Report on Design, Testing and Commissioning of 100% Stator Ground Fault Protection at Dominion's Bath County Pumped-Storage Station

Rick Preston

Siemens Energy, Inc
Raleigh, NC USA
Richard.Preston@siemens.com

John Kandrac, PE

Dominion Energy Fossil & Hydro Technical Services
Richmond, VA USA
John.Kandrac@dom.com

Abstract

Cradled in Virginia's rugged Allegheny Mountains, the Bath County Pumped Storage Station, which went into operation in 1985, is jointly owned by Dominion and the operating companies of the Allegheny Power System, and managed by Dominion Generation. The facility, which includes six rotating machines, each operating as a synchronous generator or synchronous motor, quietly balances the power demands of homes and businesses across six states. The scheduled operation of the units is based on grid demand and changes daily. Typically, during peak demand hours, several machines will be operating as generators. Conversely, during non-peak hours, several machines will be running as motors pumping thousands of gallons of water back to the upper reservoir some 1200 ft above the powerhouse. The machines have a rated voltage of 20.5 kV which is stepped-up to 500 kV for transmission. The machines are high-impedance-grounded through single-phase neutral grounding transformers.

Several years ago the plant began upgrading their protection systems for each of the six machines. The upgrade consisted of replacing single-function electromechanical relays with redundant microprocessor-based generator protection relays. 100% Stator Ground Fault (SGF) protection (ANSI # 64S) was one of the primary enhancements made to the protection.

This paper discusses in detail the design, testing and commissioning of a 20 Hz signal injection 100% SGF protection system. The advantage this system offers over all others is the ability to detect ground faults in the stator windings and in the Iso-phase bus prior-to and during start-up of the machines. By using the sub-harmonic signal injection, the measurement of the complex ground impedance of the stator windings can be done independently of generator/motor operating modes.

INTRODUCTION

When preliminary design started, the goal was to use the latest industry-proven microprocessor-based relays to replace the existing single-function electro-mechanical relays installed at the Bath County Power Plant. The idea was not simply to replace the protection, but to enhance it and take advantage of new technologies available in the market.

For two primary reasons, the 100% Stator Ground Fault Protection is a key facet of the overall generator/motor protection.

1) After a maintenance outage and prior to releasing a unit for operation, the ground injection system is operated to ensure that no grounds exist.
2) Because the probability of a stator phase-to-ground fault is much higher than the other fault types and because the stator is connected to long runs of Isolated phase bus, reliable detection was crucial.

In addition to sensing grounds before starting, protection should encompass all four operating modes (Generation, Pumping, Synchronous Condensing, Back to Back Starting). Also, protection was required whenever the Frequency Converter was used for pump starts and for dynamic braking.

Considering all the above, the protective algorithm had to be: sensitive to ground current, insensitive to varying capacitive currents and operable through a frequency band of zero to sixty Hz. Additionally, the algorithm and its setting(s) had to eliminate any possibility of nuisance trips.

EQUIPMENT & OPERATION

The main hardware components required for this type of protection, in addition to the protective relays themselves, are auxiliary components consisting of a sub-harmonic AC signal generator, a bandpass filter, and a CT to measure the sub-harmonic current. These auxiliary components are shown below.

Figure 1: 20 Hz Generator and Bandpass Filter

Figure 2: Miniature CT to measure 20 Hz current

The picture on the left shows the 20 Hz Signal Generator and 20 Hz Bandpass. These are mounted in an enclosure adjacent to the neutral grounding transformer. The picture on the right above shows the miniature CT mounted on the secondary cable of the neutral grounding transformer. This CT is used to measure the 20 Hz current.

The output signal from the 20 Hz generator passes through the 20 Hz bandpass and is then coupled to the secondary winding of the neutral grounding transformer. The relay measures the 20 Hz voltage and current and uses these values to calculate the complex stator ground impedance. Due to the extensive lengths of Iso-Phase bus at this station, a large component of capacitive ground current is present. The relay's ability to differentiate between true resistive ground current verses capacitive ground current is imperative to detecting true stator ground faults in 100 % of the stator windings. The settings for the trip and alarm stages of the 100 % SGF protection are based on resistance thresholds rather than current thresholds, leading to high reliability.

Critical Operation and DCS Control features include:

- After a maintenance outage and before turning the unit over for grid operation, the 20 Hz injection system is started to ensure no grounds exist in the stator. Once system integrity is verified, the machine is cleared for operation.
- In generate mode 20 Hz injection is started with excitation and field current and occurs at ~ 95% speed.
- In pump or synchronous condensing mode 20 Hz injection is started when the starting breaker is open and excitation is turned on. This occurs at zero hertz when the unit is at standstill.
- In Dynamic brake mode, 20 Hz injection is started after the unit is tripped, the starting breaker is closed, and excitation is reapplied.
- In "Back to Back" starting[i], 20 Hz injection is started on the generating unit only. The injection is started when the unit spinning in the generate direction > 20 % speed

---

[i] In this *mode one machine acts as a generator while electrically locked to another in order to start it as a pump. The generating machine provides the power to bring the motor to synchronous speed and then the two machines are isolated and the motor is powered by its normal source voltage taken from the 500 kV transmission network.*

PROTECTION PHILOSOPHY

Figure 3 shows a typical unit connection with the components of generator, step-up transformer and auxiliary transformer. Depending on the plant configuration, a generator circuit breaker may also be included, which is the case at Bath County. The possible locations of a ground fault are marked in figure 3. Transient over voltages involved with insulation ageing lead to ground faults predominantly on the terminal side of the generator. Mechanical problems can also cause insulation damage, leading to a ground fault. The fault location can be anywhere in the stator winding, and a ground fault close to the neutral point of the generator is possible, too.

To minimize the damage of the stator core and winding the fault current is normally limited up to 10 A and in worst case situations up to 20 A (see figure 4). The fault current is determined by the sum of the ground capacitances on the generator side and the load resistor on the secondary side of the neutral grounding transformer.

