 10%. One hundred cases were run, and these cases suggested the maximum zero- and negative-sequence voltages recorded in Table 3.3. As can be seen, these voltages are substantially lower than sequence voltages produced by faults.

An additional case was run with the standard deviation on the load at 20%. This resulted in levels of zero- and negative-sequence voltages that were approximately twice as high (Table 3.3). However, the voltages are still a factor of 2 less than for faulted conditions except for a three-phase fault.

Therefore, if the phase currents at peak load are balanced to within $\pm$ 20% of average, these data suggest that it is possible to distinguish between faulted conditions and normal load conditions with acceptable margin. Phase

Table 3.1. Sequence voltages (volts)

	Sequence voltages at node 1: zero	negative	Sequence voltages at node 2: zero	negative	Sequence voltages at node 3: zero	negative
Three-phase fault at node:						
1	0	0	0	0	0	0
2	0	0	0	0	0	0
3	0	0	0	0	0	0
SLG fault at node:						
1	1960	2618	1960	2618	1960	2618
2	276	377	4184	1520	4184	1520
3	148	197	2244	816	4343	1448
LL fault at node:						
1	0	3600	0	3600	0	3600
2	0	870	0	3600	0	3600
3	0	491	0	2029	0	3600
LLG fault at node:						
1	2160	2160	2160	2160	2160	2160
2	201	738	3052	3052	3052	3052
3	105	421	1600	1744	3094	3094

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Table 3.2. Unfaulted phase voltage magnitude (volts, phase-to-ground)

	Unfaulted phase voltages at node 1:		Unfaulted phase voltages at node 2:		Unfaulted phase voltages at node 3:	
SLG fault at node:						
1	6895	6895	6895	6895	6895	6895
2	7175	7136	9156	8527	9156	8527
3	7165	7187	8125	7800	9387	8632
LL fault at node:						
1	7200		7200		7200	
2	7200		7200		7200	
3	7200		7200		7200	
LLG fault at node:						
1	6477		6477		6477	
2	7134		9156		9156	
3	7166		8230		9282	

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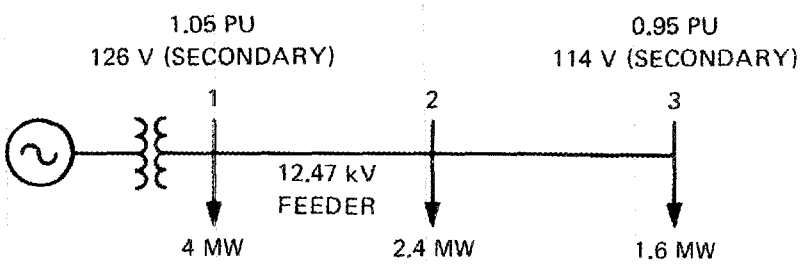

Fig. 3.5. Nominal feeder loading at maximum load.

Table 3.3. Maximum expected sequence voltages due to normal load unbalance

	Sequence voltages for 10% standard deviation in each phase balance:		Sequence voltages for 20% standard deviation in each phase balance:	
	zero	negative	zero	negative
Node:				
1	20	28	38	55
2	160	66	324	133
3	201	80	420	162

currents can have more relative unbalance at lower load levels because there is less voltage drop.

The following observations can be made from these results.

1. Faults which generate zero-sequence voltage (SLG and LLG) can be detected by zero-sequence voltage relaying.

2. All faults, except three-phase faults, can be detected by negative-sequence relays. (Three-phase faults are detectable by voltage magnitude on this feeder.)

3. Single-phase devices that sense only voltage magnitude will not be able to sense some faults until a breaker has interrupted the fault. Three-phase devices sensing only magnitude will be more reliable because it is expected that at least one phase will have a voltage disturbance sufficiently different from normal voltage so that a fault can be detected.

4. Voltage magnitude sensing alone will fail more frequently for DSG sites near the substation where

the voltage variation is less. However, phase unbalance detection will still work.

These observations suggest a primary fault detection scheme that depends on both voltage magnitude sensing and voltage phase balance sensing (for three-phase installations). With this type of protection, DSG sites should be able to detect the vast majority of faults before the interrupting breaker operates. This will give ample time to disconnect the DSG device before utility reclosing action.

There are cases where voltage sensing will not detect the fault before the utility interrupting breaker operates. These cases are for three-phase devices near the substation and for single-phase devices in general. However, voltage relaying should easily detect a problem after the breaker opens because it would not normally be expected that the DSG capacity would be sufficient to support the feeder load; therefore, the voltage would drop rapidly. This would be particularly true for single-phase generators. Normally, even a large three-phase generator near the substation would not be expected to support the entire feeder load.

The case that is a greater problem is when the generator infeed to the fault is large enough to prevent relays at the feeder breaker from sensing the fault (Fig. 3.6). In this case, neither the overcurrent nor voltage relaying can detect the fault. This is a case where the presence of a generator destroys the existing coordination. The usual method of correcting this is to add another reclosing breaker downline from the generator. Of course, this means added expense to the utility which may have to be borne by the generator's owner.

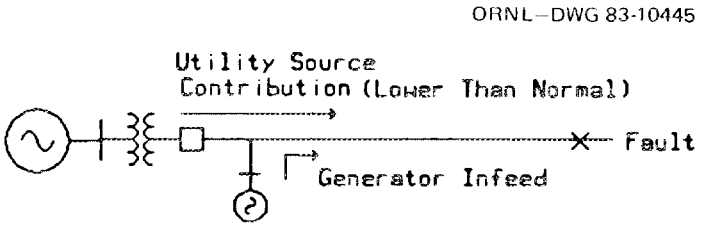

Fig. 3.6. Generator infeed to a fault, preventing utility breaker from sensing the fault.

The case where the generator can support the feeder load without significant change in voltage is referred to as "islanding." This is a real problem, and the special relaying considerations for it will be addressed later.

Effect of DSG on Temporary Fault Fuse Coordination

Assuming the fault can be detected, the next question is: Will the extra fault current contributed by the DSG devices cause nuisance fuse blowing for temporary faults? The problem is illustrated in Fig. 3.7. A branch fuse will sense additional fault current due to the nearby dispersed generator. Ideally, this fuse should not begin to melt until the second or third recloser operation. Thus, if the fault is temporary, service can be restored automatically without having to dispatch a line crew to replace the fuse.

To help answer this question, an analysis was made to determine the additional energy that the fuse would experience due to the dispersed generation. Two types of generators were considered: three-phase synchronous and induction rotating machines. Various faults were applied to the circuit in Fig. 3.7 for three different sizes of machines: 100 kW, 1000 kW, and 2000 kW.

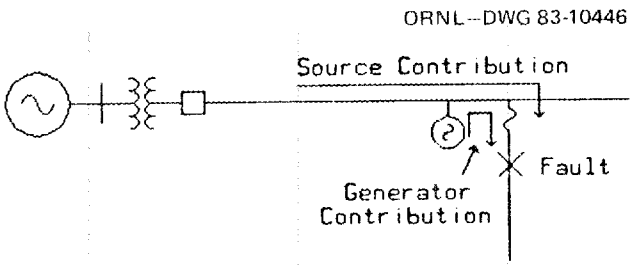

Fig. 3.7. Increased current flow into a branch fuse due to a DSG device.

From this analysis it was determined that for generator sizes 1000 kW or larger there is likely to be nuisance fuse blowing. This generation capacity would not have to be lumped into one DSG site but could be spread over several locations on the feeder. Other investigators [1] have shown that for dispersed generators the fault contribution was only about 20% less for the generation capacity spread over the feeder than if the generation capacity were lumped at one place. The implication is clear: as total penetration of induction and synchronous generators approaches 1MW on a 12.47 kV feeder, the branch fuses on the feeder will have to be re-coordinated with the recloser. This may require extensive fuse changeouts. The selected coordination scheme will also have to operate satisfactorily when the generation is disconnected from the feeder.

Because the fault current contribution of a rotating machine varies widely over the first few cycles, the fuse coordination results are not displayed on the traditional TCC (Time-Current Characteristic) plot. A fuse melts when the energy accumulated in the fuse element reaches a certain level in a given time. This energy is often expressed as "I^2t," which is mathematically

$$I^2t = \int i^2 dt.$$

It is proportional to the energy accumulated in the fuse, assuming the resistance of the fuse is constant.

The results of this analysis are displayed on graphs of I^2t vs. time. On these axes, the fuse characteristic is nearly constant for the time period of interest. The I^2t of the fuse current is monotonically increasing and the fuse melting time is given by the intersection of the two curves. The standard TCC curve analysis assumes that the fault's I^2t increases at the same rate with time. However, this is not true for faults near the terminals of rotating machinery (see Fig. 3.10). This is especially critical for induction machines which may only contribute one half-cycle of fault current. Thus, this procedure for determining the melting time was chosen.

The machine data used in the analysis was based on a typical 100 kW synchronous machine and proportionally modified for larger machines. The induction machine was assumed to have the same stator parameters, but the rotor time constant was empirically adjusted to a typical value (see Appendix B).

Synchronous Generator

Figure 3.8 shows the result of applying a three-phase fault with the three different sizes of synchronous machines. There were 2500 amperes (rms) of fault current available at this location before adding DSG. For the 100-kW machine there is little noticeable difference between the total fault I^2t and that supplied by the normal source. However, the 1000-kW and 2000-kW machines show a substantial difference. The fuse which might typically be used at this location would have a characteristic between

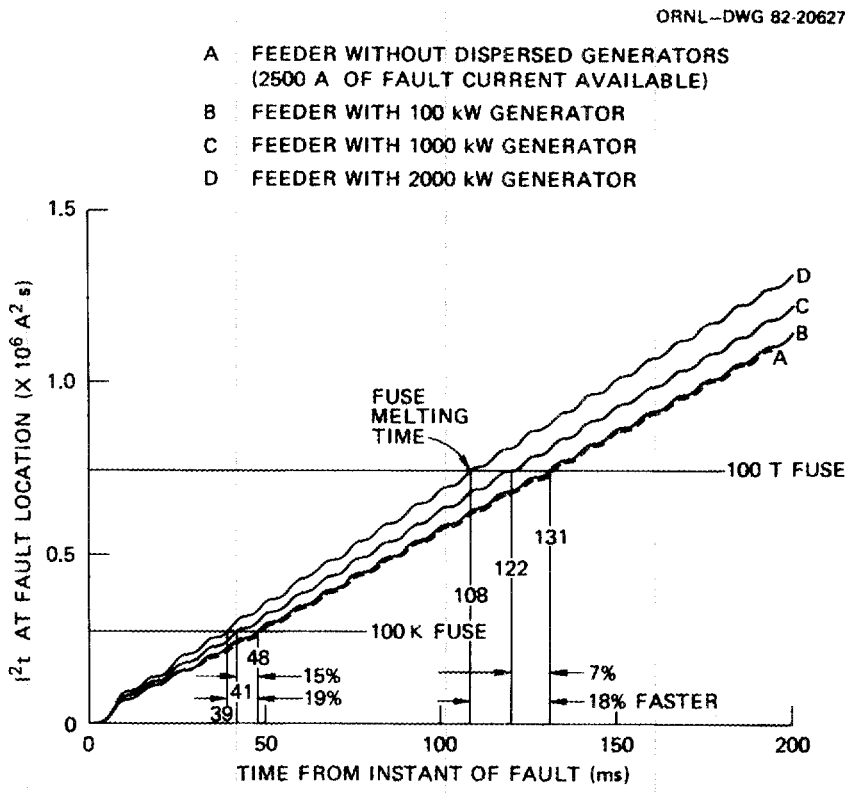

Fig. 3.8. I^2t for three-phase faults on three sizes of synchronous machines with 2500 amperes of fault current available.

the 100K and 100T fuse. (It would be selected to coordinate with the upline recloser.) In this range, the 1000-kW machine would cause the fuse to melt in about 10% less time, and the 2000-kW machine would cause the fuse to melt in about 20% less time.

Figure 3.9 shows the same case with 1250 amps of fault current available. The change in fuse melting time is even greater. A 40T fuse would melt in about 15% less time for the 1000-kW machine and 30% less time for the 2000-kW machine.

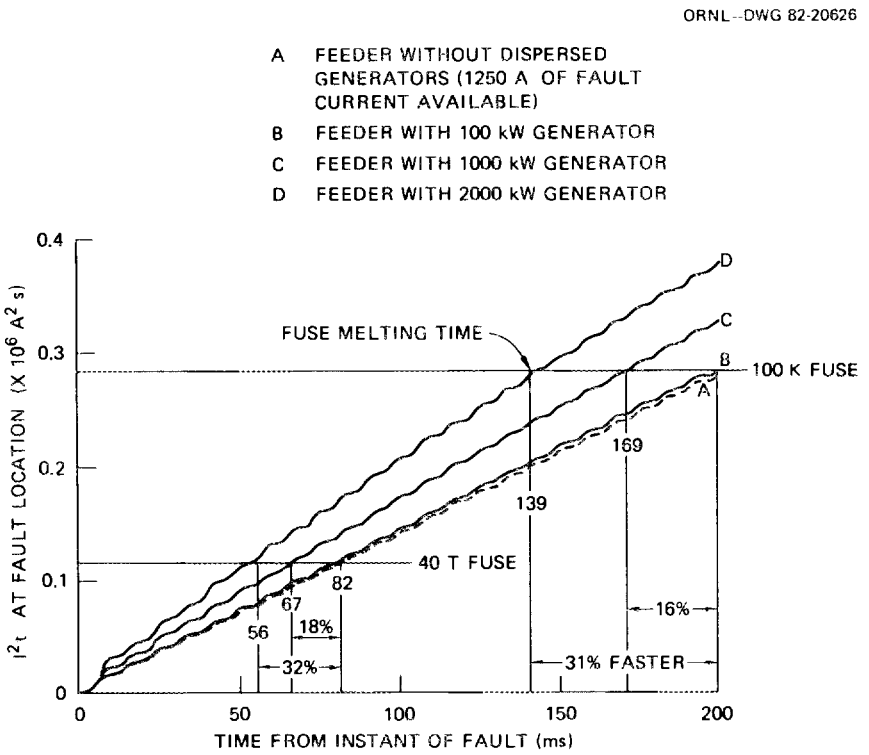

Fig. 3.9. I^2t for three-phase faults on three sizes of synchronous machines with 1250 amperes of fault current available.

These results indicate that coordination margins will be reduced significantly and suggest that there should be a reevaluation of coordination schemes if a synchronous generator 1000 kW or larger is placed on a distribution feeder. If there is a problem, the utility has two options:

1. Changing fuse sizes
2. Selecting a faster relay or recloser setting

Of course, if the latter option, is possible, it may be less expensive. However, the first operation of a recloser is generally a "fast" operation, which has no delay in it

at the higher currents. Therefore, Option 2 may not be possible and fuse changeouts would be necessary.

Figure 3.10 shows the typical waveshape of the fault currents for the three-phase faults on a distribution feeder with a synchronous machine.

Large synchronous machines often would be connected to the utility system through a delta-delta transformer. Therefore, they would not generally contribute to SLG faults. However, if they were connnected through a grounded wye-delta transformer (primary wye) they would contribute to a fault.

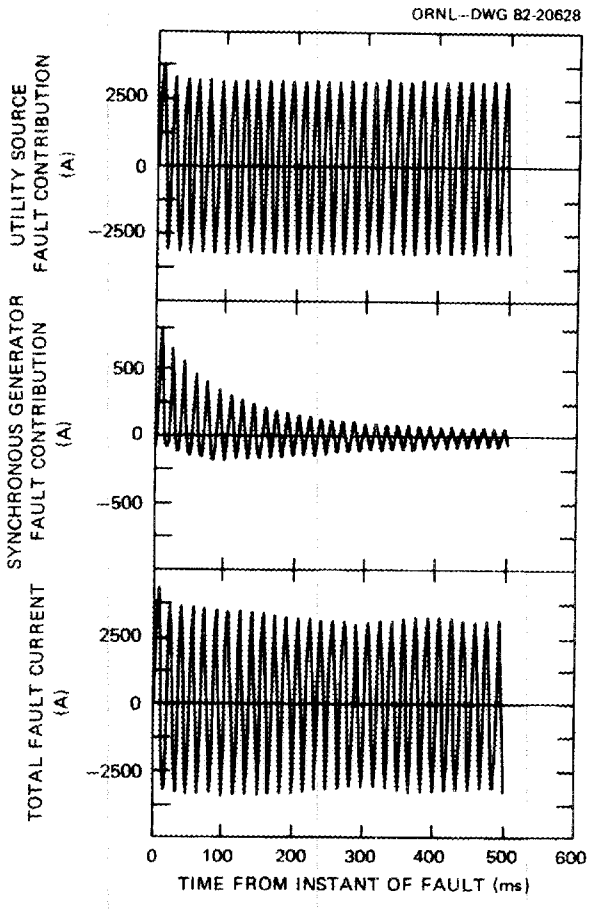

Fig. 3.10. Typical waveshapes for three-phase faults on a 2000 kW synchronous machine.

Figure 3.11 shows the I^2t plots for such a case where there were normally 1500 amperes (rms) of fault current available for an SLG fault. This type of installation affects the fuse melting time enormously: fuses could be expected to blow in half the time. However, the generator contributes only a portion of the extra I^2t. The rest of it comes from the transformer, which acts as a grounding transformer. Thus, we see different source contributions for each generator size. It was assumed that the transformer would match the generator size and would remain energized when the generator is out of service. These results suggest that unless the utility is prepared to handle the grounding transformer effect in its coordination scheme, it should avoid the grounded wye-delta connection for DSG.

