Achieving Reliable Generator 100% Stator Ground Fault Protection

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***Abstract*—The purpose of this paper is to present setting and commissioning guidelines to achieve reliable (i.e., dependable and secure) generator 100% stator ground fault protection for large high-impedance grounded generators. Using these guidelines, a recent generator relay upgrade project is used as an example of the setting calculations where a reliable generator 100% stator ground fault protection is attained.**

***Index Terms*—Synchronous generator stator ground fault protection, 100% stator ground fault protection schemes, third-harmonic voltage and subharmonic injection schemes.**

I. Introduction

For many years, Alliant Energy has devised the protection of its large generators using two microprocessor relays from different manufacturers. Fig. 1 shows the one-line drawing of a typical large unit generator-transformer configuration with the IEEE recommended protection elements [1].

The IEEE recommended protection elements specific to stator ground protection are used to safeguard normal, reliable electric power generation during internal faults, through faults, and abnormal operating conditions.

It is well-known that the basic protection against stator single-phase to ground fault in high-impedance grounded (HIG) generators is the fundamental frequency neutral overvoltage element labeled as 64G1 in the primary relay and 59N in the secondary relay. The element is rather easy to set, but since faults near $5-10\%$ of the generator neutral result in nearly zero neutral voltage at the fundamental frequency, the element has a blind zone near the generator neutral. Hence, to achieve 100% protection coverage, it must be complemented with other protective schemes. Failing to achieve 100% protection coverage has proven to result in dire consequences [2].

Three well-known complementary schemes for stator single-phase to ground fault protection are the third-harmonic differential voltage scheme, the third-harmonic undervoltage scheme (both denoted as 64G2 in the primary relay), and the optional subharmonic injection overcurrent-based scheme, 64S in the secondary relay [3]. It is well-known that both types of 64G2 schemes have a blind zone, whereas the 64S covers the whole winding. On the other hand, for security considerations, the 64S scheme must be blocked during unit startup and ramp-down when the power frequency nears the single subharmonic injection frequency.

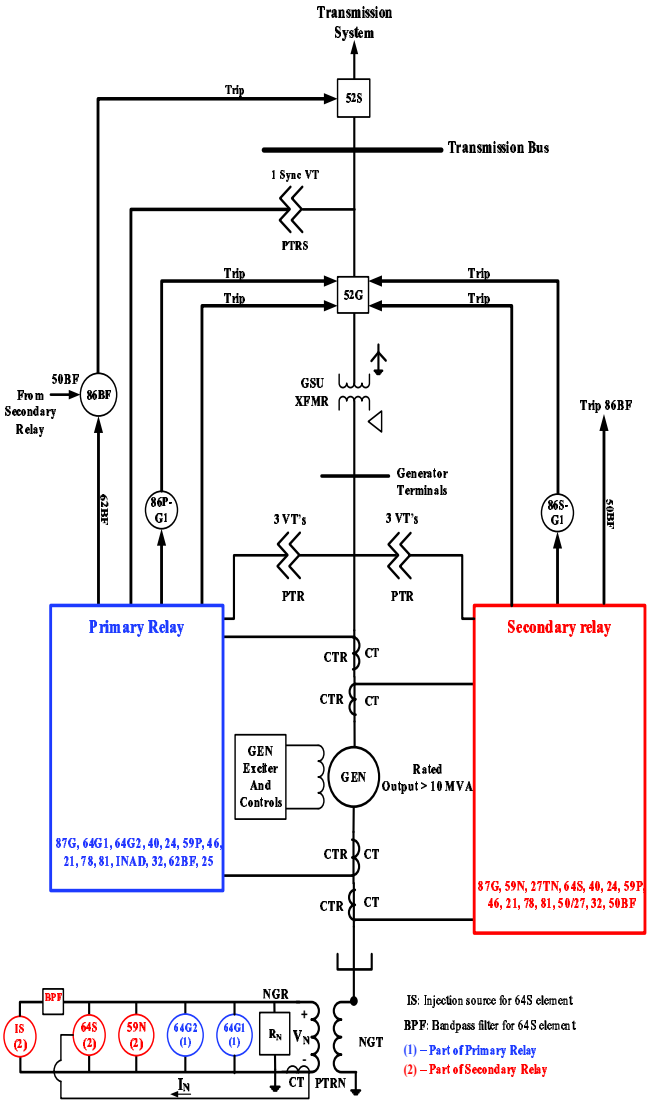

Fig. 1. One-line drawing of typical large unit generator-transformer configuration

Experience with the third-harmonic differential voltage scheme has shown that while the element is dependable, it can lack security [4]. Specifically, the element can be set securely only if comprehensive third-harmonic voltage testing is performed. Performing comprehensive third-harmonic voltage testing, however, can be a daunting task as the generator output power must be varied inside its capability

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curve, capturing as many unity and non-unity power factor operating points as possible. The paper presents a practical procedure such that testing can be done without endangering the generator stability or violating any operational limits.

