Improving System Protection Reliability and Security

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Abstract
This paper is based upon a NERC report released in 2013 that claimed a dramatic rise in the annual number of misoperations—due in large part to the complexity of programming and testing numerical protection relays. This paper illustrates results discussed in the NERC report, as well as provides several interesting examples of actual misoperations and how to mitigate them.

Introduction
This paper covers the following topics:
- Summarize conclusions from the NERC 2013 Reliability Report
- Analyze Generator Differential Protection Misoperation
- Analyze 27TN Misoperation (3rd Harmonic Neutral Undervoltage)
- Analyze Incorrect Phase Rotation Settings
- Corrective Actions

NERC 2013 Reliability Report
As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable.

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into several assessment areas within eight Regional Entity boundaries, as shown in the map and corresponding table in Figure 1.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electric Coordinating Council

Figure 1. NERC Regions

The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, México. NERC released an official report in May of 2013 that featured statistics for protection misoperations across the entire country.

Major disturbances that occurred are ranked using a Daily Severity Risk Index. These include the following blackouts:

- 1989 Quebec Solar Flare
- 1996 Western Disturbance
- 2003 Eastern Interconnection Blackout

Misoperations primarily resulted due to the following reasons as shown in Figure 2:

- Incorrect settings/logic/design errors
- Communication failure
- Relay failure or malfunction

These events include Human Error during testing and maintenance activities. Human Error during testing and maintenance resulting in protection system activation has contributed to large disturbance events.

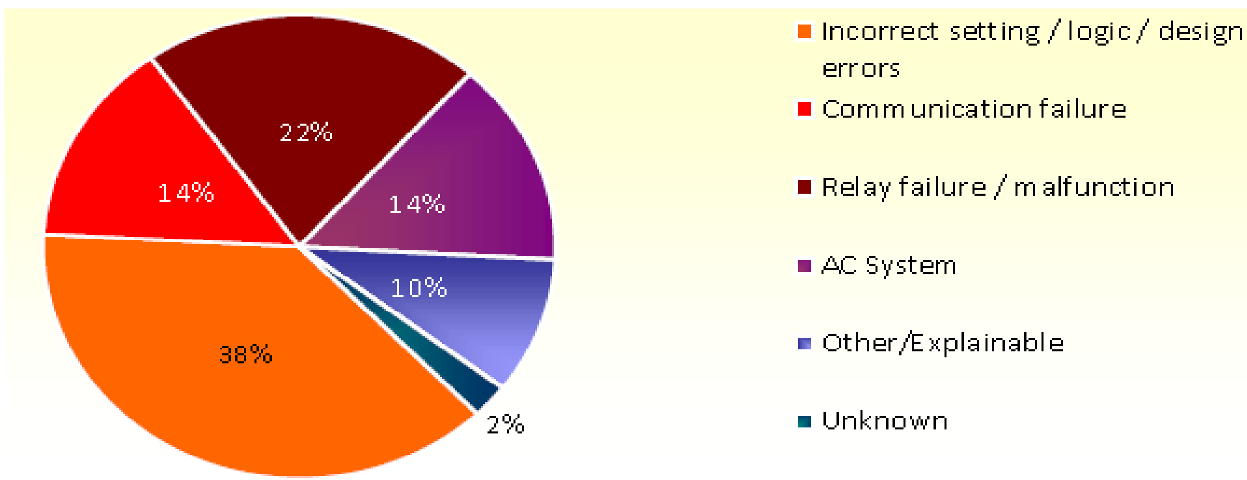

Figure 2. NERC 2012 Misoperation Table

Most of these misoperations contribute to increasing Security Risk Index (SRI) and indicate that the number of transmission element outages is increasing.

Corrective Actions

Applications requiring coordination of functionally different relay elements should be avoided. This type of coordination is virtually always problematic and is the cause of numerous misoperations reported in the study period. For example, do not coordinate an overcurrent element with a distance element; while the distance element has a fixed reach, the effective reach of the overcurrent element is dependent upon the strength of the source.

Misoperations due to setting errors can be reduced using the following techniques:

- Peer reviews
- Increased training
- More extensive fault studies
- Standard setting templates for standard schemes
- Periodic review of existing settings when there is a change in system topography

Remember that the greater the complexity of the protection scheme, the greater risk of misoperation. Simplicity is elegance.

Misoperation Analysis

87 Generator Phase Differential Protection

The customer reported a questionable generator protection relay trip. There are two main protection relays provided by different manufacturers but only one operated.

