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Advanced Applications of Multifunction Digital Generator Protection

Charles J. Mozina
Beckwith Electric Company
6190 - 118th Avenue North
Largo, FL 33773-3724 U.S.A.

Abstract: The protection of generators over the past fifteen years has evolved from discrete electromechanical relays to static (electronic) relays and finally to multifunctional digital protection systems. This paper provides the author's insight into the industry's application of multifunction generator relays and recent developments in providing more sophisticated and innovative protection functions required for utility-sized generators. These new protective areas include field ground fault detection (64F) using an injection approach, brush lift-off detection (64B) to detect high-resistance brush contact with the rotor shaft, out-of-step protection (78), and turn-to-turn stator winding fault detection using split-phase differential (50DT) and neutral voltage (59N) detection methods.

I. INTRODUCTION

As all relay engineers are aware, protective relay technology over the past fifteen years has evolved from single-function electromechanical relays to static relays and finally to digital relays. The first digital relays were single-function units. However, as microprocessors became more powerful, manufacturers soon saw the economic advantage of designing multifunction relays. In these relays, virtually all protective functions for a specific protective zone are incorporated into a single hardware platform. Fig. 1 illustrates the number of protective functions which can be installed on a single hardware platform for generator protection. A failure of the hardware platform will typically disable <u>all</u> protective functions within the relay. Therefore an important issue in the application of multifunction digital relaying is how to handle having "all the eggs in one basket." The installation of independent primary and backup protection is one of the most fundamental concepts of protective relaying.

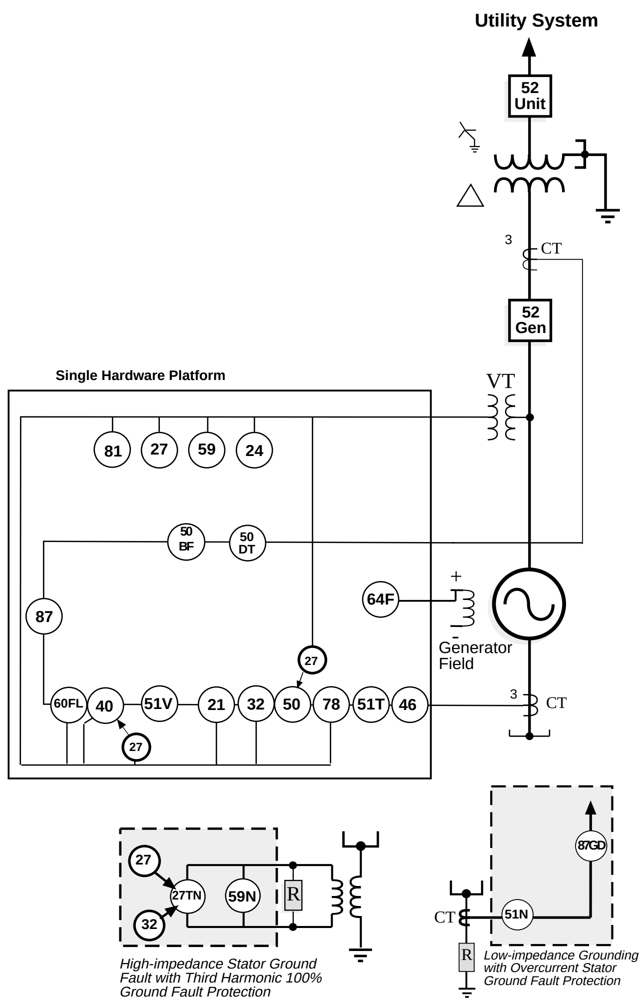


Fig. 1 Typical Generator Protection

Some gas turbine manufacturers have argued that with self-diagnostics (the ability of the relay to check itself), a relay failure would be known immediately and the protected generator could be removed from service until the relay was replaced or repaired. Most utility users have found this philosophy unacceptable especially in generator protection where there is no remote backup from power system relaying. Even with a mean-time-between-failure rate of 90 years or more (based on in-service operating experience with digital relays), the consequences of removing a major generator from service due to a single relay failure are unacceptable to most users. The loss of a major generator immediately increases the cost of generation for a utility for the time the machine is out of service. The utility compensates for this lost generation by either running less efficient generation in-house or purchasing more expensive power off-system. Even the loss of a moderately-sized (200 MW) generator can cost a utility and its customers $100,000 per day in added fuel or purchased power costs. In addition to the economic consequences, many utility relay engineers fear the failure of a digital relay could occur concurrently with a protection event when the relay operation is necessary to protect the generator.

II. LEVEL OF REDUNDANCY

Given the performance level of digital generator protection, what is the appropriate level of redundancy? On larger generators, protected solely by digital relays, the use of fully redundant systems is justified. Such a scheme is shown in Fig. 2. This system has been adopted by a number of users worldwide, including two major U.S. manufacturers of large (100 to 250 MW) gas turbines. This level of redundancy is sufficient to allow the generator to remain in-service if one relay should fail. The simultaneous failure of both relays is extremely rare. Even with two digital relays, the installation cost is generally less than half the cost of discrete static or electromechanical protection, due to savings in panel space and wiring costs. Providing redundant protection for major generators has become a common practice within the industry in recent years, but is still not accepted by some manufacturers of gas turbines.