Experience with the 64S element, on the other hand, has proven that the element can be set securely only if the total capacitance to ground of the generator stator windings, iso-phase bus work and delta-connected windings of the step-up transformer is known accurately [5]- [7]. Since this parameter changes when the unit is at stand-still versus when it is on-line, proper element pickup setting determination is a challenging task. This paper presents a practical procedure for arriving at dependable and secure, i.e., reliable, 64S settings.

A recent generator relay upgrade project at an Alliant Energy combined cycle power plant consisting of one 301.2 MVA steam turbine generator and two 204.0 MVA gas combustion turbine units is used as an example of the setting calculations and commissioning guidelines for achieving reliable generator 100% stator ground fault protection.

II. Stator Single-Phase to Ground Fault Protection Schemes

A common fault in generators is the single-phase to ground fault caused by insulation failure. There are several IEEE recommended stator single-phase to ground fault protection elements [1]. These elements apply to HIG generators where the single-phase to ground fault current is relatively small (3 A to 25 A, p. 32 in [1]) and therefore undetectable by generator differential relaying. In the following subsections, we shall briefly review the operational theory of these schemes.

A. Stator Ground Protection using Fundamental Frequency Neutral Overvoltage Scheme

The basic protection against stator single-phase to ground fault in HIG generators is the fundamental frequency (50 or 60 Hz) neutral overvoltage scheme denoted as 64G1 in the primary relay [8] and 59N in the secondary relay [9]. The scheme operates if the magnitude of the fundamental component of the voltage V_N across neutral grounding resistor R_N is greater than a user selected pickup setting, i.e.,

$$V_{N1} > \text{64G1P} \tag{1}$$

The pickup 64G1P can be calculated without any generator voltage testing, see p. 149 in [10]. However, since faults near the neutral result in $V_{N1} \cong 0$, the element has a blind zone near the generator neutral. Hence, to achieve 100% protection coverage, the 64G1 in the primary relay and the 59N in the secondary relay must be complemented with other protective elements.

B. 100% Stator Ground Protection using Third-Harmonic Differential Voltage Scheme

When the terminal VT is connected Wye-Wye and the generator produces more than 1% third-harmonic voltages at all operating conditions, the 64G2 element in the primary relay can be programmed as a third-harmonic differential voltage element to complement the 64G1 [8]. Here, V_{P3} and V_{N3} denote the magnitude of the third-harmonic voltages at terminal and neutral, respectively.

Fig. 2 shows the characteristics of V_{P3} and V_{N3} during normal operating conditions. These characteristics suggest that V_{P3} and V_{N3} are proportional to each other. However, the proportionality parameter 64RAT changes based on loading conditions.

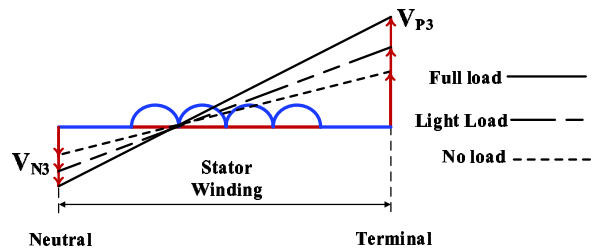

Fig. 2. Characteristics of the third-harmonic voltages during normal operations

Fig. 3 shows the characteristics of V_{P3} and V_{N3} during the neutral and terminal ground faults. Based on these characteristics, the third-harmonic differential voltage scheme operates if

$$\Delta V_3 = |V_{N3} - \text{64RAT} \times V_{P3}| > \text{64G2P} \tag{2}$$

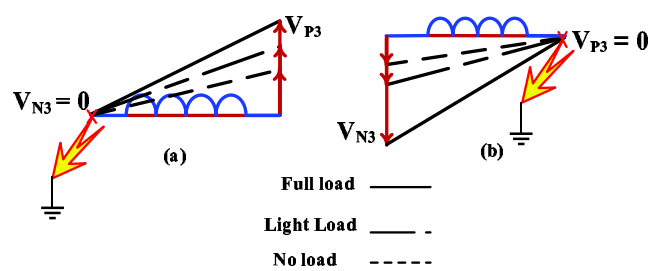

Fig. 3. (a) Ground fault at the neutral point, (b) Ground fault at the terminal point

This element is devised in the primary relay using two fixed settings for 64G2P and 64RAT. However, the calculation of these settings requires generator data. Specifically, the generator must be operated ideally over its entire capability curve while V_{P3} and V_{N3} are recorded at each operating point. Once M data points are obtained, the 64RAT setting is calculated using

$$\text{64RAT} = \frac{\sum_{i=1}^{M} V_{N3}(i)}{\sum_{i=1}^{M} V_{P3}(i)} \tag{3}$$

Moreover, a lower bound on the 64G2 pickup setting is

calculated using

$$\text{64G2P}_{min} = 1.1\left(0.1 + \max_{1\le i\le M}\{\Delta V_3(i)\}\right) \tag{4}$$

where

$$\Delta V_3(i) = |V_{N3}(i) - \text{64RAT} \times V_{P3}(i)| \tag{5}$$

Despite the added margins in (4), for the element to be secure, the pickup in (2) must be selected carefully [4]. On the other hand, for the element to be dependable, the pickup in (2) must be selected to yield at least 10% low-winding overlap coverage with the 64G1 element [8].

