Lessons Learned From Generator Event Reports

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Abstract—**Generators are critical components of the power system. In addition to being some of the most expensive pieces of equipment on the system, they are also extremely critical to power system stability. A false trip can lead to extensive testing in search of a nonexistent fault, while a delayed trip can result in unnecessary additional damage to equipment. Both misoperations result in excessive equipment outages, increasing the utility's outage costs and placing additional strain on the system. Therefore, the misoperation of protective relay schemes at generating stations is very expensive and must be avoided.**

This paper analyzes real-world event report data in the interest of uncovering valuable lessons for setting and commissioning generator relays. The paper reviews the application of phase differential relays for protection of the generator stator windings against phase faults and the application of third-harmonic voltage elements for 100 percent stator ground protection. Additionally, the effects of negative-sequence currents and overexcitation on a generator are discussed, as well as the importance of detecting and removing both conditions. With event report data, the paper teaches important lessons to be used in applying each function to protect generators. The paper discusses application limitations and considerations for each case.

I. INTRODUCTION

On September 4, 1882, Thomas A. Edison started the first generator to energize the first public electric grid. This consisted of three 150 kW generators connected directly to the grid to supply 120 Vdc to customers. The protection applied in the Pearl Street generating station consisted of fuses, breakers, and meters [1].

Within a few years, utilities switched from direct current to alternating current, allowing for the transformation of voltages. This change made it possible to transmit power over greater distances without significant losses, leading to the development of the electric grid as we know it today.

Very early on, a "general interrupter" served as an emergency cutout, isolating the generator from the system [1]. The result was that the entire grid was without power until the generator could be restarted and connected to the grid. Therefore, the importance of generators to the successful operation of the grid was very apparent even in the beginning.

As the system evolved, it became evident that redundancy was a critical ingredient in developing a reliable power system. Transmission lines were built with more than enough capacity to supply the load for years to come, and enough generators were built to ensure that there would not be a power shortage. Because of the importance of the grid and its successful operation to developing industries, the design tools available, and the economic conditions at the time, generous margins were used in the planning and design of the system.

On the generation side of the utilities, the idea of spinning reserve was developed to provide a backup source of power in case a generator failed and needed to be disconnected from the system.

Because of the margins that were included in the design of the system, combined with the amount of spinning reserve available, the system was very stable and capable of withstanding significant disturbances in most locations without widespread blackouts.

Despite this fact, the importance of generators to the system was realized early on in the life of the power system. Elaborate protection systems were developed to avoid damage to these valuable assets. In most cases, keeping in line with the redundancy built into the system, the protection systems applied at generating stations included primary and backup relaying.

Over the years, some of the margin that was originally designed into the electric power system was lost. This occurred for several different reasons, including opposition to the construction of new transmission lines and generating stations, greater precision in design methods, and, of course, economics.

The result is a system with a much smaller gap between demand and capacity. With smaller percentages of system capacity available as spinning reserve and transmission lines operating at or near their rating during normal operation, the system today is less stable and less able to withstand significant disturbances.

Therefore, as the system is pushed closer to its limits, it is becoming more important than ever to apply protection systems that operate correctly every time.

II. EFFECTS OF A MISOPERATION

Protection systems are designed to protect a given piece of equipment on the power system without compromising the integrity of the system. This includes correctly detecting abnormal system conditions that could damage equipment, in addition to actually detecting a fault in the protected device.

Several characteristics are desirable when designing a protection system. These include reliability, sensitivity, speed, and selectivity. In order to achieve one characteristic, another will likely need to be sacrificed. This type of tradeoff is common to engineering.

Reliability consists of two aspects: security and dependability. For the protection to be secure, it must only isolate the equipment when necessary. To be dependable is to trip every time a trip is required.

Sensitivity is the ability to detect a fault early in its development, thus minimizing the damage to the protected equipment and the effect on the connected system.

Speed is necessary to minimize damage but is also becoming more critical in maintaining system stability during fault conditions.

The final characteristic, selectivity, is required to minimize the outage resulting from a fault on the system. It is desirable that only the affected equipment be isolated from the system to minimize the number of customers affected by an outage.

To summarize the goal of a protection system, it should detect every fault and hazardous operating condition and isolate only the affected equipment quickly without operating under any other circumstances. A failure to do so is referred to as a misoperation of the protection system.

Misoperations can be classified into one of two main categories: a failure to trip when a trip is required and a trip when a trip is not required.

In the case of generator protection, both misoperations can have a significant negative impact on the connected system. As discussed previously, today's electric power grid is operated close to capacity.

The immediate effect of losing a generator depends on its size and location, which determine how critical it is to the system. An unplanned trip of a large unit puts significant stress on the system and can potentially lead to cascading blackout conditions [2].

Although a generator relay misoperation may cause a power system disturbance, it is important to note that a misoperation may also be the result of a power system disturbance. In this case, the misoperation contributes to the disturbance, as was seen in the Western Systems Coordinating Council (WSCC) disturbance on August 10, 1996 [3].

In addition to the immediate stress on the system caused by a generator trip, the event has additional impact on the system. In the case of a false trip, there may be significant downtime associated with the operation while crews search for an apparent fault. One such case is the misoperation of the stator ground protection.

The utility can incur significant losses during this period with personnel or hired contractors looking for a nonexistent fault. However, the greatest cost in this case is the purchase of replacement power, which varies with a number of different factors, including fuel type, location, and the time of year. Related to the time of year is the demand on the system at the time of the fault. During peak load periods, the cost can reach $2 per kWh and accumulate very quickly over the length of the outage [4].

Although significant and undesirable, the cost of unnecessary tripping is secondary compared to the cost of failing to trip when required. Whether this results in a fault evolving or an abnormal operating condition creating a fault, unnecessary damage to a generator must be avoided. Failing to detect a fault causes additional damage to the machine. Exposing a unit to operating conditions outside of the design rating of the machine for an extended period of time can lead to a fault in the windings or worse, damage to the core. In either case, failure to adequately protect a generator leads to longer outage times and greater repair costs.

In an attempt to reduce the number of avoidable outages, this paper covers different generator protection functions in detail. The purpose is to increase awareness of how the elements function and potential issues that have been encountered as well as discuss solutions. Real-world event report data pertaining to each element are discussed as well.

III. DIFFERENTIAL PROTECTION

A. Phase Differential Protection

Phase differential protection is typically applied to generators rated 1,000 kVA and above. For machines above 5,000 kVA, it is always applied [5][6]. It provides selective and fast tripping for phase faults (three phase, phase to phase, and double phase to ground). This protection may also provide partial coverage for single-phase-to-ground faults when available ground current exceeds the minimum operating current setting of the phase differential relay.

Phase faults rarely occur on the windings of the machines, but if they do, they occur on the winding overhang where the phases cross over (end-winding region) [6][7]. These faults generate high-magnitude currents. Machines can contribute with up to $1/X''d$ (generator direct-axis subtransient reactance) pu of their nominal current. Damage to the windings and core lamination, mechanical stresses applied to the winding supports, shaft, couplings, bearings, and foundations, and power system disturbances are all examples of the damage caused by phase faults. Fast and selective tripping is required to minimize equipment damage and shorten disturbances to the power system.

The concept of generator differential protection is fairly simple. The protected zone is determined by the location of the CTs (current transformers). It requires two sets of CTs with their secondary windings connected in parallel with the differential relay. One set of CTs is located at the neutral end of the stator winding, and the other is at the phase terminals of the winding, as shown in Fig. 1.
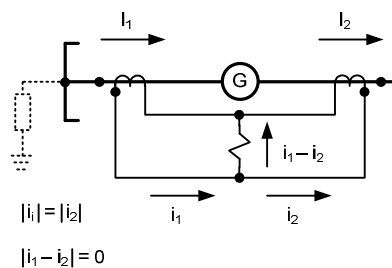

Fig. 1. Instantaneous Polarity of Primary and Secondary Currents

In this example, the primary polarity of the individual CTs is facing away from the generator.

Fig. 1 shows the instantaneous polarity of primary and secondary currents during normal operation or external fault conditions. Primary current flows through the neutral set of CTs, generator windings, and the set of CTs located at the terminals of the machine. Secondary current flows out of the

polarity of the neutral end CTs and into the polarity of the terminal CTs.

Consider that both sets of CTs have the same ratio and present no ratio or angle errors under load or fault conditions (ideal CTs). Based on Kirchoff's current law, which states that the sum of the currents entering a point must be zero, there is no circulation of current through the differential relay coil for load or external fault conditions.

Fig. 2 shows the current flow for a fault internal to the protected zone. Generator fault current flows through the neutral set of CTs and into the fault point. Power system current flows through the phase terminal set of CTs and into the fault point. Secondary currents flow out of the polarity of both sets of CTs. As a result, there is current circulation through the differential relay, causing its operation.
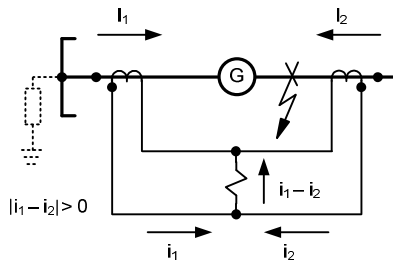

Fig. 2.   Current Flow for a Fault Internal to the Protected Zone

There are three types of generator phase differential schemes: percentage differential, high-impedance differential, and self-balancing differential. These schemes cannot detect turn-to-turn faults; therefore, a split-phase differential scheme can be used to provide backup to the overall differential protection and provide turn-to-turn protection.

1) Percentage Differential Scheme

If ideal CTs were available, a simple, instantaneous overcurrent relay could be applied to respond very sensitively and quickly to the differential current resulting from an internal fault. Unfortunately, ideal CTs do not exist, and during heavy faults external to the protected zone, differential current circulates through the overcurrent relay. The use of an instantaneous relay would either require a high pickup setting or an additional time-delay unit, resulting in less sensitive and slower operation. As a compromised solution, some generator differential scheme designs apply very inverse characteristic time-overcurrent relays with the pickup set around 10 percent of nominal generator current.

Percentage differential relays offer security for external faults without compromising sensitivity, yet resulting in fast operation. Fig. 3 shows the connections for a percentage differential relay.
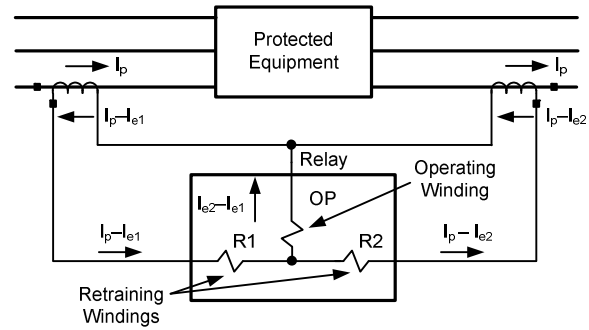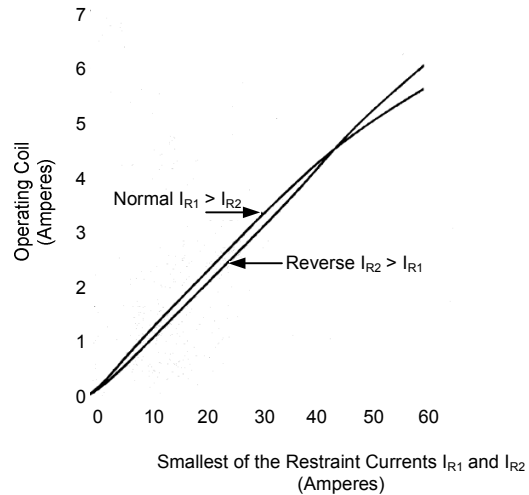

Fig. 3.   Connections for a Percentage Differential Relay

The relay produces a restraint quantity proportional to the currents circulating through restraint coils R1 and R2. The operating quantity is proportional to the current circulating through the OP coil. The restraint quantity desensitizes the relay as the through current increases during external faults. Fig. 4, Fig. 5, and Fig. 6 illustrate the characteristic of a few types of percentage differential relays. One shared characteristic is the fact that as the restraint quantity increases, more operating quantity is required for the relay to trip, resulting in secure operation.

