GENERATOR PROTECTION THEORY & APPLICATION

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Wayne Hartmann is VP, Protection and Smart Grid Solutions for Beckwith Electric. He provides Customer and Industry linkage to Beckwith Electric's solutions, as well as contributing expertise for application engineering, training and product development.

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."

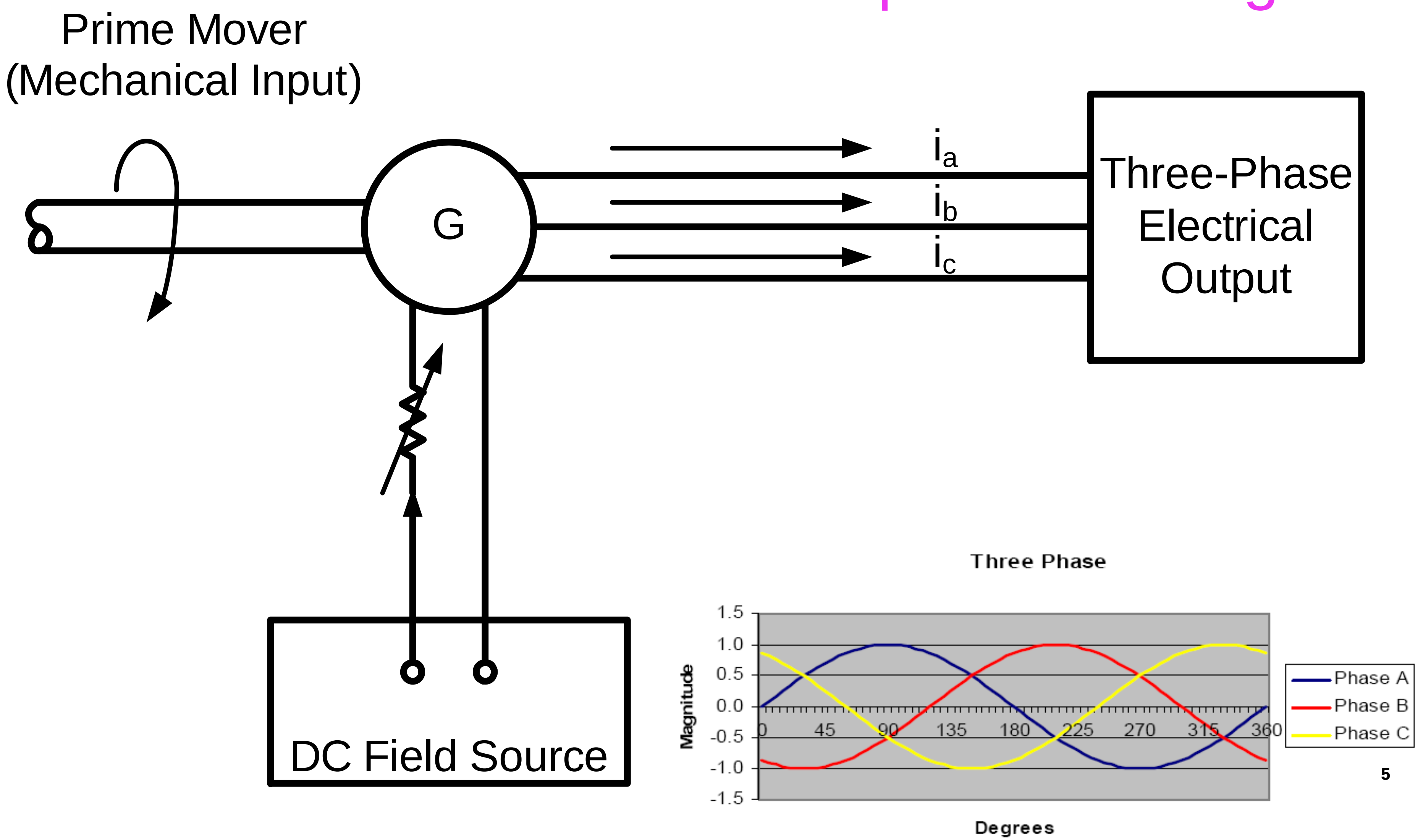
Objectives

- Review of generator construction and operation
- Review grounding and connections
- Discuss IEEE standards for generator protection
- Explore generator elements
  - Internal faults (in the generator zone)
  - Abnormal operating conditions
    - Generator zone
    - Out of zone (system)
  - External faults
- Discuss generator and power system interaction

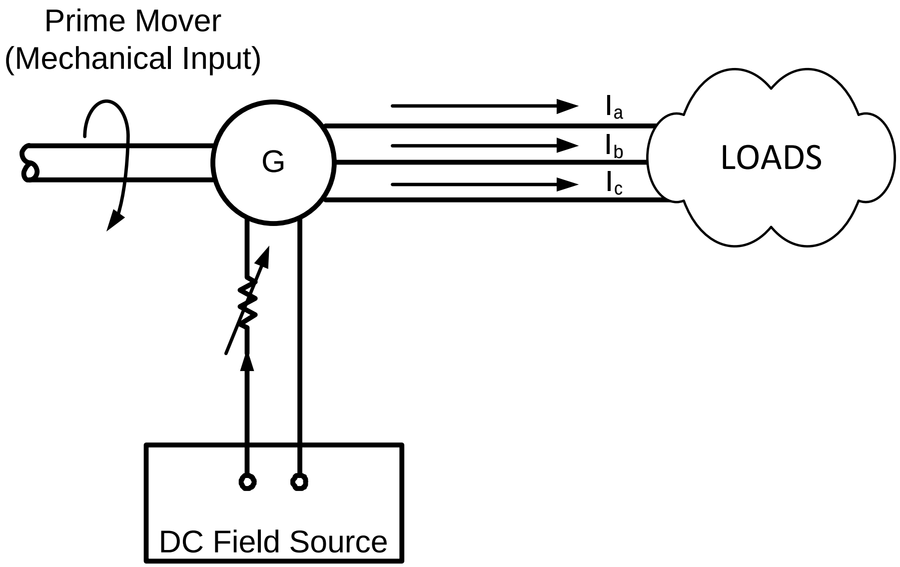
Objectives

- Tripping considerations and sequential tripping
- Discussion of tactics to improve security and dependability
- Generator protection upgrade considerations
  - Advanced attributes for security, reliability and maintenance use
- Review Setting, Commissioning and Event Investigation Tools
- Q & A

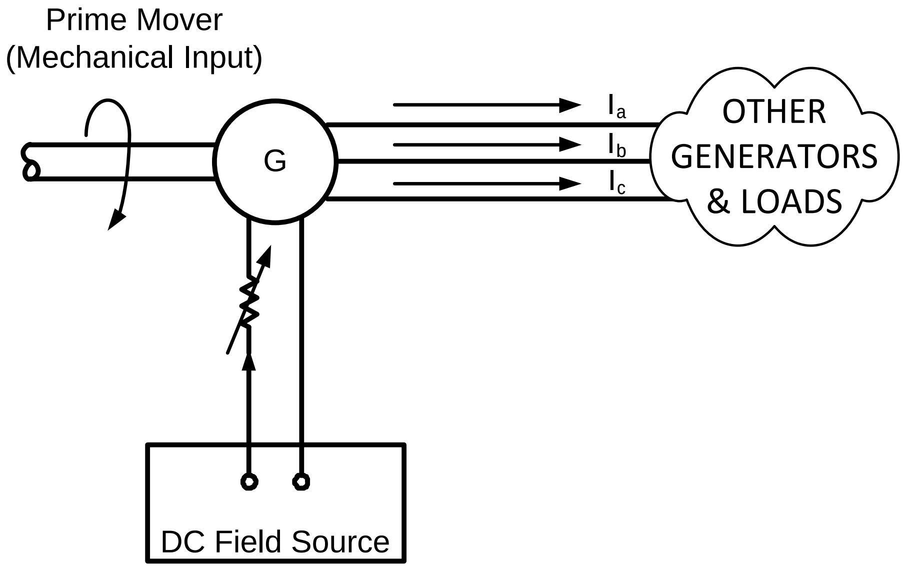
Generator Construction: Simple Bock Diagram



Islanded (Prime Power) vs. Interconnected

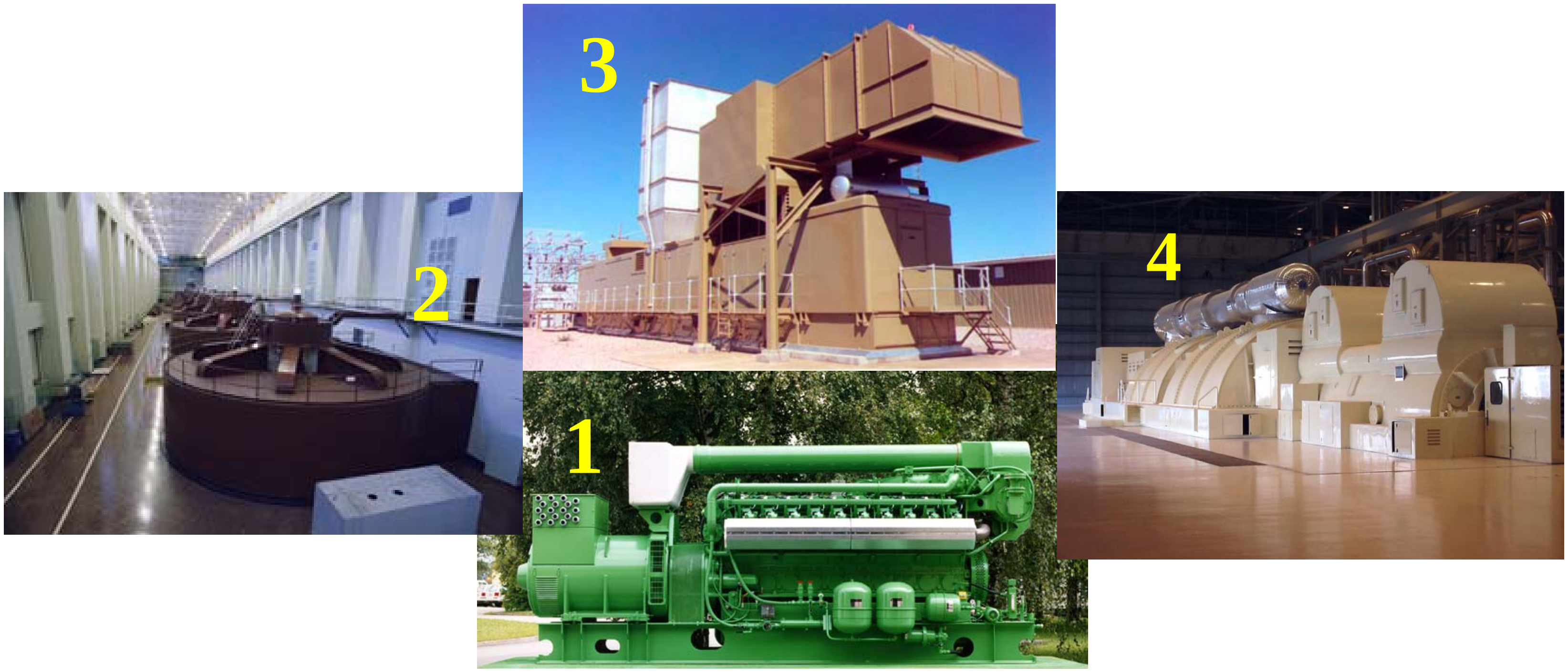


- Islanded
  - Field
    - Regulates voltage
  - Prime Mover
    - Regulates frequency



- Interconnected
  - Field
    - Controls VARs/PF
  - Prime Mover
    - Controls real power

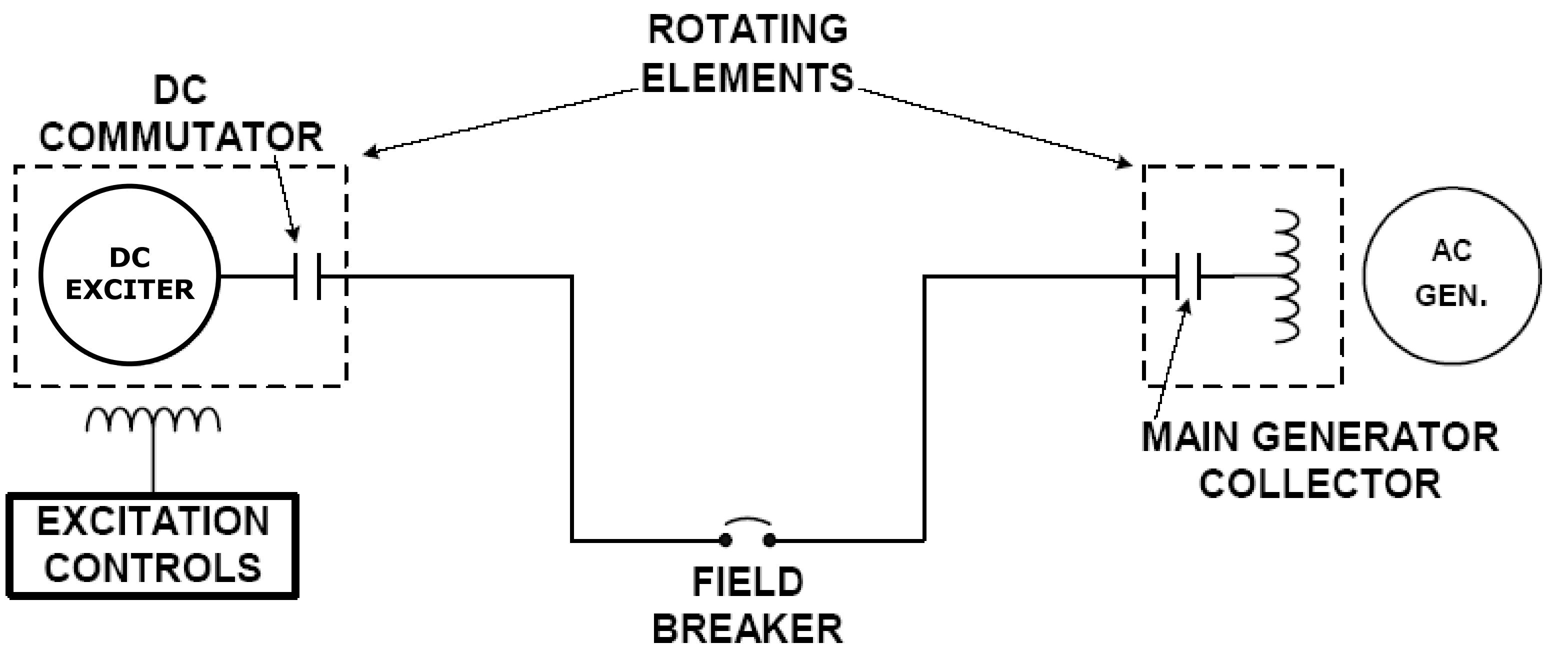
Applying Mechanical Input



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

Applying Field

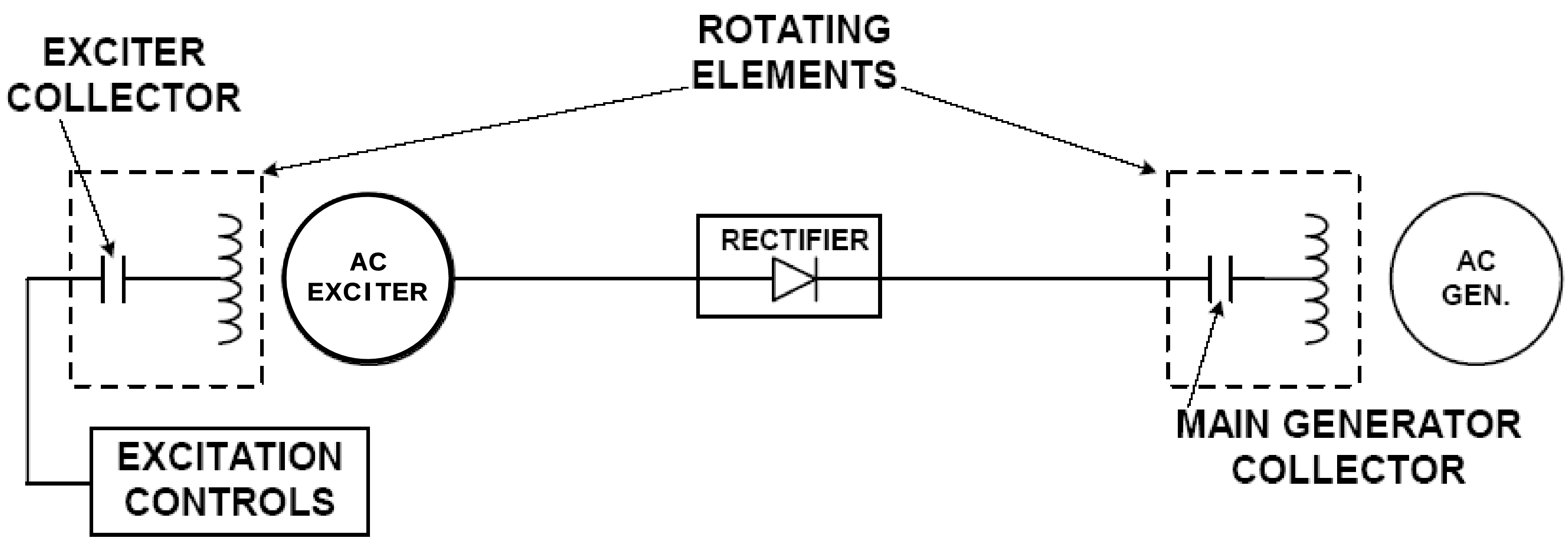
DC Generator Commutator Exciter



- DC is induced in the rotor
- AC is induced in the stator

Applying Field

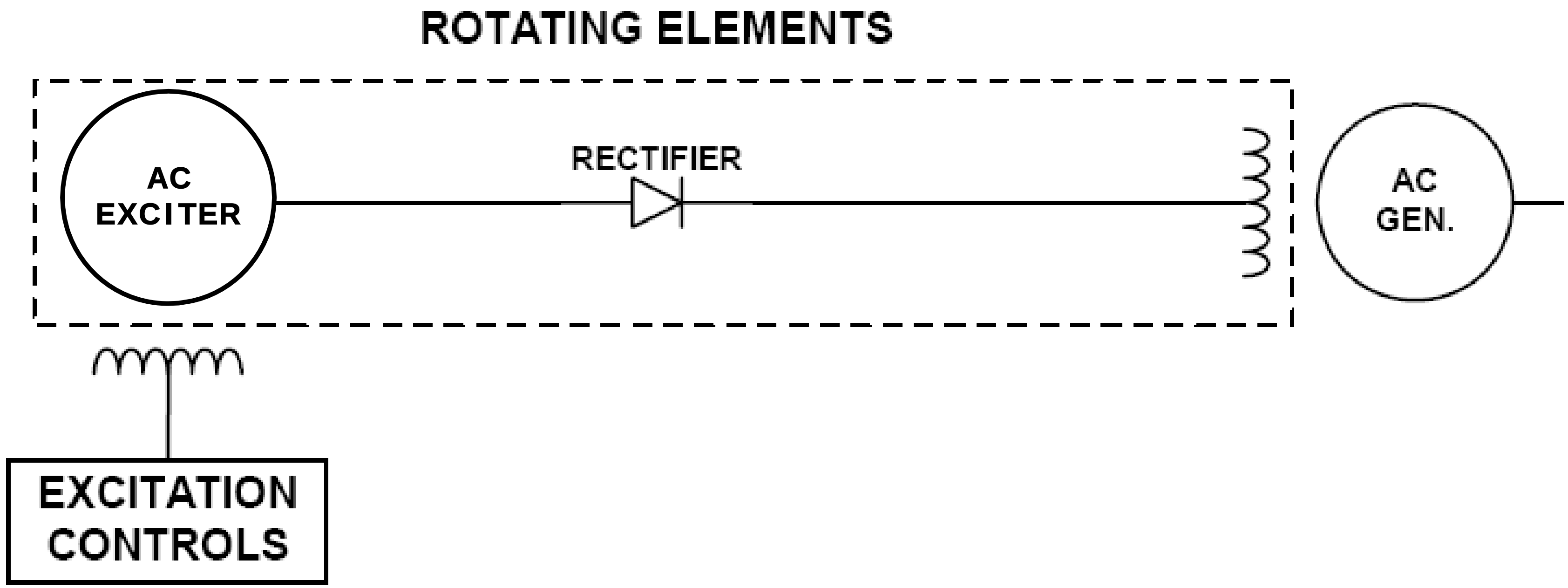
Alternator Rectifier Exciter and Stationary Exciter/Stationary Rectifier



- DC is induced in the rotor
- AC is induced in the stator

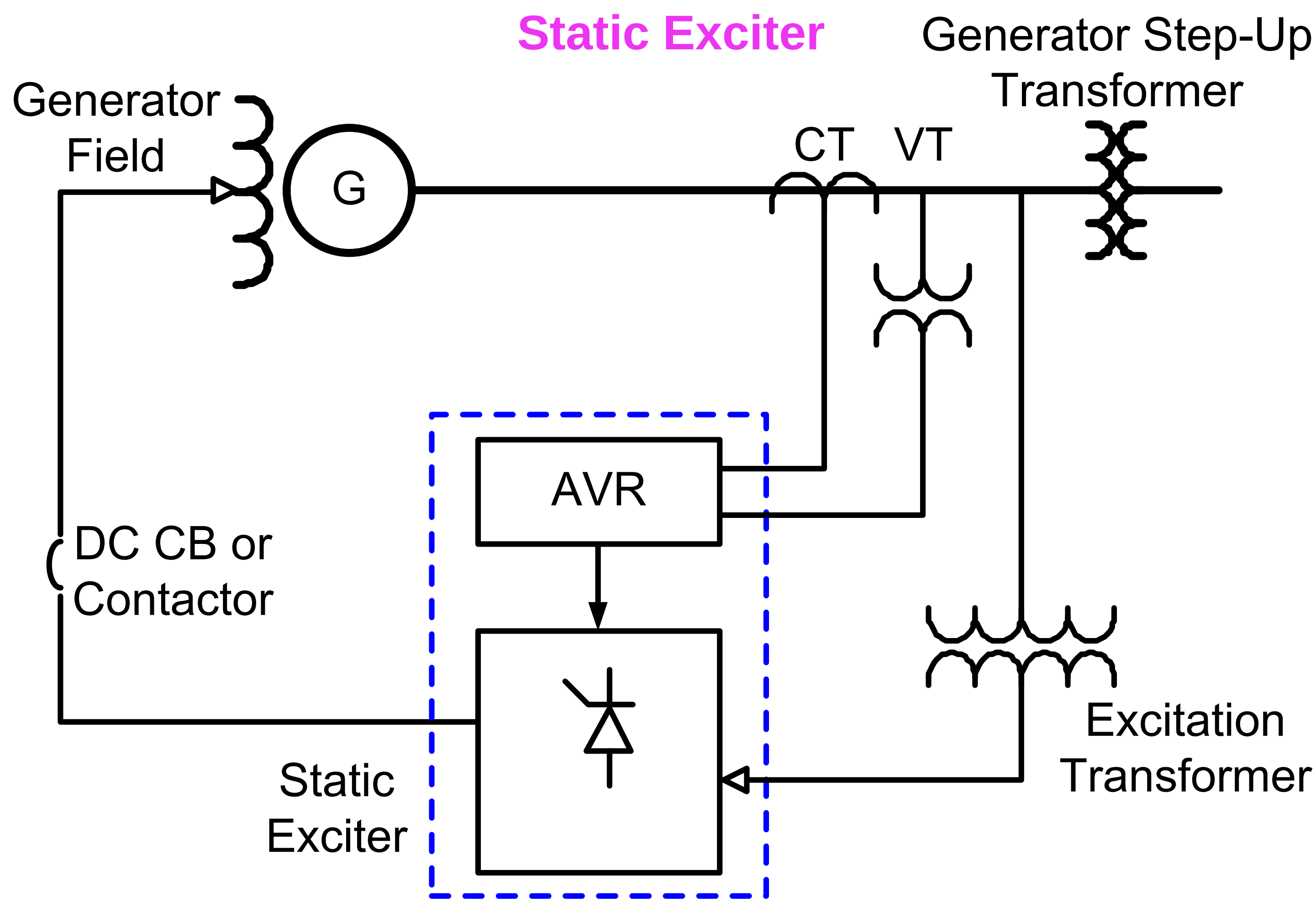
Applying Field

Alternator Rectifier Exciter and Rectifiers (Brushless Exciter)



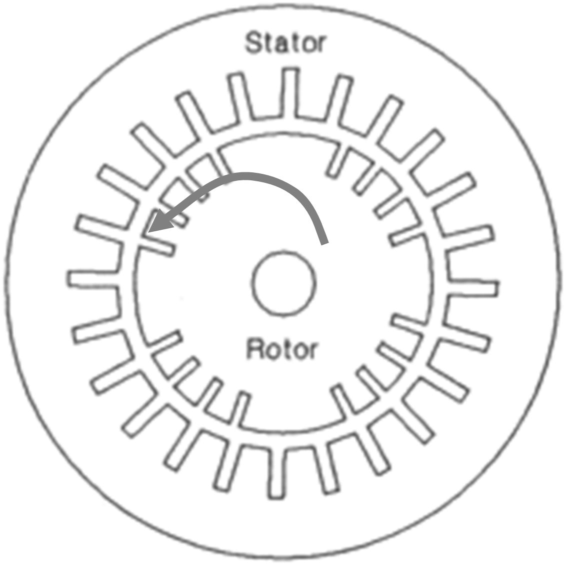
- DC is induced in the rotor
- AC is induced in the stator

Applying Field

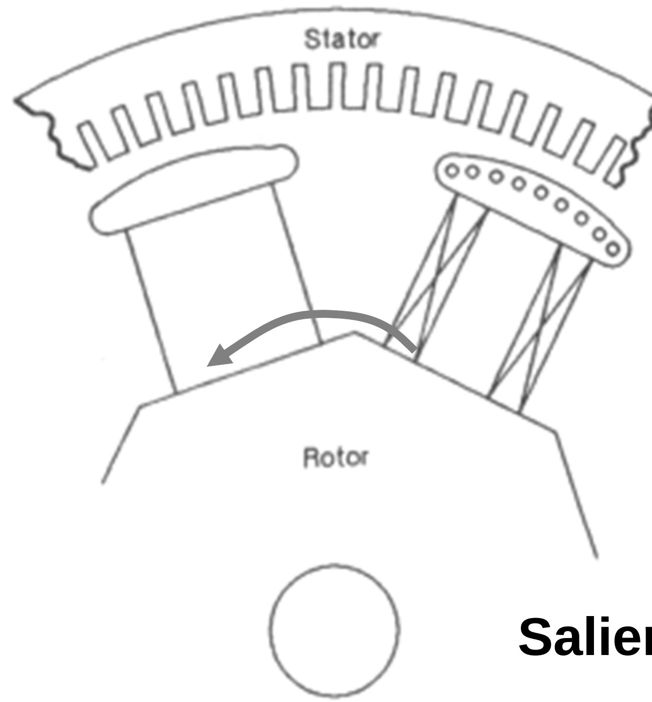


- DC is induced in the rotor
- AC is induced in the stator

Rotor Styles



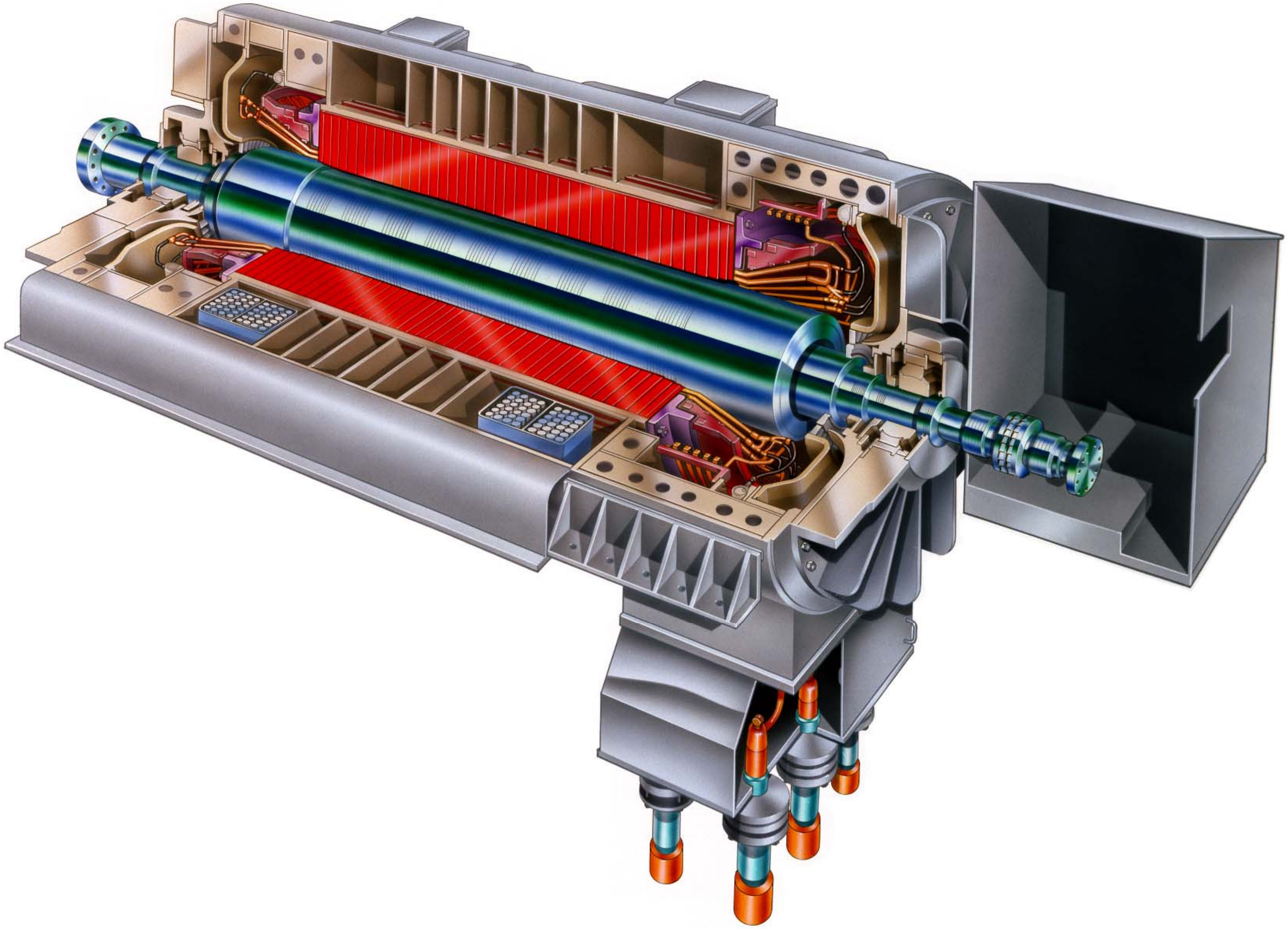
Cylindrical (Round)



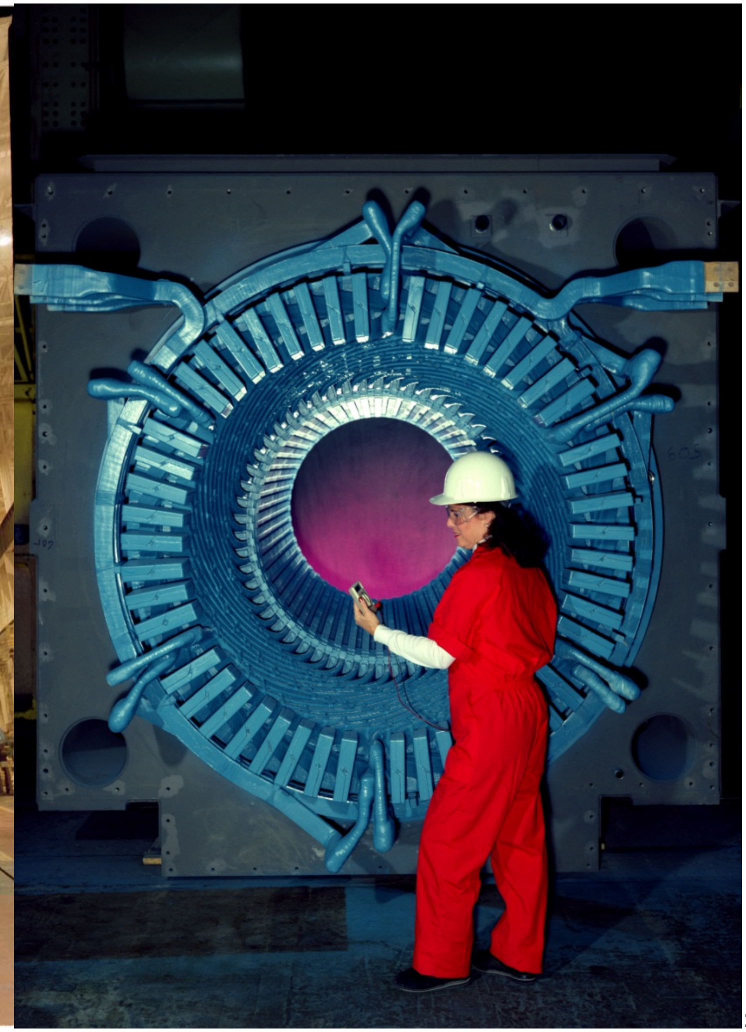
Salient

- 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= [RPM/60] * [P/2] = [RPM * P] / 120

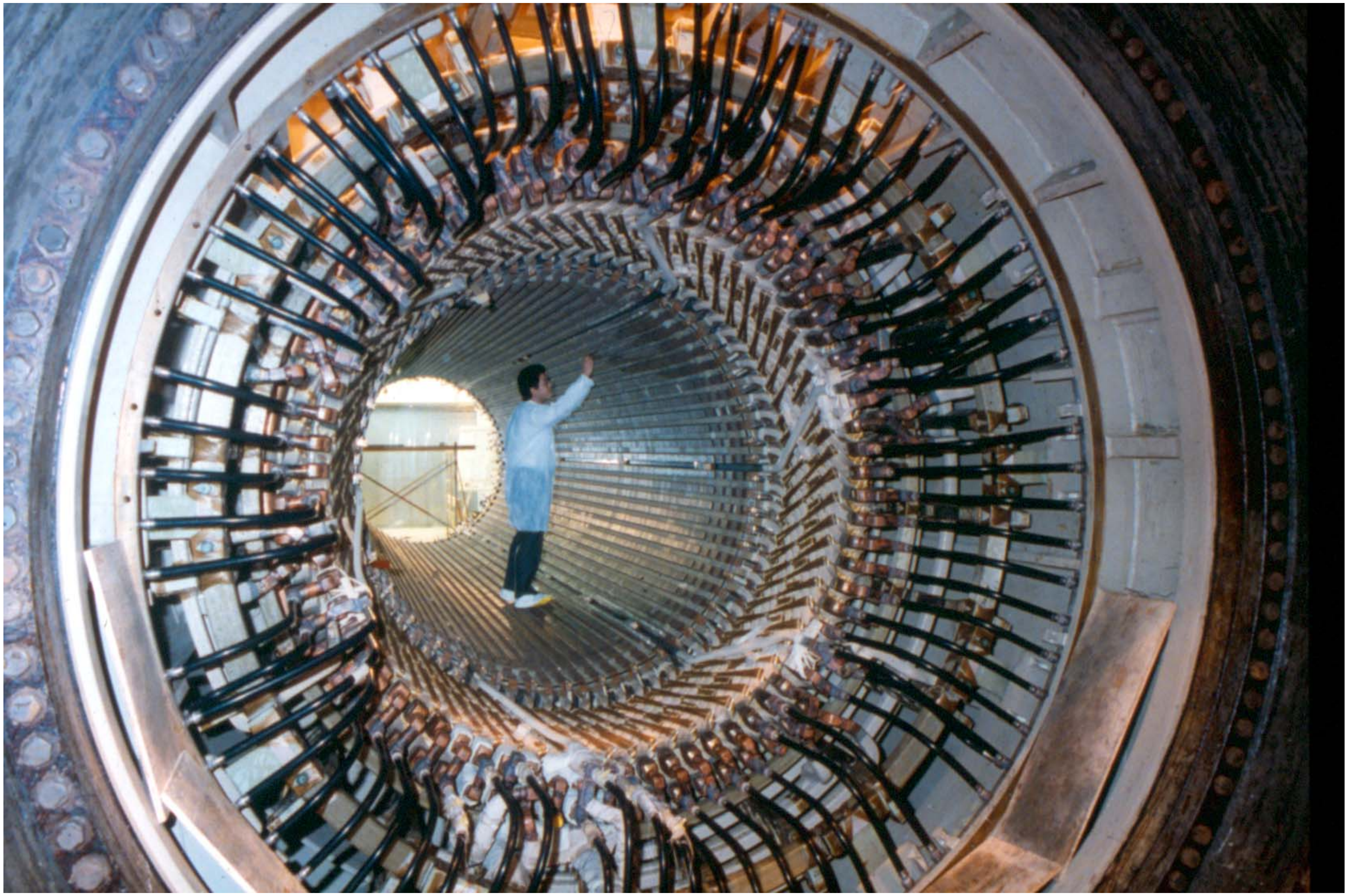
Cylindrical Rotor & Stator



Cylindrical Rotor & Stator

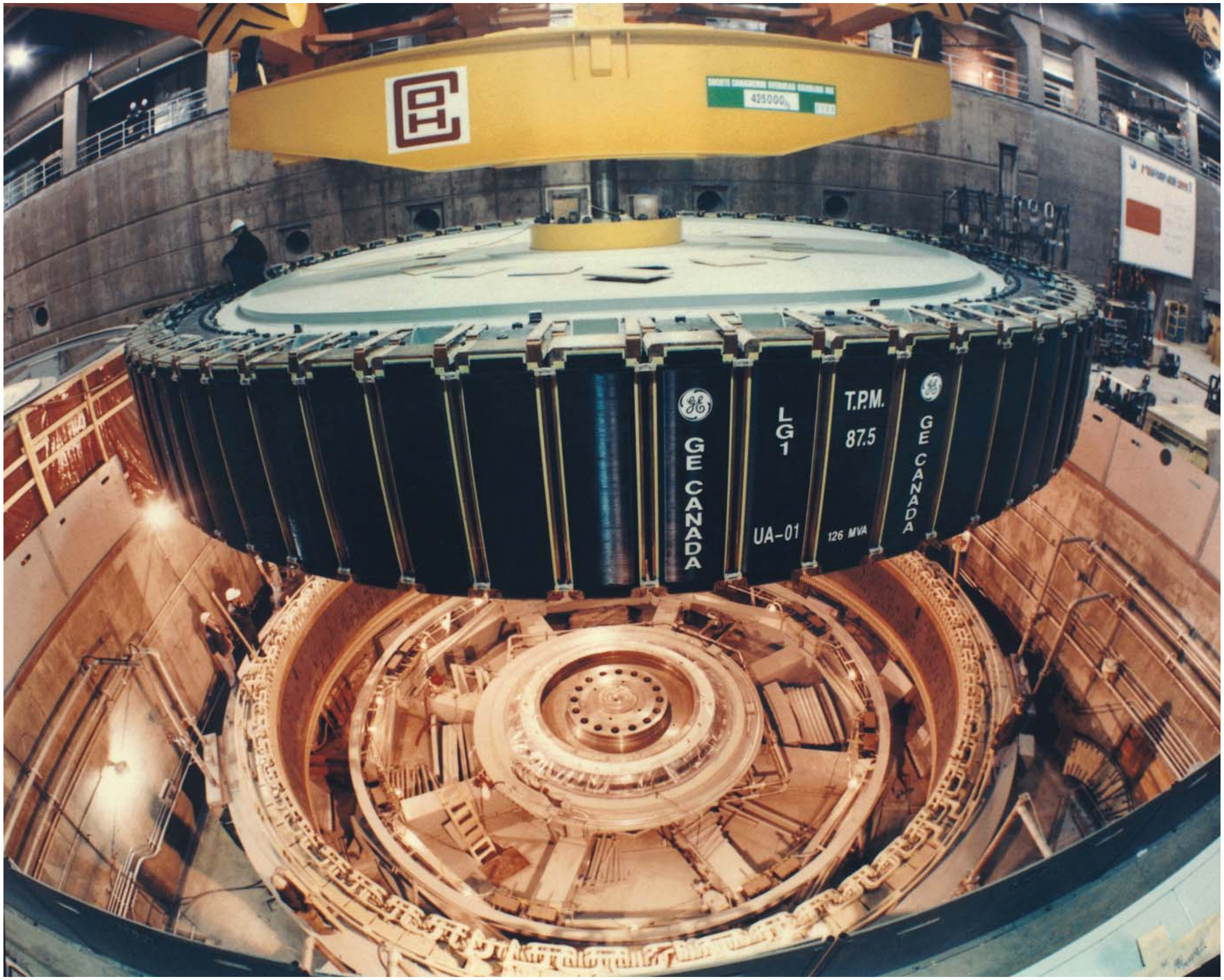


Cylindrical Rotor & Stator

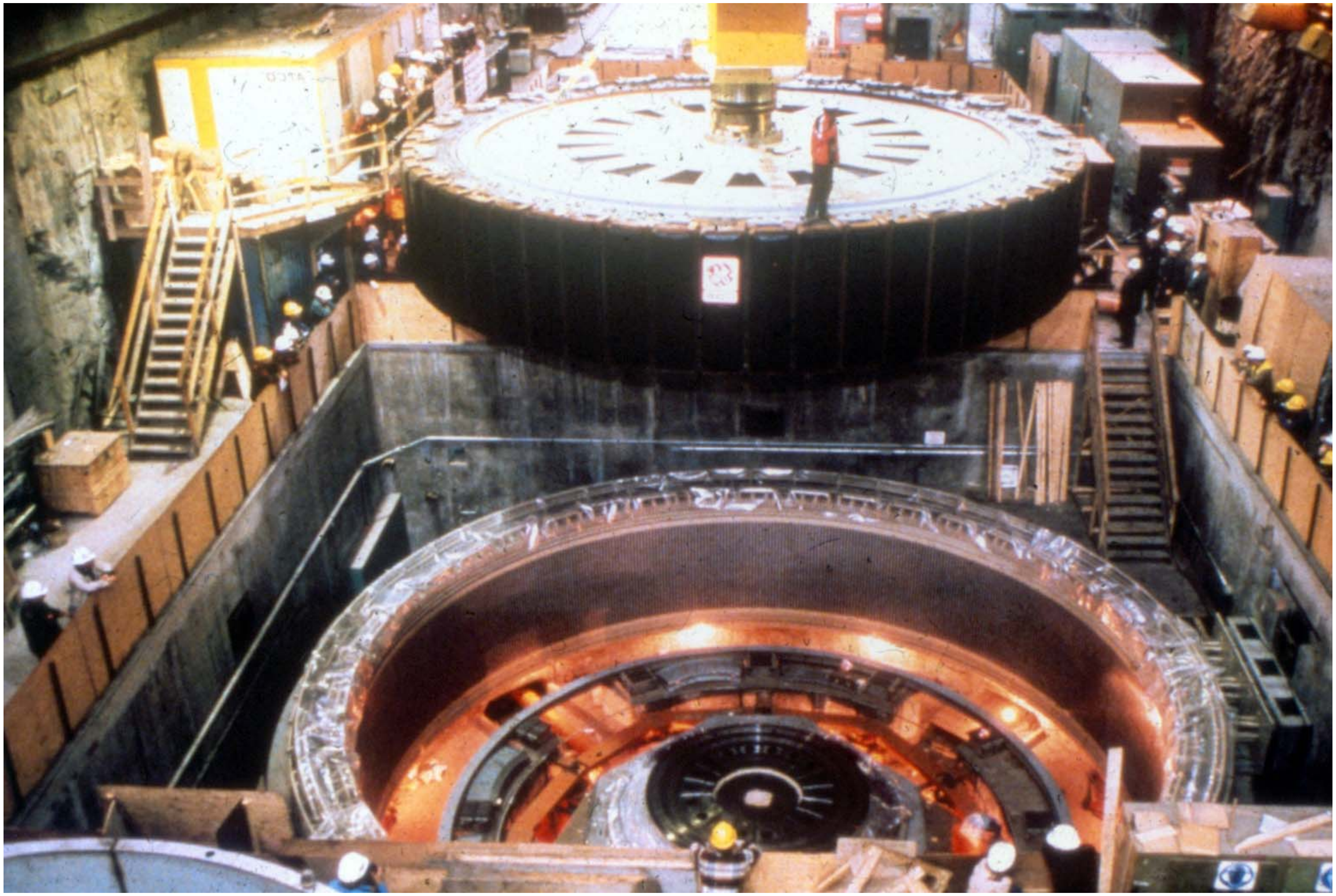


Cylindrical Rotor & Stator

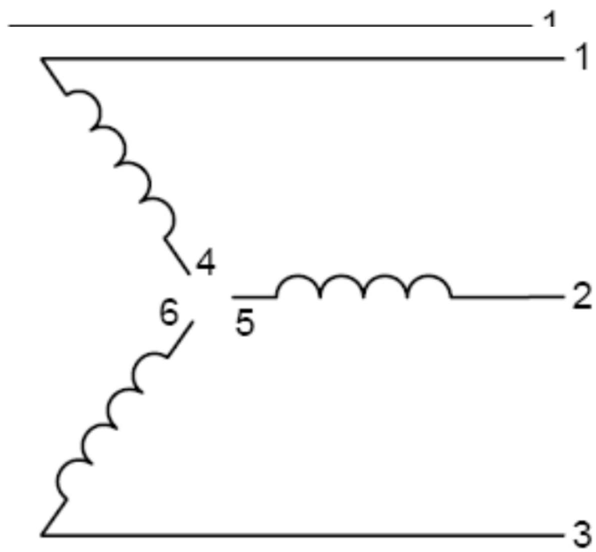
Salient Pole Rotor & Stator



Salient Pole Rotor & Stator

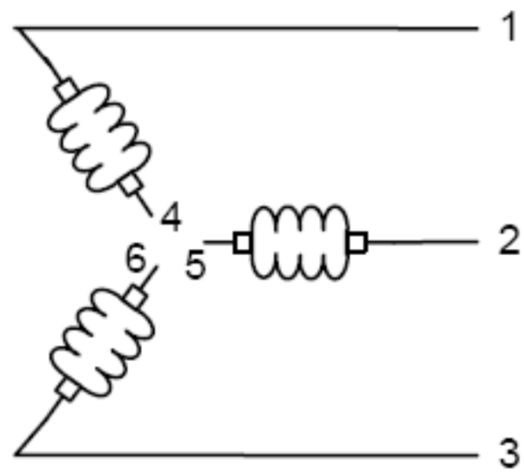


Winding Styles and Connections



Wye

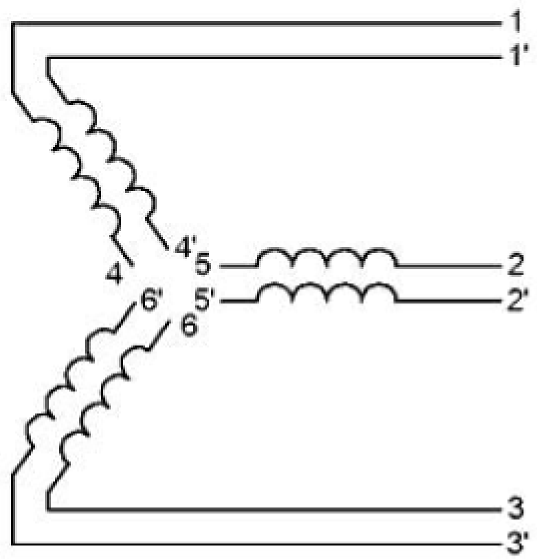
- 1 Circuit
- 3 Phase
- 6 Bushings

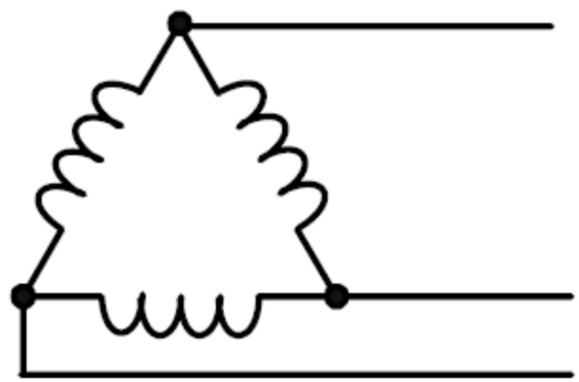


Wye

- 2 Circuit
- 3 Phase
- 6 Bushings

Winding Styles and Connections





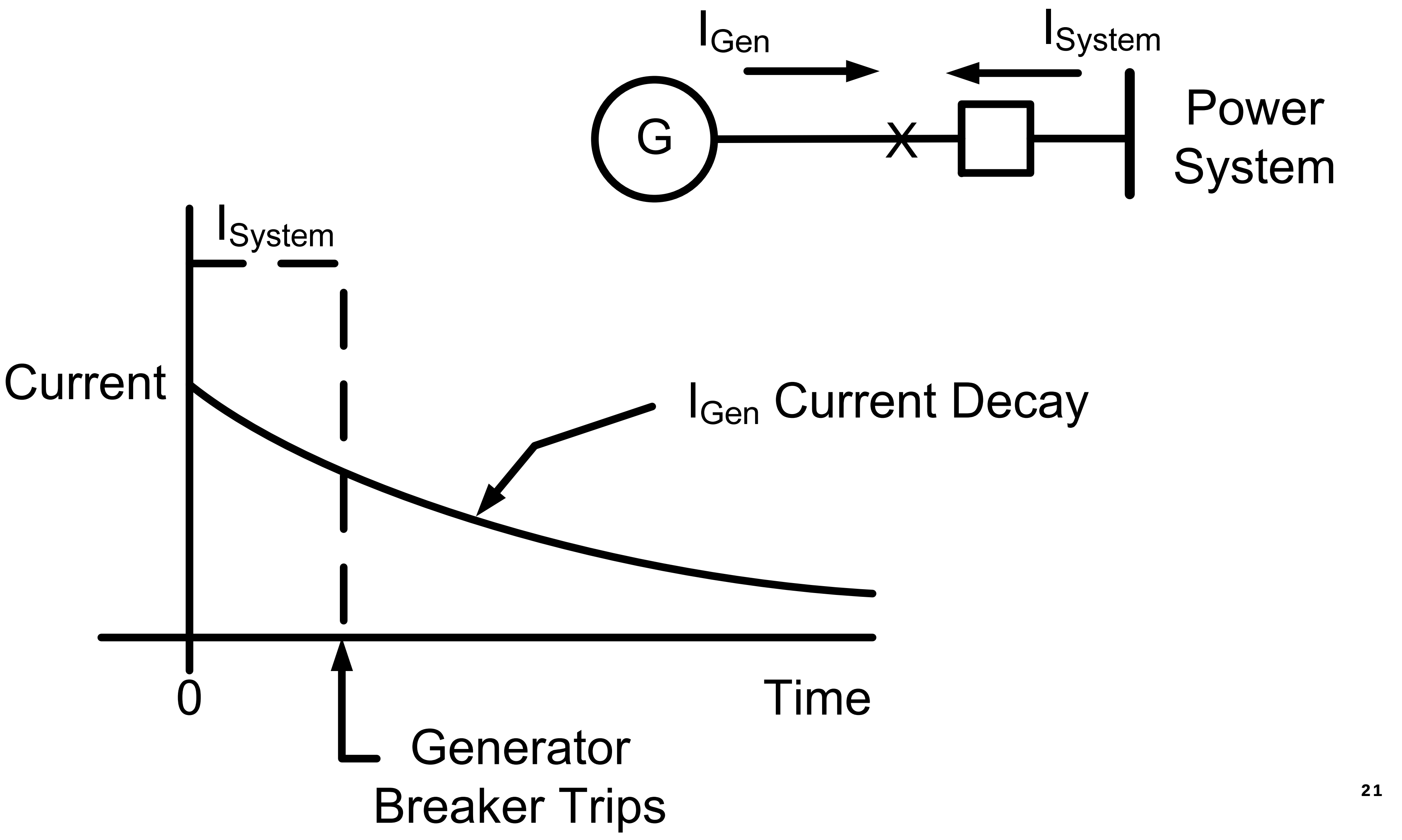
Double Winding

- 1 Circuit
- 3 Phase
- 12 Bushings

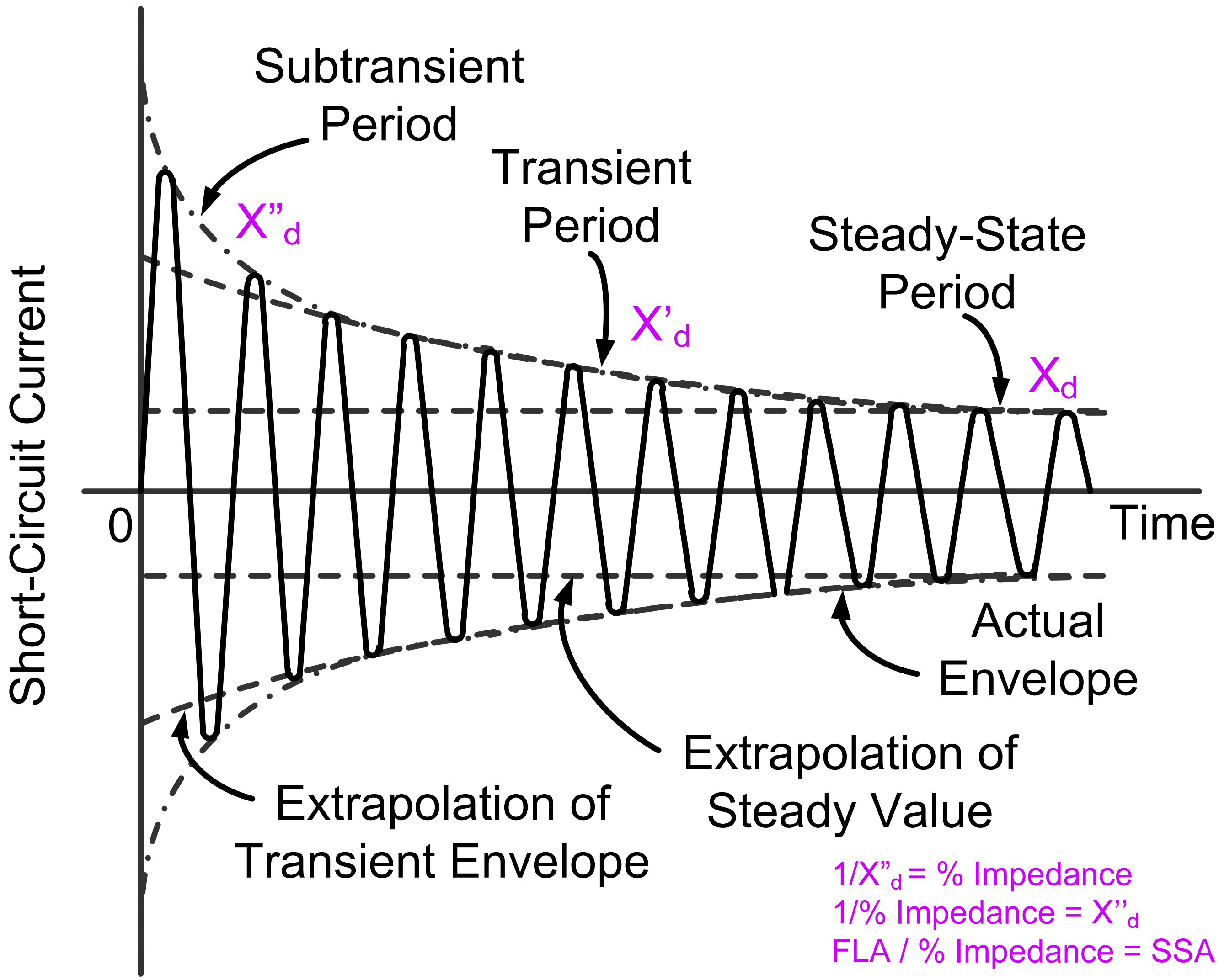
Delta

- 1 Circuit
- 3 Phase
- 3 Bushings

Generator Behavior During Short Circuits

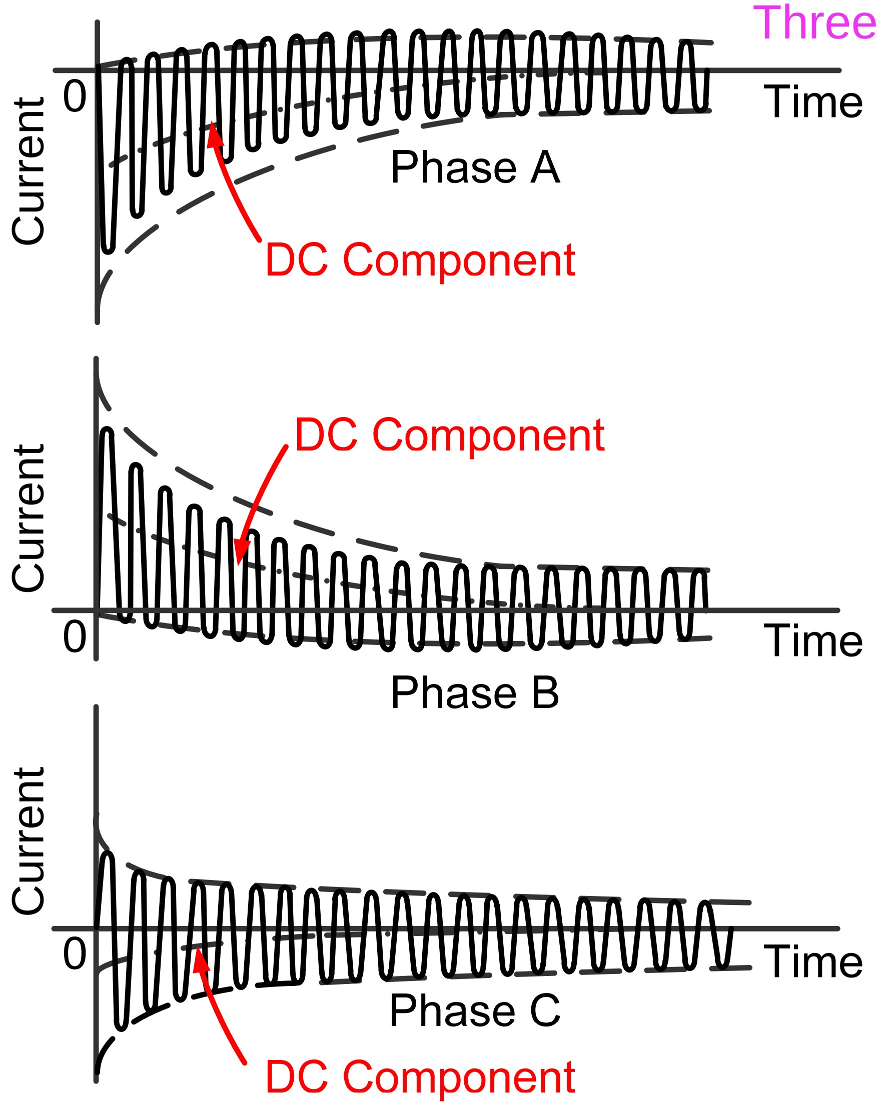


Generator Short-Circuit Current Decay



$1/X''_d$ = % Impedance
1/% Impedance = X''_d
FLA / % Impedance = SSA

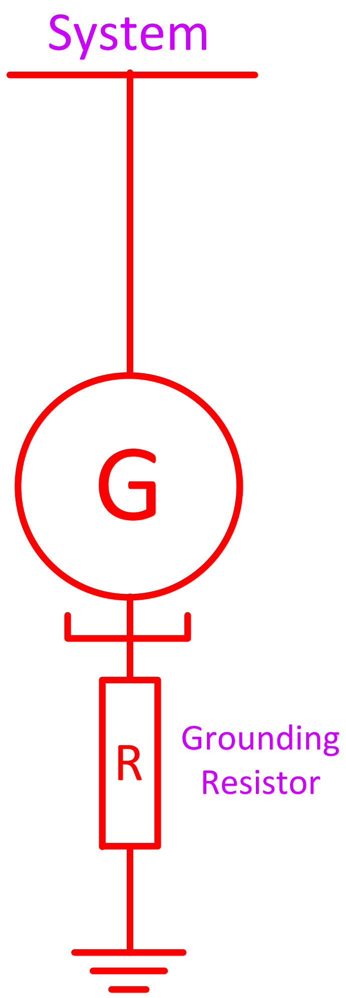
Effect of DC Offsets



Grounding Techniques

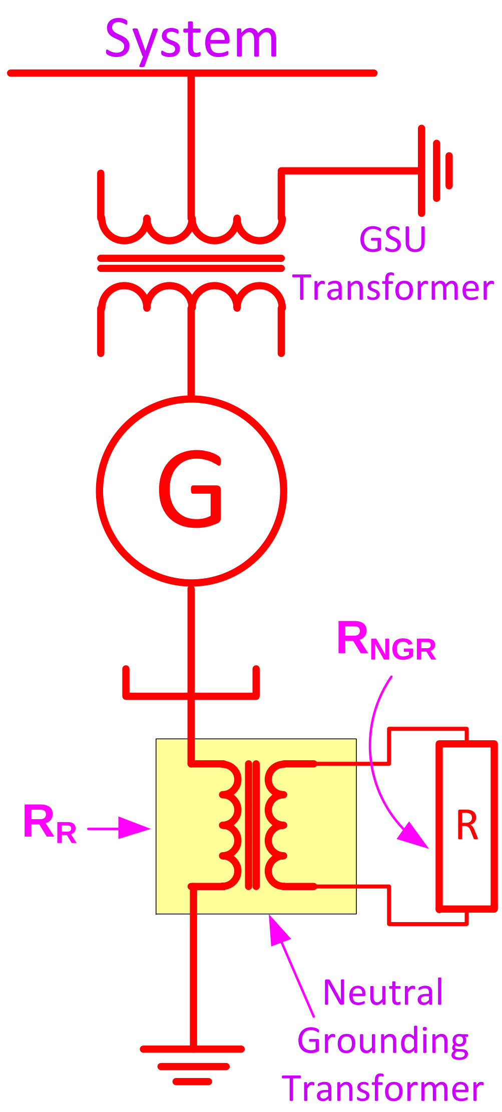
- Why Ground?
  - Improved safety by allowing detection of faulted equipment
  - Stop transient overvoltages
    - Notorious in ungrounded systems
  - Ability to detect a ground fault before a multiphase to ground fault evolves
  - If impedance is introduced, limit ground fault current and associated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

