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Before joining Beckwith Electric, Wayne performed in application, sales and marketing management capacities with PowerSecure, General Electric, Siemens Power T&D and Alstom T&D. During the course of Wayne's participation in the industry, his focus has been on the application of protection and control systems for electrical generation, transmission, distribution, and distributed energy resources.

Wayne is very active in IEEE as a Senior Member serving as a Main Committee Member of the IEEE Power System Relaying Committee for 25 years. His IEEE tenure includes having chaired the Rotating Machinery Protection Subcommittee (‘07-’10), contributing to numerous standards, guides, transactions, reports and tutorials, and teaching at the T&D Conference and various local PES and IAS chapters. He has authored and presented numerous technical papers and contributed to McGraw-Hill's “Standard Handbook of Power Plant Engineering, 2nd Ed.”
Generator Construction: Simple Bock Diagram

Prime Mover (Mechanical Input)

DC Field Source

Three-Phase Electrical Output

Three Phase

- Phase A
- Phase B
- Phase C

Degrees

Magnitude

Generate Diagram
Applying Mechanical Input

1. Reciprocating Engines
2. Hydroelectric
3. Gas Turbines (GTs, CGTs)
4. Steam Turbines (STs)
Applying Field

Static Exciter

- DC is induced in the rotor
- AC is induced in the stator
- Cylindrical rotor seen in Recips, GTs and STs
- Salient pole rotor seen in Hydros
  - More poles to obtain nominal frequency at low RPM
  - Eq: \[ f = \frac{\text{RPM}}{60} \times \frac{P}{2} = \frac{\text{RPM} \times P}{120} \]
Cylindrical Rotor & Stator
Salient Pole Rotor & Stator
Generator Behavior During Short Circuits

\[ I_{\text{Gen}} \]

\[ I_{\text{System}} \]

Current

\[ I_{\text{System}} \]

I\text{Gen} Current Decay

0

Time

Generator Breaker Trips

Power System
Generator Short-Circuit Current Decay

Subtransient Period

Transient Period

Steady-State Period

Actual Envelope

Extrapolation of Transient Envelope

Extrapolation of Steady Value

1/X''_d = % Impedance
1/% Impedance = X''_d
FLA / % Impedance = SSA
Effect of DC Offsets

Three-Phase Fault

Current

DC Component

Time

Phase A

Phase B

Phase C

Generator Protection

11
Grounding Techniques

- Why Ground?
  - Improved safety by allowing detection of faulted equipment
  - Stop transient overvoltages
    - Notorious in ungrounded systems
  - Ability to detect a ground fault before a multiphase to ground fault evolves
  - If impedance is introduced, limit ground fault current and associated damage faults
  - Provide ground source for other system protection (other zones supplied from generator)
Types of Generator Grounding

- **Low Impedance**
  - Good ground source
    - The lower the R, the better the ground source
    - The lower the R, the more damage to the generator on internal ground fault
  - Can get expensive as resistor voltage rating goes up
  - Generator will be damaged on internal ground fault
    - Ground fault current typically 200-400 A
Types of Generator Grounding

- **High Impedance**
  - With delta/wye GSU, creates “unit connection”
  - System ground source obtained from GSU
  - Uses principle of reflected impedance
    - Eq: $R_{NGR} = R_R / \left(\frac{V_{pri}}{V_{sec}}\right)^2$
    - $R_{NGR} = \text{Neutral Grounding Resistor Resistance}$
    - $R_R = \text{Reflected Resistance}$
  - Ground fault current typically $\leq 10A$
Hybrid Impedance Grounding

- Has advantages of Low-Z and High-Z ground
- Normal Operation
  - Low-Z grounded machine provides ground source for other zones under normal conditions
    - 51G acts as back up protection for uncleared system ground faults
    - 51G is too slow to protect generator for internal fault

Ground Fault in Machine

- Detected by the 87GD element
- The Low-Z ground path is opened by a vacuum switch
- Only High-Z ground path is then available
  - The High-Z ground path limits fault current to approximately 10A (stops generator damage)
Hybrid Ground
Converts from low-Z to high-Z for internal generator fault
Types of Generator Ground Fault Damage

- Following pictures show stator damage after an internal ground fault
- This generator was high impedance grounded, with the fault current less than 10A
- Some iron burning occurred, but the damage was repairable
- With low impedance grounded machines the damage is severe
Stator Ground Fault Damage
Stator Ground Fault Damage
Stator Ground Fault Damage
Generator Protection

Stator Ground Fault Damage
Types of Generator Connections

- **Bus or Direct Connected (typically Low Z)**
  - Directly connected to bus
  - Likely in industrial, commercial, and isolated systems
  - Simple, inexpensive
Types of Generator Connections