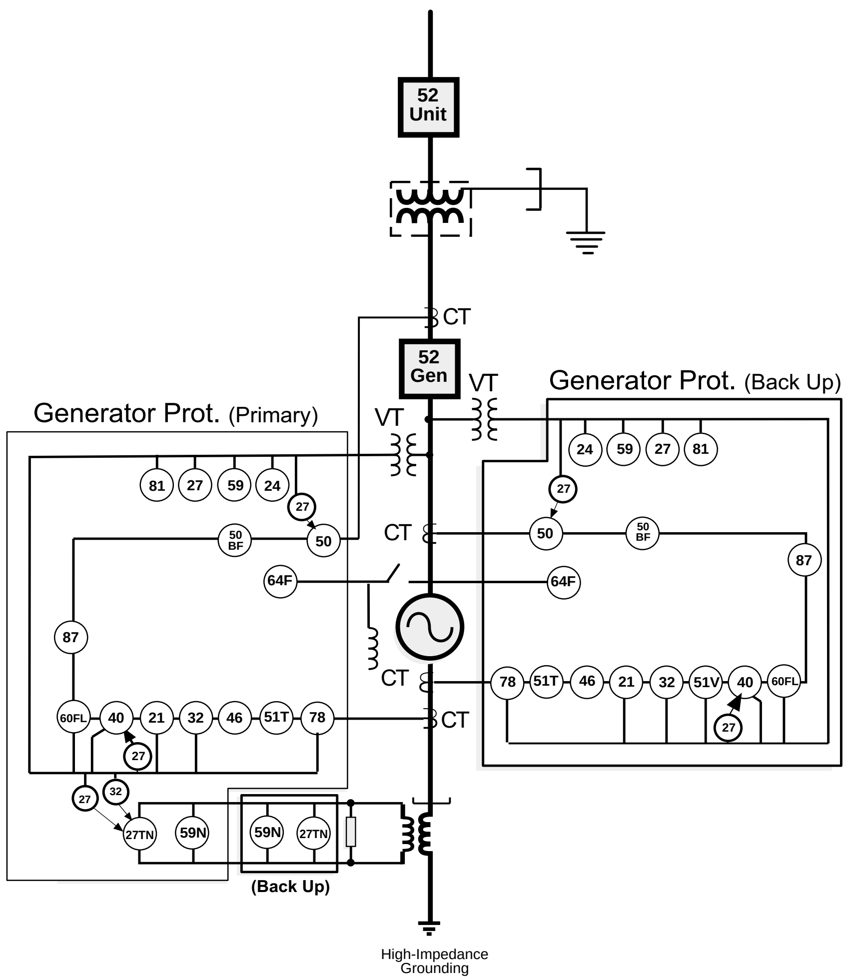


Fig. 2 Dual Relay Approach

III. ADVANCED PROTECTION FUNCTIONS

With the advances in digital technology, more computing power within new digital relays has become available. This allows more sophisticated protection functions to be added—providing more complete generator protection within a single hardware platform. Functions such as field ground fault detection (64F), brush lift-off detection (64B), out-of-step protection (78), and turn-to-turn stator winding fault detection using split-phase differential (50DT) and neutral voltage (59N) detection methods were typically excluded from most manufacturer's digital generator relays because they required substantial modifications to hardware platforms. The hardware platforms, in many cases, had been designed primarily for transmission line or transformer protection. These advanced functions, however, are key protection areas required on utility-size generators.

Field Ground Fault Protection (64F)

The field circuit of a generator is an ungrounded dc system, as shown in Fig. 3. A single ground fault generally will not affect the operation of a generator nor will it produce any immediate damaging effects. However, the probability of a second ground fault occurring is greater after the first ground fault has occurred because field insulation has deteriorated and the first ground has established a ground reference. When a second ground fault occurs, a portion of the field winding will be short-circuited, thereby producing unbalanced air gap fluxes in the machine. The unbalanced fluxes produce unbalanced magnetic forces which result in machine vibration and damage. A field ground also produces rotor iron heating from the unbalanced short circuit currents. The tripping practices within the industry for field ground relaying are not well established. Some utilities trip while others prefer to alarm, thereby risking a second ground fault and major damage.

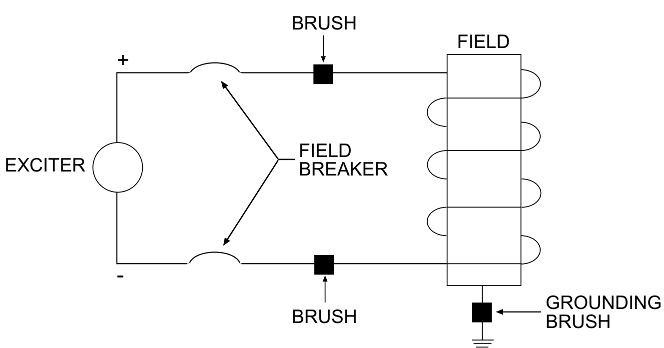


Fig. 3 Basic Generator Field Circuit

The existing practice within the industry had been to use dc voltage relaying to detect field ground faults. These schemes are illustrated in Fig. 4 and Fig. 5.

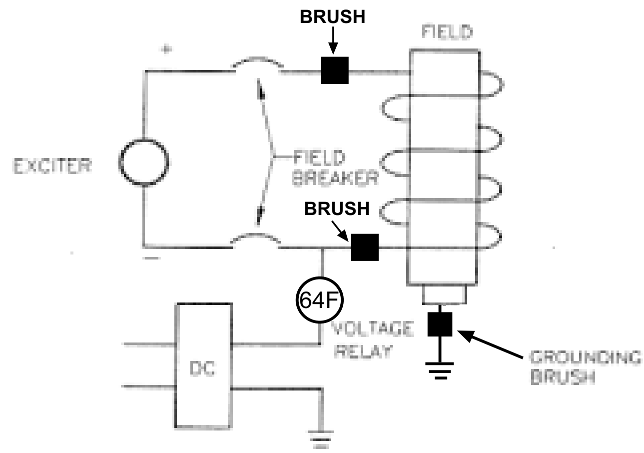


Fig. 4 Field Ground Detection Using a dc Source

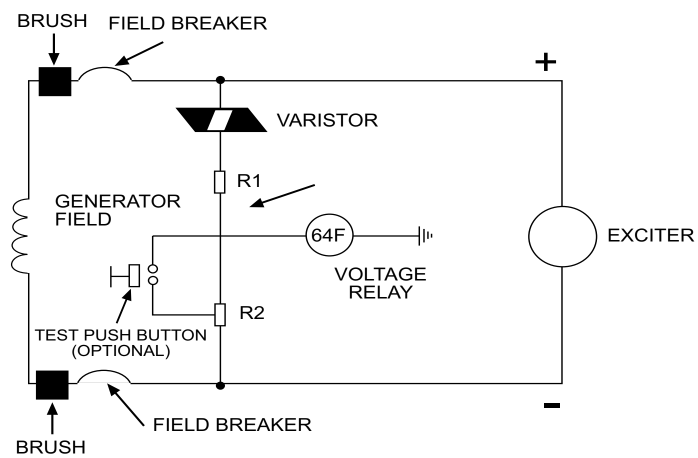


Fig. 5 Field Ground Detection Using a Voltage Divider

Both these voltage schemes are prone to false operation especially during unit start-up due to intermittent grounds produced by moisture or system transients. Unit operators would routinely reset the alarm and continue with start-up procedures. If a persistent alarm occurred, operators attempted to locate the problem. If the ground could not be found within a reasonable period, the unit was supposed to be tripped manually. However, the many nuisance alarms and the very few legitimate ones caused unit operators to lose confidence in the field ground relays depicted in Fig. 4 and Fig. 5. Therefore, the alarm lost credibility. Operators continued to keep the units on-line, hoping that a second ground would not occur. Catastrophic rotor failures have occurred due to a second ground in the field developing very quickly after the first ground. In these instances, the operators were not able to isolate the cause of the first alarm nor were they able to bring the units off-line in an orderly fashion before the second ground occurred.