Review of the relay settings revealed the relay that did not trip had a higher pickup setting by a factor greater than four times. The CTs have a knee point of 100 volts or less which is low and there was the presence of heavy dc offset in the C-Phase current (Figure 3).

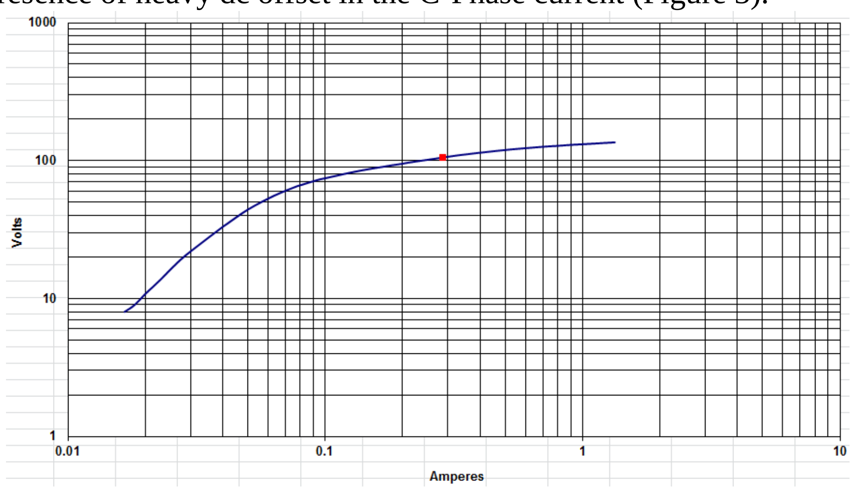

Figure 3. C Phase Neutral Side CT Excitation Characteristic

Figures 4A and 4B show the high levels of dc offset present in C-Phase current during the event. DC offset current is the number one cause of CT saturation.