- Multiple Direct or Bus Connected (No/Low Z/High Z)
  - Directly connected to bus
  - Likely in industrial, commercial, and isolated systems
  - Simple
  - May have problems with circulating current
    - Use of single grounded machine can help
  - Adds complexity to discriminate ground fault source

Same type of grounding used on 1 or multiple generators
Bus (Direct) Connected

- Generator Protection

Diagram showing a bus (direct) connected to generators with unit auxiliary transformer and reactor or resistor.
Types of Generator Connections

- **Unit Connected (High Z)**
  - Generator has dedicated unit transformer
  - Generator has dedicated ground transformer
  - Likely in large industrial and utility systems
  - 100% stator ground fault protection available
Types of Generator Connections

- **Multiple Bus (High Z), 1 or Multiple Generators**
  - Connected through one unit xfmr
  - Likely in large industrial and utility systems
  - No circulating current issue
  - Adds complexity to discriminate ground fault source
    - Special CTs needed for sensitivity, and directional ground overcurrent elements
Unit Connected
Generator Protection Overview

Internal and External Short Circuits
Abnormal Operating Conditions

Generator Protection Overview

- Loss of Field
- Overexcitation
- Open Circuits
- Loss of Field
- Abnormal Frequency
- Reverse Power
- Inadvertent Energizing, Pole Flashover
- Breaker Failure
- Loss of Synchronism
- Overexcitation

"Wild" Power System

Exciter
Typical Unit Connected Generator (C37.102)

Unit Connected, High Z Grounded

Notes:
1. Dotted devices optional.
3. See Chapter 2.2 regarding 100 percent ground protection.
4. Device 50 requires external time. See Chapter 4.1.
Stator Ground Fault-High Z Grounded Machines

- 95% stator ground fault provided by 59G
  Tuned to the fundamental frequency
  - Must work properly from 10 to 80 Hz to provide protection during startup

- Additional coverage near neutral (last 5%) provided by:
  - 27TN: 3rd harmonic undervoltage
  - 59D: Ratio of 3rd harmonic at terminal and neutral ends of winding

- Full 100% stator coverage by 64S
  - Use of sub-harmonic injection
  - May be used when generator is off-line
  - Immune to changes in loading (MW, MVAR)
Stator Ground Fault (59G)

- High impedance ground limits ground fault current to about 10A
  - Limits damage on internal ground fault
- Conventional neutral overvoltage relay provides 90-95% stator coverage
- Last 5-10% near neutral not covered
- Undetected grounds in this region bypass grounding transformer, solidly grounding the machine!
Neutral grounding transformer (NGT) ratio selected that provides 120 to 240V for ground fault at machine terminals

- Max L-G volts = 13.8kV / 1.73 = 7995V
- Max NGT volts sec. = 7995V / 120V = 66.39 VTR
59G System Ground Fault Issue

- GSU provides capacitive coupling for system ground faults into generator zone
- Use two levels of 59G with short and long time delays for selectivity
- **Cannot** detect ground faults at/near the neutral (very important)
Multiple 59G Element Application

- **59G-1**, set in this example to 5%, may sense capacitance coupled out-of-zone ground fault
  - Long time delay

- **59G-2**, set in this example to 15%, is set above capacitance coupled out-of-zone ground fault
  - Short time delay
Use of Symmetrical Component Quantities to Supervise 59G Tripping Speed

- Both $V_2$ and $I_2$ implementation have been applied
  - A ground fault in the generator zone produces primarily zero sequence voltage
  - A fault in the VT secondary or system (GSU coupled) generates negative sequence quantities in addition to zero sequence voltage
59G – Generator Neutral Overvoltage: Three setpoints

- 1\(^{st}\) level set sensitive to cover down to 5% of stator
  - Long delay to coordinate with close-in system ground faults capacitively coupled across GSU

- 2\(^{nd}\) level set higher than the capacitively coupled voltage so coordination from system ground faults is not necessary
  - Allows higher speed tripping
  - Only need to coordinate with PT fuses

- 3\(^{rd}\) level may be set to initiate waveform capture and not trip, set as intermittent arcing fault protection
59G/27TN Timing Logic

Interval and Delay Timers used together to detect intermittent pickups of arcing ground fault
Intermittent Arcing Ground Fault Turned Multiphase
Why Do We Care About Faults Near Neutral?

- A fault at or near the neutral shunts the high resistance that saves the stator from large currents with an internal ground fault.
- A generator operating with an undetected ground fault near the neutral is an accident waiting to happen.
- We can use 3rd Harmonic or Injection Techniques for complete (100%) coverage.
Third-Harmonic Rotor Flux

- Develops in stator due to imperfections in winding and system connections.
- Unpredictable amount requiring field observation at various operating conditions.
- Also dependent on pitch of the windings, which a method to define the way stator windings placed in the stator slots.
Generator winding and terminal capacitances (C) provide path for the third-harmonic stator current via grounding resistor.

