Field Experience With Detecting an Arcing Ground Fault on a Generator Neutral Point

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Field Experience With Detecting an Arcing Ground Fault on a Generator Neutral Point

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***Abstract*—Marshall Steam Station is a four-unit, coal-fired generating facility owned by Duke Energy and located in Catawba County, North Carolina. While reviewing event records from the protective relays on one of the 790 MVA generating units, Duke Energy engineers noticed that both the fundamental ground overvoltage and third-harmonic undervoltage elements were intermittently picking up and dropping out before timing out. Analysis of relay and digital fault recorder oscillography indicated that an intermittent, arcing ground fault might exist near the neutral end of the generator. An injection-based stator ground relay was added to the unit. The additional relay measured short, intermittent, and very low impedance values to ground. They eventually found that the unit experienced an arcing fault in the neutral enclosure due to a bus bracing bar that had vibrated loose and shifted toward the enclosure, thereby causing the arcing. This paper shares the events collected in detail and describes the characteristics of an arcing ground fault on the neutral end of a generator. In addition, it investigates the limitations of present ground protection techniques as well as techniques to overcome these limitations when detecting an arcing ground fault.**

I. Introduction

Marshall Steam Station is a four-unit, coal-fired generating facility owned by Duke Energy and located in Catawba County, North Carolina. One of the largest coal facilities owned by Duke Energy in the Carolinas, Marshall Steam Station generates enough electricity to power approximately two million homes. This paper addresses Marshall Unit 3, which is a 790 MVA, 24 kV, unit-connected, high-impedance grounded generator. The unit connects to the 230 kV Duke Energy transmission system through a 750 MVA 22.8/230 kV delta-wye generator step-up (GSU) transformer into a switchyard with a breaker-and-a-half configuration.

A relay upgrade was completed on Marshall Unit 3 in July 2013 to replace the existing electromechanical relays with the following microprocessor-based relays:

- Two generator differential relays with 21, 24, 32, 40, 46, 50/27, 59GN, 78, 81, and 87 functions.
- Two GSU/unit differential relays with 87 and 51TN functions.
- Two unit auxiliary transformer (UAT) differential relays on each of two UATs with 87, 51TN, and 67G (REF) functions.
- Two breaker failure relays with 25 function for each of the two generator breakers.

On November 22, 2014, a trip of one of the two redundant unit lockout relays (86GB) tripped Marshall Unit 3 offline. An investigation commenced as to the cause of the trip. As part of the investigation, the author examined the sequential events recorder (SER) from the generator differential relay. The SER recording was filled with the third-harmonic undervoltage component of the 100 percent stator ground protection (27TN), which was asserting several times each second.

This paper discusses the events collected in detail and describes the characteristics of an arcing ground fault on the neutral end of a generator. It discusses the ground detection used at Marshall Unit 3 and its reaction to the arcing ground fault. In addition, the paper investigates the limitations of present ground protection techniques as well as techniques to overcome these limitations when detecting an arcing ground fault.

II. Traditional 100 Percent Stator Ground Protection

When a ground fault occurs high in the winding of a high-impedance grounded generator, a fundamental voltage develops at the generator neutral. The magnitude of this voltage during the fault is proportional to the fault location within the winding. For instance, if a fault occurs 50 percent up the winding from the neutral point, the neutral voltage is approximately 50 percent of the generator rated line-neutral voltage. For this reason, an overvoltage relay (59GN) has traditionally been used to detect stator ground faults. This relay, however, cannot be set sensitively enough to protect the stator as the fault gets closer to the neutral of the generator because the neutral voltage magnitude approaches zero. As shown in Fig. 1, the 59GN element can typically be set to provide protection for the top 95 percent of the stator winding for relays that filter out harmonic voltages to the 59GN element.