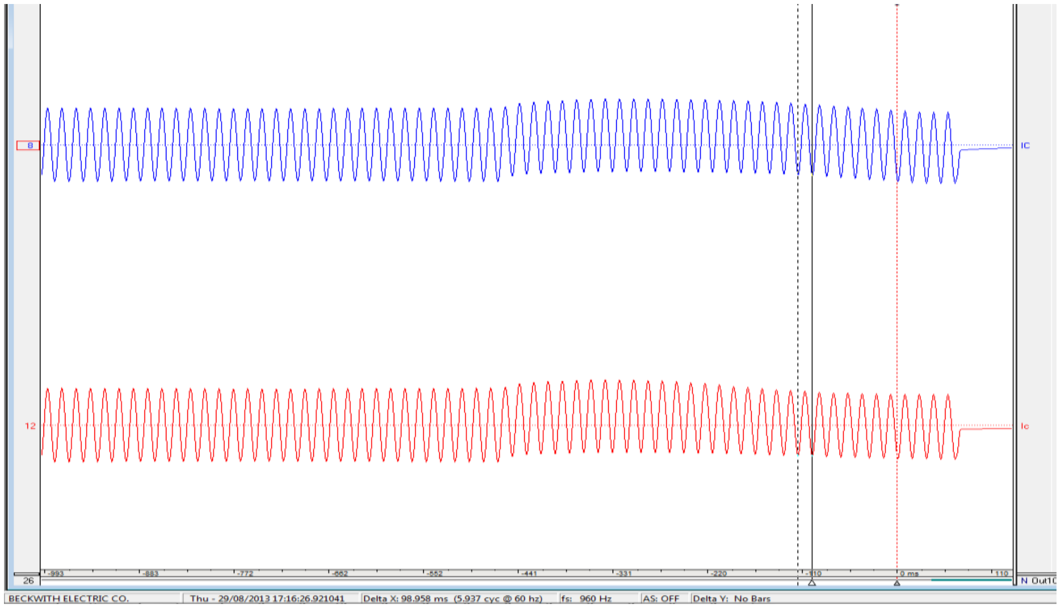

Figure 4A. Generator C-Phase Current

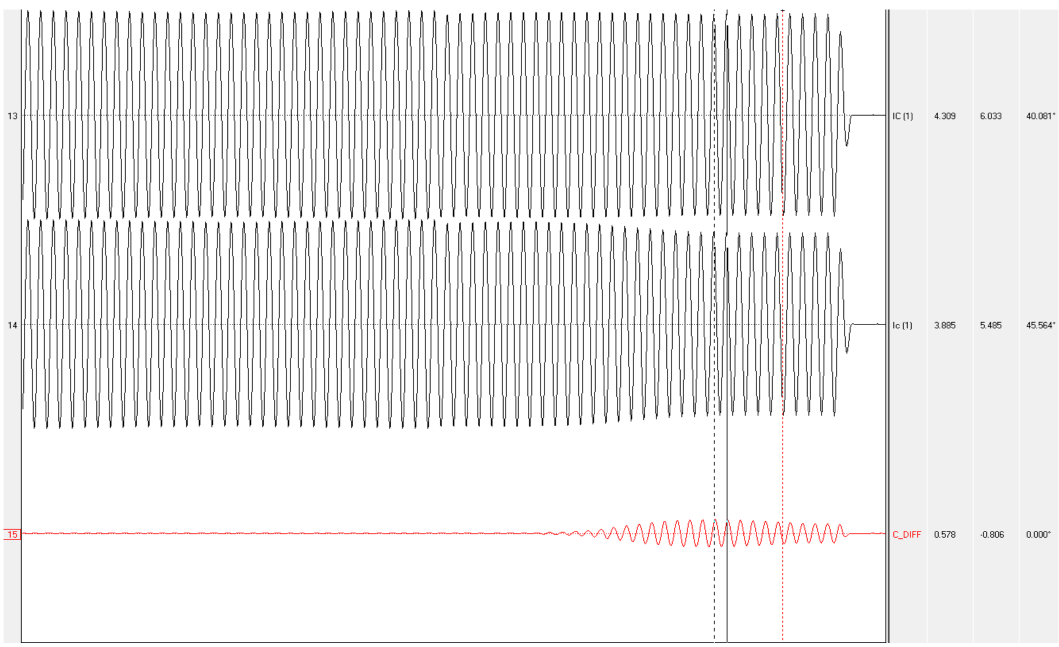

Figure 4B. Generator C-Phase Differential Current

Here is the minimum pickup for the relay that did not operate:

$$Tap \cdot O87P = (4.4 \text{ amps}) \cdot (0.3) = 1.32 \text{ amps}$$

As shown in Figure 5, the customer copied the settings from an arbitrary example in the manufacturer relay instruction book. The relay that tripped was more than four times as sensitive.

$$MVA_G := 44 \cdot 10^6$$

$$kV_G := 11.5 \cdot 10^3$$

$$I_{rated} := \frac{MVA_G}{kV_G \cdot \sqrt{3}}$$

$$I_{rated} = 2.209 \times 10^3 \quad \text{amps primary}$$

$$\frac{I_{rated}}{500} = 4.418 \quad \text{amps secondary}$$

Figure 5. Nominal Current Calculations

The blue triangle in Figure 6 corresponds to the C-Phase operating point which was just on the boundary of operation. The misoperation occurred when the current was coming out of saturation.

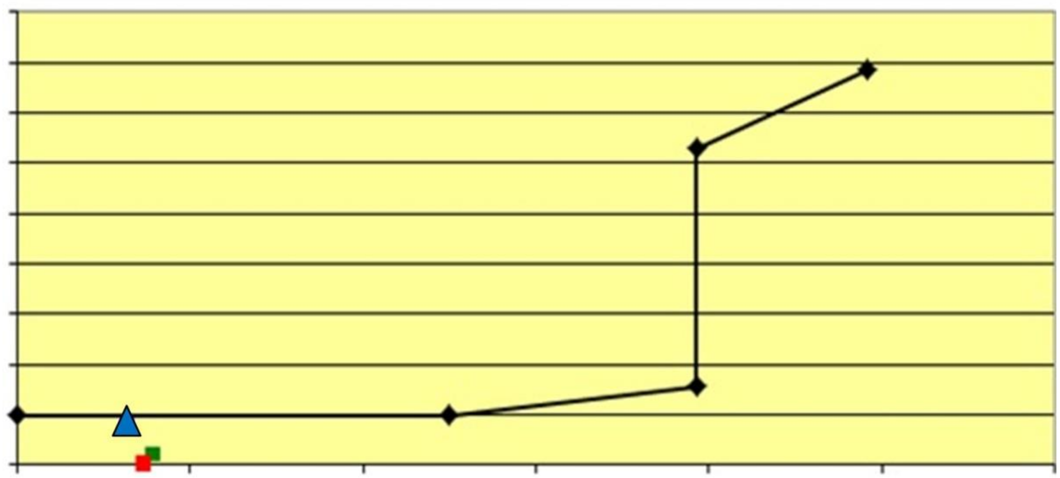

Figure 6. 87 Phase Differential Operating Characteristic

The DC offset present in fault current exponentially decays as shown in Figure 7. The digital Fourier transform algorithm cannot fully reject it.