This can be applied in protection schemes for enhanced ground fault protection coverage.
Generator Capacitance and 3<sup>rd</sup> Harmonics

- 3<sup>rd</sup> harmonics are produced by some generators
  - Amount typically small
    - Lumped capacitance on each stator end is C<sub>S</sub>/2.
  - C<sub>T</sub> is added at terminal end due to surge caps and isophase bus
  - Effect is 3<sup>rd</sup> harmonic null point is shifted toward terminal end and not balanced
3rd Harmonic in Generators

- 3rd harmonic may be present in terminal and neutral ends

- Useful for ground fault detection near neutral
  - If 3rd harmonic goes away, conclude a ground fault near neutral

- 3rd harmonic varies with loading
27TN – 3\textsuperscript{rd} Harmonic Neutral Undervoltage

- Provides 0-15\% stator winding coverage (typ.)
- Tuned to 3\textsuperscript{rd} harmonic frequency
- Provides two levels of setpoints
- Supervisions for increased security under various loading conditions: Any or All May be Applied Simultaneously

- Phase Overvoltage Supervision
- Underpower Block
- Forward & Reverse
- Under VAr Block; Lead & Lag
- Power Factor Block; Lead & Lag
- Definable Power Band Block

- Undervoltage/No Voltage Block
- Varies with load
- May vary with power flow direction
- May vary with level
- May vary with lead and lag
- May be gaps in output

\textit{Loading/operating variables may be Sync Condenser, VAr Sink, Pumped Storage, CT Starting, Power Output Reduction}
3\textsuperscript{rd} Harmonic in Generators:

**Typical 3\textsuperscript{rd} Harmonic Values**

<table>
<thead>
<tr>
<th>UNIT LOAD</th>
<th>180 HZ RMS VOLTAGE</th>
<th>VOLTAGE RATIO</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW</td>
<td>NEUTRAL</td>
<td>TERMINAL</td>
</tr>
<tr>
<td>0</td>
<td>2.8</td>
<td>2.7</td>
</tr>
<tr>
<td>7</td>
<td>2.5</td>
<td>3.7</td>
</tr>
<tr>
<td>35</td>
<td>2.7</td>
<td>3.8</td>
</tr>
<tr>
<td>105</td>
<td>4.2</td>
<td>5.0</td>
</tr>
<tr>
<td>175</td>
<td>5.5</td>
<td>6.2</td>
</tr>
<tr>
<td>340</td>
<td>8.0</td>
<td>8.0</td>
</tr>
</tbody>
</table>

Magnitudes of Third Harmonic Voltages for a Typical Generator

- 3\textsuperscript{rd} harmonic values tend to increase with power and VAr loading
- Fault near neutral causes 3\textsuperscript{rd} harmonic voltage at neutral to go to zero volts
Example 3rd Harmonic Plot: Effects of MW and MVAR Loading
100% Stator Ground Fault (59G/27TN)

Third-Harmonic Undervoltage Ground-Fault Protection Scheme
100% Stator Ground Fault (59G/27TN)

Overlap of Third Harmonic (27TN) with 59G Relay
59D – 3\textsuperscript{rd} Harmonic Ratio Voltage

- Examines 3rd harmonic at line and neutral ends of generator
- Provides 0-15% and 85-100% stator winding coverage (typ.)
- Does not have a security issue with loading, as can a 27TN
  - May be less reliable than 27TN (not enough difference to trip)
- “Blind spot” at mid-winding protected by 59G
- Needs wye PTs; cannot use delta PTs
59D – 3rd Harmonic Ratio Voltage

- Employs comparison of 3\textsuperscript{rd} harmonic voltages at terminal and neutral ends
- These voltages are fairly close to each other
- One goes very low if a ground fault occurs at either end of the winding
Stator Ground Faults: 59N, 27TN, 59D
Subharmonic Injection: 64S

- 20Hz injected into grounding transformer secondary circuit
- Rise in *real component* of injected current suggests resistive ground fault
- Ignores *capacitive* current due to isophase bus and surge caps
  - Uses it for self-diagnostic and system integrity

Notes:
- Subharmonic injection frequency = 20 Hz
- Coupling filter tuned for subharmonic frequency
- Measurement inputs tuned to respond to subharmonic frequency
Generator Protection

64S: Stator Ground Faults – Subharmonic Injection

- Injects subharmonic frequency into generator neutral
  - Does not rely on third harmonic signature of generator

- Provides full coverage protection

- Provides on and offline protection, prevents serious damage upon application of excitation

- Frequency independent
Stator Ground Faults: High Z Element Coverage
Brushed and “Brushless” Excitation