C. 100% *Stator Ground Protection using Third-Harmonic Stator Undervoltage Scheme*

When the generator produces more than 1% third-harmonic voltages at all operating conditions but the terminal VT is Delta connected rather than Wye-Wye, or the analysis of the collected third-harmonic voltage data reveals that the 64G2 element cannot be set reliably as third-harmonic differential voltage scheme, the 64G2 element in the primary relay and the 27TN element in the secondary relay can be set as third-harmonic neutral undervoltage elements. This element uses the fact that for a stator ground fault near neutral, V_{N3} decreases. Hence, the third-harmonic neutral undervoltage scheme operates if

$$V_{N3} < \text{64G2P} \tag{6}$$

where the pickup is typically set to 50% of the lowest V_{N3} during generator normal operation, i.e.,

$$\text{64G2P} = \frac{1}{2}\left(\min_{1\le i\le M}\{V_{N3}(i)\}\right) \tag{7}$$

In calculating the pickup, it must be emphasized that the lowest V_{N3} does not necessarily occur at the no-load operating point.

D. 100% *Stator Ground Protection using Subharmonic Injection Scheme*

As mentioned earlier, the conventional third-harmonic stator ground protection schemes are not applicable to generators with insufficient third-harmonic voltages. Hence, a variety of subharmonic injection schemes have been introduced to ensure 100% stator ground protection in HIG generators [7].

The 64S protection element in Fig. 1 is only provided by the secondary relay. Implementation of this element requires that the relay is ordered with the optional 64S element along with three external components: i) a 20 Hz injection source (IS), ii) a bandpass filter (BPF) with center frequency of 20 Hz, and iii) a 20 Hz measuring current transformer. With the bandpass filter, the injected signal impresses a 20 Hz sinusoidal voltage V_s that appears on the primary side of the neutral grounding transformer. As a result, the corresponding 20 Hz current through the stator winding and generator capacitive coupling is monitored by the 64S element. The element can be set to operate based on the magnitude of the total 20 Hz neutral current. The element can also be set more sensitively based on the real part of the total 20 Hz neutral current [5]. In either case, when the 20 Hz signal-generator is powered on, the protection is provided when the machine is on-line or off-line. As stated earlier, however, the element is blocked when the unit is spinning up or down and the power frequency nears the subharmonic injection frequency which in our case is 20 Hz.

To calculate the 64S pickup settings, the 20 Hz neutral voltage V_N and current I_N are measured at several unfaulted operating conditions along with staged faulted conditions during relay commissioning. However, since not all faulted conditions can be staged, the equivalent circuit model of the 64S element shown in Fig. 4 is used to generate calculated data complementing the measured data. Henceforth, the data obtained using the equivalent circuit model is referred to as the *calculated data*. The calculated data in the paper are obtained using the Matlab software.

To obtain calculated data, the equivalent circuit model in Fig. 4 is used to derive the following expressions for the 20 Hz neutral voltage V_N and current I_N, along with the real part of I_N, i.e.,

$$\begin{aligned} V_N(j\omega_0) &= \left(\frac{R_N(R_S\|R_F)}{\Gamma(j\omega_0)}\right)V_s(j\omega_0) \\ &= |V_N(j\omega_0)|\angle\theta \end{aligned} \tag{8}$$

$$\begin{aligned} I_N(j\omega_0) &= \frac{N^2}{n}\left(\frac{R_N(1+j\omega_0(R_S\|R_F)C_0)}{\Gamma(j\omega_0)}\right)V_s(j\omega_0) \\ &= |I_N(j\omega_0)|\angle\phi \end{aligned} \tag{9}$$

$$\text{Re}\left(I_N(j\omega_0)\right) = |I_N(j\omega_0)|\cos(\theta-\phi) \tag{10}$$

$$\begin{aligned} \Gamma(j\omega_0) &= (R_N + R_{BPF} + R_L)(R_S\|R_F) \\ &\quad + N^2R_N(R_{BPF}+R_L)(1+j\omega_0(R_S\|R_F)C_0) \end{aligned} \tag{11}$$