Types of Generator Grounding



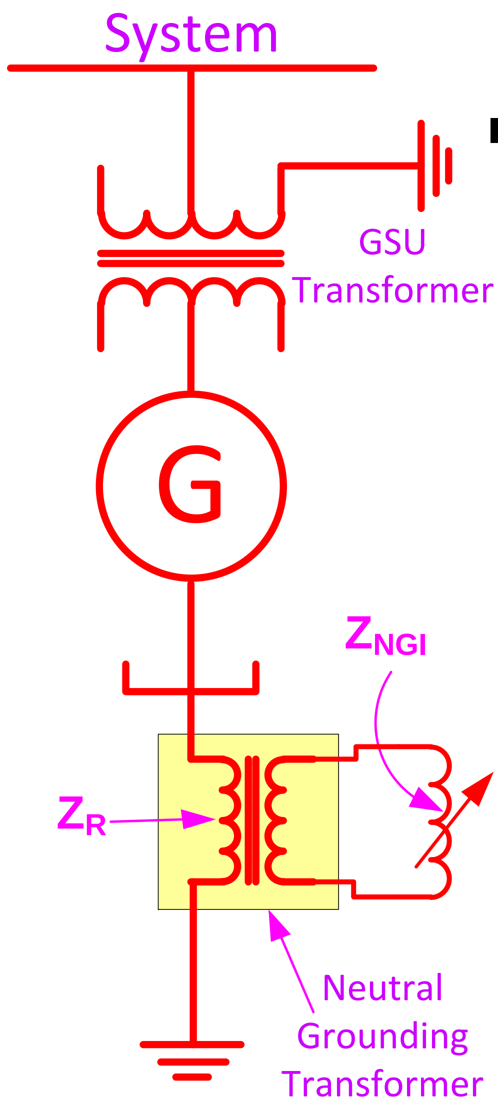
- Low Impedance
  - Good ground source
    - The lower the R, the better the ground source
    - The lower the R, the more damage to the generator on internal ground fault
  - Can get expensive as resistor voltage rating goes up
  - Generator will be damaged on internal ground fault
    - Ground fault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

Types of Generator Grounding



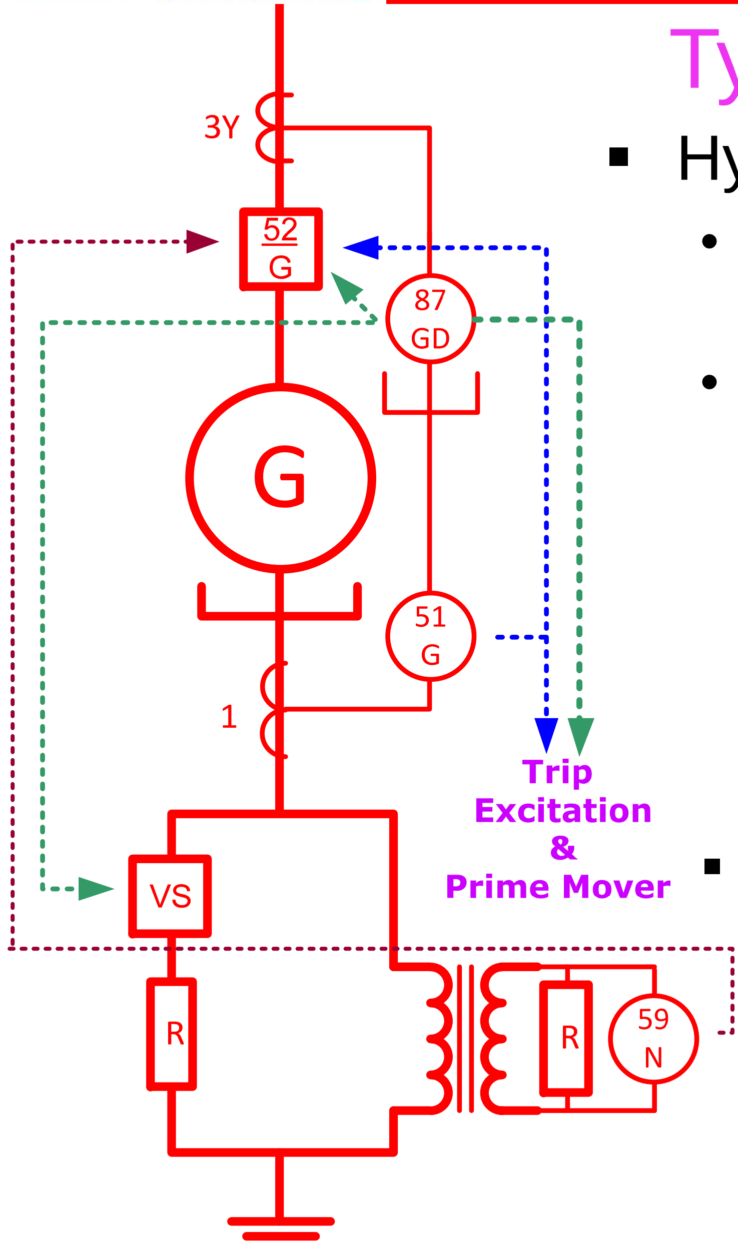
- High Impedance
  - Creates “unit connection”
  - System ground source obtained from GSU
  - Uses principle of reflected impedance
    - Eq: $R_{NGR} = R_R / [V_{pri}/V_{sec}]^2$
      - R_{NGR} = Neutral Grounding Resistor Resistance
      - R_R = Reflected Resistance
    - Ground fault current typically <=10A

Types of Generator Grounding



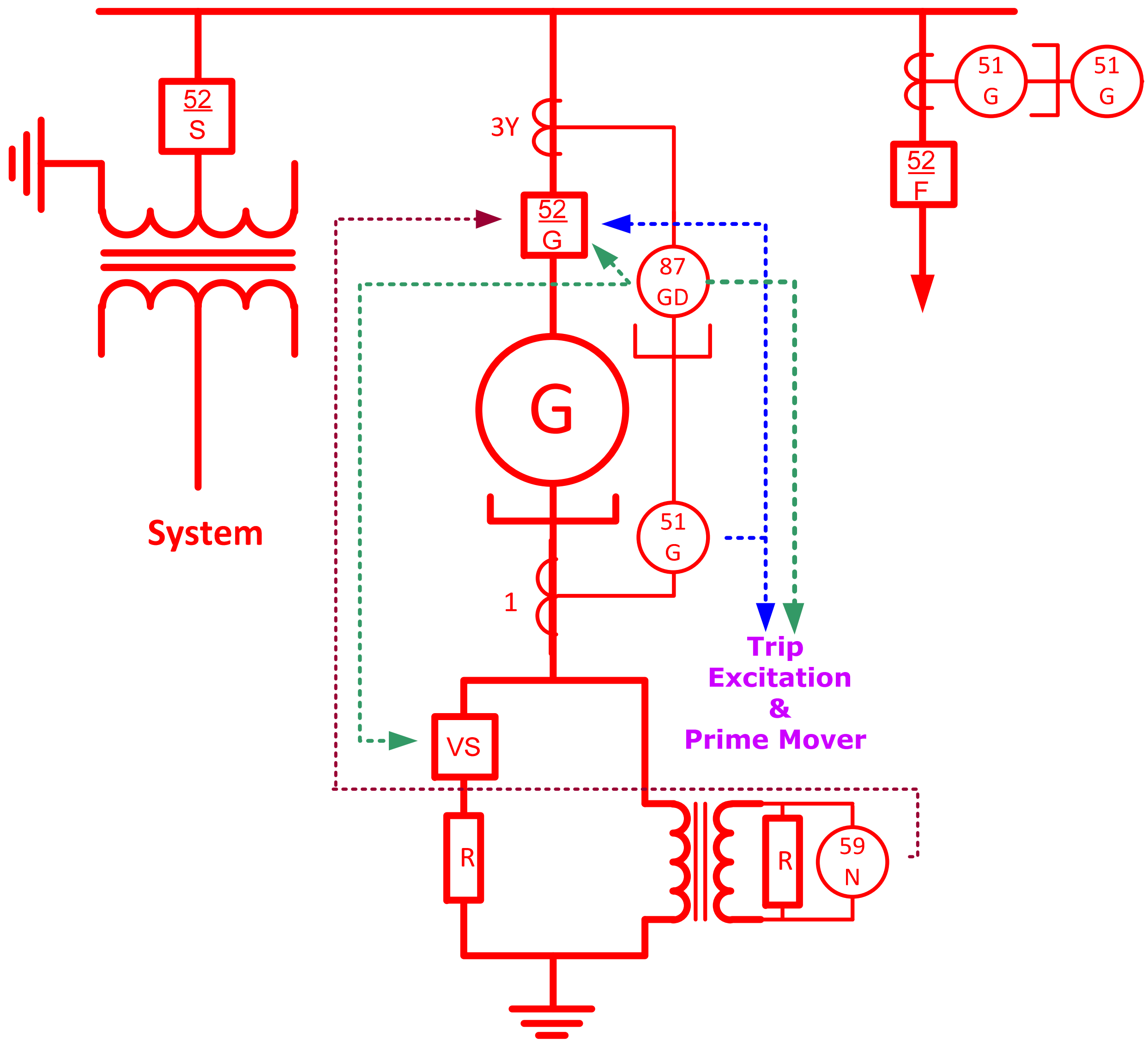
- Compensated
  - Creates "unit connection"
  - Most expensive
    - Tuned reactor, plus GSU and Grounding Transformers
  - System ground source obtained from GSU
  - Uses reflected impedance from grounding transformer, same as high impedance grounded system does
  - Generator damage mitigated from ground fault
  - Reactor tuned against generator capacitance to ground to limit ground fault current to very low value (can be less than 1A)

Types of Generator Grounding



- 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)

Types of Generator Grounding

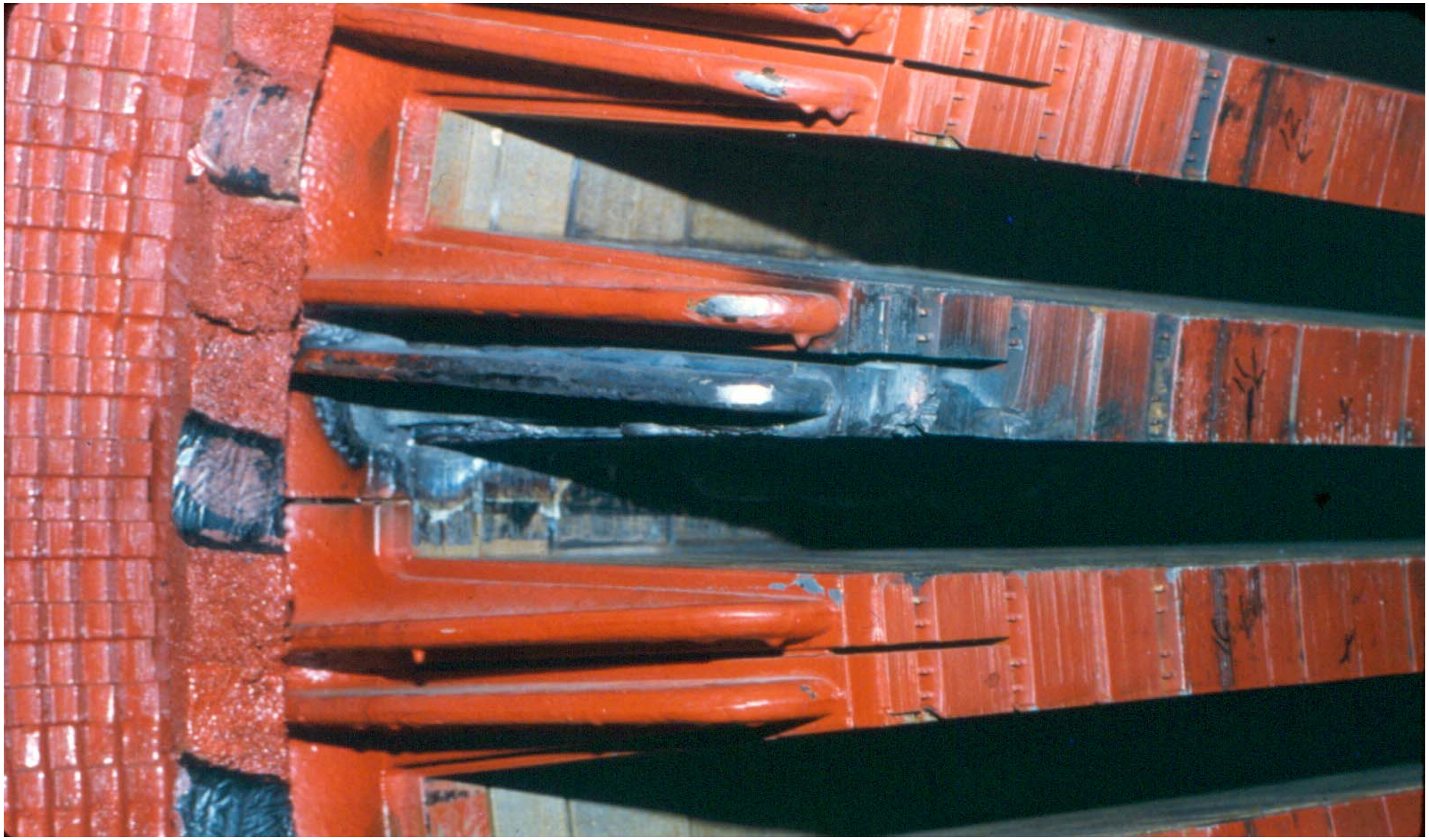


Types of Generator Ground Fault Damage

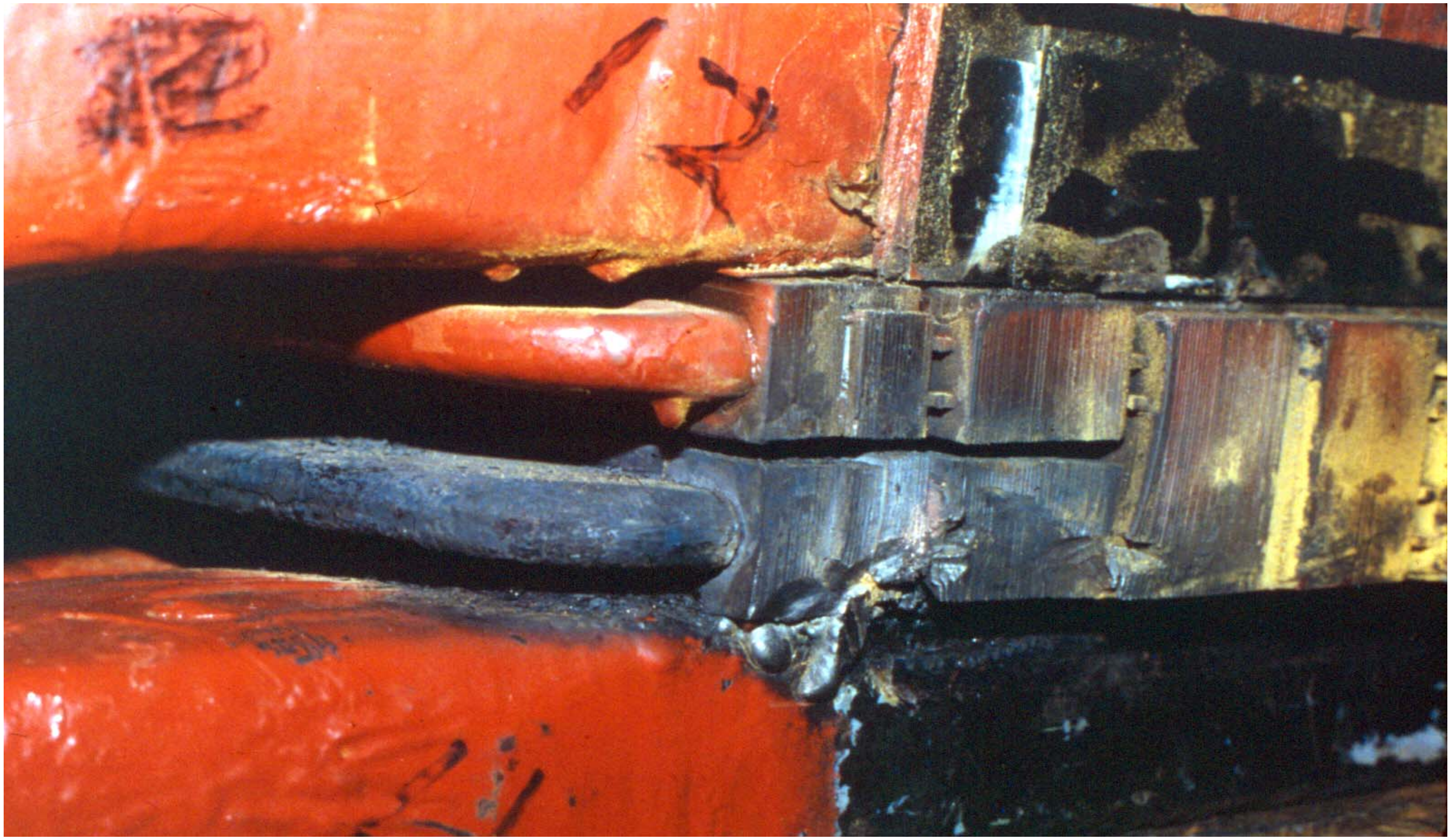
- Following pictures show stator damage after an internal ground fault
- This generator was high impedance grounded, with the fault current less than 10A
- Some iron burning occurred, but the damage was repairable
- With low impedance grounded machines the damage is severe

Stator Ground Fault Damage

Stator Ground Fault Damage



Stator Ground Fault Damage



Stator Ground Fault Damage

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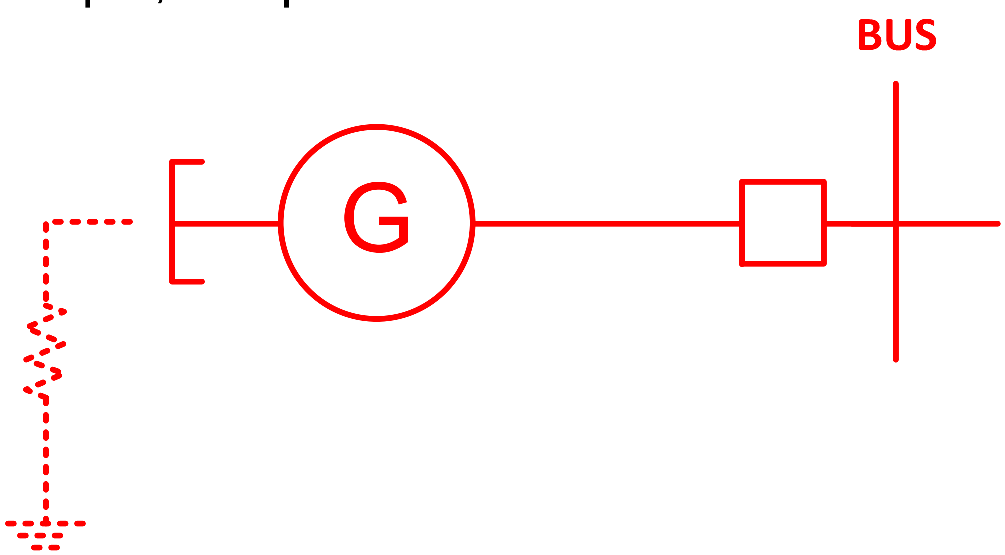
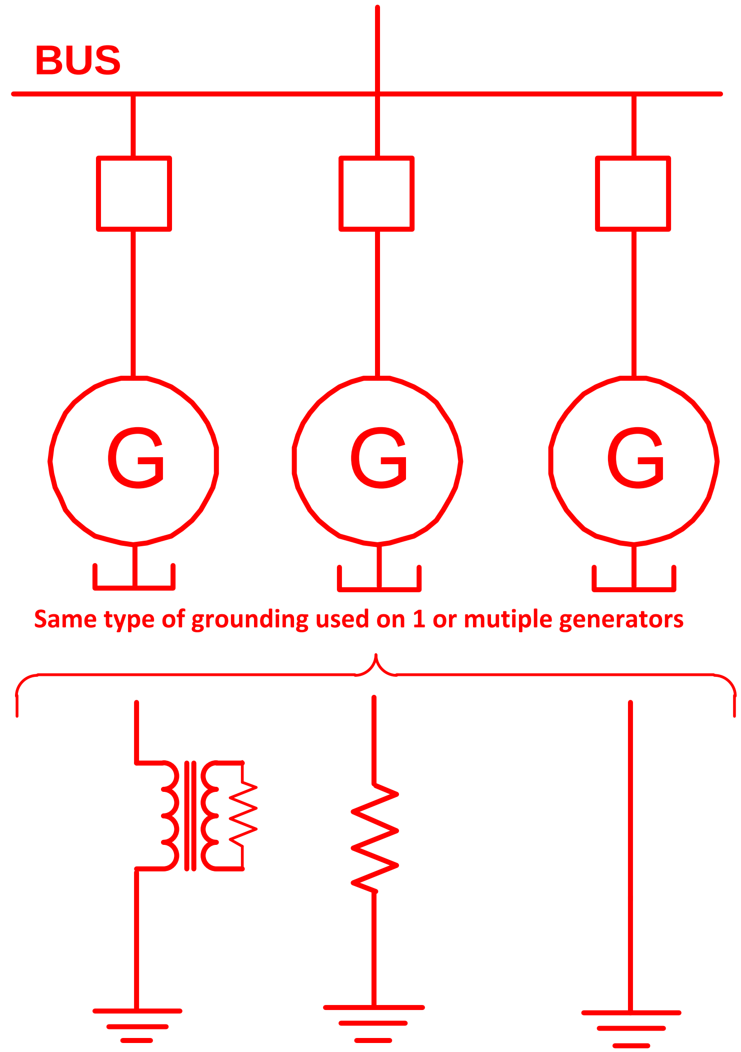
Types of Generator Connections

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

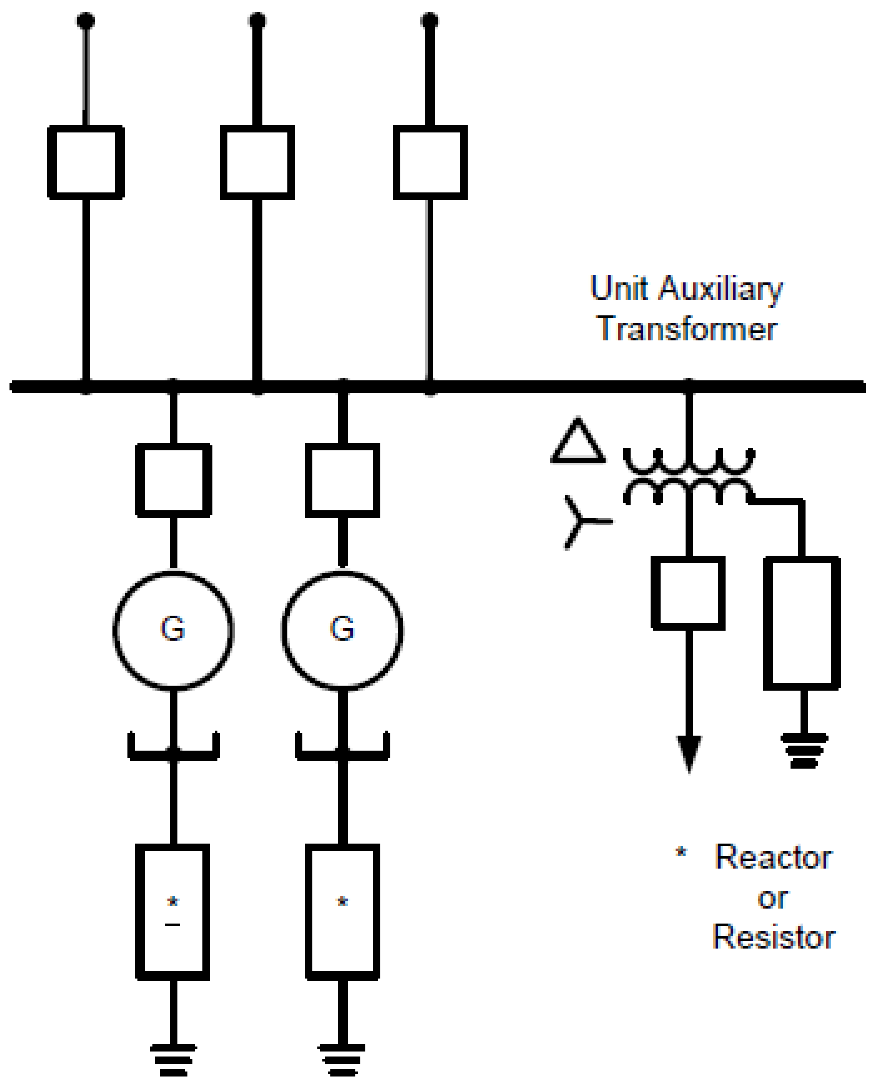


Types of Generator Connections

- **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

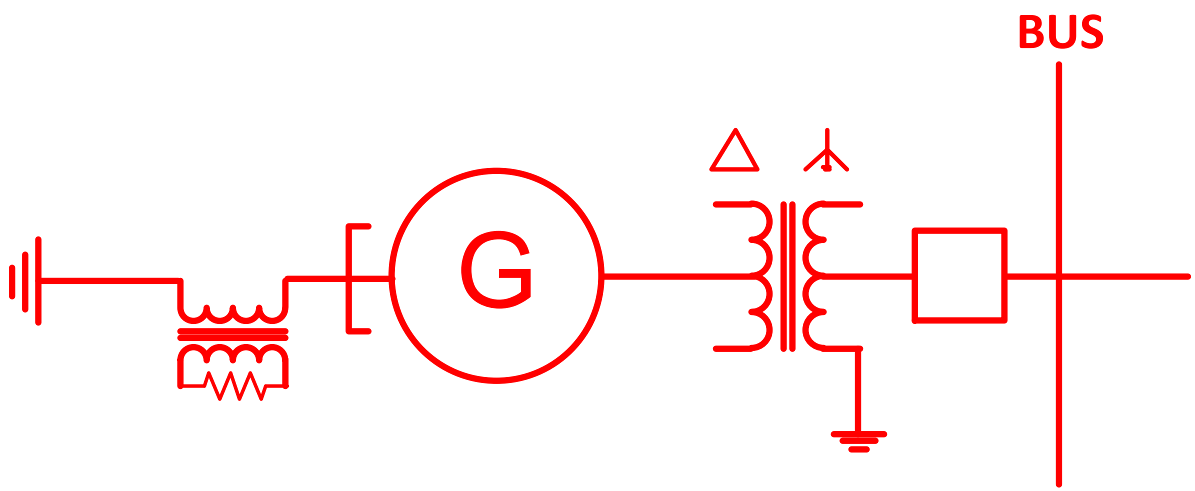


Bus (Direct) Connected



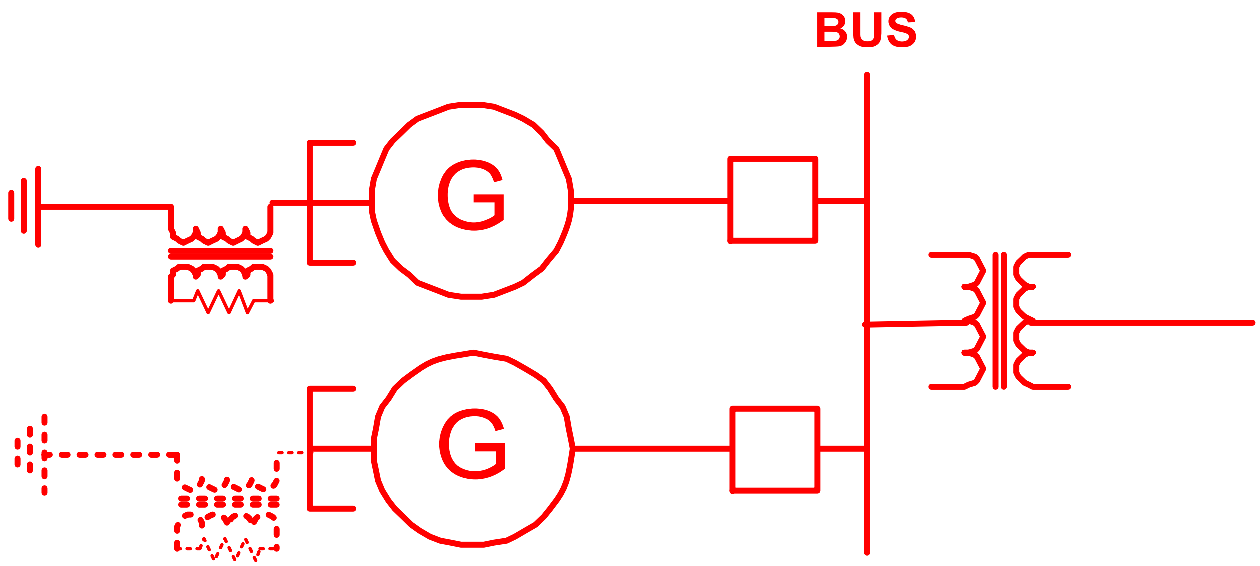
Types of Generator Connections

- **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

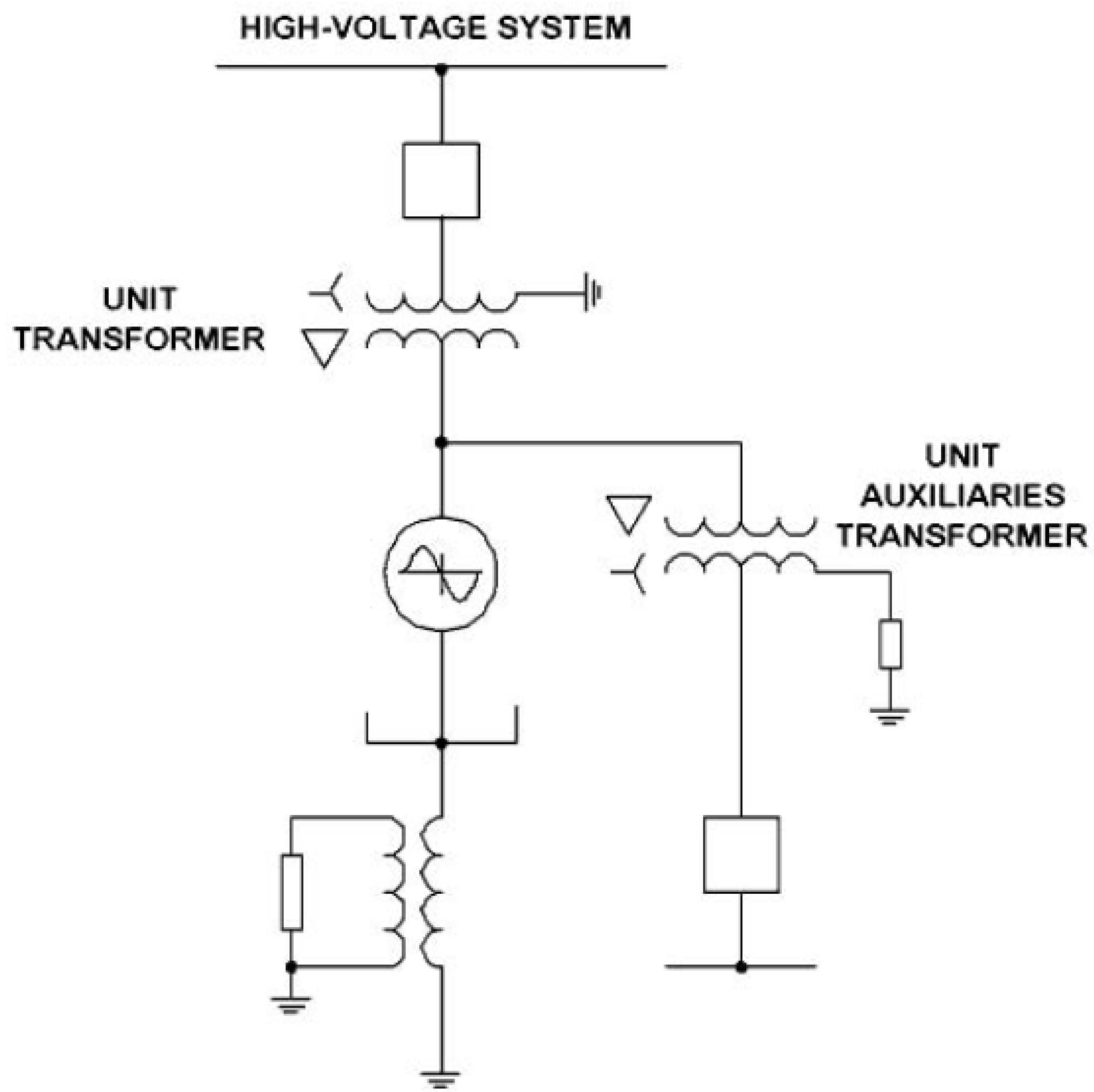


Types of Generator Connections

- **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



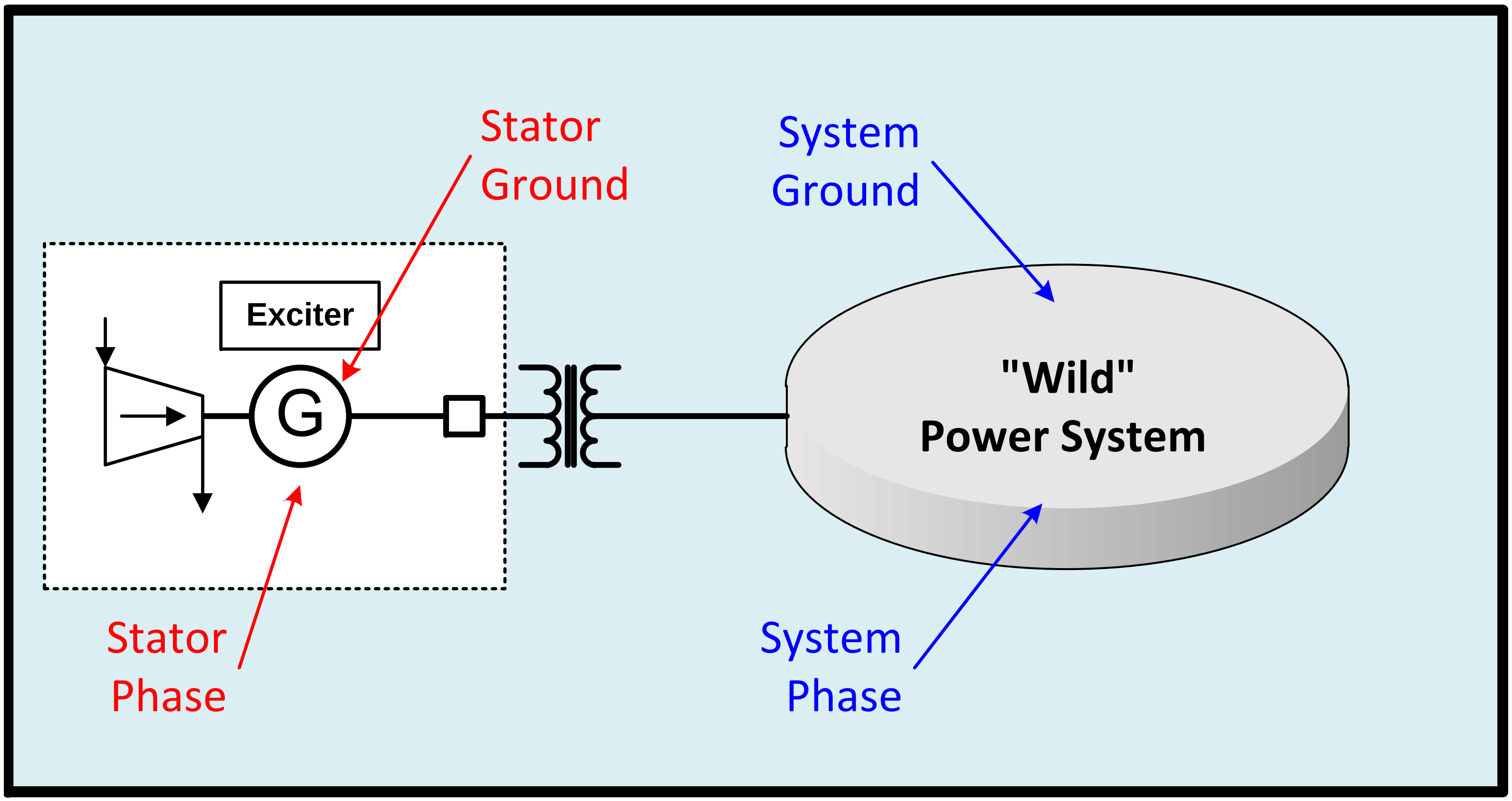
Generator Protection Overview

- Generators experience shorts and abnormal electrical conditions
- Proper protection can mitigate damage to the machine
- Proper protection can enhance generation security
- Generator Protection:
  - Shorts circuits in the generator
  - Uncleared faults on the system
  - Abnormal electrical conditions may be caused by the generator or the system

Generator Protection Overview

- Short Circuits
  - In Generator
    - Phase Faults
    - Ground Faults
  - On System
    - Phase Faults
    - Ground Faults

Generator Protection Overview

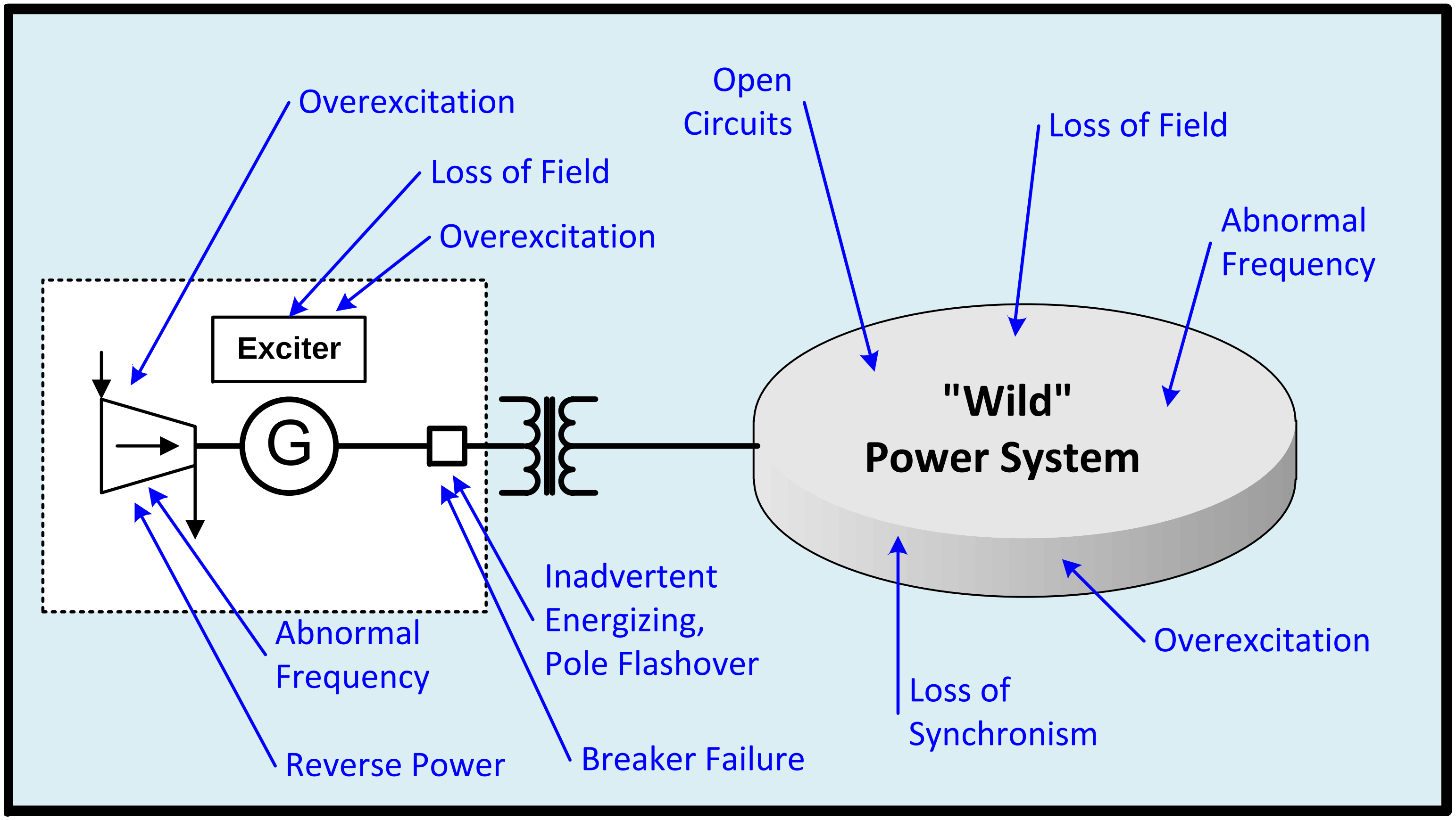


Internal and External Short Circuits

Generator Protection Overview

- Abnormal Operating Conditions
  - Abnormal Frequency
  - Abnormal Voltage
  - Overexcitation
  - Field Loss
  - Loss of Synchronism
  - Inadvertent Energizing
  - Breaker Failure
  - Loss of Prime Mover
  - Blown VT Fuses
  - Open Circuits / Conductors

Generator Protection Overview



Abnormal Operating Conditions

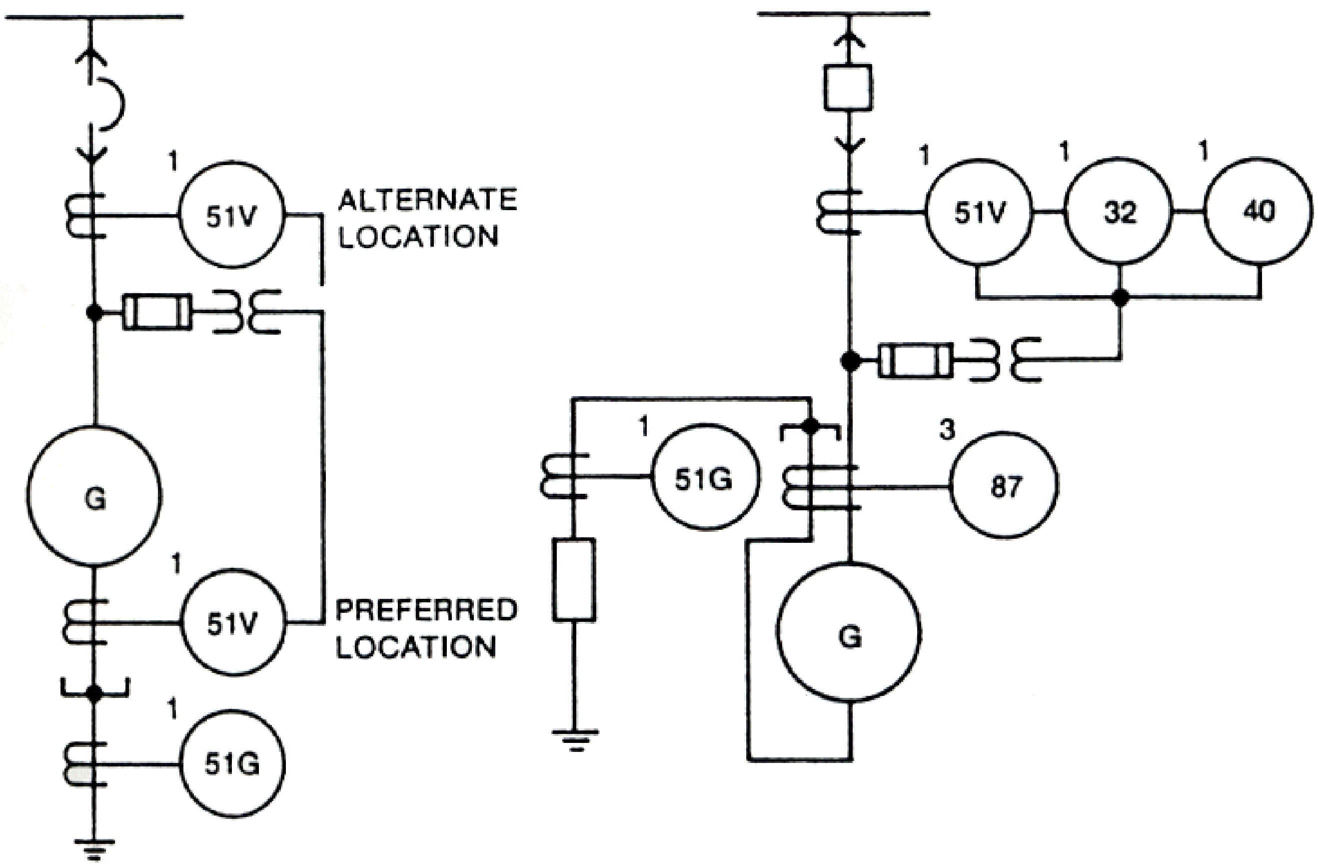
ANSI/IEEE Standards

- **Latest developments reflected in:**

  - Std. 242: Buff Book
  - C37.102: IEEE Guide for Generator Protection
  - C37.101: IEEE Guide for AC Generator Ground Protection
  - C37.106: IEEE Guide for Abnormal Frequency Protection for Power Generating Plants

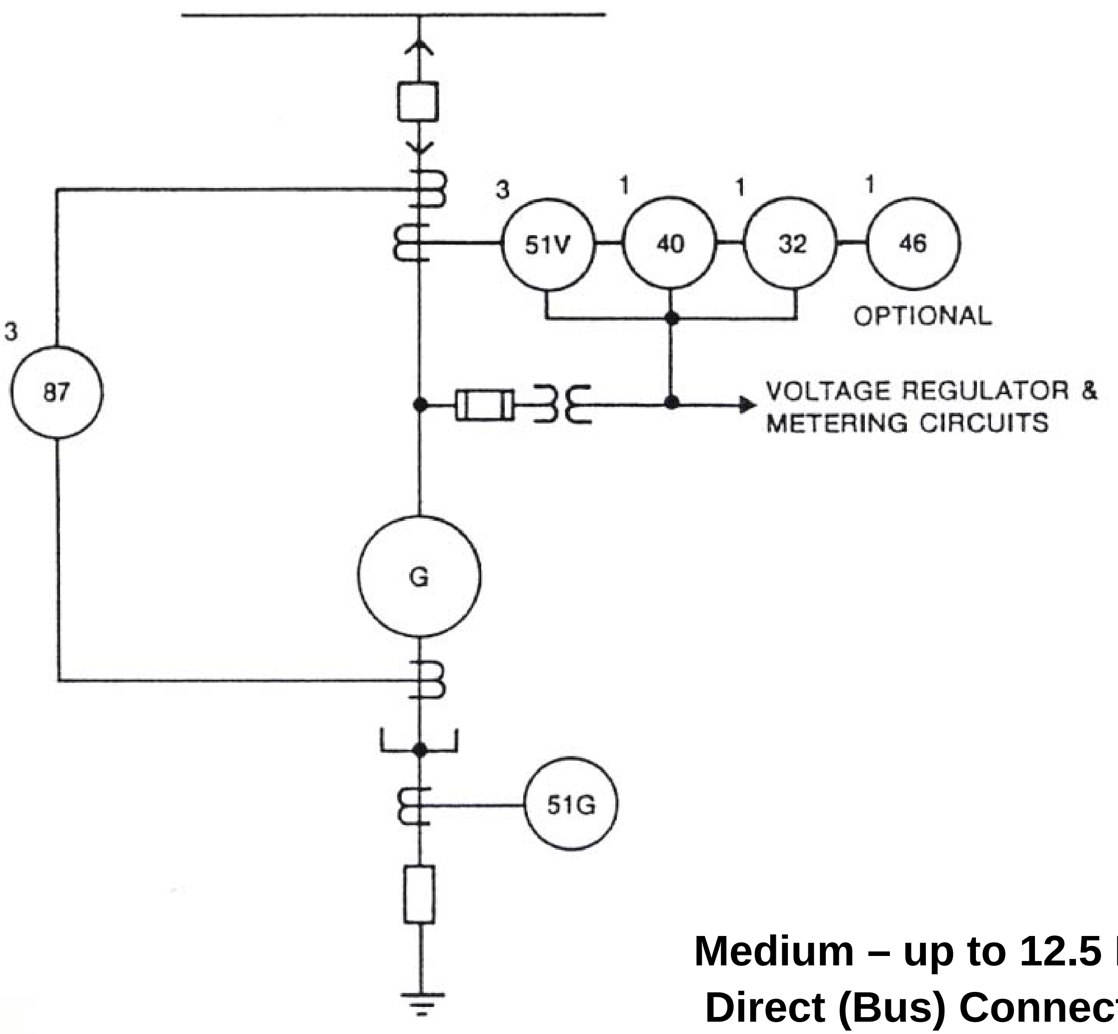
These are created/maintained by the IEEE PES PSRC & IAS

Small Machine Protection IEEE "Buff Book"



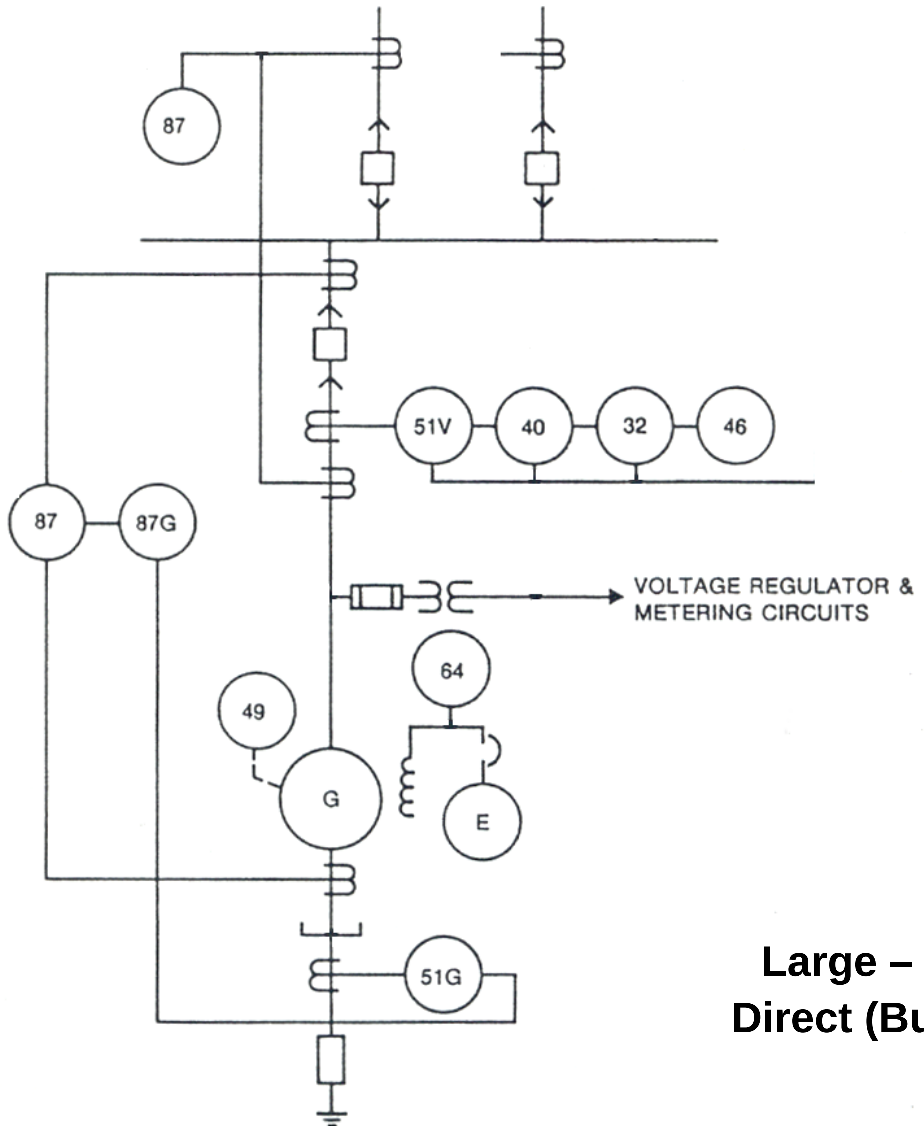
Small – up to 1 MW to 600V, 500 kVA if >600V
Direct (Bus) Connected

Small Machine Protection IEEE "Buff Book"



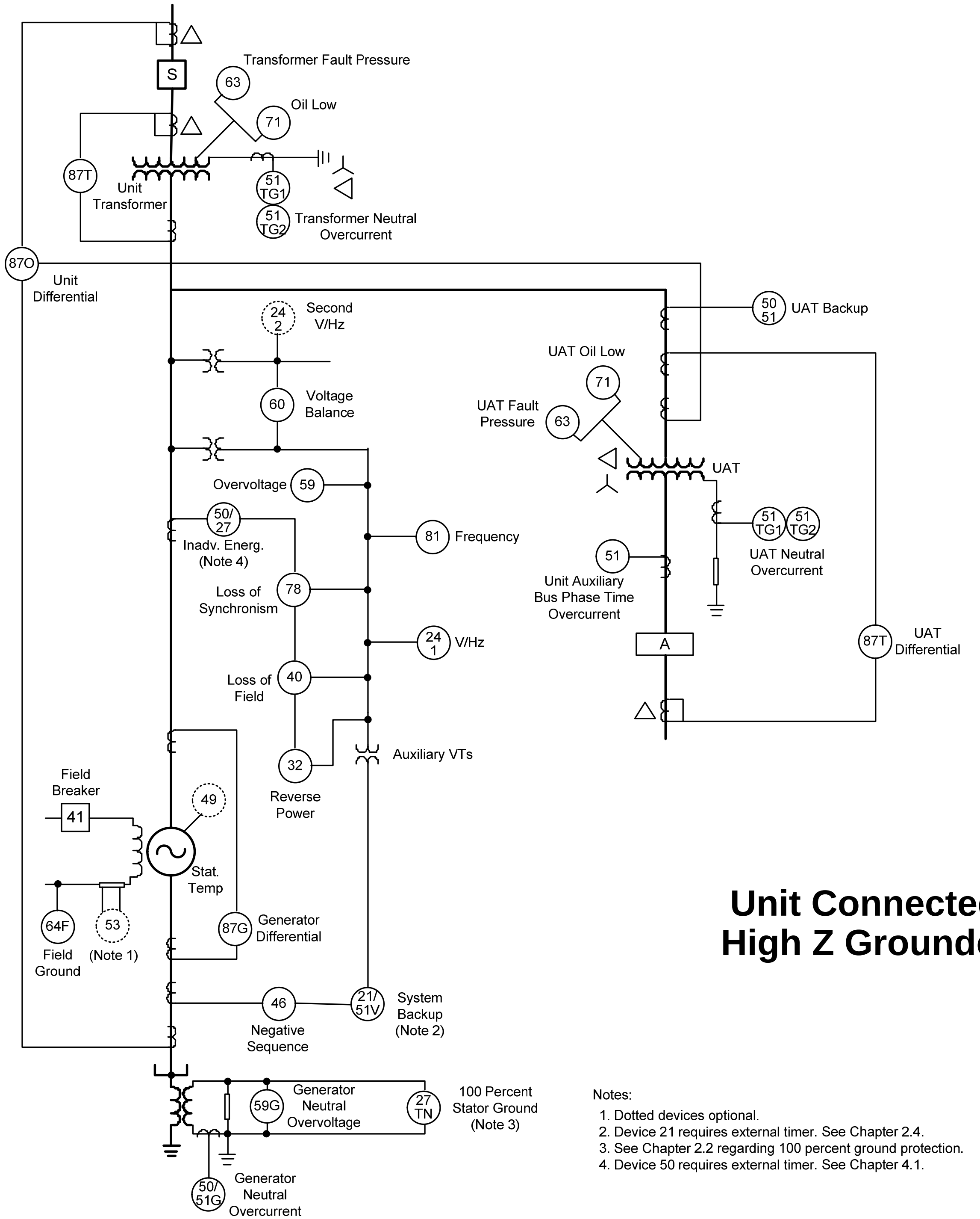
Medium – up to 12.5 MW
Direct (Bus) Connected

Small Machine Protection IEEE "Buff Book"



Large – up to 50 MW
Direct (Bus) Connected

Typical Unit Connected Generator (C37.102)



Unit Connected, High Z Grounded

Notes:

1. Dotted devices optional.
2. Device 21 requires external timer. See Chapter 2.4.
3. See Chapter 2.2 regarding 100 percent ground protection.
4. Device 50 requires external timer. See Chapter 4.1.

