WHY UPGRADE THE PROTECTION AND GROUNDING OF GENERATORS AT PETROLEUM AND CHEMICAL PLANTS?

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Abstract – Significant changes have occurred in the protection and grounding of generators in the past 15 years which impact generators at petroleum refineries and chemical plants. This paper updates the author’s earlier paper on the subject of generator protection upgrades [1] and highlights areas of protection that are still not addressed by some generator owners as well as new protection areas not previously addressed. New generator protection changes are reflected in recent IEEE standards such as C37.102-2006 [2]. This paper discusses these changes as they apply to industrial generators as well as the risks of ignoring them. The paper outlines the risks in several functional areas where old generator electromechanical relay protection is inadequate. In addition, the paper discusses hybrid grounding of the generator stator windings, which substantially reduces stator ground fault damage—avoiding lengthy generator outages to repair. This type of grounding is a relatively new concept in generator grounding introduced in a series of IAS Working Group papers publicized in 2002 [3]. This grounding scheme has been installed on a number of generators but must be coupled with proper relaying as well as transient overvoltage protection. The paper also highlights the major new protection requirements for gas turbine starting with an LCI and protection advances made possible by the use of digital technology which have fostered new methods not possible with older technologies.

Index Terms – upgrade, digital protection, hybrid generator grounding, negative sequence, oscillographic data, stator ground fault, LCI gas turbine starting.

I. INTRODUCTION

As generators become older, the likelihood for failure increases as insulation begins to deteriorate. Generators, unlike some other power system components, need to be protected not only from short circuits, but also from abnormal operating conditions. Examples of such abnormal conditions are overexcitation, loss-of-field, unbalanced currents, and abnormal frequency. When subjected to these conditions, damage or complete failure can occur within seconds, thus requiring automatic detection and tripping.

In 2006, the IEEE PES Power System Relaying Committee updated ANSI/IEEE C37.102 guide for the protection of synchronous generators. Many of the recommended practices applicable to industrial-sized generators are incorporated in the latest revision of the IAS Buff Book ("IEEE Recommended Practices for the Protection and Coordination of Industrial and Commercial Power Systems," ANSI/IEEE Standard 242 Chapter 11) [4]. These industry guides outline current recommended practices for the protection of generators and document the substantial changes that have occurred in generator protection over the last fifteen years. These changes fall into three broad categories: improved sensitivity and grounding to reduce damage, new protection areas, and special protection applications. These are the key functional areas that need to be addressed when developing an upgrade program to bring the generator protection up to current industry standards.

The ground fault protection of industrial generators that are bus-connected and low resistance-grounded has been a particular problem within the industry. These generators are typically grounded with 200-400A neutral grounding resistors in the stator neutral. Traditional thinking was that this level of ground current was a good compromise between selective protection and minimizing damage. Despite the application of protection as recommended in current IEEE standards, stator ground fault damage has been observed to be much more severe than expected. This prompted the investigation into stator ground fault protection by a Working Group of the IAS. The findings and conclusions of the Working Group were presented in a series of four papers [3]. One of the major findings of the Working Group is that the 200-400A traditional grounding will typically cause unacceptable stator ground fault damage. The Working Group papers introduced a new concept in industrial machine grounding called Hybrid Grounding, which combines low- and high-resistance grounding; this is discussed more fully in Section III of this paper. The hybrid grounding method adaptively switches to lower current high resistance grounding (less than 10A) when a stator ground fault is detected. The application of hybrid grounding should be strongly considered when upgrading generator protection within petroleum and chemical faculties that currently have low resistance-grounded generators.
II. PROTECTION UPGRADE AREAS ON OLDER GENERATORS

A. Improved sensitivity and reduction of damage — in protection areas where older relaying does not provide the level of detection required. Examples of protection in this area are:
1. Stator grounding, ground differential protection and hybrid grounding
2. Field ground fault protection
3. Negative sequence (unbalanced current) protection
4. Sensitive overexcitation protection

B. New or additional protection — areas which twenty years ago were not perceived to be a problem, but operating experiences have since proved otherwise. These areas are:
1. Inadvertent generator energizing
2. Sequential tripping
3. Oscillographic monitoring