Here, ω_0, R_L and R_N denote the angular subharmonic frequency, the resistance associated with cable between the 20 Hz equipment, and the neutral grounding resistance, respectively. C_0 denotes the total capacitance to ground of the generator stator windings, including the iso-phase bus work and delta-connected windings of the step-up transformer. Moreover, R_S, and R_F denote the insulation resistance of unfaulted stator windings and ground fault resistance, respectively. Finally, n and N denote the subharmonic CT ratio and neutral potential transformer ratio (same as PTRN in Fig. 1), respectively. Note that R_F is added to the model so that fault values for $V_N(j\omega_0)$, $I_N(j\omega_0)$ and $\text{Re}\left(I_N(j\omega_0)\right)$ can be calculated at varying ground fault resistances.

III. CASE STUDIES

In Fall of 2019, a relay upgrade project was kicked off to replace the outdated protective relays at an Alliant Energy combined cycle power plant having one 301.2 MVA steam turbine generator (ST13) unit and two identical 204.0

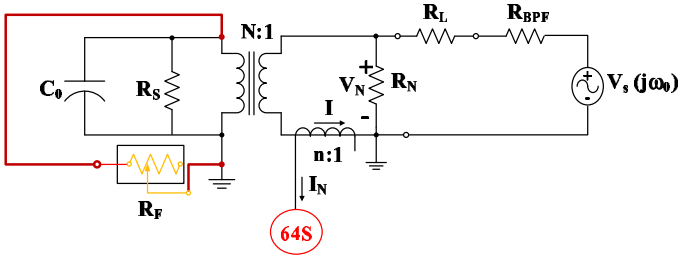

Fig. 4. Equivalent circuit model of the 64S element

MVA gas combustion turbine (GT1 and GT2) units. Table I displays the units' ratings and terminal and neutral potential transformer ratios, i.e., PTR and PTRN, respectively.

TABLE I
GENERATOR RATINGS AND AUXILIARY EQUIPMENT DATA

Unit	MW	MVAR	MVA	$\phi - \phi$ kV	PTR	PTRN
ST13	241.0	180.7	301.2	18	150	50
GT1 (GT2)	173.4	107.5	204.0	18	150	50

This section explains the process of setting the stator ground protection elements for ST13 and GT1 (GT2) in both primary and secondary relays shown in Fig. 1. In the case of ST13, it must be mentioned that the secondary relay was ordered *without* the optional 64S element.

A. Steam turbine generator case

As explained in Subsection II-A, the basic protection against stator single-phase to ground fault in HIG generators is the fundamental frequency neutral overvoltage scheme 64G1 (59N). The pickup of this element is independent of the generator loading and is set based on a selected percentage coverage using

$$64\text{G1P} = \frac{(1 - \frac{\%\ \text{Coverage}}{100}) \times (\phi - \phi\,\text{kV} \times 1000)}{\sqrt{3} \times \text{PTRN}} \tag{12}$$

Typically, a 95% recommended percent coverage is used [8] yielding the pickup

$$64\text{G1P} = \frac{(1 - \frac{95}{100}) \times (18\,\text{kV} \times 1000)}{\sqrt{3} \times 50} = 10.4 \tag{13}$$

in secondary volts (sV).

The last 5% of the stator winding and a certain percentage of the winding toward the generator terminal can be protected using the third-harmonic differential voltage scheme. However, setting the element reliably requires a thorough generator third-harmonic voltage testing.

Fig. 5 shows the ST13 power capability curve with its under-excitation and steady-state stability limits, UEL and SSSL, respectively. To collect a rich set of third-harmonic voltage test points, the generator operator is supplied with a set of operating points indicated by the square-wave trajectory inside the generator capability curve. The test points are designed to capture as many unity and non-unity power factor operating points as possible without encroaching any of the operational limits. There may, however, be some additional limitations. For example, as shown in Fig. 5, the plant normal *high maximum dispatch level* limits selecting operating points at high output power.