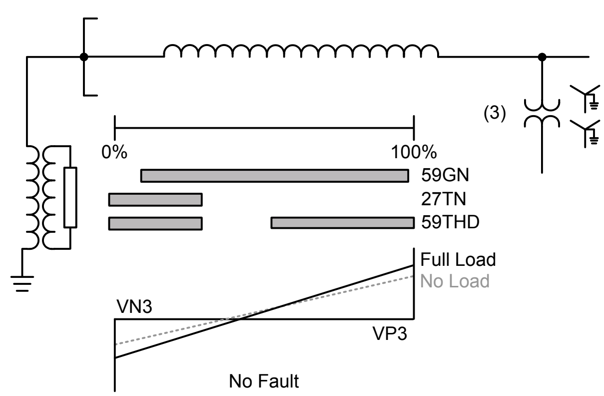

Fig. 1. Comparison of stator ground protection methods

The 27TN element is a third-harmonic neutral undervoltage element used to protect against ground faults that are close to the neutral of the stator winding. All generators produce some amount of harmonics, with the triplen harmonics (third, ninth, fifteenth, and so on) existing as zero-sequence voltages. These voltages result in triplen harmonic current flow through the distributed capacitance of the generator windings and other components attached to the generator. This current develops a zero-sequence voltage on the neutral grounding resistor (NGR) and on the secondaries of wye-connected generator voltage transformers (VTs), as shown in Fig. 1. The third-harmonic voltage has the largest magnitude of any of the triplen harmonic voltages, making it the most useful in 100 percent stator ground protection. If a stator ground fault occurs near the neutral of the generator, the magnitude of the third-harmonic voltage at the generator neutral is reduced. An undervoltage relay sensitive to third-harmonic voltage can be set to respond to this reduced voltage on the neutral, providing ground detection for the neutral end of the generator.

Special consideration must be given when setting this element, however, because the third-harmonic voltage magnitude varies with load, as shown in Fig. 1, and varies greatly from machine to machine. Factors influencing the available third-harmonic voltage include the generator design, load, terminal voltage, neutral ground impedance, and distributed capacitance to ground. Therefore, it is necessary to perform thorough testing at different loads and power factors to accurately choose a pickup value for the 27TN that will remain secure. In some cases, there may be insufficient third-harmonic voltage under all conditions to set a 27TN element securely [1] [2].

The third-harmonic voltage developed is split across the stator windings as the result of voltage division across the stator capacitance, the system capacitance, and the grounding resistance. This voltage is split almost equally across the stator such that a point exists near the center of the stator that has a third-harmonic voltage magnitude of zero. An adaptation to the third-harmonic undervoltage element (known as a third-harmonic voltage differential element, or 59THD) uses this balance by comparing zero-sequence third-harmonic voltage on the terminals of the generator to that measured on the generator neutral. A ground on either end of the generator shifts the location of the voltage crossing point from the center of the stator to the location of the fault, causing a low magnitude of third-harmonic voltage on the faulted end of the generator and a high magnitude on the other end.

The 59THD element measures the third-harmonic voltage magnitudes at the generator terminals and neutral point. If the difference between the measured third-harmonic voltage magnitudes is greater than a threshold, the relay trips. Determining a secure setting for the 59THD also requires testing, similar to setting the 27TN.

III. Initial Investigation of the Chattering 27TN

The author began investigating the chattering 27TN that was found while reviewing the generator differential relay SER recording on November 22, 2014. The author determined that protective relays did not trip the 86GB on Marshall Unit 3. The operation was determined to be unrelated to the unit protection. When the generator differential relay was commissioned, third-harmonic testing was performed; however, the 27TN element was not set to trip because of limited test points and undesired operations on other units.

The 27TN element was set with a pickup of 2.5 V on the secondary of a 14,400/240 V grounding transformer, with a time delay of 5 cycles for monitoring purposes. The chattering of the 27TN element was seen on average every 101 ms, with each event lasting an average of 25 ms. The 27TN element never timed out.

The 27TN was removed from the SER trigger list on November 24, 2014 to prevent data loss. After this, it was noticed that the 59GN was chattering as well, although at a lesser rate. Between November 24 and 26, the 59GN asserted on average once every 8.5 minutes, with each event lasting an average of 5 ms. The 59GN was set with a pickup of 5 V secondary with a time delay of 5 cycles and was armed to trip. The 59GN element also never timed out.