C. Special protection application considerations — that are unique to new generator practices such as Gas turbine LCI (Load Commutating Inverter) starting

III. IMPROVED SENSITIVITY AND REDUCED DAMAGE

A. Stator Grounding, Ground Differential Protection (87GD) and Hybrid Grounding

When a generator stator ground fault is detected by protective relays, the generator is shut down by tripping the generator breaker, field breaker, and turbine. The system contribution to the fault will immediately be removed when the generator breaker trips as illustrated in Fig. 1. The generator stator ground current, however, will continue to flow after the tripping. The generator short circuit current cannot be "turned off" instantaneously because of the stored energy in the rotating machine. The flow of damaging generator fault current will continue for several seconds after the generator has been tripped. This long decay time results in the vast majority of the damage occurring after tripping as outlined in [3].

Reducing the decay time is very difficult; however, reducing the fault current during the generator "coast-down" can be easily done. As machines get older, the possibility of stator ground faults increases. Reducing the damage, therefore, becomes a major objective. Recent high repair costs and long outages of industrial generators due to stator ground faults have caused engineers to ponder the problem of reducing ground fault damage during generator coast-down. The most promising solution is called Hybrid Generator Grounding.

In most petroleum and chemical plant applications, generators are directly connected to a bus that services the local load. Fig. 2 illustrates this type of configuration. Hybrid grounding can typically be applied to these types of generators.

In Fig. 2, the generator is both high impedance- and low impedance-grounded. Under normal operating conditions, both generator ground sources are operated in parallel. For ground faults on the industrial system, the ground fault contribution from the generator will typically flow almost entirely through the low impedance (200-400 A) source. This provides the required level of system ground current for proper industrial plant ground relay operation, allowing the generator to supply the load when the utility system is unavailable (breaker A and B open). When there is a ground fault in the generator stator windings or associated bus connection to the generator breaker, the ground differential (87GD) will operate to initiate a unit shutdown. As part of the generator tripping, the ground interruption device in series with the low-impedance path is also tripped, which typically reduces ground current to less than a 10A level. This greatly reduces stator ground fault damage during the generator "coast-down." This is a relatively new idea, but a number of generators have been converted to hybrid ground. One of the first applications was at a pulp and paper mill [5]. To properly apply hybrid grounding, both fault protection as well as surge protection needs to be addressed.
Many industrial generators rely solely on the phase differential (87G) to provide stator ground fault protection despite the fact that ground differential (87GD) has long been recommended in industry standards. Phase differential protection does not provide the level of sensitivity to detect faults over the entire stator winding. For example, a 45 MVA, 13.8 kV generator with 400A grounding, 2000/5 CTs and typical 87G relay pickup of 0.2 secondary amps can only respond to faults in 80% of the stator winding. Ground faults in the 20% of the winding at the neutral of the generator will not be detected. More sensitive detection of stator ground faults can be substantially increased through the addition of an 87GD ground differential relay, which uses a product approach, utilizing the following equation. The relay-operating characteristic is:

\[ I_{OPP} = (-3I_o)I_N \cos \Theta \]

Where:
- \( -3I_o \) = residual current from the bus side CT's
- \( I_N \) = generator neutral current
- \( \Theta \) = phase angle between the currents

The scheme is illustrated in Fig. 3. The use of digital technology allows the scheme to be applied using the normal complement of generator CT's, without the need for auxiliary CT's. This technology also offers many advantages in commissioning this scheme. This scheme provides excellent security against mis-operation for external, high-magnitude faults, even for cases where the phase CT saturates.

Surge protection at the wye point (generator neutral) is almost always recommended as shown in Fig. 4. The neutral switching device will generate a switching transient upon opening (due to current chopping) and compromise the insulation integrity at the generator neutral wye point. This is especially a concern with aging generators.
Both magnitude (arrester) and dv/dt (surge capacitor or resistive-capacitive snubber) protection are typically required. For older installations, with existing air-magnetic or oil neutral breakers (with minimal chop characteristics), a simple arrester may be sufficient. Conversion of the existing generator terminal surge capacitors to RC snubber is also recommended. A non-inductive medium voltage series resistor sized to match cable surge impedance serves this purpose. Conversion of the existing surge capacitors to snubbers was deemed very desirable as there can be unacceptable transient voltage interactions from switching of the neutral device through the stator inductance to the shunt surge capacitors under arcing ground fault conditions.