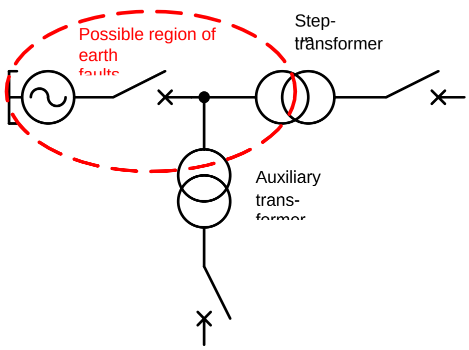


Figure 3: Typical Plant Design

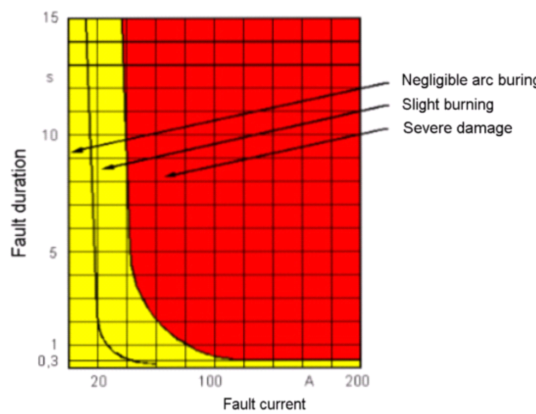


Figure 4: Influence of fault current and duration on damage to stator core

A standard protection philosophy for large power plants is to design two protection groups with independent principles for the same protection task. One group would protect 90% of the stator winding and another group would protect from 0 to 100% of the stator winding. In a transient operating range of a generator between 10 Hz and 40 Hz a low zero sequence frequency close to 20 Hz is possible from the generator side. Both signals, one from the generator and other from the 20-Hz-generator, can superimpose like a power swing and lead to improper tripping of the 20-Hz-protection (unwanted pickup). Therefore the 20-Hz-protection is internally blocked in this 10 to 40 Hz frequency range. This feature is very important at pump storage stations whenever starting as pump or dynamically braking at the end of generation or pumping cycle. Figure 5 summarizes both, the redundancy and the frequency operating range.

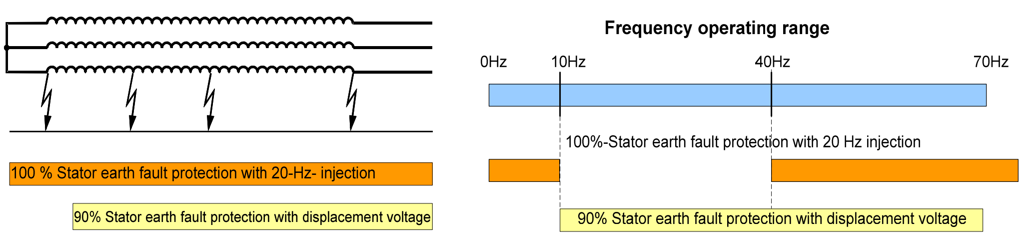


Figure 5: Redundancy and frequency operating range

As seen in figure 5, the 20-Hz-injection method is active from 0-10 Hz and then is blocked from 10-40 Hz. The function again becomes active from 40-70 Hz. The displacement voltage method is active from 11-70 Hz.

SYSTEM DESIGN

Design and analysis included evaluating: the neutral grounding transformer, the loading resistor, how to connect new hardware components into the existing system, protective settings with the recorded measurements taken while commissioning the new system.

Though some protective settings would be derived at commissioning, existing plant equipment and the basic idea of the 20 Hz system provides information for several settings that can be entered into the relay prior to commissioning. Figure 6 illustrates the basic idea of the 20-Hz-injection method.

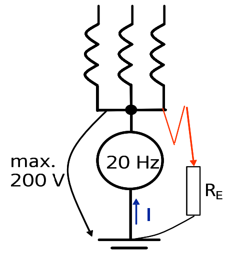


Figure 6: Basic idea of 20-Hz-injection method

As seen in figure 6, a 20-Hz-voltage with a low magnitude (< 1% of rated generator voltage) operates as an electromotive force (e.m.f) on the neutral point of the generator. With a ground fault, a closed loop exists and a 20-Hz-fault current flows. Detection is independent either of the fault's location or if the unit is on or off line. A maximum of 200 volts is shown so a decision had to be made as to whether the 20 Hz system would be connected at the 240 V tap or the 120 V tap of the neutral grounding transformer secondary. Since the maximum voltage that could be seen at the 240 V tap was calculated to be less than 200 V, it was decided to connect the 20 Hz system to the 240 volt tap. Figure 7 illustrates the practical design of the 20-Hz-injection method.

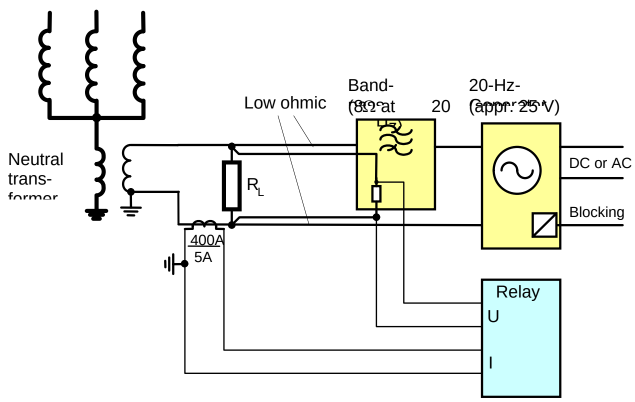


Figure 7: Practical design of the 20-Hz-injection method

Additional design considerations were the sizing of the loading resistor and verifying the 400/5 ratio of the 20 Hz measuring CT would provide measuring quantities suitable for the protection. Based on calculations of the maximum amount of ground current possible on the secondary of the neutral grounding transformer during a fault with full displacement, the 400/5 ratio of the CT was acceptable. The load resistor rating of 0.4 Ω, though slightly lower than optimal, proved suitable in limiting current in case of a solid ground fault. The internal resistance of the bandpass is 8 Ω. This resistance combined with the load resistance resulted in an injected 20 Hz voltage of $(0.4\Omega/8.4\Omega)*25\text{ V} \approx 1.2\text{ V}$. The band-pass provides a protection function also. If the load resistor carries the full displacement voltage during a terminal-to-earth fault, the higher series resistance of the bandpass protects the 20 Hz generator from excessive feedback currents. An overview of the measuring technique used by the protection relay is shown in Figure 8.