Clearly a more secure field ground relay is required if automatic tripping is being considered. Such a relay is shown in Fig. 6 and uses an injection principle. This principle has been widely used in Europe with great success, but until recently, it was not available in a multifunction digital relay. As illustrated in Fig. 6, a ±15 volt squared signal is injected into the field. The return signal waveform is modified due to its field winding capacitance. The injection frequency setting is adjusted (0.1 to 1.0 Hz) to compensate for field winding capacitance. From the input and return voltage signals, the relay calculates the field insulation resistance. The relay setpoints are in ohms typically with a 20 KΩ alarm and 5 KΩ trip or critical alarm. The injection scheme provides a major improvement over traditional voltage schemes in terms of both sensitivity as well as security. In addition, digital relays can provide real-time monitoring (Fig. 7) of future insulation resistance so deterioration with time can be monitored.

Brush Lift-Off Detection (64B)

The use of the injection method for field ground detection provides a means of detecting how well the brushes of a generator are making contact with the rotor shaft. This is done by analyzing the return voltage signal. Brushes on older generators are a constant maintenance headache for plant personnel. If brushes open on an in-service generator, they can cause substantial arcing damage to the brush mounting structure and eventually result in unit tripping by loss of field protection. Knowing when brushes should be replaced or re-adjusted is important diagnostic information for plant maintenance personnel. Relay monitoring that provides such information can greatly reduce the changes of brush open circuit during generator operation. Analysis of the return voltage signal within the injection field ground relay can provide an indication that the brushes on a generator are not making good contact with the rotor.