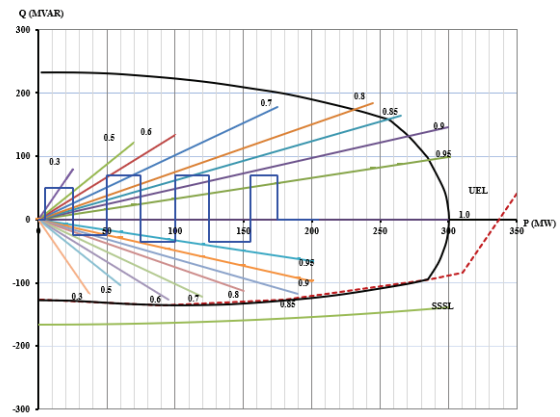

Fig. 5. ST13 capability curve with UEL and SSSL loci

During testing, the generator operator is instructed to start the unit at no-load and take it through each specified operating point. Simultaneously, the meter command (MET) in the primary relay is used to capture the third-harmonic voltages V_{P3} and V_{N3} approximately every three seconds. Since transition between the specified operating points are typically slow for steam turbine generator units, many unintended but useful intermediate data points are recorded as well. Specifically, for ST13 thirty nine test points are specified, but $M = 4193$ data points are recorded. An example of a single data point capture at lagging three-phase power factor of 0.319 is shown below.

```
=> MET
ST13 Date: 10/16/19   Time: 09:05:31.799
CB 5336/5337 ST13 SEL-300G
                  A         B         C         N         G
I MAG (A)      1562.321  1495.840  1546.634     0.000     1.266
I ANG (DEG)     -72.44    168.31     50.02   -152.42    -74.08

                  A         B         C         N         S
V MAG (KV)      10.772    10.817    10.803     0.017     0.011
V ANG (DEG)      0.00   -119.99    120.09   -160.19    122.56

                 VP3       VN3       VN1
V MAG (sV)       0.644     0.619     0.331

                  A         B         C        3P
MW                5.078     5.080     5.695   15.853
MVAR             16.044    15.362    15.707   47.114
PF                0.302     0.314     0.341    0.319
                  LAG       LAG       LAG      LAG
```

Fig. 6. An example of an operating point data capture for ST13

Once the data is collected, the primary relay manufacturer 64G element setting spreadsheet [8] is used to calculate the

64G2 settings along with its stator winding coverage and resulting overlaps with the 64G1 element. Table II shows the results.

TABLE II
64G2 SETTING'S CALCULATION

64RAT	1.0
64G2P$_{min}$	0.2
64G2P	0.3
64G2 minimum low-winding coverage	17.2%
64G2 upper-coverage boundary	32.8%
Minimum 64G1 and 64G2 overlap achieved	12.2%

Note that a unity value for the 64RAT setting implies a highly linear relationship between the third-harmonic voltage values V_{P3} and V_{N3}. Hence, in view of equation (4), a very sensitive lower bound for the pickup is obtained, i.e., 64G2P$_{min} = 0.2$.

To reduce sensitivity while maintaining element dependability, the pickup is selected at 0.3. Moreover, for the setting values in Table II, the relay manufacturer spreadsheet provides a graph of the 64G1 and 64G2 coverage at minimum element-overlap with each element's blind zone, see Fig. 7.

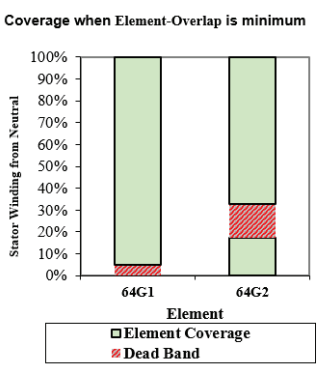

Fig. 7. 64G1 and 64G2 element-overlaps

To assess the security of the element at the selected pickup setting, equation (2) is used to obtain the 64G2 element trip boundary lines given by

$$V_{N3} = V_{P3} \pm 0.3 \tag{14}$$

The plot of trip boundary lines (red) and recorded test data points (blue) are shown in Fig. 8.

Note that by (2), the generator would be deemed faulted if the relay measures (V_{P3}, V_{N3}) values which fall above or below the upper (64G2P+), and lower (64G2P-) trip boundary lines. Hence, from Fig. 8, it appears that the selected pickup setting of 64G2P $= 0.3$ is uniformly secure. This gratifying conclusion is challenged, however, when the test data points are plotted along with the instantaneous ratio of third-harmonic voltages and the 64G2 operate quantity given by (5). Specifically, from the second plot in Fig. 9, it can be seen that the ratio $\frac{V_{N3}}{V_{P3}}$ changes slightly at low and high power output operating points. The effect of this change is clearly seen by the increase of the operate quantity ΔV_3, showing that the selected pickup setting of 64G2P $= 0.3$ is not uniformly secure for all operating points where the unit is

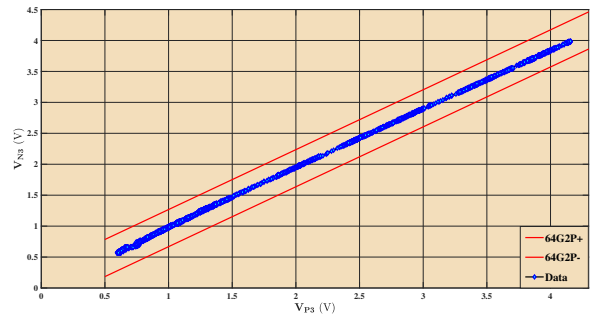

Fig. 8. ST13 third-harmonic voltage characteristics and 64G2 trip boundary lines

tested at. Specifically, security of the scheme is questionable at the high power output operating points.