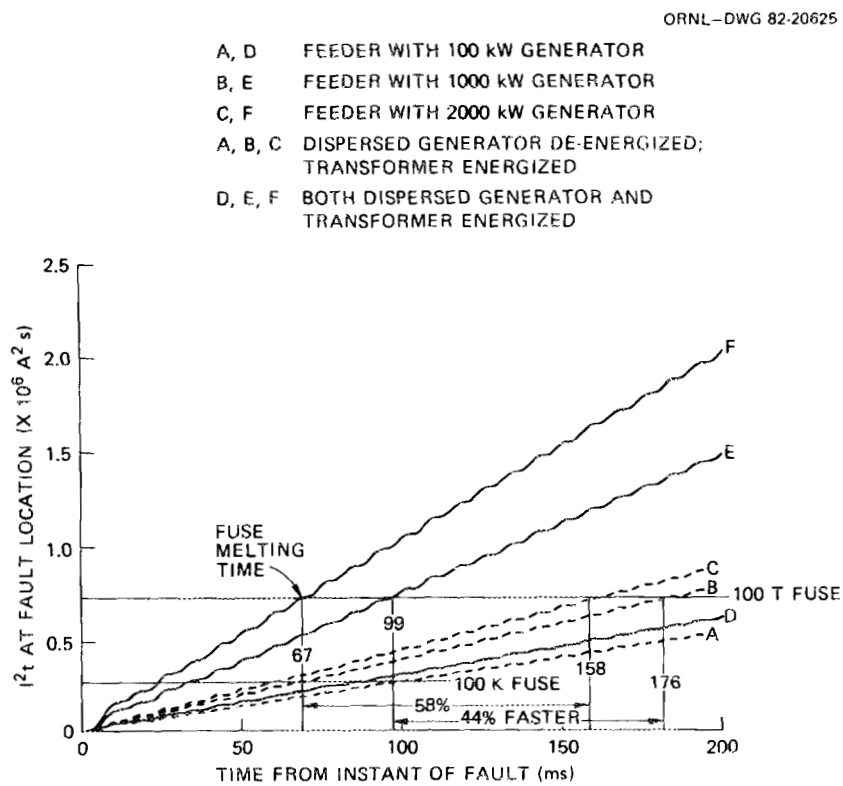

Fig. 3.11. I^2t for single line-to-ground fault on three sizes of synchronous machines connected to wye-delta transformers. Primary is wye (grounded).

Induction Generator

An induction generator responds much differently to a fault than a synchronous machine. It is not generally capable of feeding a fault for more than one or two cycles due to loss or reduction of excitation. Figure 3.12 shows the results of a case similar to the one in Fig. 3.8, except that induction generators are considered. In this case there is little significant change due to generator infeed: the 2ØØØ-kW induction generator will cause typical fuses to melt 2-5% faster for a three-phase fault. Typical fault currents for this case are shown in Fig. 3.13. As can be seen, the generator contribution decays to zero quickly.

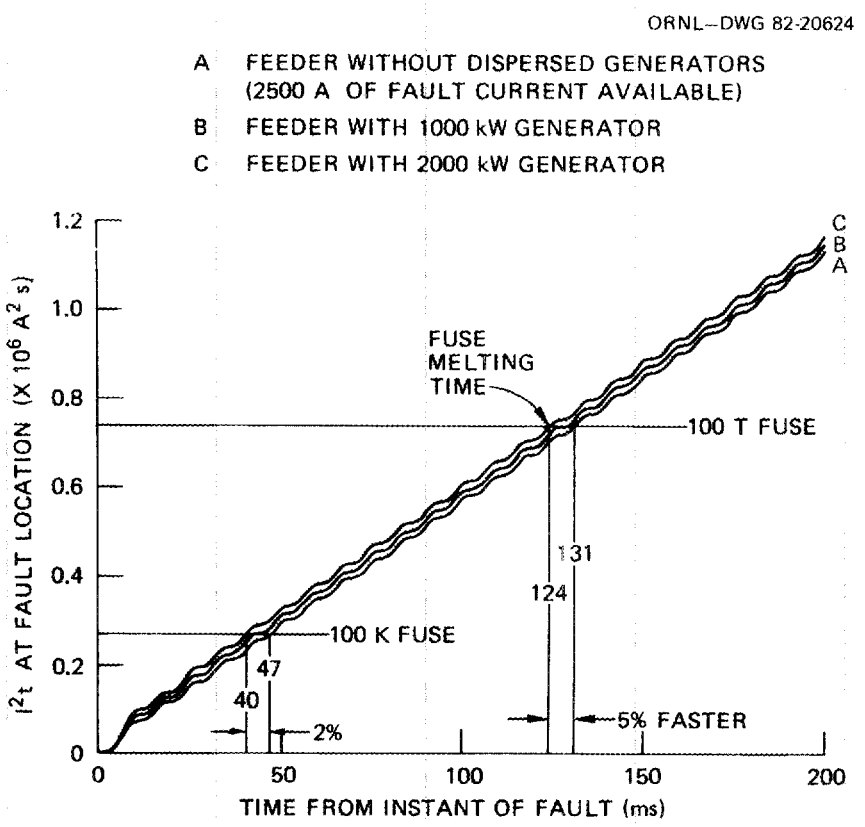

Fig. 3.12. I^2t for three-phase faults on three sizes of induction machines with 25ØØ amperes of fault current available.

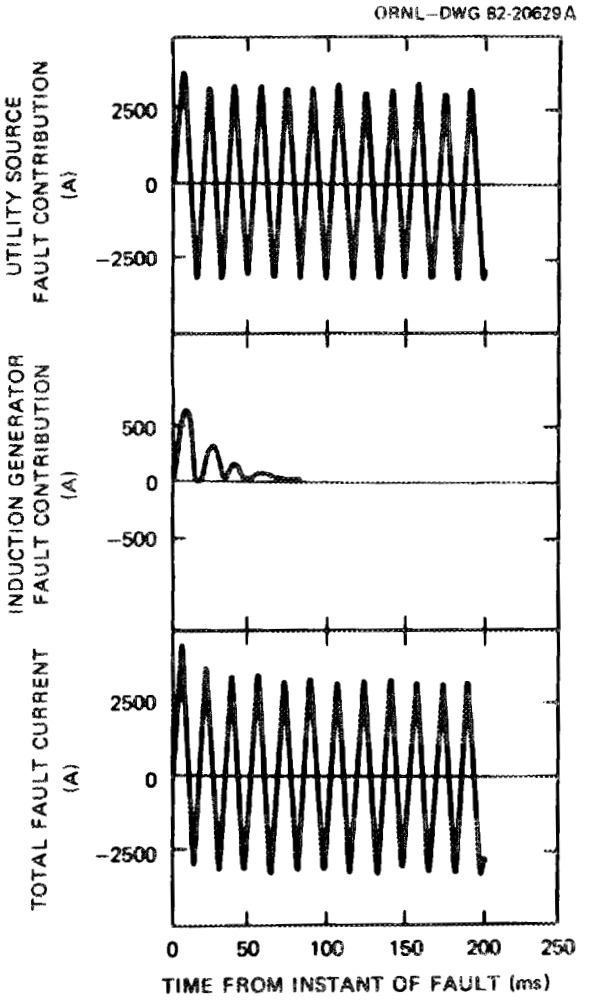

Fig. 3.13. Typical fault currents for a three-phase fault on a 2000 kW induction machine.

A line-to-line fault is slightly worse for the induction generator case (Fig. 3.14). The generator does not completely lose excitation and is able to feed more current into the fault. Protective margins are decreased by 12% to 14% for a 2000 kW generator.

Like the synchronous machine, as the available fault level decreases, the relative effect on the fuse coordinations increases. Also, the grounded wye-delta transformer

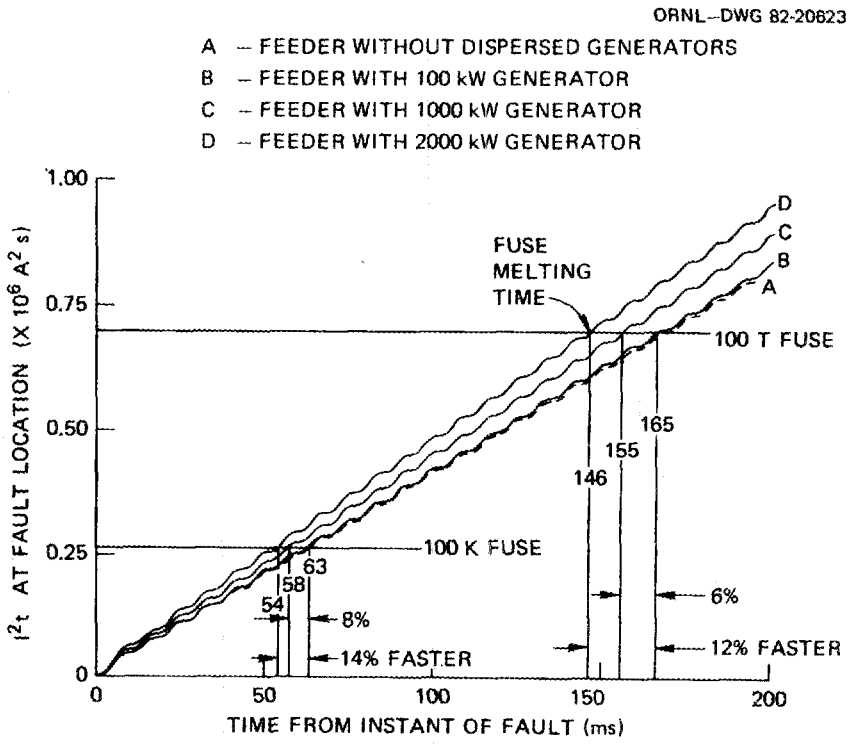

Fig. 3.14. I^2t for line-to-line faults on three sizes of induction machines with 25ØØ amperes of three-phase fault current available.

connection will act as a grounding source and contribute significantly to ground faults, as such connections do for synchronous generators. Thus, some utilities might want to avoid this connection for induction generators as well.

Induction machines are of less concern for nuisance fuse blowing than synchronous machines, but they cannot be totally ignored. If there is some means to supply excitation such as a capacitor bank, then the induction machine can feed more current than these simulations show. Also, these simulations have ignored resonance effects which might occur. This will be the next issue addressed in this subsection.

If the branch fuse in Fig. 3.7 were a breaker instead, the distribution engineer should be sure that the relaying will account for the generator infeed. Also, the capability of the breaker to interrupt the total fault current should be verified. This applies to fuses as well, since they have a maximum interrupting capability.

Resonant Conditions During Faults

A letter from W. A. Lewis, Consulting Engineer, to J. L. Koepfinger, Protection Engineer for the Duquesne Light Company, was forwarded to the investigators by Koepfinger. In this letter Lewis described a situation which he believed would yield resonant overvoltages. This condition is shown in Fig. 3.15. In this circuit an SLG fault has developed, and the utility interrupting breaker (all three phases) has opened as indicated by the open switch. This leaves the generator isolated on the faulted line section.

If the sequence networks were drawn for this situation and connected in series for a SLG fault, it would be found that the zero-sequence capacitance is in series with the generator inductances. This might lead to a resonant

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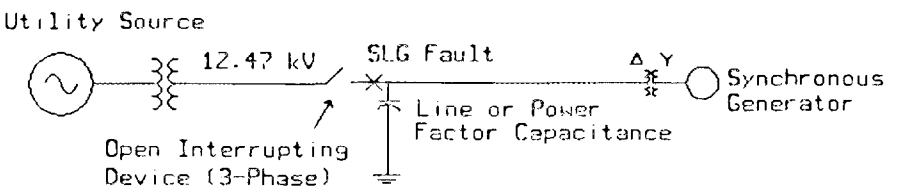

Fig. 3.15. Circuit condition for resonance during single line-to-ground fault.

condition. In the analysis here, a 100-kW synchronous generator was simulated with values of capacitance ranging from 150 kVAR to 1200 kVAR. This was to determine if resonance could occur and what typical values of overvoltages might be. The worst case was found with 150 kVAR of shunt capacitors. If surge arresters and load are neglected, the voltage will swing to over 260 kV in just 1.5 cycles after the feeder breaker opens (Fig. 3.16). There are indications that this voltage will go higher if the capacitance is smaller. The field of the generator was adjusted to give nominal line voltage at open-circuit.

This result certainly indicates that the problem Lewis describes might occur. If the voltage is allowed to rise without constraint, insulation damage is certain.

If load is considered, the overvoltage is damped. Table 3.4 shows the peak voltage reached for three different load values.

Table 3.4. Overvoltage variation with load, 100-kW synchronous generator, 150-kVAR capacitor

Load (@.9 PF lag)	Magnitude (peak)
10 kW	240 kV
100 kW	60 kV
1000 kW	6 kV

These values are calculated from simplified simulations, but they illustrate that the overvoltage could be several times normal if the generator becomes isolated on a portion of the feeder with a capacitor bank and very little load. An example of this situation might be an express feeder to a remote generator site that may have only station service loads.

In the example analyzed here, the fault current reached a peak of nearly 300 amperes after the feeder breaker opened. This would be sufficient to maintain the arc and cause a temporary fault to appear permanent if the generator does not disconnect from the line quickly enough. Thus, when the utility breaker recloses, the fault will still be present and branch fuses will operate unnecessarily.

It can be expected that this resonance condition can occur in some percentage of DSG installations. Few breakers at DSG sites will be faster than the utility feeder breakers, which will certainly result in the generator being isolated with the fault for several cycles. As shown in Fig. 3.16, it only takes 1.5 cycles (25 msec) for the overvoltages to develop. Therefore, surge arrester protection on both primary and secondary (for redundancy) sides of the distribution feeder should be a general requirement for DSG sites. The surge arrester should be sized to absorb the energy in the circuit for perhaps as much as 10 cycles. For small generators (less than 100 kW), a standard distribution class arrester should be sufficient on the primary. However, generators 100 kW and above may require intermediate or station class arresters. In the example analyzed here, 10 kV arresters were simulated on the unfaulted phases. In only 1.5 cycles (two arrester operations), the arrester absorbed 12 kJ. A McGraw-Edison VariSTAR 10-kV gapless arrester for distribution class can withstand 30 kJ. Depending on the speed of the generator

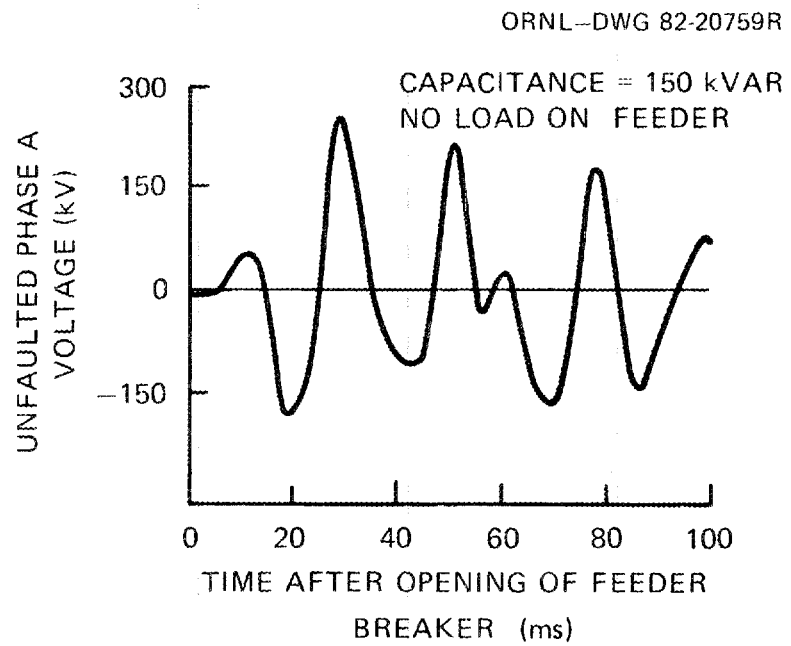

Fig. 3.16. Unfaulted phase voltage after the utility breaker opens.

breaker, it might be advisable to apply a station class arrester. The arresters had no problem clamping the voltage to a low level and should work satisfactorily, if they can withstand the energy.

There should be no difficulties in detecting that something is wrong using voltage relaying as suggested earlier. If the relays do not detect the fault before the feeder breaker opens, they will certainly detect it as the resonance develops. For arrester application, it is necessary to consider the total time from detection until the generator breaker opens.

Sizes of generators less than 100 kW were not considered. However, it may be assumed that the same condition can occur. For very small generators, such as small wind machines, perhaps line capacitance will be sufficient to

excite resonance. One larger size of generator was considered. A 1000 kW synchronous generator was simulated as being isolated on an SLG fault with capacitor sizes ranging from 300 kVAR to 1800 kVAR. Without load or surge arresters, the peak voltage for these cases ranged from 100 kV to 300 kV. The conclusion drawn from this analysis is that high resonant overvoltages can be expected for typical values of generator sizes and capacitor bank sizes. Therefore, the protection should **always** include primary surge arresters of sufficient size. Secondary arresters may also be used as added insurance.

It should be pointed out that this simulation neglected the saturation of distribution transformers. Because the waveform in Fig. 3.16 is basically fundamental frequency, transformer saturation will certainly modify the results for the lightly loaded case. From past experience with SLG faults, the distribution transformers on the unfaulted phases will probably be driven into saturation more heavily in one direction than the other. When the dispersed source is relatively weak, the voltage waveform will become distorted, containing significant amounts of second and third harmonics. The voltage magnitudes may not actually be as great as we have shown and certainly not the same shape, but will still be very high in the undamped case.

An obvious solution to this problem is to arrange the circuit so that there is very little chance that a capacitor bank can become isolated with a dispersed generator when the load is very low. Of course, this will be more difficult to guarantee as the number of generators grows.

Islanding

Islanding is the condition where DSG continues to supply power to the loads on the feeder even though the utility source is disconnected. There are a variety of scenarios which might permit this. For example, a section of line may be deenergized for maintenance while dispersed generators on the line section are still operating. If the load on this line section closely matches the output of a generator on the same section, the generator continues to feed the load without being able to detect that anything is abnormal. This is a dangerous situation because the maintenance personnel may assume that the line has been deenergized if they are not aware of the dispersed generators. Also, reenergizing the line may cause equipment damage, particularly if the voltages are out of phase at the instant of reclosing.