Generator Protection

Brushed

“Brushless”
Field/Rotor Ground Fault

- Traditional field/rotor circuit ground fault protection schemes employ DC voltage detection
  - Schemes based on DC principles are subject to security issues during field forcing, other sudden shifts in field current and system transients
DC-Based 64F
Field/Rotor Ground Fault (64F)

- To mitigate the security issues of traditional DC-based rotor ground fault protection schemes, AC injection based protection may be used.
  - AC injection-based protection ignores the effects of sudden DC current changes in the field/rotor circuits and attendant DC scheme security issues.
Advanced AC Injection Method

Generator Protection

Exciter Breaker

Exciter

Field

Square Wave Generator

Signal Measurement & Processing

Protective Relay

Coupling Network
Advanced AC Injection Method: Advantages

- Scheme is secure against the effects of DC transients in the field/rotor circuit
  - DC systems are prone to false alarms and false trips, so they sometimes are ignored or rendered inoperative, placing the generator at risk
  - The AC system offers greater security so this important protection is not ignored or rendered inoperative

- Scheme can detect a rise in impedance which is characteristic of grounding brush lift-off
  - In brushless systems, the measurement brush may be periodically connected for short time intervals
  - The brush lift-off function must be blocked during the time interval the measurement brush is disconnected
Rotor Ground Fault Measurement

- Plan a shutdown to determine why impedance is lowering, versus an eventual unplanned trip!
- When resistive fault develops, $V_f$ goes down
64B: Brush Lift Off

- Commutation brush lift-off will lead to:
  - Arcing
  - Tripping on loss-of-field
- Grounding brush lift-off can lead to:
  - Stray currents that cause bearing pitting
64B: Brush Lift Off

- As brushes lift-off, the sawtooth wave’s return signal slope gets less rounded, which is detected as a rise in voltage.
Brush Lift-Off Measurement

- When brush lifts off, $V_f$ goes up

**Diagram:**
- GENERATOR FRAME GROUND
- COUPLING NETWORK
- M-3921
- VOUT
- WEEKEND GROUND DETECTION
- SQUAREWAVE GENERATOR
- SIGNAL MEASUREMENT CIRCUIT

**Equations:**
- $V_{\text{NORMAL}}$ = Normal Voltage for Healthy Brush Contact
- $V_{\text{ALARM}}$ = Alarm Voltage when Brush Resistance Increases due to poor contact
- It is possible to apply two systems and have redundancy

- The switch system is initiated by manual means or by monitoring relay self diagnostic contacts
Stator Phase Faults

- 87G – Phase Differential (primary for in-zone faults)
  - What goes into zone must come out

  - Challenges to Differential
    - CT replication issues: Remenant flux causing saturation
    - DC offset desensitization for energizing transformers and large load pick up
    - Must work properly from 10 Hz to 80Hz so it operates correctly at off-nominal frequencies from internal faults during startup
    - May require multiple elements for CGT static start

  - Tactics:
    - Use variable percentage slope
    - Operate over wide frequency range
    - Uses $I_{\text{RMS}}/I_{\text{FUND}}$ to adaptively desensitize element when challenged by DC offset for security
      - DC offset can occur from black starting and close-in faults
CTC = CT Correction Ratio = Line CTR/Neutral CTR
Used when Line and Neutral CTs have different ratios
CT Remanence and Performance

- Magnetization left behind in CT iron after an external magnetic field is removed
- Caused by current interruption with DC offset
- CT saturation is increased by other factors working alone or in combination:
  - High system X/R ratio which increases time constant of the CT saturation period
  - CT secondary circuit burden which causes high CT secondary voltage
  - High primary fault or through-fault current which causes high secondary CT voltage
Fig. 2: 400:5, C400, R=0.5, Offset = 0.5, 2000A
CT Saturation [2]

Generator Protection

INPUT PARAMETERS:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inverse of saturation curve slope</td>
<td>S = 22</td>
</tr>
<tr>
<td>RMS voltage at 10A exc. current</td>
<td>V_s = 400 volts rms</td>
</tr>
<tr>
<td>Turns ratio = n/1</td>
<td>N = 80</td>
</tr>
<tr>
<td>Winding resistance</td>
<td>R_w = 0.300 ohms</td>
</tr>
<tr>
<td>Burden resistance</td>
<td>R_b = 0.500 ohms</td>
</tr>
<tr>
<td>Burden reactance</td>
<td>X_b = 0.500 ohms</td>
</tr>
<tr>
<td>System X/R ratio</td>
<td>X_over_R = 12.0</td>
</tr>
<tr>
<td>Per unit offset in primary current</td>
<td>Off = 0.75</td>
</tr>
<tr>
<td>Per unit remanence (based on V_s)</td>
<td>X_ren = 0.75</td>
</tr>
<tr>
<td>Symmetrical primary fault current</td>
<td>I_p = 8,000 amps rms</td>
</tr>
</tbody>
</table>