The generator differential relay captured an event report during the trip of the 86GB. It can be seen in the event report in Fig. 2 that the 27TN is chattering.

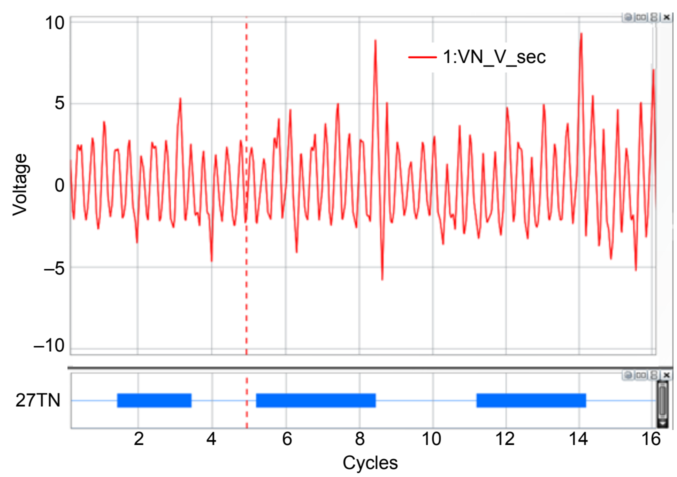

Fig. 2. Event report from 86GB trip

Upon further investigation, engineers found that a digital fault recorder (DFR) installed on the same unit was triggering numerous events due to the rate-of-change of voltage on the generator neutral voltage channel. The unfiltered generator neutral voltage from the DFR is shown in Fig. 3.

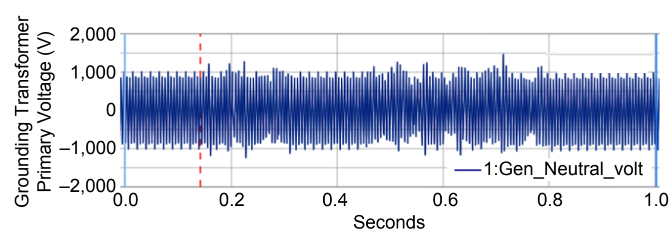

Fig. 3. Generator neutral voltage

The author took these data and, using event analysis software, filtered out the third harmonic of the neutral voltage (VN_H3) and the terminal voltage (VP0_H3), as shown in

Fig. 4. The third-harmonic voltage magnitude at the neutral repeatedly dropped as the third-harmonic voltage rose proportionally at the terminal. This behavior indicates an intermittent or arcing fault close to the neutral.

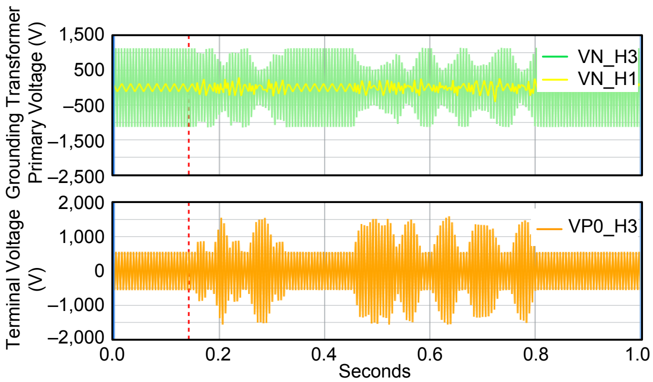

Fig. 4. Calculated third-harmonic neutral and terminal voltages

This behavior is displayed even more clearly in Fig. 5. The lower line (green) shows the third-harmonic voltage distribution across the generator stator at Point A on the waveform, where the generator is unfaulted. The upper line (red) shows the third-harmonic voltage distribution across the generator stator at Point B on the waveform, where the generator is faulted close to the neutral. It can be seen that the fault results in a fall in the third-harmonic neutral voltage and a rise in the third-harmonic terminal voltage.