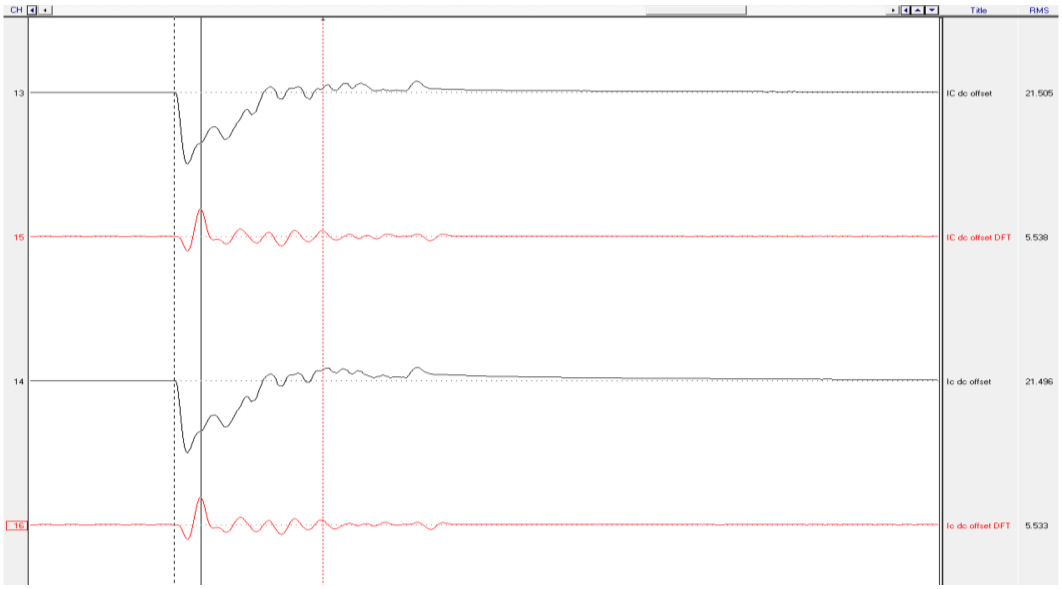

Figure 7. DC Offset Current

Best Practice: If the DC offset from transformer inrush (e.g., black start) or fault condition can cause CT saturation, then the following are appropriate for generator phase differential protection settings:

- Minimum pickup up to 0.5 amps secondary
- Slope of 20 percent
- Time delay up to 5 – 8 cycles

Detailed calculations are necessary for generator differential protection to determine if CTs can saturate; do not simply copy settings from the relay instruction book without actual verification.

Higher C class CTs can help to mitigate saturation (Figure 8).

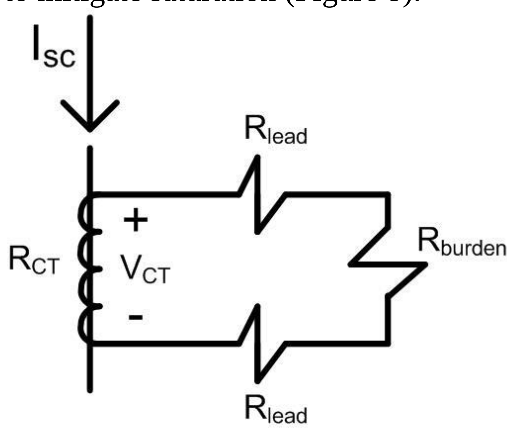

Figure 8. CT Saturation Calculation

$$V_{CT}^{MAX} = 2 \bullet (R_{CT} + 2 \bullet R_{lead} + R_{burden})$$

The factor of 2 accounts for a fully offset current waveform which is worse case.

27TN Third Harmonic Neutral Undervoltage

A utility experienced several misoperations when system voltage was low. However, the trip shown in Figure 9 occurred when the machine was under excited and drawing vars from system.