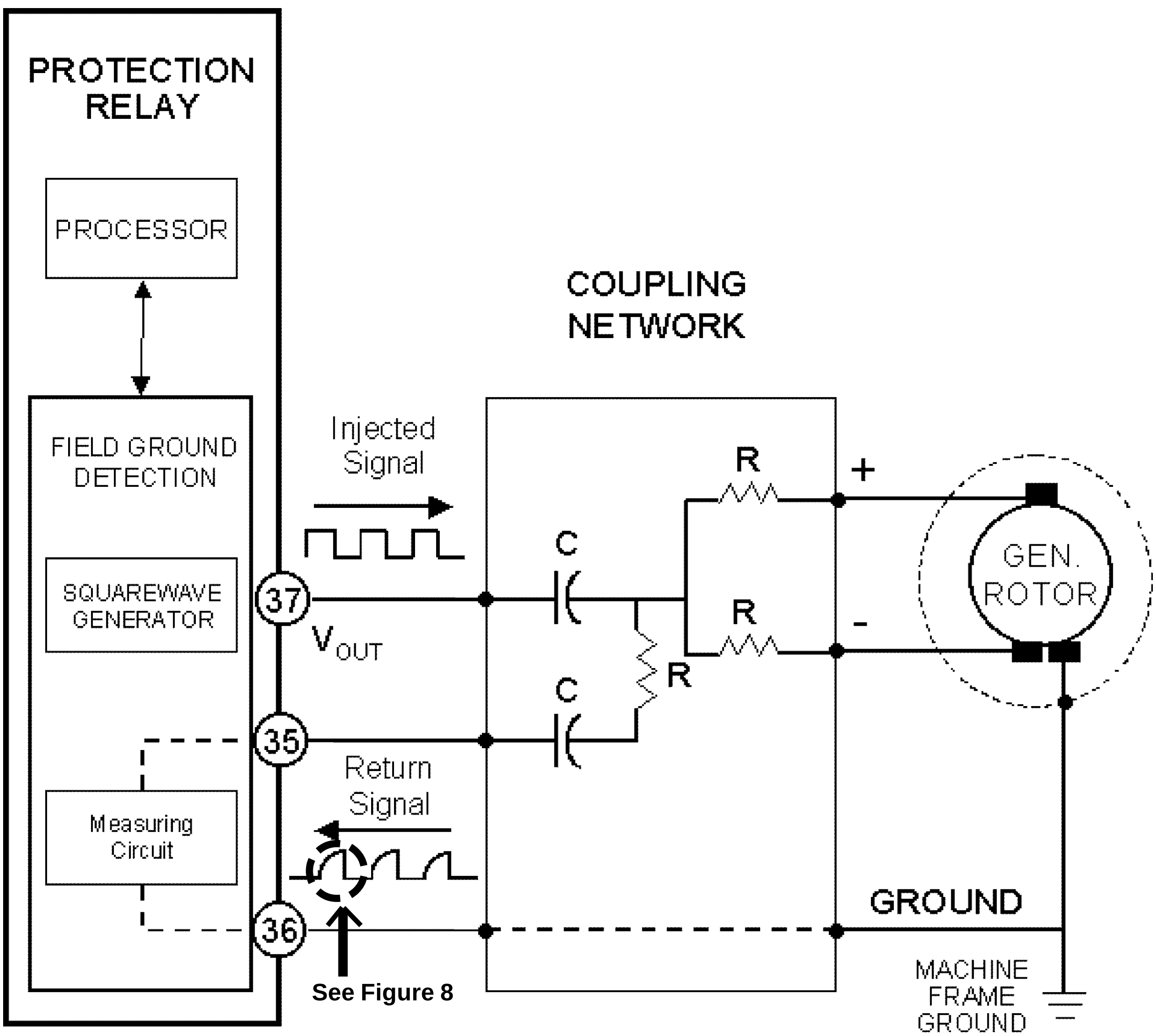


Fig. 6 Field Ground Protection Using an Injection Voltage Signal

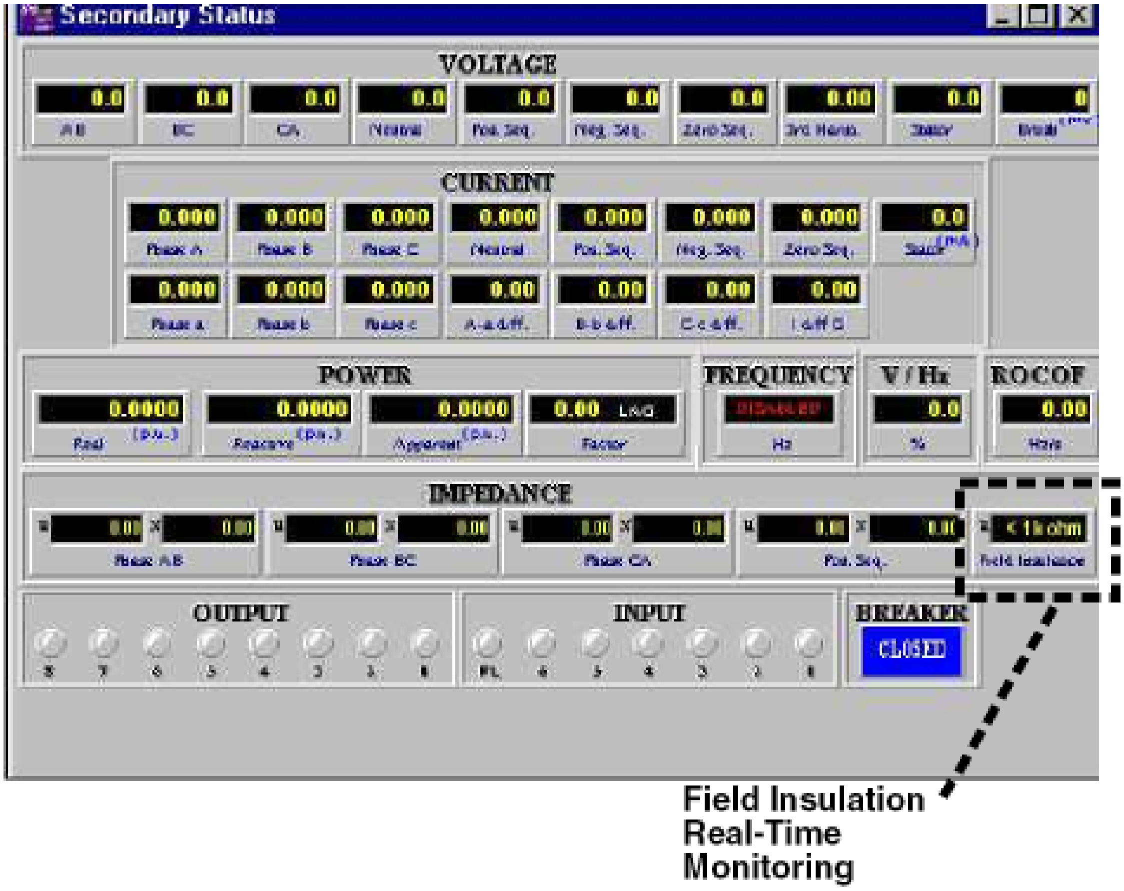


Fig. 7 Field Ground Fault Protection--Real-Time Insulation Measurements

Fig. 8 shows the method used to analyze the return voltage signal. The front of the return voltage signal is rounded due to the field winding capacitance. When the brushes begin to open, they create a higher contact resistance causing the voltage to rise. The level of voltage is measured at a fixed point on the return voltage signal. The voltage is measured each cycle. When the voltage rises above its normal level, an alarm is initiated to alert the operator that the brushes should be inspected. The brush lift-off voltage will also rise if the ground brushes on the generator begin to open. If the ground brushes are allowed to open, the only path to ground for stray ground current is through the machine bearings. Fig. 9 illustrates this point. Sustained current flow through the generator bearings results in pitting and requires the bearing to be changed.

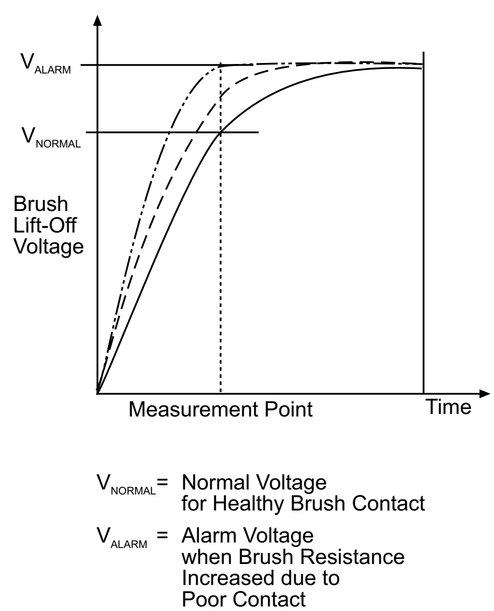


Fig. 8 Brush Lift-Off Voltage

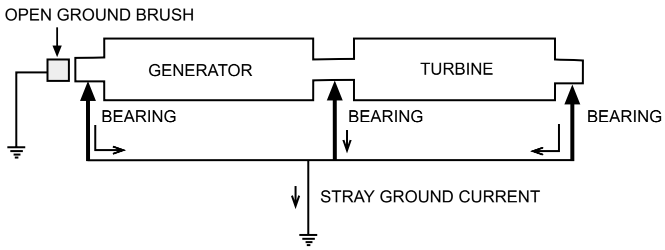


Fig. 9 Stray Bearing Ground Current

Out-of-Step (78) Generator Protection

Following the 1965 U.S. northeastern power blackout, a considerable amount of attention was given to the need for applying out-of-step protection to generators. Although out-of-step relaying protection existed on transmission lines, there were few applications to cover the increasingly common situation where the electrical center of a power system disturbance passes through the generator unit step-up transformer or the generator itself. This variation in impedance can be detected by distance-type relays. The best way to visualize and detect out-of-step generator phenomena is to analyze apparent impedance variations with time as viewed at the terminals of the generator. This apparent impedance locus depends on the type of governor and excitation system of the unit as well as the type of fault which initiated the impedance swing.

Prior to high voltage (HV) transmission systems and large generators, the electrical center during an out-of-step occurrence was out in the transmission system. Thus, the impedance locus could be detected by transmission line out-of-step relaying schemes, and the system could be separated without the need for tripping generators. With the advent of modern HV systems as well as large conductor-cooled generators, generator and step-up transformer impedances have increased while system impedances have decreased. As a result, in most power systems today, the electrical center for out-of-step conditions occur in the generator or in the step-up transformer. This requires the application of out-of-step protection on the generator.

Fig. 10 illustrates a typical breaker-and-a-half substation with a generator and a short circuit on a transmission line near the substation. If the short circuit is three-phase, very little real power (MW) will flow from the generator to the power system until the fault is cleared. The high fault current experienced during the short circuit is primarily reactive or VAr current. The real MW power is very low. During the short circuit, the mechanical turbine power (P_M) of the generator remains unchanged. The resulting unbalance between mechanical and electrical power (P_e) manifests itself with the generator accelerating, increasing its voltage phase angle with respect to the system phase angle as illustrated in Fig. 11. If the transmission system fault is not cleared quickly enough, the generator angle will advance to the point that it will be driven out of synchronism with the power system. Transient stability studies can be used to establish this critical switching angle and time.