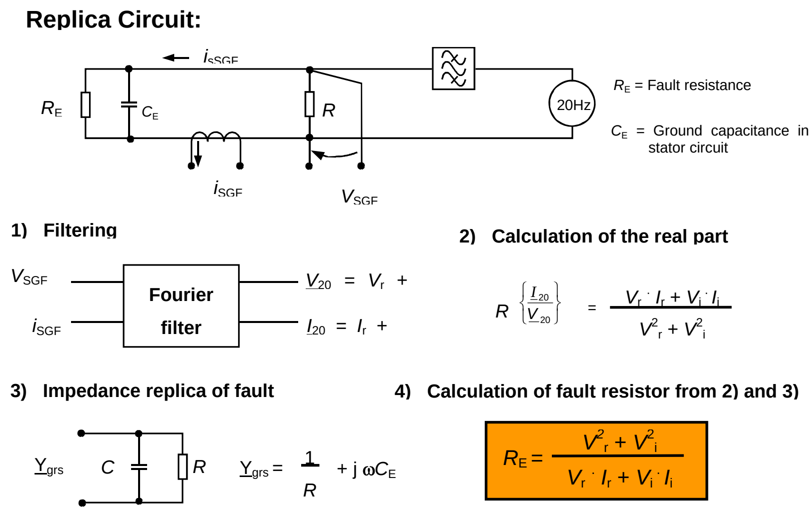


Figure 8: Replica of Numerical Measuring Technique

As seen in the measuring algorithm, the protection uses a Fourier filter to establish the values of the 20 Hz voltage and current. The real part is calculated to eliminate disturbances caused by stator ground capacitance and ensures a high sensitivity. The measuring accuracy is increased by using mean current and voltage values obtained over several cycles for calculating the resistance. In addition to determination of the ground resistance, a ground current stage of the protection is provided, which processes the rms current, and thus takes into account all frequency components. It is used as a backup stage and covers approx. 80 to 90 % of the protection zone. A monitoring circuit checks the coupled 20 Hz voltage and the 20 Hz current and detects any failure of the 20 Hz generator or of the 20 Hz connection. In such a case resistance determination is blocked. The ground current stage remains active.

Several of the protection settings can only be derived at commissioning. However, some settings were able to be derived prior to commissioning. A setting "Factor RGF" was derived. This setting represents the value, which when multiplied by the secondary measured 20 Hz impedance, would yield the primary impedance values. The calculation for this value is shown below and is based on several values and the equation below.

$$R_{Gsec} = \frac{1}{k_{transf}^{\,2}} \cdot \frac{k_{miniCT}}{k_{divider}} \cdot R_{Gpri}$$

where,

R_{Gsec} = Ground resistance, converted to the device-side

R_{Gpri} = Primary ground resistance of the stator winding (=fault resistance)

k_{transf} = Transformation ratio of the neutral transformer = 60

k_{miniCT} = Transformation ratio of the miniature CT = 400/5 = 80

$k_{divider}$ = Division Ratio of the Voltage Divider = 1 (no voltage divider was required)

therefore,

$$\text{Factor RGF} = k_{transf}^{\,2} \cdot \frac{k_{divider}}{k_{miniCT}} = 60^2 \cdot \frac{1}{80} = 45$$

In addition to the setting "Factor RGF", the setting value for the ground current stage can also be calculated prior to commissioning. It is set to a protected zone of approx. 80 %. Referenced to the maximum secondary fault current, the pickup threshold is at approx. 20 %, and the setting value is calculated as follows:

$$I_{sgf\,>>} = 0.2 \cdot \frac{V_{Nsec}}{R_L} \cdot \frac{1}{k_{miniCT}} = 0.2 \cdot \frac{240}{.4} \cdot \frac{1}{80} = 1.5\text{A}$$

The settings for the monitoring functions of the 100% SGF protection are also derived prior to commissioning. These settings provide constant monitoring of the integrity of the 20 Hz circuit by ensuring that the 20 Hz voltage exceeds a certain value and that the 20 Hz current does not fall below a certain value. Default values in the relay are typically sufficient, but since the ohmic rating of loading resistor was so low, the V20 minimum setting had to be reduced from 1 V to 0.3 V. The I20 minimum setting was left at 10 mA. The remaining settings would be derived at commissioning and are explained in the next section.

TESTING AND COMMISSIONING

Two Pre-Start tests, one fault free and the other with a grounded stator neutral, facilitated the following setting parameters.

- Stator ground resistance pickup threshold along with its time delays for alarm and trip
- Angle adjustment for error compensation

In the *fault free test*, the 20 Hz injection was initiated to capture waveforms and vector diagrams. Under this "fault-free" condition, only a small amount of capacitive 20 Hz current would be flowing. This current should be leading the 20 Hz voltage by 90°. During this test, measurements obtained from data captured by the relay's oscillographic records showed that the angle between the voltage and current was around -76°. Data was captured several times under this condition to ensure repeatable results. Figure 9 shows a capture of the 20 Hz voltage and current vectors under this condition. Based on these results, a value of -14° would be entered as the value for the angle adjustment setting.