A prerequisite for islanding is that the DSG devices be capable of self-excitation. This is always the case for synchronous machines and self-commutated inverters. These devices should always be considered as capable of sustaining islanding indefinitely. Other devices such as induction machines and line-commutated inverters are not normally capable of self-excitation. However, if there are capacitor banks to supply the reactive power for excitation, they may be able to support islanding for a short period (several cycles or even longer). Consider the circuit in Fig. 3.17. A 1000-kW induction generator was simulated as being isolated on a feeder with 1000-kW resistive load and two different sizes of capacitors: 600 kVAR and 1200 kVAR. Figure 3.18 shows the results of these simulations. The 600-kVAR bank is not quite sufficient to maintain excitation, and the voltage gradually decreases as the machine begins to accelerate. The 1200-kVAR bank overexcites the generator, causing the voltage to gradually increase and the machine to decelerate as a result of increased load.

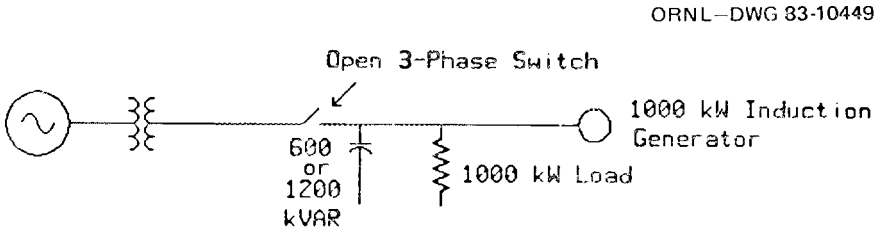

Fig. 3.17. Circuit for induction generator self-excitation simulation.

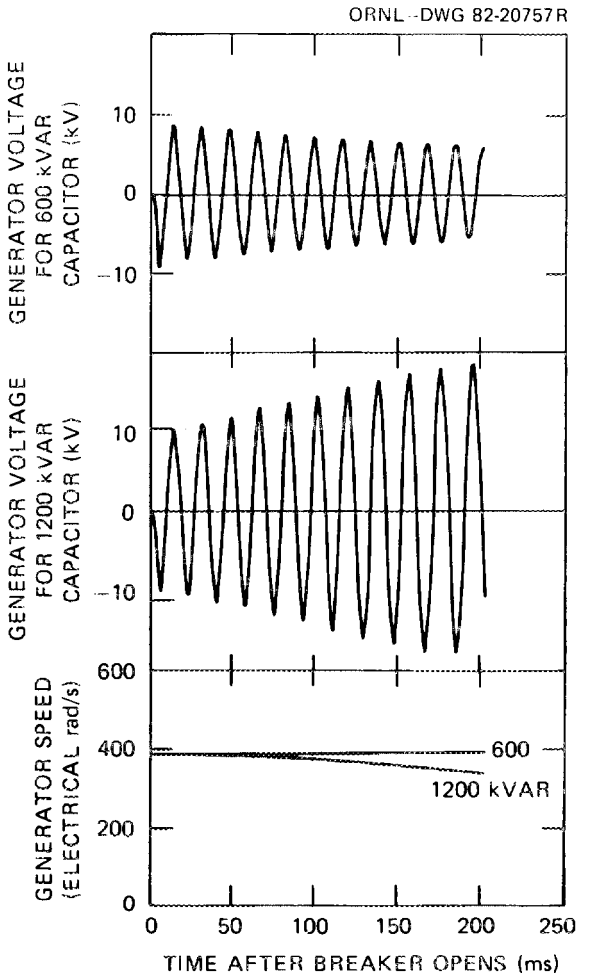

Fig. 3.18. Voltage and speed waveforms for a 1000-kW induction generator isolated with 600 and 1200 kVAR capacitors.

Conceivably, the generator requirement could be matched well enough to the capacitor to sustain islanding for several seconds. This could be damaging to the DSG device and to utility equipment if the utility source were reclosed out-of-phase during this time. More importantly, it could be a safety hazard for utility personnel.

Protection against islanding requires the cooperation of both the utility and the DSG owner. Ideally, there should be communications between the utility relays and each DSG device capable of sustaining islanding. Then when a feeder breaker (or recloser) is opened, the DSG will be disconnected as well, even if the DSG site's relaying could not detect an islanding situation. Unfortunately, such communications equipment may not be generally applied for several years.

For less than ideal protection, voltage sensing and frequency sensing are required. In the induction generator simulation, both the voltage and the speed vary sufficiently in 10 cycles (167 ms) to be detected as being abnormal. In general, if the rotating generator output does not match the load exactly at the instant of isolation, there should be sufficient change in speed to detect the islanding condition quickly enough to do something about it.

Of course, there will be some cases where neither frequency nor voltage change quickly enough. Such might be the case with a self-commutated inverter being triggered by an independent, but highly accurate, control. No relay at the DSG site can be expected to detect an abnormal condition reliably if neither the frequency nor voltage change. This is where the cooperation of the utility is required. To protect the DSG owner from the possible consequences of reclosing out-of-phase, the utility should block reclosing if voltage is present on the load side. This would allow time for the DSG device to deviate in voltage or frequency

sufficiently to detect an abnormal condition.

Modification of utility practices and the use of automated control are addressed in more detail in other sections of this report.

3.2.2 Protecting DSG From the Utility

Internal Faults

The protective relays at DSG sites must be able to detect faults internal to the DSG installation, as well as faults on the primary distribution feeder. The utility source will often be able to inflict more damage than the local generator itself. Therefore, it is imperative that the utility be isolated from the fault as quickly as possible. The action taken internally to the DSG site will depend on the type of generation and its ability to feed a fault.

The fault detection problem seems straightforward. The voltage drop should be sufficient to detect the fault since the fault would be very close to the relaying point. Also, the current should be easily determined to be excessive. Therefore, either voltage and/or overcurrent sensing should be satisfactory. Voltage relays used to detect primary faults will also detect secondary (internal) faults.

Modifications to Utility Practices

As stated previously, the usual utility practice when there is a fault is to assume it is temporary and reclose two or three times in the hope that it will either go away or

become isolated on a relatively small portion of the feeder. A typical sequence for a permanent fault would be:

1. Interrupt (fast)
2. Reclose
3. Interrupt (delayed; fuse, if any, blows)
4. Reclose
5. Interrupt (delayed; sectionalizer operates)
6. Reclose
7. Interrupt (delayed; lockout)

These operations are designed to allow feeder sectionalizing devices (fuses, sectionalizers, reclosers) to isolate the faulted portion of the feeder. For more information on reclosing practices see ref. 2.

For this scheme to work, the feeder must be radial. With DSG, the feeder is in a loop configuration; therefore, the DSG devices have to be disconnected before the first reclose operation. The consequences of this not happening are:

1. Temporary faults will not clear due to infeed from DSG

2. Reclosing may damage DSG devices and possibly, utility equipment.

The amount of time in which the DSG devices have to disconnect varies from 0.5 to 2.0 seconds. Assuming that the DSG devices are able to detect the fault and that there are no equipment malfunctions, this should be ample time. However, it is probably not always safe to make that assumption. Utility engineers will have to make a judgment based on the number of DSG devices, their size, their location, and their protective equipment as to the likelihood of their failure to sense faults and interrupt quickly. In any case, it is recommended that

utilities which use 0.5-s reclosing intervals for the first reclosing operation extend them on feeders where DSG devices are present.

If the probability of islanding is high, the utility should install equipment to block reclosing when significant voltage is present on the load side of the breaker or recloser.

These two modifications to reclosing practice should give DSG owners sufficient assurance that their equipment will not be unnecessarily damaged by utility reclosing.

In the long term, the best solution to this problem is provided by automated control. For example, when a fault is detected, a scram signal is sent to all DSG sites for the DSG devices to disconnect from the distribution system. Reclosing is delayed to allow time for the signal to be received and acted upon. A more elaborate scheme might be to delay reclosing until verification is received from all DSG sites that the DSG devices are disconnected. Restoration of normal service may also be controlled automatically. See Sect. 5.2 for more details.

Automated control of distribution feeders is still in its infancy, and it will be some time before it will be in common practice. In the interim, utilities can implement local, less sophisticated control schemes to help support DSG protection. For example, a large DSG site might be hardwired into an upline recloser to guarantee that the DSG site is disconnected when the recloser operates.

3.3 PROTECTION DURING UNFAULTED CONDITIONS

While the previous subsection dealt with emergency conditions, this subsection deals with the operation of distribution feeders with DSG during normal conditions. This includes switching operations, such as capacitor switching, which occur during normal operation. Again, the problems that affect the utilities most will be addressed first, followed by the problems that have more effect on DSG owners.

3.3.1 Protecting the Utility From DSG

Harmonics

Many DSG devices are interfaced to the utility system through solid-state power converters. These power converters essentially chop up dc current and switch it from one polarity to the other so that it resembles ac current (or vice versa). This results in substantial harmonics appearing on the ac side.

The harmonic current alone is not particularly troublesome. However, as it passes through the system impedances, it causes a harmonic voltage drop that distorts the line voltage. It is the voltage, rather than the current, that utilities are required to maintain within certain distortion limits. This is generally less than 5% total harmonic distortion (THD) for distribution feeders.[3]

The voltage THD on a distribution feeder is a function of two basic parameters:

1. the amount of harmonic current relative to the capacity of the feeder
2. the frequency characteristic of the feeder

Clearly, a 100-watt light dimmer will not have much effect on a 10-MVA feeder even though its current has a very high harmonic content. Each feeder can absorb a certain amount of harmonic current before exceeding the 5% THD limit. Traditionally, the current limit has been established with the assumption that the feeder impedance is entirely inductive. This has recently been found to give limits that are too optimistic.[4] The power factor correction capacitors on the feeder can often yield resonant circuits that amplify certain harmonics. Therefore, it is important to analyze the feeder in its entirety (generally requiring a computer) to establish more conservative limits.

The capacitor influence is illustrated in Fig. 3.19. In Fig. 3.19a the power factor correction capacitor is far from the substation, near the source of harmonics. Because of resonance effects, the injected harmonic current is amplified in the inductive branch. This is typical of parallel resonance of this variety: the equivalent circuit is shown in Fig. 3.19b. Therefore, the harmonic voltage drop from the substation to the load is higher than it would be if the capacitor were not present.

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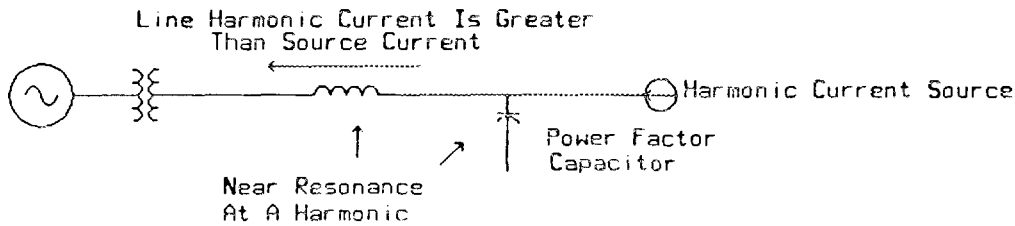

Fig. 3.19a. Capacitor influence on harmonic distortion.

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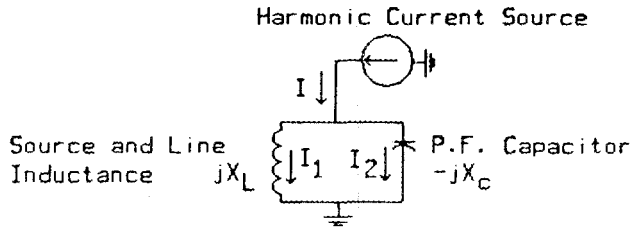

$$I_1 = I \frac{-X_c}{X_L - X_c} > I \text{ when } |X_L - X_c| < X_c$$

Fig. 3.19b. Equivalent circuit of the distribution feeder in 3-19a, as viewed from the source of harmonics.

This capacitor effect also occurs when small capacitors are placed on DSG devices. Often the effect is greater than on the primary feeder. Some utilities may require that large VAR consumers, such as line-commutated inverters, have their power factor corrected before they can be connected. This is generally not advisable from harmonics considerations unless the power factor correction also includes filtering. The only safe place for a small power factor capacitor on the secondary is directly on the distribution transformer terminals.[4] Instead, the utility may find it better to provide the reactive power itself so that harmonics do not become a problem.

Filter installations at a DSG site must be done carefully. Filters are affected by system impedance and must be tailored to each DSG site. One of the problems with filters is that they may have to absorb harmonic currents from other sources on the feeder. This might overload the distribution transformer at the DSG device. Also, the DSG owner may object to having to provide extra capacity in his filtering equipment. Filtering techniques for dispersed

harmonic sources on distribution feeders are not well understood. It is hoped that continuing efforts related to ref. 4 will provide many answers. However, in this report no recommendations concerning filtering will be made.

One of the simplest schemes for protecting against excessive voltage THD is to install a harmonic voltage relay at the DSG site that disconnects the source of harmonics when the THD exceeds predefined limits. One problem with this scheme is that the DSG device may not be responsible for the distortion. Another problem is that, due to capacitor effects, the voltage at the DSG site may not be a true indication of the actual feeder distortion. The highest THD might be elsewhere and the rest of the feeder might see little distortion.[4]

For this reason, harmonic suppression appears to be an ideal application for automated control. Several points on the feeder can be monitored and different suppression schemes implemented to meet the specific requirement of the feeder. The feeder frequency characteristic is a moving target, and it may be very difficult to design a single suppression scheme that will work well during all possible loading conditions.

With no specific guidelines at this time, each harmonic problem should be treated individually. Generally, a surprisingly large penetration of harmonic-producing devices can be accommodated on a feeder unless capacitor banks have an effect. Even then, a different capacitor switching arrangement or some other relatively simple change can often eliminate the problem.[4]

Fluctuating Generation

Some DSG devices depend on random sources of energy (e.g., solar, wind). Their power output can vary from zero to maximum in seconds. If such DSG devices are located far from the substation, there could be substantial voltage fluctuations on the feeder. The severity of this problem depends on the size of the DSG device(s) and the capacity of the feeder at the point of connection.

For example, consider the wind generator system in Fig. 3.20. Here a wind farm is connected at the end of a 12-kV feeder where the available three-phase fault current is about 1400 amps (rms). A 32-step voltage regulator is positioned at the electrical midpoint of the feeder. The intention is that the regulator will help keep the voltages near the end of the feeder within allowable limits and fairly constant. At the normal peak load without the wind farm, the feeder voltage profile is approximately as shown in Fig. 3.21. At this load, the regulator is near tap 0 which neither raises nor lowers the voltage.

This example was simulated assuming the wind-farm power output varies as shown in Fig. 3.22. This characteristic was digitized from a curve in ref. 16 for a small wind

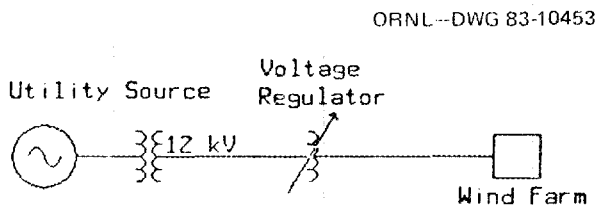

Fig. 3.20. Circuit for fluctuating generation simulation.

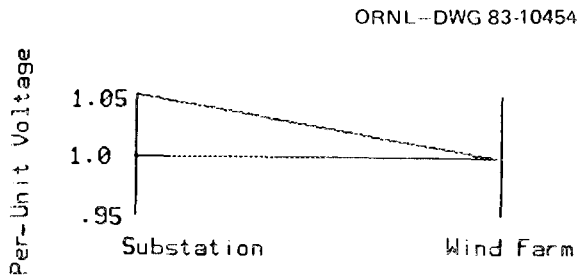

Fig. 3.21. Feeder voltage profile prior to adding wind-farm generation.

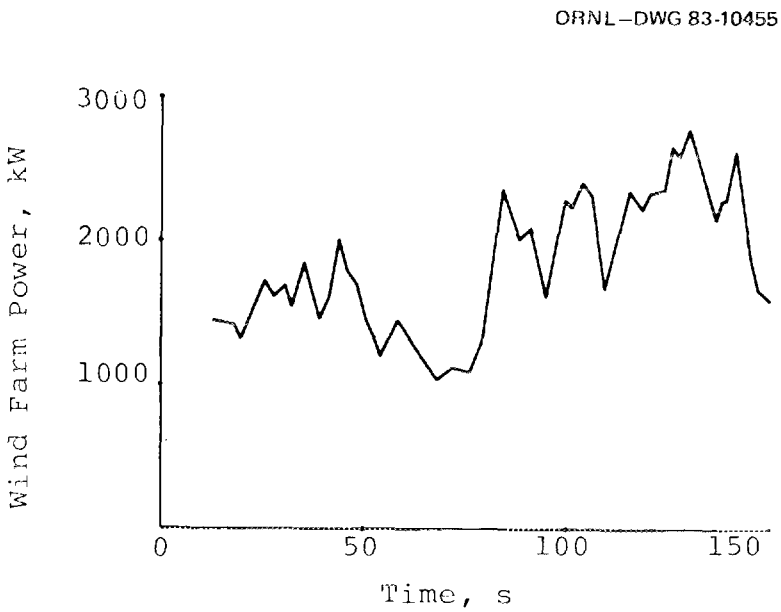

Fig. 3.22. Assumed wind-farm power output.

generator and was increased proportionally to represent a two-MW wind farm. It is recognized that this may not be typical of a wind farm, because there should be more diversity of generation and a smoother output variation. However, it does serve to illustrate what could happen during gusting wind conditions. During a severe gust, it is possible for the output to go from maximum to zero when the wind turbine reaches the critical cutout speed.

Other parameters used in this simulation include the following.

1. The regulator line-drop compensator was set to regulate the wind farm to 1.0 per unit (120V).

2. The regulator time delay was set to 15 s. This is the time from when the control determines a tap change is necessary until the tap changes begin. Once they begin, they continue as fast as possible until the tap change is complete.

3. The regulator bandwidth was 2 volts (e.g. 120 ±1 volt.

4. It was assumed that the regulator was at Tap 0 at the beginning of the simulation. A 32-step regulator has 16 raise (boost) taps and 16 lower (buck) taps.

5. The VAR requirement of the wind farm was assumed to be twice the power output (in keeping with the data in Reference 16).