B. Field Ground Fault Detection (64F)

The field circuit of a generator is an ungrounded (typically 600 V) dc system, as shown in Fig. 5. A single field 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 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. These unbalanced fluxes produce unbalanced magnetic forces, which result in machine vibration. A field ground fault 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 users trip while others prefer to alarm, thereby risking a second ground fault and major damage before the first ground is cleared. The protection schemes described in this section of the paper address generators with brushes and cannot be applied to brushless machines where the access to the rotor windings is not available.
Clearly, a more secure field ground relay is desirable 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 multifunction digital relays. As illustrated in Fig. 6, a 15 V square wave signal is injected into the field through a coupling network. The return signal waveform is modified due to 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 a 5 kΩ critical alarm or trip.

The injection scheme provides a major improvement over traditional voltage schemes in both sensitivity as well as security. In addition, digital relays can provide real-time monitoring of field insulation resistance so deterioration with time can be monitored. The scheme can also detect grounds on an off-line generator, allowing the operator to determine if the field circuitry is free of a ground before start-up. An added benefit of the injection scheme is that it operates at a low voltage (15 V) compared to the scheme it typically replaces (120 V), thus improving operator safety when changing brushes with the unit on-line.

C. Negative Sequence (Unbalanced Current) Protection (46)

There are a number of system conditions that can cause unbalanced three-phase currents in a generator. These system conditions produce negative sequence components of current that induce a double-frequency (120 Hz) current on the surface of the rotor. The skin effect of the double frequency rotor current causes it to be forced into the rotor surface, causing excessive rotor temperatures in a very short time.

The general flow of this current in a cylindrical machine rotor is shown in Fig. 7. The current flows across the metal-to-metal contact of the retaining rings to the rotor forging wedges. Because of the skin effect, only a very small portion of this high-frequency current flows in the field windings. Excessive negative sequence heating beyond rotor thermal limits results in failure. These limits are established in IEEE Standard C50.13 [7] and are shown in Table I for cylindrical rotor generators.

D. Sensitive Overexcitation V/Hz Protection (24)

Overexcitation, or V/Hz, relaying is used to protect generators from excessive magnetic flux density levels. High flux density levels result from an overexcitation of the generator. At high flux levels, the magnetic iron paths designed to carry the normal flux saturate, and flux begins to flow in leakage paths not designed to carry it. These resulting fields are proportional to voltage and inversely proportional to frequency. Hence, high flux density levels (and overexcitation) will result from overvoltage, underfrequency, or a combination of both.

Although generator manufacturers have recommended overexcitation protection for many years, it is not installed on many industrial generators that rely solely on overvoltage protection. ANSI/IEEE Standards C50.13 [7] has established 105% (generator base voltage) V/Hz limits for continuous operation. For values above this level, generators have short-time operating limits.

Damage due to excessive V/Hz operation most frequently occurs when the unit is off-line, prior to synchronization. The potential for overexcitation of the generator dramatically increases if the operators manually prepare the unit for synchronization. This is particularly true if the overexcitation alarms are inadequate, or if the VT has an open circuit due to an improper connection. Modern digital relays provide improved protection using both definite-time as well as
inverse-time characteristics to closely match the short-time overexcitation characteristics of a generator. In addition, it is also important to have modern V/Hz protection with low-frequency response to provide protection during gas turbine LCI (Load Commutating Inverter) starting as described more fully in Section V of this paper.

**IV. NEW OR ADDITIONAL PROTECTION AREAS**

**A. Inadvertent Generator Energizing (27/50)**

Inadvertent or accidental energizing of synchronous generators has been a particular problem within the industry in recent years. A number of machines have been damaged, or, in some cases, completely destroyed when they were accidentally energized while off-line. The frequency of these occurrences has prompted generator manufacturers to recommend that the problem be addressed through dedicated protective relay schemes. Operating errors, breaker contact flashovers, control circuit malfunctions, or a combination of these causes, have resulted in generators becoming accidentally energized while off-line. In industrial applications, the major cause of inadvertent energization of generators has been by closing the generator breaker through the mechanical close/trip control at the breaker itself, thereby defeating the electrical interlocks.