Protection Considerations

- Initiate actions only for the intended purpose and for the equipment and/or zone designed to protect
- Standardization of criteria for application, set points derivations, and coordination
- Practices in place to achieve efficient system operation
- Historical experience
- Previous experience and anticipation of the types of trouble likely to be encountered within the system for which the protection is expected to perform accurately
- Costs: initial capital, operating over life cycle, and maintenance

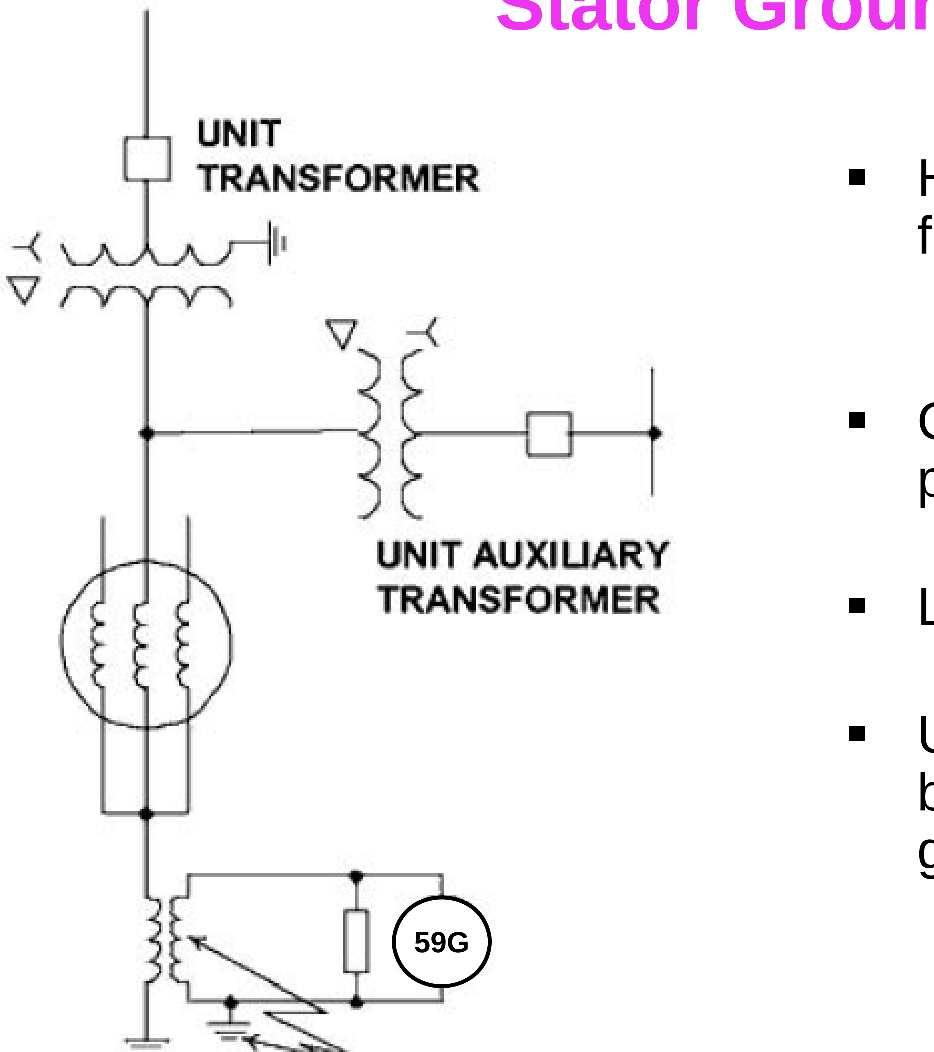
Protection Considerations

- Design of various protection schemes widely differs
- Generator and Transmission Engineering may be decoupled
- Hidden failures
- Relay settings and coordination
- Protection performance for conditions that the relay settings criteria have not been developed
  - Multiple contingencies
  - Stressed system conditions as a result of operating the system close to the limit
- Energy and market strategies
  - Reactive support and load transport issues

Stator Ground Fault-High Z Grounded Machines

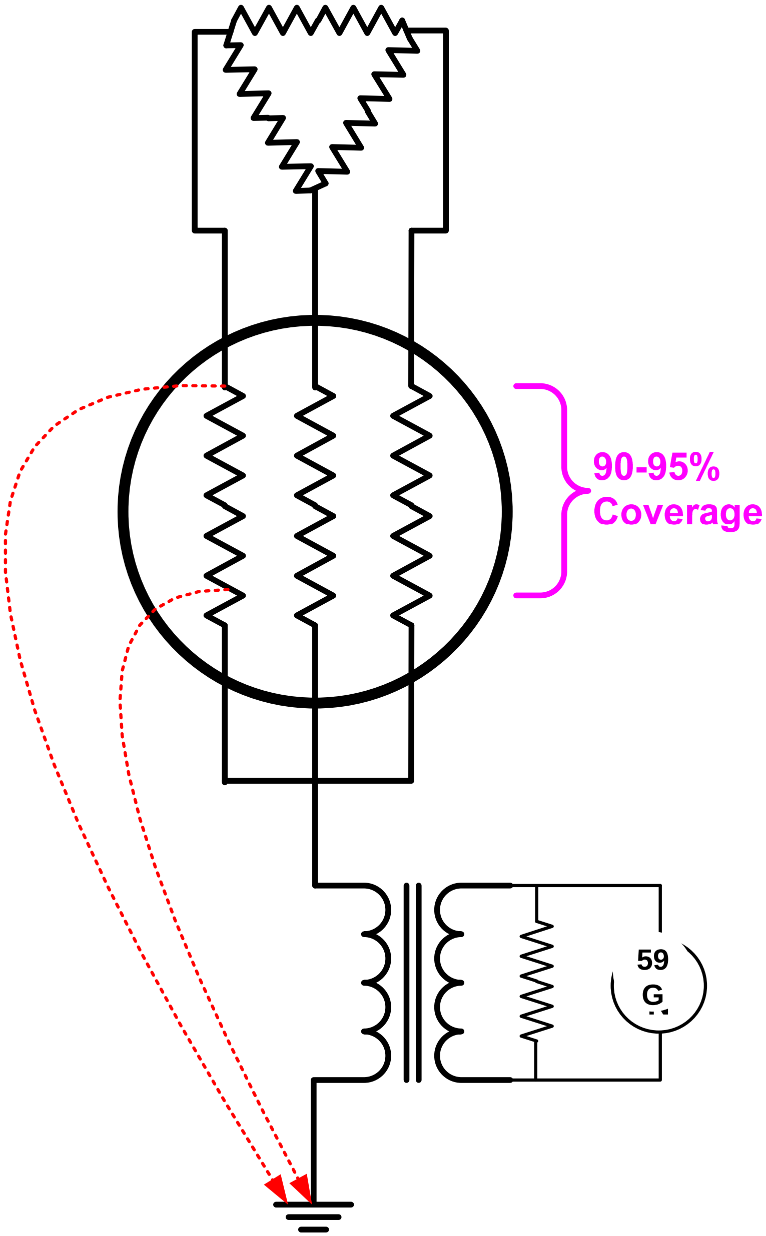
- 95% stator ground fault provided by 59G Tuned to the fundamental frequency
  - Must work properly from 10 to 80 Hz to provide protection during startup
- Additional coverage near neutral (last 5%) provided by:
  - 27TN: 3rd harmonic undervoltage
  - 59D: Ratio of 3rd harmonic at terminal and neutral 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)

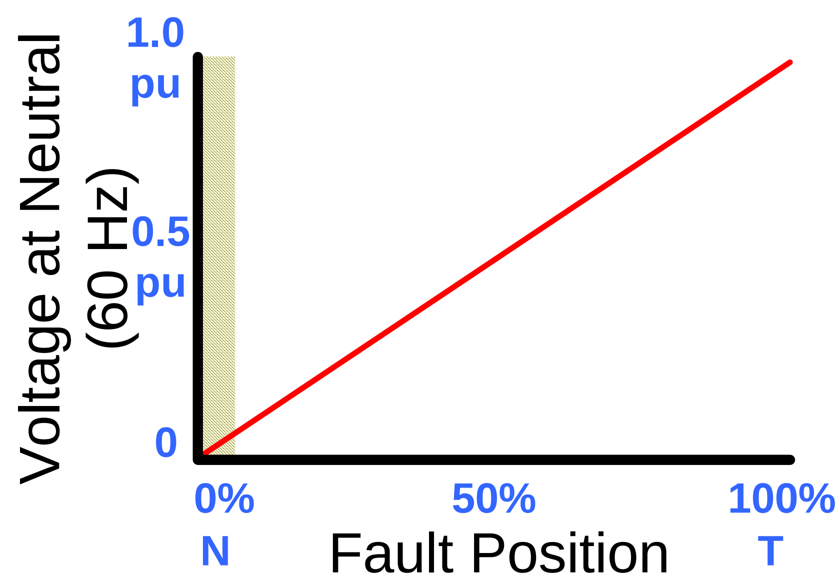
Stator Ground Fault (59G)



- 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!

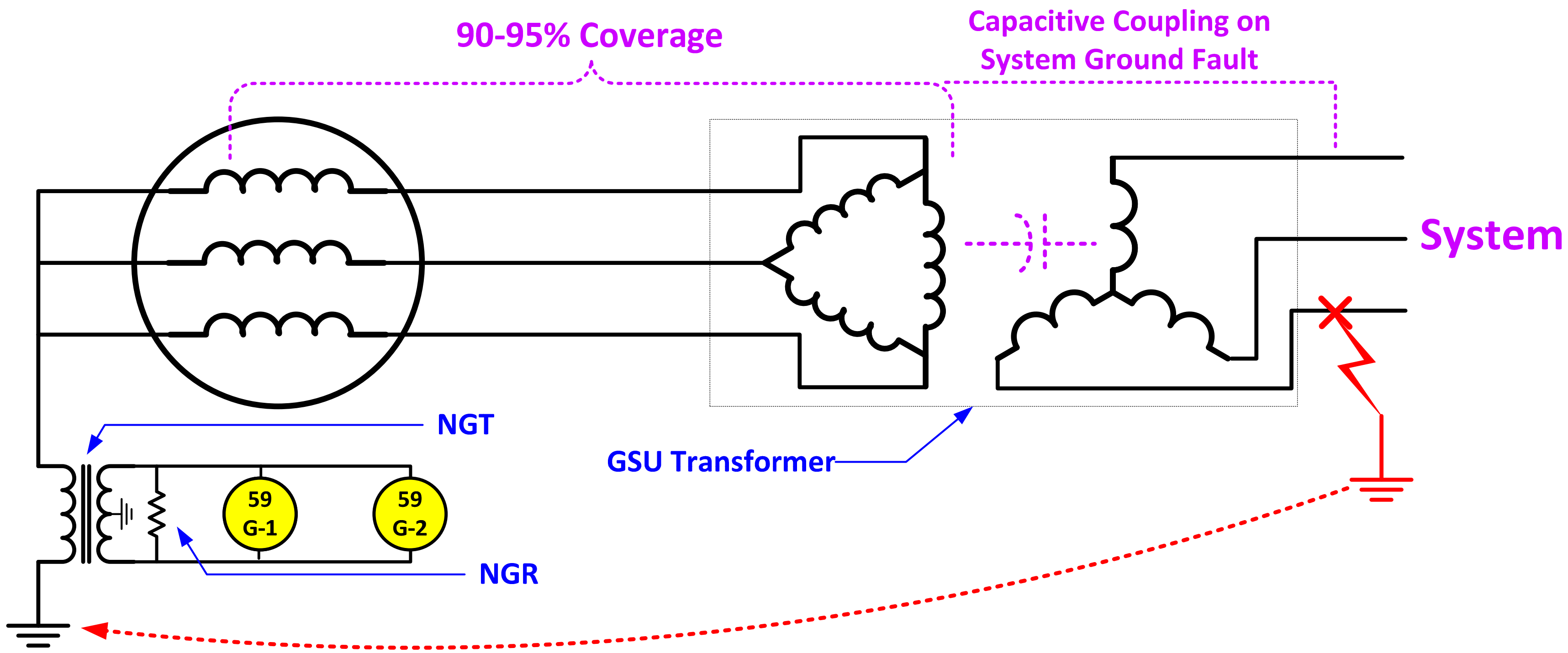
59G Element





- **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**

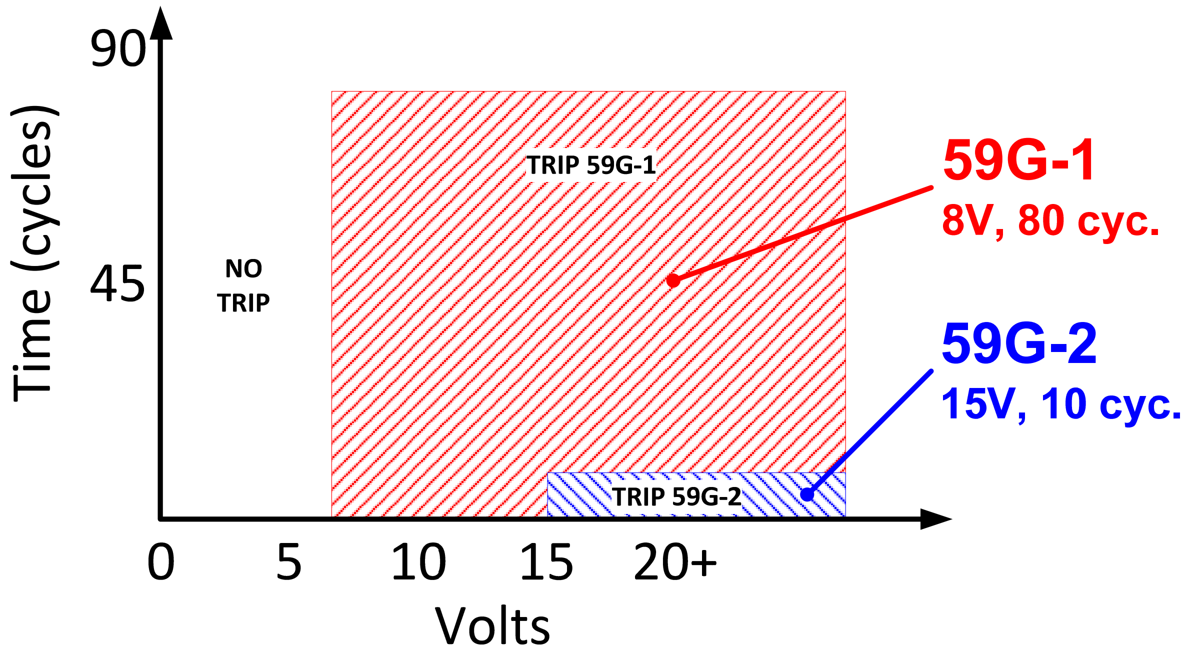
59G System Ground Fault Issue



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

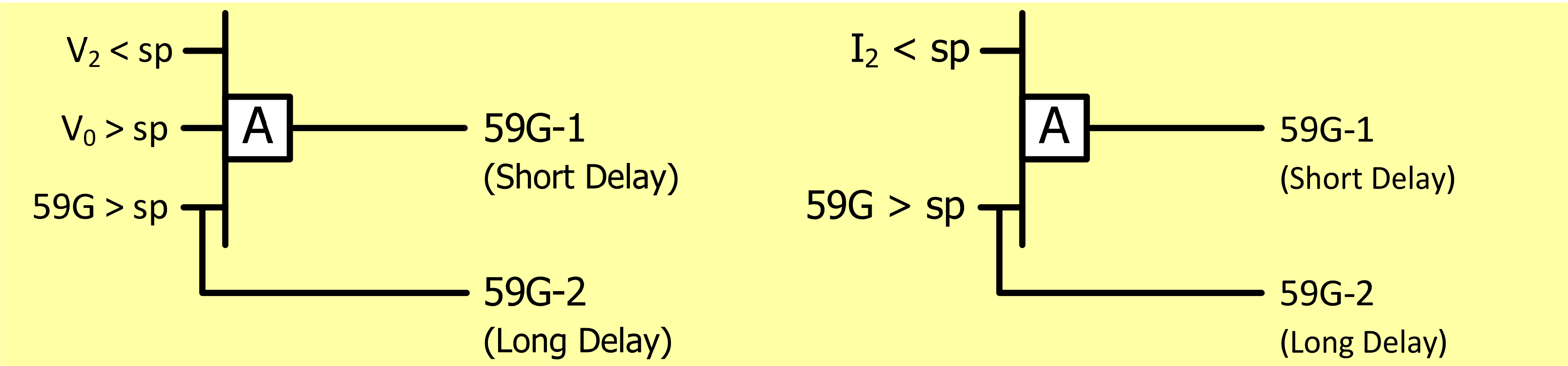
Multiple 59G Element Application

- **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



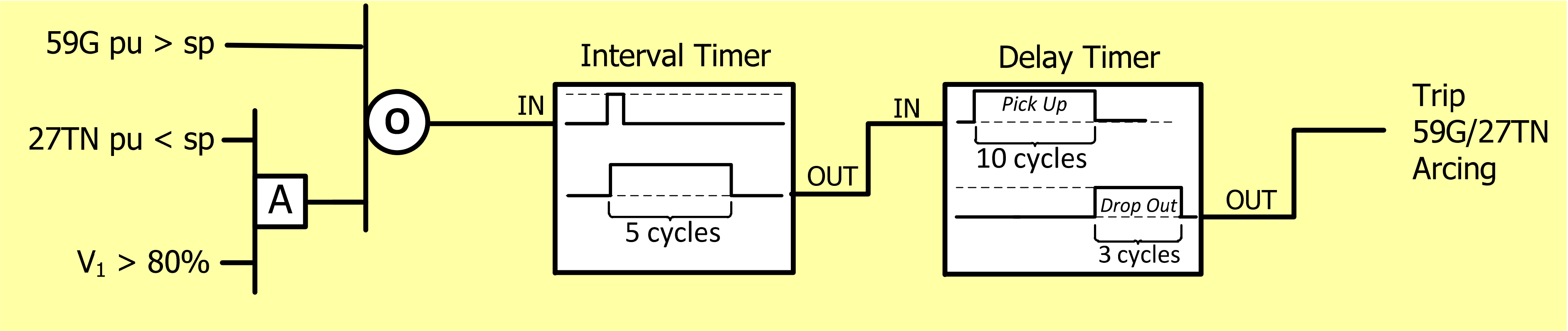
- Both V_2 and I_2 implementation have been applied
  - A ground fault in the generator zone produces primarily <u>zero</u> sequence voltage
  - A fault in the VT secondary or system (GSU coupled) generates <u>negative</u> sequence quantities in addition to zero sequence voltage

59G Element

59G – Generator Neutral Overvoltage: Three setpoints

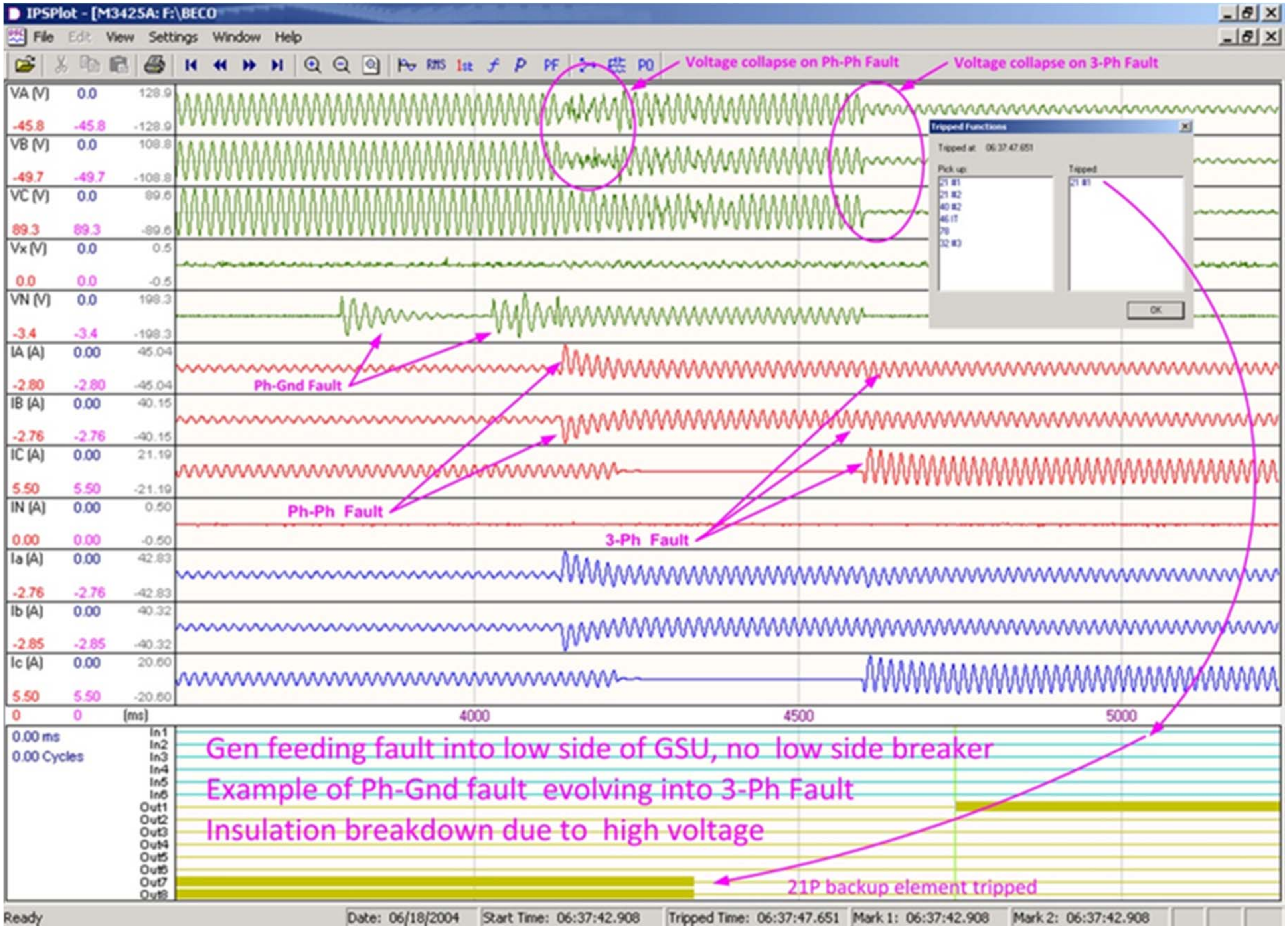
- 1st level set sensitive to cover down to 5% of stator
  - Long delay to coordinate with close-in system ground faults capacitively coupled across GSU
- 2nd level set higher than the capacitively coupled voltage so coordination from system ground faults is not necessary
  - Allows higher speed tripping
  - Only need to coordinate with PT fuses
- 3rd 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

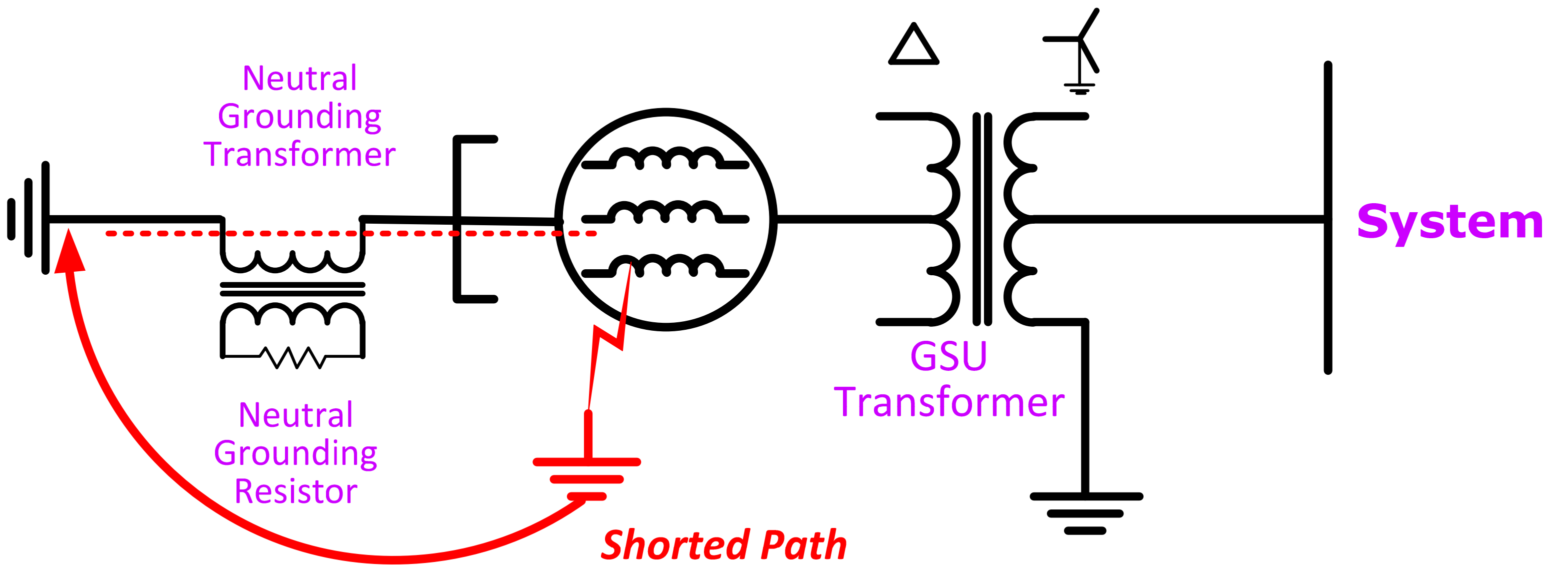
Intermittent Arcing Ground Fault Turned Multiphase



59G Element


59N: Neutral Overvoltage
#1
Pickup: 5.5 5.0 180.0 (V)
Time Delay: 90 1 8160 (Cycles)
Disable
Outputs
1 2 3 4 5 6 7 8
9 10 11 12 13 14 15 16
17 18 19 20 21 22 23
Blocking Inputs
FL 1 2 3 4
5 6 7 8 9
10 11 12 13 14
#2
Pickup: 15.0 5.0 180.0 (V)
Time Delay: 20 1 8160 (Cycles)
Disable
Outputs
1 2 3 4 5 6 7 8
9 10 11 12 13 14 15 16
17 18 19 20 21 22 23
Blocking Inputs
FL 1 2 3 4
5 6 7 8 9
10 11 12 13 14
#3
Pickup: 5.5 5.0 180.0 (V)
Time Delay: 15 1 8160 (Cycles)
Disable
Outputs
1 2 3 4 5 6 7 8
9 10 11 12 13 14 15 16
17 18 19 20 21 22 23
Blocking Inputs
FL 1 2 3 4
5 6 7 8 9
10 11 12 13 14
Setting
20Hz Injection Mode: Disable Enable
Save
Cancel

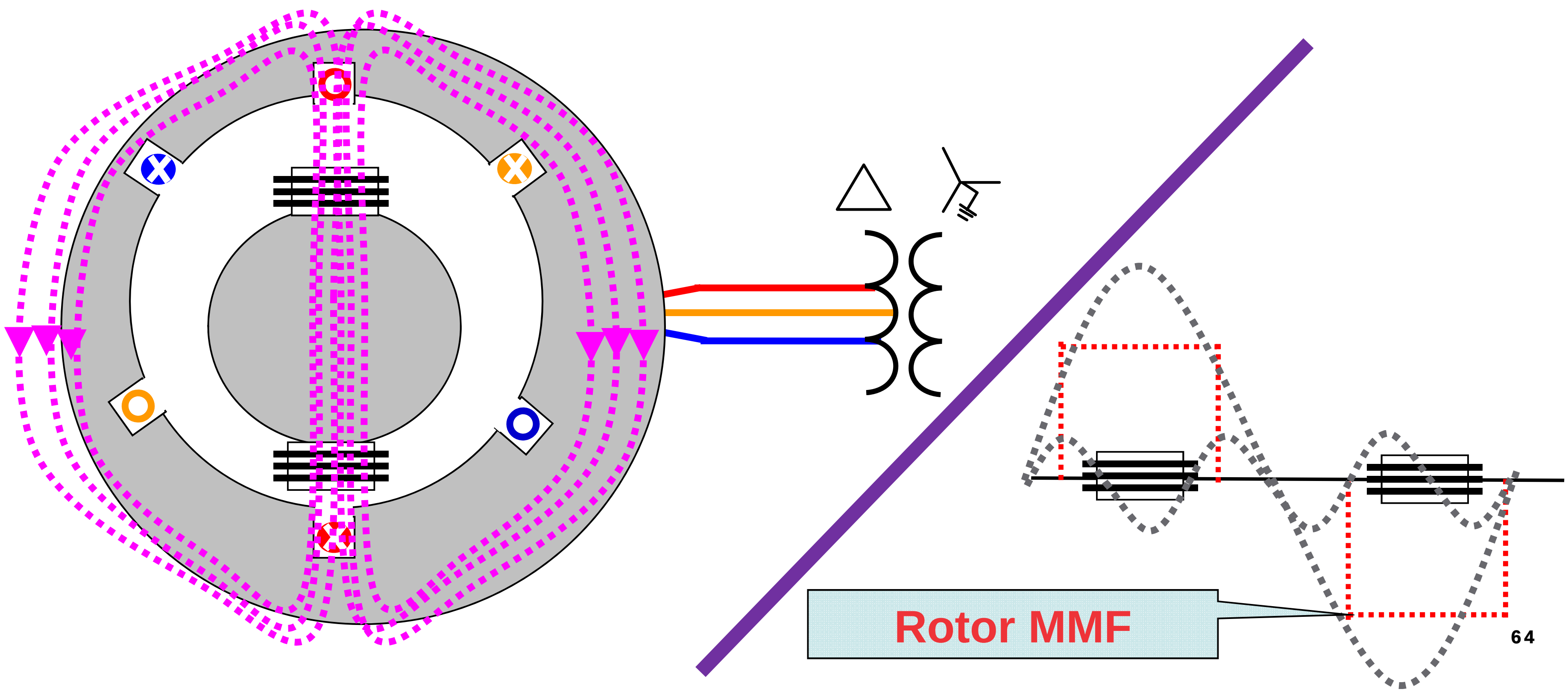
Why Do We Care About Faults Near Neutral?



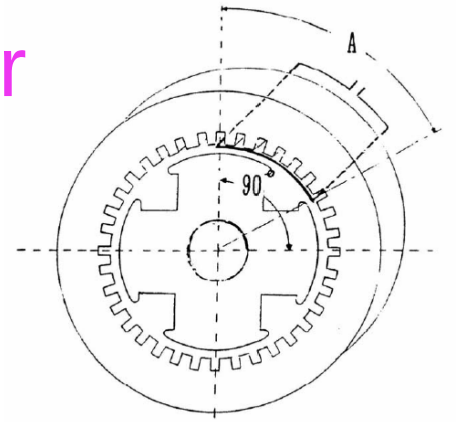
- A fault at or near the neutral shunts the high resistance that saves the stator from large currents with an internal ground fault
- A generator operating with an undetected ground fault near the neutral is a accident waiting to happen
- We can use 3rd Harmonic or Injection Techniques for complete (100%)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

Third-Harmonic Rotor Flux

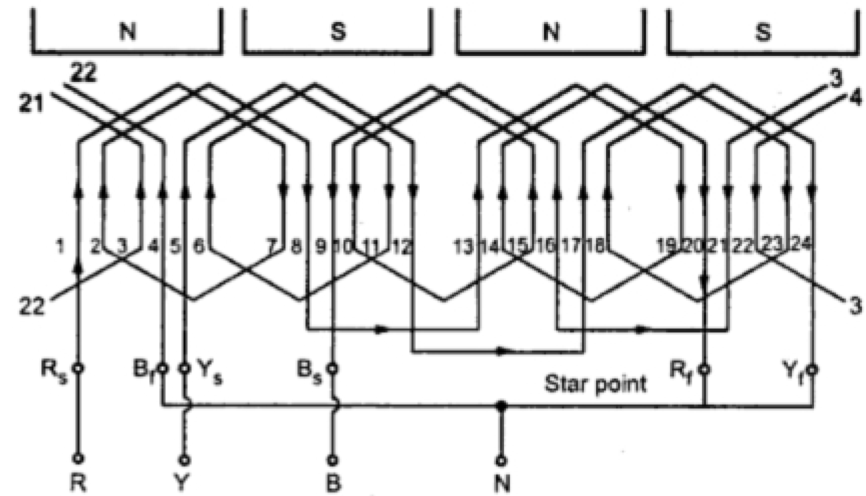
- **Develops in stator due to imperfections in winding and system connections**
- **Unpredictable amount requiring field observation at various operating conditions**
- **Also dependent on pitch of the windings, which a method to define the way stator windings placed in the stator slots**

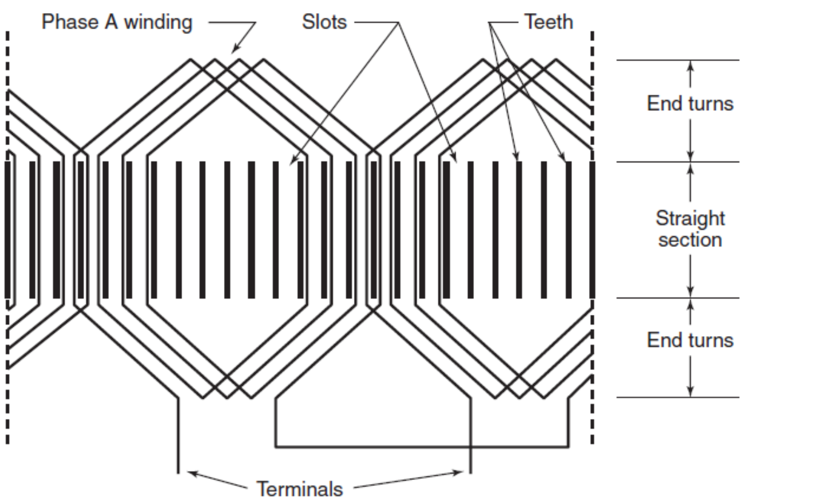


Generator Pitch



Pole spans 60 over 90 = 2/3 pitch





A	A	A	A	$\bar{B}$	$\bar{B}$	$\bar{B}$	$\bar{B}$	C	C	C	C	$\bar{A}$	$\bar{A}$	$\bar{A}$	$\bar{A}$	B	B	B	B	$\bar{C}$	$\bar{C}$	$\bar{C}$	$\bar{C}$	Upper
$\bar{C}$	$\bar{C}$	A	A	A	A	$\bar{B}$	$\bar{B}$	$\bar{B}$	$\bar{B}$	C	C	C	C	$\bar{A}$	$\bar{A}$	$\bar{A}$	$\bar{A}$	B	B	B	B	$\bar{C}$	$\bar{C}$	Lower

Slot allocation

Pitch Factor is calculated by dividing the coil throw (–) 1 (coil span), by the number of slots per pole.

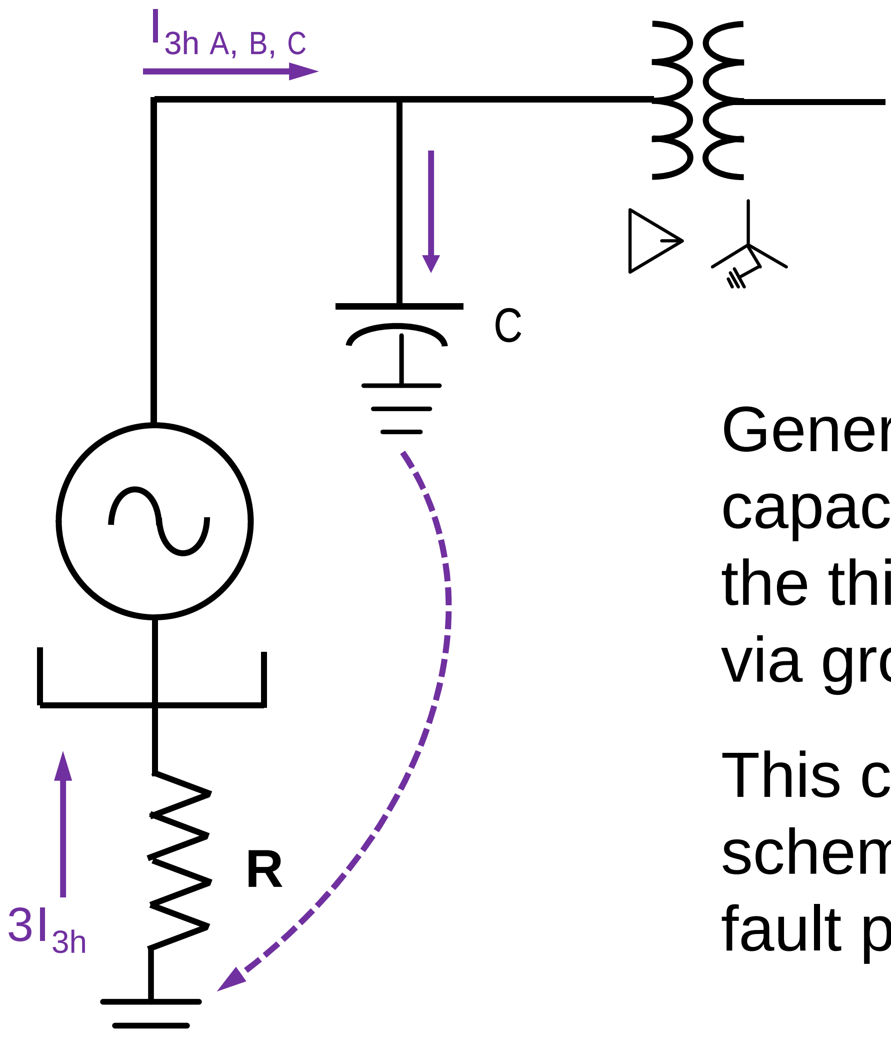
Using the examples in 1 through 3 above:

$$\text{Pitch Factor} = \frac{\text{1 to 9 throw (-) 1}}{\text{48 Slots} \div \text{4 Poles}} = \frac{8}{12}$$

Pitch Factor = 2/3

Stator Winding Diagram Illustrating "Pitch" In Winding Construction

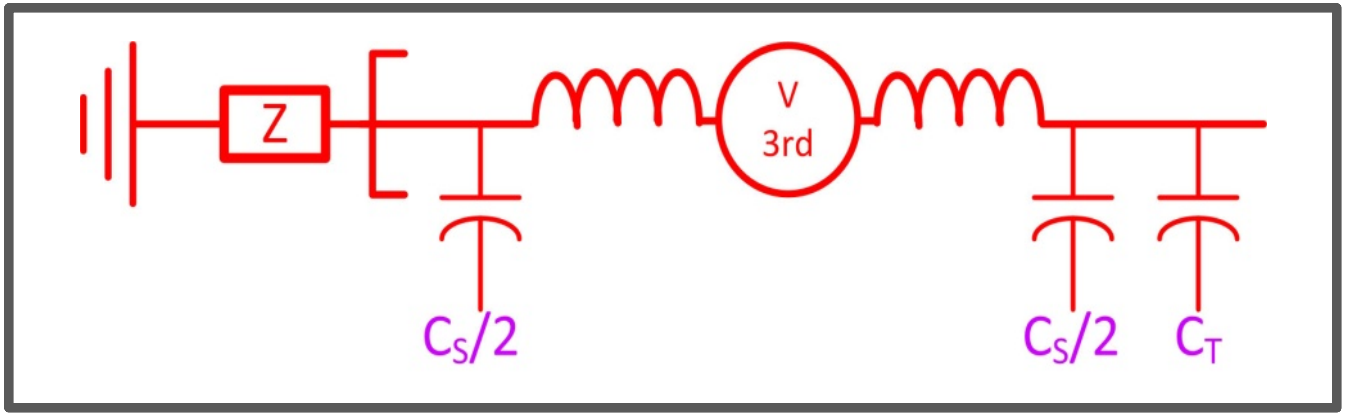
Using Third Harmonic in Generators



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

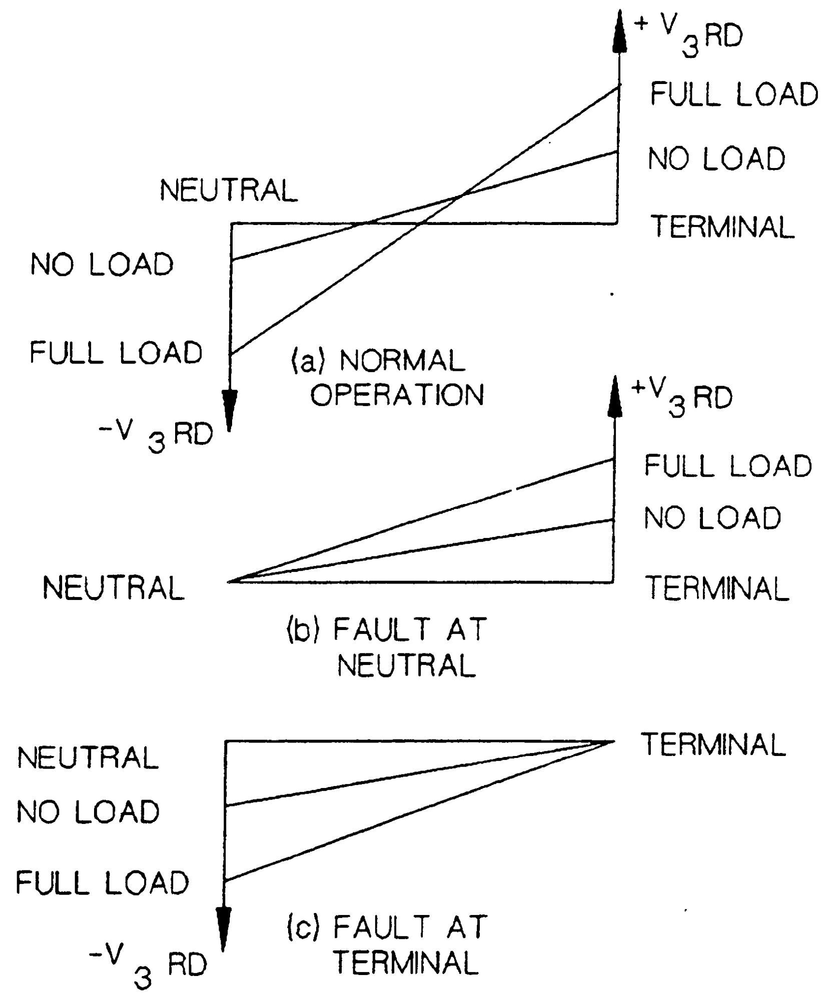
Generator Capacitance and 3rd Harmonics



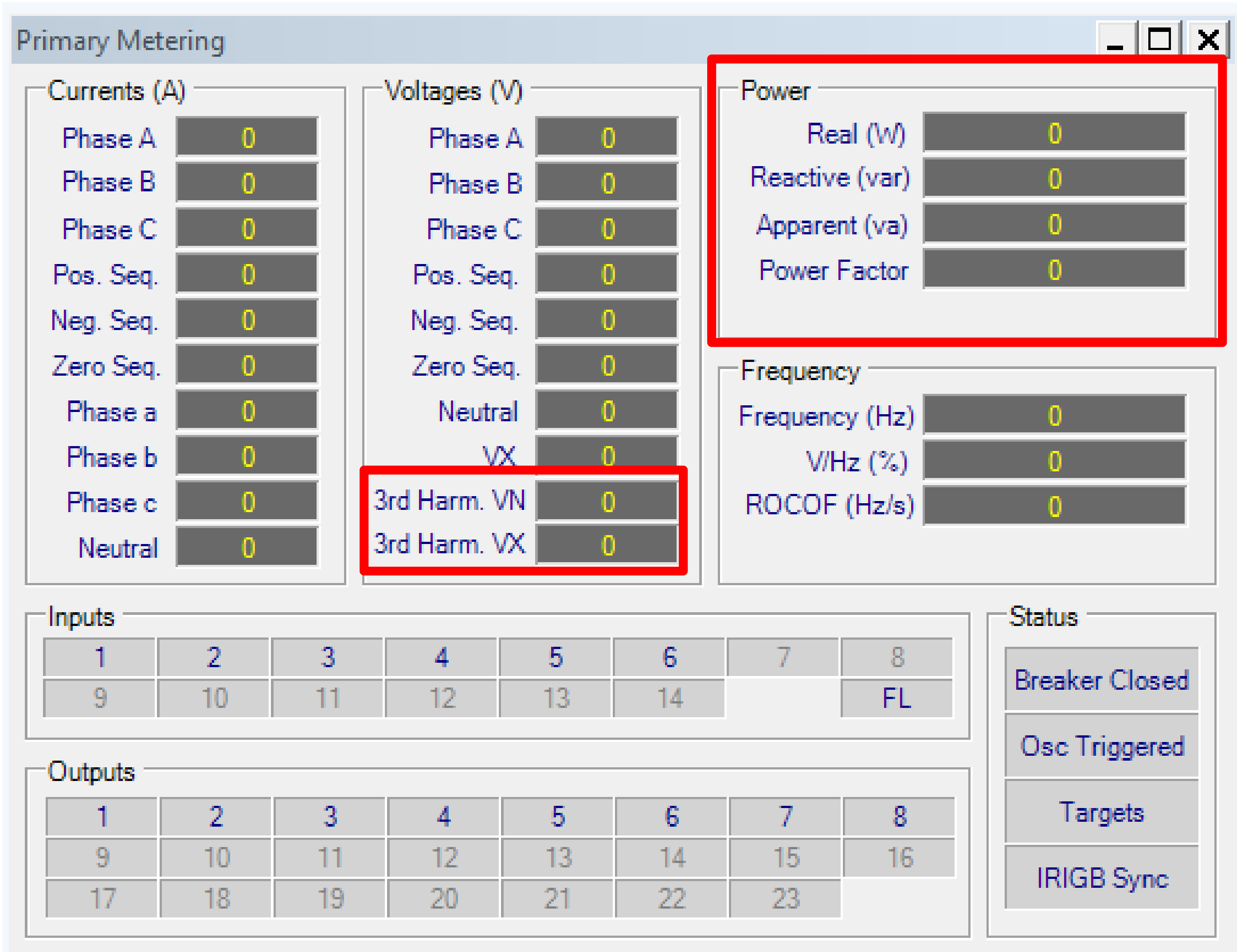
- 3rd harmonics are produced by some generators
  - Amount typically small
    - Lumped capacitance on each stator end is $C_S/2$.
  - C_T is added at terminal end due to surge caps and isophase bus
  - Effect is 3rd harmonic null point is shifted toward terminal end and not balanced

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



3rd Harmonic Voltages and Ratio Voltage



27TN – 3rd Harmonic Neutral Undervoltage

- Provides 0-15% stator winding coverage (typ.)
- Tuned to 3rd 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

Loading/operating variables may be Sync Condenser, VAr Sink, Pumped Storage, CT Starting, Power Output Reduction

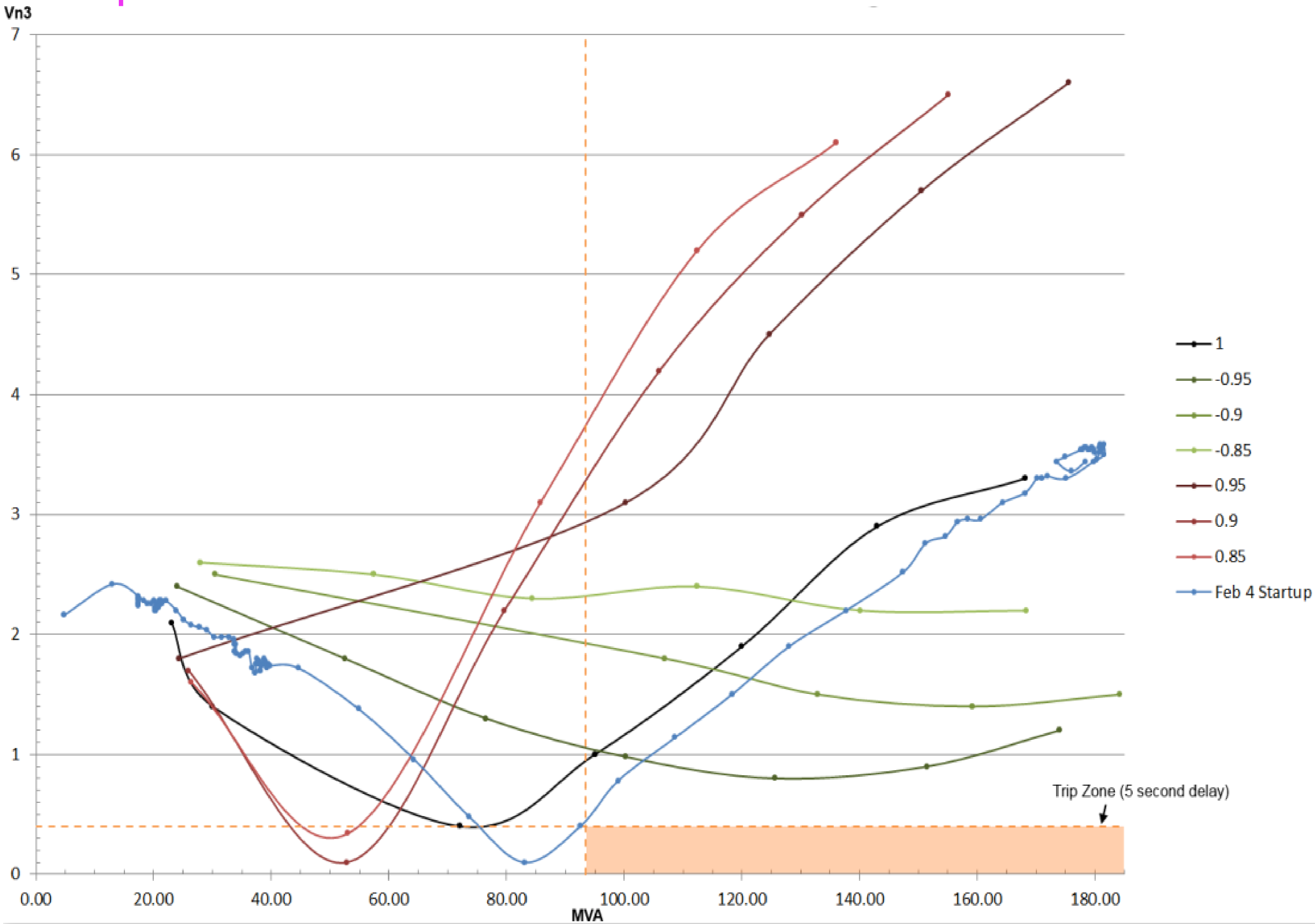
3rd Harmonic in Generators: Typical 3rd Harmonic Values

UNIT LOAD		180 HZ RMS VOLTAGE		VOLTAGE RATIO
MW	MVAR	NEUTRAL	TERMINAL	TERMINAL/NEUTRAL
0	0	2.8	2.7	1.08
7	0	2.5	3.7	1.48
35	5	2.7	3.8	1.41
105	5	4.2	5.0	1.19
175	25	5.5	6.2	1.13
340	25	8.0	8.0	1.00