CALCULATED:

- R_t = Total burden resistance = R_w + R_b = 0.800 ohms
- pf = Total burden power factor = 0.843
- Z_b = Total burden impedance = 0.943 ohms
- T_{au} = System time constant = 0.032 seconds
- L_{ms} = Peak flux-linkages corresponding to V_s = 1.501 Wb-turns
- \omega = Radian freq = 376.99 rad/s
- R_{p} = Rms-to-peak ratio = 0.34584
- A = Coefficient in instantaneous ie versus lambda curve: ie = A * f * S = 3.83E-03
- \Delta t = Time step = 0.000083 seconds
- L_b = Burden inductance = 0.00133 henries

Fig. 6: 400:5, C400, R=0.75, Offset = 0.75, 8000A
CTC = CT Correction Ratio = Line CTR/Neutral CTR
Used when Line and Neutral CTs have different ratios
46: Negative Sequence Current

- Typically caused by open circuits in system
  - Downed conductors
  - Stuck poles switches and breakers

- Unbalanced phase currents create negative sequence current in generator stator and induces a double frequency current in the rotor

- Induced current (120 Hz) into rotor causes surface heating of the rotor
Rotor End Winding Construction

- Retaining Ring
- Locking Ring
- Wedge
- Field Winding

Currents Flow in the Rotor Surface
Negative Sequence Current: Constant Withstand Generator Limits

- **Salient Pole**
  - With connected amortisseur 10%
  - With non-connected amortisseur 5%

- **Cylindrical**
  - Indirectly 10%
  - Directly cooled - to 960 MVA 8%
    - 961 to 1200 MVA 6%
    - 1200 to 1500 MVA 5%
Negative Sequence Current: Constant Withstand Generator Limits

- **Nameplate**
  - Negative Sequence Current \((I_2)\) Constant Withstand Rating
  - “K” Factor

\[
I_2^2 T = K
\]

where

\(K = \text{Manufacturer Factor (the larger the generator the smaller the K value)}\)
Generator Protection

Generator Ratings

Typical K Values
Salient Pole Generators
40
Cylindrical Generators
30
46: Negative Sequence Electromechanical Relays

- Sensitivity restricted and cannot detect $I_2$ levels less than 60% of generator rating
- Fault backup provided
- Generally insensitive to load unbalances or open conductors
46: Negative Sequence Digital Relay

- Protects generator down to its continuous negative sequence current \( (I_2) \) rating vs. electromechanical relays that don’t detect levels less than 60%.

- Fault backup provided.

- Can detect load unbalances.

- Can detect open conductor conditions.
Overexcitation (24)

- Measured
  - High Volts/Hertz ratio
  - Normal = 120V/60Hz = 1pu
  - Voltage up, and/or frequency low, make event

- Issues
  - Overfluxing of metal causes localized heating
  - Heat destroys insulation
  - Affects generators and transformers
Causes of V/HZ Problems

- Generator voltage regulator problems
  - Operating error during off-line manual regulator operation
  - Control failure
  - VT fuse loss in voltage regulator (AVR) sensing voltage

- System problems
  - Unit load rejection: full load, partial rejection
  - Power system islanding during major disturbances
  - Ferranti effect
  - Reactor out
  - Capacitors in
  - Runaway LTCs
Modern Protection

- Definite time elements
  - Curve modify
  - Alarm

- Inverse curves
  - Select curve type for best coordination to manufacturers recommendations
  - Employ settable reset timer
    - Provides “thermal memory” for repeat events
Example plot using definite time and inverse curve
Modern Protection

- V/Hz measurement operational range: 2-80 Hz

- Necessary to avoid damage to steam turbine generators during rotor pre-warming at startup

- Necessary to avoid damage to converter-start gas turbine generators at startup

- In both instances, the generator frequency during startup and shut down can be as low as 2 Hz

**NOTE:** An Overvoltage (59) function, designed to work properly up to 120 Hz, is important for Hydro Generators where the generators can experience high speed (high frequency) during full load rejection.

Since the V/Hz during this condition is low, the 24 function will not operate, and the 59 function will provide proper protection from overvoltage.
40: Loss of Field

Can adversely effect the generator and the system!!