Due to the severe limitation of conventional generator relaying to detect inadvertent energizing, dedicated protection schemes have been developed and installed. Unlike conventional protection schemes, which provide protection when equipment is in service, these schemes provide protection when equipment is out of service. One method widely used to detect inadvertent energizing is the voltage-supervised overcurrent scheme shown in Fig. 8. An undervoltage element with adjustable pickup and dropout time delays supervises an instantaneous overcurrent relay. The undervoltage detectors automatically arm the overcurrent tripping when the generator is taken off-line. The undervoltage detector will disable or disarm the overcurrent relay when the machine is returned to service. Great care should be taken when implementing this protection, so that the dc tripping power and relay input quantities to the scheme are not removed when the generator is off-line.

![Fig. 8a Relay Inputs](image1)

![Fig. 8b Relay Logic Diagram](image2)

![Fig. 8 Inadvertent Energizing Schemes](image3)

When an off-line generator is energized while on turning gear or coasting to a stop, it behaves as an induction motor and can be damaged within a few seconds. During three-phase energization at a standstill, a rotating flux at synchronous frequency is induced in the generator rotor. The resulting rotor current is forced into paths in the rotor body, similar to those rotor current paths for negative-sequence stator currents during generator single-phasing. Rapid rotor heating, and damage to the rotor will occur. The machine impedance during this high-slip interval is equivalent to the generator negative-sequence reactance. Fig. 9 shows a simplified equivalent circuit that can be used to calculate the current and voltage associated with three-phase inadvertent energizing.
where

\[ \begin{align*}
X_{1S} & \quad \text{System Positive Sequence Reactance} \\
X_{2G} & \quad \text{Generator Negative Sequence Reactance} \\
E_S & \quad \text{System Voltage} \\
E_G & \quad \text{Generator Terminal Voltage} \\
I & \quad \text{Current}
\end{align*} \]

Fig. 9  Inadvertent Energizing Equivalent Circuit

**B. Sequential Tripping**

This method of shutting down a generator is used on steam generators to prevent overspeed when delayed tripping has no detrimental effect on the generating unit. This shutdown method of generator tripping was recommended by manufacturers of steam turbine generators many years ago as a result of overspeed generator failures. The first devices tripped are the turbine valves. A reverse power relay in series with the valves’ close position switches provides security against possible overspeed of the turbine by ensuring that steam flows have been reduced—below the amount necessary to produce an overspeeding condition—before the generator breaker is tripped. For boiler or turbine mechanical problems, this is the preferred tripping mode since it prevents the overspeed of the machine. Fig. 10 shows the block diagram for sequential tripping.

**C. Oscillographic Monitoring**

The monitoring of generators with oscillographs is very rare at industrial installations because it is thought that monitoring could not be economically justified with "stand-alone" oscillographs. However, with the advent of digital protective relays for generators, oscillograph and target information can be quickly accessed from a remote location, after a generator tripping event, to determine if relay and circuit breaker operations were proper. Oscillographic information can assist in identifying the cause of a tripping incident. This valuable information gives the plant engineer the necessary data to keep machines off-line for testing and inspection, when necessary, after an electrical tripping incident or to return the unit to service with minimum delay.

**V. SPECIAL PROTECTION APPLICATION CONSIDERATIONS**

**A. Gas Turbine LCI (Load Commutating Inverter) Starting [8]**

Most modern gas turbines today are started using an LCI starter rather than being started with a diesel. This starting process requires special protection and grounding considerations. There are effects on generator VTs as well as the grounding transformer typically used to provide grounding of unit-connected generators. Static starting of a combustion gas turbine (CGT) is accomplished by using a Load Commutated Inverter (LCI), adjustable speed drive (ASD) system, to motor the synchronous machine and coupled turbine. The basic LCI static starting system consists of an isolation transformer, generally a 6-pulse drive and controls, and isolation switches. Excitation to the field is automatically controlled to limit stator voltage to prescribed levels to maintain constant volts per hertz during the process in order to be synchronous with LCI frequency.