Fig. 4.   Electromechanical Relay With Fixed Slope Characteristic [8]

Percent Slope Characteristic of High I (Restraint)
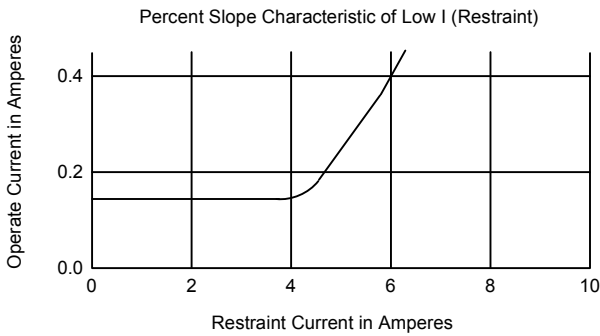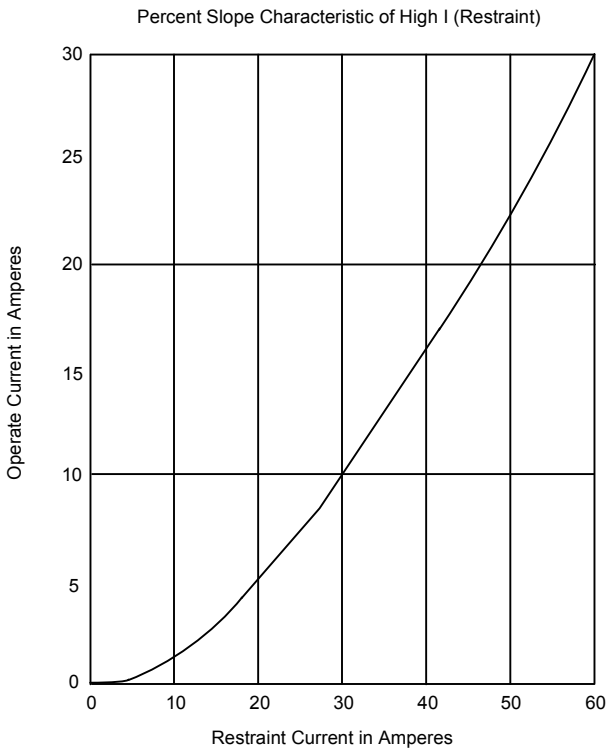
Fig. 5.   Electromechanical Relay With Variable Slope Characteristic

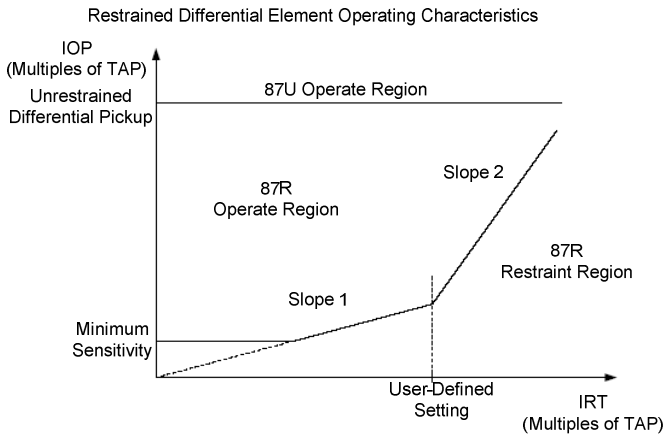Restrained Differential Element Operating Characteristics

Fig. 6.   Digital Relay With Variable Slope Characteristic

2) High-Impedance Differential Scheme

Fig. 7 illustrates the connections for a high-impedance differential scheme. The connections are similar to the low-impedance differential scheme illustrated in Fig. 3. Relay R is a high-impedance voltage relay, 86 is a normally open contact of a lockout relay, and V is a varistor. During normal operation, both sets of CTs reproduce the primary currents very accurately, and no voltage is developed across Relay R. During a heavy external fault, there is unequal performance of the CTs, and voltage is developed across Relay R. The relay should not trip under this condition.
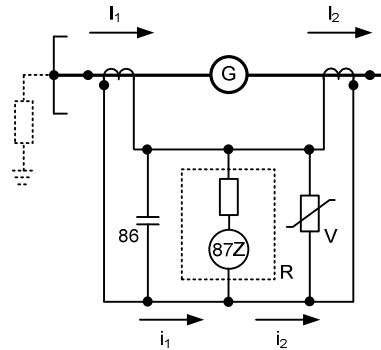

Fig. 7.   High-Impedance Differential Scheme

The pickup setting for the high-impedance relay is calculated based on the worst-case scenario of unequal performance of the paralleled CTs. It is assumed that one CT accurately reproduces the primary current while the other CT completely saturates. Differential current appears but cannot circulate through the high-impedance coil of Relay R. The saturated CT offers the lowest-impedance path for the circulation of differential current. Under complete saturation, the impedance of a CT can be approximated to the resistance of the secondary winding. The differential relay coil is submitted to a voltage that is proportional to the differential current, the resistance of the wires connecting the saturated CT, and the resistance of the secondary winding of the CT under saturation. The pickup setting is equal to the calculated voltage multiplied by a safety factor.

The function of varistor V is to limit the voltage across the differential relay.

The 86 normally open contact closes after the lockout relay trips. The contact creates a short across the differential relay and carries all of the differential current. Unlike other electrical apparatus, generators maintain a certain level of fault current until they come to a complete stop; therefore, it is very important to include the 86 normally open contact in the design.

3) Self-Balancing Differential Scheme

Fig. 8 illustrates a self-balancing differential scheme. It is typically applied to small-sized machines and offers very secure, sensitive, and economical differential protection.
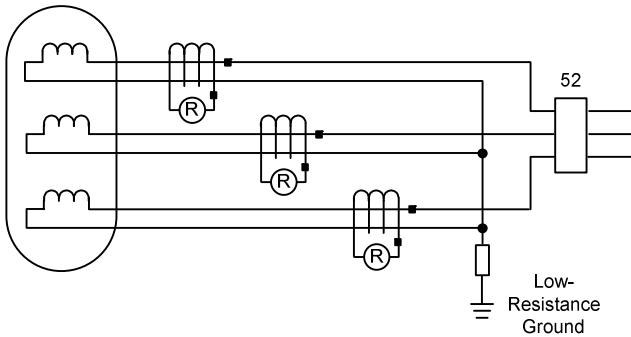

Fig. 8.   Self-Balancing Differential Scheme [9]

Each phase winding is protected by a single window-type CT (BYZ type) and an overcurrent relay. The cables connected to the neutral terminals and phase terminals are routed through a window CT. An overcurrent relay is connected to the secondary of the CT.

During normal operation and through-fault conditions, the direction of currents flowing through the cables is contrary to each other; therefore, there is no current circulation through the secondary winding of the CT. The criteria for choosing the CT are no longer based on performance during load or through-fault conditions, allowing CT ratios as low as 50:5 to be selected. With such a low CT ratio and the possibility of high-magnitude fault current circulation through the CT, it is important to maintain the burden connected to the CT secondary to a minimum. It is not uncommon to find 50:5 CTs with an IEEE accuracy rating of C10 through C20. The short-time rating capability of the relay coil should also be verified at the maximum fault current conditions.

Very sensitive relay settings can be obtained. The pickup threshold for the overcurrent relay may be set between 2 to 5 percent of rated machine current [7].

W.A. Elmore suggests using 50:5 BYZ CTs along with an instantaneous overcurrent relay setting of 0.25 A (2.5 A primary) for self-balancing differential schemes applied to motors above 1,500 horsepower [10].

Zocholl suggests using 50:5 CTs along with a definite-time overcurrent relay setting of 0.5 A with a time delay of 1 to 2 cycles for self-balancing differential schemes applied to motors [11].

B. Split-Phase Differential Scheme

A split-phase differential scheme, also known as a transverse differential scheme, is applied to generators with multiturn coils and two or more parallel circuits per phase. It provides turn-to-turn fault protection and phase fault protection.

Each phase of the synchronous generator stator winding is formed of one or more single-phase parallel circuits. Each circuit is the result of the series association of several coils.

According to the number of turns, coils can be classified as single turn or multiturn. Single-turn coils are usually found in turbogenerators and in large, modern hydrogenerators. Multiturn coils are found in some hydrogenerators but rarely found in turbogenerators.

Fig. 9 shows a complete phase winding for a hydrogenerator with six paralleled, single-phase windings. Notice that the single-phase windings are formed in two groups that are paralleled, with only two leads being brought out to external connections.
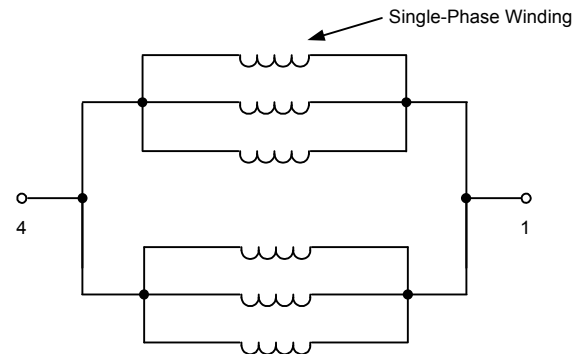

Fig. 9.   Complete Phase Winding for a Hydrogenerator

In theory, under normal operating conditions, the total current circulating through the phase winding is evenly split between the upper and lower groups of single-phase windings. In practice, the difference in current between the two groups of coils ranges from 0.5 to 2.0 percent of the machine-rated current [6][12]. External faults can cause a momentary increase of the current unbalance between the groups of coils. The magnitude, duration, and harmonic content of the unbalance are functions of the stator winding connections (adjacent pole or alternate pole), design of the rotor amortisseur windings, and prefault load conditions [13].

Split-phase differential relay schemes respond to the difference in current between the two groups of coils. This difference in current can be caused by turn-to-turn faults, phase faults, or by an open circuit within the single phase windings.

There are quite a few CT and relay arrangements that can be used for split-phase differential protection. Fig. 10 illustrates the application of bushing-type CTs connected in antiparallel and a 50:51 overcurrent relay. The pickup setting for the 50 (instantaneous) element is set high enough to be secure against differential currents that circulate through the relay coil during external faults. The increase in differential current during external faults can be the result of unequal performance of the CTs in addition to the expected surge in standing differential current because of an external fault. The high-set 50 element provides little turn-to-turn protection but provides some level of backup protection for the phase differential relays. Pickup of the 51 (very inverse-time overcurrent) is set above the maximum standing differential current under load conditions. The time dial setting is high enough to allow the surge in differential current to subside following an external fault.
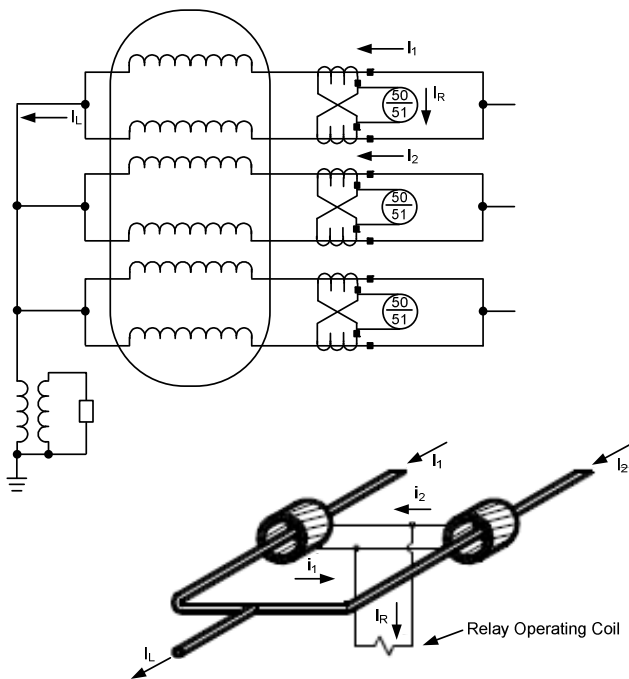

Fig. 10.   Split-Phase Differential Scheme Using Separate CTs [9]

Another method of providing split-phase differential protection is to apply a single window-type CT and an overcurrent relay. The two conductors, each one carrying half of the machine phase current, penetrate the CT from opposite directions. This scheme works as a self-balancing differential scheme. There is minimum current circulating through the CT secondary during normal operation. This arrangement is usually found on small machines due to mechanical and electrical limitations when routing the winding leads through the window CT. The setting criteria for the very inverse-time overcurrent and instantaneous overcurrent elements are the same as for the previous scheme. The only difference is that unequal performance of the CTs during external faults is no longer a concern when determining instantaneous element pickup settings. Fig. 11 illustrates this scheme.
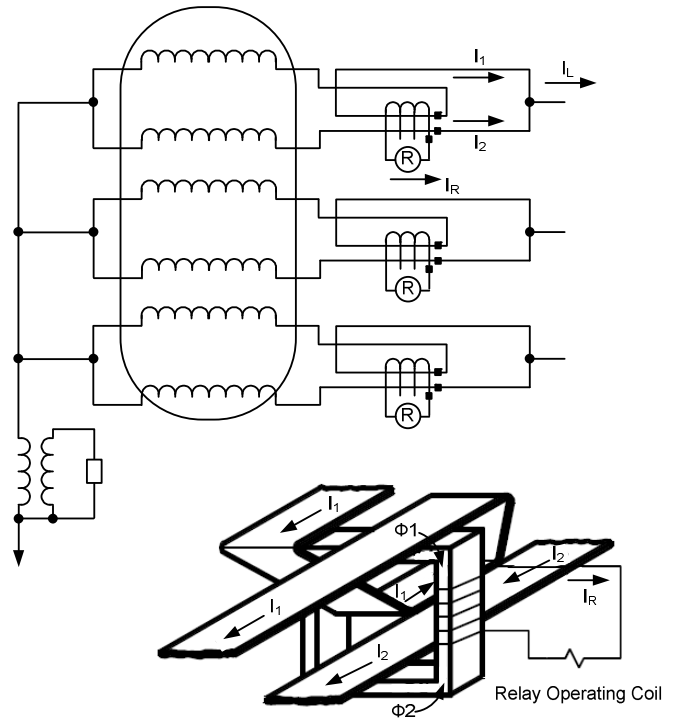