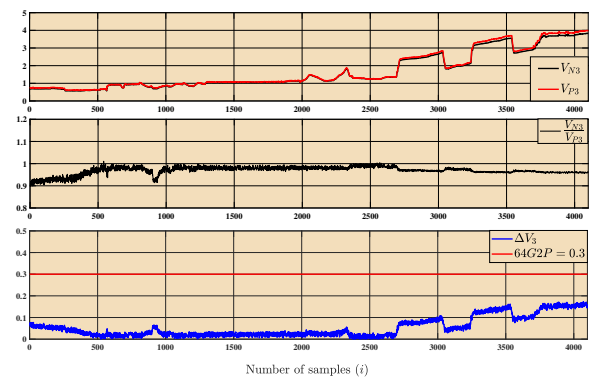

Fig. 9. 64G2 scheme response for the ST13 test data

Unfortunately, increasing the 64G2 pickup setting to the next possible level, i.e., 64G2P $= 0.4$, reduces the minimum 64G1 and 64G2 overlap to 9.6% which is less than the 10% recommended relay manufacturer spreadsheet.

Faced with this dilemma and past experience with misoperations of the 64G2 as third-harmonic differential voltage scheme [4], it is decided to set the 64G2 element as a third-harmonic undervoltage scheme in the primary relay and replicate the protection in the secondary relay's 27TN element. To do this, the minimum measured value of V_{N3} from the test data of each relay is obtained and each relay's pickup setting is calculated according to (7). The results are shown in Table III. As mentioned earlier, the secondary relay was ordered without the optional 64S element. Despite this fact, however, 100% stator ground is achieved with the 64G1 and 64G2 in the primary relay and 59N and 27TN in the secondary relay.

Using the pickup settings shown in Table III with appropriate time delays, both relays were tested and commissioned in October of 2019. After more than a year, the unit has not had any stator ground misoperation events.

B. Gas combustion turbine generator cases

The next phase of the relay upgrade project required replacing the four outdated relays on the two GT units. Here,

TABLE III
100% STATOR GROUND SETTINGS FOR ST13

Primary Relay	Secondary Relay
64G1P = 10.4 sV	59N Pickup = 10.4 sV
64RAT = 0 64G2P = 0.4 sV	27TN Pickup = 0.33 sV

it must be noted that unlike the ST13 which has only a high-side breaker as shown in the typical one-line diagram of Fig. 1, the two GT units have low-side and high-side breakers.

Per Table I, the generator rated phase-to-phase voltage, PTR and PTRN values for GT1 and GT2 are the same as the ST13 unit. Hence, the 64G1 and 59N relay settings calculate to the same values as those of ST13 shown in Table III. To protect the last $5-10\%$ of the stator winding near the neutral, it turns out that the third-harmonic differential voltage scheme is not even an option as the terminal VT's for both GT units are Delta connected.

To see if the third-harmonic undervoltage element can be set reliably, both GT's are tested. Fig. 10 shows the GT1 power capability curve along with the designed test points. GT2 power capability curve is identical. Note that similar to ST13, the plant normal high maximum dispatch level prevented obtaining test points at high output power. Moreover, whereas thirty five test points are specified, $M = 1697$ data points are recorded.