- **Generator effects**
  - Synchronous generator becomes induction
  - Slip induced eddy currents heat rotor surface
  - High reactive current drawn by generator overloads stator

- **Power system effects**
  - Loss of reactive support
  - Creates a reactive drain
  - Can trigger system/area voltage collapse
Generator capability curve viewed on the P-Q plane.
This info must be converted to the R-X plane.
TRANSFORMATION FROM MW-MVVAR TO R-X PLOT

TYPICAL GENERATOR CAPABILITY CURVE
Excitation Limiters and Steady State Stability
- Limiting factors are rotor and stator thermal limits
- Underexcited limiting factor is stator end iron heat
- Excitation control setting control is coordinated with steady-state stability limit (SSSL)
- Minimum excitation limiter (MEL) prevents exciter from reducing the field below SSSL
Loss of Field
GE and Westinghouse Methods

Two Zone Offset Mho
GE
CEH

Impedance w/Directional Unit
Westinghouse
KLF
Generator Protection

Loss of Field
Two Zone Offset Mho

Offset = \( \frac{X_d'}{2} \)

Diameter = 1.0 pu

Heavy Load

Light Load

Machine Capability

SSSL

Diameter = \( X_d \)

MEL
Loss of Field Impedance w/Direction Unit

Generator Protection

Offset = \frac{X_d'}{2}

1.1 (X_d)

Z2 Setting

Z1 Setting

X

Heavy Load

Light Load

Machine Capability

MEL

SSSL
Generator Protection

Loss of Field Event

- Generator Lost Field, then went Out-of-Step!!!
Phase Distance (21)

- Phase distance backup protection may be prone to tripping on stable swings and load encroachment
  - Employ three zones
    - Z1 can be set to reach 80% of impedance of GSU for 87G back-up.
    - Z2 can be set to reach 120% of GSU for station bus backup, or to overreach remote bus for system fault back up protection. Load encroachment blinder provides security against high loads with long reach settings.
    - Z3 may be used in conjunction with Z2 to form out-of-step blocking logic for security on power swings or to overreach remote bus for system fault back up protection. Load encroachment blinder provides security against high loads with long reach settings.
  - Use minimum current supervision provides security against loss of potential (machine off line)
21: Distance Element
With Load Encroachment Blinder for Z1, Z2, Z3

Z1, Z2 and Z3 used to trip
Z1 set to 80% of GSU, Z2 set to 120% of GSU
Z3 set to overreach remote bus

Stable Power Swing and Load Encroachment Blinding
21: Distance Element

With:
- Power Swing Blocking
- Load Encroachment Blocking for Z1 and Z2

Z1 and Z2 used to trip
Z1 set to 80% of GSU, Z2 set to overreach remote bus
Z3 used for power swing blocking; Z3 blocks Z2
Generator Out-of-Step Protection (78)

- **Types of Instability**
  - Steady State: Steady Voltage and Impedance (Load Flow)
  - Transient: Fault, where voltage and impedance change rapidly
  - Dynamic: Oscillations from AVR damping (usually low f)

- **Occurs with unbalance of load and generation**
  - Short circuits that are severe and close
  - Loss of lines leaving power plant (raises impedance of loadflow path)
  - Large losses or gains of load after system break up

- **Generator accelerates or decelerates, changing the voltage angle between itself and the system**
  - Designed to cover the situation where electrical center of power system disturbance passes through the GSU or the generator itself
  - More common with modern EHV systems where system impedance has decreased compared to generator and GSU impedance
Generator Out-of-Step Protection (78)

- When a generator goes out-of-step (synchronism) with the power system, high levels of transient shaft torque are developed.
- If the pole slip frequency approaches natural shaft resonant frequency, torque produced can break the shaft.
- High stator core end iron flux can overheat and short the generator stator core.
- GSU subjected to high transient currents and mechanical stresses.
For maximum power transfer:
• Voltage of GEN and SYSTEM should be nominal – Faults lower voltage
• Impedance of lines should be low – lines out raise impedance
Out of Step: Generator and System Issue

Generator Protection

Power Transfer Equation

\[ P_e = \frac{|E_g||E_s|}{X} \sin(\theta_g - \theta_s) \]
Generator Protection

Graphical Method: 78

- One pair of blinders (vertical lines)
- Supervisory offset mho
- Blinders limit reach to swings near the generator
Graphical Method: 78

Generator Protection

Unstable Swing

Stable Swing

2X'_D + X_T + X_S

Element Pickup

Element Pickup

Blinder Elements

Mho Element

System X_S

GSU X_T

Gen X'_d
Generator Protection

Out-of-Step (Loss of Synchronism) Event
Off-Nominal Frequency Impacts

Underfrequency may occur from system overloading
- Loss of generation
- Loss of tie lines importing power

Underfrequency is an issue for the generator
- Ventilation is decreased
- Flux density (V/Hz) increases

Underfrequency limit is typically dictated by the generator and turbine
- Generator: V/Hz and loading
- Turbine: Vibration Issues

Overfrequency may occur from load rejection
- Overfrequency is typically not an issue with the generator
  - Ventilation is improved
  - Flux density (V/Hz) decreases
- Overfrequency limit is typically dictated by the turbine (vibration)
For overfrequency events, the generator prime mover power is reduced to bring generation equal to load.

For underfrequency events, load shedding is implemented to bring load equal to generation.