Fig. 11.   Split-Phase Differential Scheme Using Single Window-Type CT [9]

When the single window-type CT arrangement is not possible, a dual window-type CT can be applied, as shown in Fig. 12. The settings criteria and benefits are the same as for the single window-type CT arrangement.
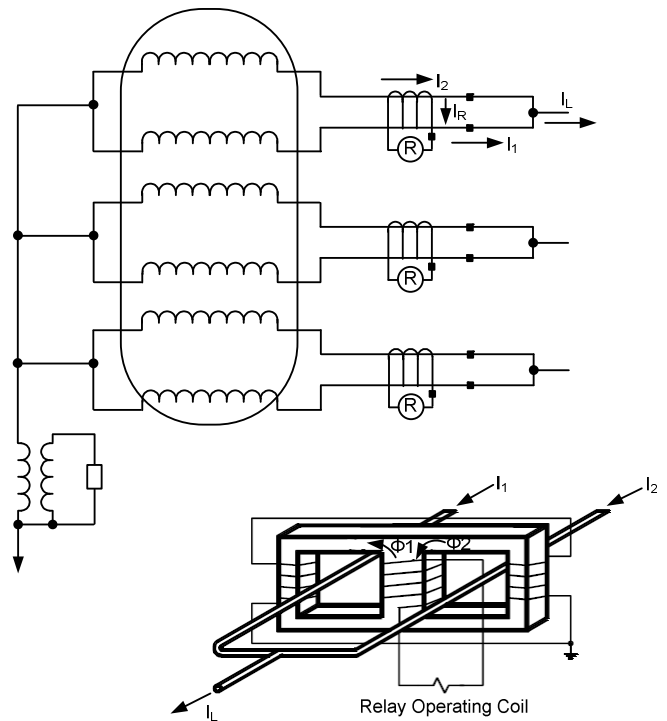

Fig. 12.   Split-Phase Differential Scheme Using Dual Window-Type CT [9]

Finally, percentage differential relays may also be applied for split-phase differential protection. Fig. 13 illustrates the CTs and relay connections for this arrangement.
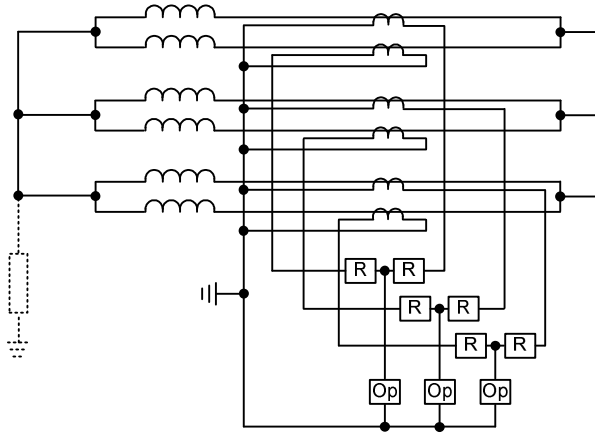

Fig. 13. Split-Phase Differential Protection Using Percentage Differential Relays

Sensitivity and security for turn-to-turn fault protection are obtained using very inverse-type overcurrent relays. In order to justify the application of split-phase relaying, the relay must be sensitive enough to detect a single turn-to-turn fault and be secure during surges in split-phase differential current caused by faults external to the generator. Security can also be obtained using percentage differential relays. On the other hand, the restraint characteristic of a percentage differential relay makes it too insensitive to turn-to-turn faults as load increases [12].

C. Event Reports

1) Event 1: CT Connection

A synchronous generator protected by a multifunction generator relay tripped on phase differential for a fault within the protected zone. The system single-line diagram is shown in Fig. 14.
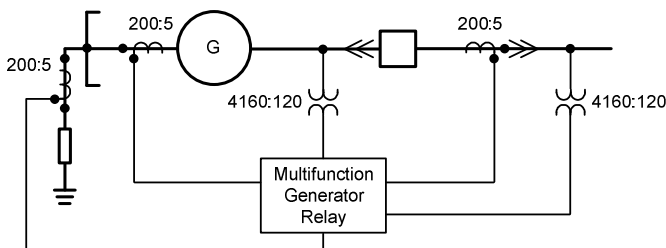

Fig. 14. Event 1 Single-Line Diagram

The analysis of the event report shown in Fig. 15 reveals that the current contribution from the system was interrupted 3.625 cycles after the trip command from the relay. The current contribution from the generator, as expected, continues through the length of the event report.

The waveforms for the currents IA, IB, and IC show no signs of CT saturation but clearly show that the A/D (analog-to-digital) converter saturated. According to the multifunction

relay specifications, the current inputs can carry 15 A continuously and are linear up to 100 A symmetrical. The event report indicates that the saturation of the A/D converter occurred at 159 A.

The instantaneous phase overcurrent element (50P1) picked up 0.375 cycles after fault inception, while the unrestrained (87U) and restrained (87R) differential elements picked up 1.375 cycles after fault inception.
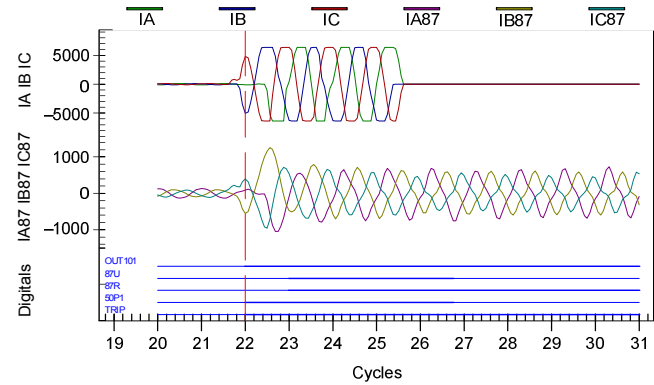

Fig. 15. Raw Event Report

A quick review of the multifunction relay instruction manual reveals that the IA87, IB87, and IC87 current inputs should be connected to the CTs located at the terminals of the machine. Current inputs IA, IB, and IC should be connected to the CTs located at the neutral end of the machine. Based on this information, we would expect that fault current would continue to flow through the inputs IA, IB, and IC after operation of the generator breaker. The event report shows the opposite. The fault current continues to flow through the inputs IA87, IB87, and IC87, revealing the incorrect connection of the CTs to the relay inputs.

The multifunction relay uses currents IA, IB, and IC for metering and most of the protection elements, so the proper phase relationship between voltages and currents must be correct. The phasor diagram in Fig. 16 shows currents IA, IB, and IC and voltages VAB, VBC, and VCA just before the fault inception. The phasors indicate the correct relationship and that the machine was operating close to unity power factor before the fault. For this particular installation and relay settings, there were no major implications of the incorrect connections, but it was suggested to the customer to correct the CT connections.
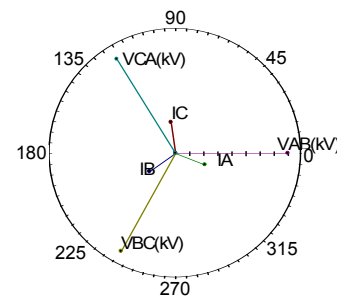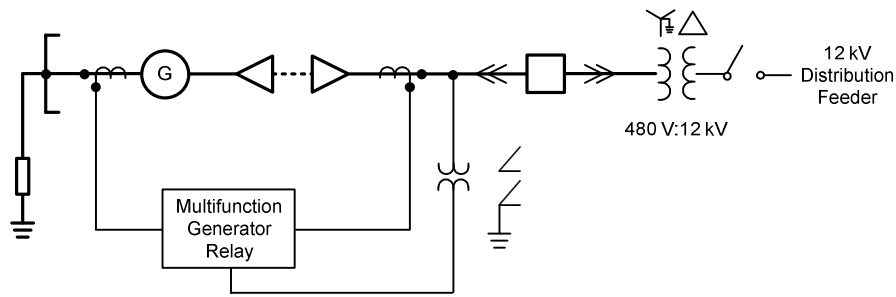

Fig. 16. Prefault Phasor Diagram

Fig. 17. Event 2 Single-Line Diagram

2) Event 2: Generator Black Start

A synchronous generator protected by a multifunction generator relay tripped on phase differential after picking up the step-up transformer. The system single-line diagram is shown in Fig. 17.

The generator shown in Fig. 17 is rated for 1.262 kVA and is applied as a backup source for a rural feeder in a remote location. In the event of a utility power loss, the 480 V generator provides power to the feeder through the 480 V/12.0 kV step-up transformer.

During a black-start condition, the transformer must be energized from the low-voltage side. This procedure was attempted several times during commissioning, resulting in multiple differential element trips of the multifunctional generator relay.

Prior to the black-start tests, the generator had already carried load, and the differential element had been checked for stability. Both sets of CTs connected to the multifunction relay are from the same manufacturer and were field tested to prove the similarity of their saturation curves.

Fig. 18 shows one of the differential event reports captured during a black-start test.
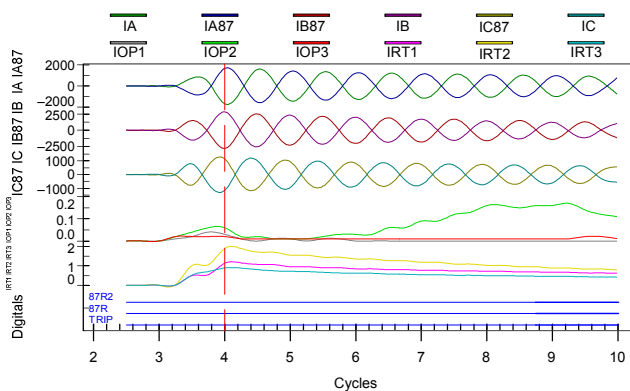

Fig. 18. Filtered Differential Event Report During a Black-Start Test

The event report shows that the 87R2 element tripped 5.75 cycles after transformer energization. It also shows the operating current (IOP2) starts to increase around Cycle 5.5 of the event report, reaching its peak at Cycle 9.5.

A similar incident of generator differential instability was reported by Hindle [5]. Detailed analysis of CT performance revealed asymmetric CT saturation, resulting in an increase in differential current with a decrease of restraint current. Reference [10] mentions the possibility of generator differential misoperation during black start due to CT saturation caused by the direct current (DC) offset found in the transformer inrush current.

Fig. 19 shows the raw waveform of the currents IA, IB, and IC seen by the generator relay during the Event 2 black-start test. The currents are characteristic of transformer inrush.
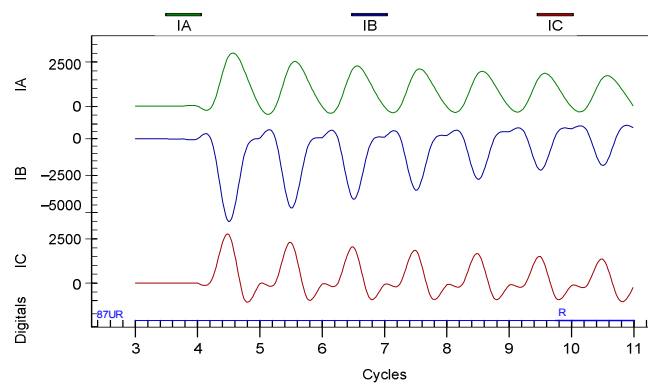
Fig. 19. Raw Waveform for Currents

Security of the generator differential relay is a must during black-start conditions and therefore has to be addressed. The original relay settings show the minimum operating current of the differential relay was set at 0.1 pu, and the single slope was set to 10 percent. The customer decided to maintain the minimum operating current of the differential relay and increase the single-slope characteristic to 45 percent. No more differential trips during black start were reported after the relay settings modification.

However, if it is not desirable to decrease sensitivity of the differential element under normal operation, another option exists in modern microprocessor-based relays. Most of these relays contain more than one settings group, and the active group is determined by logic. Therefore, in order to maintain the desired sensitivity during normal operation, a separate settings group with higher security settings can be enabled only for a black start.

IV. STATOR GROUND

Fig. 20 illustrates a unit-connected generator grounded through the primary winding of a distribution transformer. The secondary winding of the distribution transformer is loaded with a resistor. The impedance of the resistor when reflected to the primary of the transformer constitutes a high-impedance path for ground fault current, which is why this grounding method is classified as high impedance. This arrangement is typically found on unit-connected generators, but it is not uncommon to find multiple high-impedance-grounded generators connected to a common bus.

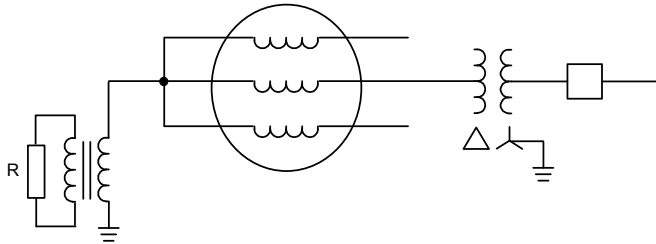Fig. 20.   Unit-Connected Generator—High-Impedance Grounding

An effective way of providing ground fault protection to the generator, bus, and delta winding of the step-up transformer is to install an overvoltage relay connected to the secondary winding of the grounding transformer. When a single-phase-to-ground fault occurs, the primary winding of the grounding transformer is submitted to a voltage equal to the phase-to-ground voltage at the location of the fault. The overvoltage relay detects an increase in voltage above its pickup threshold and initiates a definite or inverse time-delayed trip. If the fault location is close to the neutral end of the generator windings, the voltage applied to the overvoltage relay may be below its pickup threshold and remain undetected. The ultimate limitation factors of this scheme are the minimum sensitivity of the overvoltage relay and the fact that a fault at the neutral point of the machine cannot be detected.