Fig. 11 shows a plot of the static starting process of speed versus time for an example CGT. The process begins by operating the LCI to accelerate the machine from turning gear to purge speed. It typically takes 4.5 minutes to reach the purge speed of 0.3 per unit. Purging the compressor takes approximately 6 minutes. Next, the LCI is turned off and the machine is allowed to coast down for about three minutes to about 0.14 per unit speed in preparation for firing the turbine. The LCI is operated during ignition, which takes about two minutes. Finally, the LCI accelerates the machine to full speed bringing the unit up to 0.9 per unit speed.
Grounding the neutral of a generator through a transformer with a secondary resistor is common practice in North America. The neutral resistance typically limits ground fault current to 3-25A. If this equipment is left in the circuit during static starting, a ground fault on the DC link of the static starter will cause DC current to flow in the primary of the grounding transformer with resultant quick saturation. Fig. 13 illustrates the flow of DC current. On saturation, the DC current through the neutral is primarily limited by the transformer primary resistance. The transformer's thermal capability will be exceeded if the fault is not removed. The grounding transformer is less vulnerable than grounded wye VTs connected on the generator terminals, which have less capability to withstand DC. DC faults can be removed quickly and are detected by measuring primary DC current in the generator neutral.

B. Ungrounded Method

Generator static starting with the machine ungrounded is conducted by design by one manufacturer to eliminate the possible problems caused by a DC-link fault. The design switches the high-resistance neutral grounding scheme out of the circuit during starting, and uses open-delta voltage transformers for instrumentation. The rationale for this method is that an LCI DC-link reactor ground would saturate the neutral grounding transformer, wye-wye grounded VTs, and to a lesser degree, the generator. The ungrounded generator and open-delta VTs will not provide a path to ground for DC current to flow. Fig. 14 illustrates typical protection.
C. Resistance Grounding with Neutral Resistor

Grounding the neutral directly through a resistor is a common practice outside of North America. Again, the object is to limit ground fault current to less than 3-25 A. DC faults are detected by measuring primary DC current in the neutral. Fig. 15 illustrates typical protection.

A limited number of protection functions are required during LCI starting such as overexcitation and overcurrent. Overexcitation derives its operating signal from the voltage magnitude and frequency. Similarly, overcurrent uses the magnitude of the current. Some digital relays employ time domain rms calculations to produce the operating signals for these functions at low frequencies. These calculations are not affected by a change in system frequency. Other relays adapt their phasor estimation algorithms to retain accuracy. Both approaches are generally employed to produce accurate phasor estimation. One approach is to adjust the sampling rate of the relay in order to maintain a constant number of samples per cycle (frequency tracking).

VI. CONCLUSIONS

There are a number of functional protection areas on generators twenty years or older at petroleum and chemical plants which have significant shortcomings when compared to current IEEE recommended generator protection practices. This paper identifies these protection areas and the risks of not addressing the shortcomings. It also points out a new area of special protection and grounding needed for application such as LCI gas turbine starting.
VII. REFERENCES


VIII VITA

Charles (Chuck) Mozina (M’65, SM10, F11) received a B.S. degree in electrical engineering from Purdue University, West Lafayette, in 1965. He is a Consultant, Protection and Protection Systems for Beckwith Electric Co. Inc., specializing in power plant and generator protection. His consulting practice involves projects relating to protective relaying applications, protection system design and coordination. Mozina is an active 25-year member of the IEEE Power System Relaying Committee and was the past chairman of the Rotating Machinery Subcommittee. He is active in the IEEE IAS I&CPS, PCIC and PPIC Committees, which address industrial protection systems He has over 25 years of experience as a protective engineer at Centerior Energy, a major utility in Ohio, where he was Manager of System Protection. For 10 years, Mozina was employed by Beckwith Electric. He is a registered Professional Engineer in Ohio and a Life Fellow of the IEEE.