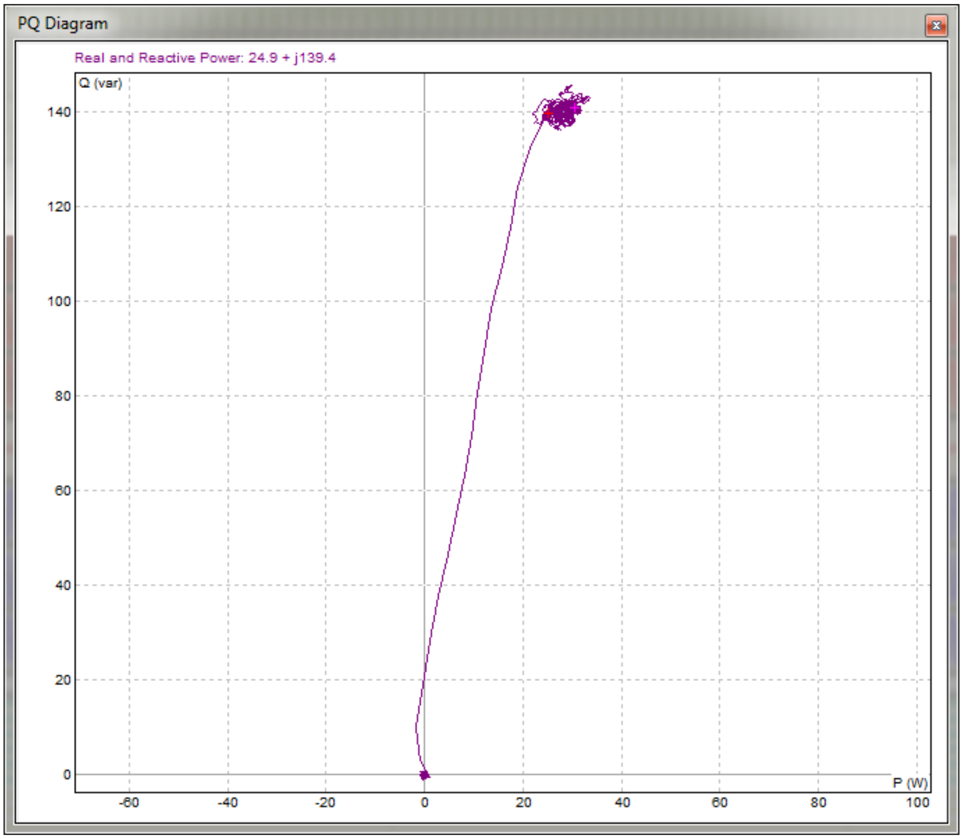

Figure 9. Machine Real and Reactive Power at time of 27TN Trip

The machine nominal power is 746.5 watts secondary.

Conventional protection (59N) cannot detect grounds in last 5 to 10 percent of stator winding. 27TN is not always reliable and may have to be blocked during specific operating conditions. If failure occurs in lower voltage portion of winding near neutral, a generator trip will not typically occur until some other relay protection detects there is a problem, (e.g., arcing becomes so widespread that other portions of winding become involved). 27TN sees stator ground faults very close to the machine neutral as shown in Figure 10.

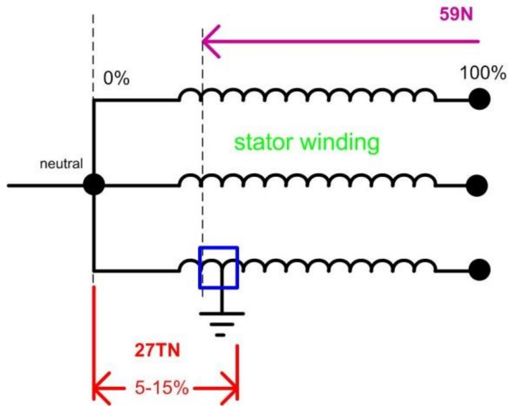

Figure 10. 27TN and 59N Zones of Stator Ground Fault Protection

Third harmonic neutral voltage changes as a function of load. The pickup setting is typically set equal to one-half of the minimum value measured during normal operation. Figure 11 illustrates how complex it can be to securely set 27TN protection by use of the blocking functions.