A. Third-Harmonic Stator Ground Protection

Another protective relaying scheme, in addition to the fundamental overvoltage relay, is required to detect faults in 100 percent of the generator stator windings. A couple of techniques are currently applied: low-frequency voltage injection and third harmonic, voltage based. This paper discusses a few aspects of the third-harmonic, voltage-based techniques.

The induced voltage on any conductor of the generator armature winding is proportional to the flux in the air gap. If the air gap flux contains both fundamental and harmonic components, then the induced voltage in a conductor will also have fundamental and harmonic components. Some of the factors that affect the amount of third harmonic produced by a generator are its electromechanical design and loading conditions.

The design of the armature windings of the generator is one of the many ways to alter the amount of harmonics available at the terminals of the generator. Fig. 21 shows a generator winding schematic for a two-pole generator with 36 stator slots, full pitch, and double-layer lap winding. The "fundamental poles" represent the actual poles of the machine and are responsible for the fundamental component of the flux in the air gap. The "third-harmonic poles" represent the third-harmonic component of the air gap flux. Fig. 22 shows the winding schematic for the same generator with the exception that the pitch is 2/3.
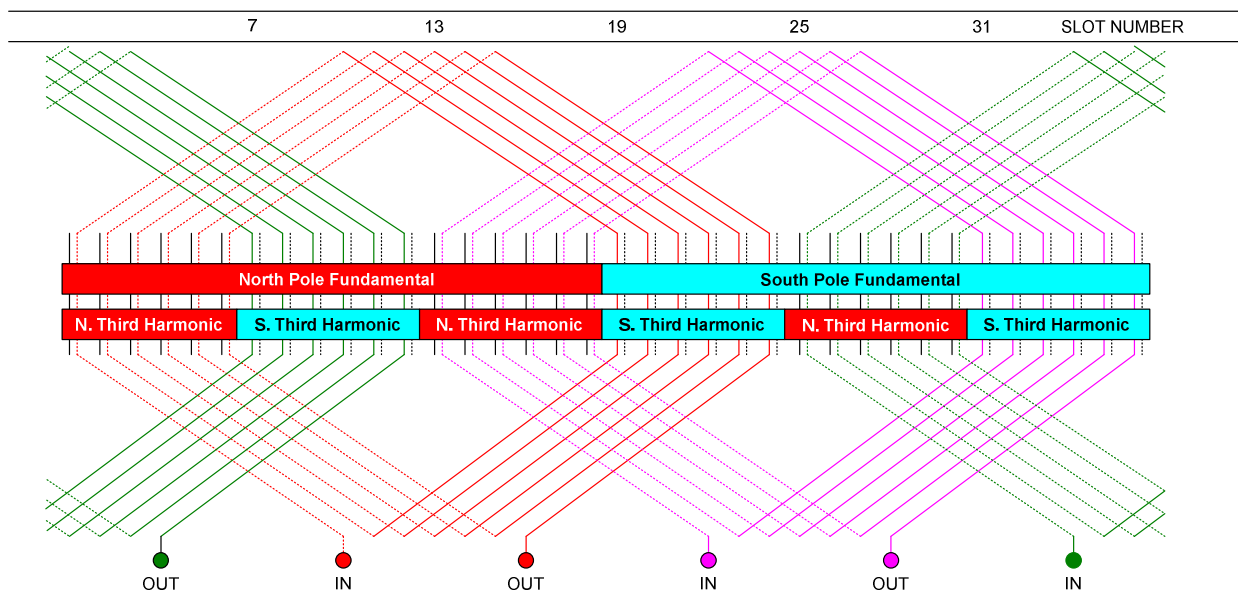

Fig. 21.   Partial Winding Schematic for a Two-Pole, 36 Slot, Double-Layer, Full Pitch, Lap Winding Generator
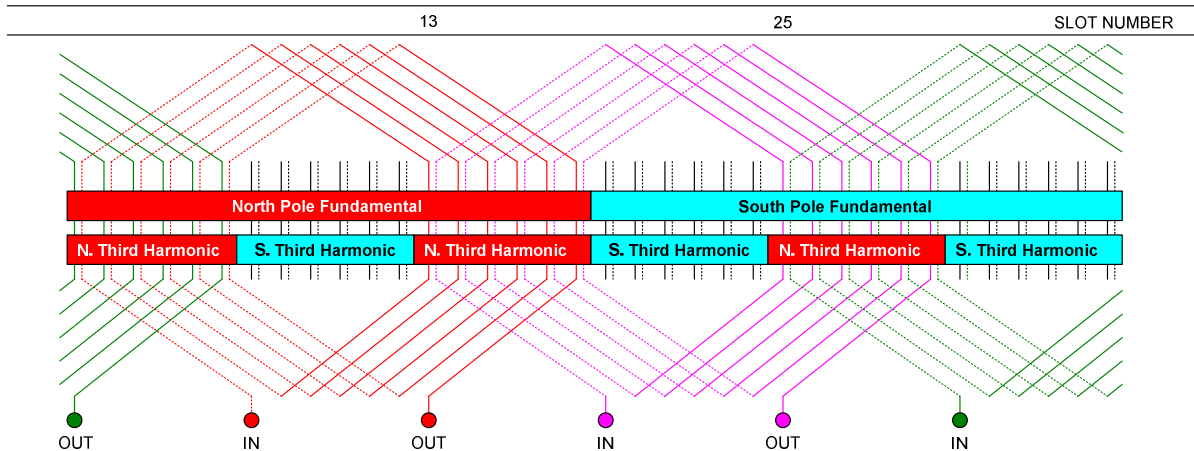
Fig. 22. Partial Winding Schematic for a Two-Pole, 36 Slot, Double-Layer, 2/3 Pitch, Lap Winding Generator

For analysis of Fig. 21, we will concentrate on the conductors located at Slot 1 (Conductor 1) and at Slot 19 (Conductor 19). Because of the physical spacing of the winding conductors around the stator with respect to the rotor poles, the induced fundamental voltage on Conductor 1 is 180 electrical degrees shifted from the induced fundamental voltage on Conductor 19. The induced third-harmonic voltage on Conductor 1 is 180 electrical degrees shifted from the induced third-harmonic voltage on Conductor 19. Therefore, the voltage across the terminals of the red group of coils (6 coils) contains both fundamental and third-harmonic components.

For analysis of Fig. 22, we will concentrate on the conductors located at Slot 1 (Conductor 1) and at Slot 13 (Conductor 13). The induced fundamental voltage on Conductor 1 is 120 electrical degrees shifted from the induced fundamental voltage on Conductor 13. The induced third-harmonic voltage on Conductor 1 is in phase with the induced third-harmonic voltage on Conductor 13. Therefore, the voltage across the terminals of the red group of coils (6 coils) contains fundamental and no third-harmonic components. The fundamental component is 86.6 percent of the one produced with a full pitch winding.

Apart from the aspects of the electromechanical design, loading conditions are also responsible for affecting the production of third harmonics in generators. There are several registered cases that indicate third-harmonic voltage can vary enough under different load conditions that the security of third-harmonic, voltage-based elements is compromised [14][15]. Therefore, these elements must be blocked to avoid misoperation under certain load conditions.

Third-harmonic, voltage-based techniques require the measurement of the third-harmonic component available at the terminals of the machine and at the neutral grounding transformer. Because third-harmonic voltage behaves like zero-sequence voltage, the use of open-delta-connected potential transformers (PTs) eliminates the possibility of using the phase-terminal component.

Fig. 23 shows the profile of the third-harmonic voltages under different generator loading conditions. VN3 is the third-harmonic voltage measured at the neutral grounding transformer. VP3 is the summation of the third-harmonic content at the phase terminals of the machine.

In the case of a fault at the neutral of the generator, the third-harmonic component of the voltage at the grounding transformer will collapse, and the third-harmonic component of the voltage at the terminals will rise.
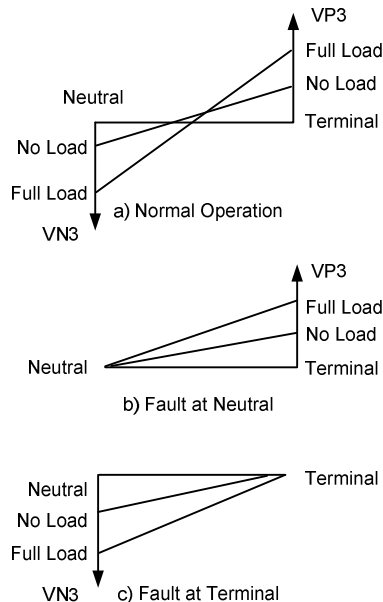

Fig. 23. Third-Harmonic Voltage Profile Under No-Load and Full-Load Conditions

There are three basic techniques of third-harmonic, voltage-based schemes: third-harmonic differential, third-harmonic neutral undervoltage, or third-harmonic terminal residual overvoltage. They all respond to the variances in third-harmonic voltage during fault conditions.

B. Event 3: 2/3 Pitch Generator

A unit-connected generator is protected for 100 percent stator ground fault protection by a combination of fundamental neutral overvoltage and third-harmonic neutral undervoltage. The single-line diagram is shown in Fig. 24.
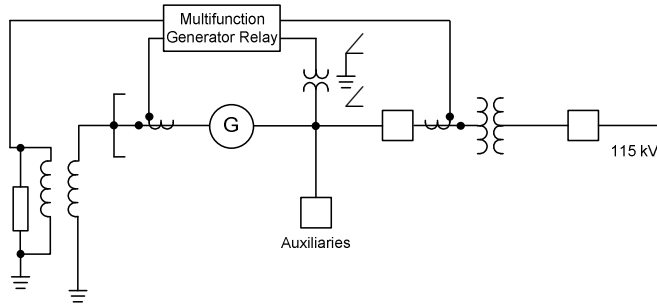

Fig. 24.   Event 3 Single-Line Diagram

During the commissioning tests, it was verified that the values for the neutral third-harmonic were very low, as seen in Table I.

TABLE I
THIRD-HARMONIC NEUTRAL VOLTAGE MEASUREMENTS
UNDER DIFFERENT LOAD CONDITIONS

Terminal Voltage (Percent)	Generator Load		MVAR Load	VN3 (Volts Secondary)
	Percent	MW		
100	0	0	0.10	0.04
95	0	0	−19.1	0.25
105	0	0	10.1	0.05
100	25%	5.5	0.40	0.30
95	25%	5.5	−20.1	0.10
105	25%	5.5	10.5	0.05
100	50%	11.2	0.30	0.20
95	50%	11.4	−16.3	0.33
105	50%	11.0	8.0	0.13
100	100%	23.1	0.2	0.36
95	100%	22.5	−14.4	0.45
105	100%	23.0	10.3	0.31

The typical setting value for the neutral third-harmonic undervoltage element is 50 percent of the lowest measured value during commissioning. In this particular case, the lowest measured value was 0.04 V, which occurred under a full-speed, no-load condition. The required setting is around 20 mV, which is below the minimum relay setting of 0.1 V secondary. The relay was finally set with only the fundamental neutral overvoltage protection, which did not provide 100 percent stator ground fault protection.

Fig. 25 shows a portion of the generator stator winding diagram. The machine has 18 poles and 216 slots. It is lap wound and uses form-wound coils. An analysis of the winding diagram reveals that the generator is wound with a 2/3 coil

pitch, which eliminates the third-harmonic component of voltage from the machine.

The full pitch can be calculated by dividing the number of slots (216) by the number of poles (18), resulting in 12 slots. The actual pitch of the winding is determined by first identifying the pair of slots occupied by a coil and then calculating the number of slots between the two sides of the coil. In this case, one coil is occupying Slot 120 and Slot 128. Therefore, the two sides of the coil are 8 slots apart. This indicates the actual pitch (8 slots) is 2/3 of the full pitch (12 slots).
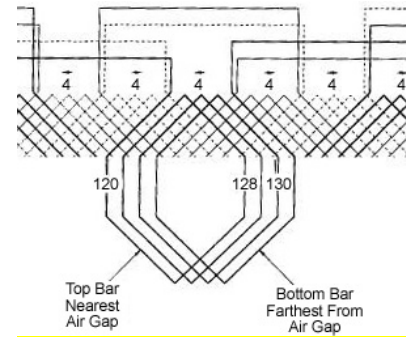
Fig. 25.   Stator Winding Diagram—Partial

Before applying any third-harmonic, voltage-based protection scheme, it is important to learn the pitch of the winding from the generator manufacturer. In the case of a 2/3 pitch winding, the generator will not produce enough third-harmonic to be used for the protection. Other pitches, different from 2/3, also do not guarantee the machine will produce enough third harmonic to be used by protective relays.