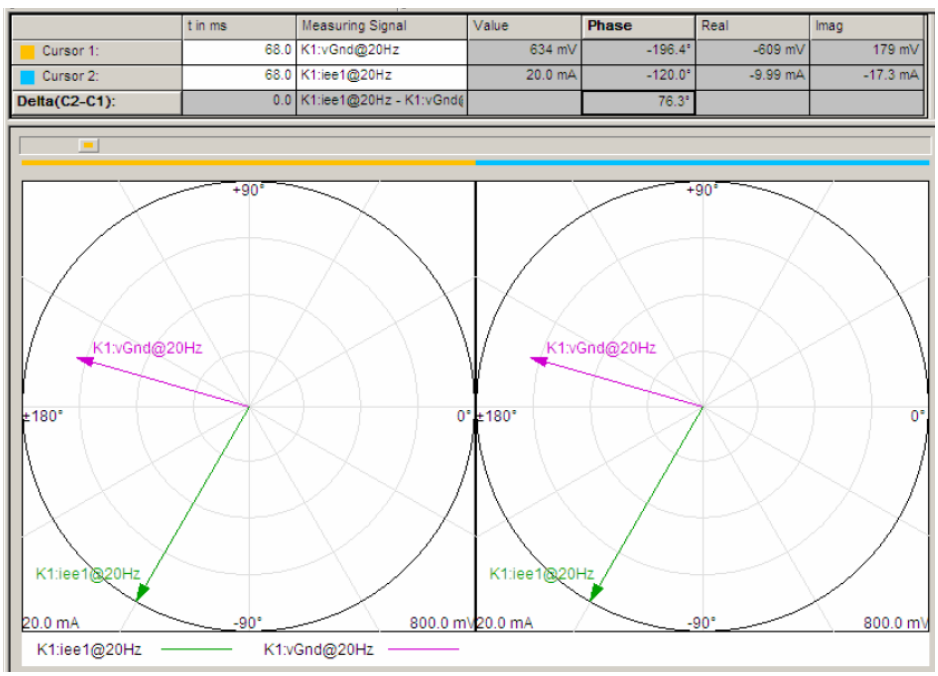


Figure 9: Capture of the 20 Hz voltage and current vectors under "fault-free" conditions.

Figure 10 shows the ground measurements of the relay prior to the setting change. The relay is calculating a stator ground resistance based on the measurement errors as indicated by measurement numbers 00764 and 00760, which are the calculated secondary and primary ground resistance values respectively. Also, measurement 00995 shows the angle measurement of -76°.

Number	Measured value	Value
00755	64R(1-3Hz): Freq. of square-wave gen.	1.4 Hz
00757	64R(1-3Hz): Volt. of square-wave gen.	50.6 V
00758	64R(1-3Hz): Curr. rotor meas. circuit	0.00 mA
00759	64R(1-3Hz): Charge at polarity rev.(Qc)	0.004 mAs
00761	64R(1-3Hz): Fault Resistance (R ground)	999.9 kOhm
00762	64G 100%: Bias volt. for stator circuit	0.7 V
00763	64G 100%: Ground curr. in stator circuit	20.8 mA
00764	64G 100%: Stator ground resistance	135 Ohm
00760	64G 100%: Prim. stator ground resistance	6.07 kOhm
00995	64G 100%: Phase angle in stator circuit	-76.0 °
00669	64G 100%: 20 Hz voltage stator circuit	0.7 V
00670	64G 100%: 20 Hz current stator circuit	20.6 mA
00627	Displacement voltage VN	0.1 V
00829	INs Senstive Ground Current 2 (Iee2)	0.0 mA

Figure 10: Ground measurement values as recorded by the relay prior to adjustment angle setting change.

After applying this setting change, another data capture in the relay was initiated and the data was analyzed. Figure 11 shows the same values as figure 10, only now the quantities have changed. The secondary and primary stator ground resistance values are showing their maximum values and the phase angle in the stator circuit is showing -90.5°.

Number	Measured value	Value
00755	64R(1-3Hz): Freq. of square-wave gen.	1.4 Hz
00757	64R(1-3Hz): Volt. of square-wave gen.	50.6 V
00758	64R(1-3Hz): Curr. rotor meas. circuit	0.00 mA
00759	64R(1-3Hz): Charge at polarity rev.(Qc)	0.004 mAs
00761	64R(1-3Hz): Fault Resistance (R ground)	999.9 kOhm
00762	64G 100%: Bias volt. for stator circuit	0.6 V
00763	64G 100%: Ground curr. in stator circuit	20.7 mA
00764	64G 100%: Stator ground resistance	9999 Ohm
00760	64G 100%: Prim. stator ground resistance	9999.99 kOhm
00995	64G 100%: Phase angle in stator circuit	-90.5 °
00669	64G 100%: 20 Hz voltage stator circuit	0.7 V
00670	64G 100%: 20 Hz current stator circuit	20.5 mA
00627	Displacement voltage VN	0.1 V
00829	INs Senstive Ground Current 2 (Iee2)	0.0 mA

Figure 11: Ground measurement values as recorded by the relay after adjustment angle setting change.

Under "fault-free" conditions, the values in figure 11 are ideally what would be measured by the relay. As seen at measurement 00670, the magnitude of the 20 Hz current has not changed. Only the angle calculation due to the setting change caused the measured resistance to go up to its maximum value.

The *Pre-Start fault test* was used to determine the stator ground resistance pickup setting. Several 20 Hz injections of short duration were placed onto a grounded neutral. In consideration that the signal generator was injecting into a constantly grounded condition, the signal durations were kept short – no more than two seconds. Initially, the "trip stage" setting was set to a default setting of 20 ohms. The objective of this test is to prove that; for a solid ground on the stator, the measured secondary ground resistance should be less than one half of the default pick up setting. If the actual ground resistance measurement is not less than half of the pick-up setting, the setting should be increased. Conversely, if the actual ground resistance measurement is considerably less than half of the pick-up setting, the setting should be decreased. Figure 12 shows data captured by the relay during an injection of the 20 Hz signal into a known grounded condition.