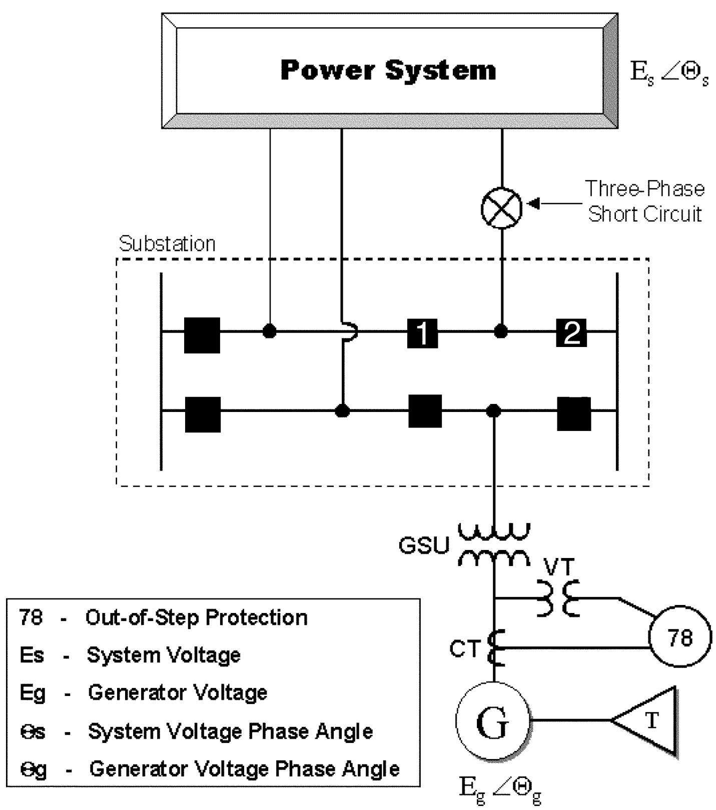


Fig. 10 Typical High Voltage Substation

The equal area criteria can also be applied to estimate the critical switching angle (Θ_c). Area $A_1 = A_2$ in Fig. 11 is the point at which the generator will lose synchronism with the power system. Note that after the fault is cleared by opening breakers 1 and 2, the resulting power transfer is reduced because of the increase in reactance between the generator and the power system. This is due to the loss of the faulted transmission line. In the absence of detailed studies many users set this instability angle at 120º. The time that the fault can be left on the system that corresponds to the critical switching angle is called the critical switching time. If the fault is left on longer than that time, the generator will lose synchronism by "slipping a pole."

Fig. 12 illustrates this concept from an R-X diagram as viewed from the terminals of the generator. This is the normal location for the out-of-step (78) relay. The generator transient reactance (X'_d), GSU transformer reactance (X_T), and power system reactance (X_s) are plotted on an R-X diagram. These impedances should be put on the generator MVA and voltage base. If one assumes $|E_s| = |E_g|$, the locus of the system swing will be located on a perpendicular line bisecting the line drawn between X_S and X'_d as shown in Fig. 12. In this widely-used graphical out-of-step method, the reactance elements in the out-of-step relay are set at Θ_c=120º. More precise angle settings can be determined from stability studies or through equal area criteria analysis. When the swing locus exits blinder A or the supervising Mho circle, generator tripping is initiated. When this happens, the generator has lost synchronism; it has slipped a pole and must be separated from the system.

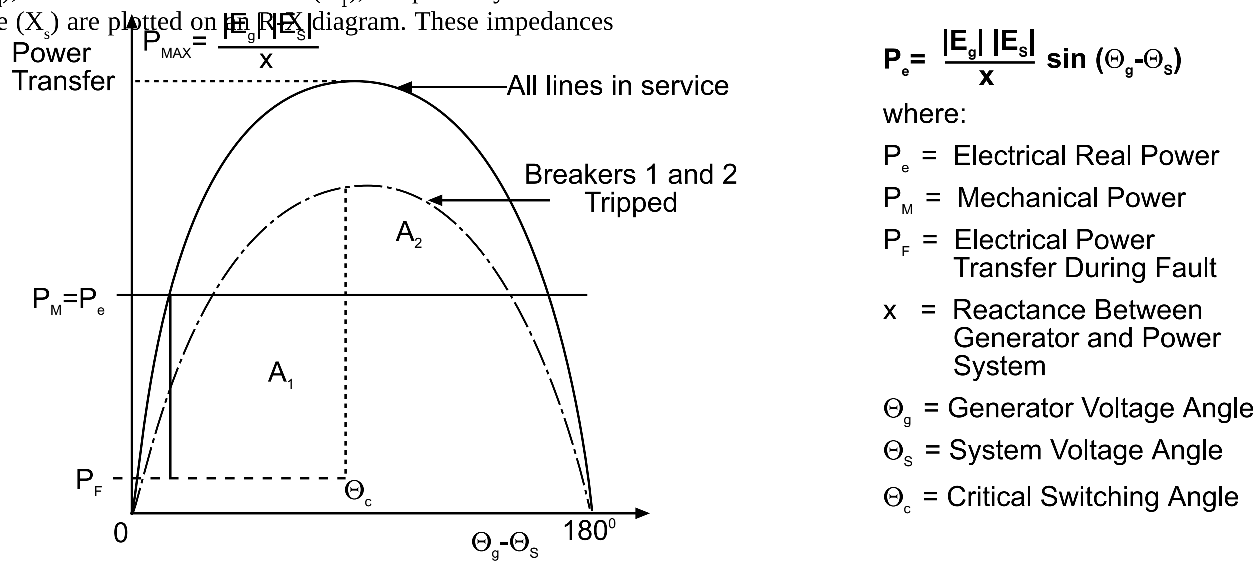


Fig. 11 Power Angle Analysis of Out-of-Step Condition

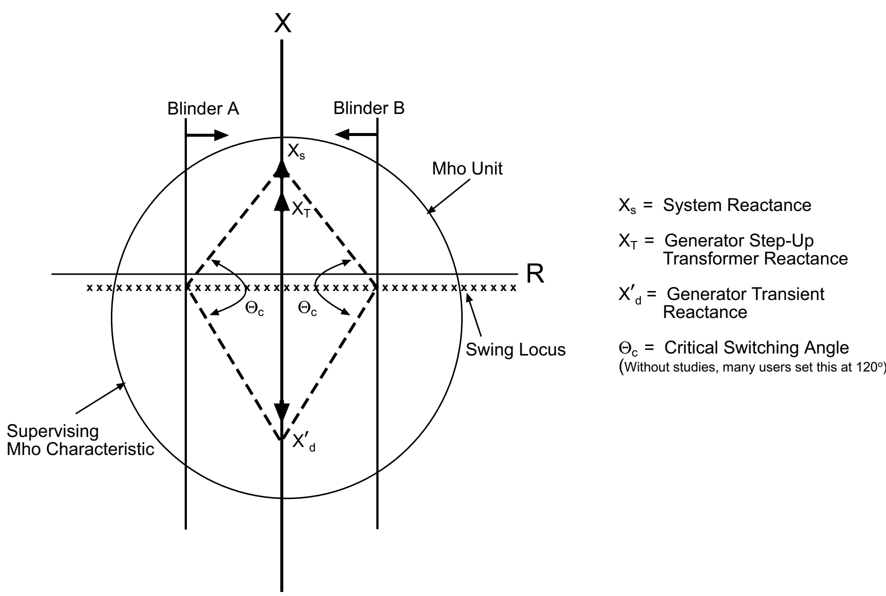


Fig. 12 Impedance Locus Analysis of Out-of-Step Protection

An out-of-step condition causes high currents and forces in the generator windings and high levels of transient shaft torques. If the slip frequency of the unit with respect to the power system approaches a natural torsional frequency, the torques can be high enough to break the shaft. It is therefore desirable to immediately trip the unit since shaft torque levels build up with each subsequent slip cycle. Pole-slipping events can also result in abnormally high stator core end iron fluxes that can lead to overheating and shorting at the ends of the stator core. The unit's step-up transformer will also be subjected to very high transient winding currents that impose high mechanical stresses on its windings.