V. NEGATIVE SEQUENCE

A. Unbalanced Load Capability

Three-phase synchronous generators are designed to operate under balanced loading conditions. Unbalanced loading conditions can be caused by untransposed transmission lines, unbalanced power system faults, open circuits, or unbalanced single-phase loads. Unbalance is also caused by the operation of the generator with bypassed stator coils or during single-phase inadvertent energization of the machine.

Under balanced conditions, the positive-sequence current circulating through the generator windings produces a magnetic flux in the air gap that rotates at synchronous speed. During normal operation of the generator, both the rotor and magnetic flux generated by positive-sequence current rotate in the same direction with the same speed.

When negative-sequence current circulates through the generator windings, it produces a magnetic flux in the air gap that also rotates at synchronous speed but in the opposite direction of the rotor. This flux induces voltages and currents in the rotor with twice the fundamental frequency. Because of the skin effect, the induced currents are concentrated on the surface of the rotor. In round rotor machines, they tend to circulate in the rotor body (poles and teeth), rotor wedges,

retaining rings, or in the amortisseur windings. In salient pole machines, the induced currents circulate on the surface of the pole and in the amortisseur windings. Accumulated heat from the circulation of these currents can lead to severe damage of the affected rotor components in a very short period of time.

Generators have continuous and short-time capabilities to withstand negative-sequence current circulation. Continuous capability is expressed as a percentage of rated stator current. The short-time capability (I_2^2t) is the integrated product of the square of the generator negative-sequence current (I_2) expressed in per unit of rated stator current and duration of the fault in seconds (t).

IEEE Standard C50-12, IEEE Standard C50-13, and NEMA MG-1 define these capabilities as shown in Table II through Table VI.

IEEE Standard C50-13 applies to cylindrical-rotor synchronous machines and defines the minimum continuous and short-time, negative-sequence current capability of these machines, as shown in Table II and Table III, respectively.

TABLE II
CONTINUOUS NEGATIVE-SEQUENCE CURRENT
CAPABILITY OF ROUND ROTOR MACHINES [16]

Generator Type	Permissible I_2 (%)
Indirectly cooled (rotor)	10
Directly cooled (rotor)	–
To 350 MVA	8
351 MVA to 1250 MVA	8 – (MVA – 350)/300
1251 MVA to 1600 MVA	5

TABLE III
SHORT-TIME, NEGATIVE-SEQUENCE CURRENT
CAPABILITY OF ROUND ROTOR MACHINES [16]

Generator Rotor Cooling Type	Minimum Generator Short-Time Capability Expressed in Terms of I_2^2t
Indirectly cooled	30
Directly cooled up to 800 MVA	10
800 MVA to 1600 MVA	10 – (0.00625)(MVA – 800)

IEEE has also published a standard outlining the design constraints for salient-pole machines. Similar to the IEEE Standard C50.13, IEEE C50.12 outlines the continuous and short-time, negative-sequence current capabilities of salient-pole machines, as shown in Tables IV and V, respectively.

TABLE IV
CONTINUOUS NEGATIVE-SEQUENCE CURRENT
CAPABILITY OF SALIENT-POLE MACHINES [17]

Generator or Generator/Motor Type	Permissible I_2 (%)
Nonconnected amortisseur winding	5
Connected amortisseur winding	10

TABLE V
SHORT-TIME, NEGATIVE-SEQUENCE CURRENT
CAPABILITY OF SALIENT-POLE MACHINES [17]

Generator or Generator/Motor Type	Minimum Generator Short-Time Capability in Terms of I_2^2t
Nonconnected amortisseur winding	40
Connected amortisseur winding	40

In addition to the IEEE standard, the National Electrical Manufacturers Association (NEMA) has also published its own standard on generators and motors, the NEMA MG 1-2003 Standard. This standard covers machines that are too small for IEEE C50.12 or IEEE C50.13 to apply. The continuous negative-sequence current as specified by NEMA is shown in Table VI. Note that this standard varies slightly from the corresponding IEEE standard.

TABLE VI
NEMA CONTINUOUS NEGATIVE-SEQUENCE
CURRENT CAPABILITY [18]

Generator Type	Permissible I_2 (%)
Salient pole	
a. Connected amortisseur winding	10
b. Nonconnected amortisseur winding	8
Air-cooled cylindrical rotor	10

B. Event 4: Unbalanced Load

A synchronous generator protected by a multifunction generator relay tripped by the negative-sequence element after picking up a 12 kV feeder load. The system single-line diagram is shown in Fig. 17.

The generator shown in Fig. 17 is rated for 1.262 MVA and is applied as a backup source for a rural feeder in a remote location. In the event of utility power loss, the 480 V generator provides power to the feeder through the 480 V/12.0 kV step-up transformer.

During commissioning tests, it was verified that the generator continuous negative-sequence capability was exceeded when the generator picked up the feeder load. Fig. 26 shows an event report triggered when the utility source to the feeder was removed and the generator had to carry most of the feeder load. At Cycle 0.0 of the event report, the generator is running in parallel with the feeder, and the negative-sequence seen by the multifunction generator relay is on the order of 20 A (primary)—the equivalent of 1.32 percent of the generator nominal current. At Cycle 2.4 of the event report, there is a sudden increase in negative-sequence current seen by the relay. This is caused by a separation of the utility source, leaving the generator carrying most of the feeder load. At Cycle 16 of the event report, the negative-sequence current seen by the relay is on the order of 220 A (primary)—the equivalent of 14.49 percent of the generator nominal current.
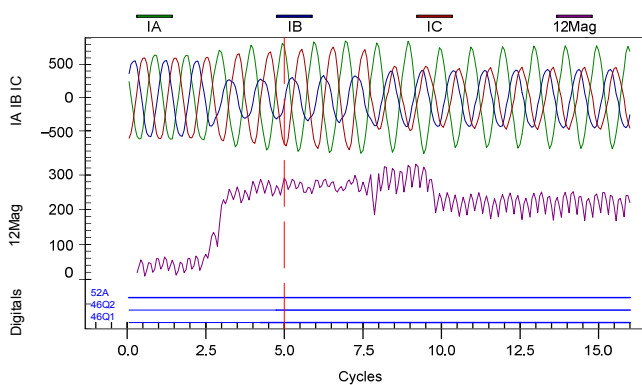

Fig. 26.   Event Report

The generator was built with salient poles with nonconnected amortisseur windings, and its design followed NEMA MG-1 specifications. Based on this information, the generator has a negative-sequence continuous capability rating of 8 percent. According to the event report, this limitation was exceeded by 80 percent or more, which would cause damage to the rotor of the generator, shortening its useful life.

The most economical solution to the problem is to redistribute the feeder load, decreasing the unbalance seen by the generator to a value below 5 percent of nominal load current. Another possible solution, but far from economical, is to size the generator based on the maximum feeder unbalanced current. A quick calculation reveals that if we want to keep the 220 A, negative-sequence current below 5 percent of the generator nominal current, we would require a generator rated at approximately 3.7 MVA.

VI. FREQUENCY

A. Off-Nominal Frequency Operation

Frequency deviations on the system occur when the balance between the load and generation is disturbed. In the case where a significant load or a tie line exporting power is tripped, generation exceeds the load. Therefore, the excess mechanical power being input into the generator is converted to kinetic energy. The rotor begins to spin at a higher rate, and the unit outputs power at an increased frequency.

The opposite effect can be seen if a generator or tie line importing power is tripped. In this case, the load exceeds generation, causing the rotor to spin slower and the system frequency to drop.

Overfrequency is normally not a concern on most units, because the increase in speed is accompanied by an increase in ventilation. Therefore, thermal overloading of the machine is not an issue. However, as the frequency increases, so does the terminal voltage. If the automatic voltage regulator (AVR) fails or is not in service, the voltage can increase to damaging levels. This is usually protected by an overvoltage relay instead of a frequency relay.

In general, most units will not have overfrequency elements set to trip. Instead, the recommendation is to only set an alarm [19].

One case where this does not hold true is for hydro units. Unlike the high-speed, round rotor units that are able to quickly cut off supply of the prime mover to the turbine, hydro machines take time to isolate the turbine from the water supply. This is due to the immense mass of water in the penstock, which if stopped too quickly would create sufficient pressure to damage the penstock.

During the time it takes to close the gates after a load rejection, the unit accelerates, reaching speeds of up to 150 percent overspeed. Under normal conditions, the governor takes action to return the unit to near nominal speed. However, if the governor fails, the unit can quickly reach speeds of 200 percent overspeed, leading to machine damage [20].

Hydro units are applied with overspeed protection to detect this case and isolate the unit before damage occurs. However, it is recommended that overfrequency protection be applied as a backup. This relay should be set to see a load rejection but time-delayed to allow for governor corrective action.

In addition, overfrequency elements can be set to trip the main breaker to isolate the unit from the system if the supplied load cannot tolerate the frequency deviation that occurs during a partial load rejection [9].

Round rotor machines, on the other hand, do not typically use overfrequency protection. Instead, they rely on governor or operator intervention to correct the situation.

However, underfrequency protection is normally applied to these units because the condition cannot be corrected locally by the generating station. An underfrequency condition leads to reduced rotational speed of the rotor and thus reduced ventilation of the machine. Therefore, the machine experiences greater heating for a given output than at rated speed. As a result, it is possible to exceed the short-time thermal capability of the machine.

The IEC standard for turbine generators, IEC 60034-3, published Fig. 27 to show the acceptable operating range of generators for frequency and voltage variations [21]. Fig. 27 is also published in the IEEE standards for both round rotor and salient pole machines, IEEE C50.13 and IEEE C50.12, respectively.
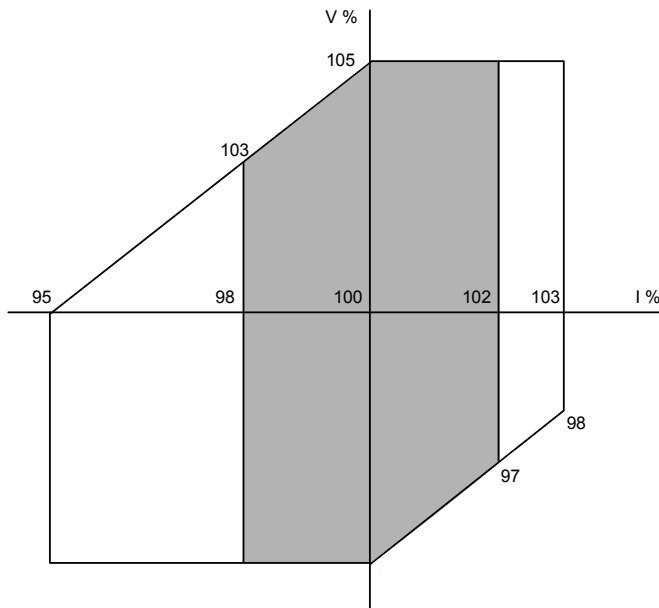

Fig. 27.   Operation Over Ranges of Voltage and Frequency [21]

The shaded region is rated for continuous operation with minimal insulation damage. Note that the insulation aging rate can be elevated two to six times from nominal with operation near the borders of the shaded region. The nonshaded region within the outer boundary indicates operating conditions that generators must endure with accepted insulation loss of life, provided the unit is not of ambient-following, round rotor construction [16][17].

Although this defines the underfrequency limit for a hydro machine, it is normally not the limiting factor for round rotor machines. High-speed turbines are designed for operation at nominal frequency and cannot tolerate significant deviation for prolonged periods.

Turbine blades have multiple natural vibration modes, including tangential, axial, and torsional. The blades are designed such that the natural frequencies of the blades do not correspond with the rated frequency of the machine or its harmonics. This limits the vibration at nominal speeds. Fig. 28 shows the natural frequency bands of a blade turbine design from one manufacturer.
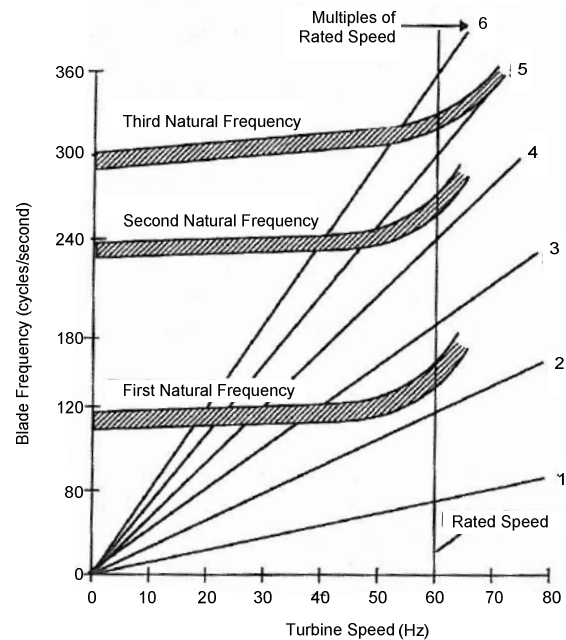

Fig. 28.   Turbine Blade Resonance [22]

Note that the width of the band is due to design specifications and tolerances. Operation to either side of a natural frequency band may still result in vibration, with severity increasing as the band is approached.