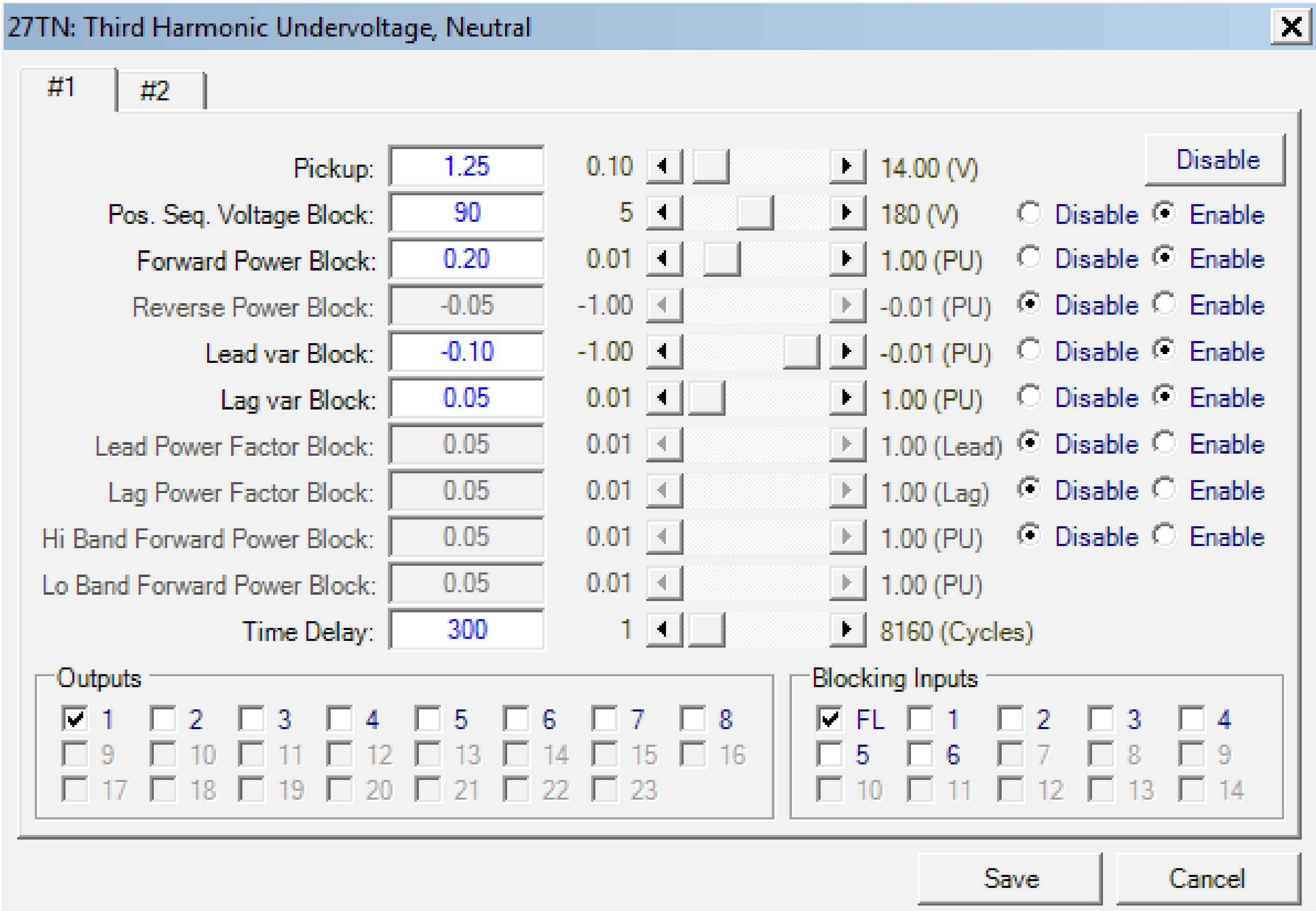
Magnitudes of Third Harmonic Voltages
for a Typical Generator

- **3rd harmonic values tend to increase with power and VAr loading**
- **Fault near neutral causes 3rd harmonic voltage at neutral to go to zero volts**

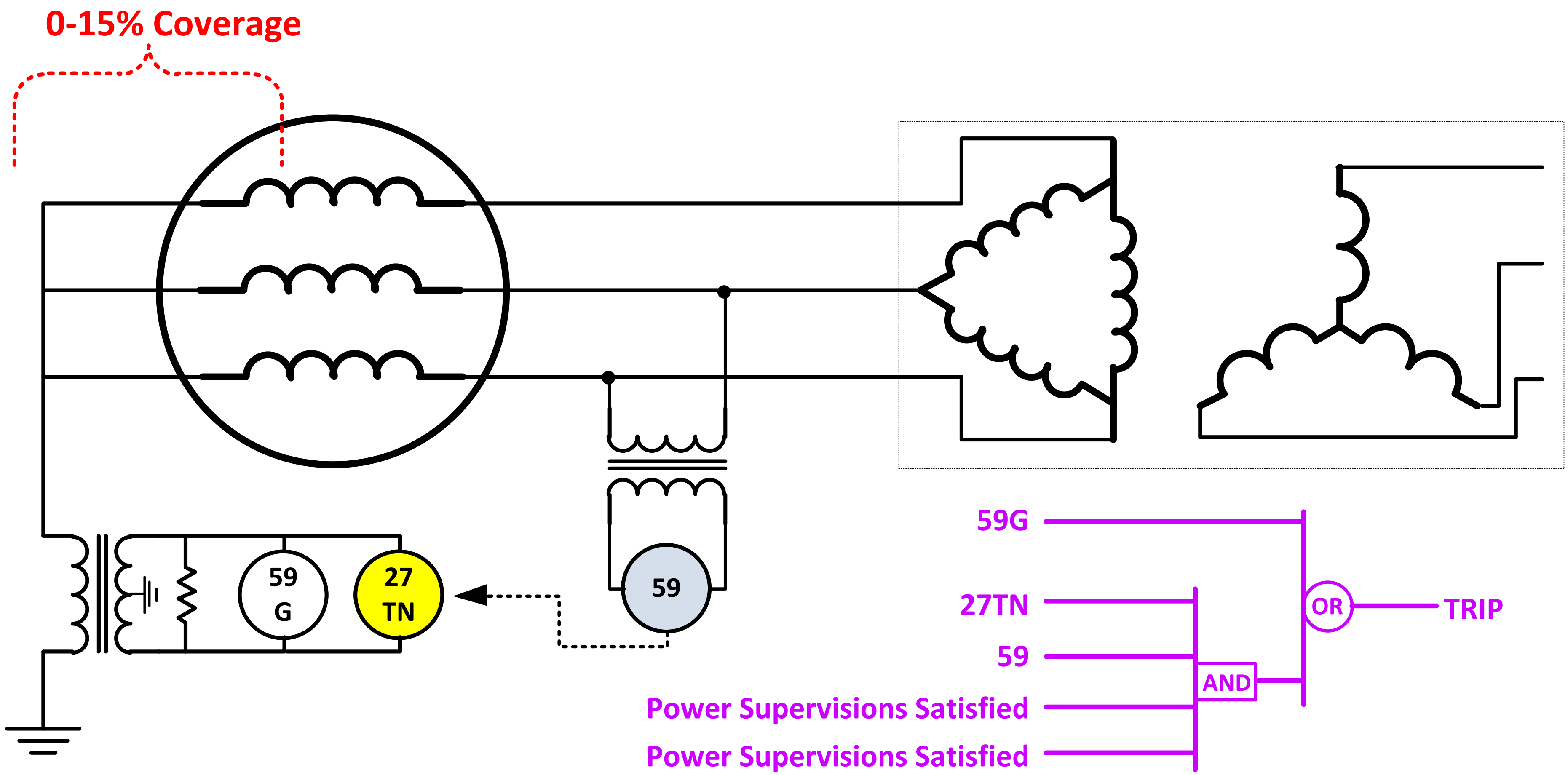
Example 3rd Harmonic Plot: Effects of MW and MVAR Loading



27TN Settings and Supervision

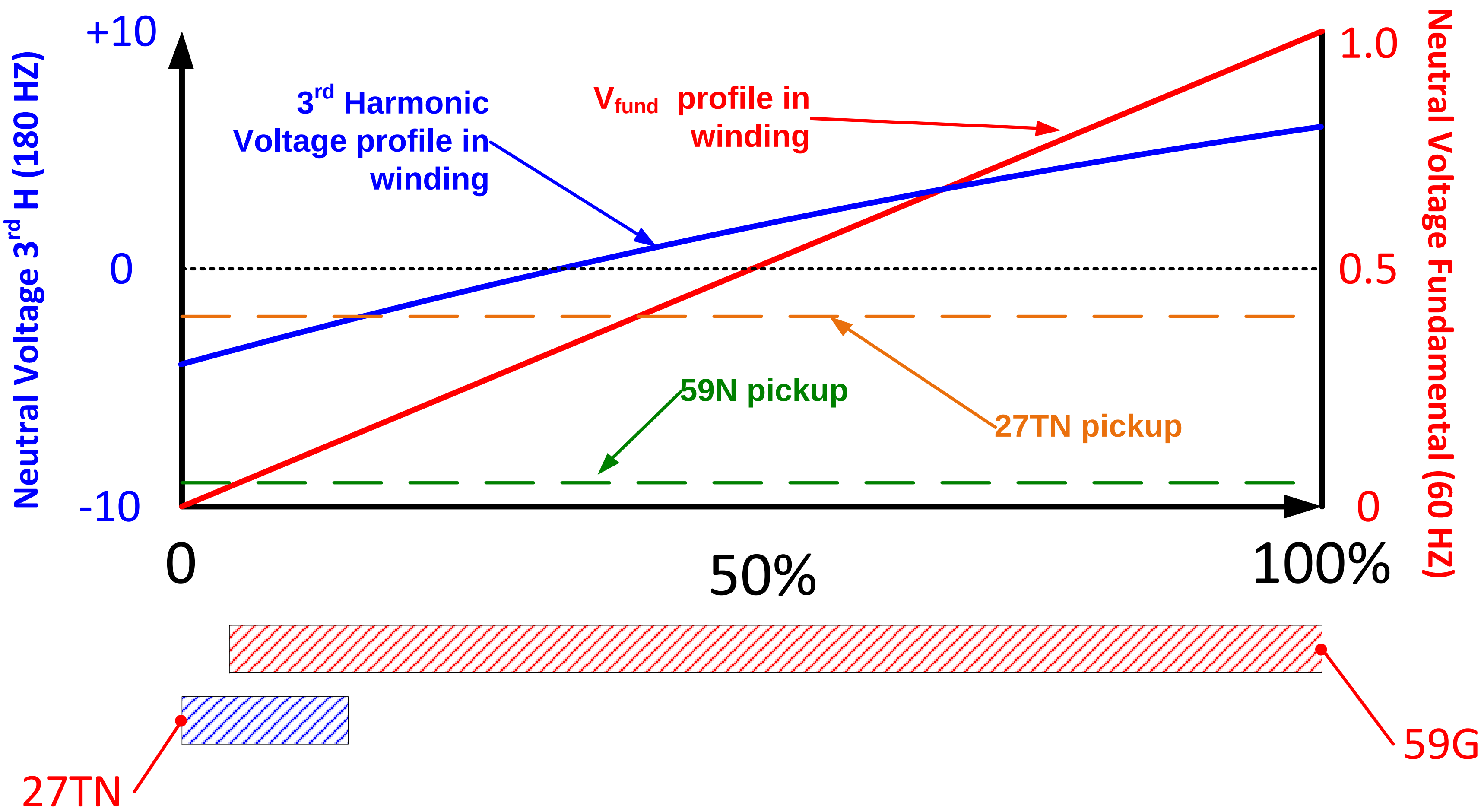


100% Stator Ground Fault (59G/27TN)



Third-Harmonic Undervoltage Ground-Fault Protection Scheme

100% Stator Ground Fault (59G/27TN)

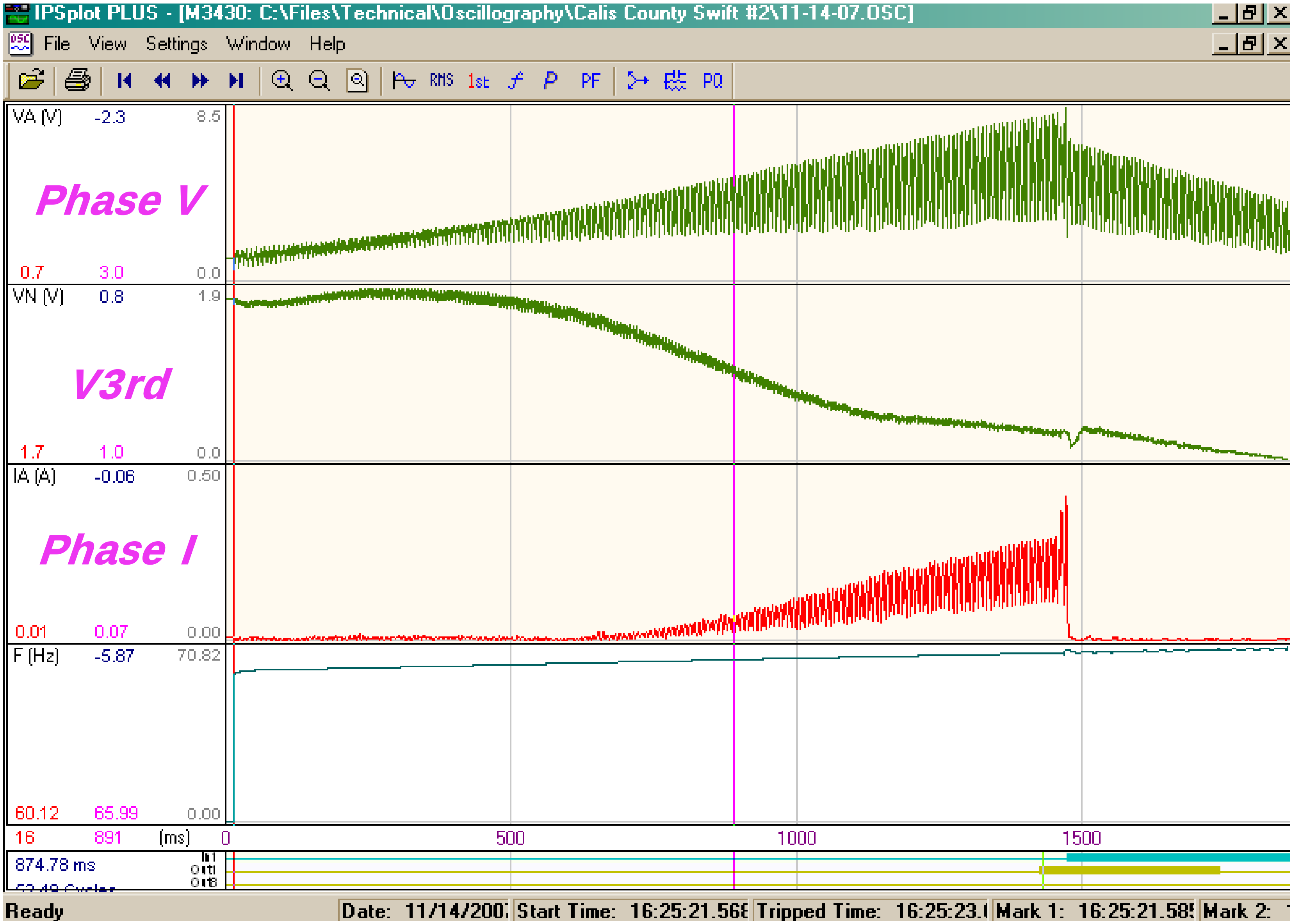


Overlap of Third Harmonic (27TN) with 59G Relay

3rd Harmonic Voltage Decrease During an Over Speed Condition in a 45MW Hydro Generator

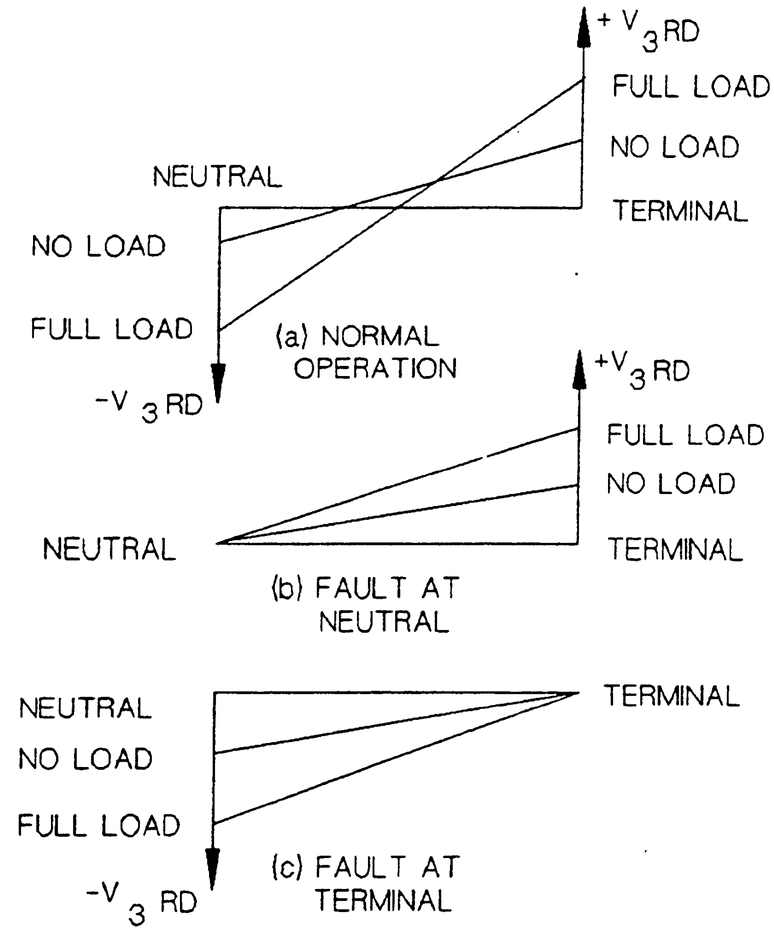
- Typical value of 3rd harmonic (V3rd) is around 1.7V, 27TN set to pick up at 1.1V.
- A line breaker tripped isolating plant, and they experienced a 27TN operation.
- Oscillograph shows the V3rd decreased from 1.7V to 1.0V as the frequency went from 60 Hz to 66Hz, (only 110% over speed).
- This is well below the 180-200% over speed condition that is often cited as possible with hydros upon full load rejection.
- What happens to 59G?

3rd Harmonic in Hydro Generators

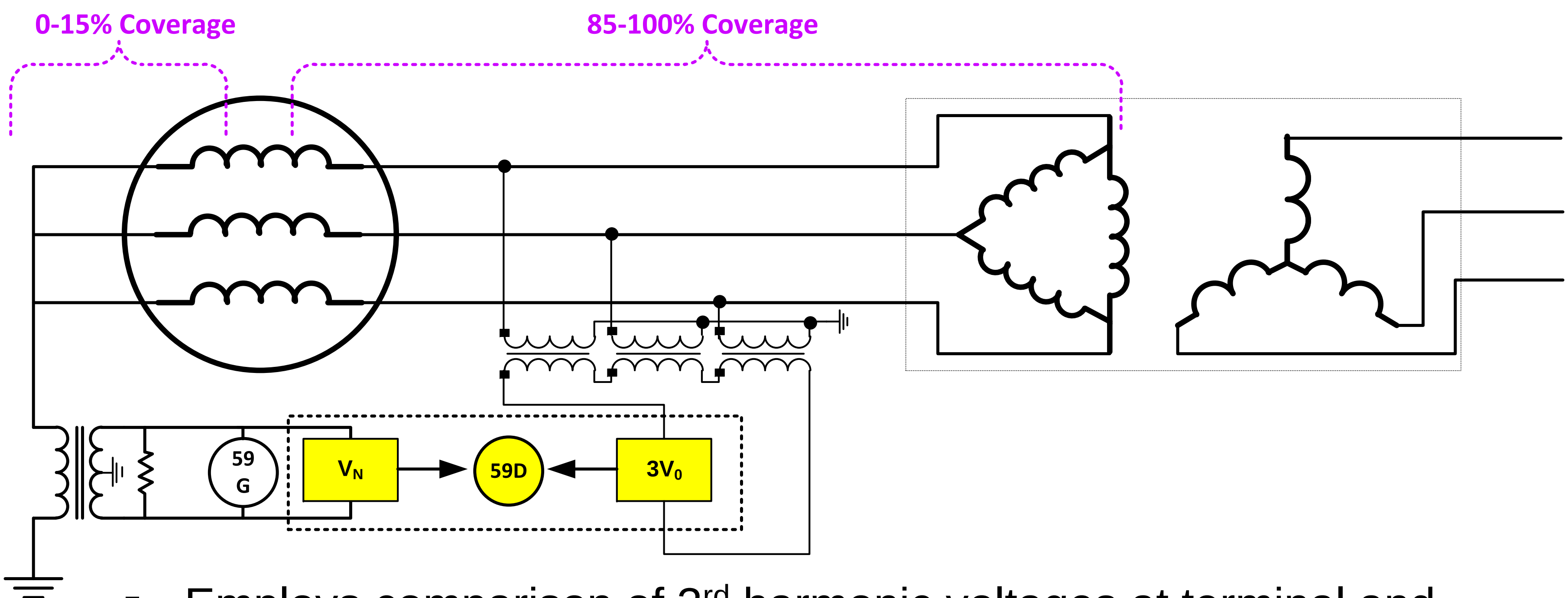


59D – 3rd Harmonic Ratio Voltage

- **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**

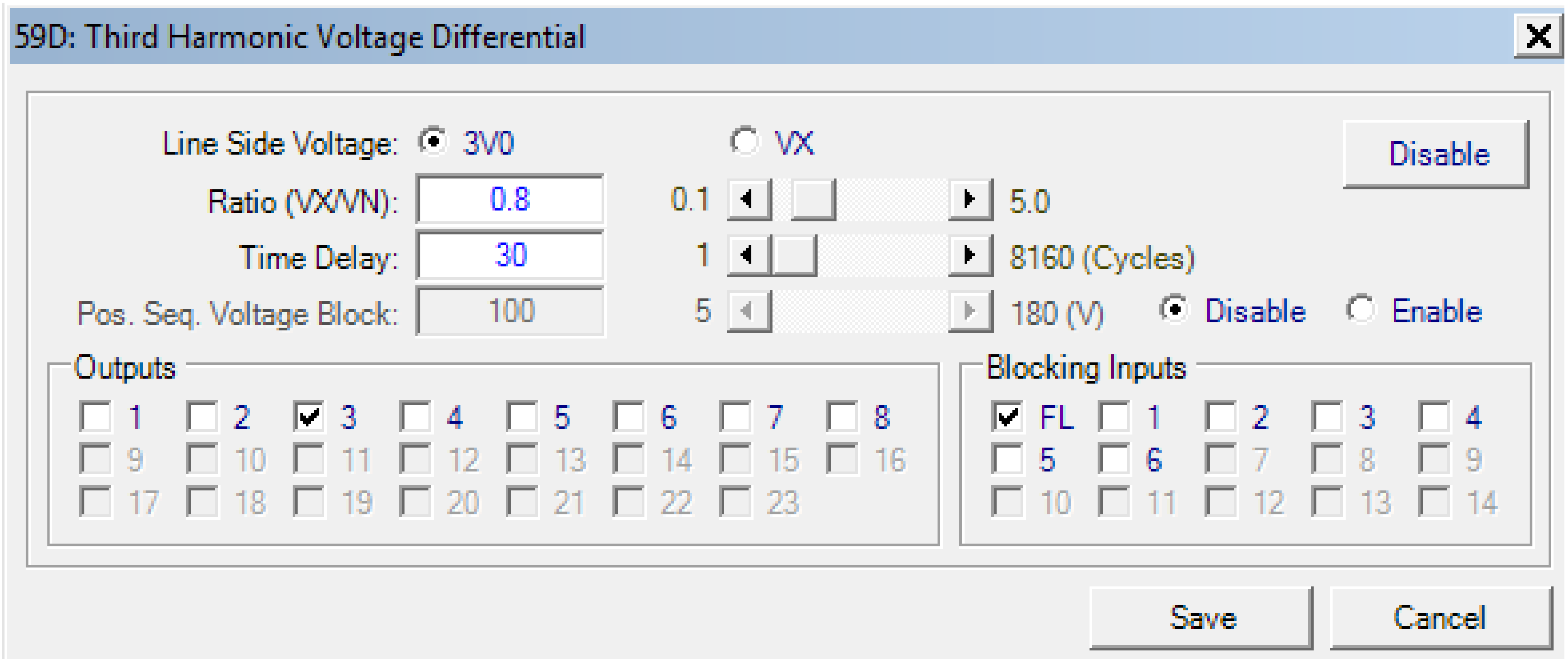


59D – 3rd Harmonic Ratio Voltage

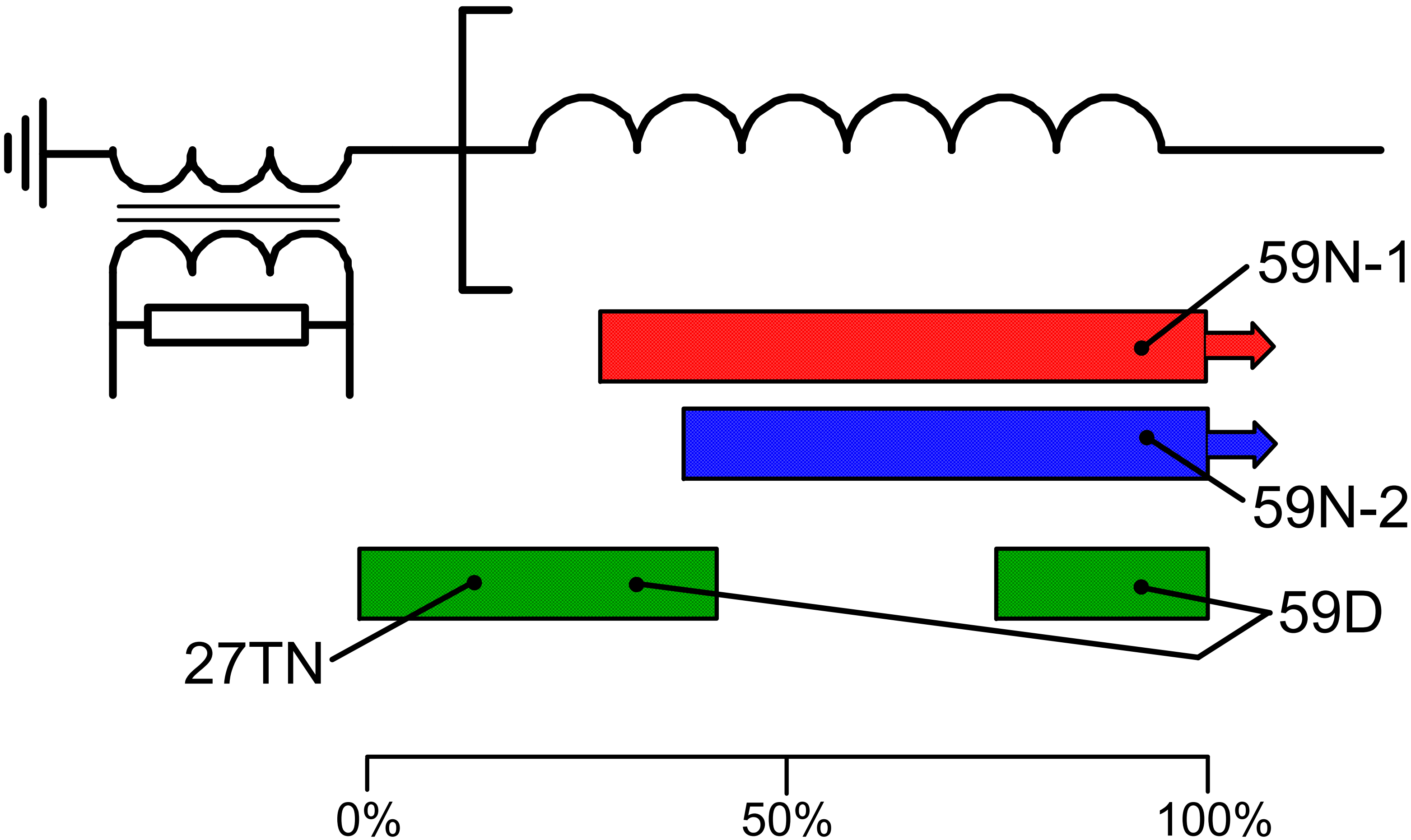


- Employs comparison of 3rd harmonic voltages at terminal and neutral ends
- These voltages are fairly close to each other
- One goes very low if a ground fault occurs at either end of the winding

59D – 3rd Harmonic Ratio Voltage

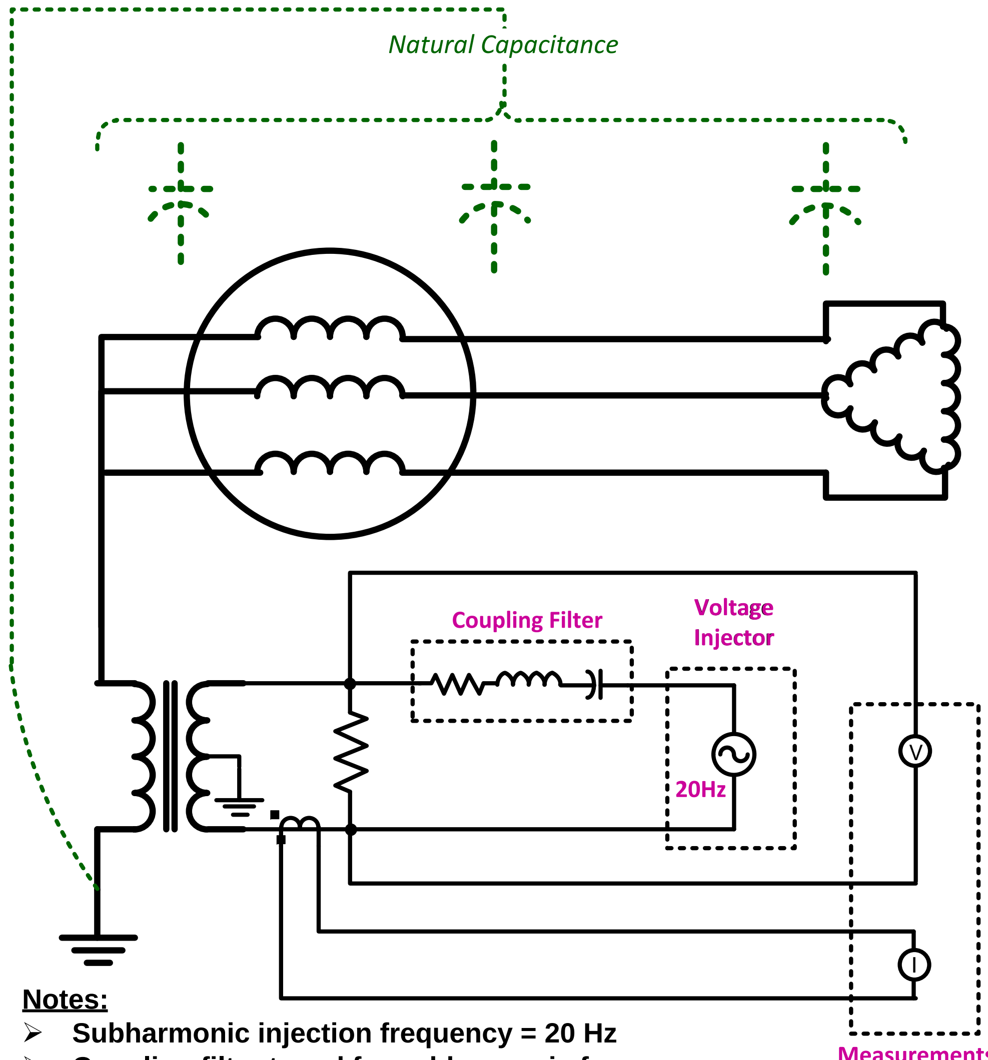


Stator Ground Faults: 59N, 27TN, 59D



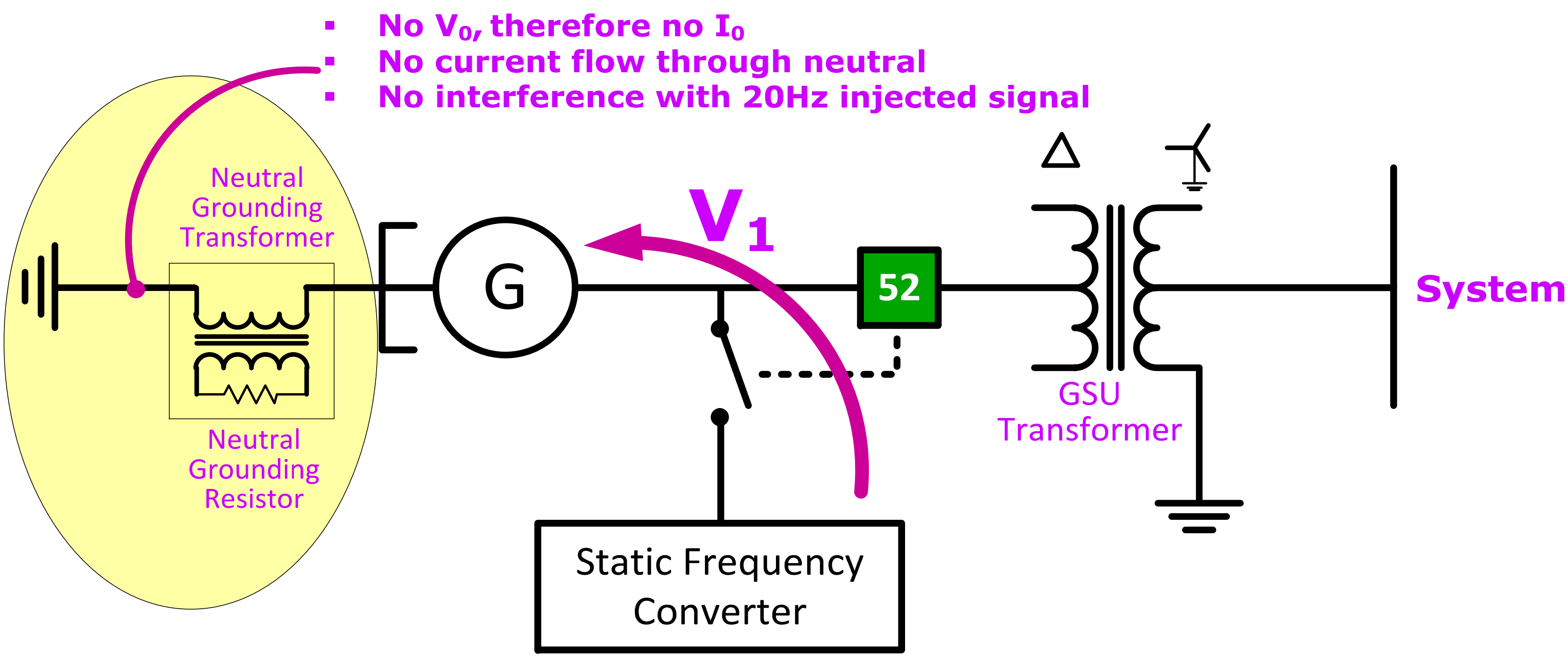
Subharmonic Injection: 64S

- 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**

Subharmonic Injection: 64S

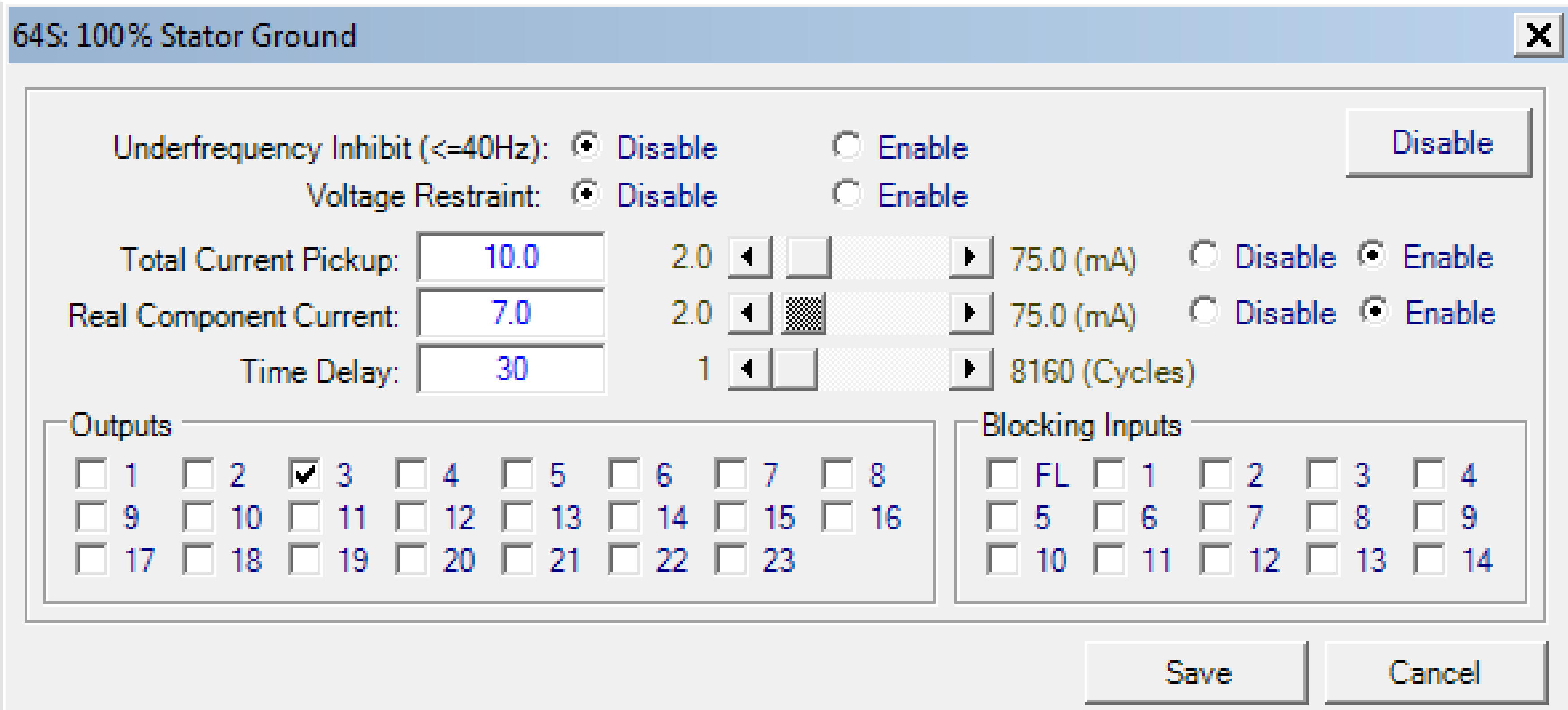


- Functions on-line and off-line
- Power and frequency independent

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

64S – Subharmonic Injection



Subharmonic Injection: 64S
Security Assessment

- *Real Component*:
  Used to detect and declare stator ground faults through entire stator winding (and isophase and GSU/UAT windings), except at the neutral or faults with very low (near zero) resistance.
- *Total Component*:
  A fault at the neutral or with very low resistance results in very little/no voltage (V_N) to measure, therefore current cannot be segregated into reactive and real components, so total current is used as it does not require voltage reference.
  - In addition, presence of total current provides diagnostic check that system is functional and continuity exists in ground primary and secondary circuits.

Subharmonic Injection: 64S Security Assessment

- A typical stator resistance (not reactance) to ground is >100k ohm, and a resistive fault in the stator is typically declared in the order of <=5k ohm.

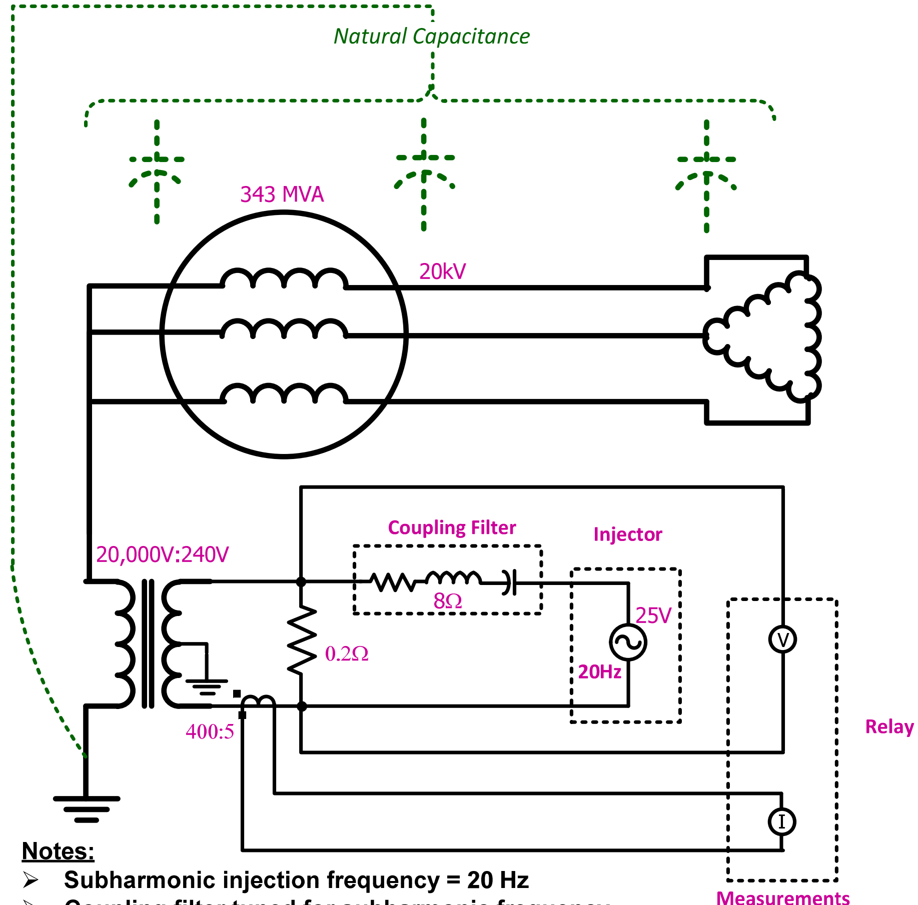
- The two areas of security concern are when the generator is being operated at frequencies of 20 Hz and 6.67 Hz.
  - ✓ All other operating frequencies are of no concern due to the 20 Hz filter and tuning of the element response for 20 Hz values

- For our analysis, we use data from a generator in the southeastern USA outfitted with a 64S, 20 Hz subharmonic injection system.

Subharmonic Injection: 64S Security Assessment

Case 1: Generator Operating at 20 Hz

- If the generator is operating as a generator at 20 Hz *without* an external source (e.g., drive, LCI, back-to-back hydro start), there is no concern as the 20 Hz at the terminals is at or very close to balanced; therefore, 20 Hz zero-sequence current will not flow through the neutral circuit.
- If the generator is being operated as a motor *with* an external source (e.g., drive, LCI, back-to-back hydro start), the phase voltages are balanced or very close to balanced.



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

Subharmonic Injection: 64S Security Assessment

Observations:

Real Ω = 118kΩ

Total Ω = 23kΩ

Generator Breaker Closed

- Generator plus isophase, surge caps and GSU delta winding

Metered values, including observed 20 Hz values, no fault conditions.

Currents (A)

Phase A	0.171	Phase a	0.177
Phase B	0.139	Phase b	0.145
Phase C	0.102	Phase c	0.108
Neutral	0.000	I diff G	-0.02
Pos. Seq.	0.143	A-a diff	0.00
Neg. Seq.	0.041	B-b diff	0.02
Zero Seq.	0.002	C-c diff	0.02
49 #1	0.05	49 #2	0.05

Voltages (V)

Phase A	68.7
Phase B	68.0
Phase C	68.5
Neutral	0.2
Pos. Seq.	68.5
Neg. Seq.	0.2
Zero Seq.	0.4
VX	0.0

Impedance (Ohm)

AB R	275.73
AB X	229.46
BC R	238.65
BC X	327.67
CA R	327.67
CA X	327.67
Pos. Seq. R	327.67
Pos. Seq. X	327.67

Low Freq. Injection

VN (V)	0.3
IN (mA)	14.1
Real (mA)	2.8

3rd Harmonic

VN (V)	0.75
VX (V)	0.00
VX/VN	0.00

Power (p.u.)

Real	0.023
Reactive	0.026
Apparent	0.032

Frequency

Frequency (Hz)	59.97
V/Hz (%)	99.1
ROCOF (Hz/s)	0.00

- **V_N** 20 Hz = voltage across the neutral grounding resistor
- **I_N** 20 Hz (mA) = ***total*** current (combined real and reactive) measured by the relay
- **Real** 20 Hz (mA) = ***real*** component of current measured by the relay

Subharmonic Injection: 64S Security Assessment

Calculate CT primary currents:

$I_{N\ pri\ (total)} = 14.1\ A * 10^{-3} * CTR$
$I_{N\ pri\ (total)} = 14.1\ A * 10^{-3} * 80$
$I_{N\ pri\ (total)} = 1.128A$

$I_{N\ pri\ (real)} = 2.8\ A * 10\text{-}3 * CTR$
$I_{N\ pri\ (real)} = 2.8\ A * 10\text{-}3 * 80$
$I_{N\ pri\ (real)} = 0.224\ A$

Currents and voltages at grounding transformer primary:

$I_{N\ pri\ (total)} = 1.128\ A\ /\ NGT\ ratio$
$I_{N\ pri\ (total)} = 1.128\ A\ /\ 83.33$
$I_{N\ pri\ (total)} = 0.013536\ A$

$I_{N\ pri\ (real)} = 0.0224\ A\ /\ NGT\ ratio$
$I_{N\ pri\ (real)} = 0.0224\ A\ /\ 83.33$
$I_{N\ pri\ (real)} = 0.002688\ A$

$V_{N\ pri} = V_{sec} * NGT\ ratio$
$V_{N\ pri} = V_{sec} * NGT\ ratio$
$V_{N\ pri} = 25\ V$

3rd harmonic voltage measured at relay = 0.75 V

$V_{pri} = V_{sec} * NGT\ ratio$
$V_{pri} = 0.75\ V * 83.33$
$V_{pri} = 62.5\ V$

Assuming a zero sequence unbalance of 0.1% of nominal at 60 Hz:

$V_{pri\ unbalance} = \%_{unbalance} / 100 * V_{L\text{-}L\ rated} / \sqrt{3}$
$V_{pri\ unbalance} = (0.1\% / 100) * (20{,}000\ V / 1.73)$
$V_{pri\ unbalance} = 11.5V$

$V_{sec\ unbalance} = V_{pri\ unbalance} / NGT\ ratio$
$V_{sec\ unbalance} = 11.5\ V / 83.33$
$V_{sec\ unbalance} = 0.14\ V$

Assuming V/Hz is kept constant in LCI or back-to-back generator start. The voltage at 20 Hz frequency is
20 Hz voltage during the start.

Assuming 1pu V/Hz 120/60 = 2 = 1pu

- Frequency divisor: 60 Hz / 20 Hz = 3.
- Voltage divisor is 3.

$V_{sec\ unbalance\ (20\ Hz)} = V_{sec\ unbalance\ (60\ Hz)} / 3$
$V_{sec\ unbalance\ (20\ Hz)} = 0.14\ V / 3 = 0.0466\ V$

Generator Protection

Subharmonic Injection: 64S Security Assessment

20 Hz current flowing through NGR:

$NGR_{I\ 20}\ Hz = V_{sec\ unbalance\ (20\ Hz)} * NGR\ \Omega$

$NGR_{I\ 20}\ Hz = 0.0466 / 0.2 = 0.223\ A$

Relay measured 20 Hz current:

$I_{20Hz\ Relay} = NGR_{I\ 20}\ Hz * CTR$

$I_{20Hz\ Relay} = 0.223\ A / 80$

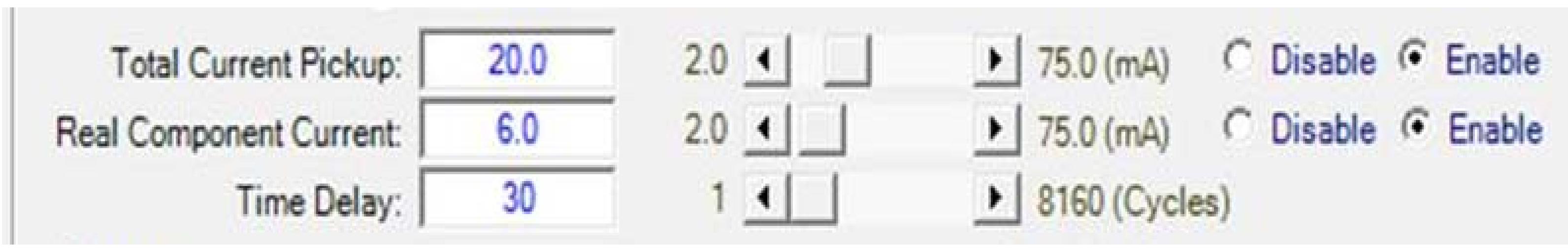
$I_{20Hz\ Relay} = 0.0029\ A = 2.9\ mA$

Settings:

Real Ω = 55kΩ

Total Ω = 16kΩ

Using pickup values are 20 mA total and 6 mA real, element remains secure.



Note the margins:

- Total current calculated: 2.9 mA
- Total current setting: 20 mA
- Margin: 17.1 mA

- Total current calculated: 2.9 mA
- Real current setting: 6.0 mA
- Margin: 3.1 mA

Subharmonic Injection: 64S Security Assessment

Case 2: 6.67 Hz voltage at the generator terminals, assume 3rd harmonic (20 Hz) created in the neutral

In this case, we are assuming the generator under study is being started with a drive, LCI or back-to-back hydro start. The generator is acting like a motor and the unbalance is originating from the source.

Using typical values from a generator operating under full load, 3rd harmonic can be expected to be approximately 5X no load value.

$3^{rd}\ V_{60\ Hz\ NGT\ pri} = 5 * (\text{no load } 3^{rd} \text{ harmonic}) * \text{NGT ratio}$

$3^{rd}\ V_{60\ Hz\ NGT\ pri} = 5 * 0.75\ V * 83.33$

$3^{rd}\ V_{60\ Hz\ NGT\ pri} = 312.498\ V$

*The frequency during the start is reduced to 6.67 Hz (3 * 6.67 Hz= 20 Hz).*

Assuming the V/Hz is kept as constant, the 3rd harmonic voltage is reduced.