Figure 3.23 shows the variation of the voltage at the wind farm over a 150-second time interval. Figure 3.24 shows the

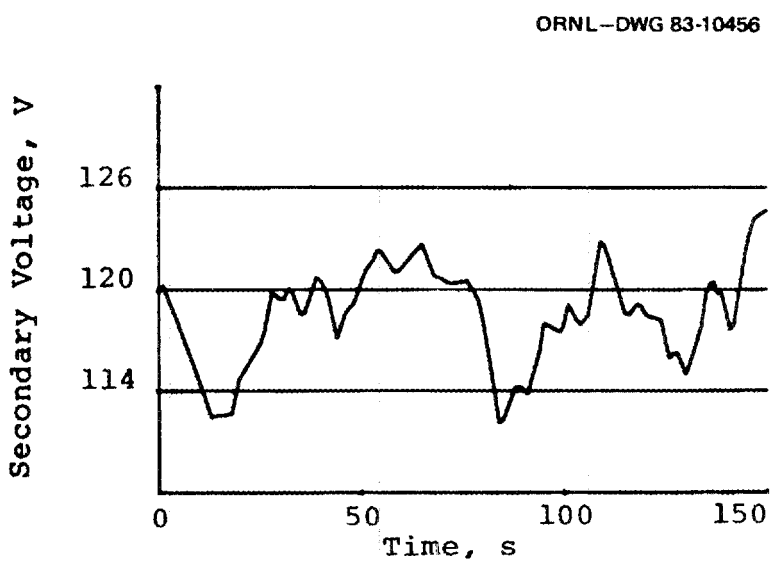

Fig. 3.23. Voltage variation due to wind generator, including effect of the regulator.

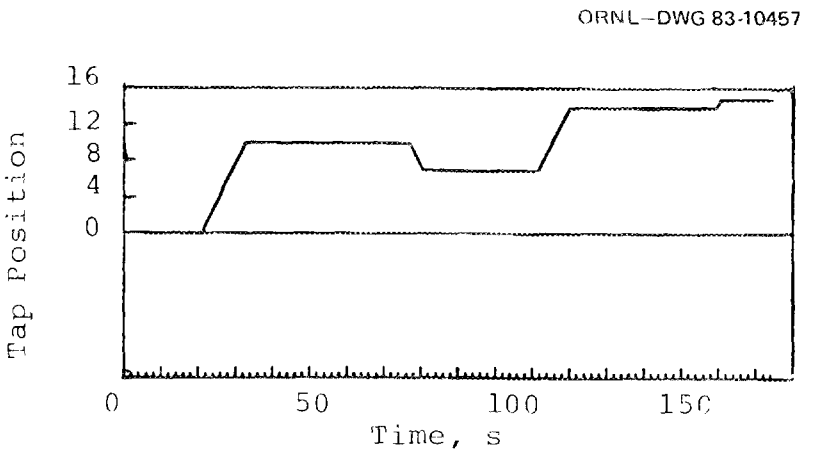

Fig. 3.24. Regulator tap variation over the simulation interval.

variation of the regulator tap position over this time period. Note that there were four sets of tap changes on this interval.

When the wind farm is on line, the voltage tends to drop even though power is being put into the utility system. This is due to the large VAR requirement of the wind farm. It is assumed that the generators will be either induction generators or dc generators connected through line-commutated inverters.

Under these circuit conditions, it is virtually impossible to maintain a constant voltage. The standard 32-step voltage regulator cannot respond quickly enough to the changes. Even if it could, the tap changer would be operating so frequently that there would be maintenance problems.

The best solution to this problem is to provide sufficient feeder capacity for the DSG device. This may mean an express feeder or a modification to an existing feeder. If VAR requirement is the fundamental cause of voltage fluctuation,

then a capacitor bank can be installed. However, this must be coordinated with other concerns, such as harmonics and islanding. Also, a fixed-capacitor bank may not work as well as desired. The ideal technical solution would be a static VAR compensator, but these are generally not economical in sizes smaller than several MW.

Again, if the feeder capacity is marginal, one way to operate it with DSG is by using some sort of intelligent automated control. For example, the regulator setting might be anticipated by measuring the wind speed at a wind farm. Some DSG devices, particularly synchronous machines and self-commutated inverters, will have the ability to regulate the voltage at their output to some degree. For other devices, a sensitive voltage relay with time delay can be used to disconnect the DSG device if the voltage is outside of a band too much of the time. Ideally, some sort of rate-of-change relay could also be used to determine if the generator fluctuations are too large and too fast for adequate voltage regulation on the feeder. This seems like a perfect application for a microprocessor-based relay.

3.3.2 Protecting DSG from the Utility

Overload

Overload is primarily a function of the generator controls, which can be used to maintain generator output within limits. However, low voltage on the utility system could aggravate the situation. Overload is detected by either overcurrent or thermal relays.

Overheating

Occasionally, the feeder phase voltages may become unbalanced sufficiently to cause excessive heating in rotating machinery. This can also happen when a fuse blows, opening one phase of a three-phase line. Therefore, it is recommended that utilities do not use fuses or other single-phase interrupting devices in the lines between the substation and a three-phase rotating generator. (Many utilities have already included this in their specifications.)[18] However, there will be accidental line openings occasionally, and the DSG operators should apply at least thermal protection to guard against this. Phase current unbalance detection might also be used, but the thermal relay is probably less expensive and may already be built into the machine.

Overvoltages

Common switching operations on the utility systems may introduce overvoltages onto DSG systems. Also, the DSG owner should be concerned about lightning and steady-state overvoltages that might be due to a resonant condition.

One of the most common switching operations on a distribution feeder is capacitor switching. This has been known to cause various problems at the primary voltage level.[5] The investigators have also encountered undocumented situations that suggest that steep-fronted voltage surges due to capacitor switching are coupled directly to transformer secondaries through the capacitance of the transformer (Fig. 3.25). Recording devices have detected voltages as high as 2 to 3 kV on a 120V secondary. Although this should not be of much consequence to rotating machinery and other electromechanical devices,

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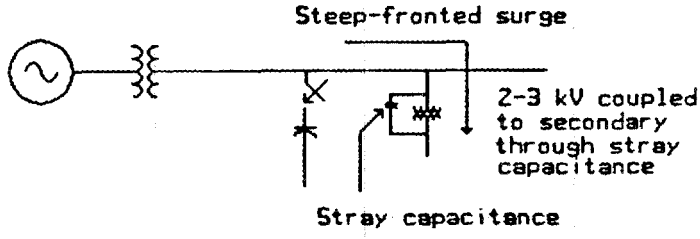

Fig. 3.25. Coupling of steep-fronted surge onto secondary of distribution transformer.

it can easily damage electronic equipment. Therefore, it is imperative that secondary arresters (metal-oxide varistors) be applied at the DSG site.

The arresters will also help prevent lightning surges from doing damage and will protect against resonant overvoltages for a few cycles. Fast voltage relaying is the best answer for protection against resonant overvoltages. These voltages are usually a result of system faults, and the fault detection scheme should suffice in detecting this condition and take protective action. The secondary arresters should be inspected periodically for damage, especially after a known fault condition. Often the energy dissipated during a resonant condition will destroy an arrester. It is necessary that primary arresters be installed by the utility.

3.4 FUNCTIONAL APPROACH TO DSG PROTECTION

The previous discussion concentrated on a few of the more important problems in DSG Protection. This subsection attempts to give a more global understanding of the problem.

The approach is termed "functional" because it determines the protection hardware by first identifying the functions that need to be performed. This approach may be used by an engineer to select the appropriate hardware for a DSG installation, at least in terms of conventional, commercially-available devices. It may also be used to determine modifications to utility procedures and equipment. For future use, this approach could be used to define the functions necessary for programming into a single, microprocessor-based relay for protection of specific DSG installations.

The approach is illustrated in the flow chart in Fig. 3.26. The engineer would simply go down the list of abnormal conditions in Tables 3.5-3.17. At each one that is a protection concern (see Table 3.18), the protection equipment or procedure which can be used is noted. After completing the

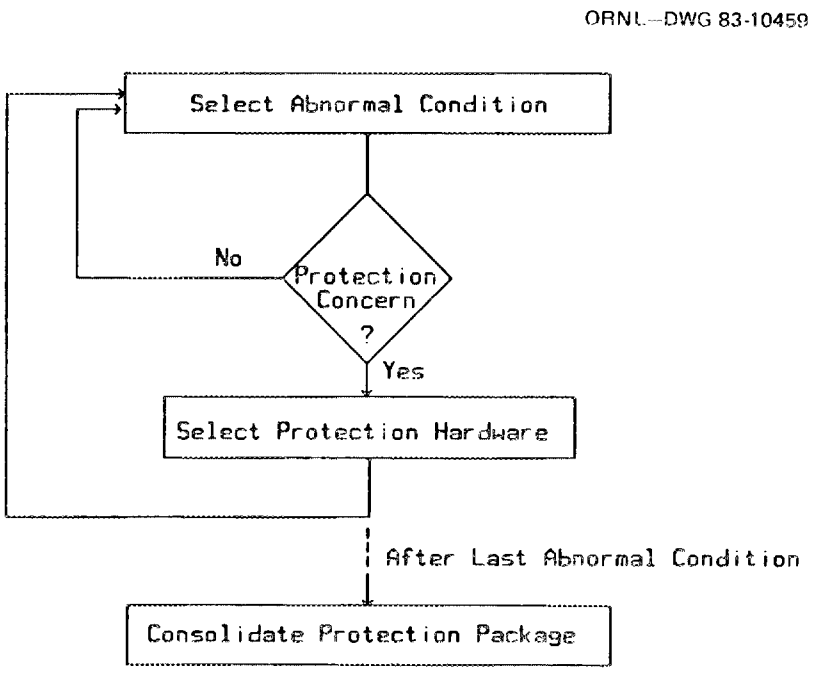

Fig. 3.26. Flow chart for functional approach.

Table 3.5. Protection choices for faulted conditions

Protection Concern	Decision Variable	Protective Device or Procedure
Thermal/mechanical damage to generator or utility system	Impedance	Distance with time delay (#21)
	Voltage	Phase sequence voltage (#47)
		Undervoltage (#27)
		Overvoltage (#59)
	Current	Instantaneous overcurrent (#50)
		Time overcurrent (#51)
		Directional overcurrent (#67)
	Power	Directional power (#32)
	Temperature	Thermal (#49)
Generator, transformer fault	Ground current	Ground protective (#64)
		Differential (#87)
Transformer fault	Oil pressure	Liquid pressure (#63)
Fuse blowing on temporary faults	Experience or generator size	Install larger fuses
		Decrease recloser operating time (faster curve/lower pickup)

Table 3.6. Protection choices for unbalanced loading conditions

Protection concern	Decision variable	Protective device or procedure
Negative sequence current heating	Current (- seq.)	Reverse phase/ phase unbalance current (#46)
	Voltage (- seq.)	Phase sequence voltage (#47)
		Voltage balance (#60)
	Temperature	Thermal (#49)

Table 3.7. Protection choices for islanding conditions

Protection concern	Decision variable	Protective device or procedure
Safety and damage due to reclosing	Voltage	Undervoltage (#27) Overvoltage (#59)
		Reclose blocking accessory
	Frequency	Frequency (#81) (over and under)
	Experience or Analysis	Delay reclosing

Table 3.8. Protection choices for generator malfunctions

Protection Concern	Decision Variable	Protective Device or Procedure
Generator motoring	Power	Directional power (#32)
	Current	Directional overcurrent (#67)
Loss of Excitation	Voltage	Undervoltage (#27)
	Field Current	Field (#40)

Table 3.9. Protection choices for single-phasing

Protection concern	Decision variable	Protective device or procedure
Negative sequence current heating of generator	Current (- seq.)	Reverse phase (#46)
	Voltage (- seq.)	Phase sequence voltage Voltage balance (#60)
	If three-phase rotating machine	Remove fuses, single-phase reclosers back to substation

Table 3.10. Protection choices for resonance or ferroresonance

Protection concern	Decision variable	Protective device or procedure
Overvoltage on system equipment	Voltage	Overvoltage (#59)
		Surge arrester

Table 3.11. Protection choices for synchronization of synchronous generators

Protection concern	Decision variable	Protective device or procedure
Prevent out-of-synch surges, torques, etc on synchronous generator	Voltage frequency phase angle	Synchronizing (#25)

Table 3.12. Protection choices for overload conditions

Protection concern	Decision variable	Protective device or procedure
Thermal damage to generator/transformer	Temperature	Thermal (#49)
	Current	Time-overcurrent (#51)

Table 3.13. Protection choices for excessive VAR demand

Protection concern	Decision variable	Protective device or procedure
Maintain voltage, minimize losses	Voltage and current	Power factor (#55)
	Voltage	Undervoltage (#27)

Table 3.14. Protection choices for lightning surges

Protection concern	Decision variable	Protective device or procedure
System equipment exposure to impulse overvoltages	Voltage	Surge arrester
		Shielding

Table 3.15. Protection choices for switching surges

Protection concern	Decision variable	Protective device or procedure
System equipment exposure to surge overvoltages	Voltage	Surge arrester

Table 3.16. Protection choices for harmonics

Protection concern	Decision variable	Protective device or procedure
Quality of voltage waveshape delivered to customers	Voltage	Harmonic voltage distortion (HVD)
	Experience or analysis	Modify capacitor switching
		Apply filters

Table 3.17. Protection choices for inrush due to magnetizing or cold load pickup

Protection concern	Decision variable	Protective device or procedure
False tripping of time-overcurrent relay	Current/Voltage	Time overcurrent (#51) with voltage restraint
Generator starting current	Current	Time overcurrent (#51)
		Speed interlock to block connection

Table 3.18. Abnormal conditions with which to be concerned for different types of DSG devices

	Faults	Single-phasing	Resonance	Synchronization	Overload	VAR Demand	Lightning	Switching surges	Harmonics	Cold-load pickup
1. Three-phase synchronous generator	X	X	X	X	X		**	**		
2. Three-phase induction generators	X	X	X		X	X	**	**		X
3. DSG with line-commutated inverters	X				X	X	X	X	X	
4. DSG with forced commutated inverters	X			X	X	*	X	X	*	
5. One-phase induction generators	X		X		X	X	**	**		X

* Dependent on control type

** Standard precautions should always be taken for lightning and switching surges. There may be additional concerns where electronic equipment is involved.

list, the engineer consolidates the protection equipment and procedures to make a package that has the desired reliability with no more hardware than is actually needed.

Example

A 200-kW induction generator driven by a wind turbine is to be installed. From Table 3.18, the following abnormal conditions are important to this installation:

1. faults
2. unbalanced loading
3. islanding
4. generator malfunction
5. single-phasing
6. resonance
7. overload
8. excessive VAR demand
9. cold-load pickup

Since the generator is a rotating electromechanical device, there is little concern for such things as harmonics and switching surges. A brief discussion of the reasoning that might be used to determine the protective hardware and procedures for each condition follows.

1. **Faults.** Faults should be detected; voltage sensing will be used. Over/under voltage and phase sequence voltage relays are chosen. There is no need to be concerned about nuisance fuse-blowing on temporary faults unless there are other generators to consider.

2. **Unbalanced loading.** Negative sequence heating is a major concern. Thermal relaying on the machine is chosen. (The phase sequence relay in No. 1 is for fault detection only.)

3. **Islanding.** Assuming that power-factor correction capacitors are present, islanding is assumed to be possible. Frequency relaying is chosen to supplement voltage relaying. The reclose interval on the first shot for the upline breaker (recloser) will be set to 2.0 seconds.

4. **Generator malfunction.** Motoring is the concern here. During low wind speed, the generator could draw considerable energy from the feeder. Depending on the wishes of the DSG owner and the metering arrangement, a directional power relay could be installed to disconnect the generator when this occurs.

5. **Single-phasing.** This could be devastating to a rotating machine. In addition to sequence voltage relays and thermal relays already chosen, all fuses and single-phase reclosers between the substation and the generator are removed, or replaced with three-phase interrupting devices.

6. **Resonance.** Primary and secondary surge arresters will be applied to clip voltage until overvoltage relays can act.

7. **Overload.** This will be covered by a thermal relay. However, a time overcurrent relay can be set to detect an overload faster because of the thermal time constant of the machine. (Use low pickup and long time delay; the voltage relays will be used for fault detection.)

8. **Excessive VAR demand.** A generator of this size could draw too many VARS for its location on the feeder. Load-flow analysis reveals no problem with this device; no protective measures are taken. If this is a problem, capacitors could be added, but the effects of harmonics and the possibility of resonance would have to be assessed.

9. **Cold-load pickup.** Assume that the generator is too large to start as a motor. A speed interlock is selected to prevent closing until a generator is brought close to rated speed by the wind turbine.

In summary, the protection package chosen includes:

1. over/under voltage relaying
2. phase sequence voltage relaying
3. thermal relay on generator
4. over/under frequency relaying
5. first reclose operation of upline breaker delayed
6. directional power relay for motoring
7. fuses and single-phase reclosers removed and replaced with three-phase fault interrupters
8. surge arresters
9. time-overcurrent relay for overload detection
10. speed interlock to block closing

4. CURRENT PRACTICES FOR PROTECTION OF DSG

This section first examines typical utility specifications for protection of DSG. Then an evaluation of these practices is made, followed by guidelines for protection of DSG. The guidelines are made with particular emphasis on existing protective equipment and techniques. Alternate protective philosophies and hardware for future use are covered in Sects. 5 and 6.

4.1 TYPICAL UTILITY SPECIFICATIONS

It was not the principal function of the investigators to seek out utility specifications. This information was supplied by another contractor also working under Oak Ridge National Laboratory.[7] Also, the Institute of Electrical and Electronics Engineers Power Engineering Society's Task Force on Dispersed Storage and Generation forwarded information to the investigators. This information has been reviewed to identify the major trends in DSG protection; several specific examples are given in Appendix A. However, only typical configurations will be discussed here.

The dominant technique of protecting DSG and the utility system is to apply a variety of relays at the interconnection point. Relay schemes differ from one utility to another, but the main concept is similar: sense one or two primary quantities and one or more backup quantities that will act for reasonably probable contingencies in which the primary relays fail to act.

The circuit breaker and transformer arrangement also differs. Some utilities show specifications for backup breakers, while others are satisfied with a single breaker.