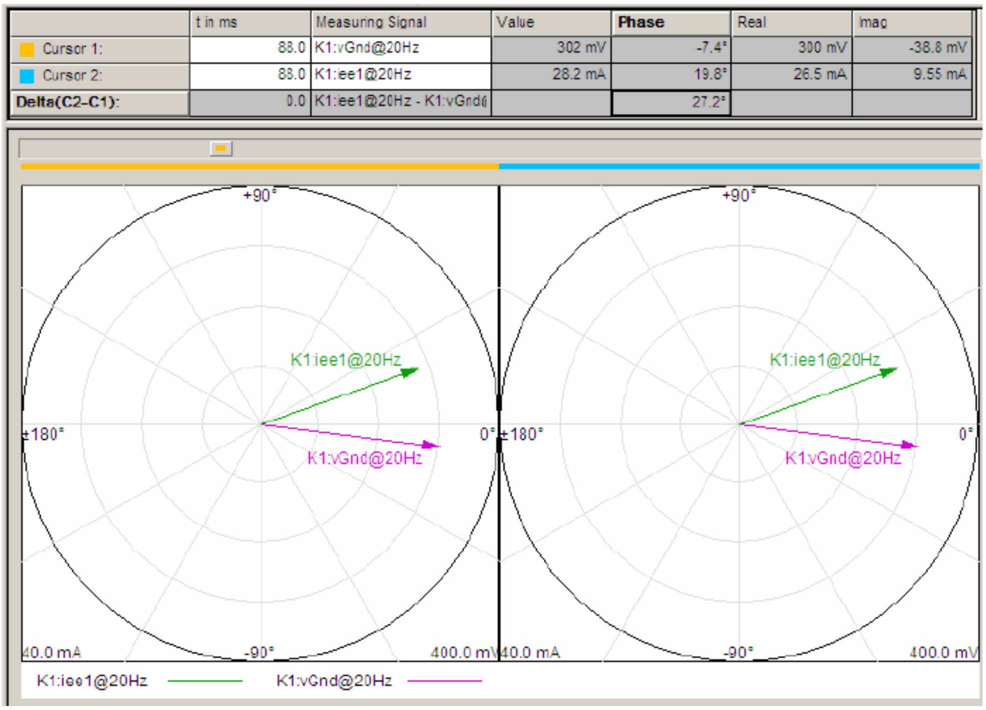


Figure 12: Capture of the 20 Hz voltage and current vectors under “grounded” conditions.

The vector diagrams shown in figure 12 show the *physical* relationship between the 20 Hz voltage and current as measured by the relay. The angle difference is indicated as -27.2°. From the data collected in the previous test, that angle would be decreased by the 14° adjustment setting and would actually be -13.2°. The calculated secondary resistance is based on that value as well as the magnitudes of the 20 Hz voltage and current of 302 mV and 28.2 mA respectively.

$$R_{Gsec} = \frac{.302}{.0282} \cdot cos(-13.2°) = 10.42\ \Omega$$

As expected, the relay did trip on 100% SGF protection considering the calculated value above is considerably less than the pick-up setting of 20 **Ω**. The fact that the calculated resistance was roughly half the pick-up, confirmed that the setting of 20 **Ω** would be acceptable.

Having completed the Pre-Start tests, efforts during start up testing would focused on how the 20 Hz injection system would perform under the planned operating conditions. The concern was not that the system would fail to operate in a grounded condition, but that it may improperly operate and trip off the unit. It was expected that the 20 Hz voltage and current vectors would move slightly depending on the loading and operating condition of the machine. Therefore, speculation did exist that a mis-operation could take place and lead to a trip of the unit. During initial runs of the unit, careful attention was paid to the calculated values of the stator ground resistance to confirm these values were above the pick-up thresholds of the protection.

The ground fault values that the relay measured and calculated would be observed in real time along with binary indications and primary measured values of the machine. The stator ground resistance value was closely observed to ensure the calculated and measured values were above the pick-up settings of the alarm and trip stages. During the first roll of the machine, several tests had to be done to check mechanical aspects such as vibration problems. Once that was completed the machine was slowly brought to synchronous speed and the ground resistance values were recorded at different frequencies. As discussed previously, the 100% SGF protection would internally block itself between generator operating frequencies of 10-40 Hz. Just prior to the machine reaching 40 Hz it was verified that the measured ground resistance was still above the pick-up threshold and that the function would not operate as it became active again. The machine was then synchronized and began to assume load. As the generator load was increased from 25% to 50% to 75% and finally to 100%, real-time ground resistance values were observed and recorded at the relay. Figure 13 below is a capture of data recorded by the relay under generating conditions at around 500 MW, nearly 100 % rated power.

Number	Measured value	Value
07742	IDiff A(I/Inominal object [%])	0.00 I/InO
07743	IDiff B(I/Inominal object [%])	0.00 I/InO
07744	IDiff C(I/Inominal object [%])	0.00 I/InO
07745	IRest A(I/Inominal object [%])	1.85 I/InO
07746	IRest B(I/Inominal object [%])	1.83 I/InO
07747	IRest C(I/Inominal object [%])	1.83 I/InO

0 ms

Number	Measured value	Value
07740	Phase angle in phase IA side 1	0 °
07741	Phase angle in phase IB side 1	240 °
07749	Phase angle in phase IC side 1	120 °
07750	Phase angle in phase IA side 2	179 °
07759	Phase angle in phase IB side 2	59 °
07760	Phase angle in phase IC side 2	300 °

Earth fault values, secondary - 3/27/2007 8:38:27.031 AM - Bath C...