$3^{rd}\ V_{20\ Hz\ NGT\ pri} = 6.67\ Hz / 60\ Hz * 312.498\ V$

(without reduction in capacitance)

$3^{rd}\ V_{20\ Hz\ NGT\ pri} = 34.74\ V$ (without reduction in capacitance)

Subharmonic Injection: 64S Security Assessment

Since the frequency is 20 Hz and not 180 Hz, there is a further reduction in 3rd harmonic current due to the capacitance at 1/9th of 60 Hz value. (180/20=9)

The model is complex and the relationship is not straightforward, so we assume a reduction of 1/5th instead of 1/9th

$3^{rd}\ V_{20\ Hz\ NGT\ pri} = 34.74\ V / 5 = 6.9\ V$

Voltage at NGT secondary:

$NGT\ V\ sec = 3^{rd}\ V_{20\ Hz\ NGT\ pri} / NGT\ ratio$

$NGT\ V\ sec = 6.9\ V / 83.33 = 0.0828\ V$

Current through NGR:

$NGR_{I\ 20\ Hz} = NGT\ V_{sec} / NGR\ \Omega$

$NGR_{I\ 20\ Hz} = 0.0828 / 0.2 = 0.414\ A$

Relay measured 20 Hz current:

$I_{20Hz\ Relay} = NGR_{I\ 20\ Hz} * CTR$

$I_{20Hz\ Relay} = 0.414\ A / 80$

$I_{20Hz\ Relay} = 0.005175\ A = 5.175\ mA$

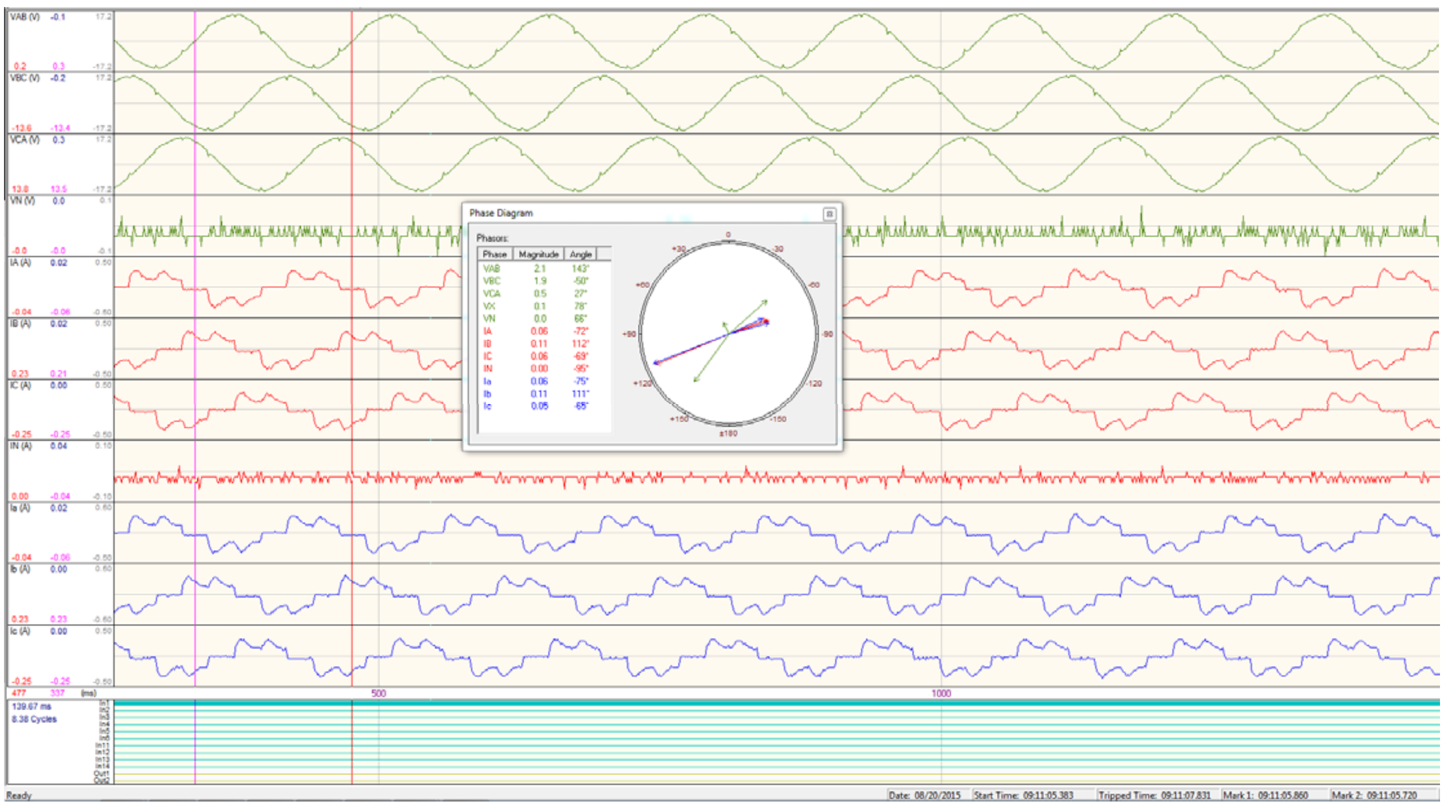
Subharmonic Injection: 64S Security Assessment

Note the margins:

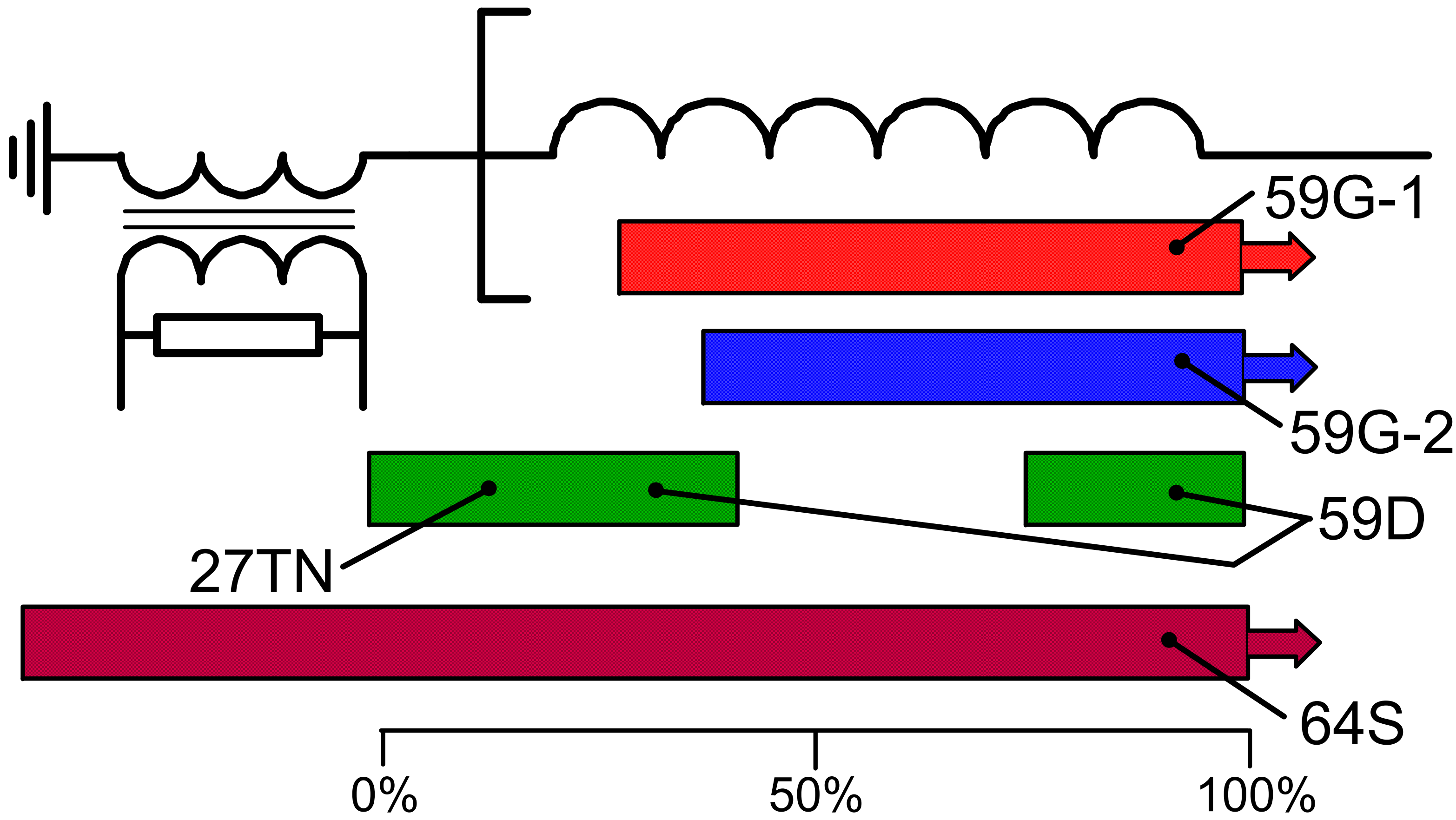
- Total current calculated: 5.175 mA
- Total current setting: 20 mA
- Margin: 14.825 mA

- Total current calculated: 5.175 mA
- Real current setting: 6.0 mA
- Margin: 0.825 mAin

Higher Margin for Real Ω: 7.0mA = 47.2kΩ; 8.0mA = 41.3kΩ

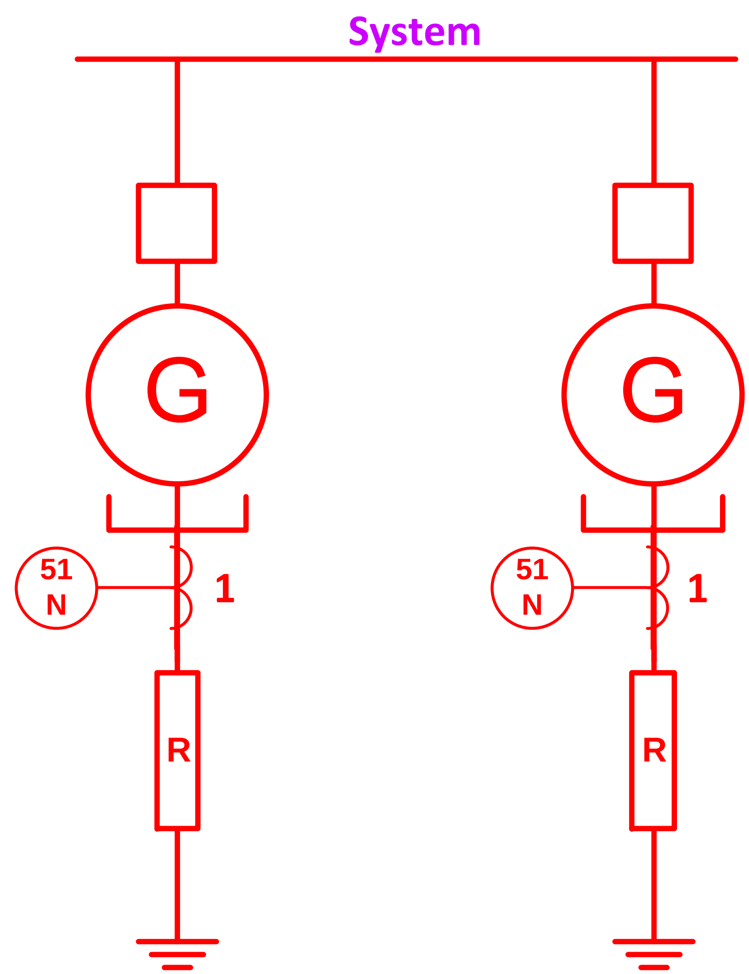


Stator Ground Faults: High Z Element Coverage

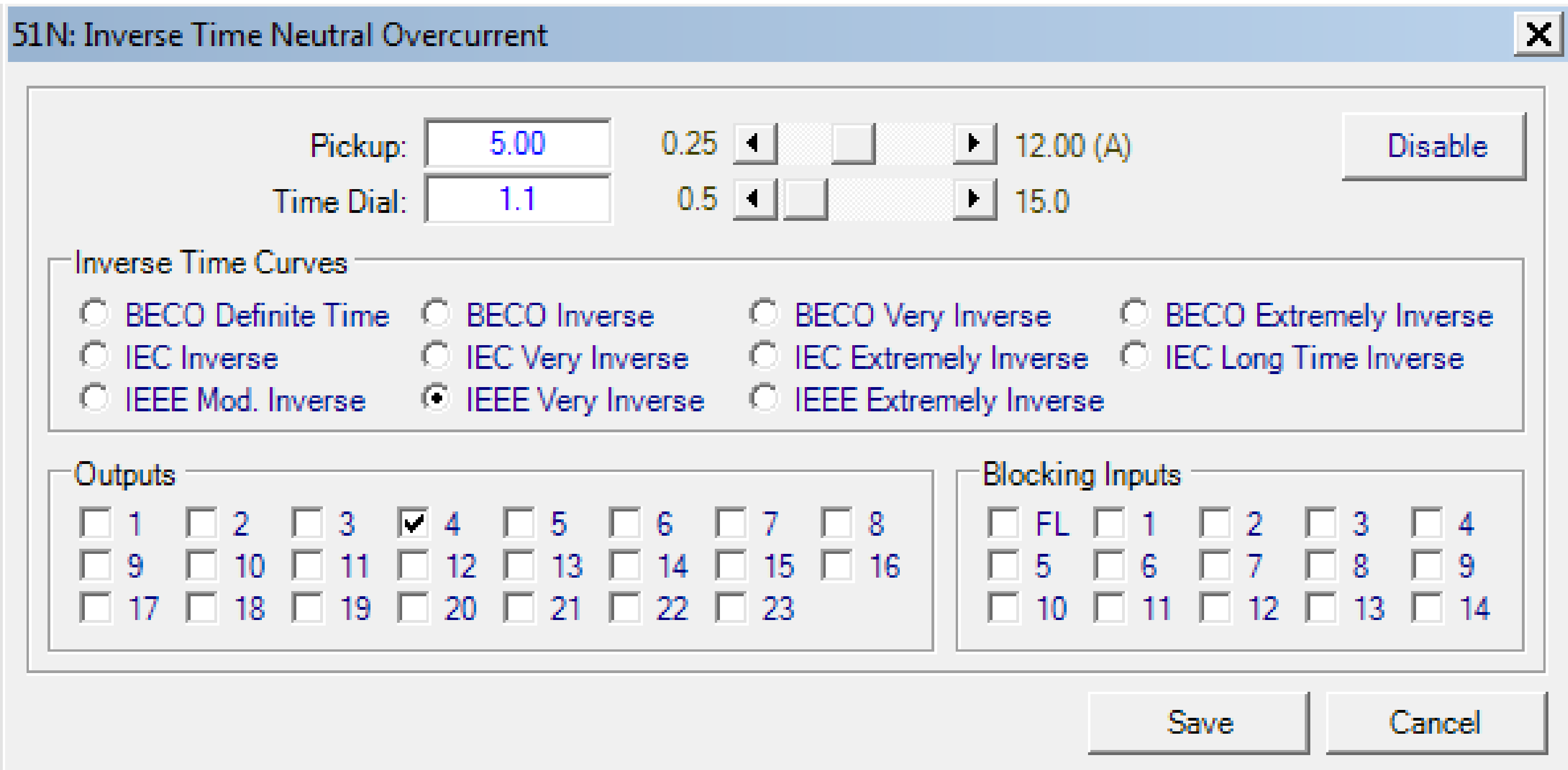


Stator Ground Fault: Low Z Grounded Machines

- 51N element typically applied
  - Coordinate with system ground fault protection for security and selectivity
  - Results in long clearing time for internal machine ground fault
  - Selectivity issues with bused machines



51N: Neutral Overcurrent



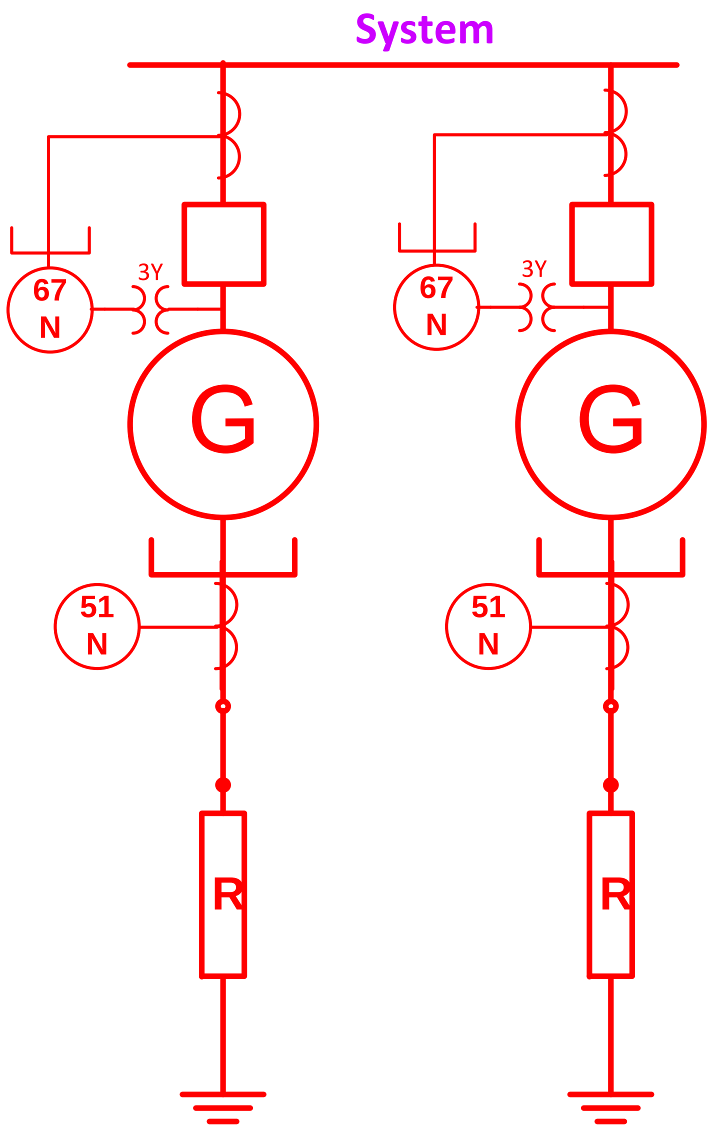
Directional Neutral Overcurrent: 67N

Low-Z Grounded Generator

- 67N element provides selectivity on multiple bused machine applications
- Requires only phase CTs, or terminal side zero-sequence CT
- 67N directionalized to trip for zero-sequence (ground) current toward a generator
- 67N is set faster than 51N
  - May be short definite time delay
  - Ground current should not flow into a generator under normal operating conditions
- May be applied on ungrounded machines for ground fault protection if bus or other generators are a ground source

Directional Neutral Overcurrent: 67N

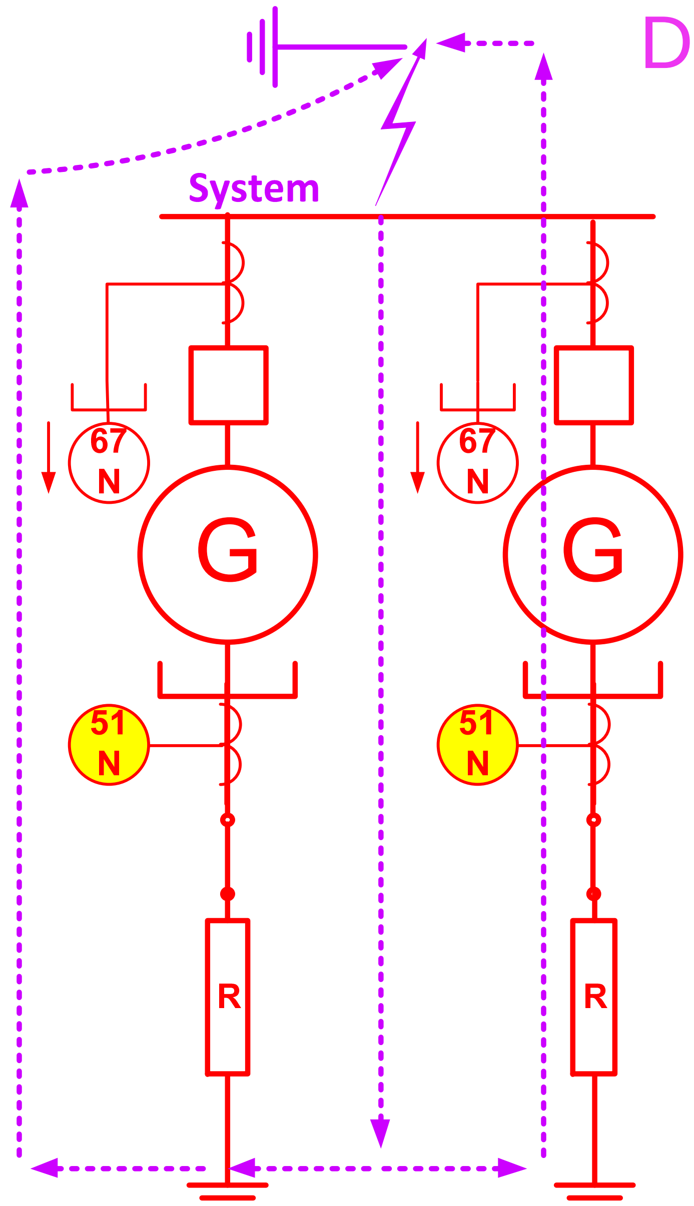
Low-Z Grounded Generator



- Employ 67N to selectively clear machine ground fault for multi-generator bus connected arrangements
- Use with 51N on grounded machine(s) for internal fault and system back up
- Ground switches on all machines can all be closed

Directional Neutral Overcurrent: 67N

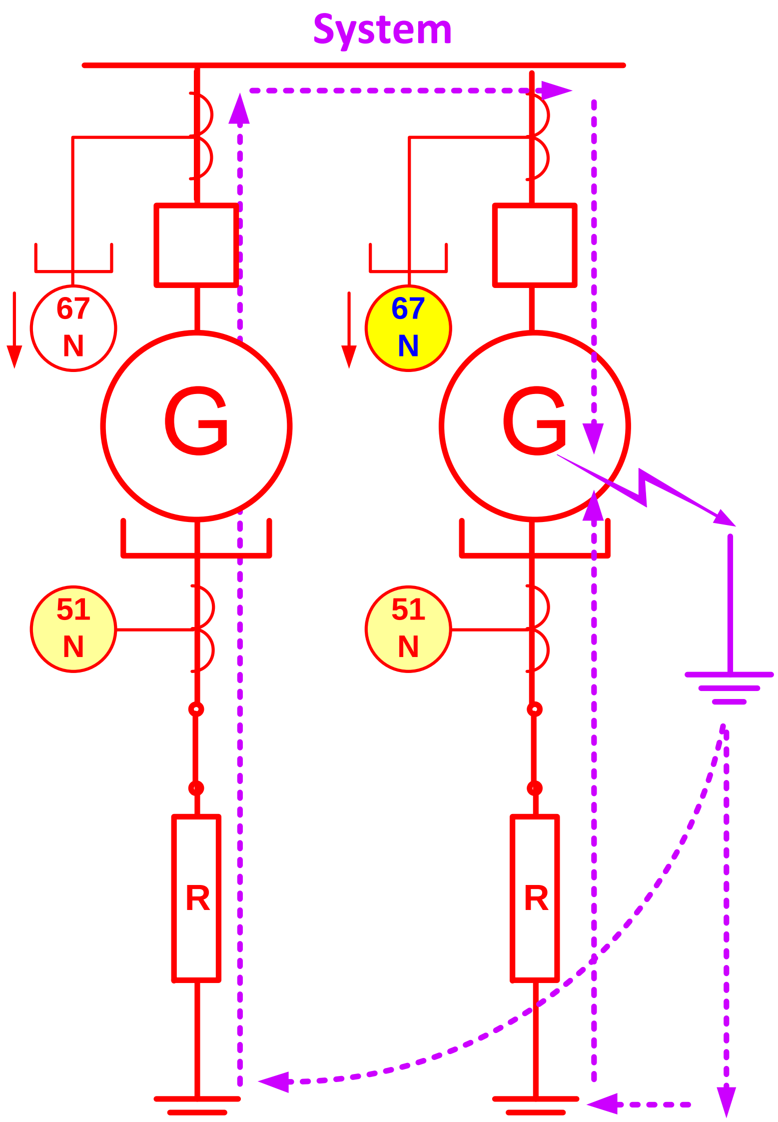
Low-Z Grounded Generator



- Ground fault on system is detected by grounded generator's 51N element
- Coordinated with system relays, they should trip before 51N
- 67N sees fault current in the reverse direction and does not trip

Directional Neutral Overcurrent: 67N

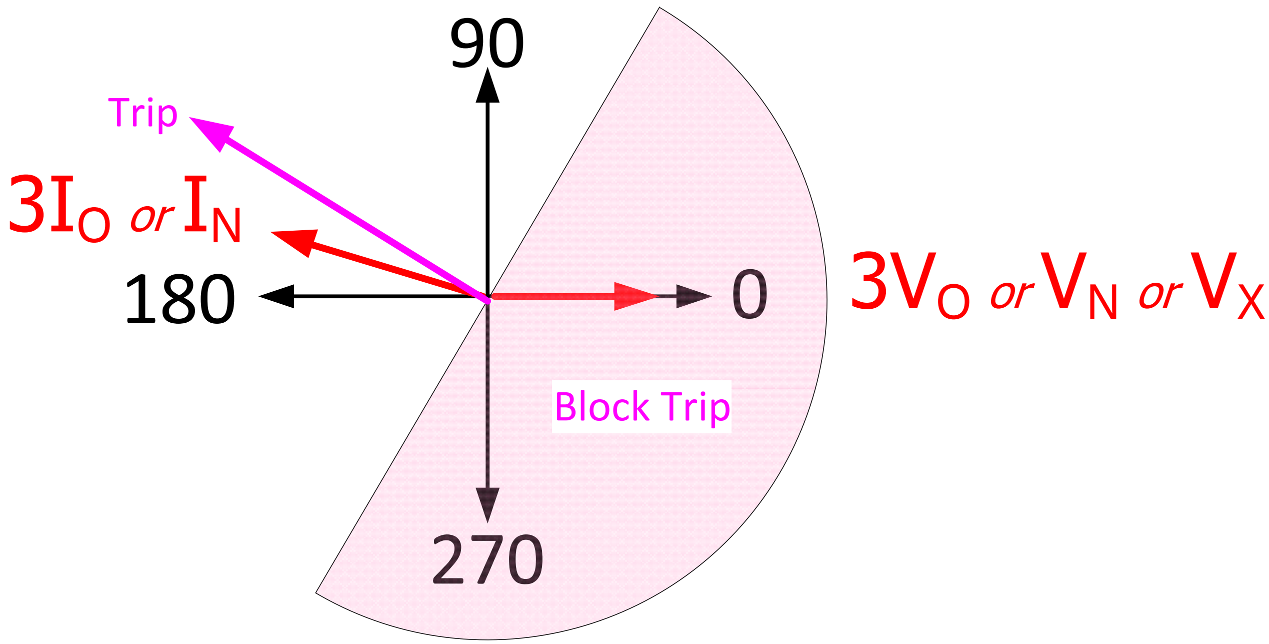
Low-Z Grounded Generator



- Ground fault in machine is detected by 67N & 51N
- 67N picks up in faulted machine
- 51N picks up in faulted and unfaulted machines
- 67N trips fast in faulted machine
- 51N resets on faulted and unfaulted machines

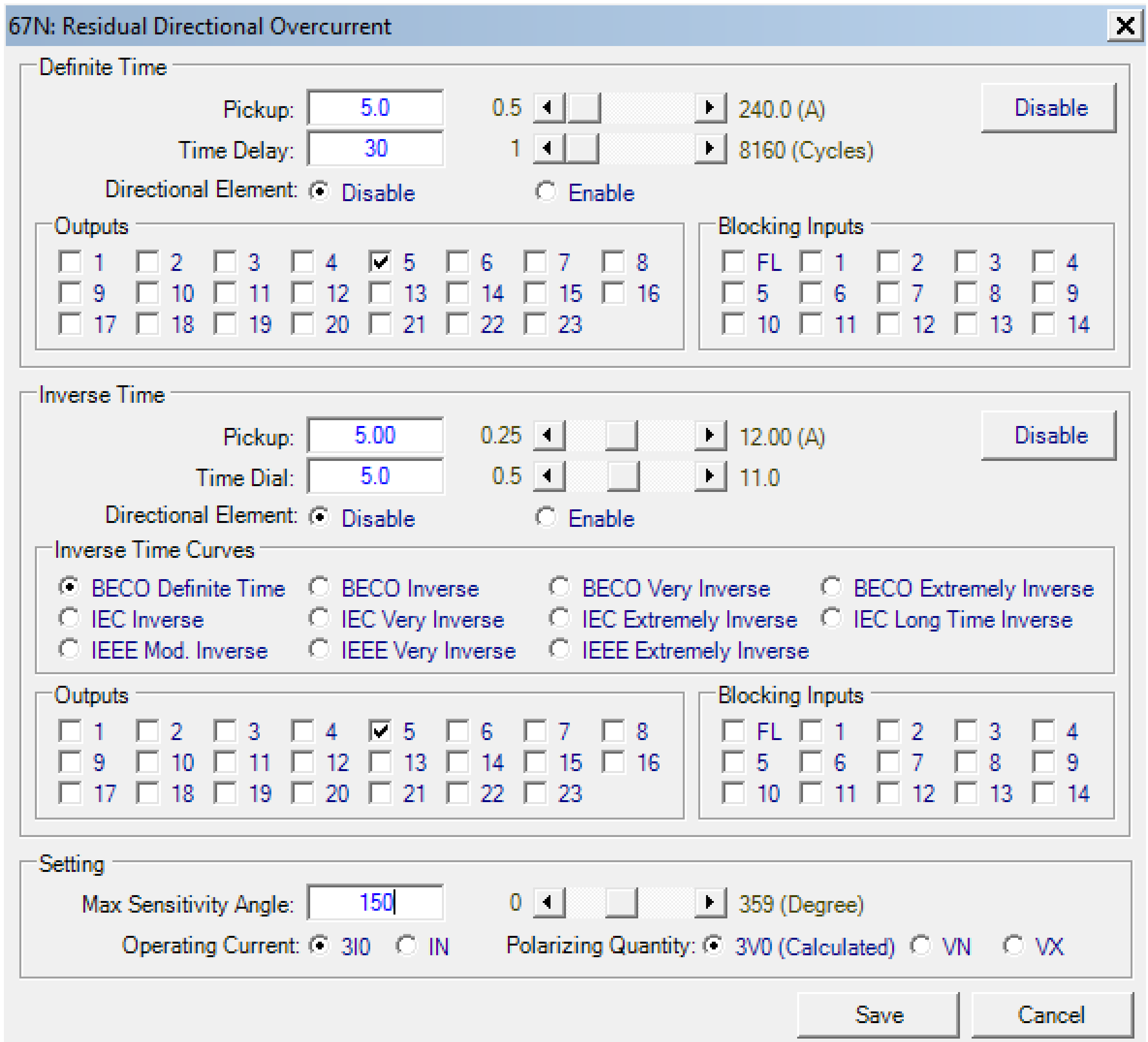
Directional Neutral Overcurrent: 67N

Internal Fault



- Internal faults create angles of $3I_0$ or I_N current flow into generator from system that are approximately 150 degrees from $3V_0$
- This is from reactive power being drawn in from system as well as real power

67N: Directional Neutral Overcurrent



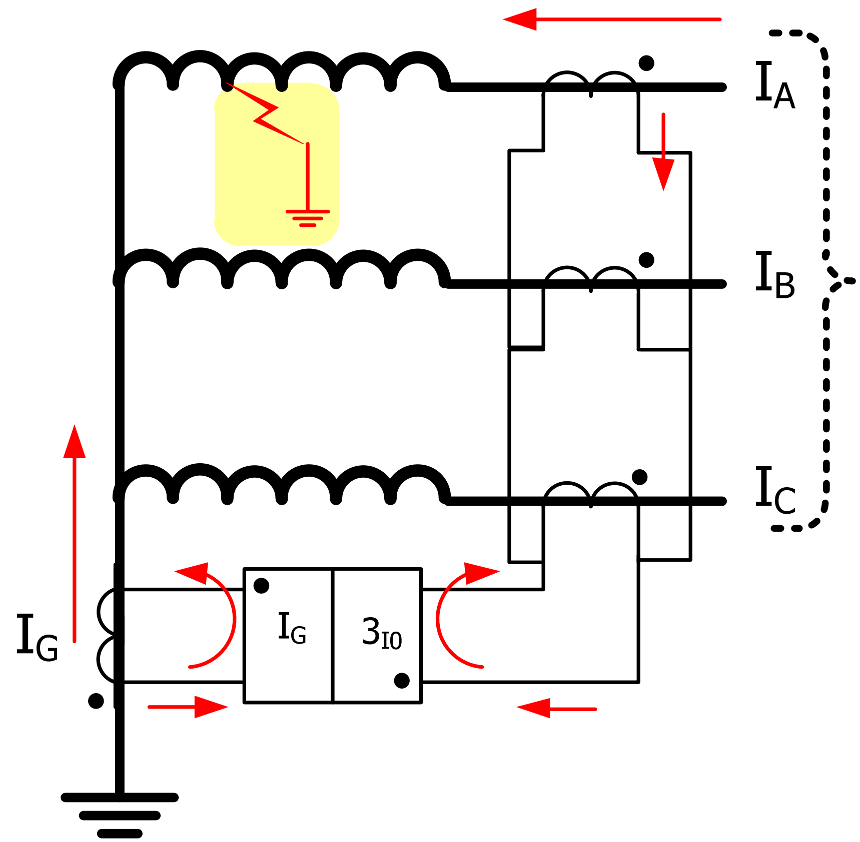
Directional Neutral Overcurrent: 87G

Low-Z Grounded Generator

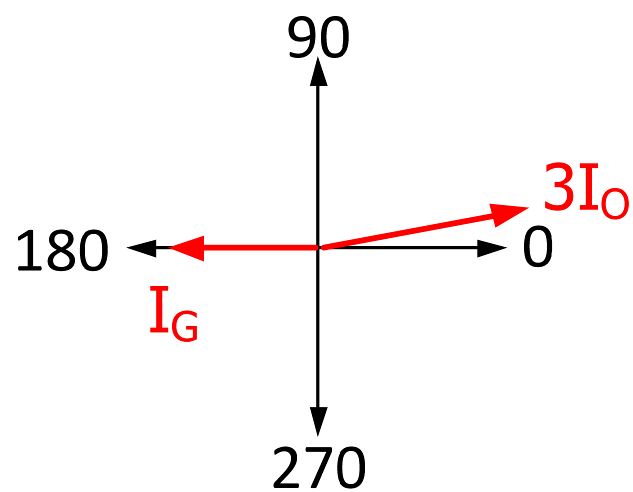
- 87GD element provides selectivity on multiple bused machine applications
- Requires phase CTs, or terminal side zero-sequence CT, and a ground CT
- 87GD uses currents with directionalization for security and selectivity
- 87GD is set faster than 51N
  - May use short definite time delay
- Ground current should not flow into a generator from terminal end under normal operating conditions
- Ground current should not flow unchallenged into machine

Trip Characteristic – 87GD

Internal Fault



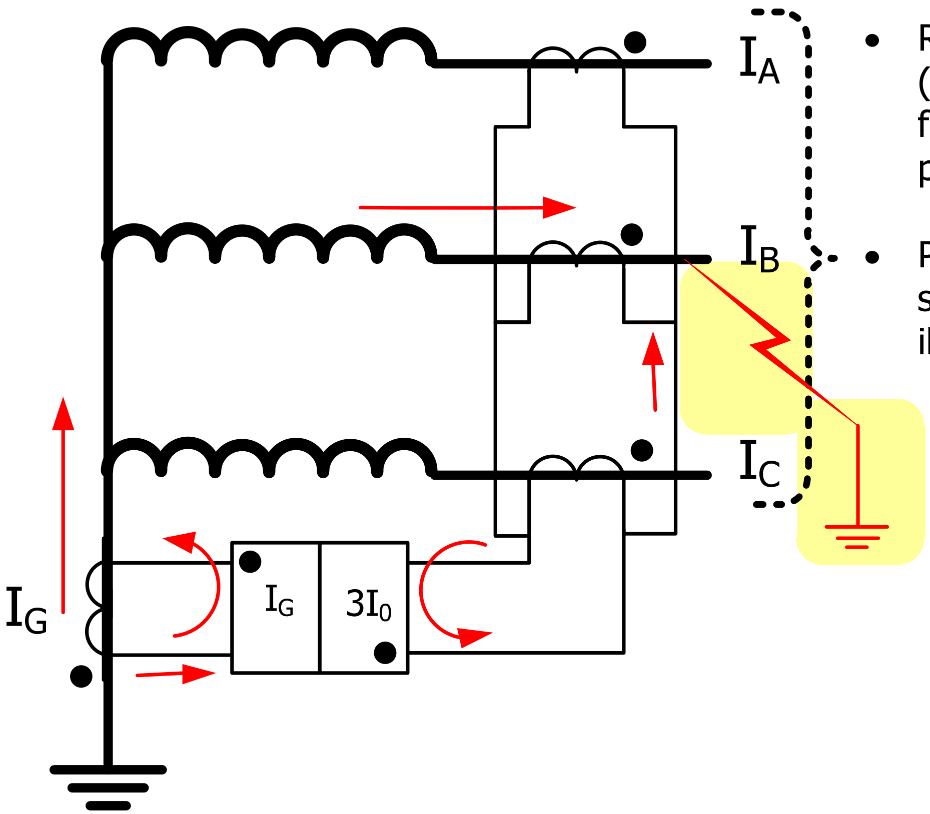
- Residual current (3_{I0}) calculated from individual phase currents
- Paralleled CTs shown to illustrate principle



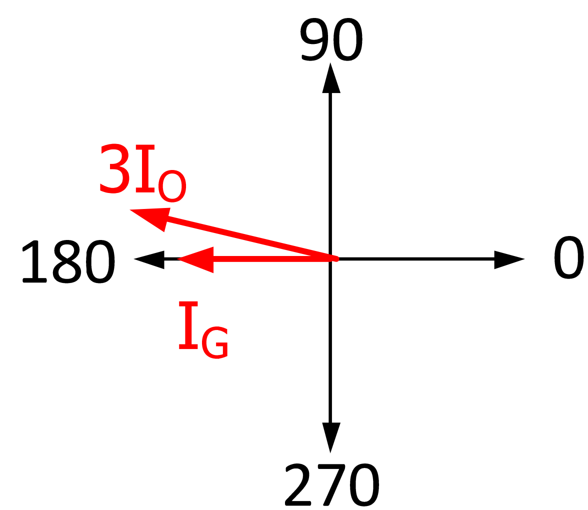
$$-3I_o \times I_G \cos(0) = -3I_oI_G$$

Trip Characteristic – 87GD

External Fault



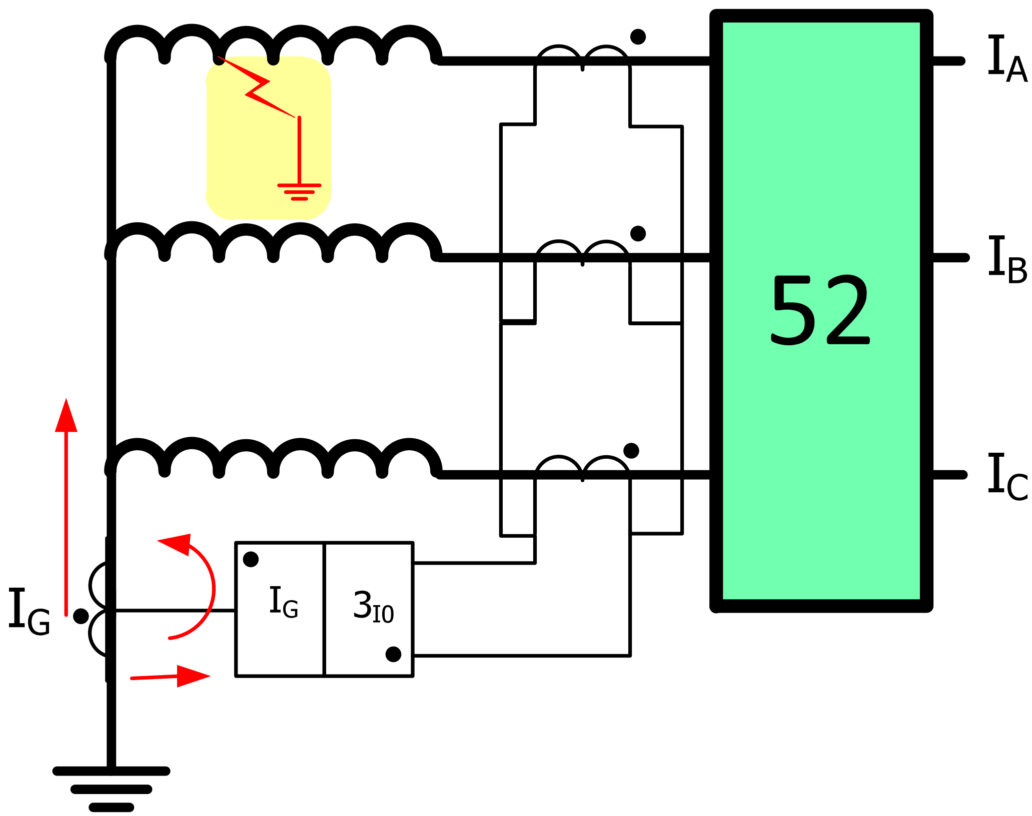
- Residual current (3_{I0}) calculated from individual phase currents
- Paralleled CTs shown to illustrate principle

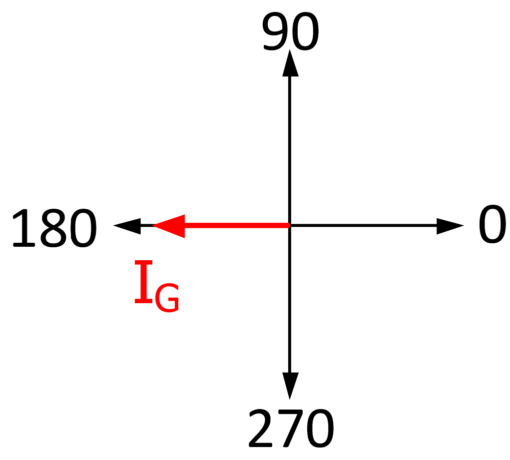


$$-3I_o \times I_G \cos(0) = -3I_oI_G$$

Trip Characteristic – 87GD

Open Breaker, Internal Fault





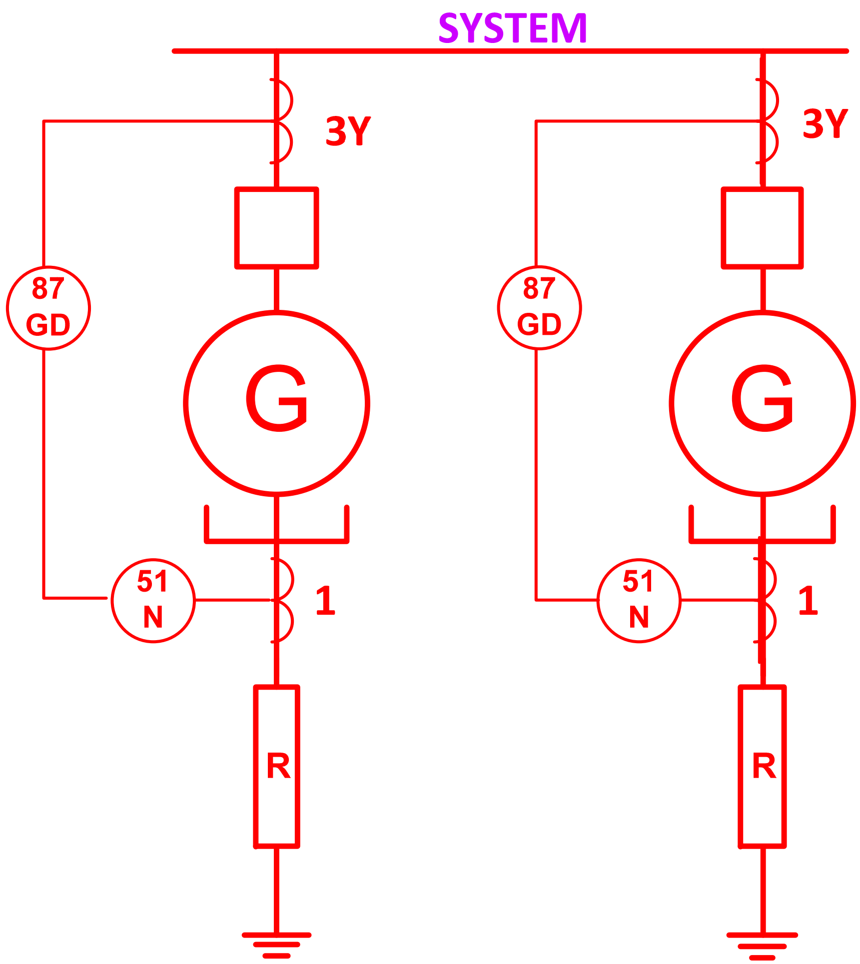
I_G > setting

Improved Ground Fault Sensitivity (87GD)

- Direction calculation used with currents over 140mA on both sets of CTs (3_{I0} and I_G)
- Directional element used to improve security for heavy external phase to phase faults that cause saturation
- When current >140mA, element uses current setting *and* directional signal
- When current <= 140mA, element uses current setting only
  - Saturation will not occur at such low current levels
  - Directional signal not required for security
  - Allows element to function for internal faults without phase output current (open breaker, internal fault source by generator only)

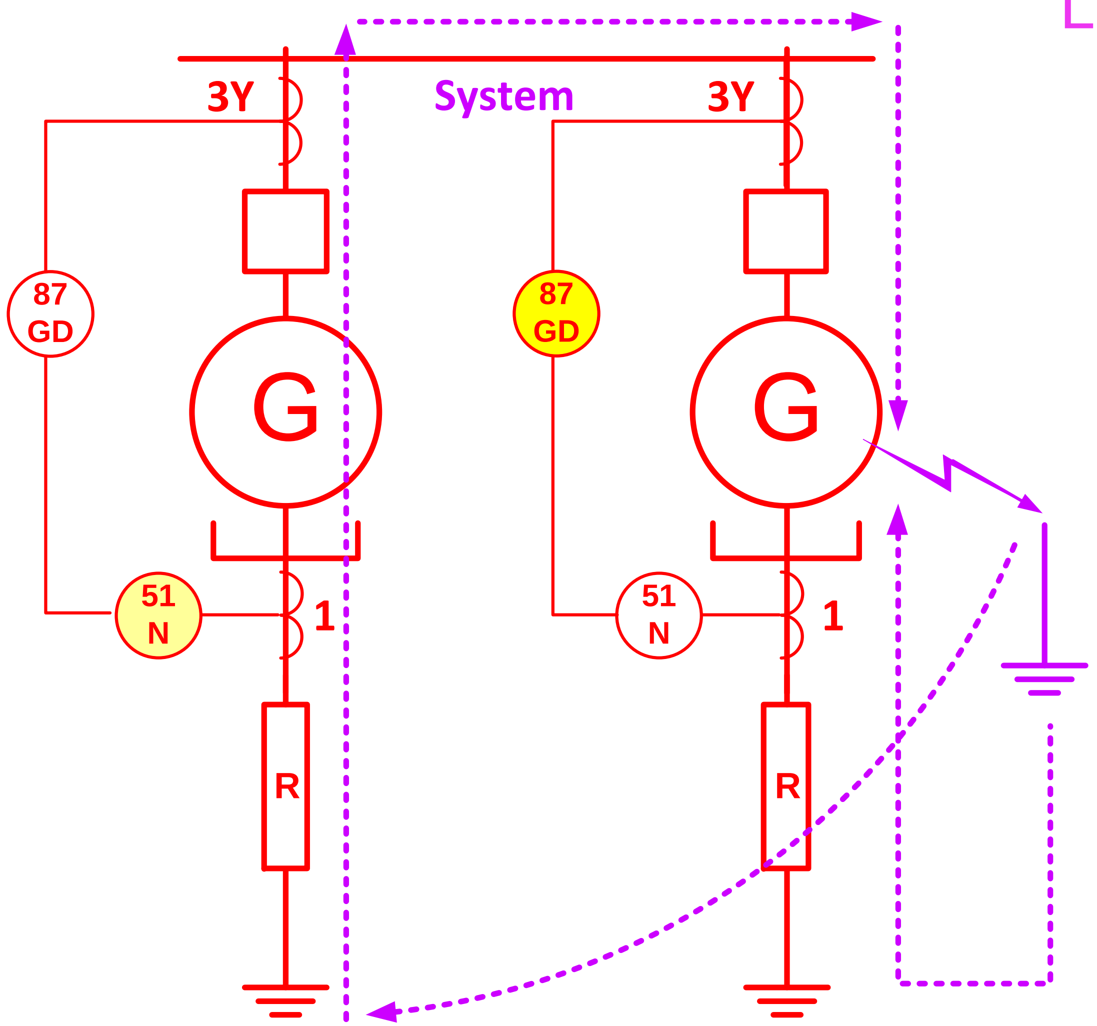
Directional Neutral Overcurrent: 87G

Low-Z Grounded Generator



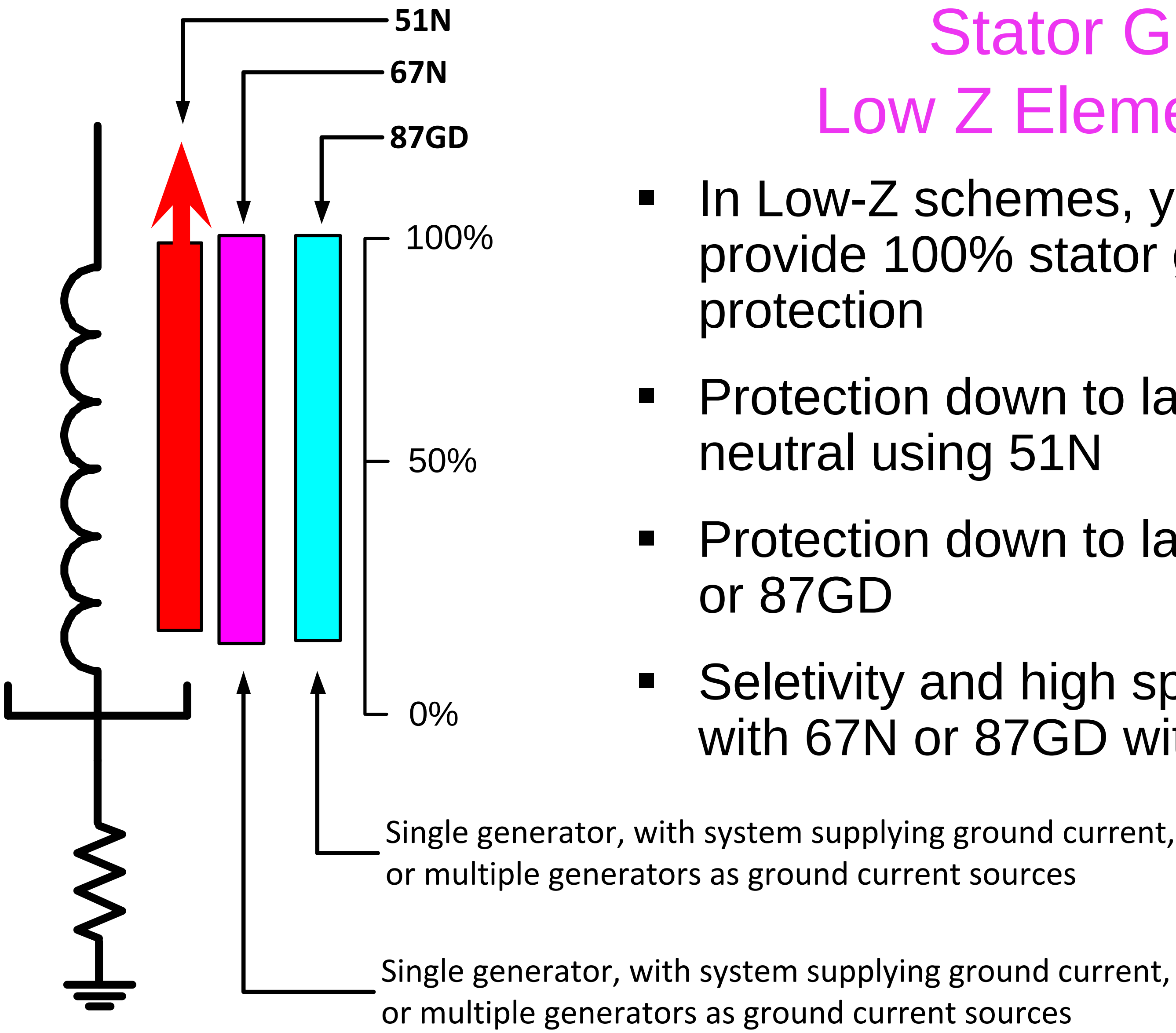
- Employed 87GD to selectively clear machine ground fault for multi-generator bus connected arrangements
- Use with 51N on grounded machine(s) for internal fault and system back up
- Ground switches on all machines can all be closed

Directional Neutral Overcurrent: 87G
Low-Z Grounded Generator



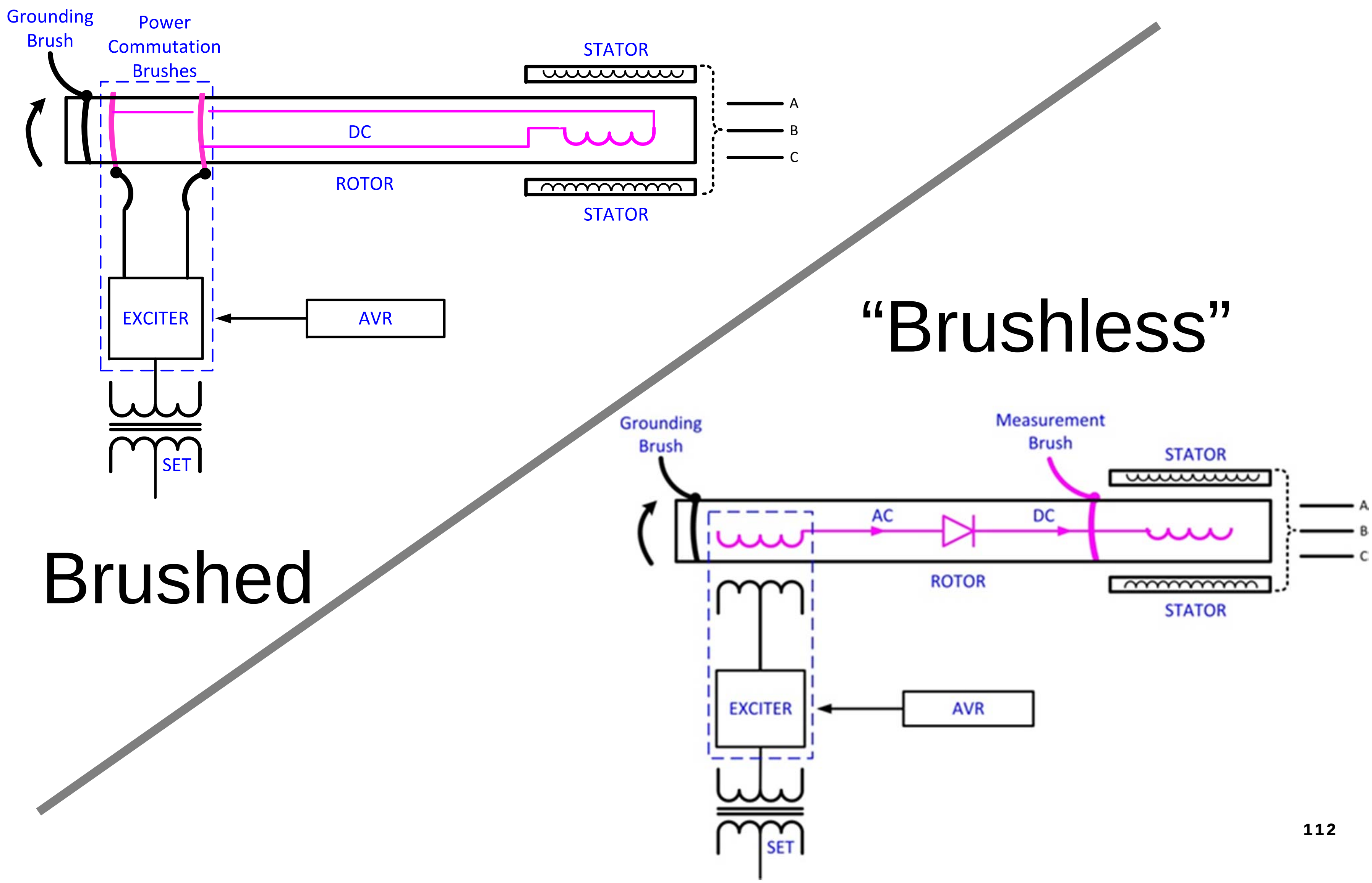
- Ground fault in machine is detected by 87GD & 51N
- 51N picks up in unfaulted machine
- 87GD trips fast in faulted machine
- 51N resets on unfaulted machine

Stator Ground Faults: Low Z Element Coverage



- In Low-Z schemes, you cannot provide 100% stator ground fault protection
- Protection down to last 5%-10% near neutral using 51N
- Protection down to last 5% using 67N or 87GD
- Seletivity and high speed possible with 67N or 87GD with in zone fault

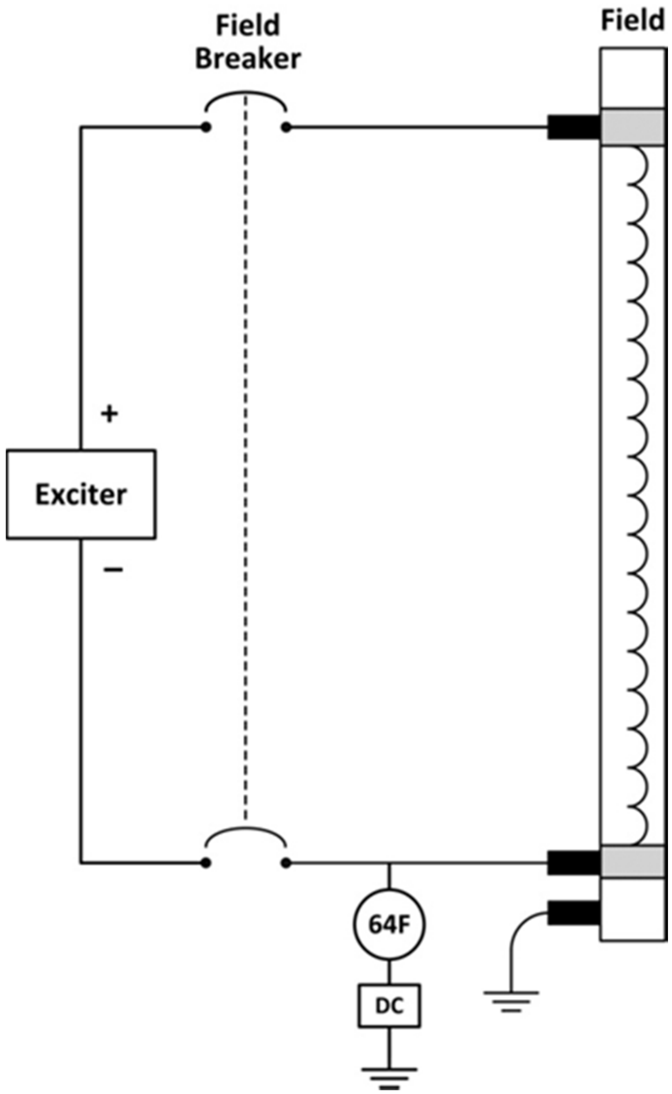
Brushed and "Brushless" Excitation

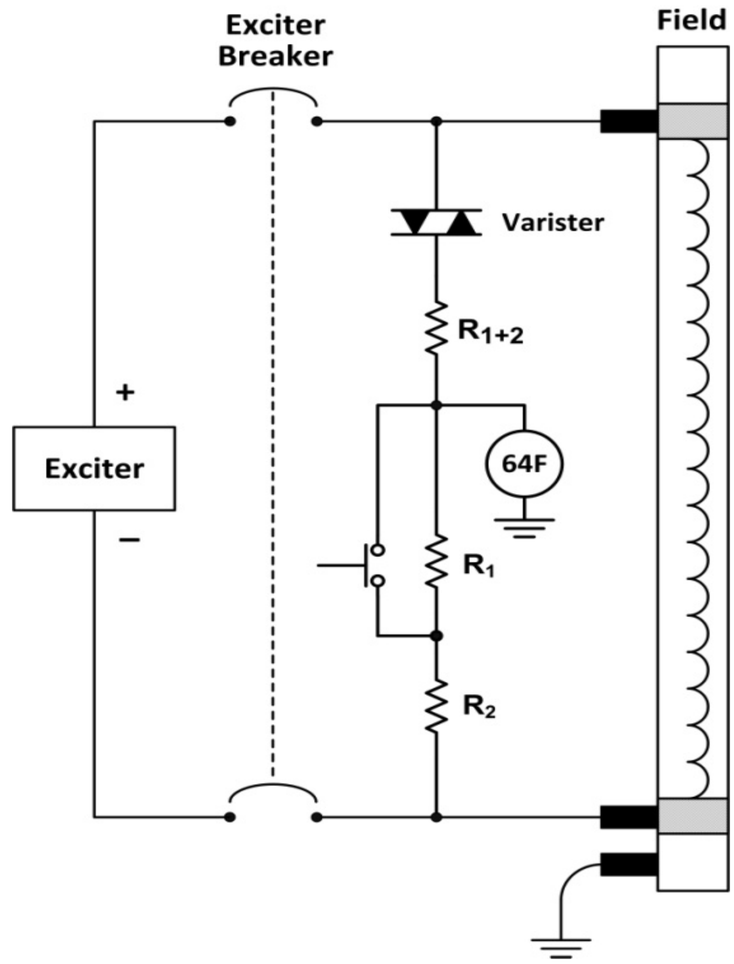


Field/Rotor Ground Fault

- 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

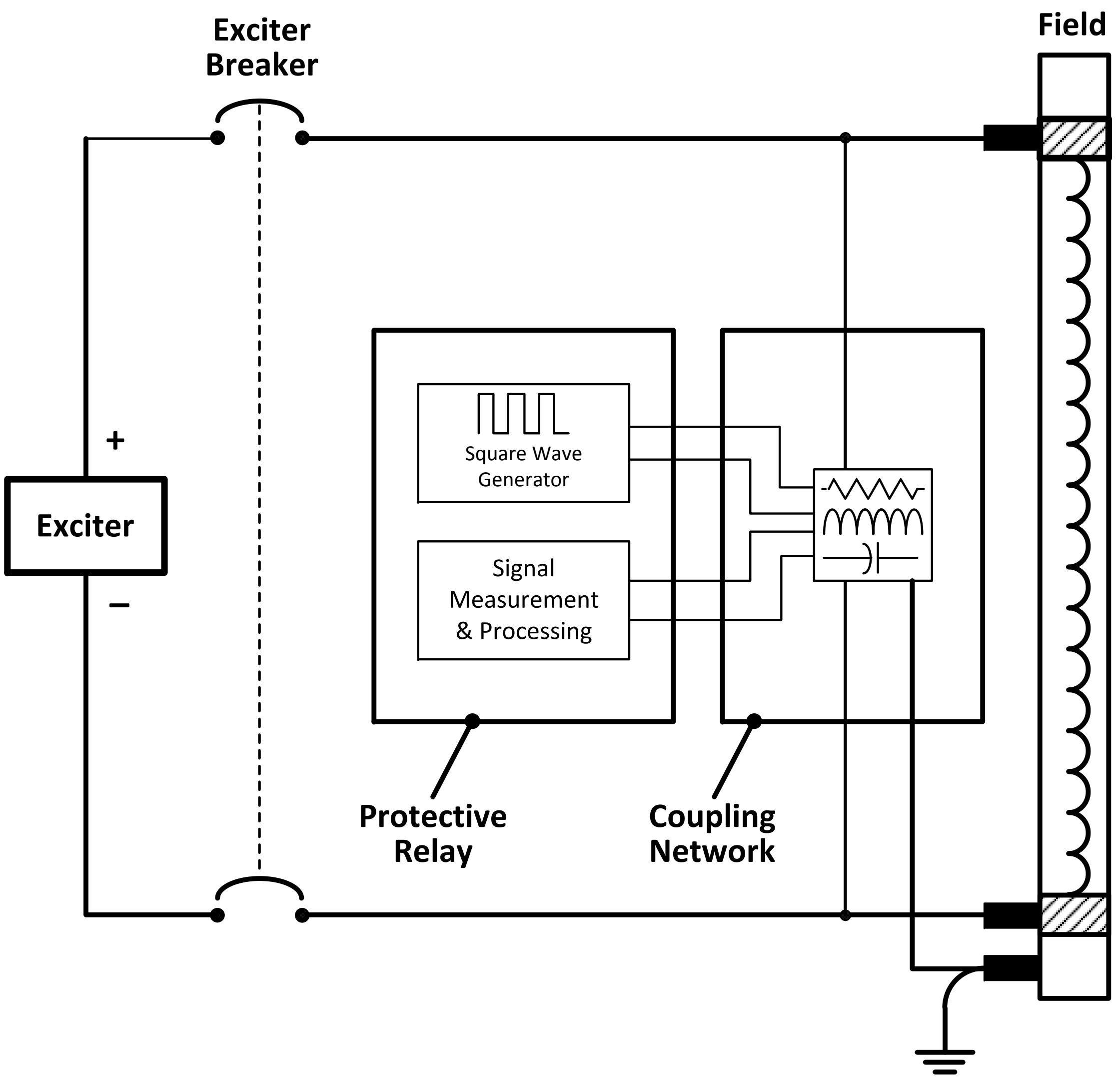

Field
Breaker
Field
+
Exciter
–
64F
DC


Exciter
Breaker
Field
Varister
R1+2
+
Exciter
–
64F
R1
R2

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

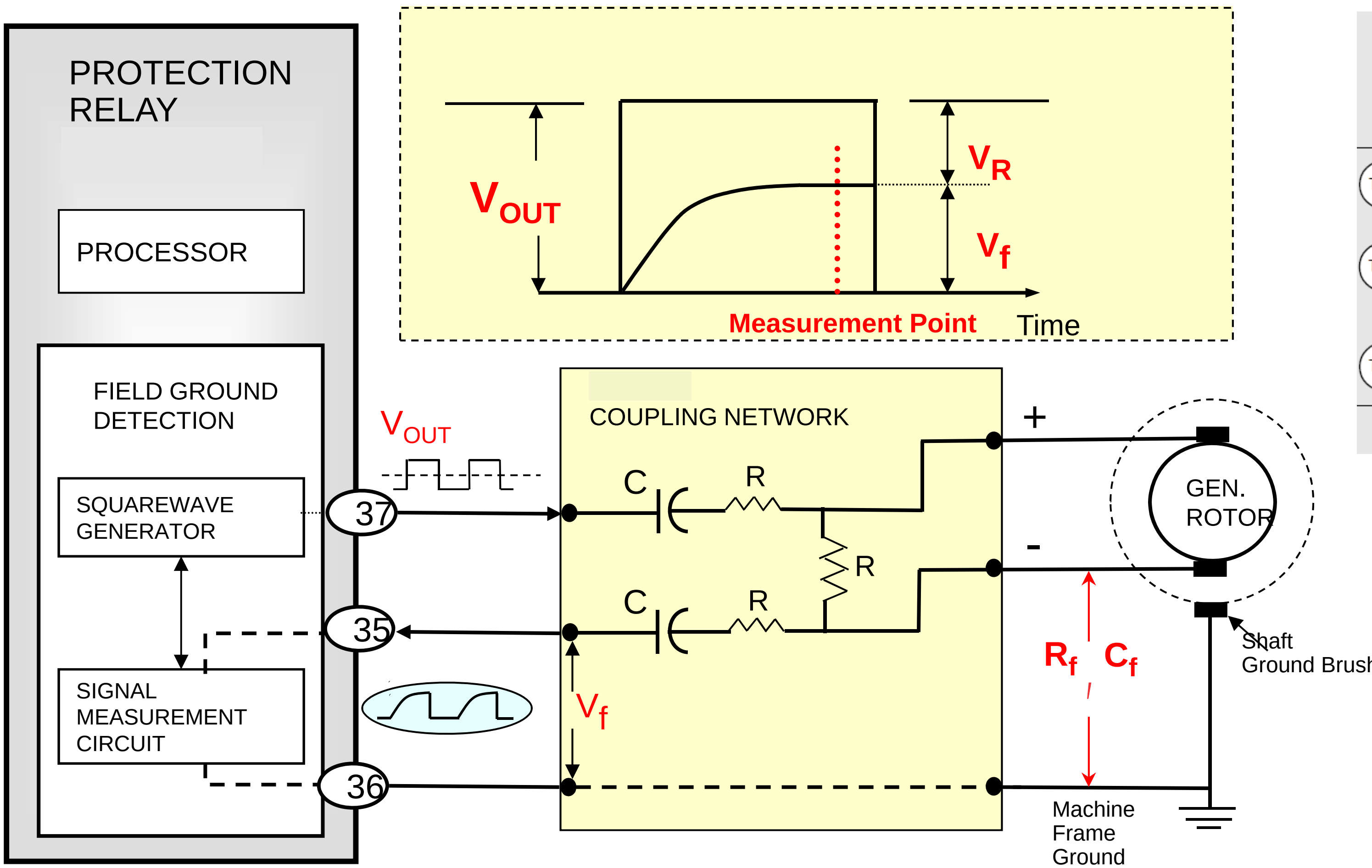


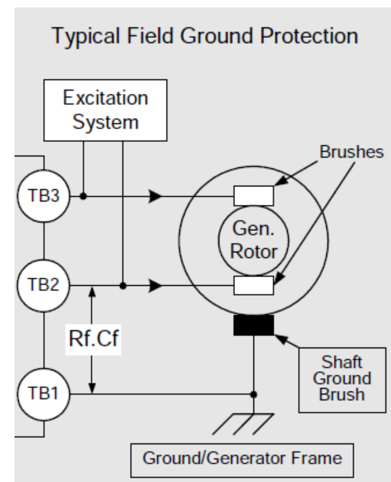
Advanced AC Injection Method: Advantages