Some utilities seem to prefer to put the larger generators (defined variously from 100 kW to 1000 kW) on separate transformers. The separate transformers act as a kind of buffer to protect both the utility, other customers, and the DSG installation from some of the problems that can occur. Small residential systems are still applied with several units to a distribution transformer.

4.1.1 A Typical Protection Arrangement

Protection requirements vary with size, the connection point to the utility, and the utility's attitude toward dispersed generators. Scanning a number of utility specifications, the configuration shown in Fig. 4.1 is a typical arrangement for protective devices for a generator not requiring synchronization.

The quantities being sensed here are:

1. frequency (81),
2. over- and undervoltage (59/27),
3. negative sequence voltage (47), and
4. generator overcurrent (50/51).

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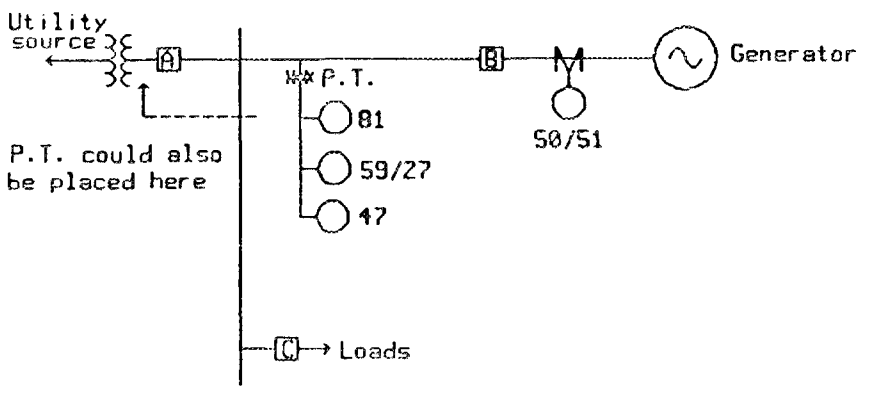

Fig. 4.1. Typical protection configuration.

Generally, in a configuration like this, the primary fault detection quantities are generator overcurrent and voltage. The frequency relay helps eliminate islanding, since it is assumed that isolated generators will drift off-frequency rather quickly. The negative sequence relay will help detect unusual feeder conditions resulting from single-phasing and unbalanced faults.

In most specifications, each relay will trip both breakers A and B. Not all utility specifications require breaker A; they may require a visible-break, motor-operated switch instead. Some also show breaker A on the high side of the transformer and some show an additional breaker on the high side with associated overcurrent relaying. The customer may have other relays that will trip A and/or B.

In all cases, breaker B is interlocked so that it cannot close until there is voltage of normal magnitude, frequency, and phasing present on the utility side.

If the generator is synchronous, another set of PTs and a synchronizing relay (#25) is added around breaker B.

The PT and CT locations may be different than shown in some cases.

One common deviation from this scheme is useful when there is no reverse power flow permitted. The overcurrent relay and frequency relay are replaced by a reverse power relay. Thus, any fault in which power flows back into the utility causes the main breaker(s) to trip.

4.1.2 A Minimum Protection Arrangement

For generators less than 10 kW, many utilities have less stringent protection requirements. This may change when

there are many small generators on a feeder. Figure 4.2 shows the utility specification which required the fewest protection relays.

This basically differs from the typical case in that sensing of backup quantities is omitted.

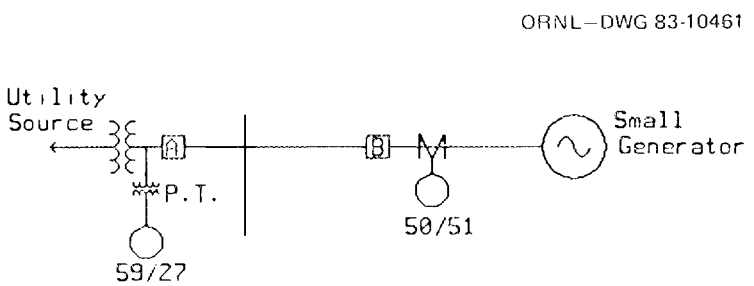

Fig. 4.2. Minimum protection configuration.

4.1.3 A Maximum Protection Arrangement

Some utility protection specifications are quite extensive for larger generators. "Large" is variously defined as greater than some size between 100 kW and 1000 kW. The scheme in Fig. 4.3 was presented for protection of a large wind turbine.[6]

This scheme provides internal generator protection as well as protection for the utility system. There is much redundancy to insure the removal of the generator under a variety of conditions.

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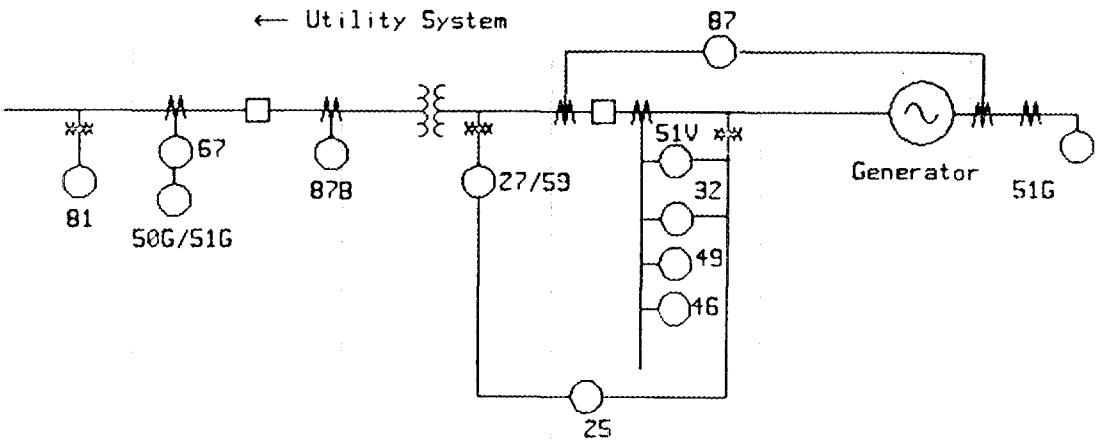

Fig. 4.3. A maximum protection configuration.

Relays not previously identified are:

#67-directional overcurrent
#87-differential protection
#32-directional power
#25-synchronizing
#49-thermal
#46-phase balance current

In this scheme there is a total of 21 separate relays (assuming the conventional type), 16 CTs, and 7 PTs.

4.2 EVALUATION OF CURRENT PRACTICES

The typical DSG protection specifications were evaluated here with respect to the protection problem areas as defined in Sect. 3 of this report. Observations were made concerning the hardware, its cost, and its function. These specifications may be found in ref. 7. They cannot be repeated here because of their length.

4.2.1 Hardware Used for DSG Protection

The majority of utility specifications for DSG protection are not typical of distribution protection practices for loads of comparable sizes. In distribution system protection, procedures are based on series overcurrent devices. With the exception of substations, this equipment is generally self-contained packages including both the relaying and the interrupting means. The basic idea is to have a simple, relatively inexpensive package that can be mounted on a pole. For example, fuses are self-contained overcurrent protection devices. The fuse element is both the fault detector and the interrupter. Likewise, hydraulic reclosers are self-contained devices with few possible adjustments. Electronically-controlled reclosers have the intelligence in a separate box which contains relaying functions for all three phases and the ground. For a load the same size as many proposed DSG installations (<1000 kW), the utility would normally provide only fuses. For larger loads, a recloser might be provided.

In contrast, many DSG protection specifications take on the flavor of substation protection, or even central station generator protection. There are separate relays for each phase, for example, and a tendency to recommend the kind of relay typically used in substations. These relays are physically large, requiring large cabinets and a sheltered environment. They are not generally made to be pole-mounted; they require large batteries to supply dc operating current. For large DSG installations (several MW) this may not matter, but the cost of such relaying for small DSG is probably prohibitive (see Sect. 4.2.2).

Alternatives to this include use of lower-cost, secondary-voltage class relays or relays packaged especially for DSG

protection. Since DSG protection is a relatively new technology, there are few manufacturers of protection equipment for small DSG installations. This may explain why utility specifications call for the more traditional utility grade relays.

Packaged relaying for DSG is not yet a common item. However, there is a movement in that direction, as evidenced by the announcement of the PRIDE relay by Beckwith Electric Company.[8] This is a microprocessor-based relay that provides voltage and frequency relaying functions, two of the most important for DSG protection. It is anticipated that there will be other devices using this concept (a programmable, multi-function relay) available in the near future. This should ease the interconnection of DSG with utilities.

Utility specifications do not always identify particular types of breakers to be used. When they do, it is generally in regard to primary breakers only. For example, they may call for a conventional line recloser on the primary. The only specification on the secondary breaker is often that it must clear for a fault within a certain time. The time specifications vary from 10 cycles (1/6 second) to 1 second. This probably has to do with breaker reclosing intervals. It would seem that a modular breaker/relay device similar to the electronically controlled recloser, but designed for secondary voltages, would be useful for DSG protection (see Sect. 5).

Many utilities place a strong emphasis on overcurrent protection in their DSG protection specifications. Some specifications use voltage relaying alone (for small generators), and most use it in conjunction with overcurrent relaying, but the proposed schemes appear to

depend heavily on overcurrent relaying. This is probably based on tradition more than function. As indicated in Sect. 3.2, voltage relaying alone may be adequate for detecting faults. This idea is supported by the fact that the manufacturers who are targeting the DSG protection market are emphasizing voltage relaying.

Most utilities seem to assume that their standard distribution surge arrester scheme will offer adequate protection. (Distribution arresters are installed on every pole-mounted transformer in some areas of the country.) This is inferred by the notable lack of attention given the subject in most specifications. It is not clear that this adequate protection will be offered. As pointed out in Sect. 3, there can be resonant conditions where the energy to be discharged is very high. Distribution arresters are designed to absorb the energy in a lightning stroke, perhaps, for a half-cycle of power-follow current. This energy is relatively small compared to the energy that can be developed during a resonant condition. If the generator is a rotating machine and can become isolated with a capacitor bank (or a long line or cable, if a very small generator), it is probably good practice to install a larger arrester to absorb the energy for a few more cycles until it can be assured that the generator is off the line.

4.2.2 Economic Considerations

Economic evaluation of DSG protection schemes was not one of the tasks the investigators were to emphasize. However, certain economic information was collected during the course of the contract to help determine the effect of costs on the types of protection systems to be considered for the future.

One of the first impressions gathered from reading utility specifications was that they probably cost more than many DSG device owners would want to pay. One of the most commonly published examples of a protection specification is one of Georgia Power Co.'s specifications[18] reproduced in Fig. 4.4.

Notice in the specification that the utility company would own and install the protection equipment. The question was asked of Georgia Power Company: What would be the costs assessed to a cogenerator for the installation of this equipment? The Georgia Power Company complied with our request and returned the following cost figures.

Current transformers	$2,100
Potential transformers	1,425
Foundations	500
Battery and charging equipment	3,000
Relays, wiring and cable	4,105
Grounding	50
Stores expense	500
Sales tax	350
Labor	2,400
Subtotal	14,430
42% overhead	6,060
Total	$20,490

It is believed that these costs are quite consistent with costs reported for similar installations.[9] It is also the opinion of the investigators that these costs are economically justifiable only for large generators (several MW). For small generators, a more economical relay package must be designed. This relay package should eliminate the need for most of the peripheral facilities such as foundations and batteries. Such peripheral equipment is typical for large utility substations, but it is inappropriate for a typical distribution-line application. This is discussed further in Sect. 6.1.

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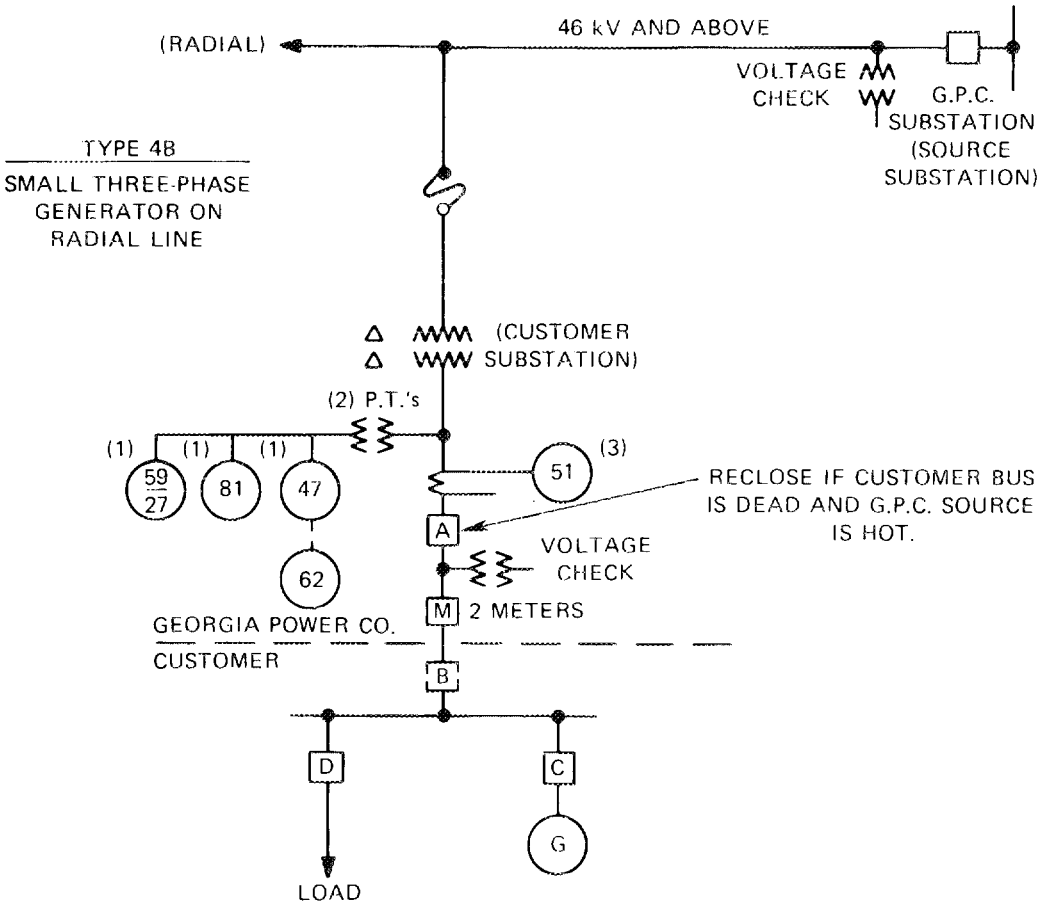

DEVICE NO.	FUNCTION	TRIPS
51	PHASE OVERCURRENT	A
47	NEGATIVE SEQUENCE OVERVOLTAGE (VOLTAGE UNBALANCE)	STARTS TIMER 62
62	TIMER FOR 47	A
81	OVERFREQUENCY AND UNDERFREQUENCY	A
59/27	OVERVOLTAGE AND UNDERVOLTAGE	A

Fig. 4.4. A Georgia Power Company protection specification.

4.2.3 Function of DSG Protection Hardware

Areas of Adequate Protection

The existing DSG protection schemes are adequate in most respects. Generally, all the equipment required for fault detection is present in the utility specfications. In fact, with both voltage and overcurrent relaying, there is often redundancy in this area. Specifications for three-phase rotating machines often include some sort of unbalance detection, and this is good for minimizing the chances of overheating.

Many utilities have recognized the changes they must make to their own systems to accommodate DSG. For example, many specifications state that no single-phase interrupting device is to be placed between the substation and the three-phase generator. Also, many utilities specify that the DSG device can have up to one second to disconnect after a fault occurs on the feeder. This indicates a longer reclosing interval, which is good for DSG protection.

Areas of Inadequate Protection

No protection scheme that lacks communication between the utility and the DSG installation can hope to prevent islanding completely. Most of the utility specs do not suggest any communications schemes; this is one of the greatest areas of inadequacy.

Another area where there is likely to be a problem is the first reclosing interval. Some utilities require DSG devices to disconnect within 10 cycles after a fault; this is not reasonable for all conditions. It may work for generators that are too small to support much load, but it will not

always work where the generator is able to support load on an isolated part of the feeder. More time must be allowed for reliable operation.

Surge-voltage protection is also a questionable area. Because of potential resonance situations with rotating machinery, it is recommended that surge arresters be applied to both primary and secondary sides of the distribution system. It is also not clear that standard distribution arresters will be able to withstand the discharge energy.

4.3 RECOMMENDATIONS FOR DSG PROTECTION

In light of the preceding discussions, general recommendations for DSG protection can be made. These recommendations are intended for existing protection technology, but most should be applicable to future technological advances. In fact, they might serve as functional specifications for future equipment development.

4.3.1 Universal Requirements

For most three-phase DSG installations, four relaying functions are required:

1. over/under voltage
2. unbalance voltage
3. over/under frequency
4. overcurrent

A distribution engineer can use this as a starting point; then the remainder of the functions required for a DSG installation may be determined by using a chart similar to Tables 3.5-3.17.

If the generator is synchronous, a synchronizing relay is also required. If the generator is a rotating machine, a thermal relay is recommended.

Most of these relays serve at least two functions. The over/under voltage relays operate when the utility source voltage goes out of tolerance (e.g., +10%, -20%). This serves to help identify faults and prevent accidental energizing of the utility line. The unbalanced voltage detection protects against both faults and abnormal load conditions that might cause generator heating (e.g., single-phasing). The frequency relay is to help detect an islanding situation. The overcurrent relay can detect overload, internal faults, and external faults (if the generator can feed fault current).

For small, single-phase generators, unbalance detection can be eliminated. The frequency relay may also be eliminated in most cases because a single-phase generator could not support much load, and islanding should not be a problem. However, if there are many single-phase sources, the frequency relay may be necessary.

When the source has ac-to-dc power converters, there must be provisions for dc faults. Also, line-commutated inverters should be treated the same as induction generators for self-excitation considerations in islanding.

Surge voltage protection is provided by surge arresters on both primary and secondary sides of the distribution system. There is some indication that intermediate or station class arresters may be required, particularly if the generator is a rotating machine and can become isolated on a fault with a capacitor bank.