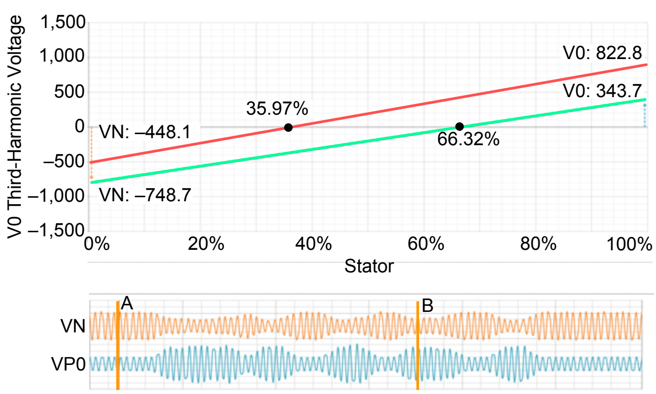

Fig. 5. Third-harmonic voltage across stator during a ground fault close to the neutral

Based on the analysis, the author felt that the data supported the conclusion that there was an arcing ground fault close to the generator neutral and shared the analysis with management. The author was asked to closely monitor the behavior of the generator to note if a more serious fault developed, and it was suggested that an injection-based generator ground relay be installed on Marshall Unit 3.

The event analysis pointed toward an arcing ground fault near the neutral end of the generator. The system protection engineering department shared this analysis with station and general office management and other engineering departments. Removing the unit from service for testing was considered, along with advice from the generator subject matter expert that a hi-pot test might cause failing stator bars. Upper levels of management decided to accept the risk of continuing to operate the unit until stator bars could be ordered before testing was performed. A one-day outage was taken, allowing relay engineers to test the neutral grounding systems and the relay, but no problems were found. After further event analysis and monitoring of the arcing characteristics, an injection-based ground detection system was installed.

IV. Injection-Based Stator Ground Protection

Injection-based schemes do not rely on third-harmonic voltage and have the additional advantage of being able to operate at a standstill or while the generator is on turning gear. This allows for continuous supervision and reliable detection of stator winding insulation failures before the generator is put online. By injecting current and measuring the resulting voltage, the injection-based relay continuously measures insulation resistance, insulation capacitance, and grounding resistor resistance, and it can trip or alarm whenever these values fall below their chosen set points. The injection-based relay applied at Marshall Unit 3 is connected to the unit as shown in Fig. 6. The current transformer (CT) shown provides a measurement of neutral current to the relay.

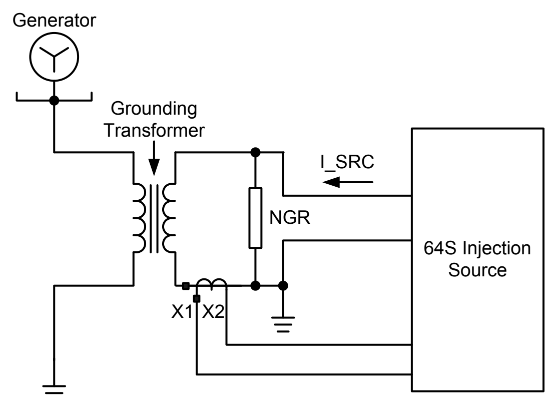

Fig. 6. Low-voltage grounding resistor on the grounding

Modern injection systems typically use low-frequency signals in the vicinity of 20 to 25 Hz and use power electronics to produce square-wave outputs. The injection system chosen for Marshall Unit 3 uses a multisine current waveform with injection frequencies set to 18, 24, 36, and 48 Hz, as shown in Fig. 7.