- 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

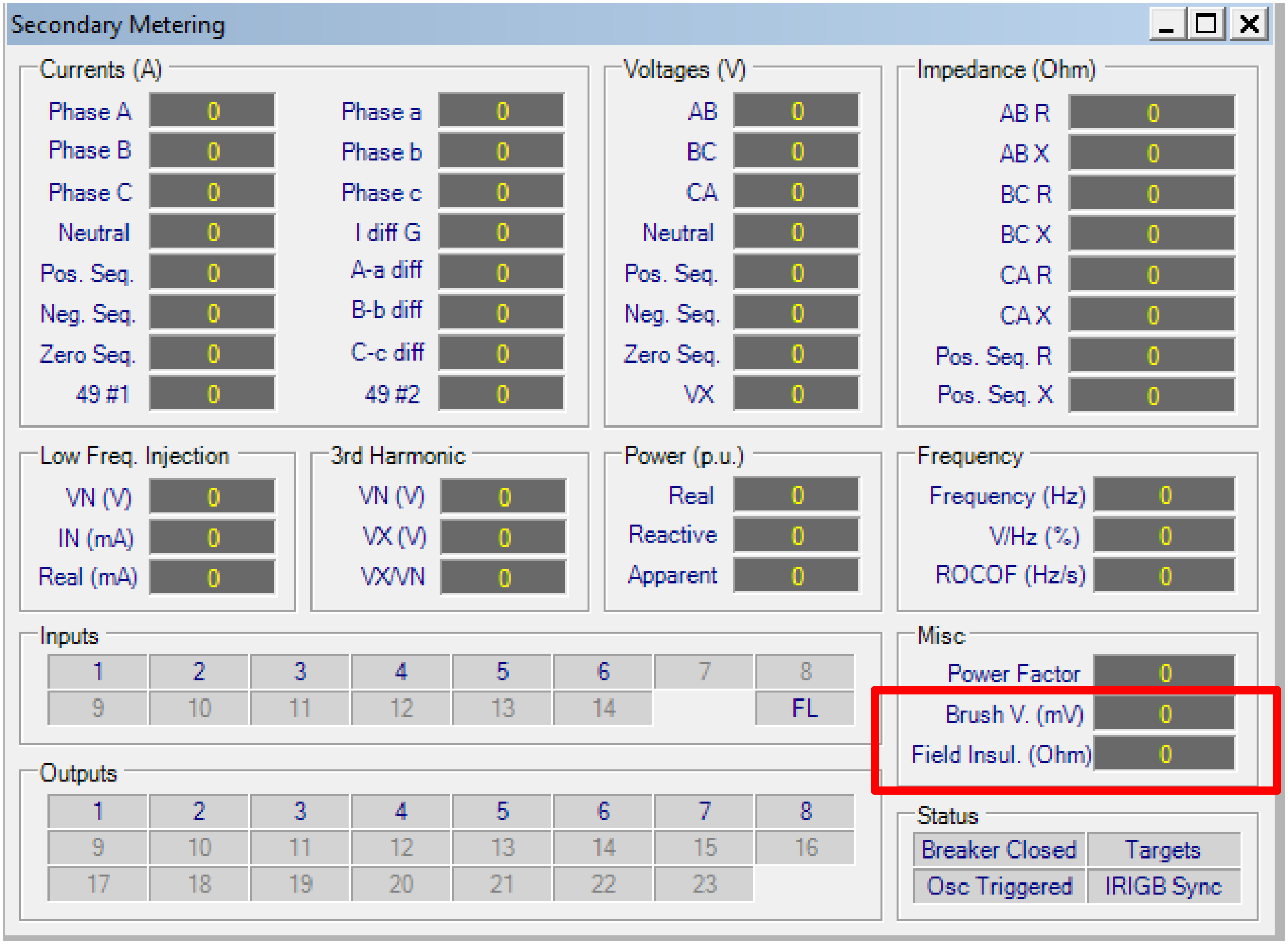
Rotor Ground Fault Measurement

- Plan a shutdown to determine why impedance is lowering, versus an eventual unplanned trip!
- When resistive fault develops, **V_f goes down**





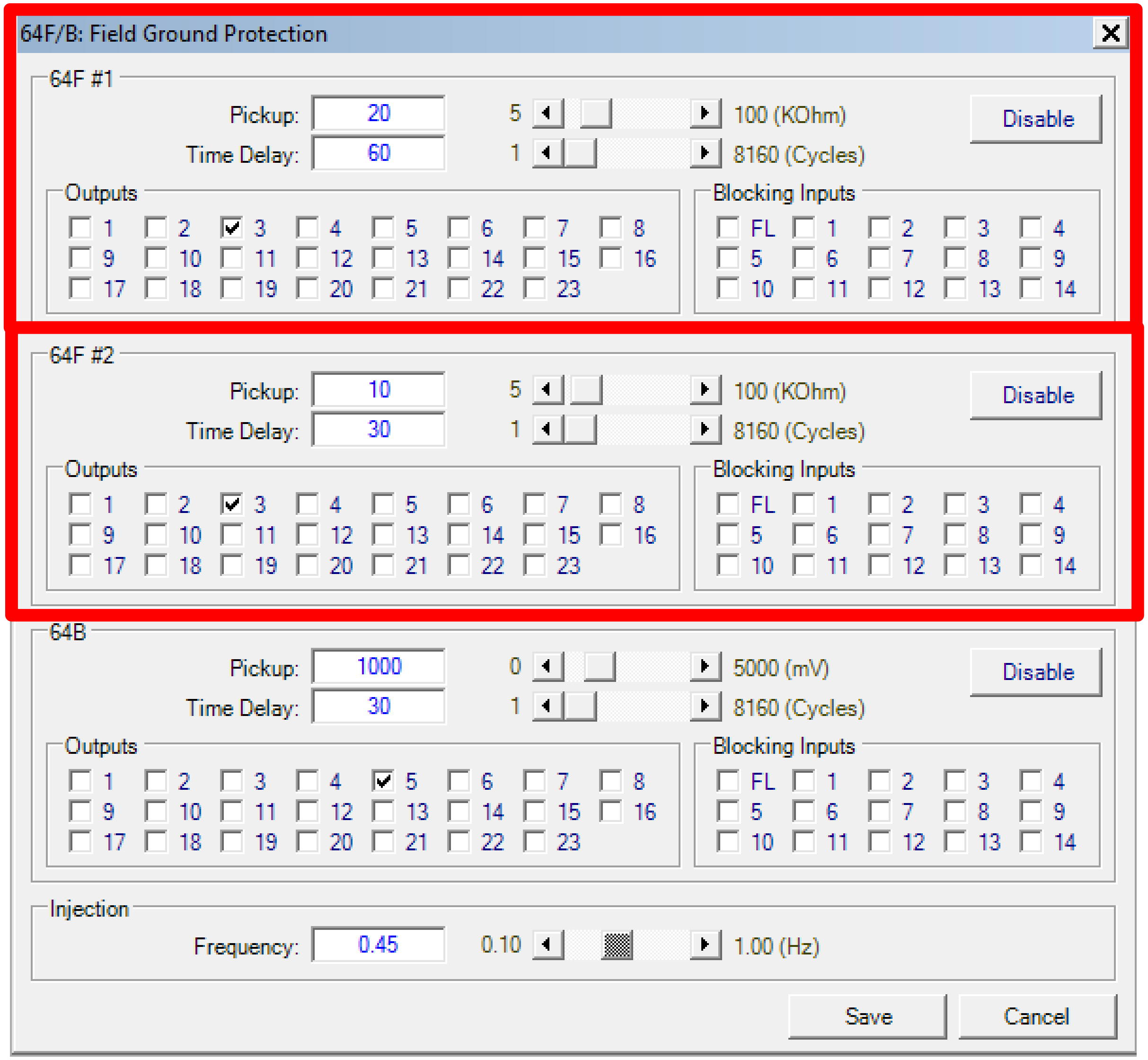
64F: Field/Rotor Ground Faults



64F: Field/Rotor Ground Faults

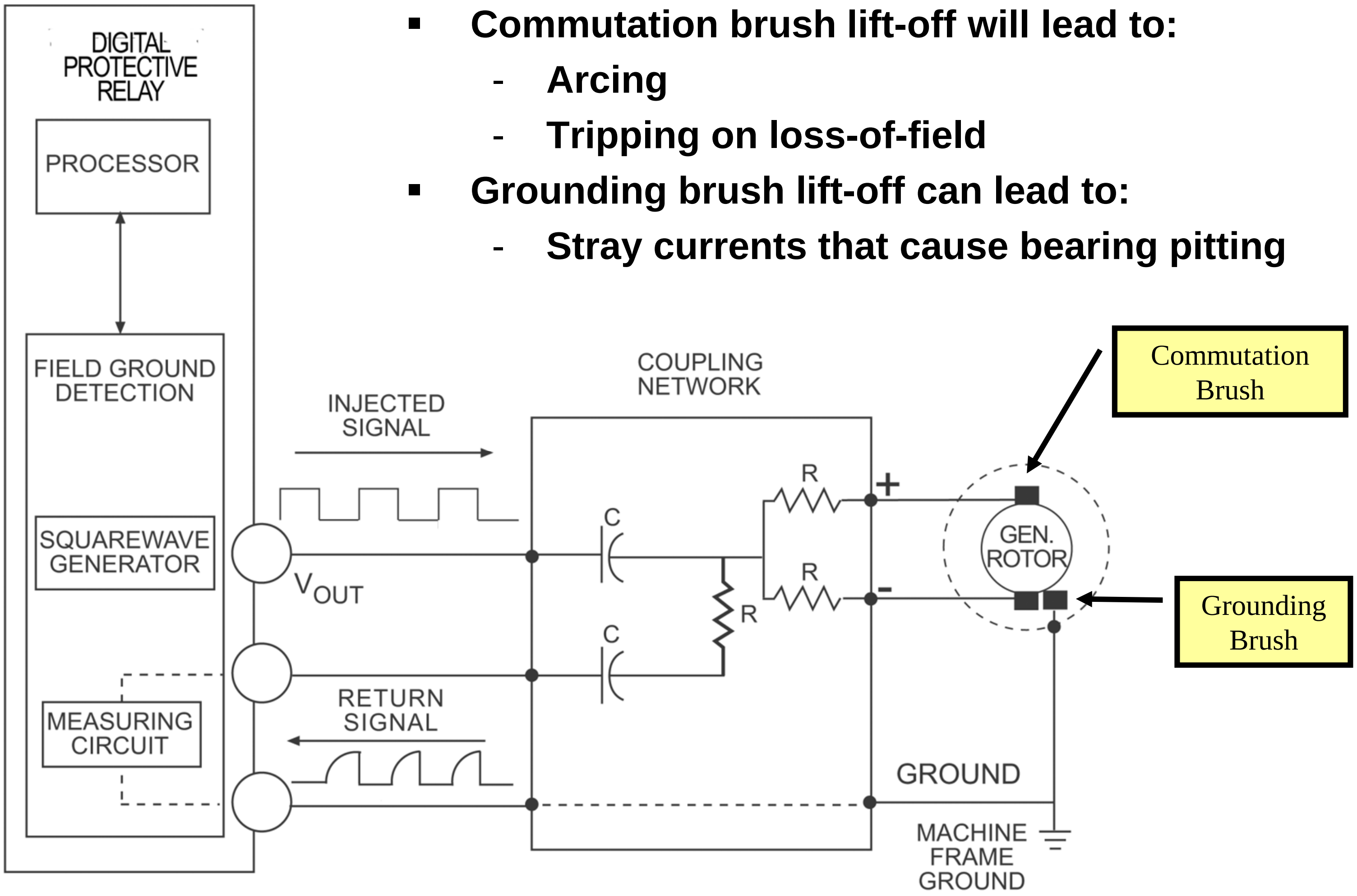
ALARM

TRIP



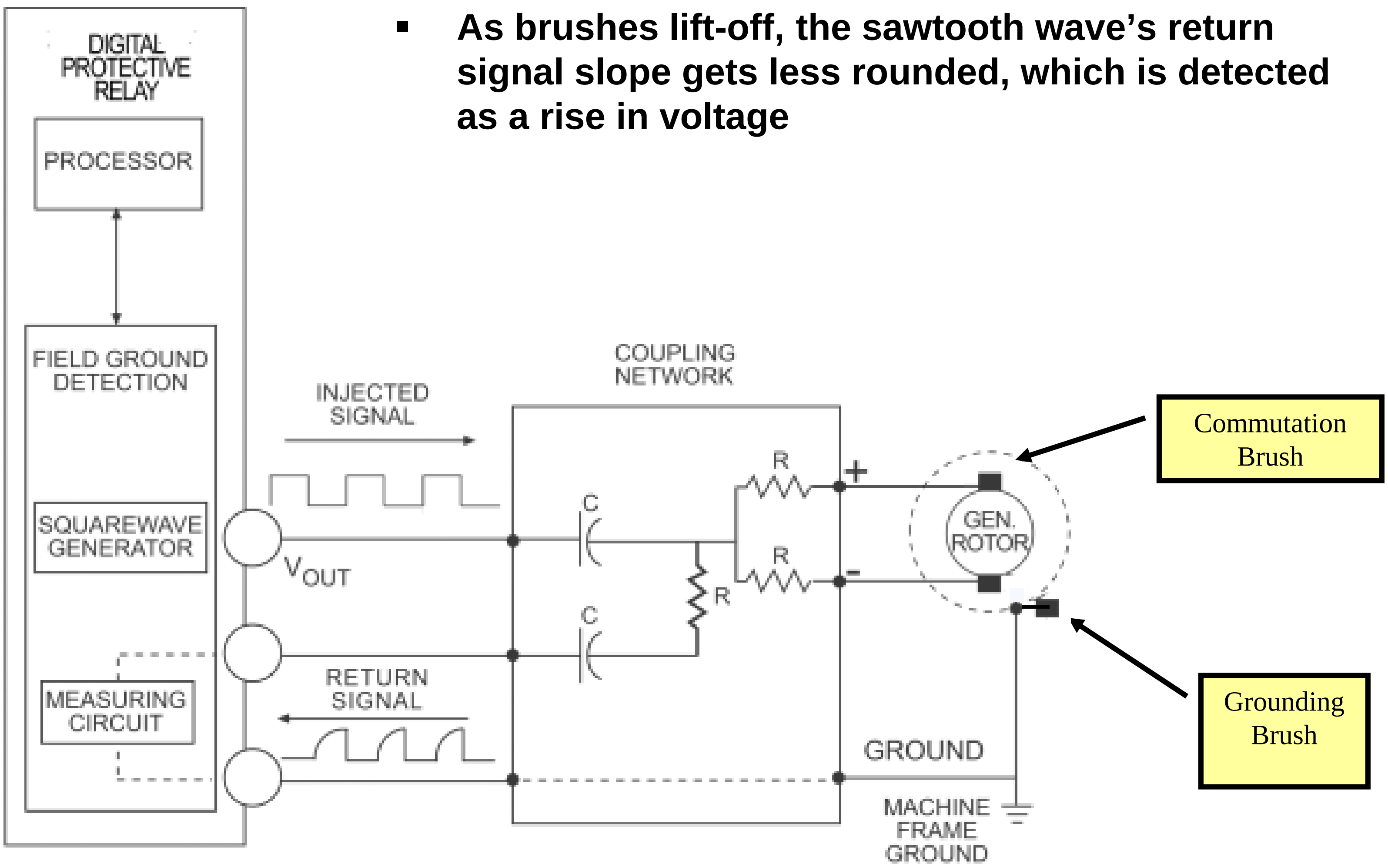
64B: Brush Lift Off

- **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**



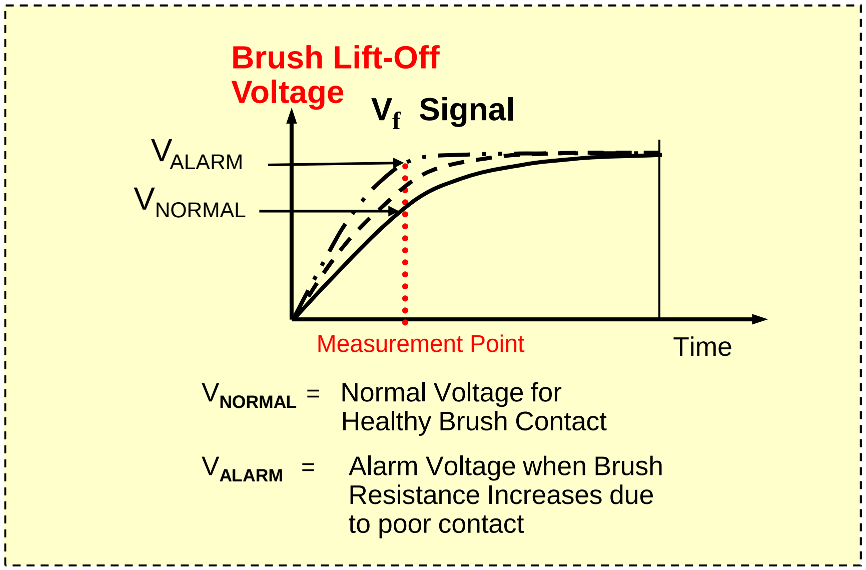
64B: Brush Lift Off

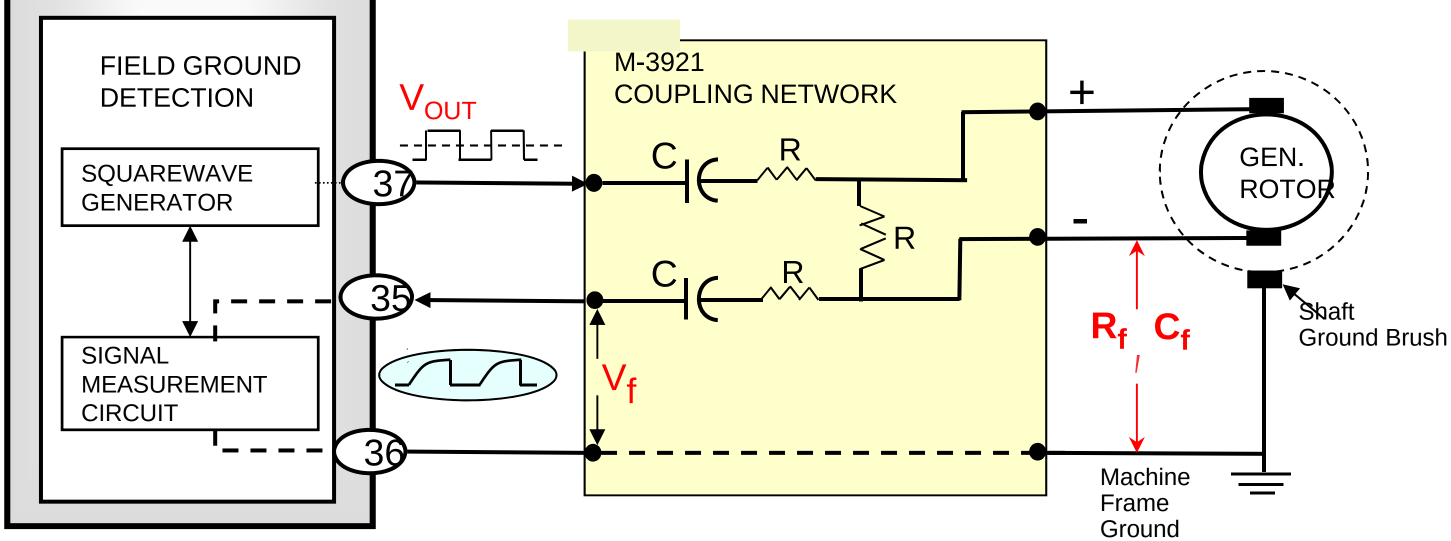
- **As brushes lift-off, the sawtooth wave's return signal slope gets less rounded, which is detected as a rise in voltage**



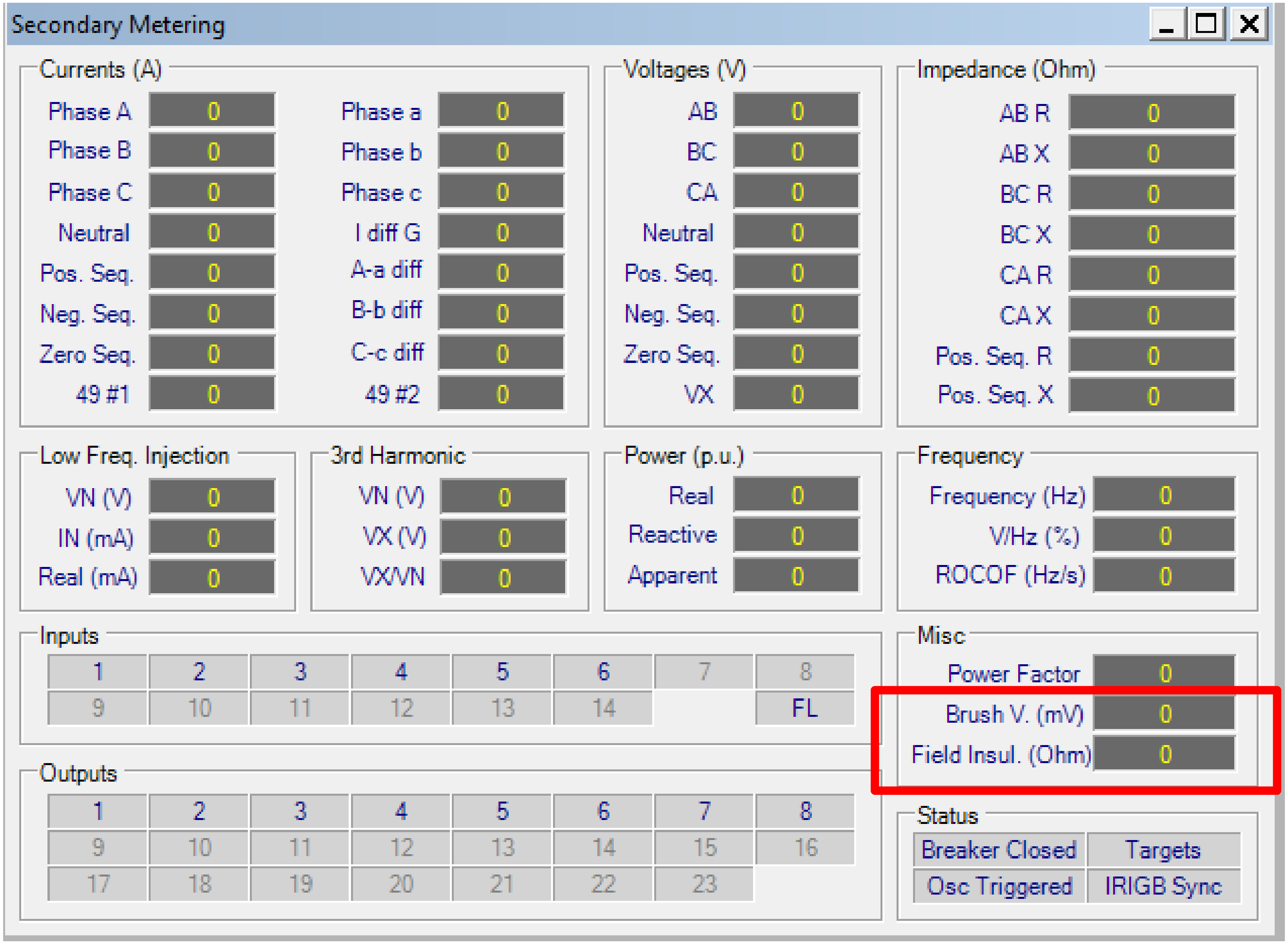
Brush Lift-Off Measurement

- When brush lifts off, V_f **goes up**

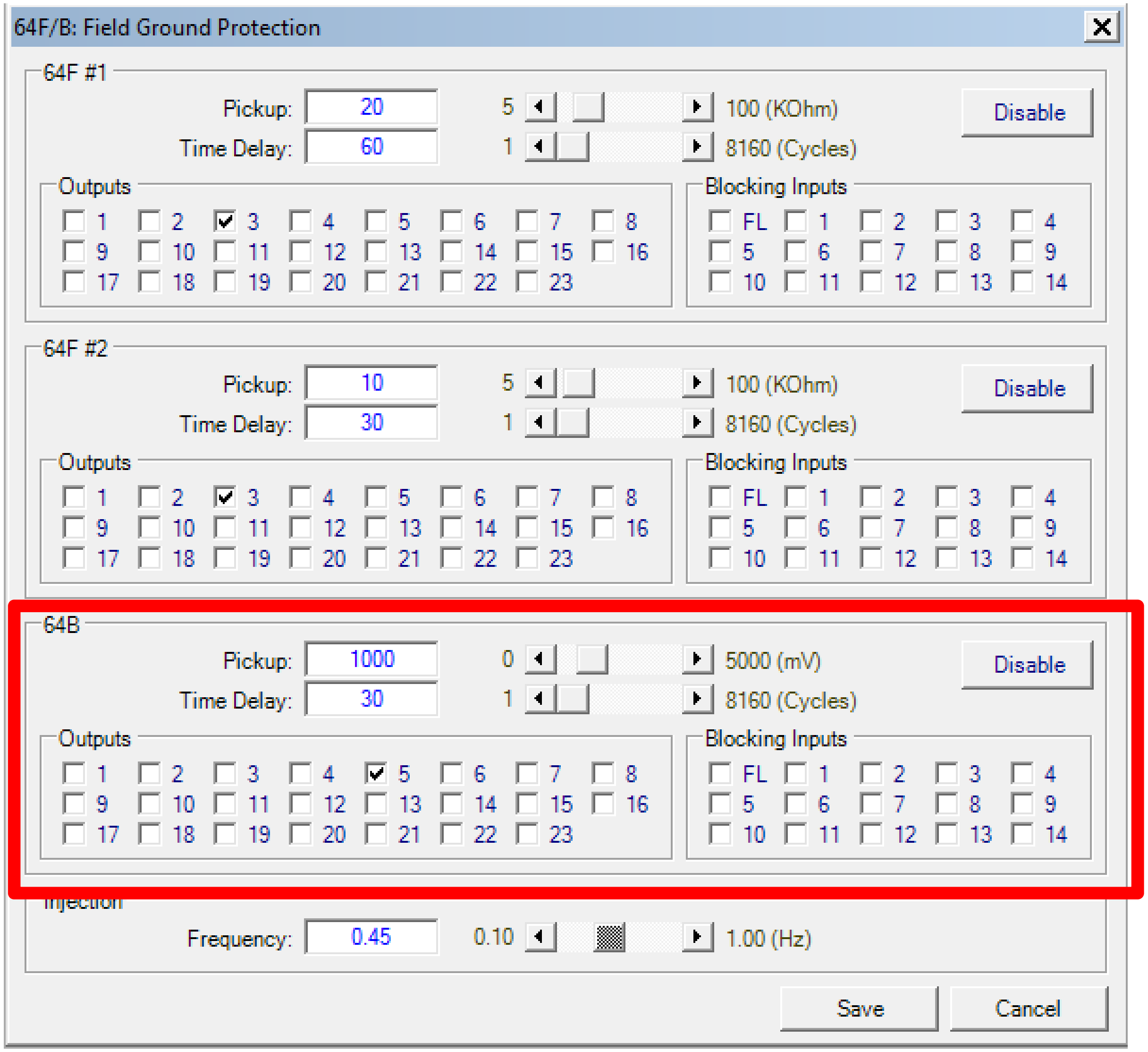




64F: Field/Rotor Ground Faults



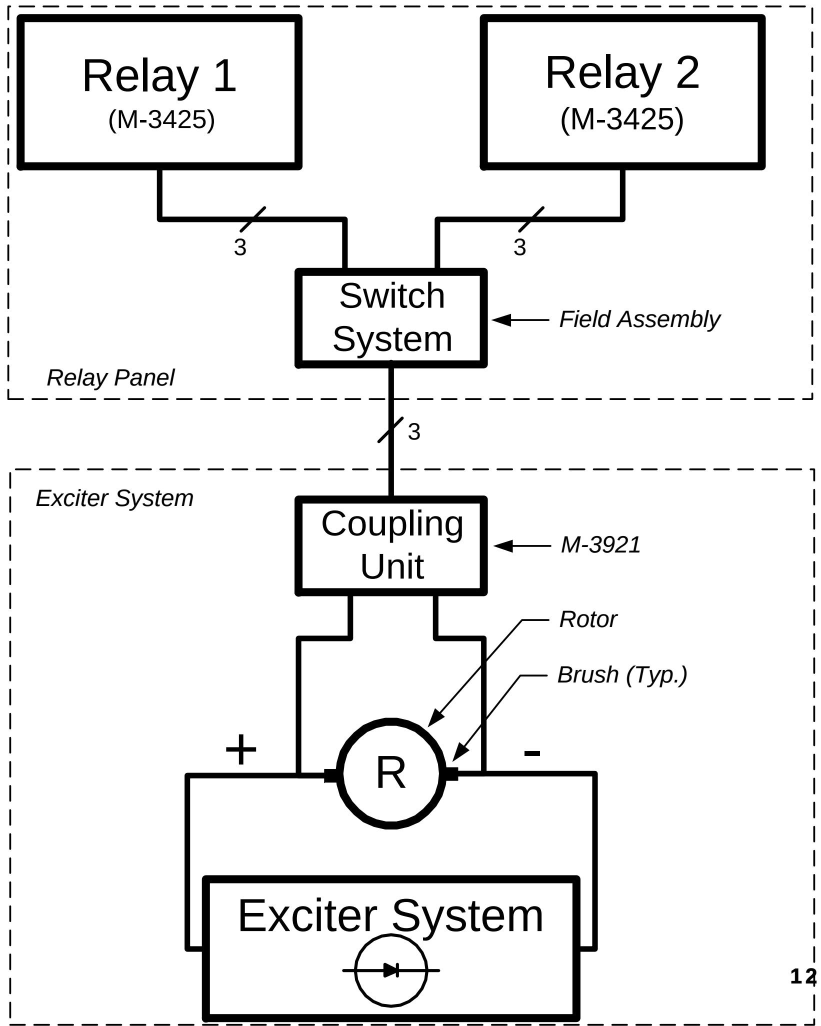
64B: Brush Lift Off



ALARM

Field/Rotor Ground Faults

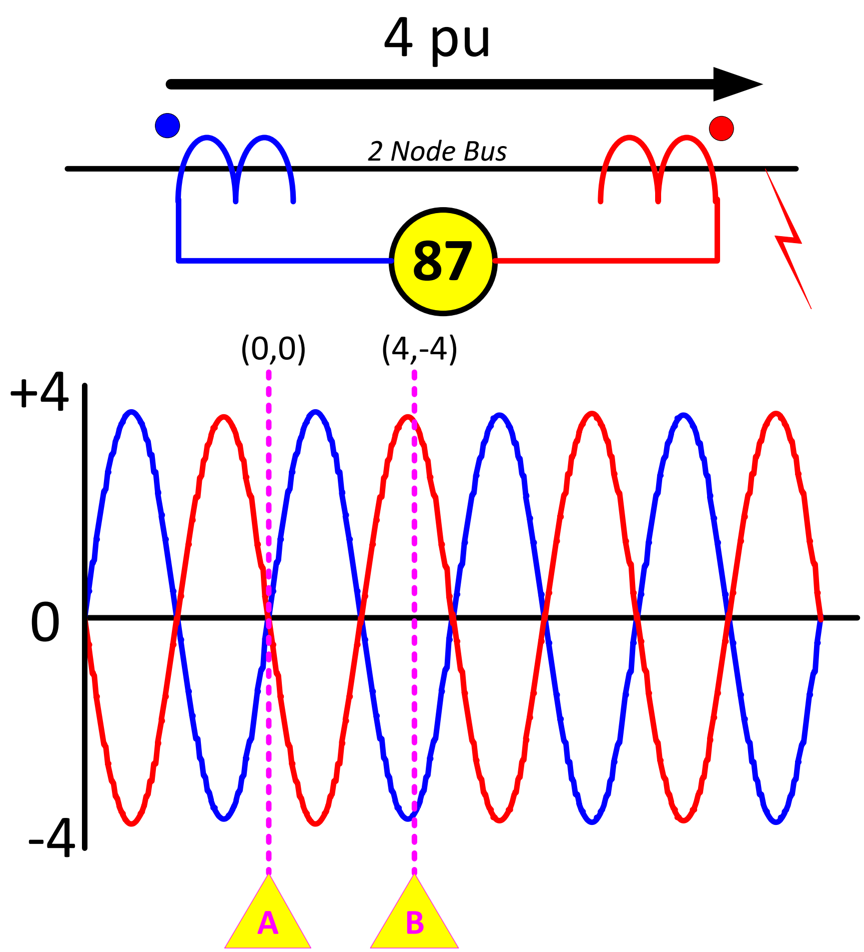
- 64F/B
  - It is possible to apply two systems and have redundancy
  - The switch system is initiated by manual means or by monitoring relay self diagnostic contacts

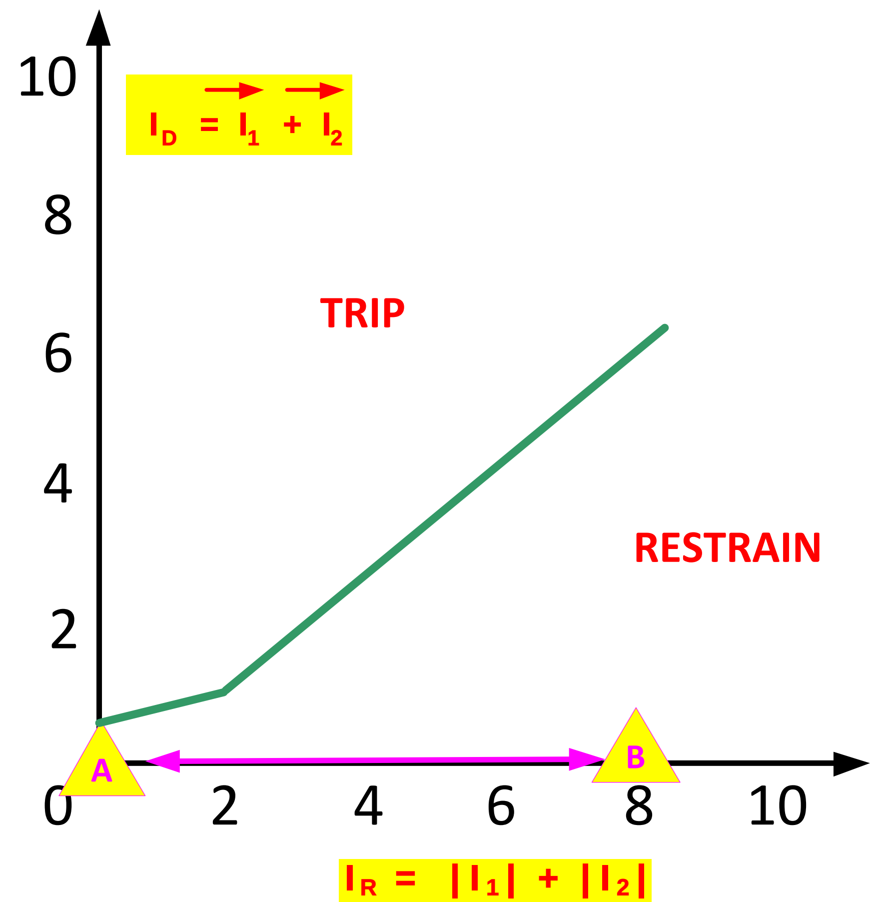


Stator Phase Faults

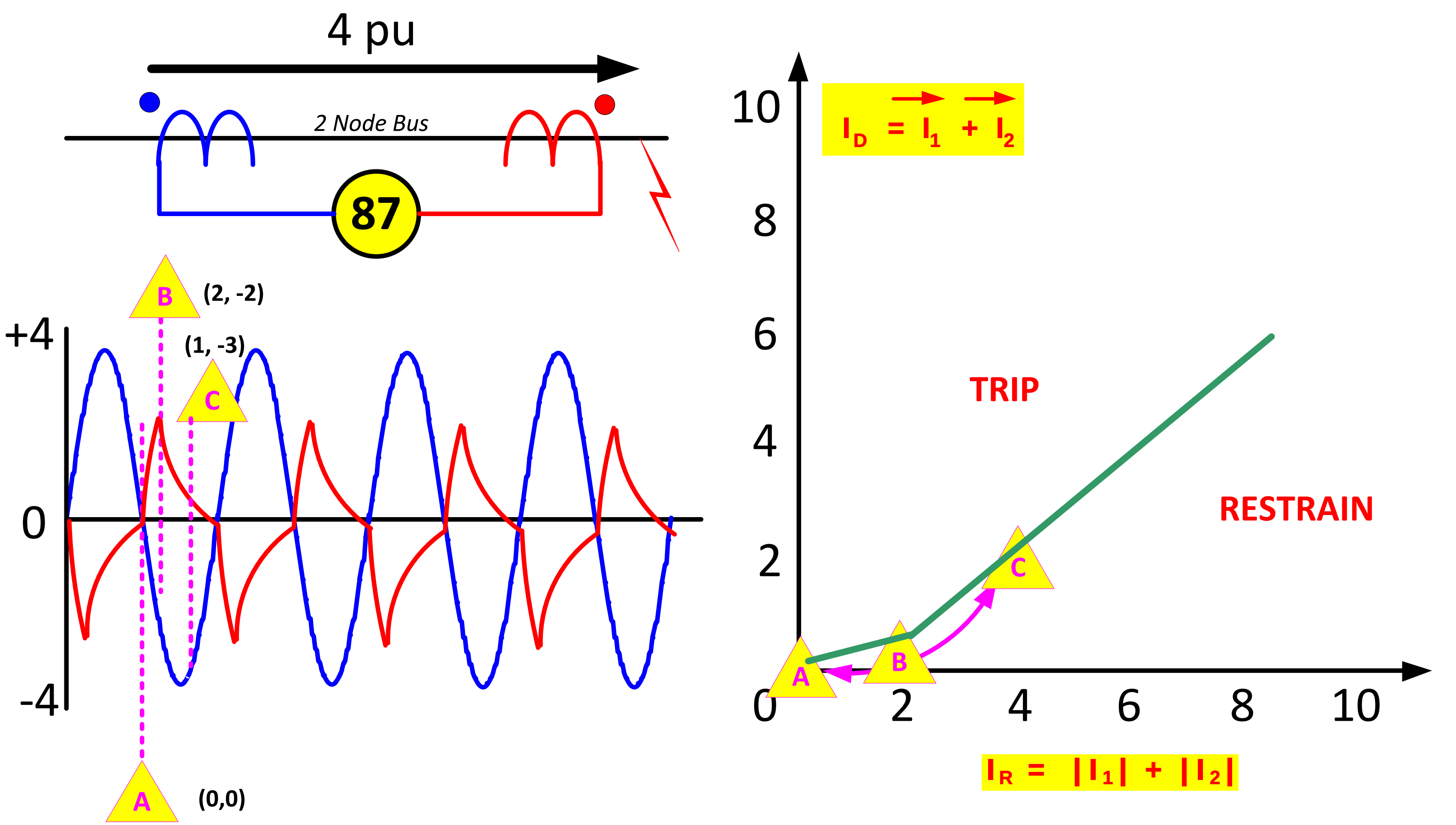
- 87G – Phase Differential (primary for in-zone faults)
  - What goes into zone must come out
  - Challenges to Differential
    - CT replication issues: Remenant flux causing saturation
    - DC offset desensitization for energizing transformers and large load pick up
    - Must work properly from 10 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_{RMS}/I_{FUND} to adaptively desensitize element when challenged by DC offset for security
      - DC offset can occur from black starting and close-in faults

Through Current: Perfect Replication

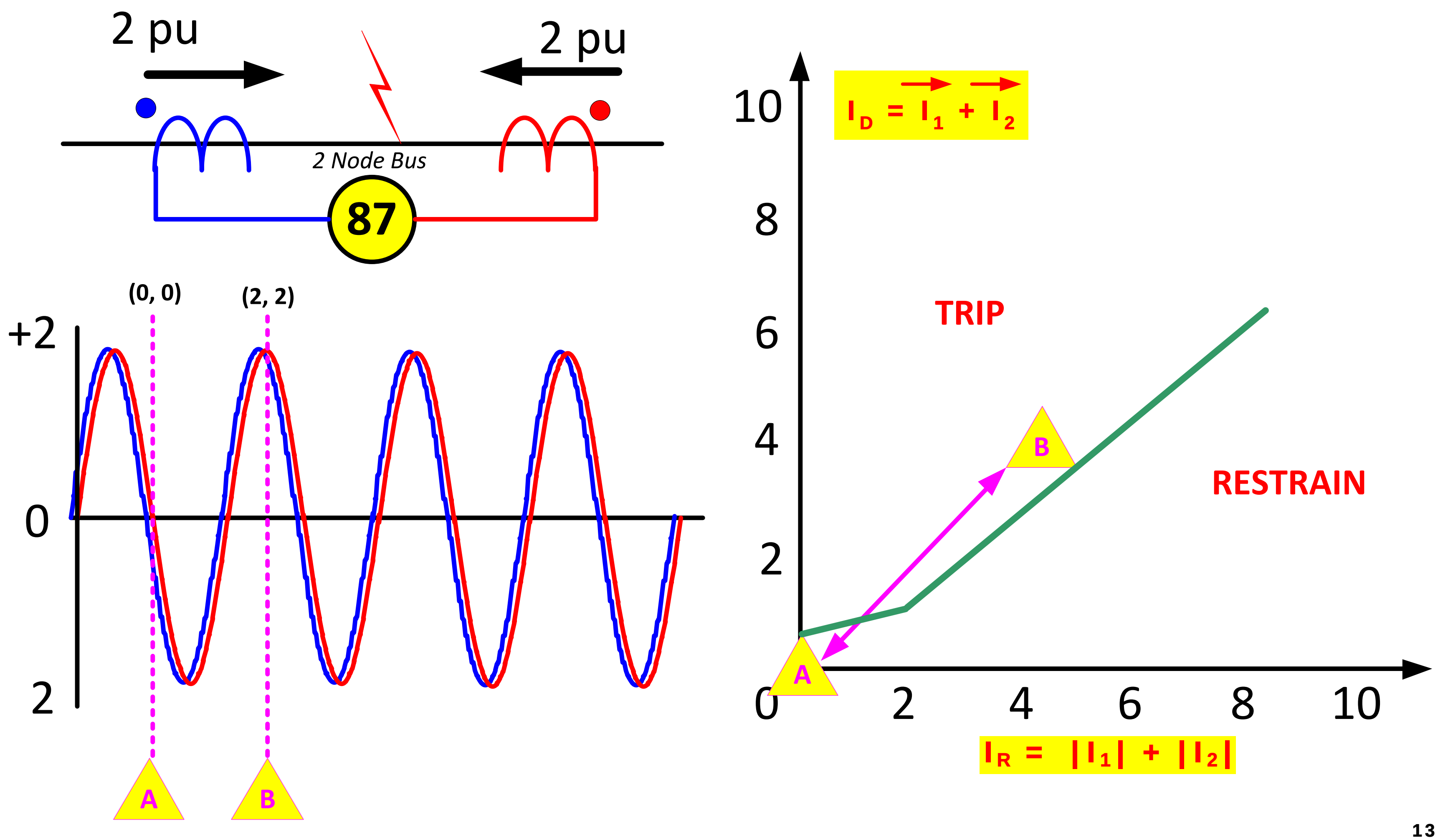




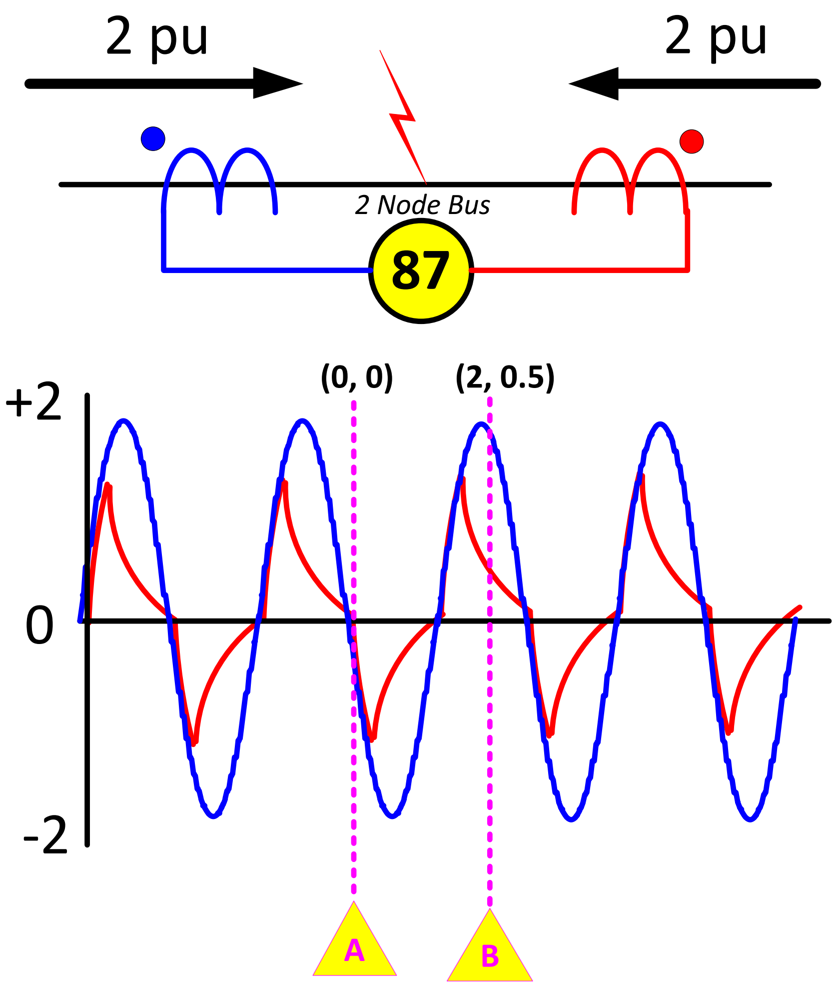
Through Current: Imperfect Replication

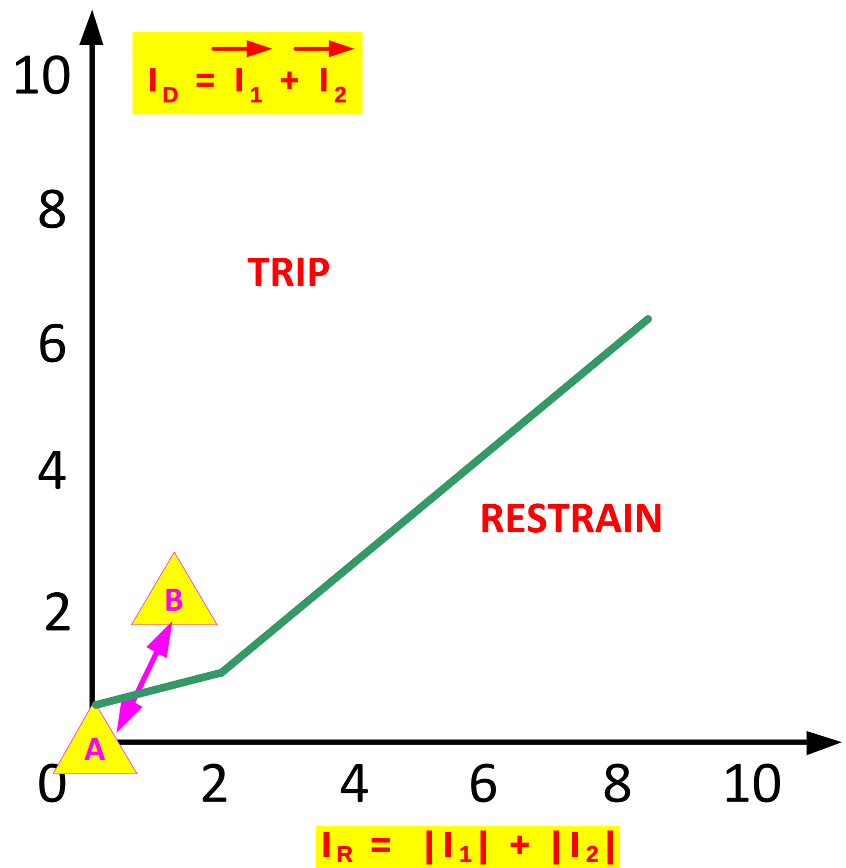


Internal Fault: Perfect Replication

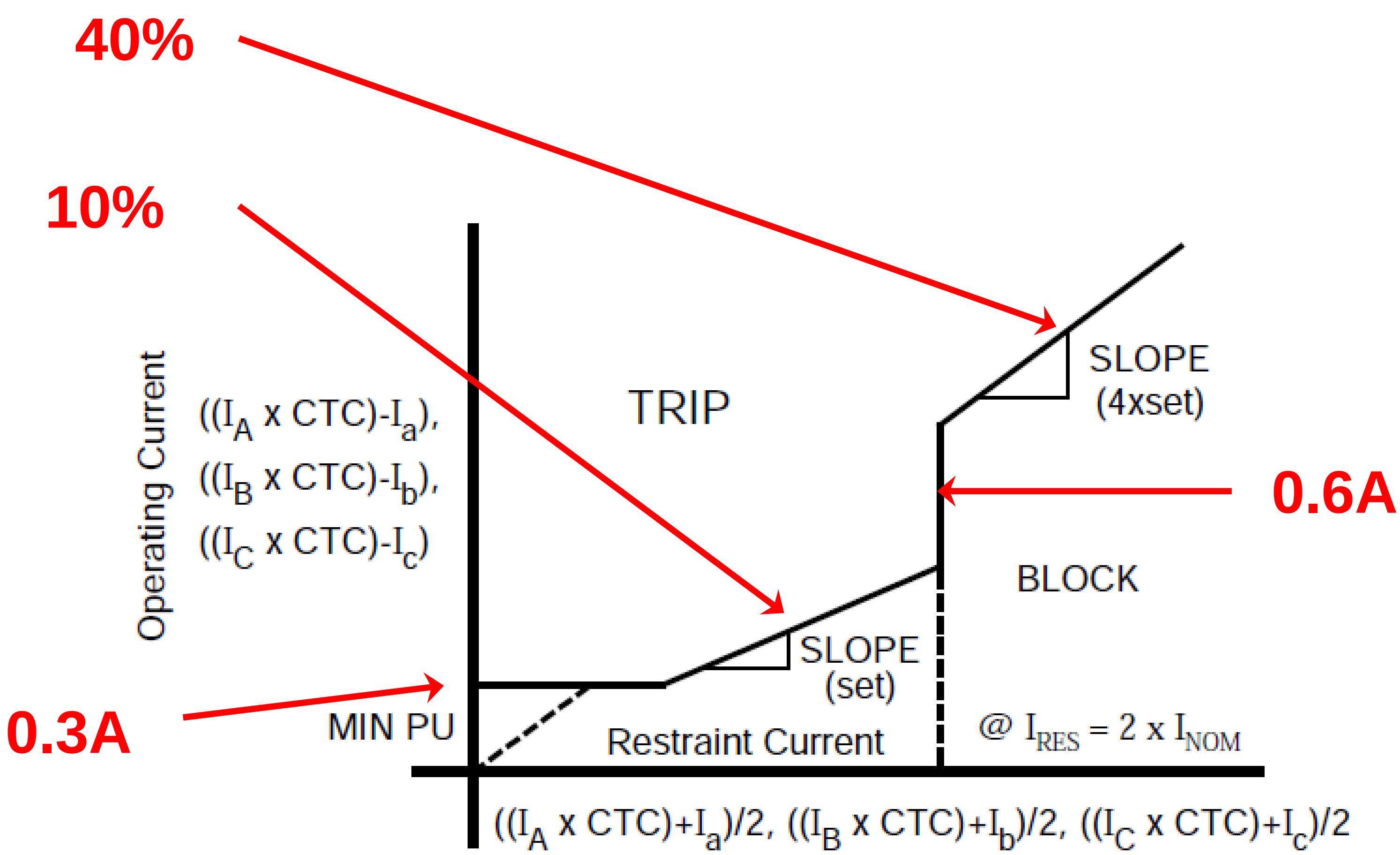


Internal Fault: Imperfect Replication





87 Characteristic



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

CT Saturation [1]