- It is imperative that underfrequency tripping for a generator be coordinated with system underfrequency load shedding.
Abnormal Operating Conditions

- **81 – Four Step Frequency**
  - Any step may be applied over- or underfrequency
  - High accuracy – 1/100\(^{th}\) Hz (0.01 Hz)
  - Coordination with System Load Shedding

- **81A – Underfrequency Accumulator**
  - Time Accumulation in Six Underfrequency Bands
  - Limits Total Damage over Life of Machine
    - Typically used to Alarm

- **81R – Rate of Change of Frequency**
  - Allows tripping on rapid frequency swing
Steam Turbine Underfrequency Operating Limitations

![Graph showing underfrequency limitations](image)

- **Continuous**
- **Restricted**
- **Prohibited**

Typical, from C37.106
Typical, from C37.106
Turbine blades are designed and tuned to operate at rated frequencies.

Operating at frequencies different than rated can result in blade resonance and fatigue damage.

In 60 Hz machines, the typical operating frequency range:
- 18 to 25 inch blades = 58.5 to 61.5 Hz
- 25 to 44 inch blades = 59.5 and 60.5 Hz

Accumulated operation, for the life of the machine, not more than:
- 10 minutes for frequencies between 56 and 58.5 Hz
- 60 minutes for frequencies between 58.5 and 59.5 Hz
Causes of Inadvertent Energizing

- Operating errors
- Breaker head flashovers
- Control circuit malfunctions
- Combination of above
Typically, normal generator relaying is not adequate to detect inadvertent energizing
  • Too slow or not sensitive enough
    • Distance
    • Negative sequence
    • Reverse power
    • Some types are complicated and may have reliability issues
      • Ex., Distance relays in switchyard disabled for testing and inadvertent energizing event takes place
Inadvertent Energizing

- When inadvertently energized from 3-phase source, the machine acts like an induction motor
  - Rotor heats rapidly (very high $I_2$ in the rotor)
- Current drawn
  - Strong system: 3-4x rated
  - Weak system: 1-2x rated
  - From Auxiliary System: 0.1-0.2x rated

- When inadvertently energized from 1-phase source (pole flashover), the machine does not accelerate
  - No rotating flux is developed
  - Rotor heats rapidly (very high $I_2$ in the rotor)

- Protection system must be able to detect and clear both 3-phase and 1-phase inadvertent energizing events
Inadvertent Energizing Oscillograph

## Generator Protection

### Oscillograph Data

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<th>VC (A)</th>
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</table>

### Graphical Data

- 2114: 0  (Time: 0)
- 2114.40 ms
- 125.66 Cycles
Inadventent Energizing Scheme

- Undervoltage (27) supervises low-set, instant overcurrent (50) – recommended 27 setting is 50% or lower of normal voltage
- Pickup timer ensures generator is dead for fixed time to ride through three-phase system faults
- Dropout timer ensures that overcurrent element gets a chance to trip just after synchronizing
Generator Protection

Breaker Failure Timeline

- Fault Occurs
- Fault Cleared
- Protective Relay Time
- Breaker Interrupt Time
- Margin Time
- Backup Breaker Interrupt Time
- BFI
- 62 - BF Timer Time
- BF Trip Command
- Time
- 62 - BF Timer Time
- Fault Occurs
Breaker Pole Flashover & Stuck Pole
Generator Breaker Failure and Pole Flashover Scheme: Simplified Conceptual View

Generator Protection

Breaker Failure

52/a

50 BF

OR

Protective Elements

Breaker is closed by current detection or position

1 = Protection BFI

Pole Flashover

52/b

50 N

AND

1 = Flashover detected

AND

Breaker Failure Trip

T

TDOE

1 = Flashover detected

1 = Protection BFI

Breaker is closed by current detection or position
- Used to protect generator from motoring during loss of prime mover power
- **Motoring:**
  - Wastes power from the system
  - May cause heating in steam turbines as ventilation is greatly reduced
  - Steam and dewatered hydro can motor with very little power; $\leq 1\%$ rated
  - CGT and Recip typically use 10-25% of rated power to motor
- Generators are often taken off the system by backing off the power until importing slightly so not to trip with power export and go into overspeed (turbine issue)
  - This is known as sequential tripping
- **Two 32 elements may be applied:**
  - Sequential trip (self reset, no lockout)
  - Abnormal trip (lockout)
  - Need great sensitivity, down to .002pu
  - Usually applied as 32R, may be applied as 32F-U
Generator Tripping and Shutdown

- Generators may be shutdown for unplanned and planned reasons
  - Shutdowns may be whole or partial
  - Shutdowns may lock out (86- LOR) or be self resetting (94)

- **Unplanned**
  - Faults
  - Abnormal operating conditions

- **Scheduled**
  - Planned shutdown
T = Turbine Trip
F = Field Trip
G = Generator Breaker Trip
Tripping Philosophy & Sequential Tripping