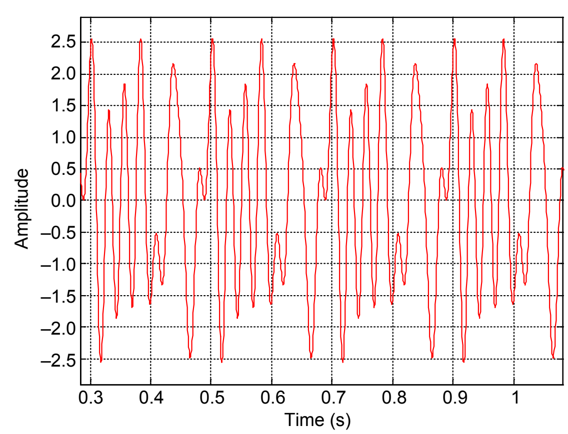

Fig. 7. Four-frequency multisine waveshape

Fig. 8 shows a functional overview of the multisine signal injection source. It starts with a power amplifier that amplifies the multisine signal generated by the processor. The amplified signal is injected through the neutral voltage (VN) terminal into the NGR. The injection current (I_SRC) and VN are measured as shown in Fig. 8. The CT output connects to the relay to measure neutral current. The switch shown at the output of the amplifier closes when the stator ground protection (64S) is enabled via an external control input to the relay.

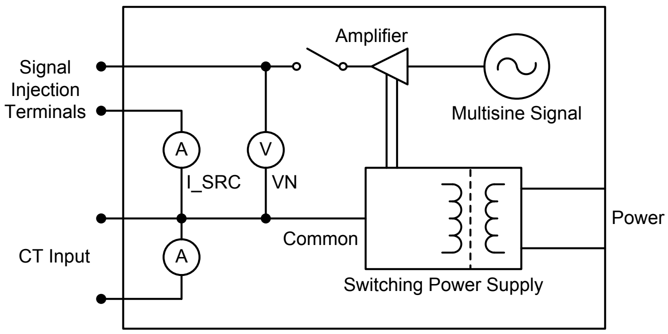

Fig. 8. Injection source block diagram

V. Confirmation of the Arcing Ground Fault

An injection-based generator stator ground relay was installed and commissioned on Marshall Unit 3 on December 3, 2014. It was installed with the capability to trip the unit only after seeing a very low stator impedance (0.1 kΩ) for a relatively long period of time (1.5 seconds).

Partial discharge sensors had been installed on the line bushings of the generator and the low-side bushings of the GSU at the same time that the unit relaying was upgraded in 2013. An expert on partial discharge analysis visited Marshall Steam Station on December 9, 2014. He hooked instruments up to the sensors and determined two things:

1. Whatever was causing the odd readings on the stator ground protection was not between the GSU and generator terminals.
2. The phenomenon was creating an odd signal on the partial discharge sensors, but it did not look like partial discharge.

While disconnecting the instruments, he noticed a flashing light coming through a small hole in the neutral enclosure; the arcing ground fault close to the generator neutral was confirmed.

Marshall Unit 3 was shut down, and it was found that a threaded rod used to clamp the neutral busbars had vibrated loose and come in close proximity to the neutral enclosure. This rod is shown in Fig. 9. The arcing that had been occurring between the rod and the neutral enclosure had actually burned a hole in the enclosure.

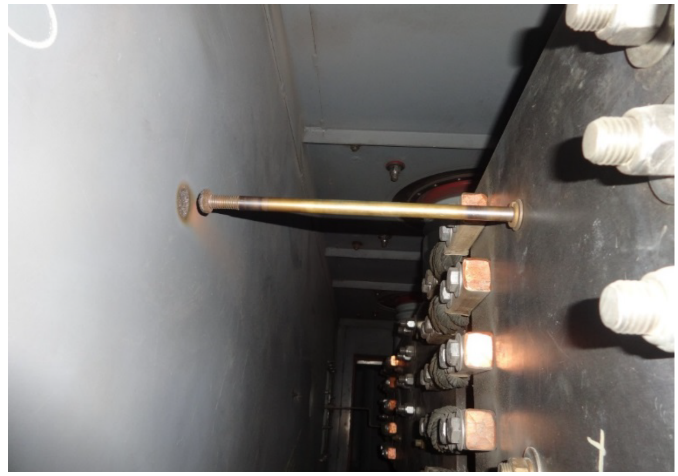

Fig. 9. Loose rod in neutral enclosure shows evidence of arcing

VI. Analysis From Injection-Based Relay Data

When the injection-based relay was commissioned with the unit at standstill, the following measurements were captured:

- Stator insulation resistance: 99.99 kΩ
- Stator insulation capacitance: 1.219 µF
- Neutral ground resistor resistance: 0.67 Ω

Note that the maximum stator insulation resistance that the injection-based relay can read is 99.99 kΩ. Newer generators should have an insulation resistance well above 100 kΩ. However, older generators may have a lower resistance depending on age and condition. Any pickup within the range of 0.1 to 10 kΩ should work, even for older units. It is a good idea to read the normal stator insulation resistance during commissioning and review the pickup setting to verify that the margin is as desired (e.g., pickup <75 percent of normal stator insulation resistance). It is Duke Energy's practice to short the secondary of any wye-connected VTs, measure the stator insulation resistance, and set the relay to pick up below that value minus some margin. This is intended to provide coordination with a fault on the secondary of the VTs. The VT impedance is so high that it has only a small influence on the setting.

There are two levels of stator ground (64) settings in the applied injection-based relay: 64S1 and 64S2. 64S1 was originally set with a pickup of 10 kΩ and a time delay of 5 seconds. 64S2 was originally set with a pickup of 1 kΩ and a time delay of 5 seconds. The 64S1 and 64S2 elements were also chattering because of the arcing. The chattering of the 64S1 element was seen on average every 2.66 seconds, with each event lasting an average of 634 ms. The 64S1 element never timed out. The chattering of the 64S2 element was similar. It was seen on average every 2.61 seconds, with each event lasting an average of 1.85 seconds. The 64S2 element did time out on a few occasions but was not programmed to trip during this testing.

The data from the current-injection-based relay were recorded once every minute using the load profile capability of the relay. This, along with MVA data from Duke Energy's system-wide data historian, allowed the author to analyze the data and see some interesting trends. Fig. 10 shows a trend of measured insulation resistance and load over the period between December 3 and December 10, 2014. The arcing is evident in these traces. Notice how the arcing is prevalent only after load gets above the 500 to 600 MVA range.

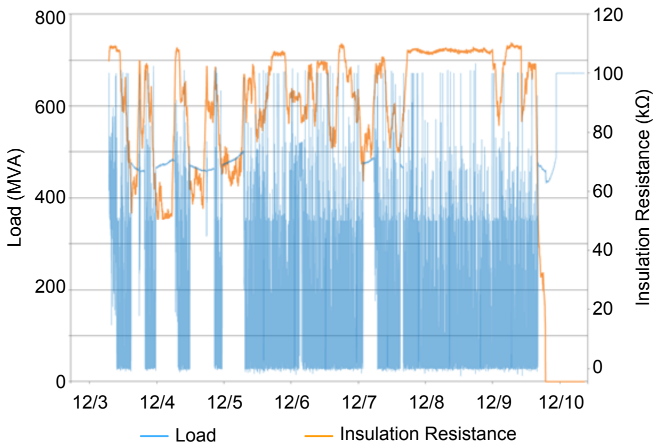

Fig. 10. Insulation resistance and load

Fig. 11 is similar. It shows a trend of third-harmonic neutral voltage (VN3) and load over the same period. VN3 increases with load, as is normally expected. Arcing begins only after VN3 rises to about 700 V, leading to the conclusion that the third-harmonic voltage at the neutral is the source driving the arcing.