4.3.2 Some Rules of Thumb

For explanations of the reasons behind these rules, see the preceding sections.

1. Single-Phase Fault Interrupters

Do not put a single-phase interrupter between a three-phase generator and the utility substation. Figure 4.5 shows an improper condition; Fig. 4.6 shows one way to correct it.

2. Reducing the Chances of Resonance and Self-Excitation

The concern for resonance and self-excitation of induction generators can be substantially reduced if the fault

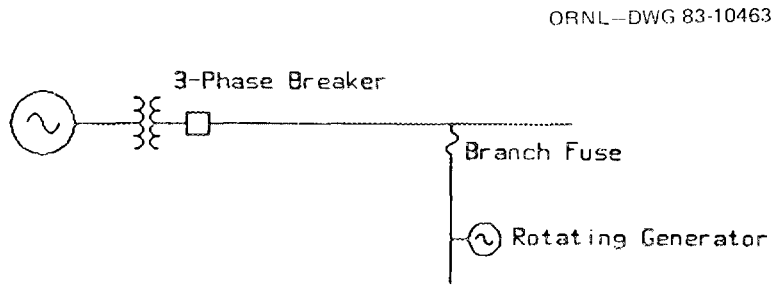

Fig. 4.5. Improper use of fuses with large rotating generators.

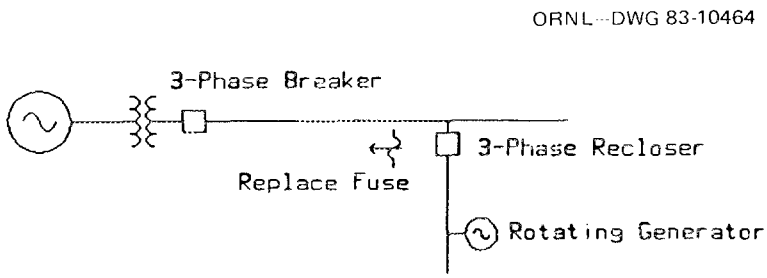

Fig. 4.6. A way to correct the problem in Fig. 4.5.

interrupter is between the generator and feeder capacitor banks (e.g., see Fig. 4.7). When the fault interrupter opens, there is no capacitance to develop resonance.

Of course, this may be impossible near the substation. Also, remember that very small generators may resonate with line or cable capacitance. Thus, this will not work in all cases.

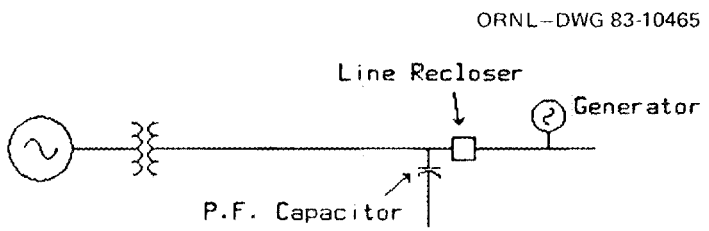

Fig. 4.7. Fault interrupter and capacitor locations to reduce chances of resonance and self-excitation after a fault.

3. Recoordination of Feeder Branch Fusing

For large generation (particularly in rotating machinery) in excess of 1000 kW, it may be advisable to change the branch fuse coordination with upline reclosers. Generator infeed into the fault may cause nuisance fuse-blowing on temporary faults if there is insufficient fuse margin on the recloser's first shot. The farther the generator is from the substation, the more important this becomes (a greater percentage of the fault current comes from the generator). If a change is required, the options are shown in Fig. 4.8. If a larger fuse size is selected, the subsequent recloser operations must be checked to make sure that the fuse will blow before the recloser operates to lockout.

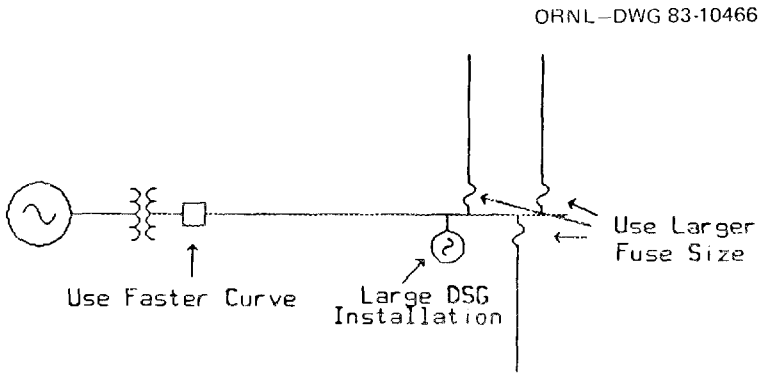

Fig. 4.8. Coordination change options.

To estimate the fault current contribution of the generator, some simple models may be used. For synchronous generators, use an inductance value that is between Xd" and Xd'. This will give a high estimate of the actual generator contribution to the fuse. Figure 4.9 shows a comparison between the I^2t computed using such a simple model and the I^2t using a complex machine model of a 2ØØØ-kW machine for a three-phase fault. The simple model assumed 2Ø% impedance, approximately Xd" for this machine. The detailed model (see Appendix B) contribution decreases steadily as time passes, while the simple model contribution is constant. (Remember that a small change in current can make a dramatic change in I^2t.) If the reader holds the page flat and rotates it, it will be seen that the detailed model curve is concave downward. The current computed from the simple model can be used with the standard TCC curve analysis since it gives a more conservative estimate for fuse margins.

For an induction generator, assume that there will be one cycle of fault current contributed to a three-phase fault. Compute the fault current for that one-cycle period using blocked rotor reactance, which should give a conservatively

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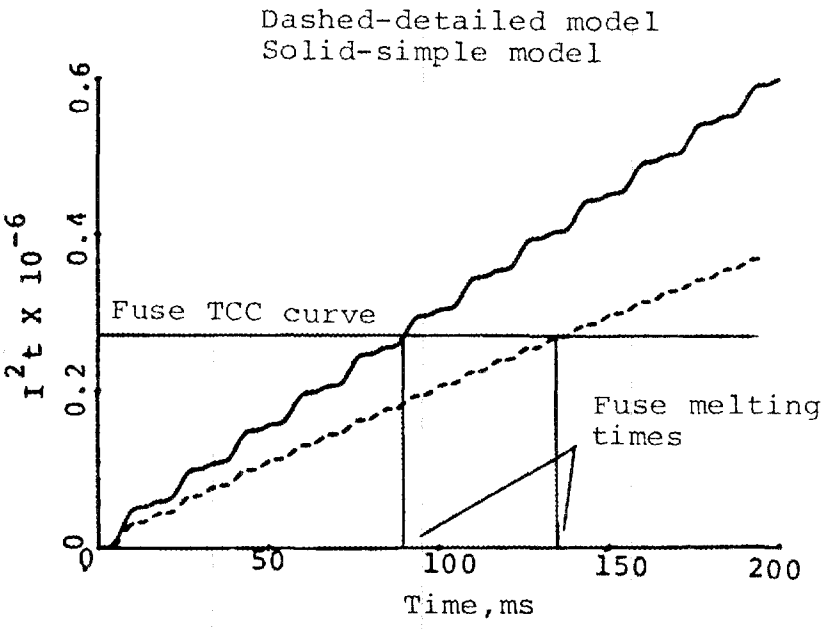

Fig. 4.9. Comparison of I^2t computed, using a detailed synchronous generator model vs. using a simple model with 20% impedance.

high estimate. With the usual TCC curve analysis, one can estimate the effect that this has on the fuse by using the technique in Fig. 4.10. This technique is an approximate method for taking into account the faster fuse melting when an induction machine is present in the circuit. Normally, the fuse melting time is where the fuse TCC curve intersects the normal fault current line. In this method, the fault current line is modified to reflect the fact that the current is changing with time. This modified line is created by connecting the one-cycle point on the fault current line for the one-cycle period with the minimum melt time on the normal fault current line.

For line-to-line faults, assume the induction generator is a synchronous machine. This will give conservatively high estimates of fault contributions.

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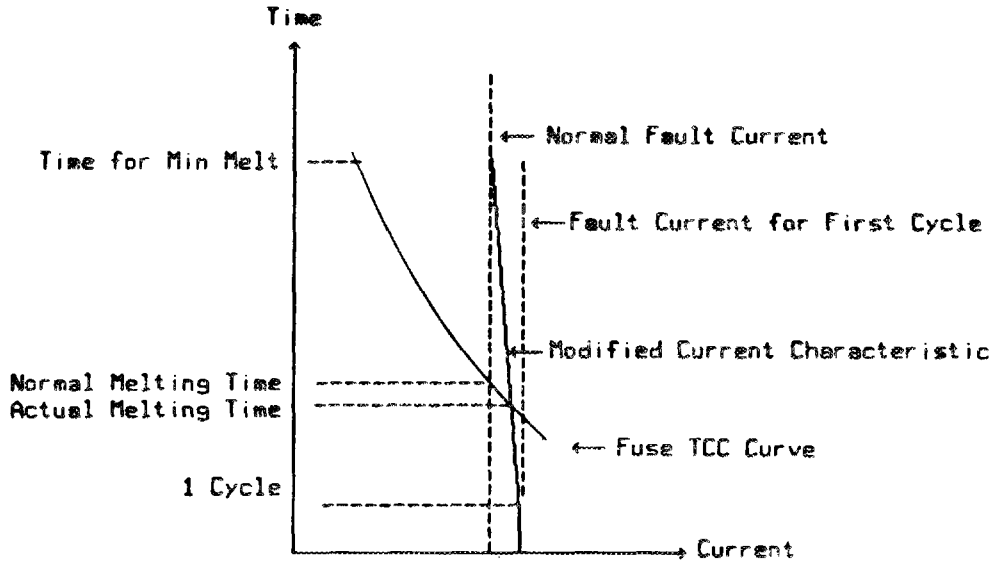

Fig. 4.10. Using TCC curves to estimate effect of induction generator contribution.

4.3.3 Some Special Considerations

Line-Commutated Inverters

Line-commutated inverters have two characteristics that can cause problems:

1. They produce significant harmonics.
2. They have a poor power factor.

Care should be taken so that the fix for one of these does not worsen the other. For example, some utility specifications require that the power factor be 0.85 lag or better. A typical line-commutated inverter will run at 0.7 lag or worse. Therefore, one may be tempted to apply a

capacitor at the inverter to correct the power factor, but this could have two bad side effects:

1. The harmonic output is drastically increased.
2. There will be more tendency for self-excitation.

In general, a power factor correction capacitor connected at the inverter is a poor choice.[4] If a capacitor is applied, it should be done in conjunction with a filter. The filter must be designed with the recognition that it might see extra duty from harmonics on the primary that originate elsewhere.

Reclosers on Larger Generation

On larger DSG installations, a line recloser may be specified for the primary breaker. **This recloser should not operate while the dispersed generator breaker is closed.** The reclosing may be delayed to allow time for the generator breaker to open. If this is not sufficiently reliable, reclosing could be blocked until a signal is received which indicates that the generator breaker is open.

5. ALTERNATE PROTECTION PHILOSOPHIES

As stated in Sect. 4.2, the existing protection specifications are adequate in most respects. However, there are two areas that need attention. One pertains to hardware and will be discussed in Sect. 6. The other is that there is no really reliable protection against islanding. That will be discussed here.

In distribution systems today, most of the protection is done with local intelligence. That is, each load or line device has its own protection, which does not communicate with the protection at any other load or line device. The local protective devices are passive, responding to the effect of an abnormal condition. When a fault occurs, the main interrupting device operates and it is hoped that other devices that must also act will detect that something has happened. There is no attempt by the relaying to directly control a breaker at a remote location. This is one situation that will eventually have to change as DSG becomes more common on distribution feeders. The reason is the same as that which spawned the use of pilot relaying schemes on transmission systems.

5.1 MODIFICATIONS TO PRESENT PHILOSOPHIES

The widespread use of automated control of distribution feeders is awaiting the development of new technologies and sufficient economic incentives. However, there are some things which can be done with existing technologies and well-established protection philosophies to improve the detection of islanding. Two of these are:

1. Because voltage is a more reliable fault-sensing quantity for most types of DSG devices, the relaying emphasis should be shifted from current to voltage sensing.

2. Breakers and line reclosers generally monitor current only. For improved islanding protection, they should be fitted with accessories that block reclosing if voltage is present on the load side (island side).

The first item above deals with the problem by providing a more sensitive detection scheme. This would decrease the frequency of islanding occurrences. The second item simply prevents some of the bad effects of islanding; it does not prevent its occurrence. It would be ideal if the recloser, after detecting voltage on the wrong side, could send a signal to all DSG devices that would cause them to disconnect. This is a feature that automated distribution systems could provide, which leads into the next section.

5.2 DSG AND AUTOMATED DISTRIBUTION SYSTEMS

With the ability to communicate to any point on the feeder, there are many aspects of handling DSG on a distribution feeder that changes. Several ideas about this are presented in the following discussion.

The application of automated control to the operation of a distribution feeder can be better understood if we think of it in terms of two operating states:

1. Normal state
2. Emergency state

"Emergency state" is defined to be a condition in which a fault exists somewhere on the feeder. "Normal state" refers to all other conditions in which power is available to all points on the feeder. Each state will be discussed separately in the following. Figure 5.1 shows a breakdown of the major areas of concern that will be discussed.

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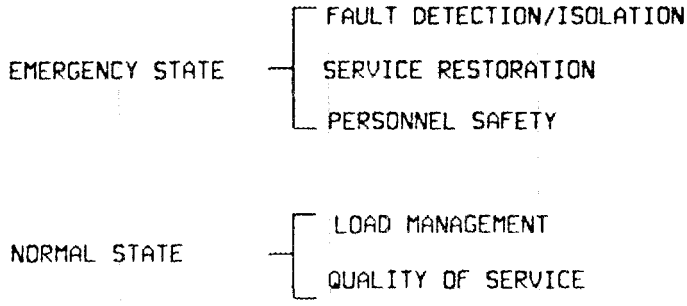

Fig. 5.1. Major areas of concern with DSG and automated control of distribution feeders.

5.2.1 Emergency State Operation

Fault Detection and Interruption

Because of the great potential for damage if a fault is allowed to persist, fault currents must be interrupted as quickly as possible. At present, it seems better to rely on local device intelligence to control the main fault interrupters. Communications systems now being employed for automated control (such as power line carrier, 60-Hz wave modification and standard AM broadcast sideband modification) cannot respond quickly enough and are inherently less reliable than locally controlled fault interrupters. However, there are some applications for automated control in fault detection and interruption when DSG exists on a feeder.

One application would be to simply issue a scram signal when a fault is detected. This would aid in the prevention of islanding. It is conceivable that the communications systems mentioned above could respond quickly enough

for this to be effective. The scram signal would serve to notify the generation to disconnect immediately. Reclosing would be delayed to allow time for the signal to be sent and the DSG devices to respond. The scram signal is not envisioned to be used for the trip signal of the main interrupting breaker.

This application could be extended to block reclosing until there was assurance that all DSG is disconnected. Each DSG installation could return an acknowledgment that it received the scram signal and the central control would block reclosing until it has heard from each installation. Of course, this might take several seconds and the utility would generally not want to do this except for very critical DSG installations. It may also be sufficient to simply check for voltage on the load side.

Since it is not always necessary to remove a dispersed source that is upline from a primary fault-interrupting device, an intelligent control could be selective in which sources to switch. This would be appropriate for large rotating generators near a substation. There would be no need to have these respond to a fault that is beyond a downline recloser.

Dispersed intelligence can also be applied effectively to DSG control during faults. For example, an intelligent recloser can be used to control a nearby generator. If the recloser sees a fault, it simultaneously trips the generator main breaker and interrupts the fault, and then blocks reconnection until some time after the service is restored.

Automated control could also be used to advantage if there is a problem with nuisance fuse-blowing on

temporary faults. It may not be easy to find a good compromise coordination scheme that will work with the troublesome generator both on line and off line. An intelligent recloser could be programmed to have one characteristic when the generator is on line and another when it is off line. The state of the generator is supplied to the recloser by the substation control. Existing electronic recloser controls already have this capability.

Feeder Restoration

One of the most productive tasks which automated controls can perform on distribution systems is to sectionalize the fault and restore power to the remainder of the feeder. Of course, DSG will impact the algorithms used for restoration.

Without automated controls, a DSG device would typically remain disconnected until voltage is restored. Then, after a time delay, the device would reconnect. One thing that is a concern for this type of operation is that the reconnection might occur at an inopportune time. For example, the power restoration may have occurred through an alternate source that is incapable of supporting the DSG device. Without communication, there is no way that local intelligence would be able to detect such a condition. With automated controls that can communicate, the DSG device would wait for a signal from the control system before it would reconnect to the utility system. The signal could originate from either a central substation control or from a local intelligent device such as a nearby recloser with intelligent controls.

There may be instances where DSG can help restore power to a feeder after a fault. One example would be a large fuel cell with a self-commutated inverter capable of supplying a significant portion of the feeder. With sufficient controls, such sources could be used to supply power to a feeder when the main source is lost due to an outage. This would be very difficult to do without some kind of intelligent controls.

Safety of Line Repair Personnel

When repairing a line after a permanent fault, there is the danger that an isolating switch will accidently close and reenergize the line. If there is only one source of power, steps can be taken to gain reasonable assurance that this will not happen. However, it is much more difficult to give this assurance if there are multiple sources on the feeder.

One can imagine faulty controls that permit reconnection or operators attempting to manually reconnect, not aware that anything is wrong. Automated control cannot completely eliminate this problem, but it could enhance the safety of personnel by giving greater assurance that there will be no unexpected connections. For example, motor-operated disconnect switches could be placed at each DSG site capable of reenergizing the feeder. When there is a fault, the disconnect switches at the affected DSG sites will be remotely opened and kept open until the line is clear.

Example of Emergency State Operation

To illustrate automated system operation for a fault on a feeder containing DSG, the following scenario has been developed.

Figure 5.2 shows the normal system condition for the example system. In this example, the squares all represent fault interrupting devices that are equipped with communications devices and may have significant local intelligence. In this scenario, it will be assumed that the line devices are intelligent as well as the central substation control.