During an underfrequency event, the machine may approach or reach an operating point such that a natural frequency of the blade is excited. The resulting resonant condition produces 10 to 30 times the normal vibratory stress and can quickly damage the turbine blades [20]. Note that the long, low-pressure blades are the ones of concern, as the high-pressure blades are shorter and able to withstand this condition.

Operating the unit at one of these points will fatigue the blade, cause cracking of the tie wires or blade covers, and eventually lead to blade failure.

There are no standards that define the frequency withstand capability of turbines, and thus, capability curves are supplied by the manufacturer. These curves vary significantly between manufacturers and have anywhere from one to six frequency bands [19]. A total allowable time is provided for each frequency band. Note that this is a cumulative quantity for the life of the blade. It is important to obtain this information in order to properly set underfrequency protection for the generator.

The primary protection for an underfrequency condition is not applied to the generator. The connected system should have an underfrequency load-shedding scheme that trips specified feeders for set frequency deviations in order to reestablish the generation-load balance.

However, because of changing system configurations and oscillations in frequency during a system disturbance, undershedding may occur. In this case, it is essential to have backup protection applied at the generator.

Underfrequency protection may be provided as one of two schemes. The first uses zero reset relays that store the accumulated operating time in each frequency band. This is the desired method because the withstand time specification is given as an accumulated value. Fig. 29 shows an example abnormal frequency allowable withstand time and the corresponding accumulating timer scheme. This scheme is only available in microprocessor-based relays.
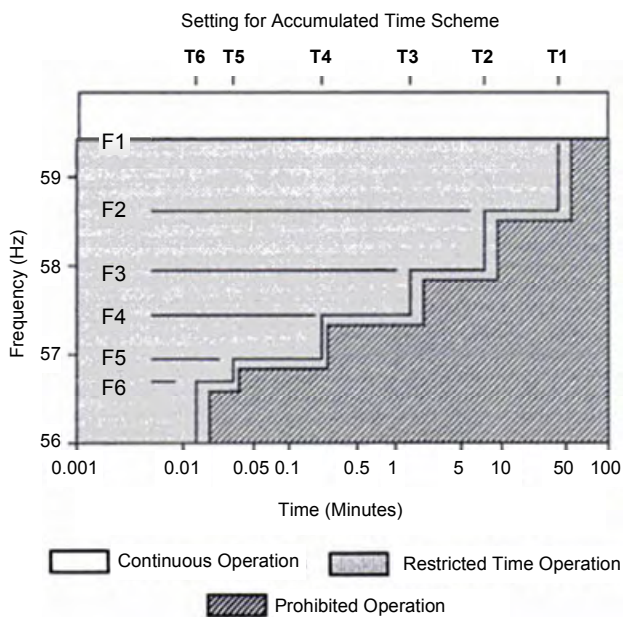

Fig. 29. Accumulating Timer Scheme [20]

The second scheme uses the instantaneous reset timers of only one or two elements. This is the more common scheme, but it does not adequately protect the turbine. It is typically set to coordinate with the system load-shedding scheme and thus sacrifices some protection. Using this scheme is not recommended, especially if underfrequency operation is probable [20].

Combustion gas turbines (CGTs) suffer from similar issues related to underfrequency operation. However, older designs were much more tolerant to underfrequency operation than steam turbines, and operation was typically allowed down to 57 Hz, which is the minimum stable operating frequency of the system [20].

The protection applied to these generators often consisted of one time-delayed element set below the lowest steam trip setting in the region.

However, because of reduced margin in modern designs, new CGTs are less tolerant to off-nominal frequency operation, often less than steam units [23].

All CGTs suffer from combustion instability and reduced turbine output at frequencies below nominal. A loss-of-air condition in the combustion turbine, known as a "compressor surge" can occur. This can alter the axial position of the rotor, cause vibration in the shaft and bearings and a loss of flame in the combustor, and overheat the turbine. If any of these conditions are detected, an instantaneous trip is issued [19].

Most CGT control circuits are equipped with a protection system to prevent this from happening by reducing the fuel fed to the machine during an underfrequency event.

B. Event 5: Load Rejection

Fig. 30 shows a report that was triggered when a definite-time overfrequency element asserted following a load rejection of an 86 MVA hydrogenerator. The load rejection was caused by the opening of the generator main breaker because of mechanical problems in one of the turbine auxiliary systems. The generator multifunction relay was programmed with two levels of definite-time underfrequency elements and one level of definite-time overfrequency. Following the load rejection, the speed of the generator increased and crossed the overfrequency element pickup setting 81D3P:= 63.00 Hz, which timed out after 81D3D:= 0.5-second time delay. The definite-time overfrequency element output 81D3T was masked to the relay trip equation (TRIP3), which in turn was masked to the relay output contact OUT103. This report illustrates an undesired operation of the relay. Because the generator was already disconnected from the power system (52A = 0), there was no need to trip on the definite-time overfrequency element.
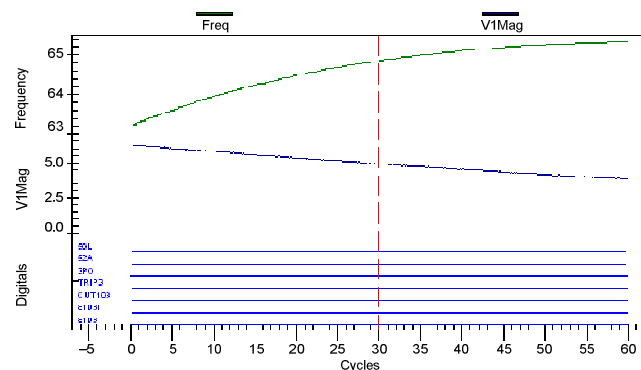

Fig. 30. Event Report Triggered Following Load Rejection

Hydrogenerators are well known for exceeding their nominal speed by a large margin following load rejections. It is important to coordinate the overfrequency protection with this mechanical characteristic of the machine. The multifunction relay has dedicated logic to detect the opening of all three poles of the generator breaker. In order to declare a three-pole-open (3PO) condition, the relay must see the 52A contact input dropped out and that the currents in all three phases are below the relay setting 50LP. See Fig. 31.
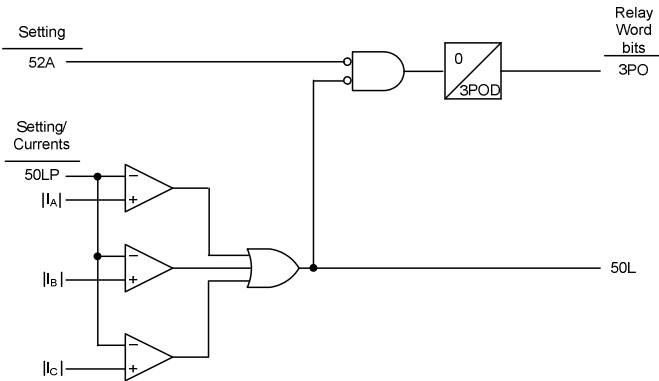

Fig. 31.   Three-Pole-Open Logic Detection

One possible solution is to allow the definite-time overfrequency element (81D3T) to only trip if the machine is connected to the power system. This can be easily achieved by qualifying the definite-time overfrequency element with the output of the 3PO logic. The original trip equation (TRIP3) for the relay is:

TRIP3 =…OR 81D3T

The modified trip equation qualifying the overfrequency element with the 3PO condition is:

TRIP3 =…OR (81D3T AND **NOT** 3PO)

The relay used in this example has six frequency elements available for use. Each element can be set either as an overfrequency or underfrequency element. In addition to modifying the TR3 logic as shown above, it may be desirable to set a second overfrequency element with a longer time delay that is only enabled during a load-rejection condition (3PO = 1). This element would function as a backup to the overspeed protection and thus must be coordinated with this mechanical protection element.

It is important when designing a scheme to know what elements are available for use in the relay. Most modern microprocessor-based relays have multiple elements available for each ANSI (American National Standards Institute) device code. In most applications, many of these elements are disabled. However, these available functions may provide the required protection at no additional cost and should be investigated.

VII. INADVERTENT ENERGIZATION

A. Effects and Detection

In addition to safe operating procedures, generating stations are designed with special precautions and interlocks to prevent an inadvertent energization of a generator. Despite this fact, accidentally energizing a generator is becoming more and more common. This is partially due to the increasing complexity of the switching stations to which generators are connected [24].

Inadvertent energization can be the result of operator error, breaker flashover, control circuit failure, or a combination of the above. The protection schemes applied to detect these conditions are typically divided into two separate functions: inadvertent energization protection and breaker flashover protection.

Inadvertent energization protection is intended to detect when the generator is energized from a standstill or while on the turning gear. This can be either three phase or single phase in nature, due to the closing of a breaker or disconnect switch.

Breaker flashover can involve one, two, or three phases and typically occurs either right before connecting or right after disconnecting from the system. During these cases, the voltages on either side of the breaker are near rated magnitude but slipping with respect to one another. When they are 180 degrees out of phase, the voltage across the open breaker contacts is 2 pu, corresponding to the maximum stress on the dielectric over the slip cycle.

Most breaker flashover protection is designed to detect the single- or dual-phase flashover condition. However, although a three-phase flashover is very unlikely, it is possible and should be considered when designing a protection scheme [25].

When a generator is energized from a standstill, the machine operates as an induction motor, drawing anywhere from 1 pu to 4 pu current for a three-phase energization, depending on the strength of the connected system. The voltage will also collapse between 20 percent and 70 percent of rated voltage [9].

Since the rotor is at a standstill when the unit is energized, the rotating magnetic field in the stator induces currents in the face of the rotor at rated frequency. As the generator accelerates, both the stator and induced rotor currents decrease, following a profile similar to that of an induction motor start.

Although the high currents cause heating in the stator, the induced currents in the rotor will damage the machine first. The induced currents follow the same path through the wedges, teeth, and retaining rings as those induced by negative-sequence current during unbalanced operation. However, the contact between the wedges and retaining rings is significantly decreased while the rotor is at rest, resulting in arcing and increased localized heating. Damage can result in seconds [20].

When energized through a single phase, the generator will not accelerate from a standstill. The positive- and negative-sequence current magnitudes are equivalent for this case. Since the phasors rotate in opposite directions, the torque on the rotor produced by one is cancelled by the other. However, both currents still induce currents of rated frequency on the rotor, leading to heating similar to the three-phase case [9].

Cases involving inadvertent energization through the auxiliary transformers have also been reported. However,

because of the high impedance of this path, the current is typically limited to 0.1 pu to 0.2 pu. Although less damaging to the machine, this condition should be detected, or unit auxiliary transformer failure could result.

Regardless of the source, an inadvertent energization condition can cause significant damage to the station equipment. In addition to the electrical damage discussed above, the unit can also experience mechanical damage to the bearings, shaft, couplings, and supporting structure [20].

There are typical elements used in generator protection that can detect an inadvertent energization condition, including loss of field, reverse power, negative sequence, and system backup relays. However, the lack of sensitivity and unacceptable time delays associated with these elements prevent their use for inadvertent energization protection. In addition, common practice is to disable generator protection by removing the PT fuses in the generator protection circuits and blocking other elements with 52a contacts to prevent tripping a breaker that has been returned to service after the disconnect switch is opened [9][20].

Therefore, because the relay elements dedicated to protect the machine during internal faults, abnormal operating conditions, and power system faults cannot be relied on to detect an inadvertent energization condition, dedicated protection is required. Common schemes include voltage or frequency supervised overcurrent or distance protection.

Set the overcurrent element pickup to 50 percent of the minimum expected energizing current. A voltage element should be set to 85 percent of rated voltage with an arming delay of 2 to 5 seconds and a dropout delay of 10 to 15 cycles. Once armed, the overcurrent element should instantaneously trip. Note that a loss-of-potential (LOP) relay should be used to prevent enabling for a blown PT fuse [20].

Similarly, an underfrequency element can be used in place of the undervoltage element for supervision. Set the element with a pickup between 48 and 55 Hz with no arming delay. This should be below the minimum expected frequency. However, maintain the same dropout delay mentioned above, and block the scheme with an LOP element [19].

A distance relay can be applied on the high-voltage side of the generator step-up (GSU) transformer, set to look into the generator with a reach equal to the transformer impedance plus the generator negative-sequence impedance and margin. This relay can be enabled during normal operation with a time delay to ensure security during stable system power swings. Use a breaker auxiliary contact to enable instantaneous tripping while the unit is offline [9].

Although any of the above schemes can be used to detect inadvertent energization from a standstill, they cannot be relied on to detect a breaker flashover condition. As mentioned, flashovers mainly occur while near rated speed and voltage.

Should a breaker flashover occur, the breaker failure scheme must be used to initiate tripping of all connected breakers. However, breaker failure schemes are typically initiated by a trip condition. As discussed above, most elements enabled while the unit is energized will not detect this condition. A negative-sequence element may operate for a single- or dual-phase flashover, but this element is slow and unreliable for detecting a flashover [25].