Number	Measured value	Value
00755	64R(1-3Hz): Freq. of square-wave gen.	1.4 Hz
00757	64R(1-3Hz): Volt. of square-wave gen.	50.6 V
00758	64R(1-3Hz): Curr. rotor meas. circuit	0.00 mA
00759	64R(1-3Hz): Charge at polarity rev.(Qc)	0.004 mAs
00761	64R(1-3Hz): Fault Resistance (R ground)	999.9 kOhm
00762	64G 100%: Bias volt. for stator circuit	2.6 V
00763	64G 100%: Ground curr. in stator circuit	114.7 mA
00764	64G 100%: Stator ground resistance	192 Ohm
00760	64G 100%: Prim. stator ground resistance	8.64 kOhm
00995	64G 100%: Phase angle in stator circuit	-83.4 °
00669	64G 100%: 20 Hz voltage stator circuit	0.6 V
00670	64G 100%: 20 Hz current stator circuit	23.7 mA
00627	Displacement voltage VN	0.1 V
00829	INs Senstive Ground Current 2 (Iee2)	10.6 mA

Operational values, primary - 3/27/2007 8:38:20.343 AM - Bath

Number	Measured value	Value
00721	Operat. meas. current A side 1 [%] is	13.7 kA
00722	Operat. meas. current B side 1 [%] is	13.6 kA
00723	Operat. meas. current C side 1 [%] is	13.7 kA
00828	INs Senstive Ground Current 1 (Iee1)	0.3 A
00724	Operat. meas. current A side 2 [%] is	13.7 kA
00725	Operat. meas. current B side 2 [%] is	13.6 kA
00726	Operat. meas. current C side 2 [%] is	13.7 kA
00829	INs Senstive Ground Current 2 (Iee2)	6 mA
00831	3Io (zero sequence)	0.0 kA
00605	I1 (positive sequence)	13.7 kA
00606	I2 (negative sequence)	0.1 kA
00621	Va	12.22 kV
00622	Vb	12.26 kV
00623	Vc	12.23 kV
00627	Displacement voltage VN	0.01 kV
00650	VN 3rd harmonic	0.18 kV
00832	Vo (zero sequence)	0.03 kV
00629	V1 (positive sequence)	12.24 kV
00630	V2 (negative sequence)	0.02 kV
00624	Va-b	21.16 kV
00625	Vb-c	21.22 kV
00626	Vc-a	21.21 kV
00641	P (active power)	501.90 MW
00642	Q (reactive power)	16.50 MVAR
00645	S (apparent power)	502.17 MVA
00902	Power angle	1.88 °
00901	Power Factor	1.00
00644	Frequency	60.02 Hz
00765	(V/Vn) / (f/fn)	1.04
00903	Resistance	0.89 Ohm
00904	Reactance	0.03 Ohm

Figure 13: Data captured by relay during start-up run as a generator

As shown, the stator ground resistance is showing 192 Ω secondary, which is considerably higher than the "alarm-stage" pick-up threshold setting of 80 Ω. The phase angle measurement under loaded conditions was showing around -84 ° consistently as opposed to the -90 ° quantity observed at stand still. Similar angle measurements were observed and recorded during start-up operations when the machine was running as a synchronous motor. Considering this data, the angle adjustment setting was changed to -20 ° rather than the initial setting of -14 °. This proved to be a good value through commissioning and into operation.

One obstacle that did present itself and was evident during start-up was that sometimes the alarm stage of the 100% SGF protection would operate at low frequencies close to 7 Hz and cause a control room alarm. Based on the data recorded, it seemed that a 3rd-harmonic of the generating frequency at around 7 Hz, resulted in a signal of close to 20 Hz that was leading to spurious low ground resistance measurements. This harmonic induced resistance caused nuisance alarms, which required some kind of resolution. One consideration was to increase the pick-up threshold resistance of 80 Ω to a higher value. This change, while preventing the alarm around this certain frequency, would de-sensitize the protection under other operating frequencies. Another consideration, which eventually became the solution to blocking the alarm, was to configure an algorithm in the relay's PLC logic to block the alarm stage of the 100% SGF function from machine operating frequencies of 6-10 Hz. The trip stage would still be active from 0-10 Hz. Then, as mentioned, both the trip and alarm stages are dynamically blocked from 10-40 Hz normally by the protection. The functionality worked properly as the relay indicated the function being blocked dynamically at around 6-10 Hz, and the alarm to the control room ceased.

In order to complete commissioning, one last mode of operation was checked to see if the 20 Hz injection system would operate properly. This mode, a "back-to-back" operation between two adjacent machines is most challenging because the 20 Hz signal is coupled to the stators of both machines through their connecting starting bus. With this mode of operation, we expected the highest capacitive current along with a lower value of measured stator resistance which might cause nuisance tripping. If that did occur, the plan was to have a separate setting group that would activate under "back-to-back" conditions to increase the alarm threshold setting.

The first "back-to-back" operation involving the new 20 Hz injection system began as relay measured values and binary indications we observed and recorded. As done in previous tests, special attention was paid to the stator ground resistance. The entire operation resulted in no alarms of the 100% SGF protection. The ground resistance values never went below 100 Ω, which is higher than the alarm stage pick-up setting of 80 Ω. The algorithm that was used under normal starting conditions (via SFC) was again active to block the alarm stage of the function from 6-10 Hz. Figure 14 shows the captured data as recorded by the relay during a "back-to-back" starting condition. The magnitude of the 20 Hz current is noted to be higher (25 mA vs. 22 mA) than is the case in a normal starting mode. However, the ground resistance remained above the alarm threshold and no alarms were issued. Consequently, a second setting group was not required.