For this example, assume that a permanent fault exists between Device 1 and Device 2. The following sequence occurs:

1. Device 1 senses overcurrent and begins its tripping sequence. Since the fault is permanent, it will operate to lockout. The first reclosing operation may be delayed to permit all DSG to disconnect.

2. The existence of the fault may be detected at the DSG site by either loss of voltage or high current. Device 3 will open and lockout.

3. As a redundant measure, Device 2, which has some local intelligence, will sense reverse power flow and will also signal Device 3 to open. Also, it will block reclosing on Device 3.

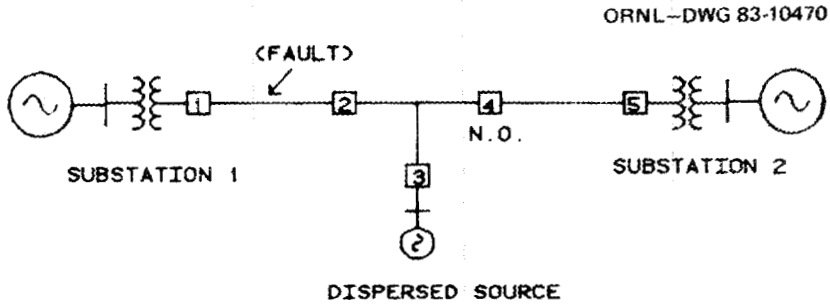

Fig. 5.2. Normal operating state.

Figure 5.3 shows one possible state of the feeder immediately after the completion of these steps. The problem now is to restore power to as much of the feeder as possible.

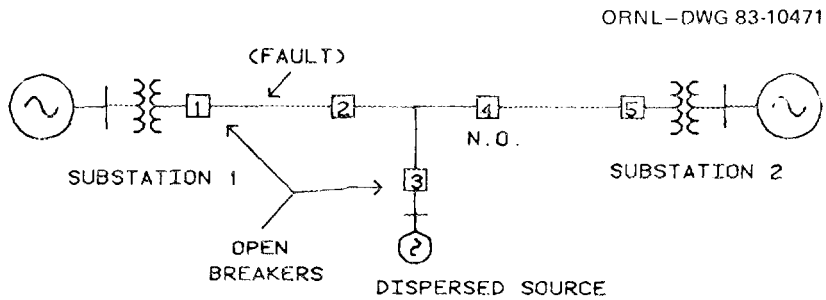

Fig. 5.3. State immediately after fault interruption.

The two substation controls communicate to determine where the fault is located and what to do about it. The restoration sequence could be as follows:

1. Device 2 is opened; this isolates the fault.

2. Device 4 is closed; this causes Substation 2 to pick up the load on the faulted feeder up to Device 2. The programming of any changes of pickup levels and TCCs also take place at this time.

3. The reclose block on Device 3 is lifted. The DSG device can be synchronized, if necessary, and reconnected. This assumes that the feeder from Substation 2 is capable of supporting the DSG device.

The feeder containing the DSG device would again be in a normal state, although not in the original normal state. Normal state algorithms in the Substation 2 control computer would have to be modified to represent present

conditions. Normal state operations would continue until the fault is corrected.

When the fault is corrected, one way to restore the feeder to its original state would be:

1. Substation 2 would instruct Devices 4 and 3 to open. This could be done using a "foreign device" disconnect command. That is, all devices not normally on Substation 2 would disconnect.

2. Substation 1 would instruct Devices 1 and 2 to close, perhaps in sequence. This might also be done using a group-connect command that causes all devices normally connected to this feeder to close. DSG device reconnection might be delayed until the rest of the feeder is restored.

5.2.2 Normal State Operation

Utilities in the United States are accustomed to operating distribution feeders with large, stable sources of power with high-quality voltage waveshape. Thus, the load flow and voltages on a distribution feeder are easily predictable and controlled by relatively simple techniques. These techniques often rely on the power flowing in only one direction and the voltages being distortion-free. These conditions can not be guaranteed as easily when there are large amounts of DSG on a feeder. The feeder conditions will tend to be more unpredictable and automated control technology may be needed to maintain the quality of service to which consumers are accustomed.

Load Management

The usual discussion of applying automated controls to load management deals with the control of passive load to

reduce demand. The same principles will, in general, apply to the control of feeders with large amounts of DSG. However, the objectives of control would be different: instead of switching off load during high-demand periods, the control would tend to switch on more generation. Also, it would tend to switch off generation in very low-demand periods.

One can visualize the need for a type of generation scheduling control for a feeder with large DSG devices. For example, a utility would probably want to maintain some base load to help with system stability. If there were a large generation source (1 MW or more) on a distribution feeder, its controls could be tied into the substation control to limit generation if the feeder load were to reach predefined low-load levels. At peak load, the control would have two options:

1. If there is excess capacity available from dispersed generators,they could be called upon to produce more power to help serve the load.

2. If there is insufficient excess capacity available, the control can revert to a load shedding mode.

It would take an intelligent control system with communications between the feeder control and generator control to make the optimum decision in this example.

Another potential problem which might result from having large amounts of DSG on a distribution feeder is varying generation. This could cause voltage regulation problems. The most likely types of generation to cause these problems are solar and wind generation. Other sources, such as small hydro and excess process steam, would be expected to be much more constant. Intelligent devices at selected

points on the feeder (e.g., capacitor bank locations) could detect the voltage fluctuation and initiate the appropriate action. If a single generator is causing the problem, control actions include:

1. adjusting the generator to a lower output level
2. disconnecting the generator

If the problem is due to a large number of small wind generators, it is probably more economical to resort to a remotely controlled switch that would respond to a "group disconnect" command than to attempt to adjust the output of each generator.

Quality of Service Voltage

The most common way to control harmonics on distribution feeders is to try to anticipate the problems. As the complexity of feeders increases, it becomes more difficult to design suppression schemes that are adequate for all possible configurations. An integrated control system could monitor the voltage at various places on the feeder and react more intelligently to an excessive harmonic condition. Possible control actions include:

1. switching the shunt capacitors in such a way to reduce harmonic amplification,
2. disconnecting DSG devices with harmonic-producing inverters until feeder loading is sufficient to attenuate harmonics, and
3. switching in filters at selected locations to siphon off harmonic currents.

When the harmonic content of the voltage becomes too great to be controlled easily, filters will have to be applied, preferably at the source of the harmonics. With widely dispersed generation this may not always be practical. Also, filters can interact with power systems in unexpected ways. Automated control may be usefully employed to enhance the application of filters by detecting unusual conditions and attempting various corrective actions until a satisfactory one is found.

6. NEW HARDWARE NEEDS FOR DSG PROTECTION

The most noticeable hardware need is for equipment especially designed for small- and medium-sized DSG installations. Because these have been virtually nonexistent in the past, there has been no need to develop such equipment. Traditional distribution protection hardware generally does not provide the functions required. Traditional generation and substation protection was designed for larger capacity devices and is either too bulky or too costly for many DSG installations. Little of the traditional relaying hardware is well-suited for the communications schemes needed to prevent such phenomena as islanding.

What is needed is a relay/breaker package patterned after the electronically controlled line recloser that can be applied at the interconnection point. It must contain the necessary relaying and communications functions, and it must be sufficiently reliable so that both the utility and the DSG owners can use it with confidence.

In this section, the specifications for such a protection package are presented. Following that, there is a discussion of the technical and institutional barriers to developing and applying it.

6.1 DSG PROTECTION PACKAGE SPECIFICATIONS

6.1.1 Package Form

Depending on the voltage class and kVA rating, the DSG protection package can take one of two forms. For smaller devices and lower voltage levels, all equipment might be

contained in a single cabinet. At higher voltages and ratings it would probably be best to have the relaying separated from the breaker by some distance. Higher voltage systems should also contain an integral visible disconnect for safety.

6.1.2 Cabinet Requirements

The breaker and relaying should be self-contained, not requiring installation in special cabinets. That is, the cabinet should be integral with the devices. Installation should consist of mounting the devices in the desired place and making the connection to the power source. It is assumed that most of this hardware will be mounted where it is sheltered from the weather (i.e., sun, rain, etc.) but not in a temperature-controlled environment. However, there is also merit in designing equipment in weather-tight cabinets for outdoor mounting. It is expected that there will be need for pole-mounted, high voltage protection packages.

6.1.3 Power Requirements

The relaying should operate from standard station service or from power supplied by potential transformers. Devices requiring battery backup should be designed to require as small a battery as possible. One of the biggest expenses in conventional generation and substation relays is the large battery required for backup. If possible, the battery and charger should be integral with the package.

6.1.4 Relaying Function

The relaying package should provide at least these functions:

1. over-and undervoltage with time delay,
2. over-and underfrequency, and
3. overcurrent (primarily for overload).

Options to this should include:

1. phase current unbalance,
2. phase voltage unbalance,
3. synchronization,
4. directional overcurrent, and
5. directional power.

These options may be added to or substituted for the other functions as required.

One way of achieving multiple relaying functions in a single cabinet is to use microprocessors. Although these are not traditionally used for power system relaying, it is recommended that they be considered for this application. The advantage of this approach is that different relaying functions and characteristics may be obtained by software changes rather than hardware changes. Also, several functions can be incorporated into a single device. It is reasonable to consider this, given that:

1. New hardware must be developed, and the choice of which technology to use is "wide open."

2. Microprocessor technology is advancing rapidly, decreasing in cost and improving in reliability.

3. Communications can be more easily handled in digital devices.

6.1.5 Communications Requirements

The package should have the ability to be interfaced with a communications link from a remote control center. Ideally, the package should also be able to transmit digital signals via a communications link to the remote control center to give such information as breaker position, generator capacity available, voltage, current, power factor, kW, kVA, kVAR, etc.

6.2 BARRIERS TO COMMERCIALIZING THE DSG PROTECTION PACKAGE

In this section, barriers to the commercialization of a microprocessor-based DSG protection package with multiple relaying functions are addressed. It is recognized that one of the primary barriers is economics (limited market potential, marginal cost justification for DSG, etc). However, this issue will not be addressed here. Instead, we will concentrate on technical and institutional barriers.

6.2.1 Technical Barriers

Processor Power

A relay must operate in real time. Therefore, there is an upper limit to the number of functions one can pack into a microprocessor. There have been single- and dual-function microprocessor-based relays and controls built for power systems applications. The investigators are familiar with three of these:

1. McGraw-Edison's recloser control,[10]

2. Beckwith Electric Company's PRIDE relay,[8] and

3. The static VAR system model on McGraw-Edison's Transient Network Analyzer.[11]

Each of these performs one or two primary functions of varying complexity. It is not likely that they have the power to incorporate all the functions needed for all types of DSG protection. However, there are two things happening that suggest that it will be practical soon:

1. Microprocessor technology is advancing at a very rapid pace.

2. Parallel processing techniques are being developed for use with multi-microprocessors.[12]
   A relay can contain several microprocessors, each dedicated to a separate task.

Therefore, it is only a matter of time until the barrier of processor power is overcome.

Software Development

Hardware capability far outdistances the capability of applications developers to use it, and will continue to do so. This implies that it is also only a matter of time before the desired function is developed. But it also implies that software costs will be much more than the hardware costs. This is an established fact for many projects.

If careful thought is not taken, software costs will be prohibitive, and there will be a significant time lag between the availability of hardware and the availability of applications software. With careful planning in designing modular software, costs can be minimized and new hardware can be utilized as soon as it is available. The key to a successful, economical, microprocessor-based relay is a software system that can be easily adapted to different needs and different hardware configurations. Although the real-time constraint makes the processor computing power barrier seem large, it will probably be the software barrier that will delay implementation. However, if the initial software design is good, subsequent implementations will be limited less by the software barrier.

Response Time and Priorities

With a definite upper limit on the processor power, priorities of different functions have to be established. For example, fault detection is a more critical function than overload detection. More damage can be done in a shorter time; therefore, the relay must respond more rapidly. However, the DSG breaker is not the primary breaker responsible for interrupting a utility fault. The DSG protection package does not have to respond as quickly as a utility protection relay. In most cases, the DSG installation must simply disconnect before the first reclose operation. Therefore, it may be possible to take a microprocessor-based relay designed for utility use and make a suitable DSG protection relay by reducing the priority on the main task. This barrier is one of deciding how the priorities and response times must be set.

Accuracy

The DSG protection package depends heavily on voltage and frequency measurements. The accuracy requirements appear to be somewhat greater for these functions than for overcurrent. This may be particularly true of voltage phase balance relays. The accuracy of the relay would be affected by

1. A/D converters,
2. sampling algorithms,
3. presence of harmonics, and
4. instrumentation transformers, etc.

It is estimated that the accuracy for measuring voltages and frequency must exceed 99%. This will place a difficult requirement on the relay. The accuracy is somewhat time-dependent: basically, the longer the available time, the more accurate the measurement. The microprocessor will have less than 0.5 seconds to achieve this accuracy to meet most specifications; less than 1/6 second (10 cycles) to meet others.

Number of Inputs

An adequate DSG protection package would be able to sense voltages on both sides of the breaker, as well as the breaker current. For three-phase devices, this is nine quantities. In addition, it would be able to sense breaker state, other local signals from the DSG site, and remote signals from the utility control. To process all these inputs imposes quite a strain on a single microprocessor, which makes a strong argument for going to multiprocessors.

The economical provision of enough A/D converters for all the inputs also presents a hardware cost barrier. Fortunately, sampling 60-Hz waveforms is not a technically difficult task, and it may be possible to do multiplexing on the inputs, if necessary.

Reliability

The issue of reliability stems from lack of confidence in electronic relays. Consideration must be given to failure modes to maximize the probability of failing safely. It should be assumed that microprocessors will stop running periodically. One way to get around this problem is to have a separate circuit that checks to see if the microprocessor is running and restarts it when necessary. Other solutions include using more than one processor in parallel.

One advantage of microprocessors is that they can be programmed to check on themselves and report malfunctions. Then they can be repaired, if necessary, before their operation is needed. In contrast, it is never known if anything is wrong with electromechanical relays until after they fail to operate.

The burden of proving reliability of the hardware will fall on its manufacturer.

Surge Withstand

Electronic devices on power systems face much exposure to high-voltage surges. For small- and medium-sized DSG

installations, the problem may be less severe because the voltage class is lower than for utility equipment. However, the problem will still exist.

Over the past two decades, solid-state relays based on discrete components have become very reliable. Much has been learned about protecting these devices against voltage surges. However, the microprocessor presents new challenges. Not only is it more susceptible to being physically damaged by high voltage, but surges could affect its operation. For example, a surge could change some bits in random access memory (RAM) that would alter the operation of the program.

The only difference between the requirements for DSG protection devices and the utility devices might be a requirement to withstand high voltage at low frequency (60 Hz) that might persist for several seconds due to resonance.

Field experience and laboratory testing will be required to develop an adequate surge-protection scheme.

6.2.2 Institutional Barriers

It is assumed that most DSG device owners would favor the use of an integrated protection package because of lower cost and simple installation requirements. Therefore, the institutional barriers discussed will deal only with the power utility. This discussion is based on the investigators' experience in marketing electronic relaying devices to utilities.

Resistance to Electronic Relays

Many distribution protection engineers are reluctant to trust any electronic relaying equipment. This feeling is derived from bad experiences with electronic equipment failing from surges, high temperature, etc. This barrier is one that can be removed only after many years of reliable operation. Fortunately, the feeling is not universal, and there should be ample opportunity to implement the type of DSG protection package recommended here.

Resistance to New Equipment

While some people are eager to try any new thing that comes along, others resist change. It is expected that there will be a delay in getting a special DSG protection package approved for use. The time lag would depend on each utility's need for such a device and the eagerness of the protection engineers to try it. This barrier is one that can be largely overcome through marketing efforts and personal contacts between utility personnel and manufacturing representatives.

Confusion Over Application Responsibility

The major goal for the DSG protection package should be to ease application by distribution protection engineers who may have limited experience in generation protection. However, it appears that many DSG protection specifications were written by utility generation-protection engineers. Thus, the specifications tend to call for typical large

generator protection equipment. The potential barrier here is that generation protection engineers may tend to ignore new devices not directly applicable to their main area of expertise.

Computer Fear

Although it is diminishing, many technical people are still fearful of anything computerized. Also, the owner of the DSG device may feel that having a computer on site will give the utility too much opportunity to "spy" on his operation.

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APPENDIX A

EXAMPLES OF DSG PROTECTION SCHEMES

Ten representative examples of DSG protective relaying configurations taken from utility specifications or actual applications are presented here (Figs. A.1 through A.10). This will give the reader a better idea of the different protective relaying configurations being considered. The diagrams have been redrawn with a common format for continuity. The names of the utilities that supplied the information are given in the figure captions.

Throughout this appendix, relays are referred to by number. This number refers to the function of the relay. For those readers not familiar with the standard numbering code, Table A.1 is provided.

Note: Some figures show prefixes or suffixes to these codes to designate a specific application called for on the utility specification.

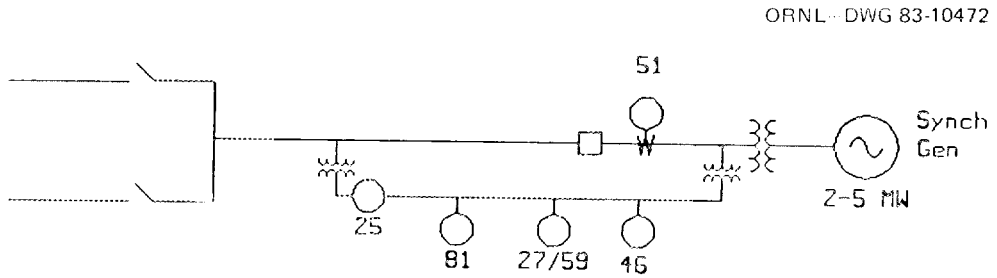

Fig. A.1. McGaw Labs (Southern California Edison Company).