Turn-to-Turn Stator Winding Fault Detection using Split-Phase Differential (50DT)

On generators with multi-turn coils and two or more windings per phase, a split-phase relay scheme can be used to detect turn-to-turn faults. This is a particularly popular winding design on hydro generators. In this protection scheme (Fig. 13), the currents in each phase of the stator windings are split into two equal groups and the currents of each group compared. A difference in these currents indicates an unbalance caused by a turn-to-turn fault. A definite time overcurrent relay is used for this scheme. The overcurrent pickup is set above any normal unbalance current but below the unbalance caused by a single shorted turn. The time delay is set to prevent operation for transients occurring during external faults caused by an unequal CT response. Any expected problem with CT error can be eliminated by the use of a window CT as shown in Fig. 13. The elimination of CT errors will permit the use of a more sensitive setting. Split-phase protection will detect phase and some ground faults in the stator winding. However, because of the time delay, it is normally used to supplement high-speed differential protection for high magnitude phase faults.

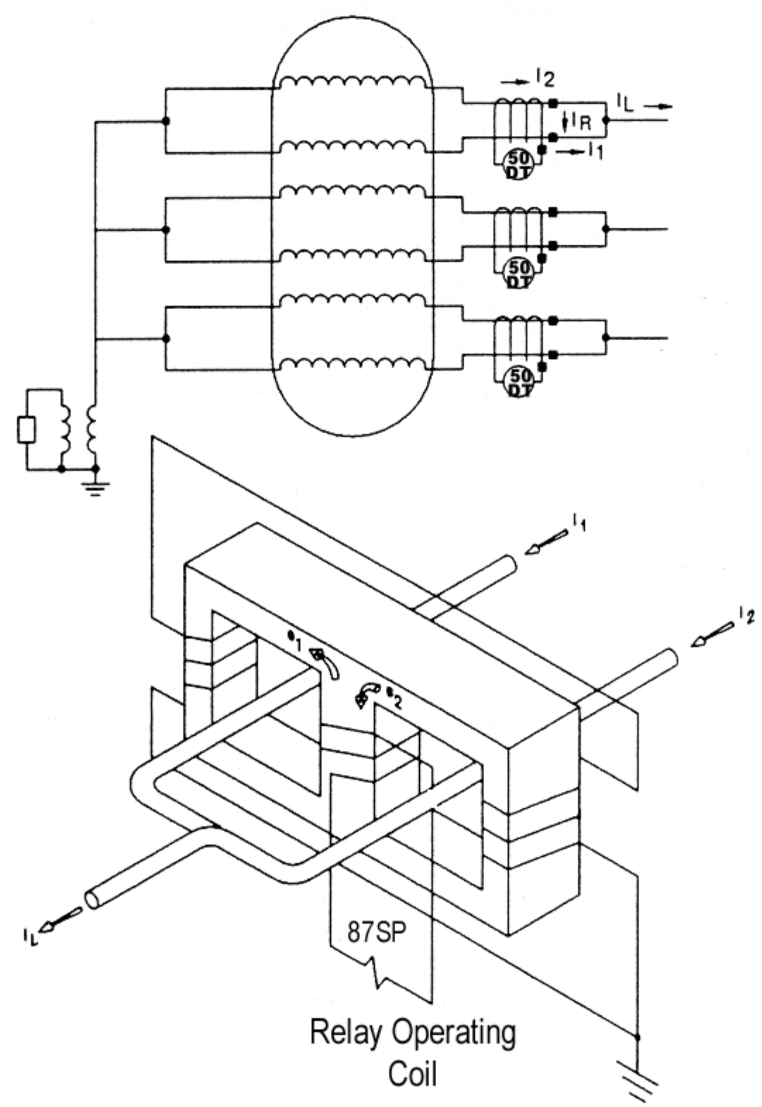
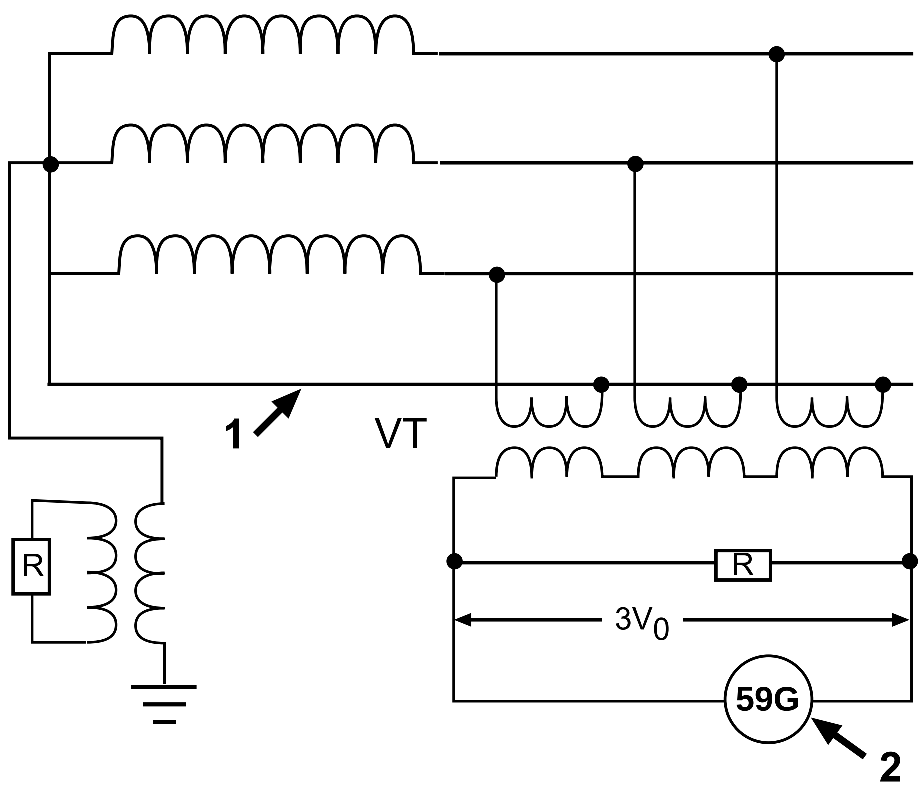


Fig. 13 Split-Phase Differential

It is the practice of many utilities not to immediately replace the section of generator winding that has sustained a turn-to-turn fault. These utilities isolate the faulted winding section and return the generator to service. Full repairs are deferred to a later date. During the period prior to full winding repair, the phase currents between the winding groups are unbalanced. The split-phase overcurrent relay pickup must be increased on the effected phase to overcome this unbalance. Thus it is an advantage to have the ability to increase or decrease the pickup on each phase of this split-phase relay to accommodate this utility practice.