IEEE Standard C37.102-2006 recommends modifying the breaker failure initiate (BFI) condition to include a neutral overcurrent element from the transformer X0 bushing that is supervised by the generator breaker status. The logic of this scheme is shown in Fig. 32.
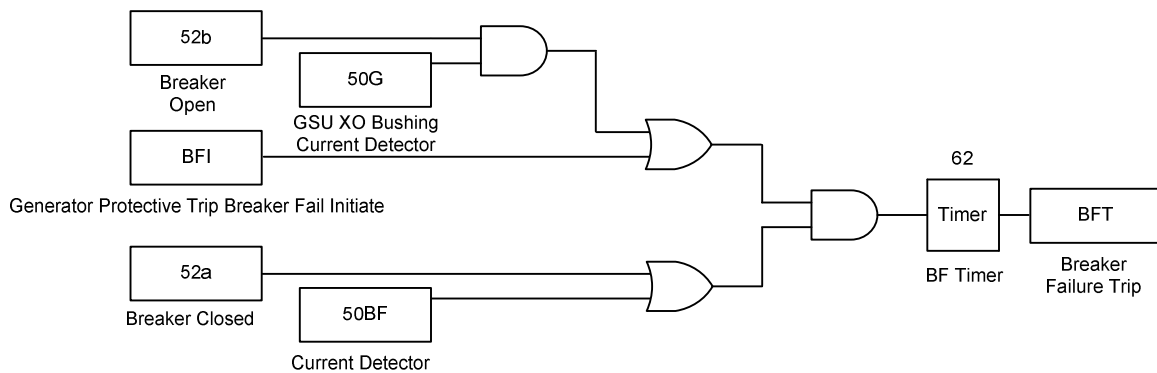

Fig. 32.   Breaker Failure Logic Scheme 1 [19]

Leon and Sandoval suggest verifying the 52a status with either current or a 52b auxiliary contact to improve the security of this scheme. They also propose the Scheme 2 shown in Fig. 33, which uses a close signal and 52a contacts from all three phases to improve security and dependability. In addition, these modifications allow the scheme to be applied to breakers with single-phase tripping capabilities [25].
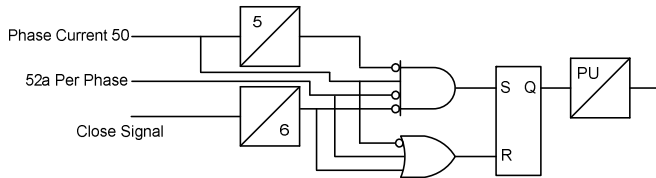

Fig. 33. Breaker Failure Logic Scheme 2 [25]

B. Event 6: Inadvertent Energization

An event occurred on a 13.8 kV, 100 MW machine after being isolated from the grid due to a mechanical alarm. The turbine and main breaker were opened to isolate the unit. The unit auxiliary transformer breaker was not tripped.

Approximately 3 minutes later, the main breaker was closed, energizing the high-side breaker to energize the auxiliary bus. However, the auxiliary transformer had not been isolated from the generator, allowing power to flow through the transformer and energize the unit. Fig. 34 shows the event report captured when the breaker was closed.
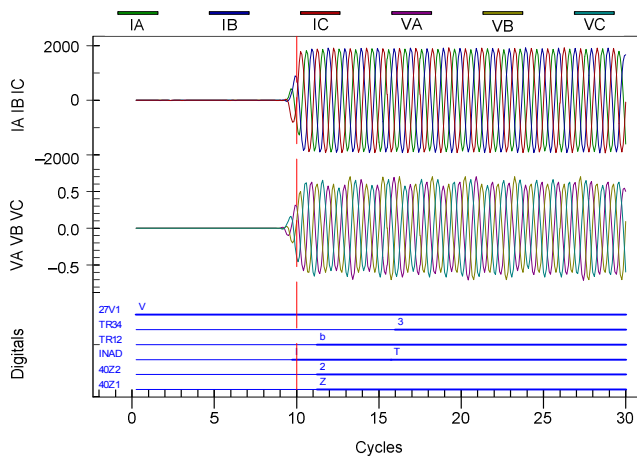

Fig. 34. Inadvertent Energization Event

Notice that the loss-of-field elements, 40Z1 and 40Z2, saw the energization as discussed above. Since 40Z1 is an instantaneous element, it issued the trip before the inadvertent energization (INAD) time delay expired.

Also notice that the currents did not disappear after the trip was issued. This is because the relay that captured the event was only installed on a trial basis, and therefore, the trip contact was not connected to a trip coil.

The other protection in place at the station was responsible for detecting the condition and isolating the unit. It took just over 3 seconds to trip the breaker.

During this time, the unit was exposed to approximately 1,900 A primary at 600 V. This equates to nearly 45 percent of the full-load A of the machine, but because of the reduced voltage, the unit saw only 1.4 MW and 3.14 MVAR flowing into the machine. As described above, the reduced current, voltage, and power magnitudes are a result of the high impedance of the auxiliary transformer. Damage can occur even at these reduced quantities if sufficient exposure is permitted.

In this case, 3 seconds was not enough to damage the machine. The event does, however, show the importance of inadvertent energization protection. If the unit had been energized through the main breaker, the resulting current and power flow would have been significantly larger, possibly resulting in damage before the unit was isolated.

It was recommended that the protective relay that captured this event be connected to initiate the trip coil, rather than simply set to monitor the system. Had the trip coil been initiated by the relay, it would have significantly limited the exposure of the unit to this inadvertent energization condition.

This event also illustrates the importance of designing safety measures into the system to prevent the occurrence of such an incident. It would be helpful to provide an interlock that prevents closing the high-side breaker while a path exists to energize the unit at a standstill.

VIII. OVEREXCITATION AND OVERVOLTAGE

A. Overexcitation

Overexcitation is a phenomenon that can occur in any magnetic device. It is typically referred to while talking about power transformers, GSU transformers in particular, and generators. However, it is this same phenomenon that is responsible for CT saturation.

The principle of operation is the same for both transformers and generators. Both are based on Faraday's law, which states that a changing magnetic field that cuts a conductor or coil induces a voltage in the conductor or coil. Transformers and generators use coils, and the voltage induced in the coils is given by the following equation.

$$E = -N \bullet \frac{d\Phi}{dt} \tag{1}$$

where:

N is the number of turns in the coil.

Φ is the flux.

E is the induced voltage.

The flux is created by either alternating current flowing through the primary winding of a transformer or the direct current in the field winding on the rotor of the generator. The magnitude of the flux is proportional to the product of the magnitude of this current and the number of turns in the coil.

The core of a generator stator or transformer is constructed of iron. A physical property of iron is the maximum flux density that can exist in it. When this flux density is reached, all of the domains in the iron are aligned, and the iron becomes saturated, meaning that the flux density cannot increase within it. At this point, the reluctance of the iron significantly increases, forcing the excess flux to travel through another path.

The problem in both generators and transformers is that only the core is designed as a flux path, while the supporting structure is not intended to carry flux.

When flux cuts the core of the generator or transformer, it induces circulating currents in the iron, known as eddy currents. These currents result in losses (I^2R) in the form of heat being released in the core. Excessive heating causes damage to the core.

The magnitude of the eddy currents induced in the core is proportional to the cross-sectional area of the flux path. In a generator, the flux travels in the radial direction under normal conditions. Therefore, stator and transformer cores are formed with laminated sheets of iron separated by thin sheets of insulation in order to reduce the eddy current losses in the machine.

When the core is overexcited, the flux density reaches its maximum, and the core saturates. Since the eddy currents are proportional to the flux density, the eddy currents within the core become significant, leading to voltage gradients between the laminations [20]. These gradients can be significant enough to result in the breakdown of the interlaminar insulation. If this occurs, the failed portion of the core must be restacked. Note that this damage can occur in a matter of seconds.

Another effect of the saturated core is that the flux begins to flow into nonlaminated portions of the generator, namely the core ends. During normal operation, the core permeability is high with respect to the core ends. However, when the core is saturated, its permeability significantly decreases. The result is that the flux begins to flow axially through the ends of the core, which are not laminated, inducing large eddy currents and causing significant heating.

Therefore, it is important that this condition is detected and that the generator and GSU transformer are isolated from the system. It is difficult to measure the amount of flux in the core, but the flux amount can be monitored indirectly by monitoring the voltage and frequency and the ratio between them. Solving (1) for Φ shows that flux is proportional to voltage and inversely proportional to frequency, hence, the V/Hz relay, which is designated the 24 device code by ANSI.

According to IEEE Standard C50.13, a generator must be rated for 1.05 pu on the generator base, while IEEE Standard C57.12 gives two ratings for transformers: 1.05 pu at rated load and 0.8 power factor or greater as well as 1.10 pu at no load, both on the transformer secondary base [19].

The transformer is typically selected with a lower-rated voltage in order to allow full use of the rating on the secondary terminals (high-voltage winding of a GSU transformer). Therefore, to set this element, the transformer limiting curve is transferred to the generator base.

V/Hz relaying is typically applied in one of three formats: a single definite-time element, a dual-level, definite-time element, or an inverse-time curve. Although a dual-level, definite-time element is most common, a combination of a definite-time element and an inverse-time curve may provide the best protection [9].

The goal of applying a V/Hz relay is to match the relay characteristic to the combined limiting curve characteristic of the generator and GSU transformer. This should sufficiently protect the equipment without limiting the operation range. Fig. 35 shows a typical limiting curve for a generator and GSU transformer plotted on the generator base and a corresponding relay characteristic.
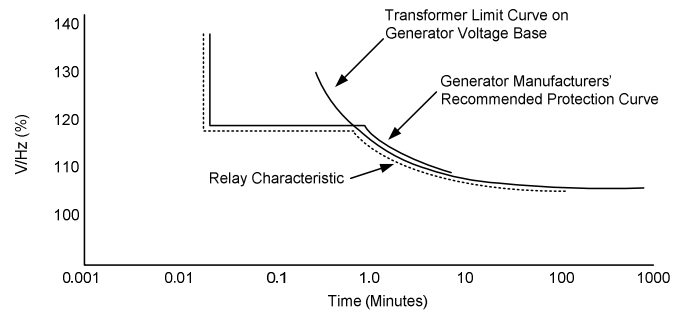
Fig. 35.   Example V/Hz Limiting Curve [19]

In some cases, a separate definite-time element is also set to alarm at 1.05 pu.

A common belief is that an overexcitation condition only occurs during startup—before the unit is connected to the system. Although this is a more common case, it is not the only cause. Overexcitation can also occur as a result of AVR failure, manual regulator control operating error, or load rejection. In the last case, if the unit is connected to a capacitive load, VARs will begin to flow into the machine. If this VAR flow approaches the minimum excitation limit of the AVR, the regulator will boost the excitation in an attempt to reduce the VAR flow into the machine. The terminal voltage of the machine increases as a result, possibly leading to an overexcitation condition [20].

A V/Hz element is often only set on machines larger than 100 MW [9]. However, as microprocessor-based relays are being applied for generator protection, the V/Hz relay function is normally included and only requires setting. Due to the serious effects that can result from an undetected overexcitation condition, it is recommended that this element be applied, even on smaller units. The cost to set the element is less than the cost of repairing even a small machine, especially when the downtime cost is considered.

Distributed generation (DG) applications are becoming increasingly popular on today's grid. In a large number of these installations, the protection being applied is not a generator relay, and thus, no V/Hz element is provided.

B. Overvoltage

However, it is common to apply an interconnection relay with voltage inputs to synchronize to the system. Most of these relays also have overvoltage elements included. These elements can be set to provide both overvoltage and some overexcitation protection.

Note that overvoltage and overexcitation functions, although sometimes linked, serve two completely separate functions. In contrast to overexcitation discussed above, overvoltage protection is designed to protect the unit from

extreme voltages that can damage and break down the insulation in the machine, leading to a fault.

In many cases, overvoltage protection is not applied to generators [3]. However, IEEE Standard C37.102-2006 recommends either an inverse-time overvoltage element set to pick up at 110 percent overvoltage or a dual-level, definite-time element. It is also recommended that an instantaneous element be set to 130 to 150 percent of rated voltage to protect against extreme cases.

Overvoltage has typically been associated more with protecting the machine in the case where both frequency and voltage increase, resulting in no net change in the flux in the machine. Such is the case during a load rejection. It is imperative that the overvoltage element operates correctly over a wide frequency range, because hydro units can reach 200 percent overspeed during a full load rejection [19].

On a high-impedance-grounded system, a ground fault between the generator and GSU transformer results in the phase-to-phase voltage on the unfaulted phases. If this is combined with a full load rejection when the high-side breaker is tripped, it is possible to have overvoltages in excess of 2.5 pu [26].

Although overvoltage and overexcitation conditions have separate effects on the generator, they are related in that an overvoltage condition at rated frequency is also an overexcitation condition. Therefore, in the absence of an overexcitation element, an overvoltage element can provide some overexcitation protection. The overvoltage element should be set as recommended above in the IEEE Standard C37.102-2006.