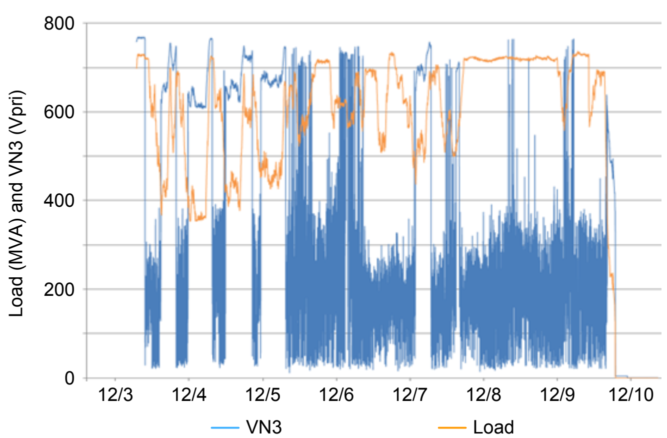

Fig. 11. Third-harmonic neutral voltage and load

Fig. 12 also presents an interesting trend. It is a scatter graph of VN3 against load. The normal curve shape of VN3 against load can be readily seen, as well as the increasing density of data points below that curve as arcing takes place at higher loads. (Based on Duke Energy's experience, this textbook curve shape of VN3 against load is fairly typical for steam units, but their test results from hydro and combustion turbine units have varied from this considerably.)

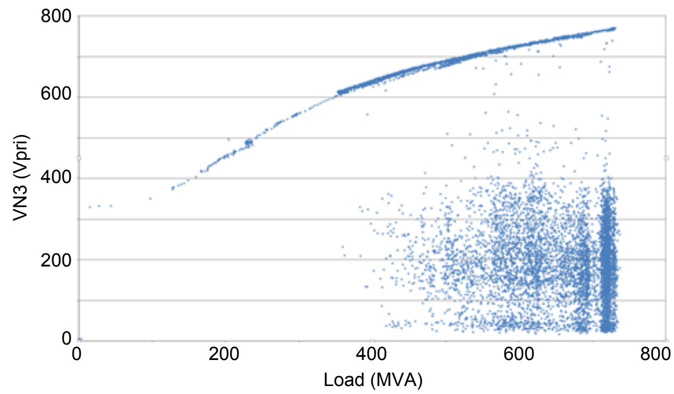

Fig. 12. Third-harmonic neutral voltage versus load

VII. Detecting Arcing Ground Faults

An arcing fault is a chaotic process that irregularly starts and stops and produces a very wide frequency spectrum that spreads its energy across all harmonics. One interesting thing that can be said about each of the methods described in this paper is that, although none of them were directly designed to detect an arcing ground fault, each did indicate that something was going on, which led the author to realize that there was, in fact, an arcing ground fault. However, none of the relays were set up to automatically indicate the existence of an arcing ground fault. This feature would be very desirable for alerting the operator to the problem and, perhaps, even tripping the unit. Simple methods using the existing elements and programmable relay logic can be used to recognize the arcing ground fault and either trip or alarm, as described in the following subsections.

A. Traditional 100 Percent Stator Ground Protection

The 27TN element was set with a pickup of 2.5 V with a time delay of 5 cycles. The chattering of the 27TN element was seen on average once every 101 ms, with each event lasting an average of 25 ms. This arcing ground fault can be sensed using a pair of timers, as shown in Fig. 13. This logic requires that an arc occur at least once every 0.2 seconds for at least 1 second. This timer scheme can be set at other intervals at the discretion of the engineer and still be successful.

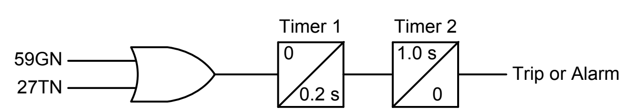

Fig. 13. Arcing ground detection using only timers

The logic scheme in Fig. 13 was tested and proven to work by using a generator relay and replaying the event from Fig. 5 using a test set. The 59GN was also simulated by sending a pulse train, with each pulse being 4 ms wide and 125 ms apart from the next one. This was demonstrated at voltages similar to a 100 percent stator ground fault and was successful with voltages down to a voltage representing a fault at 17 percent of the machine (see Fig. 1 as a reference). Although this is not a true representation of a stator ground fault, it was enough to prove the method.

Fig. 14 shows an alternate logic scheme that can be applied when the generator relay offers a counter. This scheme was tested and proven to work in the same manner as the logic in Fig. 13. This alternate logic scheme offers some slight advantages in that it does not require arcing to be spaced out in a specific time like the previous scheme, nor will it assert for a solid ground fault. Of course, this counter scheme can also be set with other time delay dropouts or counter final values (e.g., PV = 10) at the discretion of the engineer.