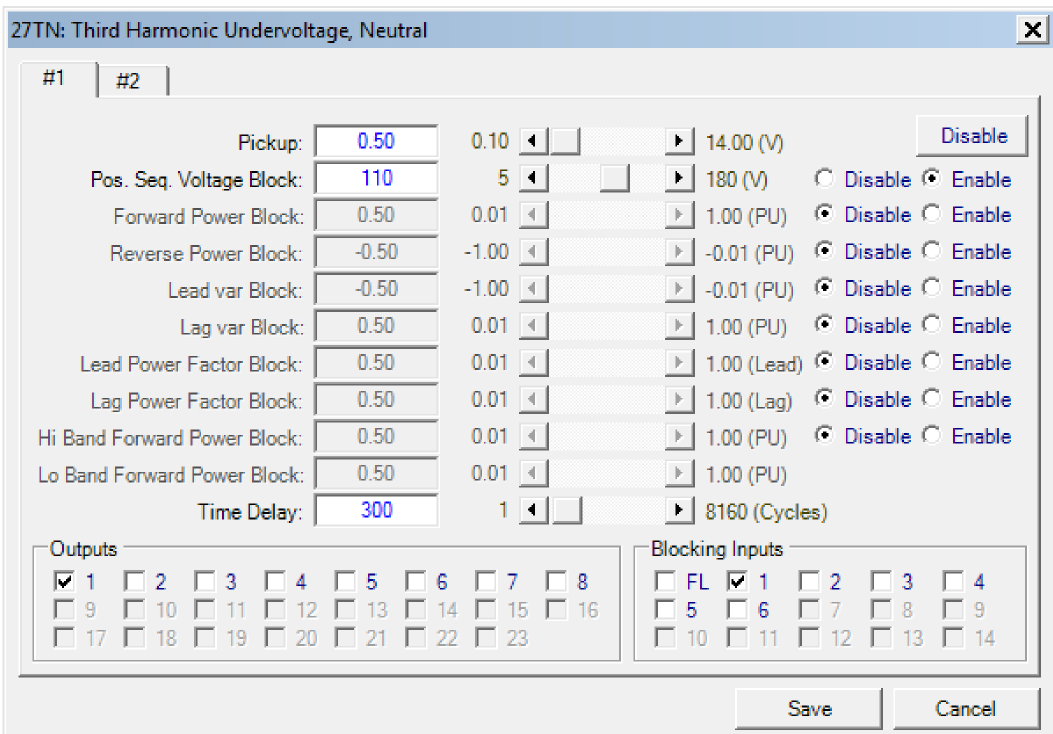

Figure 11. 27TN Settings

The solution for this particular machine is to block on low forward power as this is the prevailing system condition when the nuisance trip occurs. The main drawback to this solution is there is no protection for stator ground faults close to neutral during this operating condition.

Best Practice: The customer was urged to considering installation of 100 percent stator ground fault protection using sub-harmonic voltage injection (64S) which they did (Figure 12).