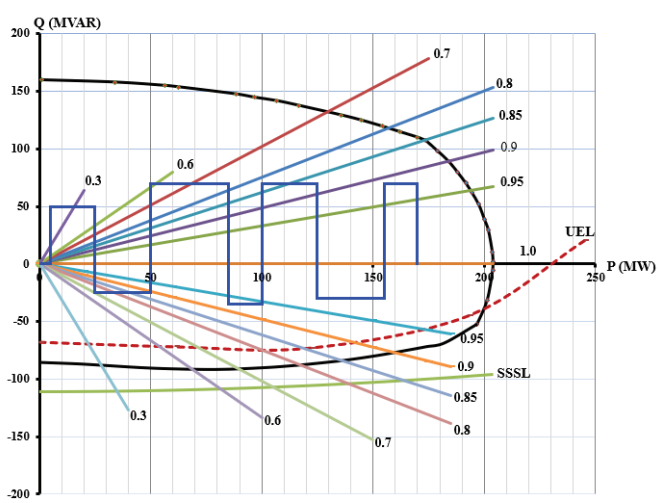

Fig. 10. GT1(GT2) capability curve with UEL and SSSL loci

Based on the collected third-harmonic test data, the minimum measured value for $V_{N3} = 0.180$ sV. The particular meter data which captured this value is shown in Fig.11. Note that this value is recorded at a 49.6 MVA leading power factor operating point. This is a clear reminder that the minimum V_{N3} does not always occur at no-load. In any case, this low value of V_{N3} cannot yield a secure setting since by (6), the pickup would need to be set at 0.09 sV. This, however, is impossible due to the element minimum pickup setting being 0.1 in both relays. Hence, to provide 100% stator ground protection, setting a reliable 64S element in the secondary relay becomes an absolute necessity. Fortunately, the optional 64S element in the secondary relay was ordered for both GT1 and GT2.

```
=> MET                                  Date: 03/22/20   Time: 13:13:46.599
GT1-BKR0011 SEL-300G
                    A          B          C          N          G
I MAG (A)      1584.492   1674.171   1675.513      0.000      0.790
I ANG (DEG)       3.74    -114.41     122.04      49.30     -80.48

                   AB         BC         CA          N          S
V MAG (KV)      17.427     17.432     17.387      0.009      0.020
V ANG (DEG)       0.00    -120.16     119.90      94.30      84.84

                  VP3        VN3        VN1
V MAG (sV)      0.000      0.180      0.179

                   3P
MW              41.175
MVAR           -27.648
PF               0.830
                 LEAD
```

Fig. 11. An example of GT1 relay meter data capture

Similar to the third-harmonic schemes, setting the overcurrent based 64S element in the secondary relay requires field data which is typically taken at stand-still, no-load and light-load. An example of a captured data of the subharmonic quantities using the secondary relay metering is shown in Fig. 12.

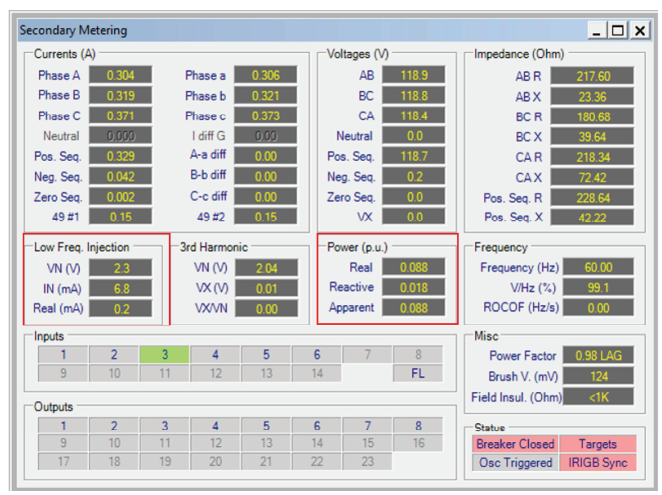

Fig. 12. An example of GT1 64S meter data capture at light-load

Table IV shows the summary of measured data as well as calculated data. Note that the required parameter values for the calculated data are those shown in Table V along with $V_s(j\omega_0) = 26\,V\angle 0°$, $R_s = \infty$, and $\omega_0 = 40\,\pi$ rad/sec.

Per Table V, the nominal value of R_N, and the generator stator windings capacitance are $0.525\,\Omega$ and $0.8171\mu F$, respectively. However, to account for resistance tolerance, temperature variations and addition of other equipment raising the capacitance (when the generator low-side breaker is

TABLE IV
64S ELEMENT MEASURED DATA VS. CALCULATED DATA

Measured Data	$\lvert V_N \rvert$ (V)	$\lvert I_N \rvert$ (mA)	Re (I_N) (mA)
1. Unfaulted at stand-still	2.1	5.2	0.0
2. Unfaulted with exciter on	2.3	5.3	0.2
3. Unfaulted at light-load	2.3	6.8	0.2
4. Staged terminal solid ground fault at stand-still	0.9	33.8	32.9
5. Staged neutral solid ground fault at stand-still	0.9	34.4	33.7
Calculated Data	$\lvert V_N \rvert$ (V)	$\lvert I_N \rvert$ (mA)	Re (I_N) (mA)
6. Unfaulted with breaker open	2.0	6.6	0
7. Unfaulted with breaker closed	2.0	7.0	0
8. Ground fault with $R_F = 100\,k\Omega$ (low-side breaker open)	2.0	6.6	0.6
9. Ground fault with $R_F = 100\,k\Omega$ (low-side breaker closed)	2.0	6.9	0.6
10. Ground fault with $R_F = 50\,k\Omega$ (low-side breaker open)	2.0	6.6	1.3
11. Ground fault with $R_F = 50\,k\Omega$ (low-side breaker closed)	2.0	6.9	1.3
12. Ground fault with $R_F = 5\,k\Omega$ (low-side breaker open)	1.5	11.1	9.9
13. Ground fault with $R_F = 5\,k\Omega$ (low-side breaker closed)	1.5	11.2	9.9
14. Ground fault with $R_F = 1\,k\Omega$ (low-side breaker open)	0.8	25.5	25.4
15. Ground fault with $R_F = 1\,k\Omega$ (low-side breaker closed)	0.8	25.5	25.4
16. Ground fault with $R_F = 0\,k\Omega$ (low-side breaker open)	0	41.6	41.6
17. Ground fault with $R_F = 0\,k\Omega$ (low-side breaker closed)	0	41.6	41.6

closed), δ_1, and δ_2 parameter uncertainties are considered. These parameter uncertainties are fixed at $\delta_1 = 0.30$ and $\delta_2 = 0.05$ to achieve a close match between the calculated and measured data.