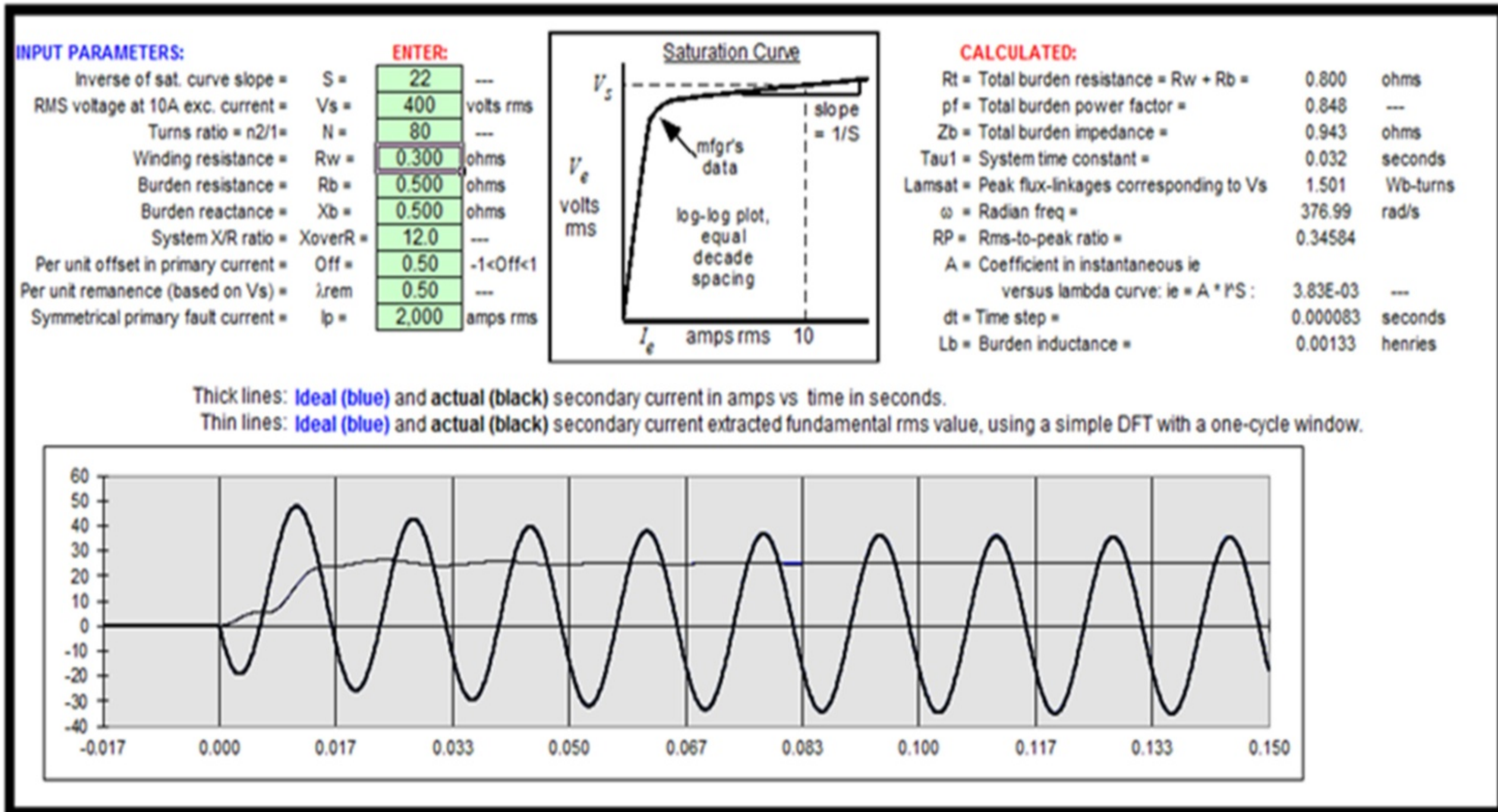
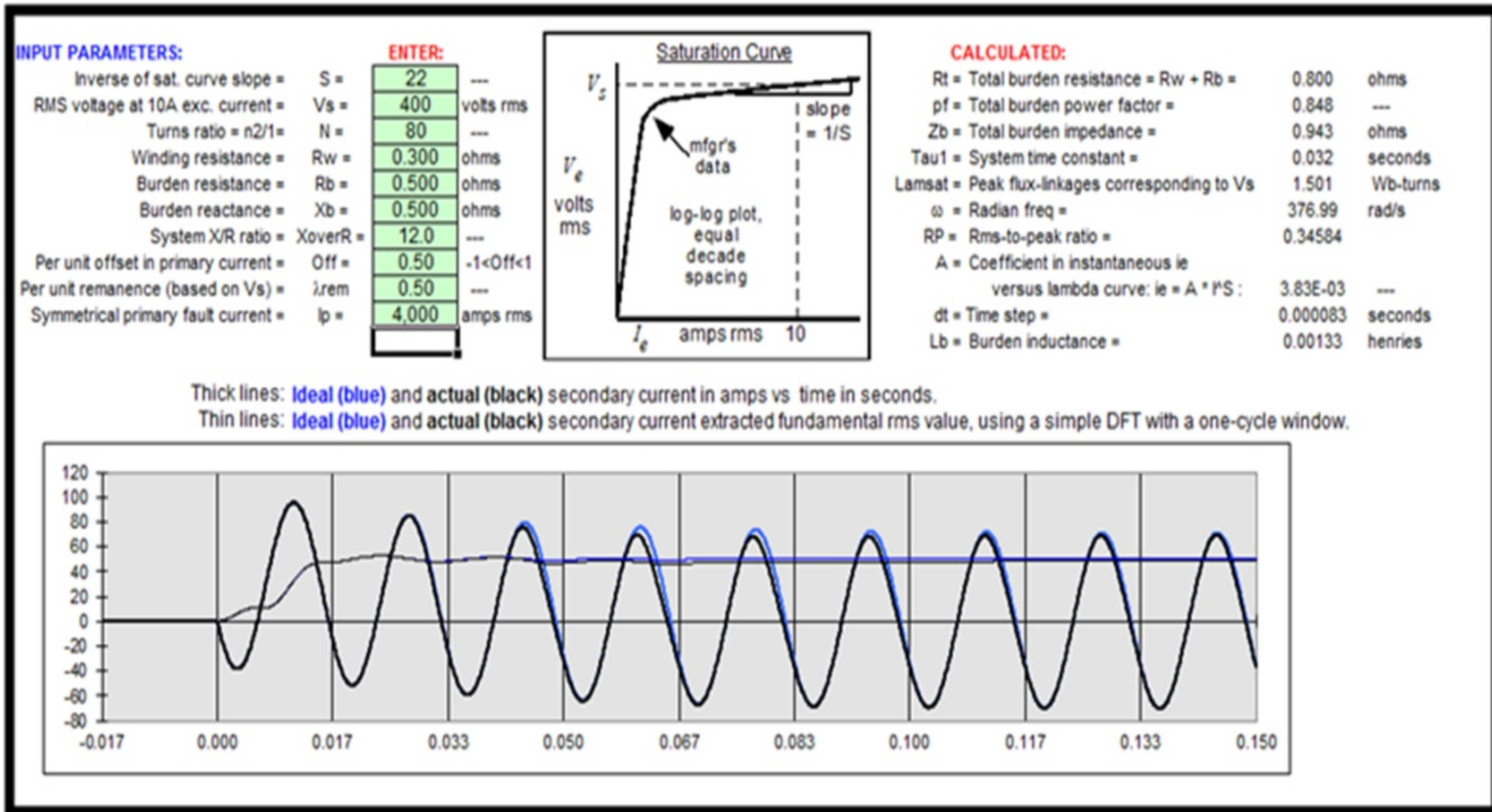


Fig. 2: 400:5, C400, R=0.5, Offset = 0.5, 2000A

CT Saturation [2]



INPUT PARAMETERS:

		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	80	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.50	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	4,000	amps rms

CALCULATED:

Rt =	Total burden resistance = Rw + Rb =	0.800	ohms
pf =	Total burden power factor =	0.848	---
Zb =	Total burden impedance =	0.943	ohms
Tau1 =	System time constant =	0.032	seconds
Lamsat =	Peak flux-linkages corresponding to Vs	1.501	Wb-turns
ω =	Radian freq =	376.99	rad/s
RP =	Rms-to-peak ratio =	0.34584	
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	3.83E-03	---
dt =	Time step =	0.000083	seconds
Lb =	Burden inductance =	0.00133	henries

Fig. 3: 400:5, C400, R=0.5, Offset = 0.5, 4000A

CT Saturation [3]

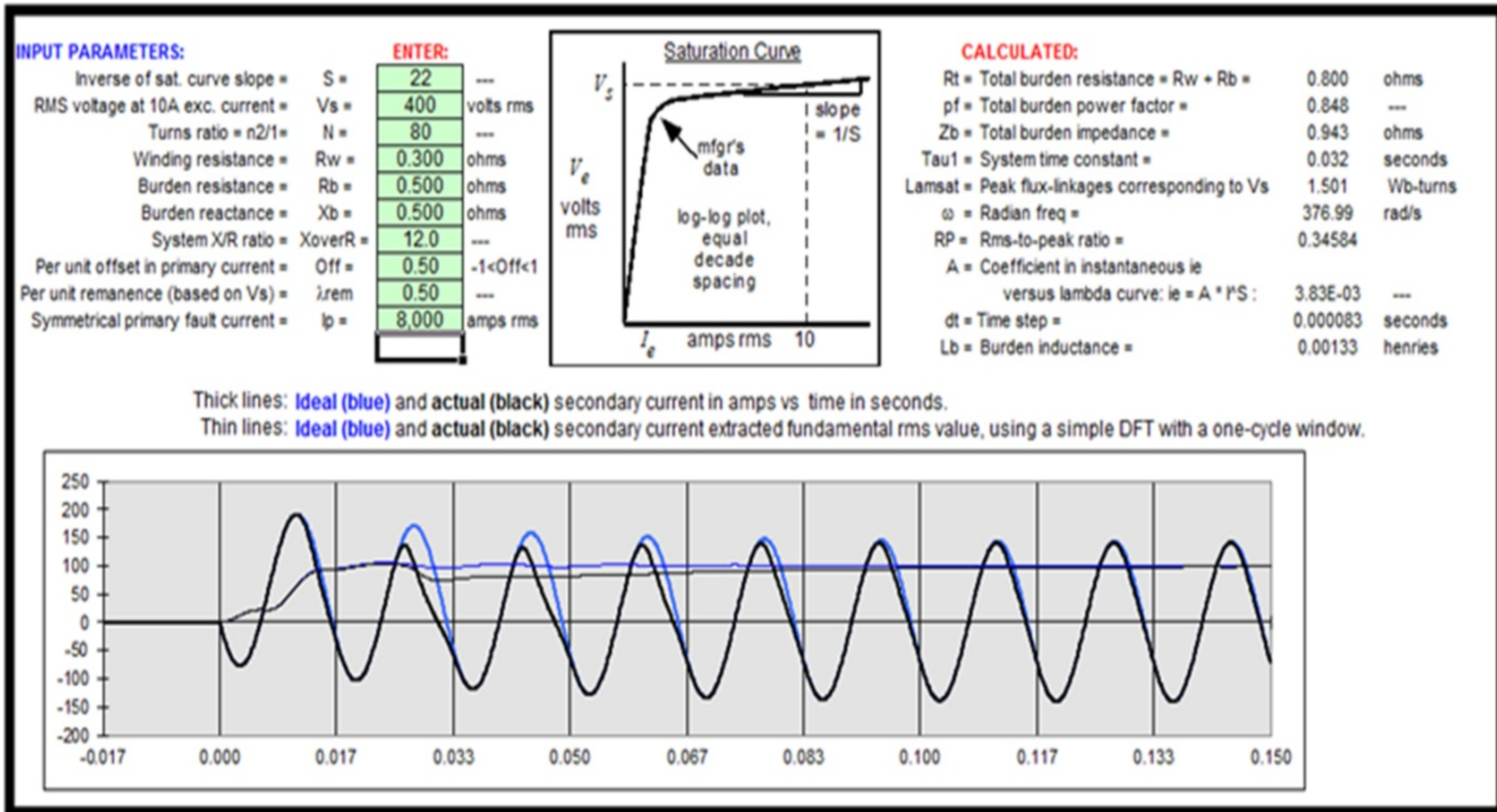
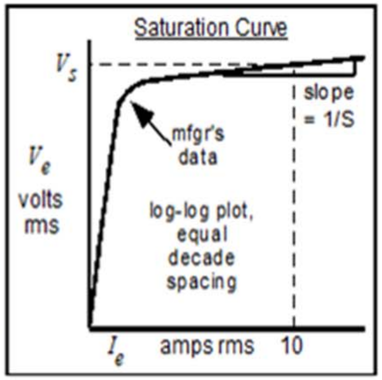


Fig. 4: 400:5, C400, R=0.5, Offset = 0.5, 8000A

CT Saturation [4]

INPUT PARAMETERS:

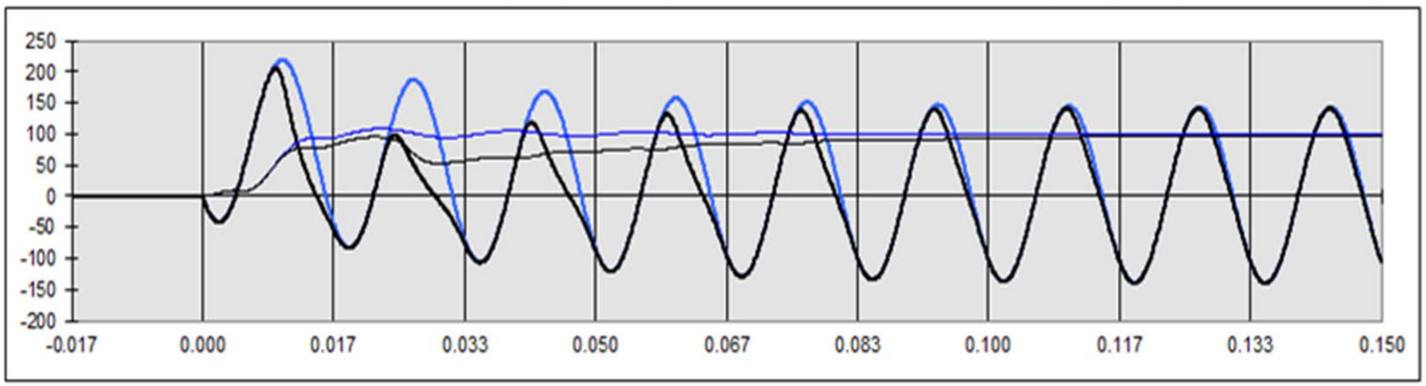
		ENTER:	
Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	80	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.75	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.50	---
Symmetrical primary fault current =	Ip =	8,000	amps rms



CALCULATED:

Rt =	Total burden resistance = Rw + Rb =	0.800	ohms
pf =	Total burden power factor =	0.848	---
Zb =	Total burden impedance =	0.943	ohms
Tau1 =	System time constant =	0.032	seconds
Lamsat =	Peak flux-linkages corresponding to Vs	1.501	Wb-turns
ω =	Radian freq =	376.99	rad/s
RP =	Rms-to-peak ratio =	0.34584	
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	3.83E-03	---
dt =	Time step =	0.000083	seconds
Lb =	Burden inductance =	0.00133	henries

Thick lines: Ideal (blue) and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: Ideal (blue) and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.



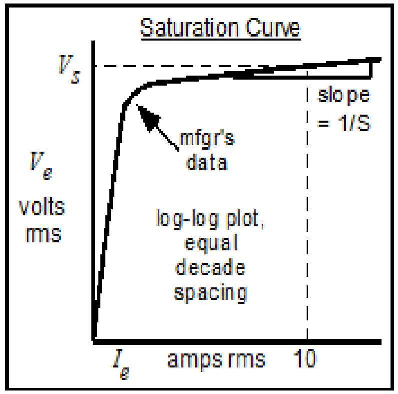
To determine the effect of saturation on a particular digital relay, one must have "models" for the blocks shown below:

Fig. 5: 400:5, C400, R=0.5, Offset = 0.75, 8000A

CT Saturation [5]

INPUT PARAMETERS: / **ENTER:**

Inverse of sat. curve slope =	S =	22	---
RMS voltage at 10A exc. current =	Vs =	400	volts rms
Turns ratio = n2/1=	N =	80	---
Winding resistance =	Rw =	0.300	ohms
Burden resistance =	Rb =	0.500	ohms
Burden reactance =	Xb =	0.500	ohms
System X/R ratio =	XoverR =	12.0	---
Per unit offset in primary current =	Off =	0.75	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.75	---
Symmetrical primary fault current =	Ip =	8,000	amps rms



CALCULATED:

Rt =	Total burden resistance = Rw + Rb =	0.800	ohms
pf =	Total burden power factor =	0.848	---
Zb =	Total burden impedance =	0.943	ohms
Tau1 =	System time constant =	0.032	seconds
Lamsat =	Peak flux-linkages corresponding to Vs	1.501	Wb-turns
ω =	Radian freq =	376.99	rad/s
RP =	Rms-to-peak ratio =	0.34584	
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	3.83E-03	---
dt =	Time step =	0.000083	seconds
Lb =	Burden inductance =	0.00133	henries

Thick lines: Ideal (blue) and **actual (black)** secondary current in amps vs time in seconds.
Thin lines: Ideal (blue) and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.

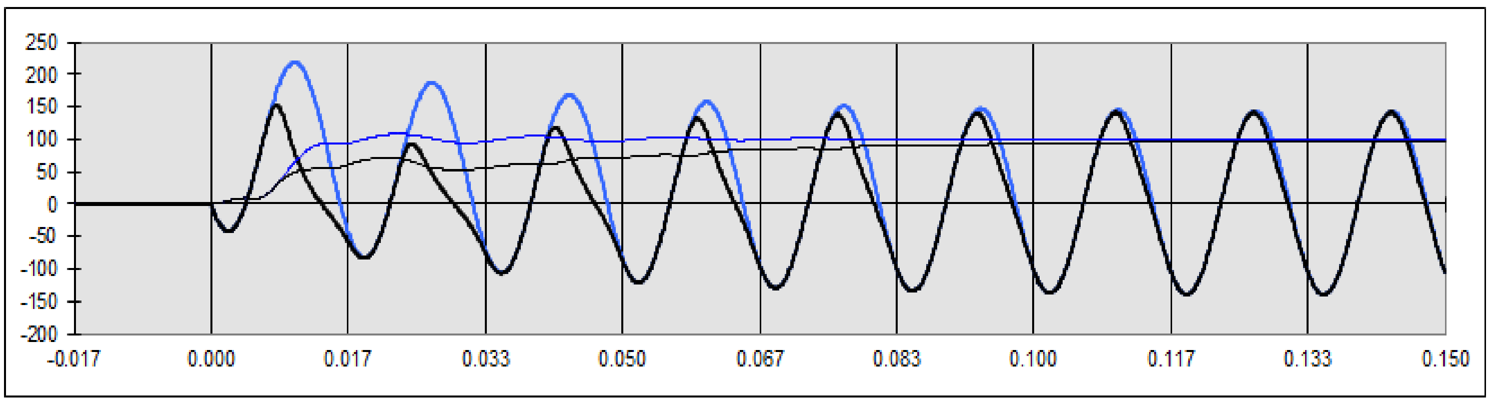
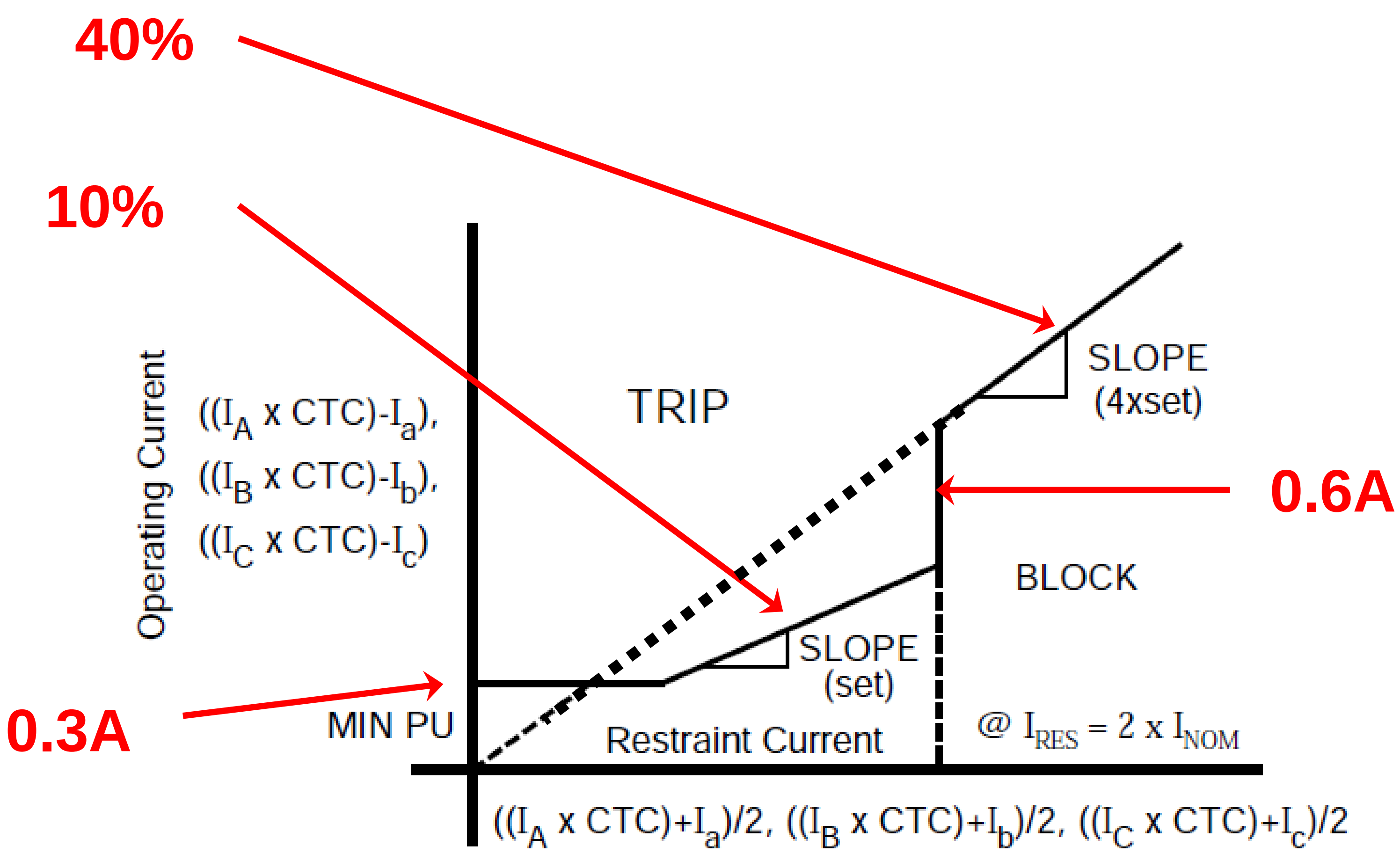


Fig. 6: 400:5, C400, R=0.75, Offset = 0.75, 8000A

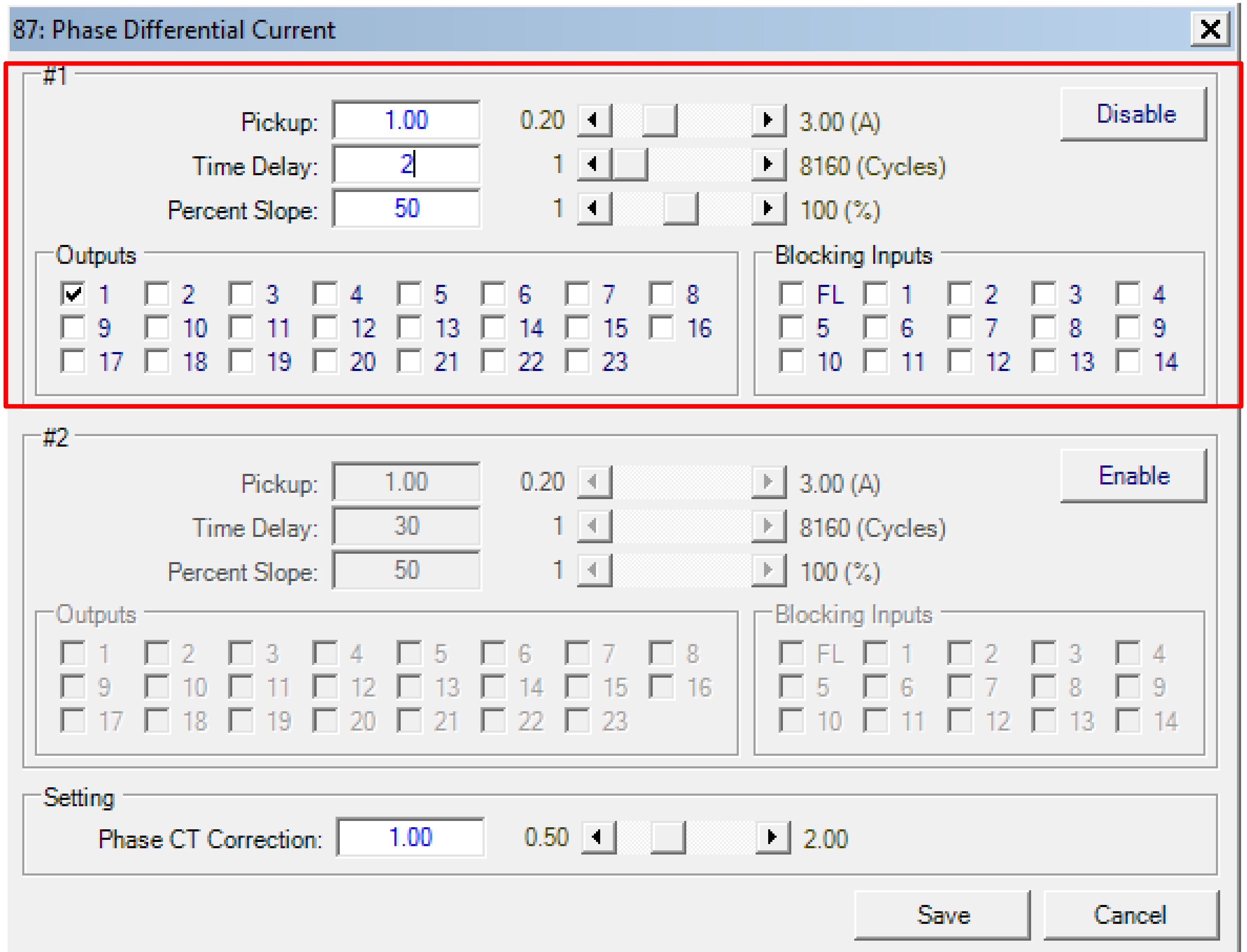
87 Characteristic

I_{RSM}/I_{FUND} > Pickup



CTC = CT Correction Ratio = Line CTR/Neutral CTR
Used when Line and Neutral CTs have different ratios

87 Setting Screen



Stator Phase Faults – Other Elements

- 21 – Phase Distance (in-zone back up)
  - Use Z1 with reach set 80% of impedance of GSU
  - Provide high speed back up to 87G

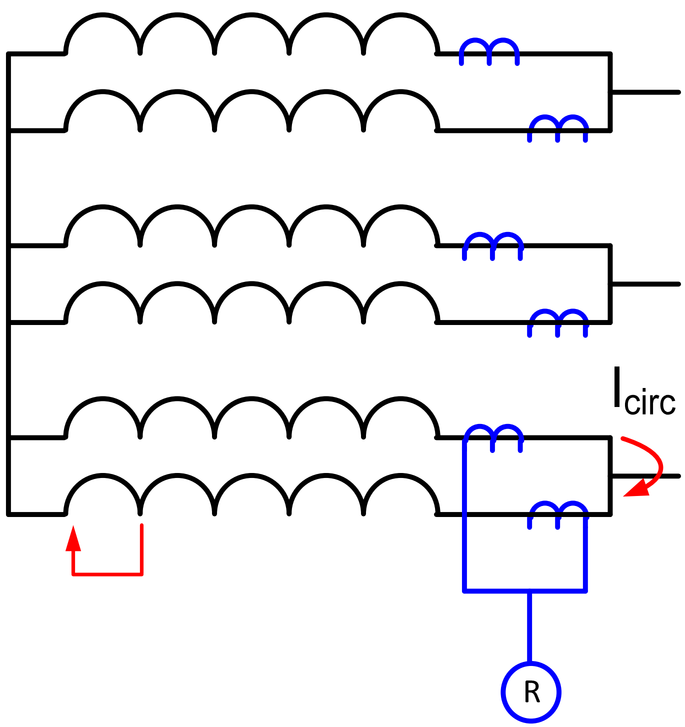
- 50/50N/51N – Phase and Ground Overcurrent (back up)
  - Should operate from 8 Hz to 80 Hz
  - Provides protection for generator from phase and ground faults during startup and shutdown
  - Provides backup for 87 function and extends the frequency range down to 8 Hz.

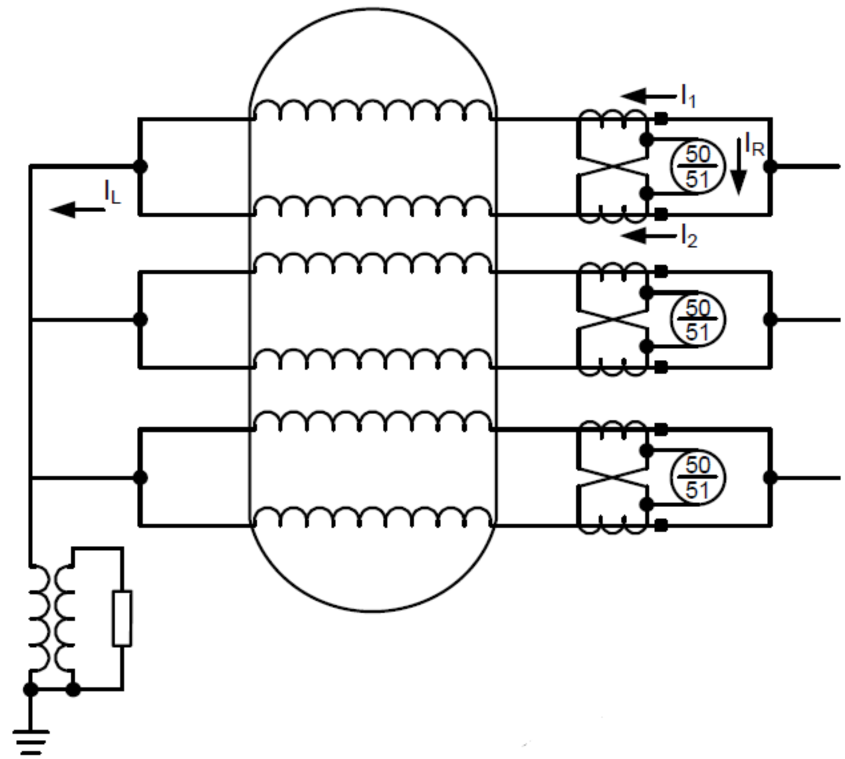
- 51V – Voltage Restrained/Controlled Overcurrent (back up)
  - Accommodate current decrement
  - Provide back up to 87G
  - May be applied in parallel with the 21 to initiate waveform capture and <u>not</u> trip

Turn-to-Turn Fault Protection

- Most low-speed hydroelectric generators in North America are constructed with two or more parallel circuits per phase.
- Under normal conditions, the currents in the two parallel circuits are equal.
- When a turn fault occurs, the difference in the voltages that develop in the two circuits causes a current to circulate.
- Stator differential protection does not detect turn-to-turn faults
- Current can be 6 to 7 times nominal and can damage stator
- Use turn-to-turn protection schemes to detect and avoid damage

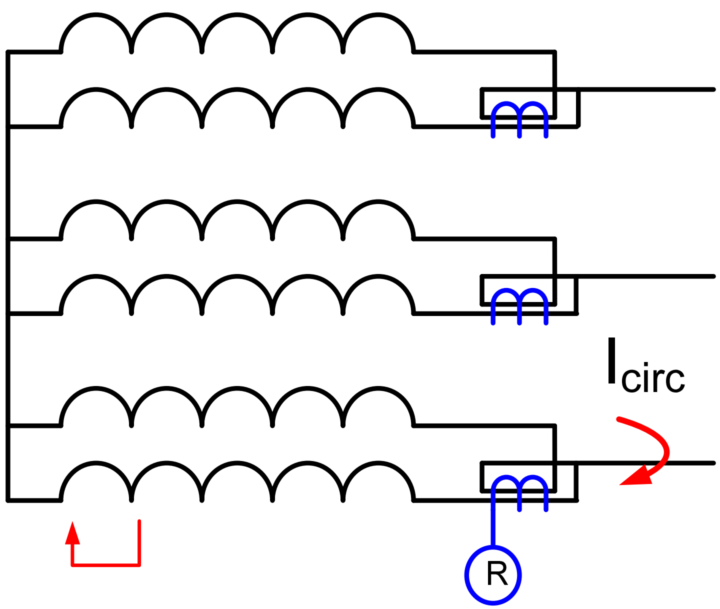
Split Phase Using Separate CTs

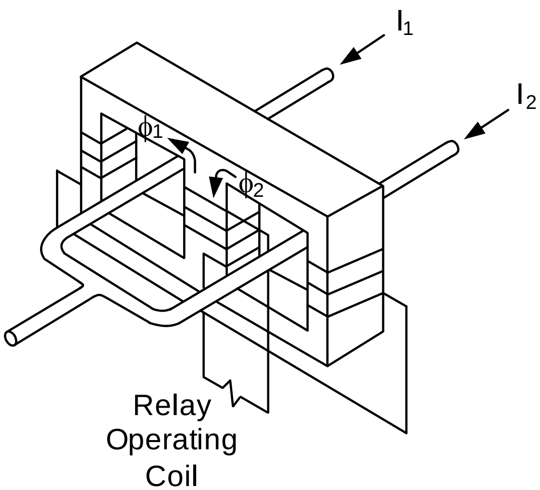


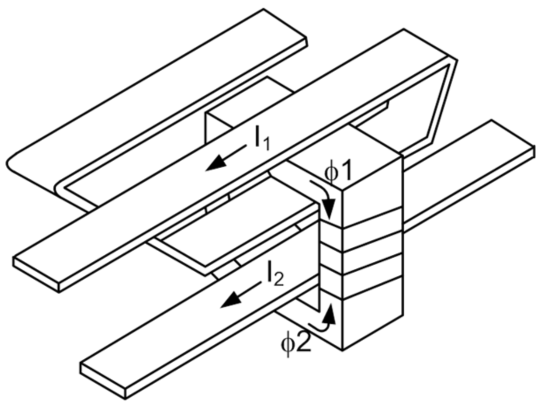


Separate CTs may have slightly different replication characteristics, therefore my require desensitizing setting

Split Phase Using Core Balance CTs







Balance CTs allow greater sensitivity

46: Negative Sequence Current

- **Typically caused by open circuits in system**

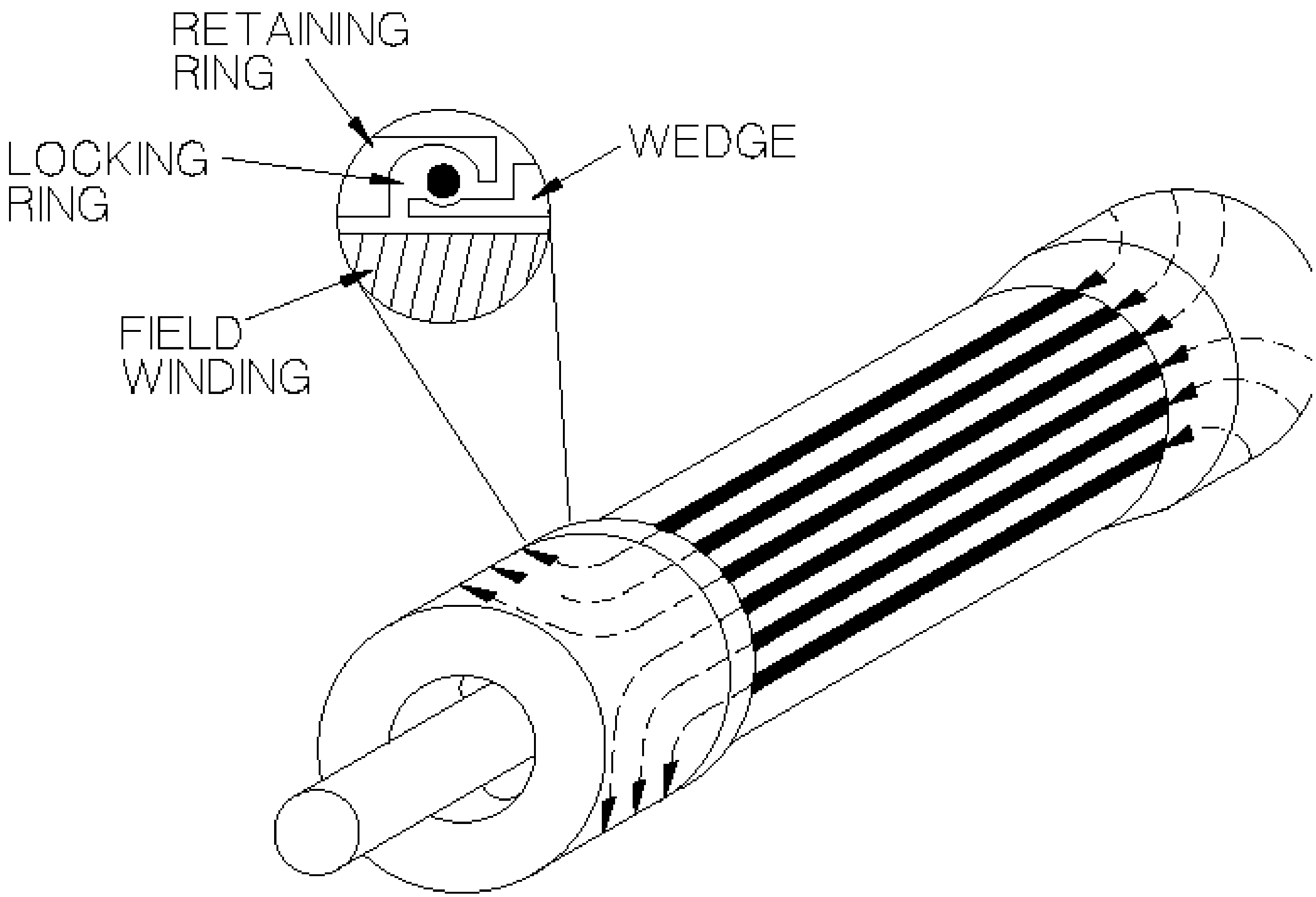
  -Downed conductors

  -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



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%

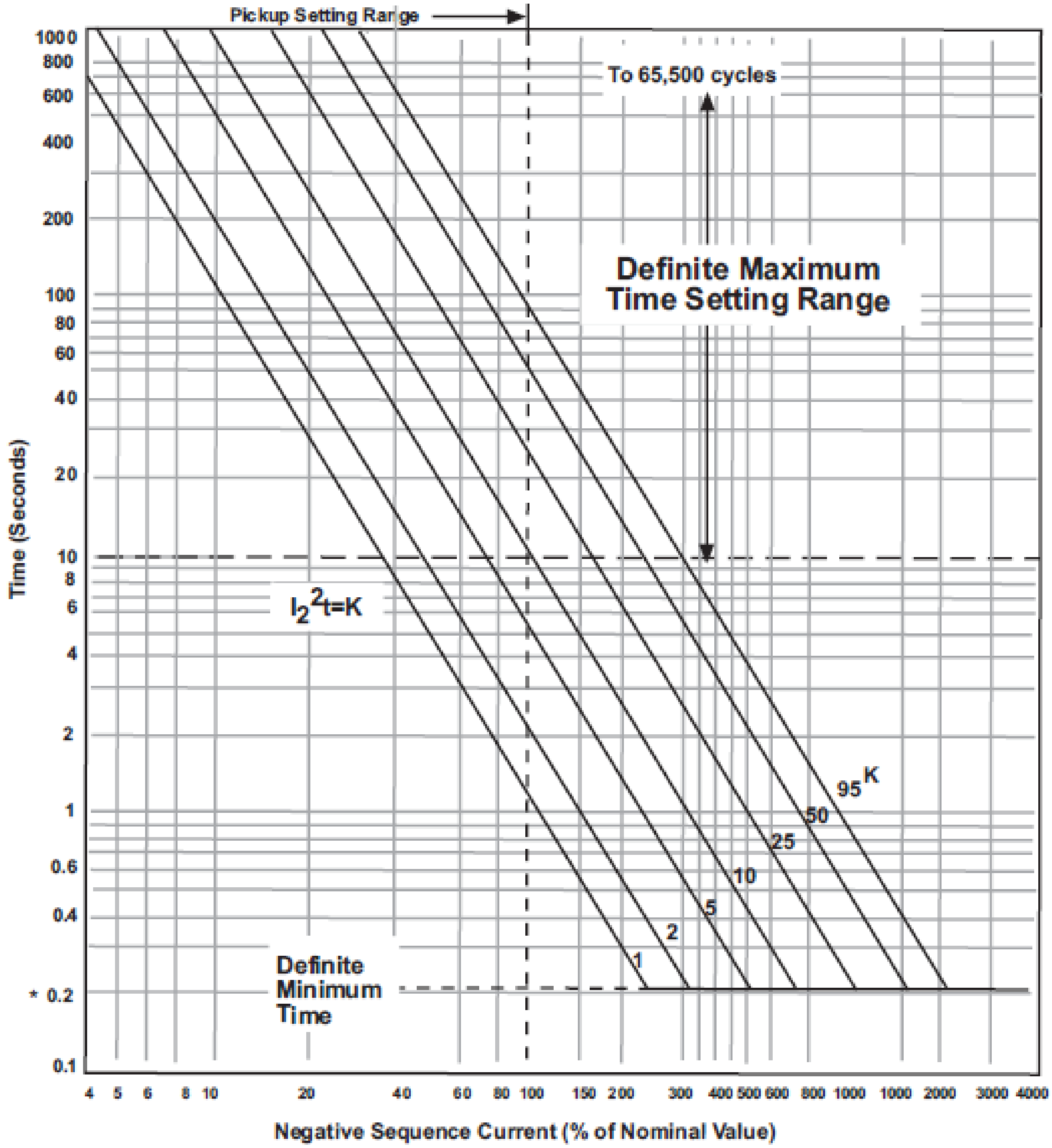
Negative Sequence Current: Constant Withstand Generator Limits

- **Nameplate**
  - Negative Sequence Current (I2) Constant Withstand Rating
  - "K" Factor

$$I_2^2 T = K$$

where K = Manufacturer Factor (the larger the generator the smaller the K value)

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

Overexcitation (24)

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

Overexcitation (24)

Protects machine against excessive V/Hz (overfluxing)

<u>Legacy Protection</u>

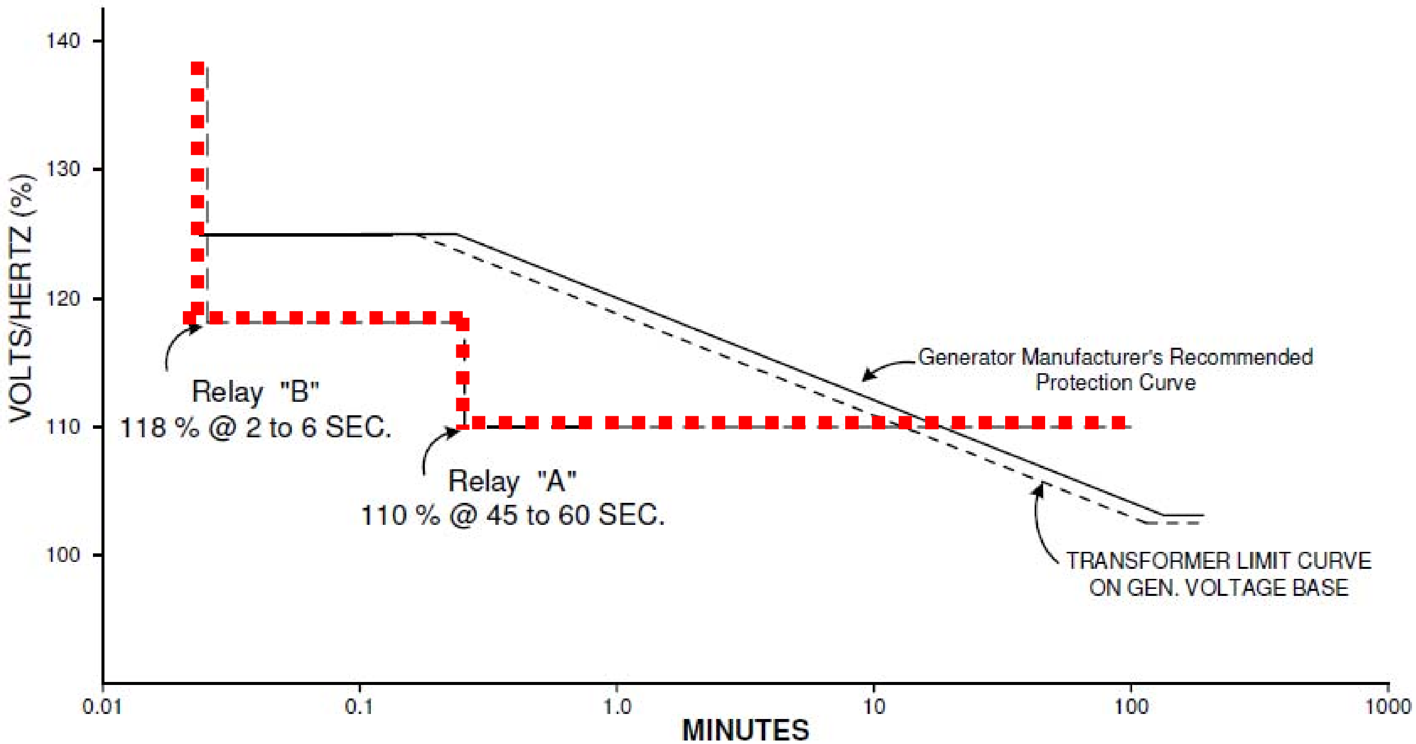
- Typically “stair-step” two definite time setpoints
- Two definite time elements
  - One may be used to alarm
  - One may be used for high set fast trip

- Either overprotects or underprotects

- Instantaneous Reset

Legacy Approach

Dual-Level, Definite-Time V/Hz Protection



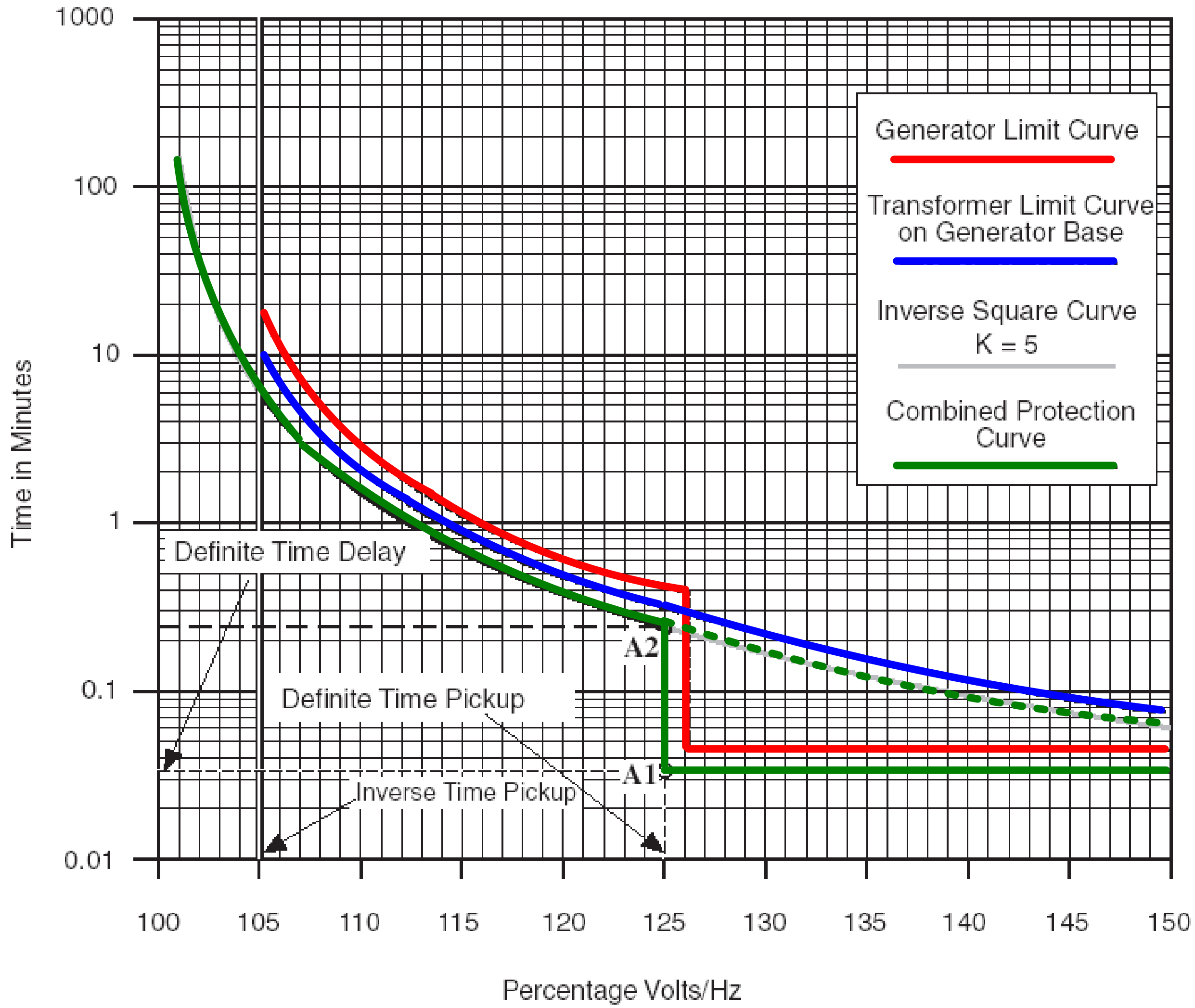
Attempts to approximate curves with stairsteps

Overexcitation (24)

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

Overexcitation (24)



Example plot using definite time and inverse curve

Overexcitation (24)

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.

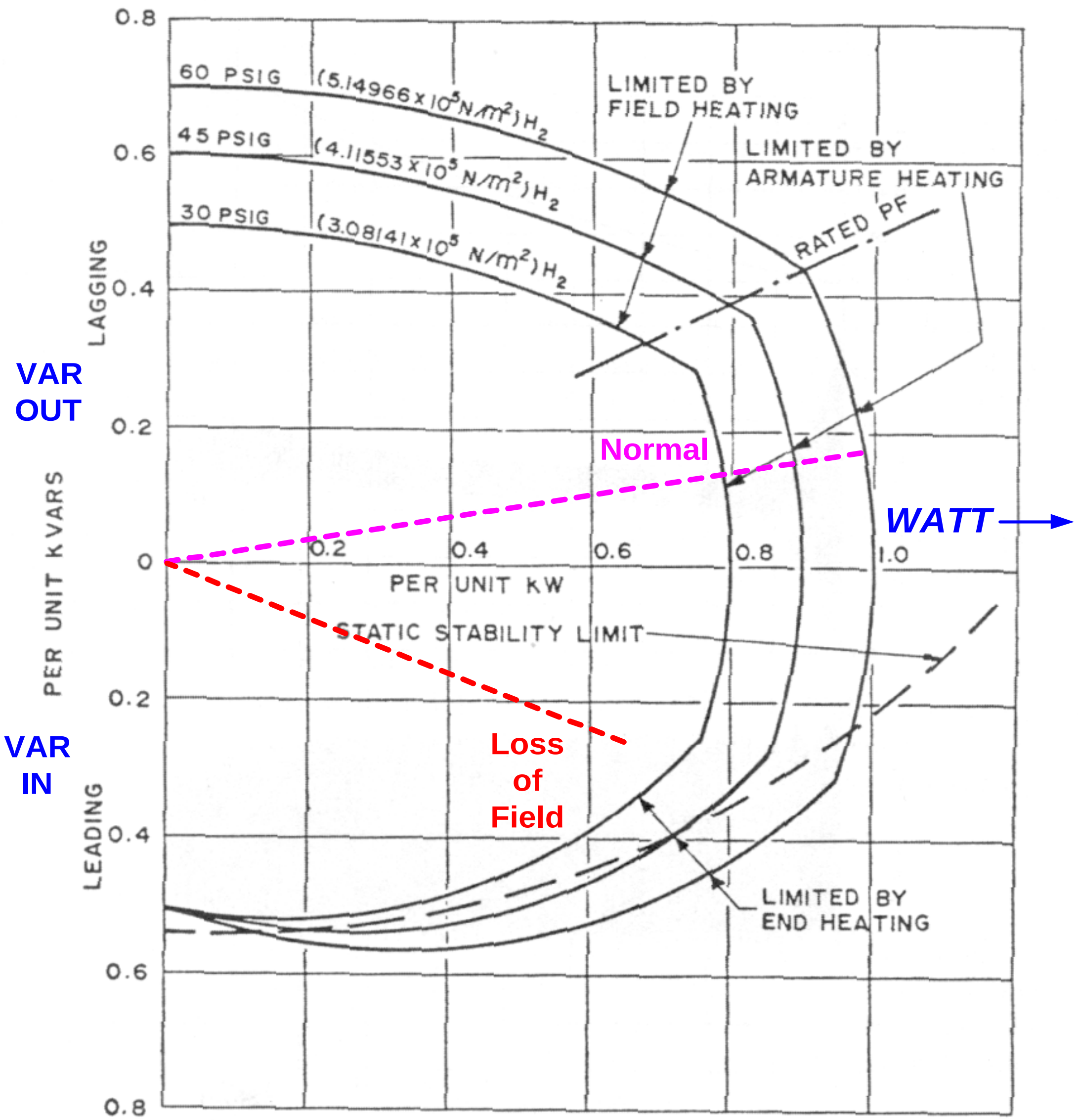
Since the V/Hz during this condition is low, the 24 function will not operate, and the 59 function will provide proper protection from overvoltage.

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 Protection

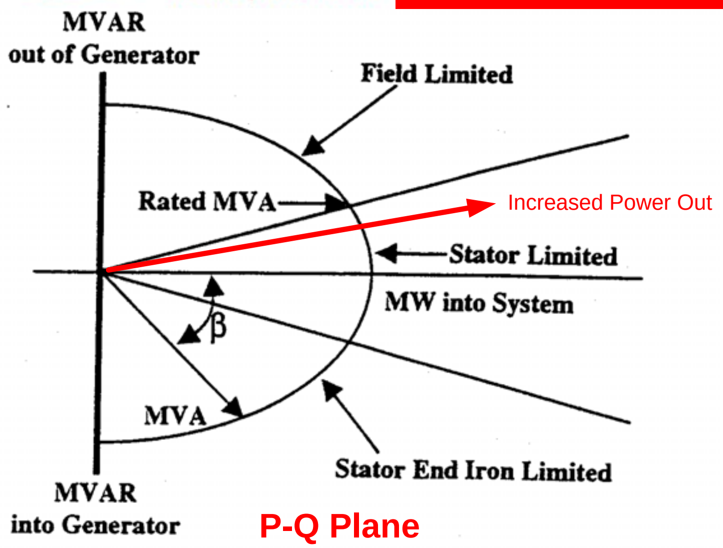


TYPICAL GENERATOR CAPABILITY CURVE

Generator capability curve viewed on the P-Q plane.