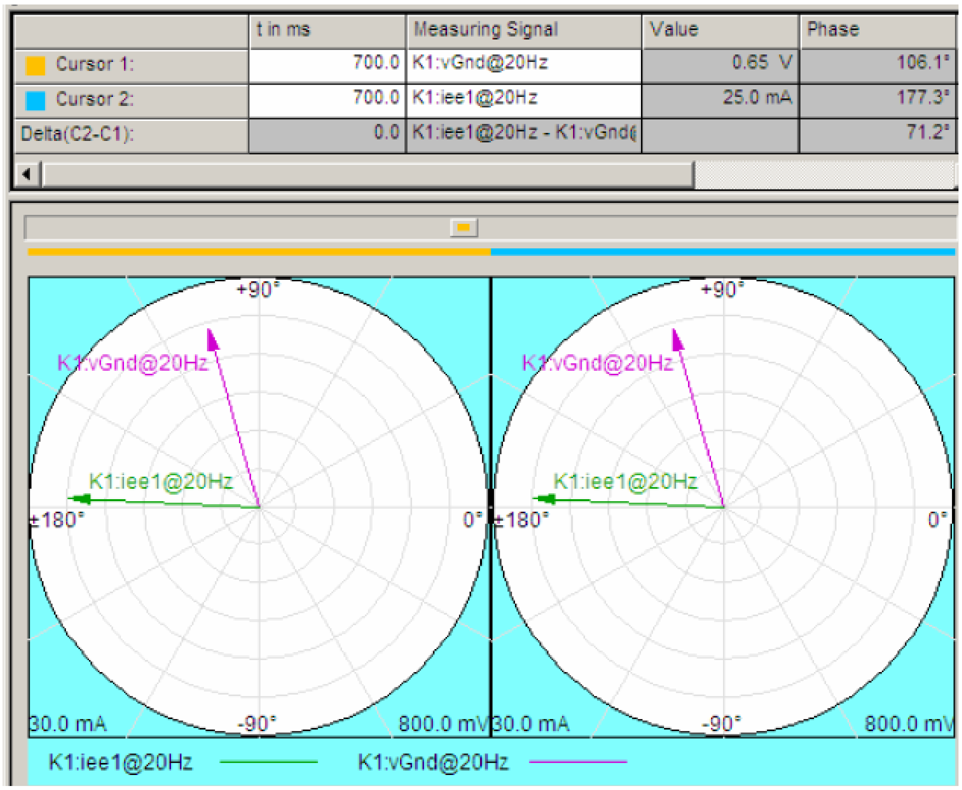


Figure 14: Capture of the 20 Hz voltage and current vectors under "back-to-back" conditions.

CONCLUSIONS

In the past, 100% stator ground protection was not often applied, but today, the relay protection engineer has many considerations in applying this protection. An operating utility first must establish standards to define the MVA ratings where this protection is desired. Next, the choices in harmonic detections or sub harmonic injection must be evaluated and applied for each installation. Any stations having cross compound generation, pumped storage generation, or long runs of Iso-phase bus are ideal applications for the sub-harmonic injection method. In this Pumped Storage Plant, the sub-harmonic injection method has proven benefits because it is independent of generator operating conditions, and it verifies that no grounded phase conditions exist prior to starting a unit. Trending the stator ground resistance is also beneficial in detecting possible winding insulation degradation.

ATTACHMENTS

1. Bath County One Line Diagram

2. DCS control Logic – 100% Stator Ground Injection

REFERENCES

[1] IEEE Guide for the application of neutral grounding in electrical utility systems. Part II – Grounding of synchronous generator systems, published by IEEE, New York, 1989

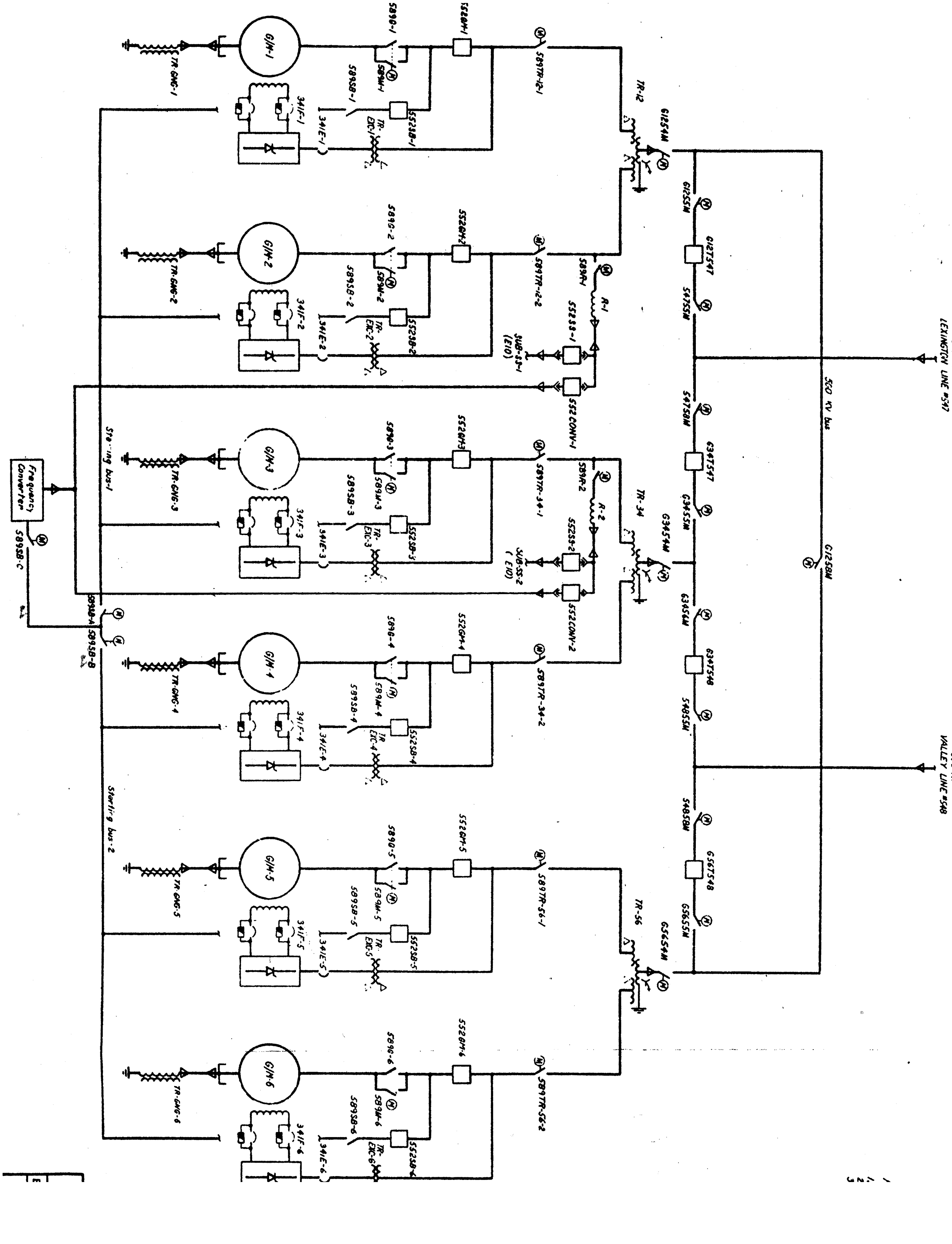
[2] Planning Machine Protection Systems, Siemens application guide, No. E50400-U0089-U412-A2-7600