TABLE V
64S ELEMENT EQUIVALENT CIRCUIT MODEL PARAMETERS

R_{BPF} (Ω)	R_L $(m\Omega)$	R_N (Ω)	C_0 (μF)	N	n
8	5	$(1+\delta_1)\,0.525$	$(1+\delta_2)\,0.8171$	50	78

Two observations are in order regarding Table IV values:

1) As can be seen from rows 2 and 3, I_N increases when the low-side generator breaker is closed. This increase is a direct consequence of the increase of circuit capacitance due to the addition of the unit auxiliary transformers, surge equipment, and instrument transformers.
2) As stated earlier, equations (8)-(11) represent the model of the 64S element. These equations are coded in Matlab software to generate the calculated data shown in Table IV. The model imperfection can be clearly seen by comparing rows $1-5$ with those in $6-17$. If desired, the model could be improved by including a non-ideal transformer model rather than an ideal one for the neutral grounding transformer.

Based on Table IV, the 64S overcurrent relay pickup denoted $|I_N^{PU}|$ must be set so that it operates for a ground fault at generator terminal, neutral, or any location in between, but does not operate during normal operation, i.e.,

$$\max\{\text{normal}\,|I_N|\} < |I_N^{PU}| < \min\{\text{faulty}\,|I_N|\} \tag{15}$$

The secondary relay application note [11] recommends that the $|I_N^{PU}|$ is set so that the element is sensitive enough to detect a stator ground fault with up to $1\,k\Omega$ primary ground resistance, i.e.,

$$7.0\,mA < |I_N^{PU}| < 25.5\,mA \tag{16}$$

Selecting the pickup for the 64S based on total I_N magnitude at the mid-point between the upper and lower bounds in (16) yields

$$|I_N^{PU}| = \frac{7.0+25.5}{2} = 16.3\,mA \tag{17}$$

In general, the decision whether the 64S element based on Re (I_N) should be set or not depends largely on the value of the generator total capacitance C_0. For instance, it is well-known that for hydro-generators with large C_0 value, the 64S based on the total I_N magnitude does not have an acceptable sensitivity to high-impedance ground faults [6]. For these cases, [5] suggests setting the 64S element based on the Re (I_N) in addition to the total I_N magnitude. Specifically, if the C_0 value is larger than $1.5\,\mu F$ and R_N is less than 0.3 secondary Ohm, the 64S based on the Re (I_N) is enabled and its pickup is determined based on Table IV data. Here, we have $C_0 = 0.8580\,\mu F$ and $R_N = 0.683$ secondary Ohm, which does not fall into this category. Regardless, it is prudent to set the 64S based on the Re (I_N) to backup the total I_N magnitude, and gain more sensitivity to ground faults up to $5\,k\Omega$ primary ground resistance, i.e.,

$$\max\{\text{normal Re}\,(I_N)\} < \text{Re}\,(I_N^{PU}) < \min\{\text{faulty Re}\,(I_N)\} \tag{18}$$

Using this criterion in our application, yields

$$0.2\,mA < \text{Re}\,(I_N^{PU}) < 9.9\,mA \tag{19}$$

Similar to (16), the pickup for the 64S based on the Re (I_N) is then selected as the mid-point between the upper and lower bounds in (19), i.e.,

$$\text{Re}\,(I_N^{PU}) = \frac{0.2+9.9}{2} = 5.1\,mA \tag{20}$$

The final stator ground protection element settings for the GT units are summarized in Table VI. Both units were commissioned in March of 2020 one after the other, and so far there has not been any misoperation events.

TABLE VI
100% STATOR GROUND SETTINGS FOR GT1 (GT2)

Primary Relay	**Secondary Relay**
64G1P = 10.4 sV	59N Pickup = 10.4 sV
64G2 Disabled	64S $\lvert I_N \rvert$ Pickup = 16.3 mA 64S Re (I_N) Pickup = 5.1 mA

IV. Conclusion

There are many challenges in attaining 100% stator ground protection of HIG generators. The paper presents practical means of arriving at this goal using conventional third-harmonic voltage as well as the subharmonic injection schemes. In the former case, the key ingredient to attaining reliability is conducting comprehensive generator testing followed by careful analysis of the recorded data. As seen in the paper, even then there are cases when it may be difficult to set conventional third-harmonic voltage schemes. In the latter case, however, field data and use of accurate subharmonic model are essential and can lead to reliable protection.

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