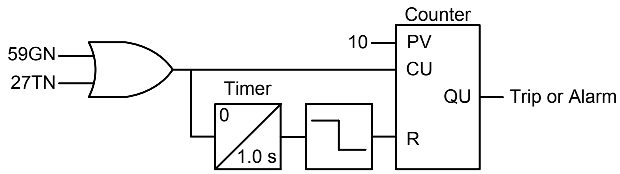

Fig. 14. Arcing ground detection using a counter

B. Current-Injection-Based Stator Ground Protection

The 64S1 and 64S2 in the injection-based relay also chattered during the event, and this fact can be used much like the chattering of the 27TN. The chattering is a bit slower because the element is a bit slower: the impedance measurement takes about 400 ms to accomplish. For this reason, a longer time delay dropout is added to the timer, as shown in Fig. 15.

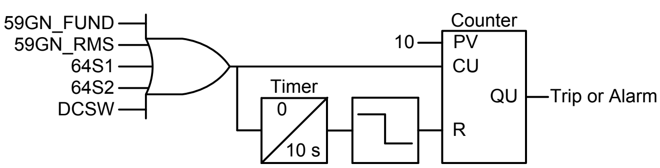

Fig. 15. Arcing ground detection with the injection-based relay

The injection-based relay has a 59GN that works on fundamental voltage like the generator relay, but it also has a 59GN that works on root-mean-square (rms) voltage. That makes the element in the injection-based relay more sensitive to the harmonic content in an arcing fault.

The switch shown at the output of the amplifier in Fig. 8 opens very quickly if more than 26 V are seen at the output terminals of the applied injection-based relay. This is one more means to indicate a stator ground fault within the protected machine. The open condition of the switch (DCSW) is shown being used in the same counter logic as the other elements for detecting an arcing fault.

VIII. Conclusion

By analyzing the relay data described in this paper, the author was able to correctly predict the existence of an arcing ground fault and its location close to the neutral of Marshall Unit 3. Once the threaded rod was put in its proper place and secured, all evidence of an arcing ground fault ceased. None of the applied devices were able to notify the operator of an arcing ground fault or to trip the unit offline. However, the author’s analysis and subsequent testing demonstrate that both traditional 100 percent stator ground protection and current-injection-based stator ground protection can adequately detect an arcing ground fault by applying simple logic built into a microprocessor-based relay.

IX. References

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[2] J. W. Pope, “A Comparison of 100% Stator Ground Fault Protection Schemes for Generator Stator Windings,” *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-103, Issue 4, April 1984, pp. 832–840.

X. Biographies

Nathan Klingerman received a B.S. degree in electrical engineering in 2012 from North Carolina State University. He has worked for Duke Energy since 2009 and has been a member of the Fossil/Hydro Generation System Protection Engineering group since 2010. Nathan’s responsibilities include generator, transformer, and motor protection design, engineering, and field support. Nathan is a member of multiple IEEE-PSRC working groups.

Larry Wright, P.E., received a B.S. in electrical engineering in 1982 from North Carolina State University. From 1982 until 2003, he worked for Duke Energy, designing nuclear, hydroelectric, and fossil-powered generating stations for Duke Energy, other utilities, and independent power producers. From 2003 to 2005, Larry served as the subject matter expert on protective relaying for Duke Energy’s generating stations. He joined Devine Tarbell Associates in 2005 as Manager of Electrical Engineering, providing consulting services to the hydroelectric industry. In 2008, he joined Schweitzer Engineering Laboratories, Inc., where he is presently employed as a field application engineer. Larry is a registered professional engineer in the states of North and South Carolina.

Brett Cockerham earned his B.S., summa cum laude, in 2014 and his M.Sc. in applied energy and electromechanical systems in 2016. Both degrees were awarded by the University of North Carolina at Charlotte. His graduate school research focused on power system frequency and frequency estimation methods. Brett joined Schweitzer Engineering Laboratories, Inc. in 2016 as a protection application engineer in Charlotte, North Carolina.

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