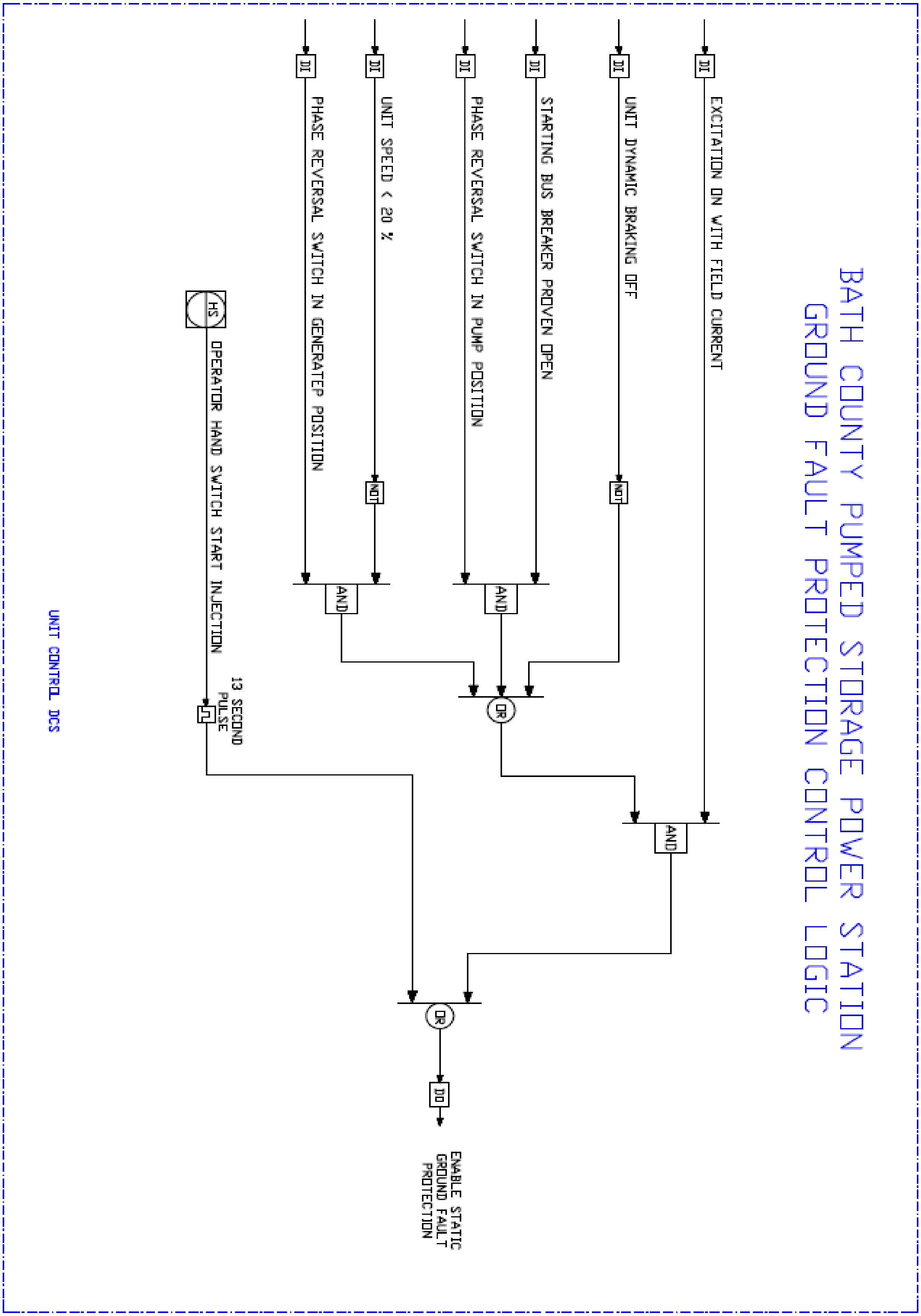
[3] SIPROTEC 7UM62 V4.6, Multifunction Generator, Motor and Transformer Protection Relay, Manual No C5300-G1176-C149-4

BIOGRAPHY

John Kandrac received his B.E.E.T. from the Pennsylvania State University in 1975 and his MBA from the University of Richmond in 2000. Upon graduation he joined Virginia Electric & Power Company in 1975 and is presently a Consulting Engineer providing both Project and Electrical Engineering support for Dominion Resources Fossil & Hydro Generating Plants. Mr. Kandrac is a registered Professional Engineer in the Commonwealth of Virginia.

Rick Preston has over nine years experience in the Protective Relaying industry. He studied Electrical Engineering at North Carolina State University in Raleigh, NC. In 1999, he was hired by Siemens as an Applications Engineer for the protective relay group. Rick has extensive experience testing and commissioning numerical protective relays as well as designing relay systems. While his primary focus is generator protection, Rick has a vast background in testing and designing a wide array of protective relaying applications


G/M-1
G/M-2
G/M-3
G/M-4
G/M-5
G/M-6
TR-12
TR-34
TR-56
R-1
R-2
500 KV LEXINGTON LINE #547
500 KV VALLEY LINE #548
500 KV bus
Frequency Converter
Starting bus-2



BACK TO THE TABLE OF CONTENTS