Neutral Overall Turn-to-Turn Fault Detection (59N)

For generators where the stator winding configuration does not allow the application of split-phase differential, a neutral voltage method can be used to detect turn-to-turn stator winding faults. Fig. 14 illustrates this method. A VT is connected in wye and the primary ground lead is tied to the generator neutral. The secondary is connected in a "broken delta" with an overvoltage relay connected across its open delta to measure $3E_0$ voltage. By connecting the primary ground lead to the generator neutral, the 59N relay is made insensitive to stator ground faults. The relay will, however, operate for turn-to-turn faults which increase the $3E_0$ voltage above low normal levels. This scheme is widely used outside the U.S. with excellent results. Installation requires the cable from the neutral of the VT to generator neutral be insulated for the system line-to-ground voltage and the 59N relay to be turned to fundamental (60 Hz) voltage since some third-harmonic voltages will be present across the broken delta input.



1. Insulate cable for generator line to neutral voltage.
2. 59G relay needs to be tuned to fundamental (60 Hz) voltage.

Fig. 14 Turn-to-Turn Stator Winding Fault Protection--
Neutral Overvoltage Method (59N)

IV. GENERATOR VT CONNECTIONS

There are a number of unique subtleties in the application of VT inputs to generator protective relays that need to be considered by relay engineers. The VT connections widely used within the industry to supply generator protection are line-to-line voltage and line-to-ground voltage (4-wire connection and 3-wire connection).

The choice of line-to-line or line-to-ground VT connections is largely dependent on generator size and the bus construction used to connect the generator to the GSU transformer. Smaller size machines, below typically 100 MVA, use line-to-line VT inputs (Fig. 15), because bus work may be typically cable or calvert bus-type construction, where phase-to-phase primary VT connections can be done conveniently. As machine size increases, an isophase bus is commonly used. Providing a primary VT phase-to-phase connection is difficult in isophase bus construction and introduces the possibility of a phase-to-phase fault. Preventing such a fault is one of the reasons an isophase bus is used. Thus, most large generators use phase-to-ground primary VT connections. There are two types of line-to-ground VT connections.

Fig. 16 illustrates a 4-wire line-to-ground connection. This VT connection has two major problems that need to be addressed. If there is a ground fault in the secondary of the VT, the 59N ground overvoltage relay can respond because there is a zero sequence path due to the wye-wye VT configuration. Typically, the 59N is set at a fairly sensitive (5-6 V) pickup to detect a fault as near as possible to its generator neutral. This sensitive pickup setting will also respond to a VT ground fault. The relay engineer needs to coordinate the 59N delay with the secondary VT fuses. Reference 9 has an example of how this coordination can be accomplished. Many relay engineers (including the author) have been embarrassed when a screwdriver has slipped and caused a VT ground fault, which resulted in tripping the entire generator.

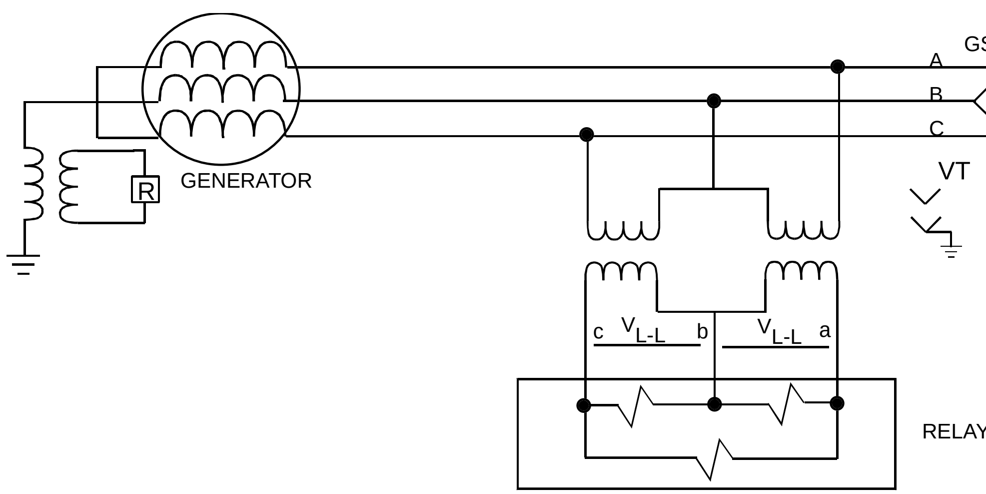


Fig. 15 Line-to-Line VT's

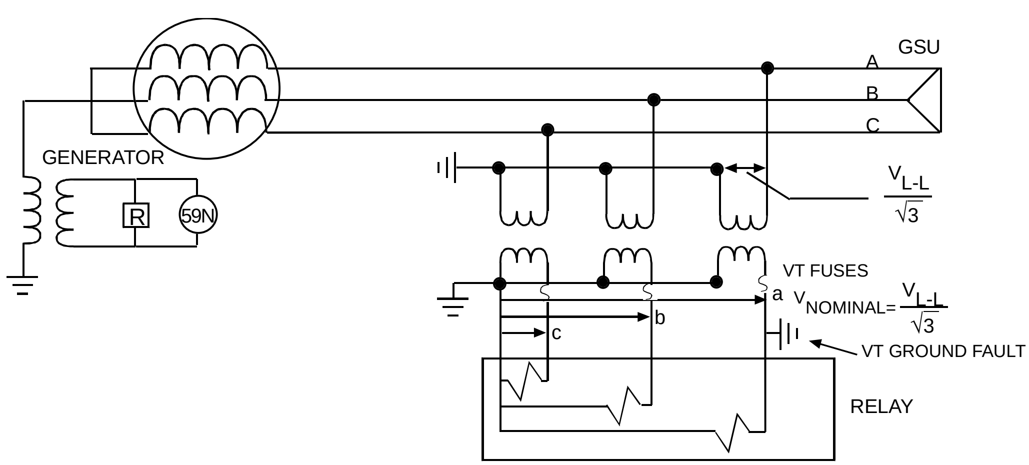


Fig. 16 Line-to-Ground VT's, Four-Wire Connection

Fig. 17 illustrates another problem with the 4-wire line-to-ground VT connection. For a stator ground fault, there is a neutral shift which occurs that results in the ungrounded phases rising to full phase-to-phase voltage. This results in a possible false operation of overvoltage (59) and overexcitation (24) relaying. An ideal solution for this situation is to supply the voltage functions with phase-to-phase voltage. With digital generator protection packages, this has been done by at least one major manufacturer. A major advantage in internally converting line-to-ground inputs to phase-to-phase voltage is that the oscillograph elements still monitor line-to-ground voltage and can be used to phase identify which phase has sustained a stator ground fault.