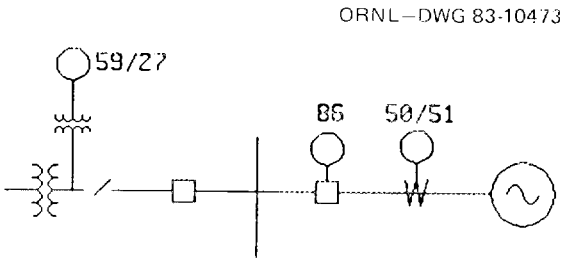

Fig. A.2. Induction generator < 10 kVA (Sierra Pacific).

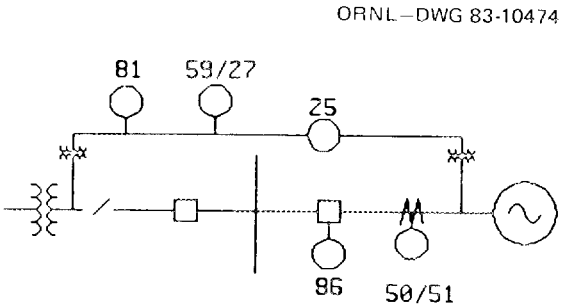

Fig. A.3. Synchronous generator 10 - 100 kVA (Sierra Pacific).

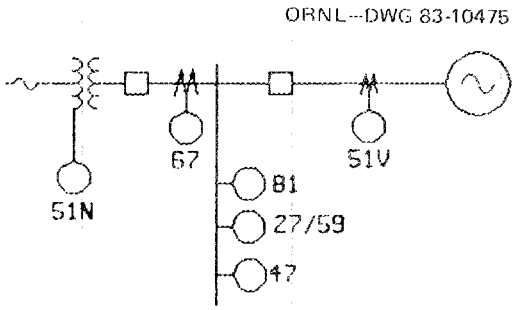

Fig. A.4. Synchronous generator < 1ØØØ kVA (Central Hudson).

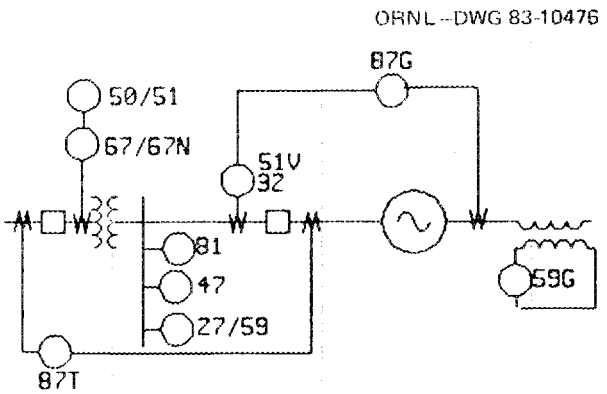

Fig. A.5. Synchronous generator > 1ØØØ kVA (Central Hudson).

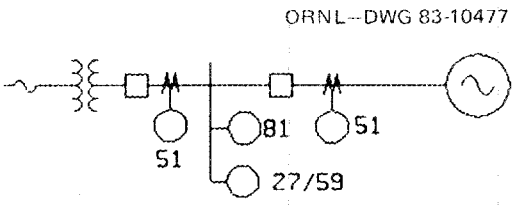

Fig. A.6. Single-phase induction generator (Central Hudson).

ORNL-DWG 83-10478

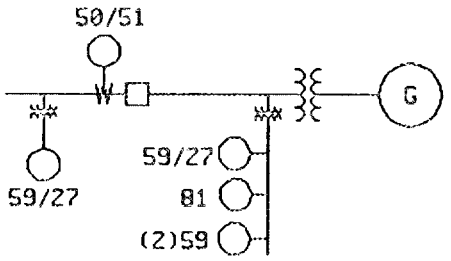

Fig. A.7. Small three-phase generator on radial line (Georgia Power Company).

ORNL–DWG 83-10479

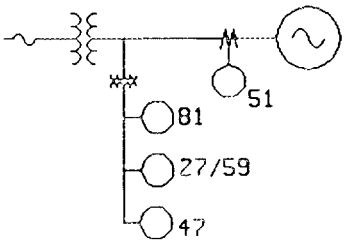

Fig. A.8. Three-phase generator on radial line (Georgia Power Company).

ORNL–DWG 83-10480

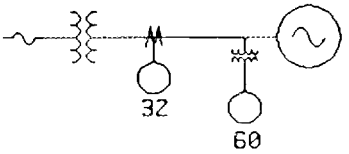

Fig. A.9. Small generator on radial line, no reverse power permitted (Georgia Power Company).

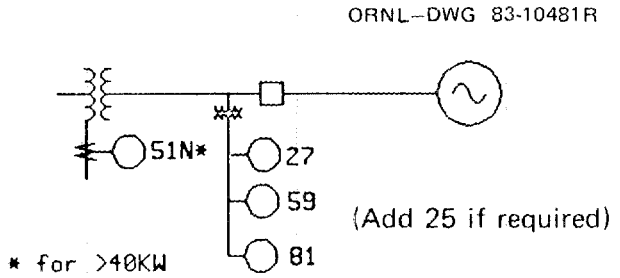

Fig. A.10. Generator less than 100 kW (Pacific Gas & Electric).

Table A.1. Standard relay numbers

(a subset)

Number	Function
25	Synchronism check
27	Undervoltage
32	Directional power
46	Reverse phase current
47	Phase sequence voltage
50	Instantaneous overcurrent
51	Time delay overcurrent
59	Overvoltage
60	Voltage balance
62	Timer
67	Directional overcurrent
68	Blocking
81	Frequency
86	Lock out
87	Differential protective

APPENDIX B

SIMULATION METHODS

This appendix is provided to give the knowledgable analyst a better idea of what was done for the various simulations performed for this work. Five major simulations and several minor ones were performed. Unfortunately, space does not permit a detailed description of each. However, an attempt will be made to provide sufficient information about the major simulations so that those familiar with power system analysis can duplicate them.

The basic simulation tools were the McGraw-Edison Transient Analysis Program (METAP) and its steady-state counterpart, called MESSAP (McGraw-Edison Steady State Analysis Program). These are general-purpose electrical network simulation programs capable of accepting a variety of models of power-system devices. More information on these can be obtained from ref. 13. (MESSAP uses the same general algorithms as METAP, except it works in the sinusoidal steady state.)

In the following, each type of simulation performed in this work will be described. Special models used will also be described.

1. SEQUENCE VOLTAGES FOR FAULT AND LOAD CONDITIONS

The objective of this simulation was to determine whether the sequence voltages during fault conditions are noticeably different than the sequence voltages during load conditions. The analysis consisted of two parts:

1. Determination of sequence voltages during fault conditions.

2. Determination of sequence voltages during normal load conditions.

A hypothetical 12.47-kV feeder was chosen for simulation. The basic parameters of the feeder are given in Figs. 3.4 and 3.5. The peak loading condition was established by experiment using McGraw-Edison's Regulator and Capacitor Application Program (RCAP). Among other things, this program computes voltage profiles on radial feeders. The loading was designed to give a voltage profile such that the secondary voltage at the substation was 125 volts and the voltage at the end of the feeder was 115 volts. The feeder was modeled as lumped, three-phase inductances having positive- and zero-sequence impedances that yield the fault currents given on the figures. Node 2 was selected to be halfway between Nodes 1 and 3.

The procedure for determining the sequence voltages during faults is straightforward. Faults of various types (three-phase, single line-to-ground, and line-to-line) are applied at each of the three nodes, and the resultant phase voltages are recorded. Then the phase voltages are transformed to sequence quantities.

The procedure for determining normal magnitudes of sequence voltages is more complicated. Because the voltage unbalance is due to unbalanced load currents flowing in the three phases, the degree of current unbalance will determine the sequence voltage values. A probabilistic load model was chosen. Each phase of each load in Fig. 3.5 was allowed to vary in a normal (gaussian) distribution around the target values shown. One hundred variations at two values of standard deviation (10% and 20%) were computed. At each variation, the sequence voltages were recorded. After all variations were recorded at each of the two levels of unbalance, the maximum sequence voltages were estimated by plotting the probability density function on probability paper and projecting to the 0.1% probability value. This was approximately 20% higher than the 1% probability value (the highest value of the 100 cases).

2. SIMULATION OF GENERATOR INFEED TO FAULTS

The objective of this simulation was to determine if rotating machine generators would destroy the coordination between reclosers and fuses on temporary faults. This was a time-consuming analysis due to development and fine-tuning of the machine models. The simulation circuit was simple (Fig. 3.7) and did not require much computer time.

The simulation consisted of first initializing fluxes in the machine model to the instant of fault. Then the transient currents were computed over a period of 200 ms. Later, a postprocessor program computed the I^2t for the currents of interest.

$$I^2t\ (x) = \int i^2 dt.$$

2.1 Synchronous Machine Model

The synchronous machine was modeled in phase components using the equations as presented by Elgerd.[14] The inductance matrix of the machine is given by

$$
\begin{aligned}
L_{aa} &= L_1+L_2 \cos(2\alpha) \\
L_{bb} &= L_1+L2 \cos(2\alpha+2\pi/3) \\
L_{cc} &= L_1+L_2 \cos(2\alpha-2\pi/3) \\
L_{ab} &= L_{ba} = -L_3+L_2 \cos(2\alpha-2\pi/3) \\
L_{ac} &= L_{ca} = -L_3+L_2 \cos(2\alpha+2\pi/2) \\
L_{bc} &= L_{cb} = -L_3+L_2 \cos(2\alpha) \\
L_{af} &= L_{fa} = L_5 \cos(\alpha) \\
L_{bf} &= L_{fb} = L_5 \cos(\alpha-2\pi/3) \\
L_{cf} &= L_{fc} = L_5 \cos(\alpha+2\pi/3) \\
L_{ff} &= L_4
\end{aligned}
$$

α = rotor angular position in electical radians

The values L_1 through L_5 may be determined from the commonly supplied d- and q-axis data as follows:

L_{md} = direct axis magnetizing inductance
L_{mq} = quadrature axis magnetizing inductance
L_{1s} = stator winding leakage inductance (each phase)
L_{1f} = field leakage inductance

$$
\begin{aligned}
L_1 &= L_{1s}+(L_{md}+L_{mq})/3 \\
L_2 &= (L_{mq}-L_{md})/3 \\
L_3 &= (L_{md}+L_{mq})/6
\end{aligned}
$$

$$
\begin{aligned}
L_4 &= 2L_{md}/3 + L_{1f} \\
L_5 &= 2L_{md}/3
\end{aligned}
$$

For the simulation, a 100-kW, cylindrical rotor machine was assumed with the following parameters (all based on 12.47 kv).

L_1 = 6.0953
L_2 = 0
L_3 = 2.915 (all inductances in henries.)
L_4 = 6.5164
L_5 = 5.83

Stator resistance = 38.19 ohms (each phase)
Field resistance = 6.22 ohms

Inertial constant = 2.32 kg-sq. m = 55 lb-sq. ft

The basic data from which these values were derived were supplied by the Electric Machinery Division of McGraw-Edison Company.

The parameters for the 1000-kW and 2000-kW machines were assumed to be directly proportional to these. Impedance values were ratioed down, and the inertial constant was ratioed up in proportion to generator ratings.

A value of five amps of field current is required to produce rated terminal voltage at no load. It was assumed that this was the initial condition of the machine at the instant of fault.

Given these values, the METAP program solves the resulting time-variant differential equations through numerical integration (trapezoidal rule). It was assumed that the fault occurred near point of interconnection of the 12-kV

feeder and the generator. The inductance and three-phase connection of the stepdown transformer was included, but the line inductance was assumed to be negligible.

2.2 Induction Machine Model

The induction machine model used for the simulations was derived directly from the synchronous machine model. The model is essentially of a wound-rotor machine with three rotor windings. The inductance matrix is expanded by two rows and columns to represent the two additional rotor windings. L_4 and L_5 are assumed to remain the same as for the synchronous machine. The mutual inductance between the three rotor windings is assumed to be the same as the stator windings (on the same voltage base).

When all rotor windings are shorted, this model duplicates fundamental three-phase induction machine behavior very well. The biggest problem in this simulation was to fine-tune the rotor resistance so that the rotor time constant was typical of induction machines. This was done empirically by duplicating the oscillograms of a faulted induction machine in ref. 15. This resulted in an equivalent rotor resistance of approximately 60 ohms. Otherwise, all impedance values were identical to the synchronous machine values.

For initial conditions at the time of fault, field currents of 2.5, -1.25, and -1.25 give good results.

3. SIMULATIONS OF RESONANT CONDITIONS DURING FAULTS

The objective of this simulation was to determine if high voltages could appear during single line-to-ground faults. A

one-line diagram of the simulation circuit is shown in Fig. 3.15. Actually, only the right-hand side of this circuit was represented. (The utility source is disconnected by the switch.) The circuit model was three-phase, consisting of a capacitor bank, a delta-wye transformer, and a three-phase synchronous generator as shown. The 100-kW generator parameters were as previously described in this appendix. The transformer short circuit impedance was assumed to be negligible in comparison to the generator.

The simulation consisted of initializing the circuit to the instant of time at which the switch opened. Then the transient response of the circuit was computed for a period of 100 ms.

Initially, no loads were modeled. The amount of capacitance was varied, and the peak voltages for each capacitance value was recorded. A typical waveform is shown in Fig. 3.16. For the 100-kW synchronous machine model used in the simulation, it was found that typical power-factor capacitors (150, 300, 600, and 1200 kVAR) caused high voltages. When this was discovered, the effects of loads and surge arresters were studied.

The loads (see Table 3.5) were modeled as paralleled resistance and inductance. The load model was three-phase, with each phase being connected in parallel with the capacitors.

The arrester model used to determine the discharge energy was a model of a McGraw-Edison 10 kV VariSTAR distribution arrester. Because the discharge currents were low (300 amps), the arrester was modeled as a simple two-slope nonlinear resistor as follows:

First slope = 10 000 ohms
Second slope = .01 ohms

Voltage at intersection of the two slopes: 28 kV

The first slope of the actual arrester is much higher than the model. However, 10,000 ohms was chosen because it was high enough not to affect the results, yet low enough not to cause any numerical precision problems.

Following the calculation of the transient waveforms, a post-processor program was used to compute the arrester energy:

$$E(x) = \int v(t)\,i(t)\,dt,$$

where E = arrester energy,
v = arrester voltage, and
i = arrester current.

4. SIMULATION OF INDUCTION MACHINE SELF-EXCITATION

The objective of this simulation was to determine how easily an induction machine would self-excite. The 1000-kW induction machine model described previously was used in the circuit shown in Fig. 3.17. The generator shaft power was set to 1000 kW and a resistive load of 1000 kW (at nominal voltage) was used to absorb the power. The circuit model was three-phase, consisting of only the lumped elements shown.

It was not known what value of capacitance might lead to self-excitation, so it was decided to try typical power-factor capacitor sizes. The first size chosen was 600

kVAR. This yielded a slowly decreasing voltage waveform that definitely showed that the machine would self-excite, at least for several cycles. The next capacitor size chosen was 1200 kVAR; this yielded a rising voltage characteristic. Since these two simulations verified that self-excitation can easily occur for typical distribution system values, no further simulations were conducted. The objective here was simply to determine if induction generator self-excitation is likely for typical values of equipment found on utility systems. Further research will be needed to better determine the probability and effects of islanding.

Note the speed characteristic in Fig. 3.18. The speed increases for the 600 kVAR case and decreases for the 1200 kVAR case. If this seems unusual, remember that the load is modeled as a resistor which draws more power as the voltage increases. The generator shaft power was assumed to remain constant. Therefore, as the terminal voltage rises, the generator must slow down because it is producing more electrical power than incoming mechanical power.

5. FLUCTUATING GENERATION

There were two objectives in this simulation:

1. To determine if wind generators could cause voltage regulation problems; and

2. To determine if conventional, 32-step voltage regulators could be effective in maintaining regulation.

The circuit used in the simulation is shown in Fig. 3.20. The regulator was placed at the electrical midpoint between the wind farm and the infinite bus. The total impedance to the wind farm was $Z = R + jX = 1 + j5$ ohms at 12.47 kV. The

wind-farm generation varied from 1 to 3 MW. The wind farm was assumed to have either induction generators or line-commutated inverters which require substational VARS. It was assumed that the VAR requirement was double the power output, in keeping with the data by Parks, et al.[16] The circuit was preloaded to achieve the voltage profile shown in Fig. 3.21. This load was determined by trial-and-error, using the RCAP (Regulator Capacitor Application Program) program.

The simulation was carried out by time-stepping in the sinusoidal steady state using the MESSAP program. Because the loads were modeled as constant kVA loads at each time step, this simulation is like doing a series of load-flow solutions with one load varying as a function of time (Fig. 3.22).

5.1 The Regulator Model

The regulator was modeled as an ideal autotransformer with thirty-two 5/8% taps (16 raise, 16 lower).[17] The tap position was determined by a model of a conventional regulator control. The adjustable parameters of the control are:

1. line drop compensator,
2. voltage setting and bandwidth, and
3. time delay.

The line drop compensator was set at 0.5 + j2.5 ohms, which puts the regulation center for the regulator at the wind farm. The voltage setting was 120 volts (at the wind farm), with a bandwidth of 2 volts (tolerance of ± 1 volt). The time delay was set to 15 seconds.

At each time stop, the control-model algorithm is, in simplified form:

1. If the regulated voltage is outside the bandwidth, increment the delay timer. Otherwise, reset the delay timer to zero.

2. If the timer has elapsed, the voltage regulator determines which way to change the tap, and it can only change one tap per time step.

This model is sufficient for the simulation performed here. However, it does have some deficiencies, of which the reader should be aware:

1. There is a finite time required for a tap change. This model crudely approximates this time requirement by only allowing one tap change per time step. This will not work well in all cases.

2. Some regulator controls reset the timer after every five tap changes. This model does not have this function.

The model did include a reverse power accessory. However, it was not called upon to operate during the simulation.

This simulation showed that the regulator, as modeled, was ineffective in controlling the feeder voltage. One improvement would be setting the regulator time delay to 5 seconds. However, this would cause even more tap change operations and the frequency of tap changing is too great with the 15-second delay. Therefore, no additional simulations were performed. However, it is doubtful that even a 5-second delay would be effective. What is needed is a continuously variable regulator that can respond within a few cycles.

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