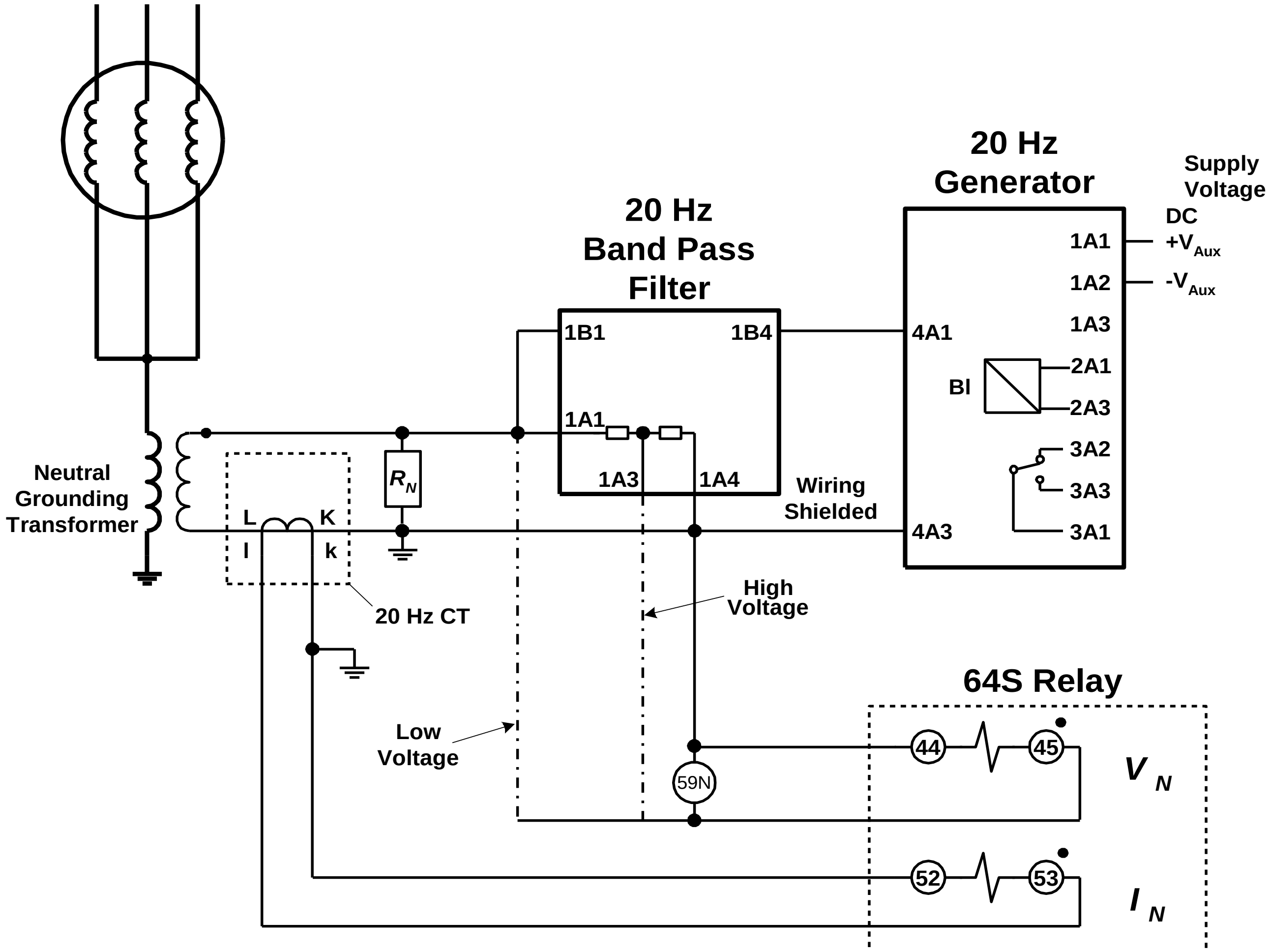

Figure 12. 64S Protection Connection Diagram

There has been recent experience with four such failures in large generators that demonstrate lack of proper protection can be disastrous. Each of four failures caused massive damage to generator and collectively had total cost, including repair and loss of generation, close to $500,000,000. This demonstrates that <u>the failure of stator windings in the last five percent of the winding is not uncommon</u>. See Figures 13A, 13B and 13C.

Figure 13A. Winding Damage - Broken Stator Winding Conductor

Figure 13B. Core and Winding Damage - Burned Open Bar in a Slot

Figure 13C. Burned Away Copper - Fractured Connection Ring

64S provides all of the following advantages:

- Detect stator ground when winding insulation first starts to break down and trip unit before catastrophic damage occurs.
- Trip in order of cycles since 20 Hz signal is decoupled from 60 Hz power system.
- Detect grounds close to machine neutral or even right at neutral thus providing 100 percent coverage of stator windings.
- Detect grounds when machine is starting up or offline.
- Reliably operate with generator in various operating modes (such as a synchronous condenser) and at all levels of real and reactive power output.
- 64S can be commissioned in less than one hour assuming there are no wiring errors. See Figure 14.

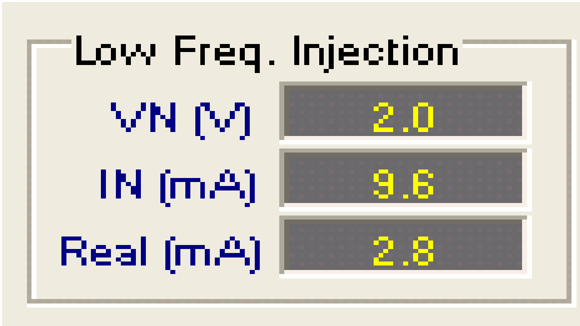

Figure 14. Numerical Generator Relay 20 Hz Metering

Incorrect Phase Rotation Settings

Numerical protection relays require a setting to determine the correct phase rotation. Figure 15 illustrates ABC phase rotation; however, some power systems are ACB.

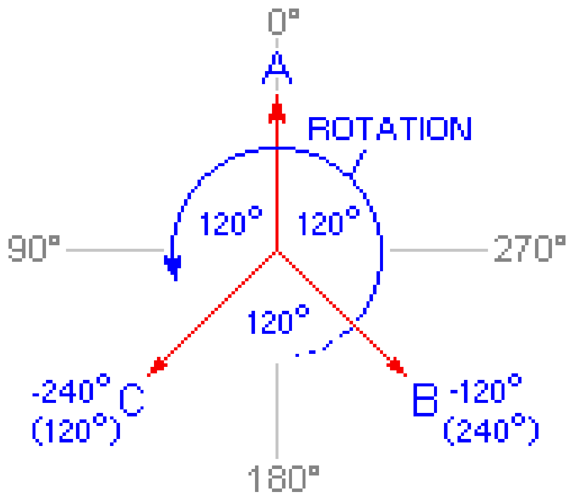

Figure 15. ABC Phase Rotation

Two customers experienced generator protection misoperations due to incorrect phase rotation settings. The first misoperation was 40 loss-of-field protection (Figure 16).