Fig. 18 illustrates a line-to-ground 3-wire VT connection widely used within the industry. In this connection, the secondary wye uses a 3-wire connection with relay voltage inputs connected phase-to-phase. This connection avoids the need to coordinate the 59N neutral overvoltage relay with secondary VT fuses because of an open zero sequence circuit (wye ground-wye ungrounded VT). Also by connecting the voltage input phase-to-phase, there is no false operation of overvoltage (59) and overexcitation (24) protection due to neutral shift. This connection is illustrated in Fig. 17. The only drawback of this connection is that oscillograph voltage inputs are connected phase-to-phase and cannot be used to phase identify a stator ground fault.

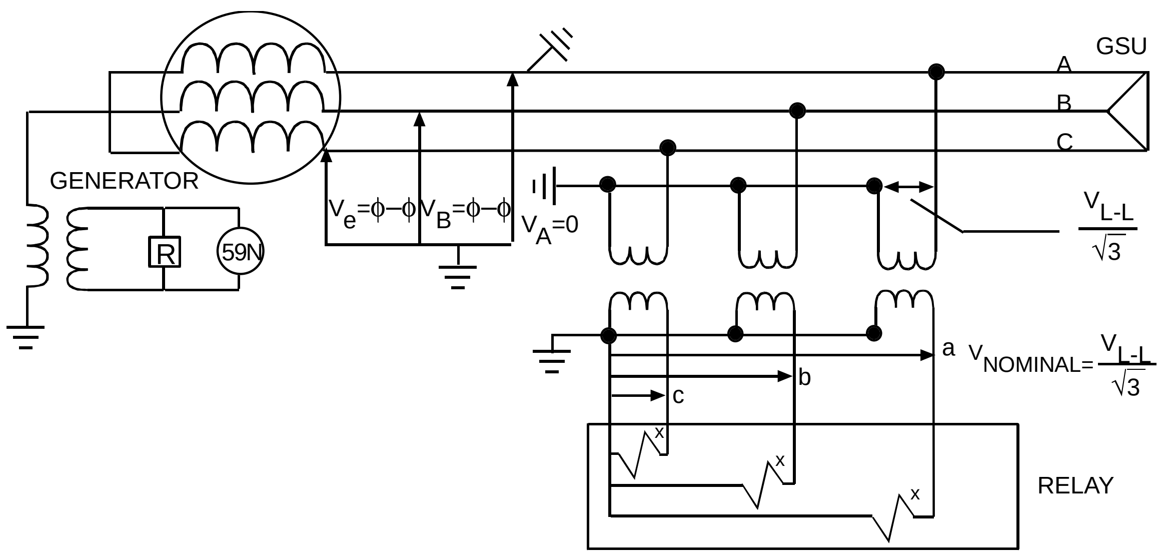


Fig. 17 Line-to-Ground VT's, Neutral Shift

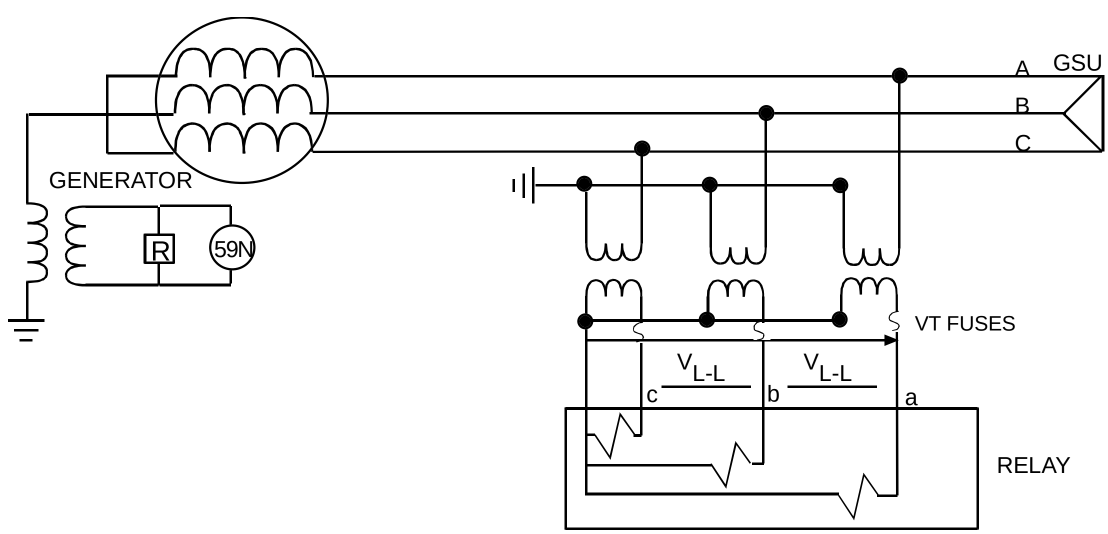


Fig. 18 Line-to-Ground VT's, Three-Wire Wye Connection

V. CONCLUSIONS

The advances in digital technology have provided relay designers with the tools to increase the capabilities of modern digital relays to provide more complete protection of generators. Important protective functions such as reliable field ground fault, brush lift-off detection, out-of-step, and split-phase differential protection functions can now be added to the normal complement of generator relaying. These functions are key protective areas on utility-sized generators.

The paper also outlines some of the major considerations in applying modern multifunction digital relays to generators. The rational for justifying the dual-relay approach to primary and backup protection was also summarized.

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VII. BIOGRAPHY

Charles J. Mozina is Manager of Application Engineering for Protection and Protection Systems for Beckwith Electric Co. He is responsible for the application of Beckwith products and systems used in generator protection and intertie protection, synchronizing and bus transfer schemes.

Chuck is an active member of the IEEE Power System Relay Committee and is the past chairman of the Rotating Machinery Subcommittee. He is active in the IEEE IAS I&CPS committee which addresses industrial system protection. He is a former U.S. representative to the CIGRE Study Committee 34 on System Protection and chairs a CIGRE working group on generator protection. He also chaired the IEEE task force which produced the tutorial "The Protection of Synchronous Generators," which won the PSRC's 1995 Outstanding Working Group Award. Chuck is the 1993 recipient of the PSRC's Career Service Award.

Chuck has a Bachelor of Science in Electrical Engineering from Purdue University and has authored a number of papers and magazine articles on protective relaying. He has over 25 years of experience as a protective engineer at Centerior Energy, a major investor-owned utility in Cleveland, Ohio where he was the Manager of the System Protection Section. He is also a former instructor in the Graduate School of Electrical Engineering at Cleveland State University as well as a registered Professional Engineer in the state of Ohio.