During an overexcitation condition, the exciting current increases significantly. The stray flux present during overexcitation results in current and voltage waveforms that are rich in harmonics. Fig. 36 shows the excitation current of a single-phase laboratory transformer overexcited to 150 percent [27]. This is the result of applying 150 percent of the rated voltage to the terminal of the transformer at nominal frequency.
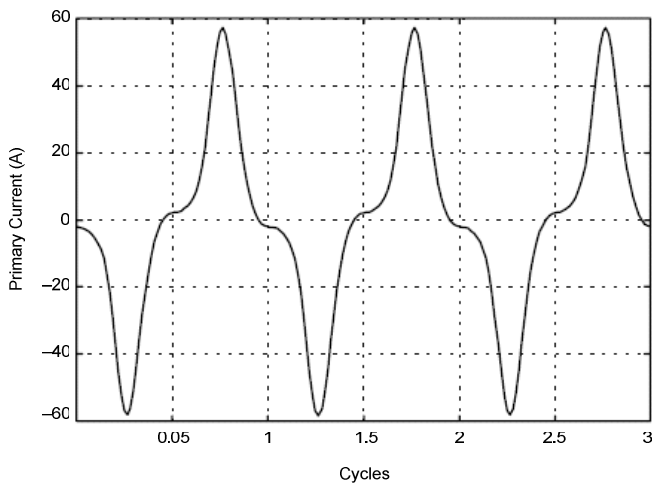
Note that the exciting current is not sinusoidal. However, the symmetrical nature of the waveform indicates the presence of odd harmonics. Fig. 37 shows the harmonic content of the magnetizing current as the terminal voltage is varied. Note that the frequency is held at nominal [27].

I_n: Rated Current
I_m: Magnetizing Current
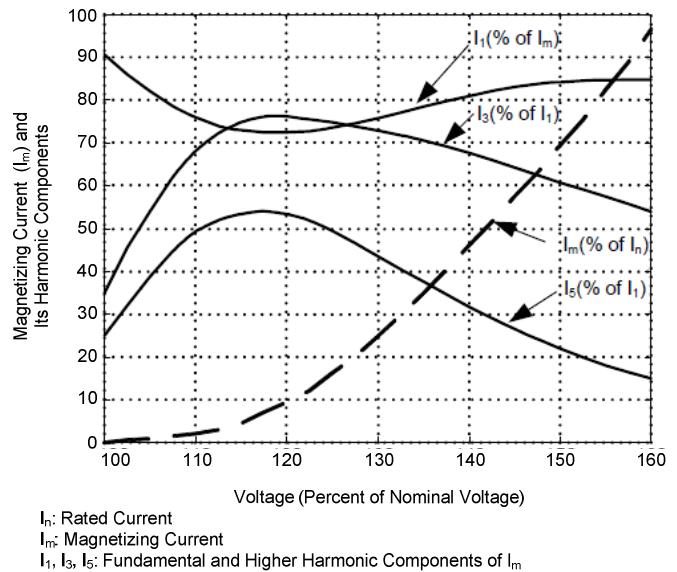I_1, I_3, I_5: Fundamental and Higher Harmonic Components of I_m

Fig. 37.   Harmonic Content of Transformer Exciting Current as a Function of the Applied Voltage

Due to high excitation current, it is necessary to detect this condition and block the transformer differential to prevent an incorrect target. This is done by monitoring the level of fifth-harmonic content. A fifth-harmonic blocking element is typically set to approximately 35 percent of the fundamental.

C. Event 6: Overvoltage Failure

A DG site with three 1 MW generators experienced an overvoltage and overexcitation condition. The system one-line diagram is shown in Fig. 38.

Fig. 38.   Event 7 System Single-Line Diagram
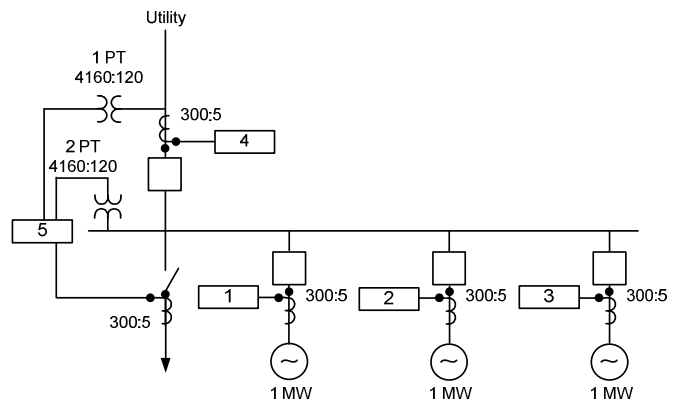
Relay 1 through Relay 4 are all set with phase and ground instantaneous and inverse-time overcurrent elements, while Relay 5 is set with phase instantaneous and inverse-time overcurrent, overvoltage and undervoltage, and synchronism-check elements.

Fig. 36.   Exciting Current of an Overexcited Transformer; Overvoltage of 150 Percent Applied to a Single-Phase Transformer

A portion of the settings in Relay 5 are shown in Fig. 39.

```
PTR  = 35.00   PTRS = 35.00   VNOM = 118.90
59PP = 130.70
SV3PU = 300.00   SV3DO = 30.00
SV3  =59AB OR 59BC OR 59CA
TR   =51PT OR 51GT OR 50P1 OR SV3T OR ...

where:

PTR is the PT ratio (applied to the two PTs connected to the bus).
PTRS is the PT ratio (applied to the single PT connected to the utility side of the incoming breaker).
VNOM is the nominal system voltage (phase to phase) in secondary volts.
59PP is the pickup for the phase-to-phase overvoltage element in secondary volts.
59AB, 59BC, and 59CA are the outputs of the phase-to-phase overvoltage elements.
SV3PU is the time delay on pickup for timer SV3.
SV3DO is the time delay on dropout for timer SV3.
SV3 is the input logic to timer SV3.
SV3T is the time-delayed output of timer SV3.
TR is the trip equation.
51PT is the output of the inverse-time phase overcurrent element.
51GT is the output of the inverse-time ground overcurrent element.
50P1 is the output of the instantaneous phase overcurrent element.
```
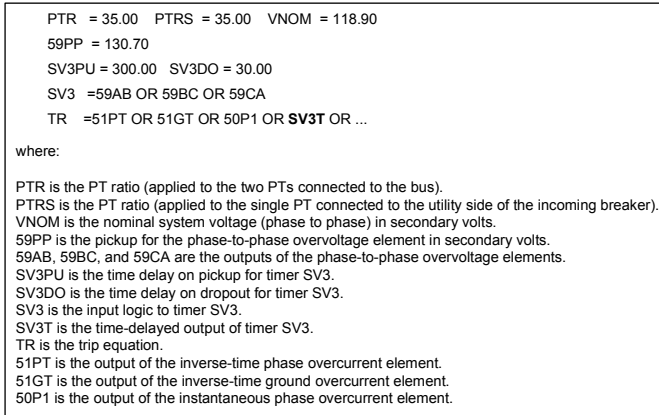
Fig. 39.   Relay 5 Settings

As seen in Fig. 39, the nominal voltage of the system is 118.90 V secondary or 4,160 V primary. One overvoltage element is set in Relay 5 to pick up at 130.70 V secondary or 110 percent overvoltage. A 5-second time delay is applied to this element.

At the time of the event, the system was isolated from the utility, and the condition began when Generators 2 and 3 were brought online to supply the local load. The overvoltage condition lasted for 5 seconds before Relay 5 issued a trip signal to isolate the system. Fig. 40 is the event report triggered in Relay 5 at the time of the trip (12:24:53.425).
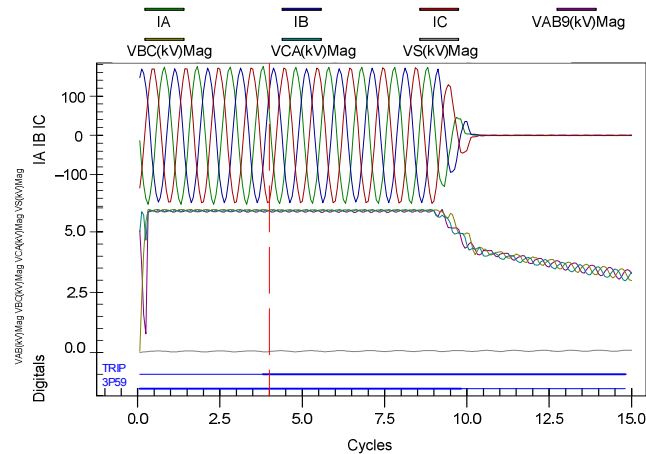

Fig. 40.   Relay 5 Filtered Event Report

At the time of the trip, the voltage magnitude on all three phases was 5,900 V primary at 60.0 Hz. Therefore, the generators are at 141.8 percent overvoltage. Fig. 41 shows the unfiltered waveforms recorded by Relay 5.
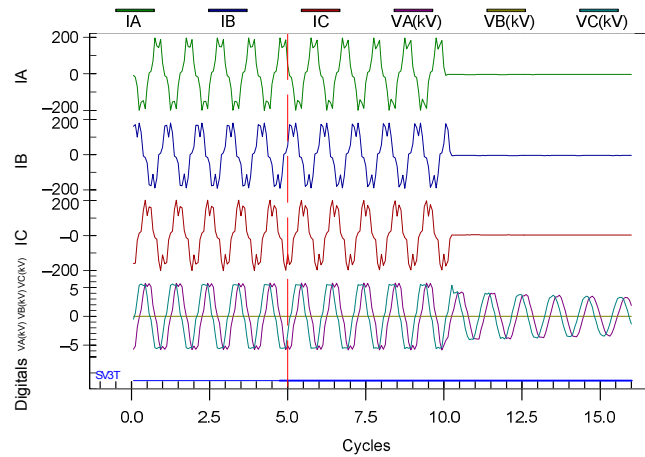

Fig. 41.   Relay 5 Unfiltered Event Report

These waveforms indicate a significant odd harmonic component that is present during overexcitation conditions as described above. Fig. 42 shows the harmonic analysis as a percentage of the fundamental for the A-phase current.

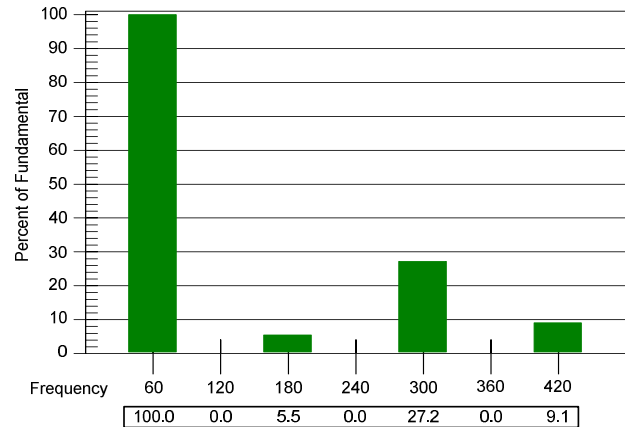| Frequency	60	120	180	240	300	360	420
	100.0	0.0	5.5	0.0	27.2	0.0	9.1

Fig. 42.   A-Phase Current Harmonic Analysis

The result of this overvoltage condition was a fault in one of the generators. The fault was attributed to some contamination but occurred during the overvoltage condition. Fig. 43 shows the damage to the stator winding.

Fig. 43.   Generator Fault Damage

This fault could have been avoided or at least delayed if IEEE recommendations were followed and an instantaneous element was set between 130 and 150 percent overvoltage. This should be accompanied with either an inverse-time curve or a dual-level, definite-time element [19].

In this case, only two 59 elements are available in the relay. Therefore, a dual-level, definite-time element is the best option. The original setting will work well for the first level, while a second level should be set. Possible settings for the second element are a pickup of 130 percent overvoltage with a time delay of 0.25 seconds. This is to combine the second level of the definite-time element with the instantaneous element recommended by IEEE.

Applying these settings would not have prevented exposure to the overvoltage condition but would have significantly limited exposure and reduced the probability of a fault. This added protection would have come at a minimal cost, because the element is already included in the relay and only needed to be enabled.

IX. CONCLUSIONS

Although generators have been a critical asset to the operation of the power system from its onset, they are becoming even more important in recent years. Because of this, it is imperative that good protection schemes are applied correctly in order to reduce generator outages and the duration of unavoidable outages. This is essential from both a system operation and an economic standpoint.

This paper discussed in detail multiple elements that are necessary to adequately protect a generator. Various schemes were presented, and associated settings criteria were discussed.

It is clear that a good understanding of the functions available in the relay is required in order to design a sufficient protection scheme. This includes not only what functions are available to use but also how the algorithm operates for each function to be applied.

We as protection engineers have an important job, and there are many people who rely on us. Therefore, we must do the required research and our due diligence to ensure that the systems we apply will indeed protect our generators and the system as a whole.

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XI. BIOGRAPHIES

Rogerio Scharlach received his BSEE from the University Mackenzie, Brazil, in 1991. Upon graduating, he served nearly 13 years at Siemens in Brazil and the United States, where he worked as a commissioning and field service engineer in the areas of power generation, transmission, and distribution. He joined Schweitzer Engineering Laboratories, Inc. in 2005 as a field application engineer.

Jason Young graduated from the University of Waterloo in 2006 with a BASc in electrical engineering. In 2004, he joined Ontario Power Generation as a protection and control engineering intern. He also worked as a planning technician intern for Hydro One Networks. He joined Schweitzer Engineering Laboratories, Inc. in August 2006, where he serves as an associate field application engineer in Boerne, Texas.