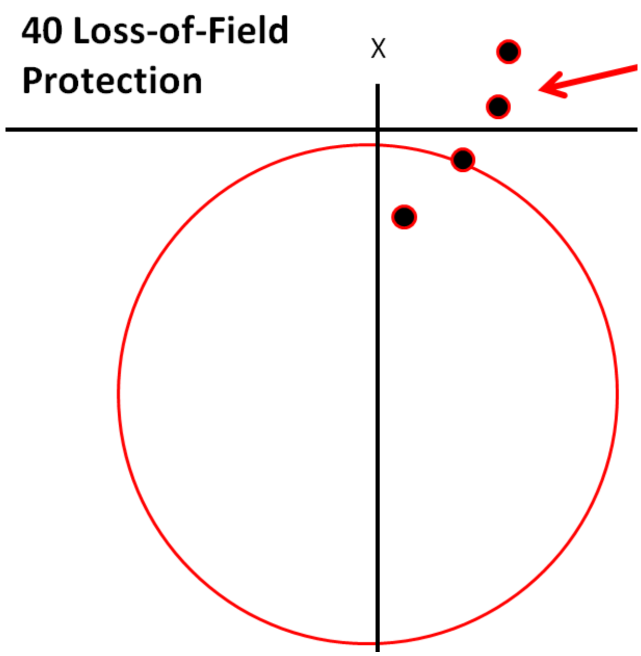

Figure 16. 40 Loss-of-Field Protection

Sequence of events:

- 40 operates on Z_1 (positive-sequence impedance)
- 40 measures incorrect impedance due to wrong phase rotation setting
- 40 trips each time customer attempts to synch the generator to the grid

The second misoperation was 78 out-of-step protection (Figure 17).

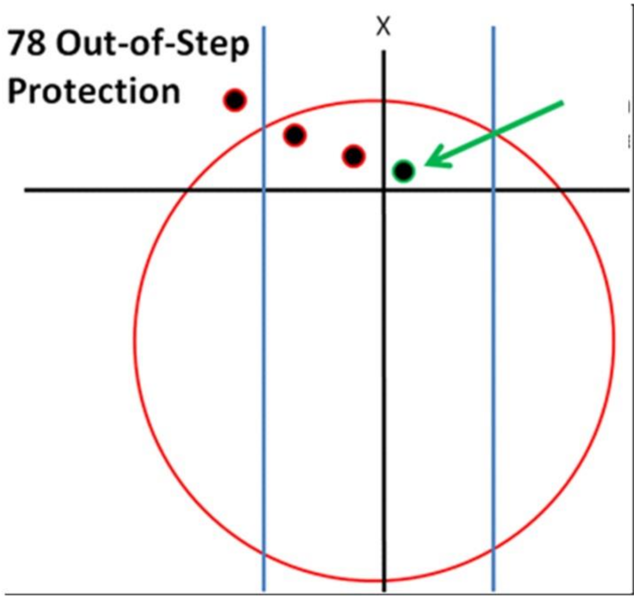

Figure 17. 78 Out-of-Step Protection

Sequence of events:

- 78 operates on Z_1 (positive-sequence impedance)
- 78 measures incorrect impedance due to wrong phase rotation setting
- 78 tripped during external event

How did either incorrect relay setting make it past commissioning? Both elements (40 and 78) were effectively operating on Z_2 (negative-sequence impedance) due to the incorrect phase rotation settings.

Best Practice: Modern numerical relays have built-in tools provided to determine the actual phase rotation. Phase rotation can quickly be checked using numerical relay metering.

Conclusions

The 2013 NERC report covered relay misoperations across the country. 33 events (over one third of the total) were due to incorrect settings, logic, testing and design errors.

Simplified software for complex applications and visualization tools can aid in enhancing proper relay settings and operation.

Corrective actions include the following steps:

- Peer reviews
- Training
- Analysis
- Standard settings templates
- Periodic reviews

Author Biography

Steve Turner, IEEE Senior Member, is a Senior Applications Engineer at Beckwith Electric Company. His previous experience includes work as an application engineer with GEC Alstom, and an application engineer in the international market for SEL, focusing on transmission line protection applications. Steve worked for Duke Energy (formerly Progress Energy), where he developed a patent for double-ended fault location on overhead transmission lines.

Steve has a BSEE and MSEE from Virginia Tech. He has presented at numerous conferences including Georgia Tech Protective Relay Conference, Western Protective Relay Conference, ECNE and Doble User Groups, as well as various international conferences.