- **Unit separation**
  - Used when machine is to be isolated from system, but machine is left operating so it can be synced back to the system after separating event is cleared (system issue)
  - Only generator breaker(s) are tripped
– Generator Trip
  
  • Used when machine is isolated and overexcitation trip occurs
  • Exciter breaker is tripped (LOR) with generator breakers already opened
Simultaneous Trip (Complete Shutdown)
- Used when internal (in-zone) protection asserts
- Generator and exciter breakers are tripped (LOR)
- Prime mover shutdown initiated (LOR)
- Auxiliary transfer (if used) is initiated
Tripping Philosophy & Sequential Tripping

- Sequential Trip
  - Used for taking machine off-line (unfaulted)
    - Generator and exciter breakers are tripped (94)
    - Prime mover shutdown initiated (94)
    - Auxiliary transfer (if used) is initiated
Generator Protection

Sequential Tripping
• Back down turbine and excitation
  – Backing down excitation to allows easier better measurement of power

• Initiate Sequential Trip
  – Use 32 element that trips G, F and T, but does not do this through a LOR
  – When a small amount of reverse power is detected, trip G, F and T
In-Zone Issues

System Issues

In-Zone Issues

Normal Shutdown

Alarms

Generator Protection

Trip Logic

LOR

LOR or 94

LOR

94
Typical Protection Functions for a Large or Important Generator

Note: Only use functions as appropriate.
Mitigating Reliability Concerns

- Integrating many protection functions into one package raises reliability concerns

- Address these concerns by…
  1. Providing two MGPRs, each with a portion or all of the protection functions (redundancy for some or all)
  2. Providing backup for critical components, particularly the power supply
  3. Using MGPR self-checking ability
Aug 2003, NE Blackout: Generator Trips

531 Generators at 261 Power Plants tripped!!!

IEEE PSRC Survey

- Conducted in early '90s, exposed many areas of protection lacking
- Reluctance to upgrade:
  - Lack of expertise
  - To recognize problems
  - To engineer the work
  - The thought that “Generators don’t fault”
  - Operating procedures can prevent protection issues
Why Upgrade?

- Existing generator and transformer protection may:
  - Require frequent and expensive maintenance
  - Cause coordination issues with plant control (excitation, turbine control)
  - Trip on through-faults (external faults), stable power swings, load encroachment and energizing
  - Not follow NERC PRC Standards (PRC = protection and control)
  - Exhibit insensitivity to certain abnormal operating conditions and fault types
  - Not be self-diagnostic
  - Lack comprehensive monitoring and communications capabilities
    - Not provide valuable event information that can lead to rapid restoration
    - Part of NERC Report comments on the August 03 Blackout
  - Not be in compliance with latest ANSI/IEEE Standards!
    - Asset Reliability, Insurance, Liability Issues
    - C37-102: Guide for the Protection of Synchronous Generators
Protection Upgrade Opportunities

- **Improved sensitivity**
  - Loss of Field
  - 100% stator ground fault
  - Reverse power
  - Negative sequence
  - Overexcitation

- **Improved Security**
  - Directionally supervised ground differential protection
  - Distance Element Enhancements
    - Load encroachment blinding
    - Power swing blocking (for stable swings)
Protection Upgrade Opportunities

- **New protections**
  - Inadvertent energizing
  - VT fuse loss (integrated)

- **Special applications**
  - Generator breaker failure
    - Pole flashover (prior to syncing)
Oscillography

- **Determine if relay and circuit breaker operated properly**
  - Identify relay, control or breaker problem
  - Generators do experience faults / abnormal conditions
    - In the machine or the system?

- **Speed generator’s return to service**
  - Identify type of testing needed
  - Provide data to generator manufacturer

- **Gives plant engineer data to force unit off-line for inspection**

- **Uncovers unexpected problems**
  - Synchronizing, shutdown
Long Records Let You See the Issue

Example of Ph-Gnd fault evolving into 3-Ph Fault

- Gen feeding fault into low side of GSU, no low side breaker
- Insulation breakdown due to high voltage
- 21P backup element tripped

Voltage collapse on Ph-Ph Fault

Ph-Gnd Fault
Ph-Ph Fault
3-Ph Fault
Generators require special protection for faults and abnormal operations.
These protections are for in-zone and out-of zone events.
Modern element design matter for security and dependability.
Complexity can be made simple with the correct user tools.


References

8. Behavior Analysis of the Stator Ground Fault (64G) Protection Scheme; Ramón Sandoval, Fernando Morales, Eduardo Reyes, Sergio Meléndez and Jorge Félix, presented to the Rotating Machinery Subcommittee of the IEEE Power System Relaying Committee, January 2013.