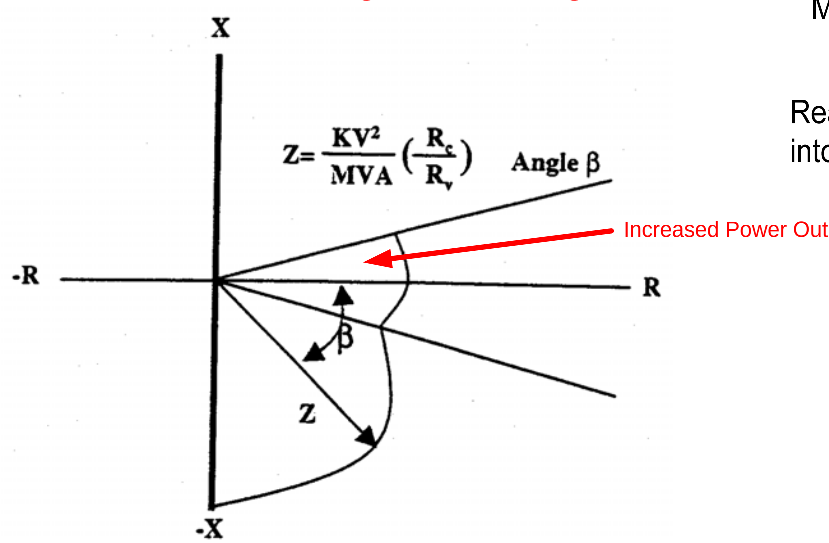
This info must be converted to the R-X plane.

Generator Protection

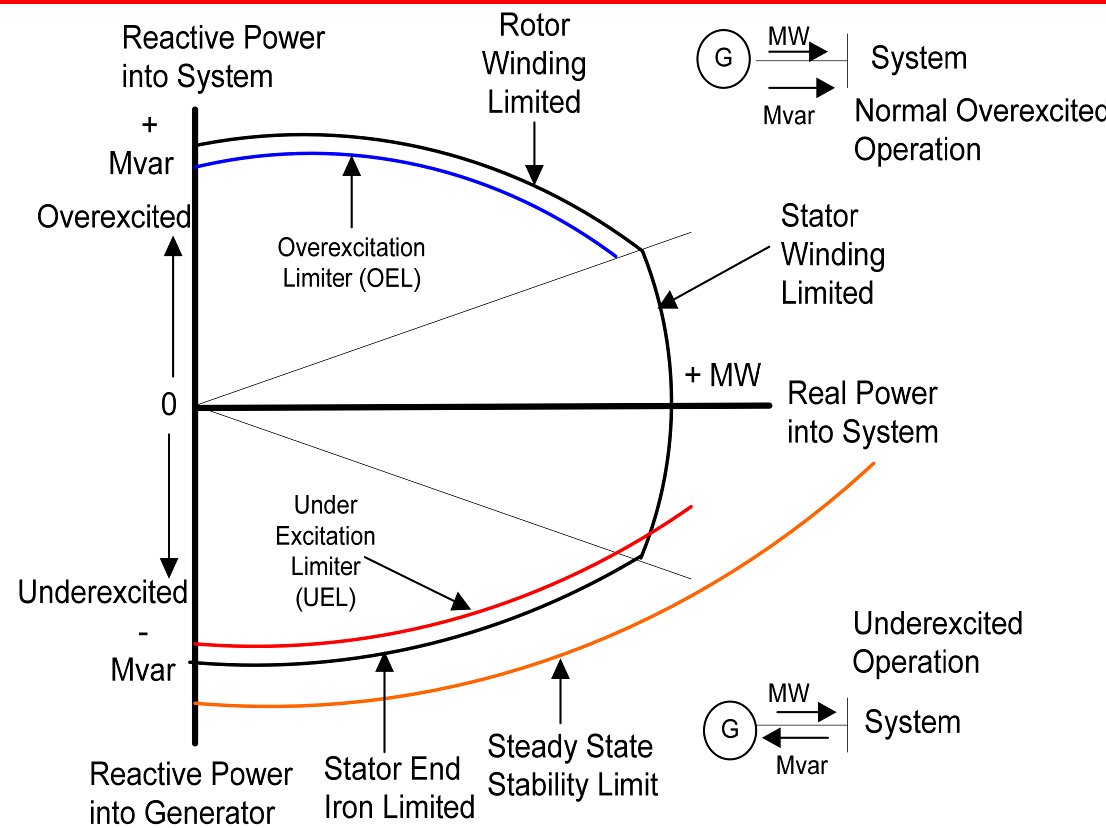


P-Q Plane

TRANSFORMATION FROM MW-MVAR TO R-X PLOT



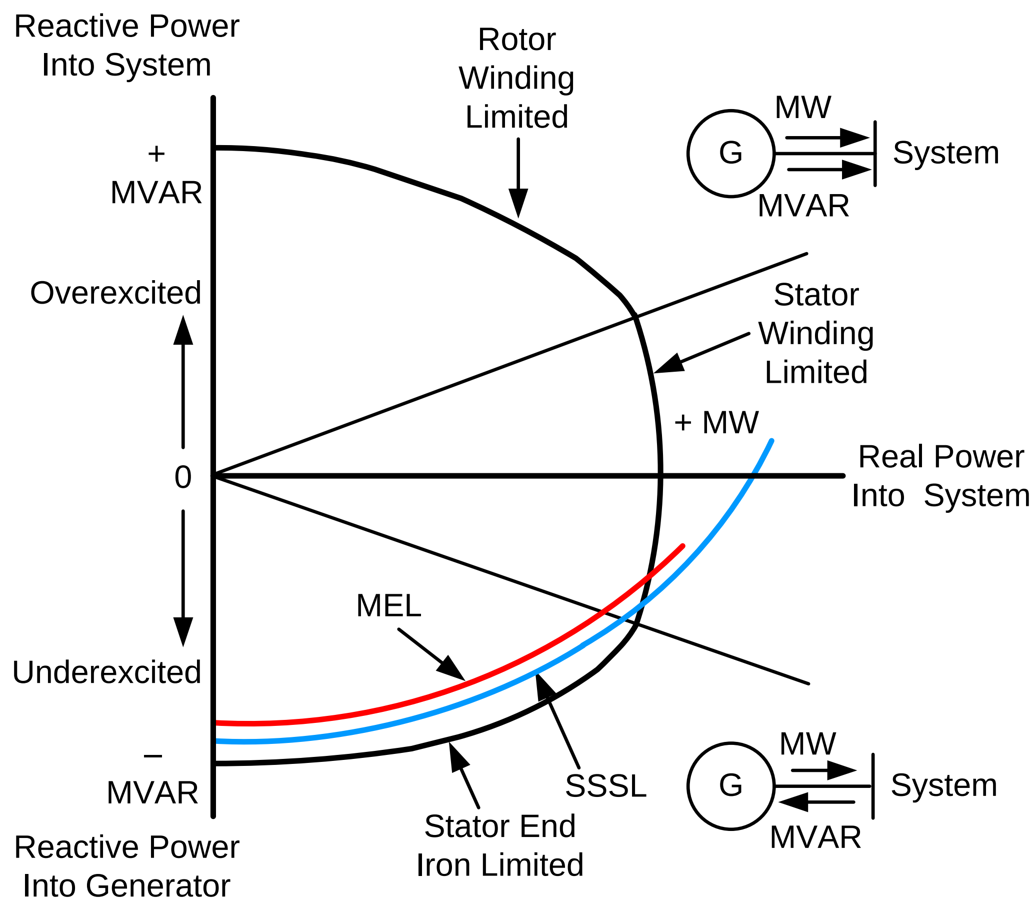
R-X Plane



TYPICAL GENERATOR CAPABILITY CURVE Excitation Limiters and Steady State Stability

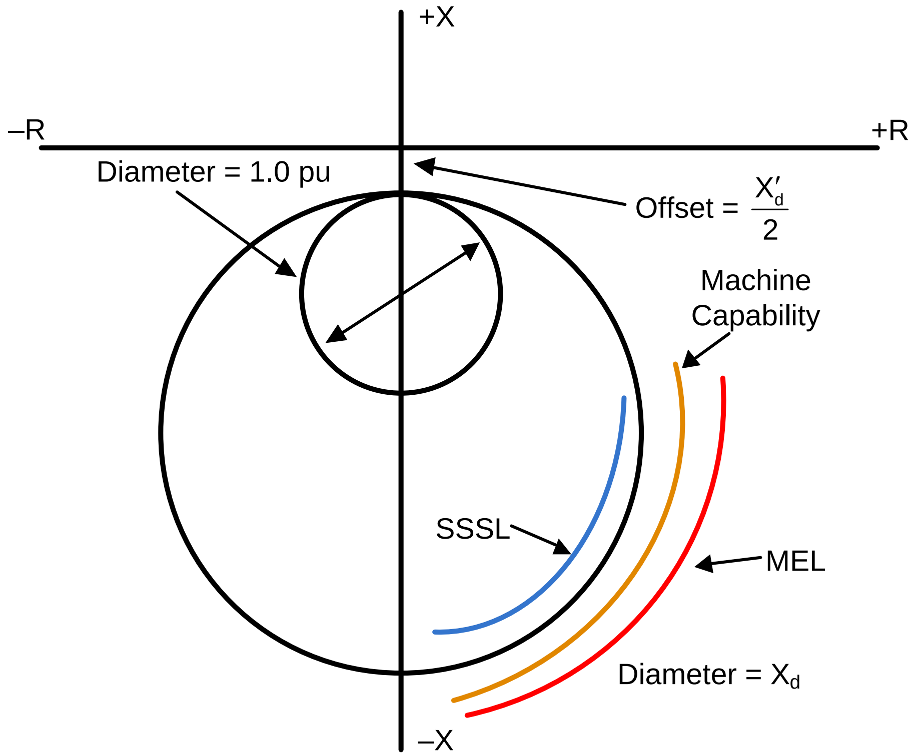
Generator Capability Curve

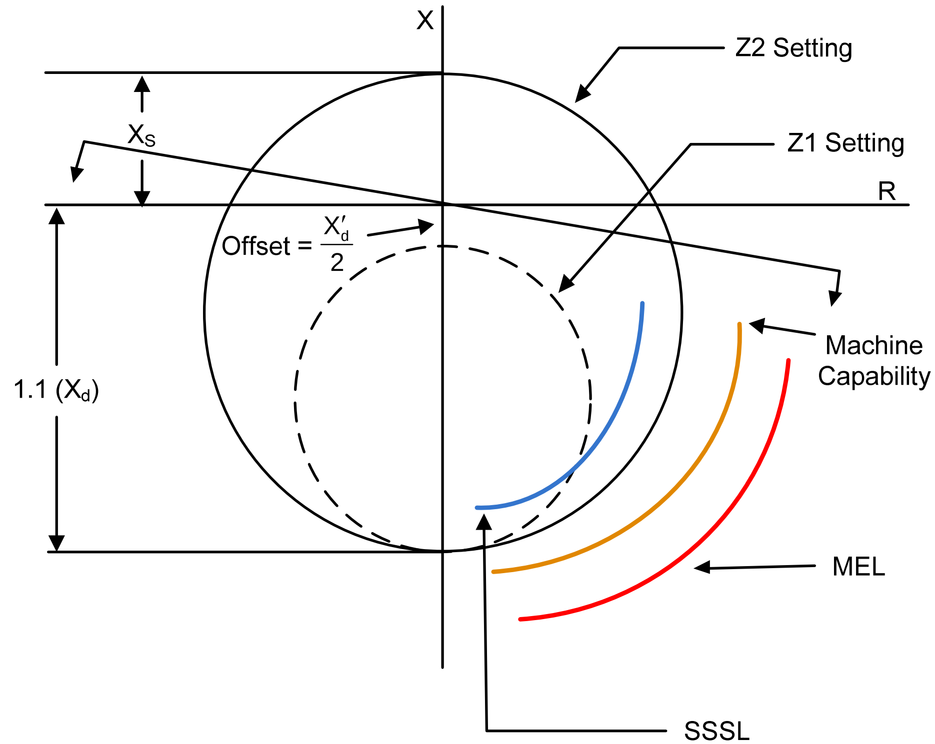
- Limiting factors are rotor and stator thermal limits
- Underexcited limiting factor is stator end iron heat
- Excitation control setting control is coordinated with steady-state stability limit (SSSL)
- Minimum excitation limiter (MEL) prevents exciter from reducing the field below SSSL



Loss of Field

GE and Westinghouse Methods



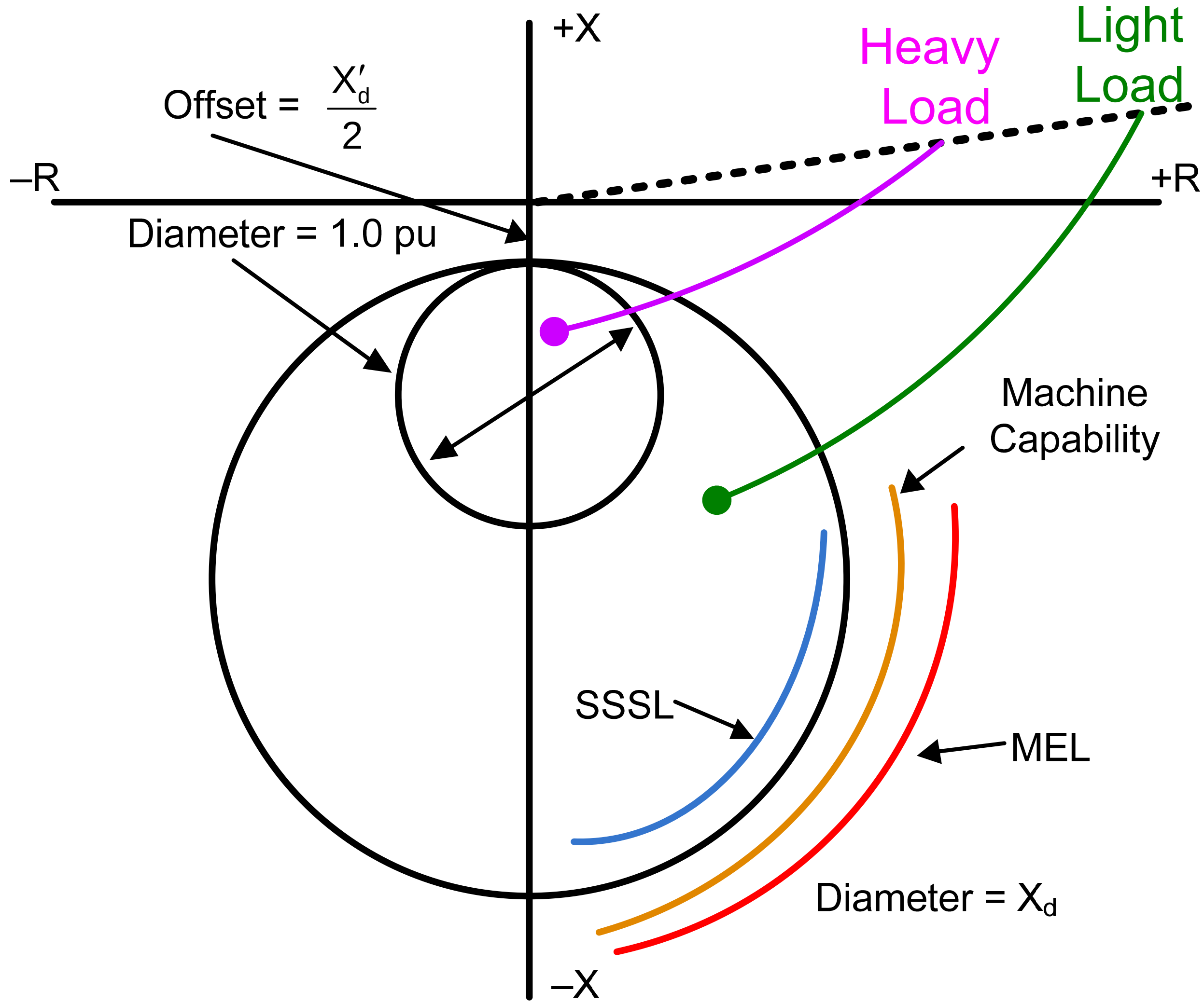


Two Zone Offset Mho
GE
CEH

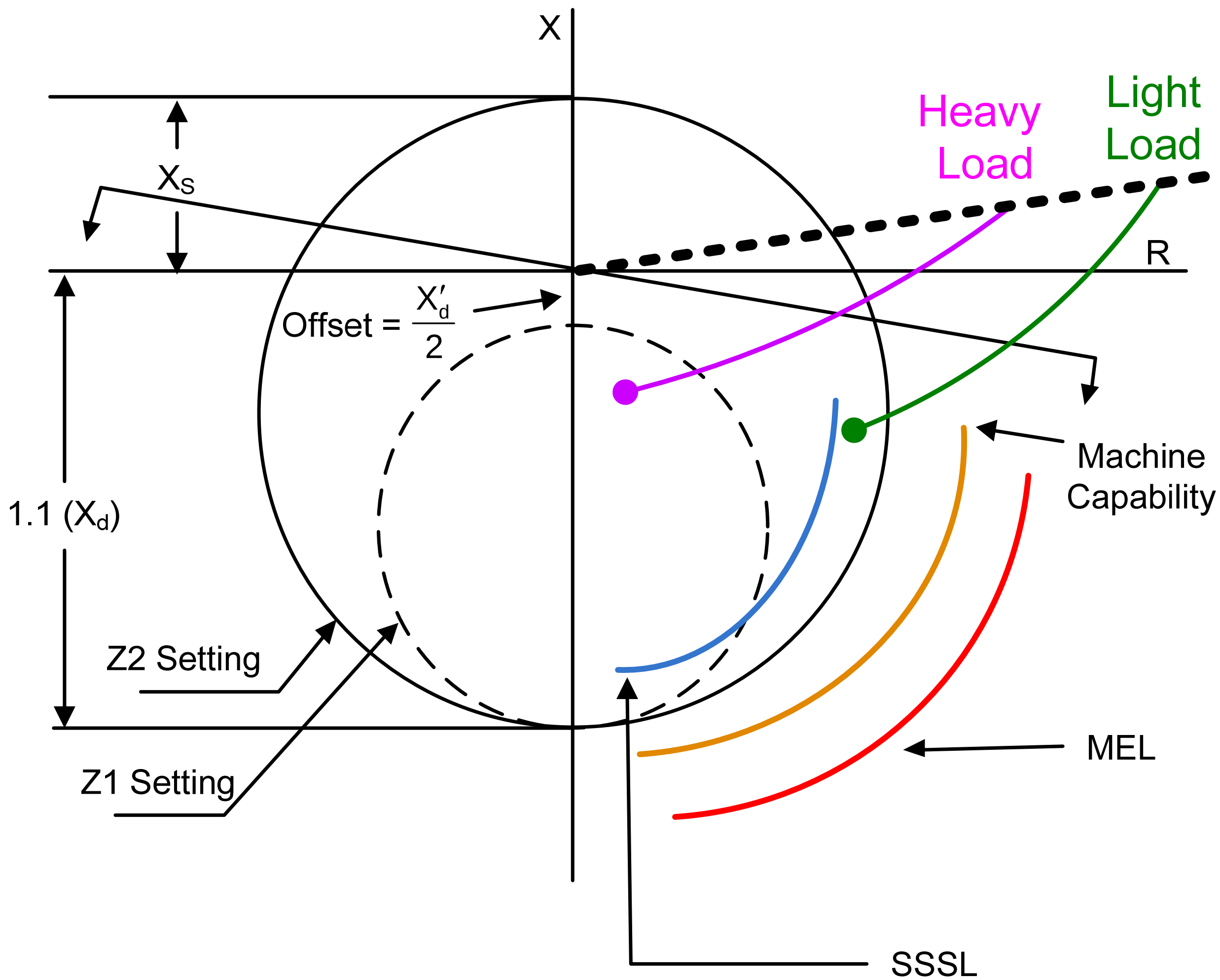
Impedance w/Directional Unit
Westinghouse
KLF

Loss of Field

Two Zone Offset Mho

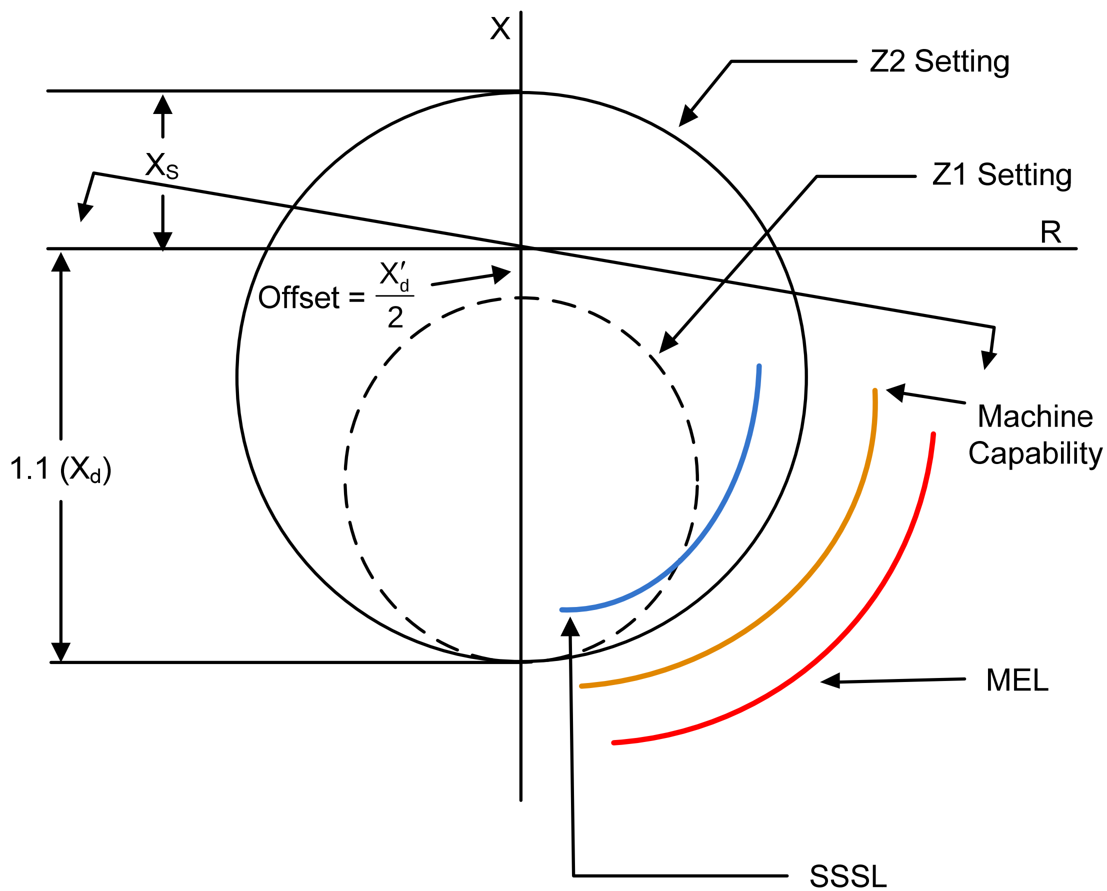


Loss of Field
Impedance w/Direction Unit



40: Multiple Mho Implementations

Better Fit Reactive Capability Curves



Two Zone Offset Mho Impedance w/Directional Unit

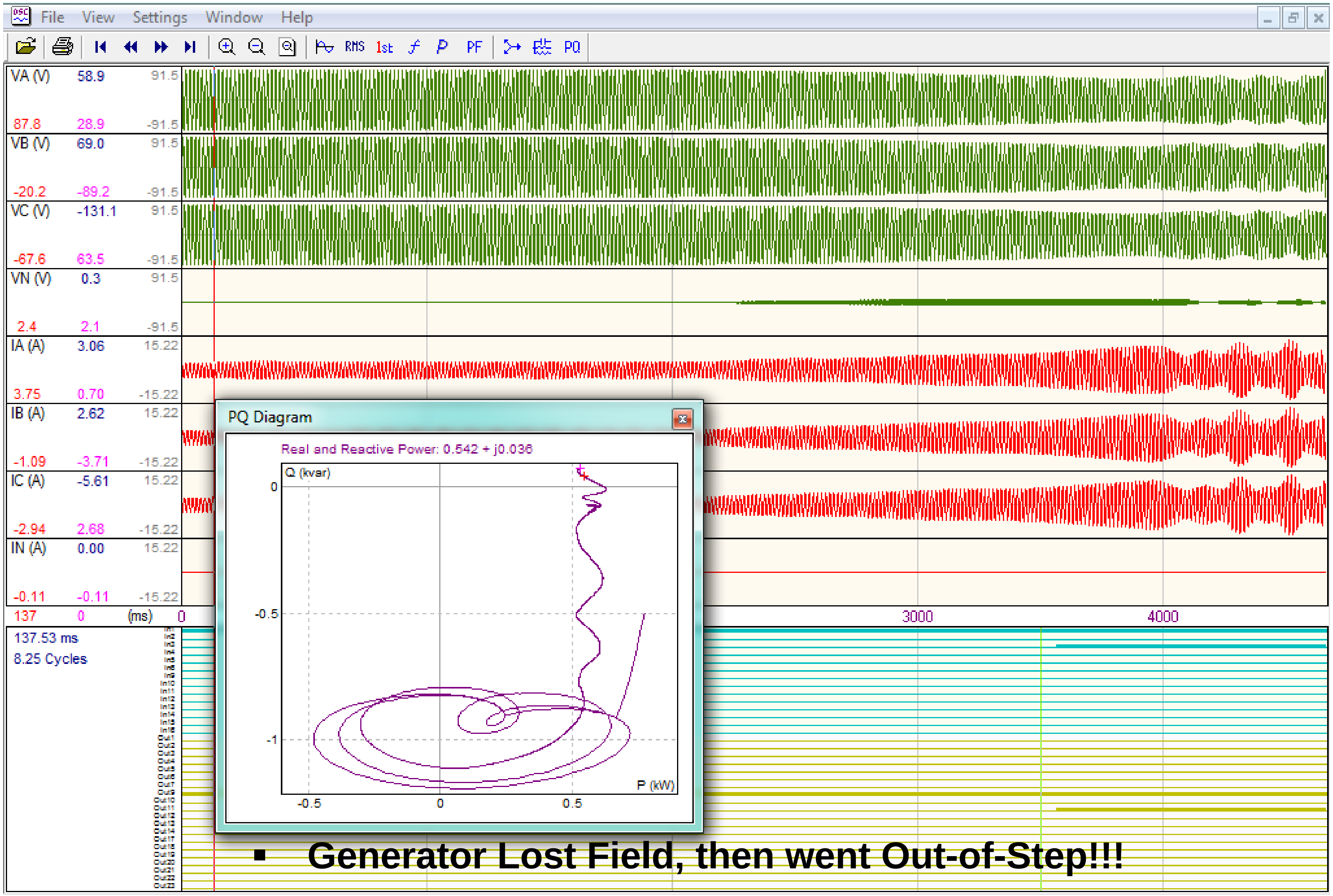
Better ability to match capability curves after conversion from P-Q to R-X plane

40: Loss of Field

- **Positive sequence quantities used to maintain security and accuracy over a wide frequency range.**
- **Must work properly from 50 to 70 Hz (60 Hz systems) Required to operate correctly (and not misoperate) with wide frequency variations possible during power swing conditions.**
- **May employ best of both methods to optimize coordination.**
  - Provide maximum coordination between machine limits, limiters and protection
  - Offset mho for Z1. Fast time for true Loss of Field event.
  - Impedance with directional unit and slower time for Z2. Better match of machine capability curve. Also able to ride through stable swing.
  - May employ voltage supervision for accelerated tripping of Z2 (slower zone) in cases of voltage collapse where machine is part of the problem, importing VArs.

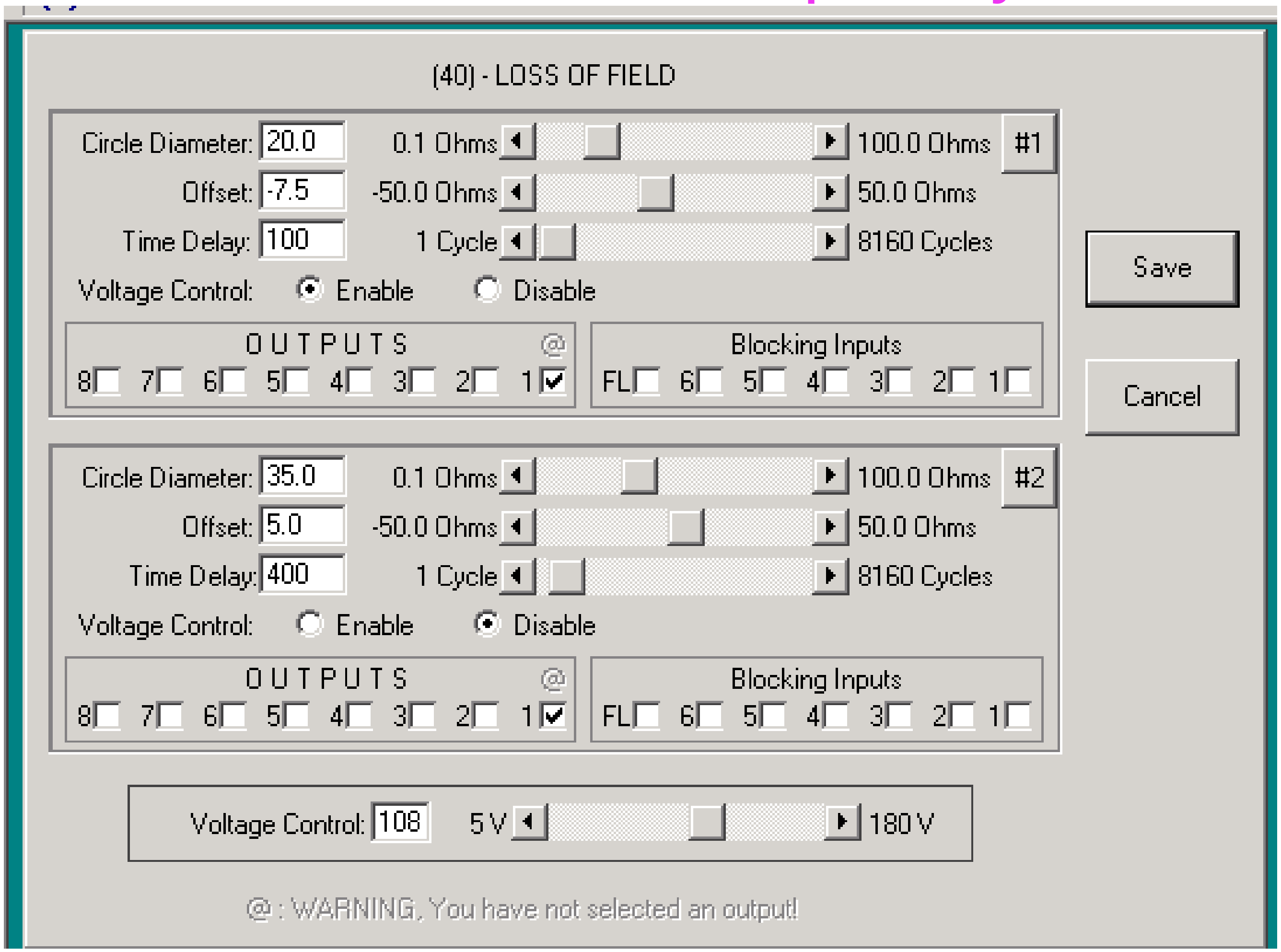
Generator Protection

Loss of Field Event



- **Generator Lost Field, then went Out-of-Step!!!**

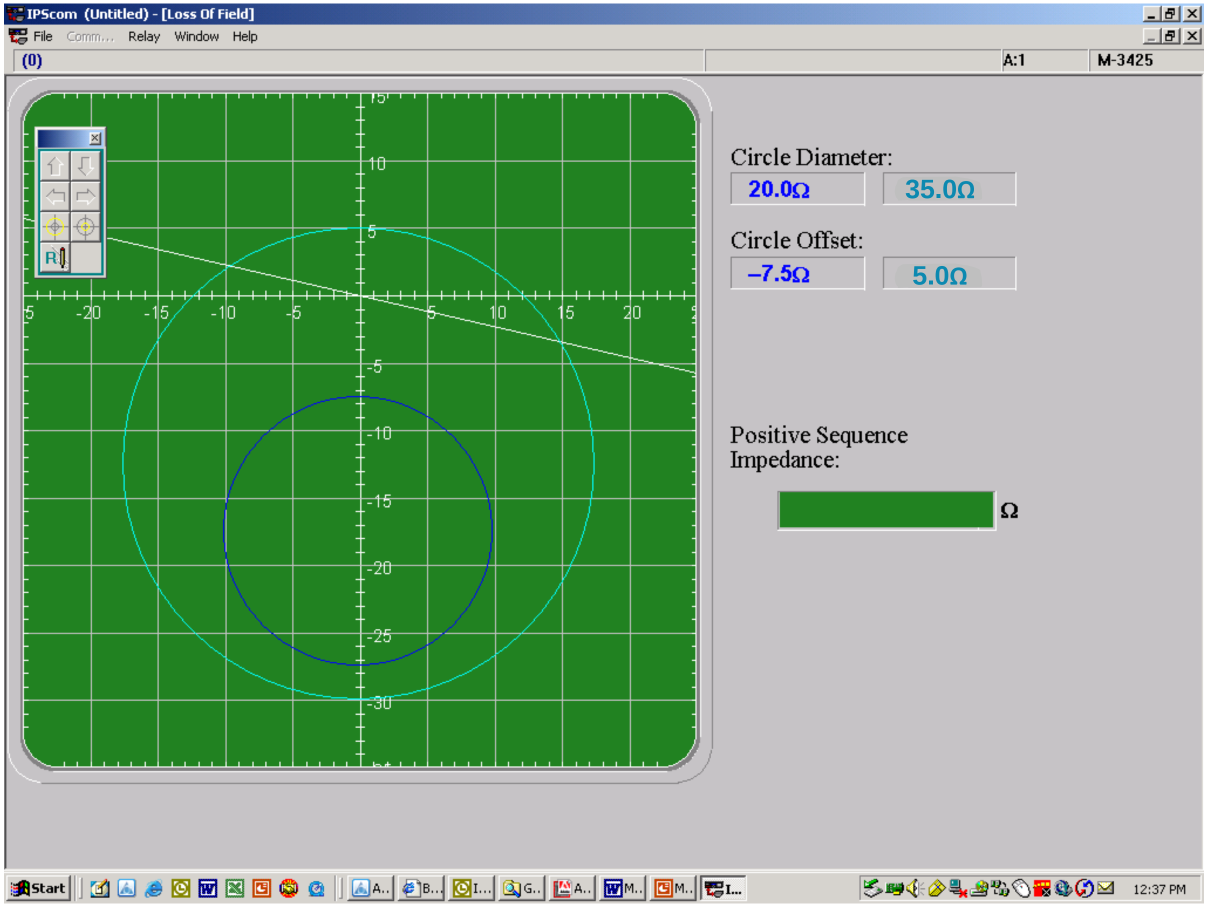
40: Multiple Loss-of-Field Mho Implementations to Better Fit Reactive Capability Curves



Two Zone Offset Mho Impedance w/Directional Unit

Better ability to match capability curves after conversion from P-Q to R-X plane

40: Multiple Loss-of-Field Mho Implementations to Better Fit Reactive Capability Curves



Two Zone Offset Mho Impedance w/Directional Unit

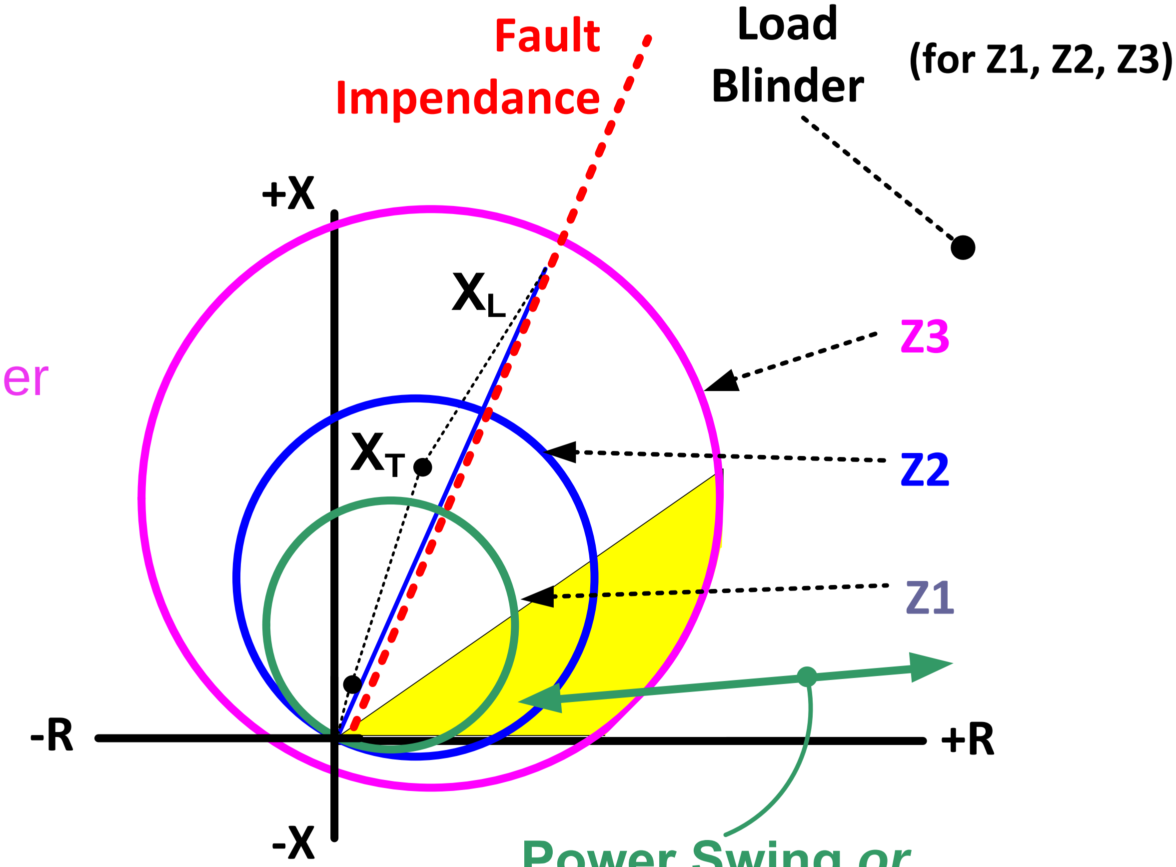
Better ability to match capability curves after conversion from P-Q to R-X plane

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

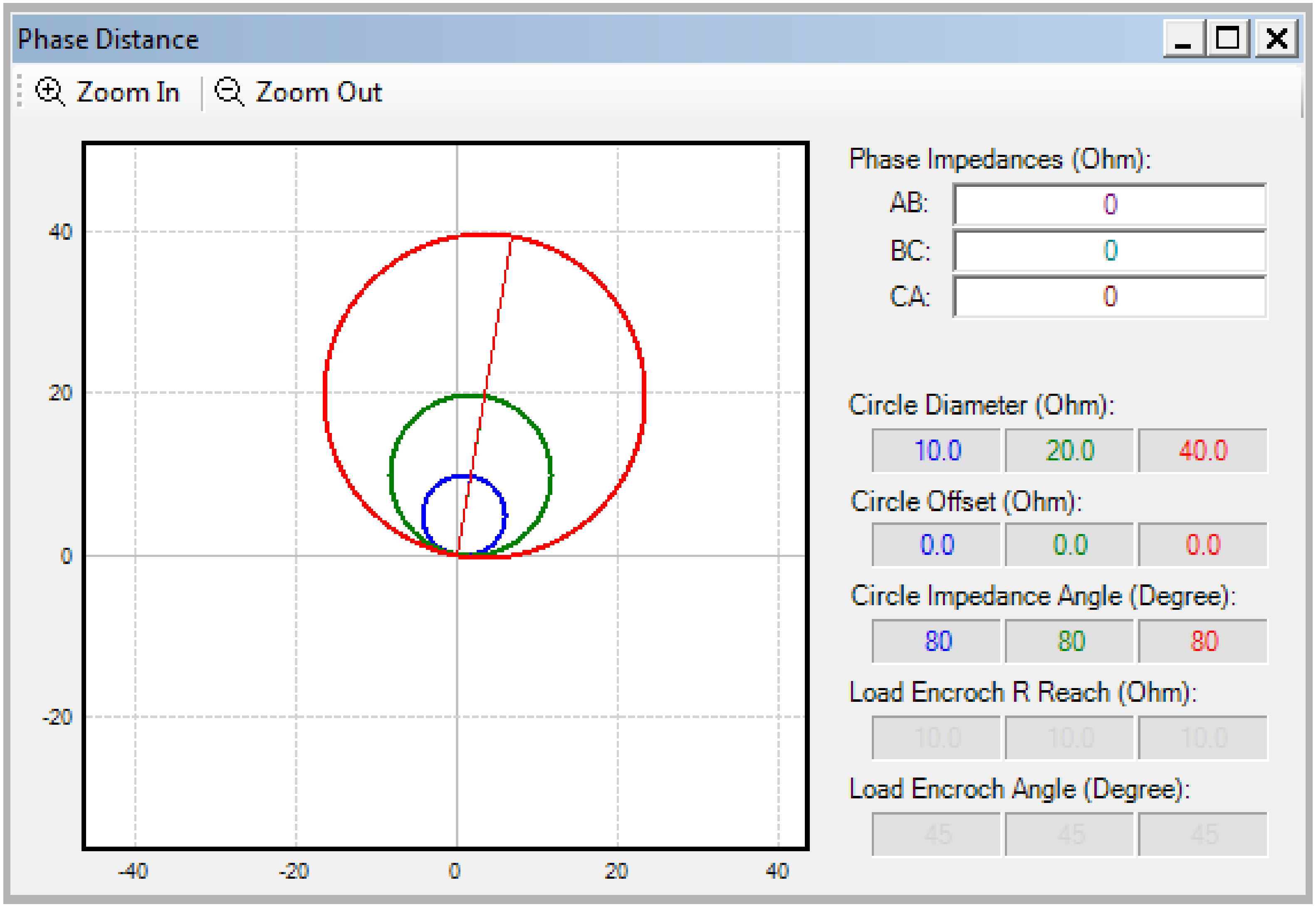
With Load Encroachment Blinder fro Z1, Z2, Z3



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

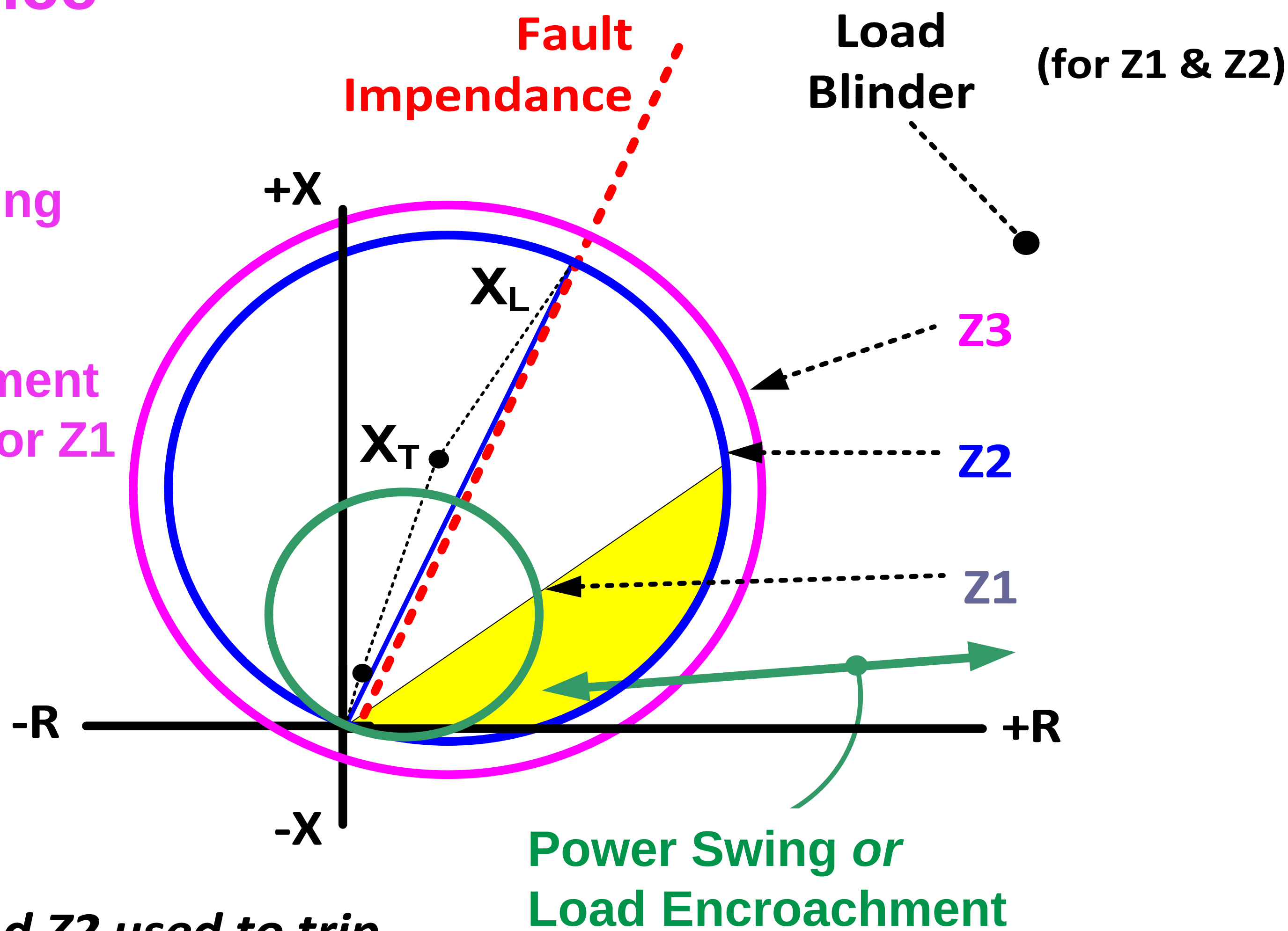
3-Zone 21 Function



21: Distance Element

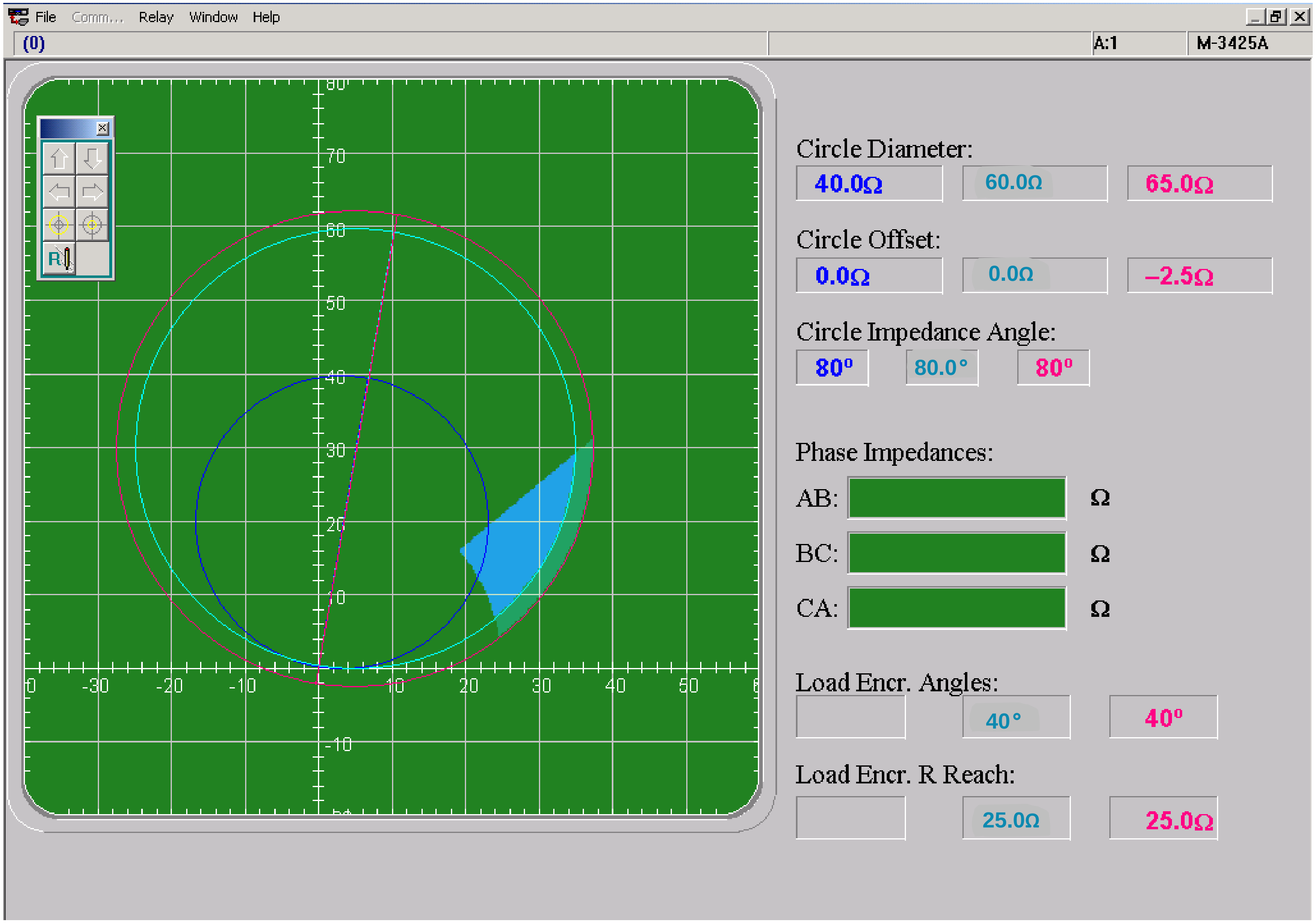
With:

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

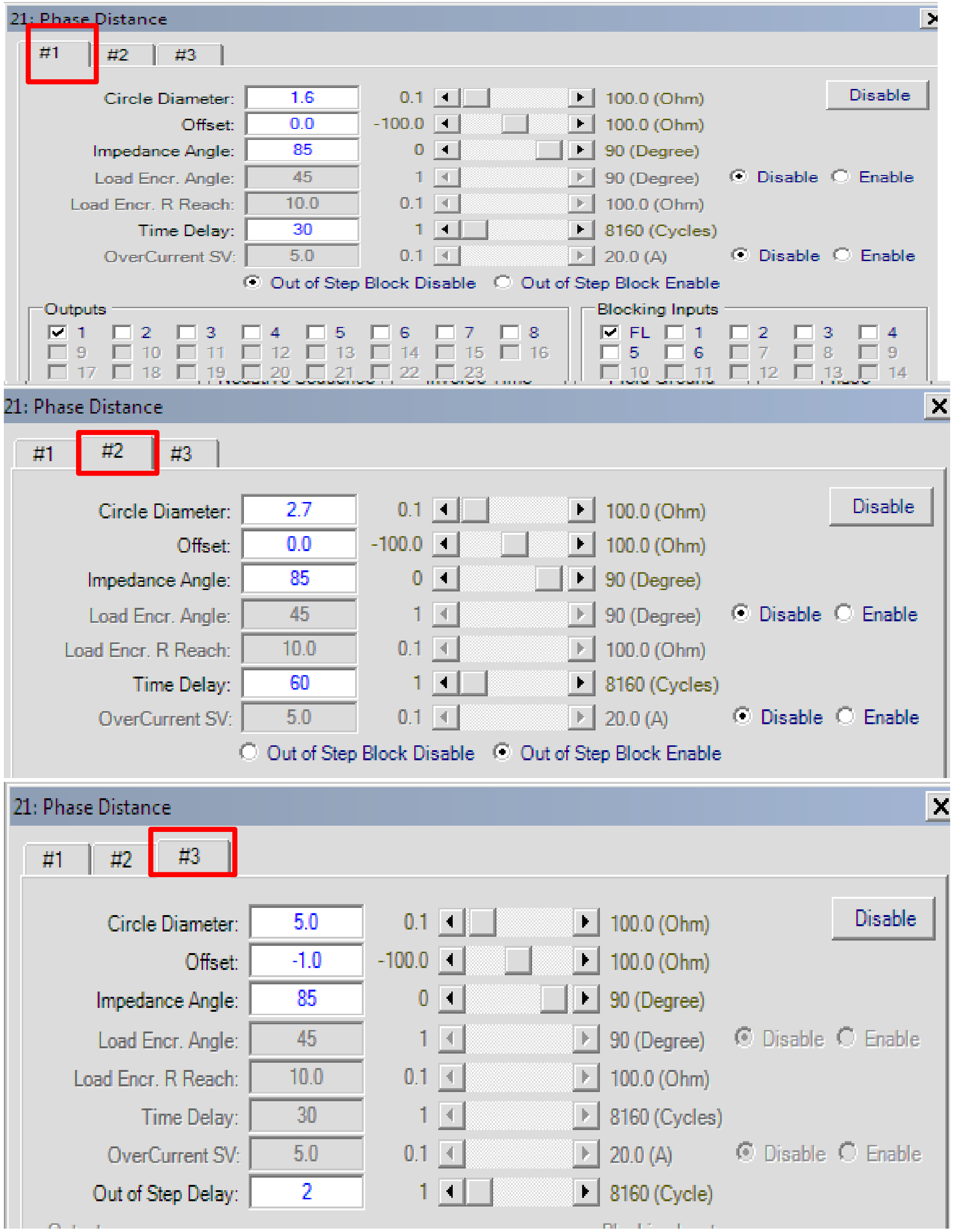


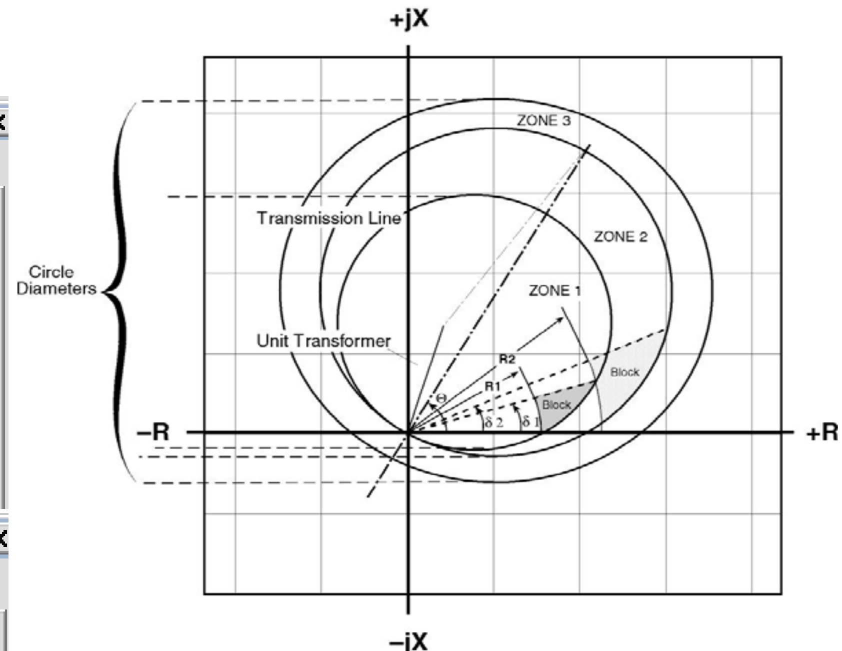
Z1 and Z2 used to trip
Z1 set to 80% of GSU, Z2 set to overreach remote bus
Z3 used for power swing blocking; Z3 blocks Z2

3-Zone 21 Function with OSB/Load Encroachment



21 Settings


21: Phase Distance
#1
#2
#3
Circle Diameter: 1.6 0.1 100.0 (Ohm)
Disable
Offset: 0.0 -100.0 100.0 (Ohm)
Impedance Angle: 85 0 90 (Degree)
Load Encr. Angle: 45 1 90 (Degree) Disable Enable
Load Encr. R Reach: 10.0 0.1 100.0 (Ohm)
Time Delay: 30 1 8160 (Cycles)
OverCurrent SV: 5.0 0.1 20.0 (A) Disable Enable
Out of Step Block Disable
Out of Step Block Enable
Outputs
Blocking Inputs
21: Phase Distance
#1
#2
#3
Circle Diameter: 2.7 0.1 100.0 (Ohm)
Disable
Offset: 0.0 -100.0 100.0 (Ohm)
Impedance Angle: 85 0 90 (Degree)
Load Encr. Angle: 45 1 90 (Degree) Disable Enable
Load Encr. R Reach: 10.0 0.1 100.0 (Ohm)
Time Delay: 60 1 8160 (Cycles)
OverCurrent SV: 5.0 0.1 20.0 (A) Disable Enable
Out of Step Block Disable
Out of Step Block Enable
21: Phase Distance
#1
#2
#3
Circle Diameter: 5.0 0.1 100.0 (Ohm)
Disable
Offset: -1.0 -100.0 100.0 (Ohm)
Impedance Angle: 85 0 90 (Degree)
Load Encr. Angle: 45 1 90 (Degree) Disable Enable
Load Encr. R Reach: 10.0 0.1 100.0 (Ohm)
Time Delay: 30 1 8160 (Cycles)
OverCurrent SV: 5.0 0.1 20.0 (A) Disable Enable
Out of Step Delay: 2 1 8160 (Cycle)


+jX
ZONE 3
Transmission Line
ZONE 2
Circle Diameters
ZONE 1
Unit Transformer
R2
R1
Block
Block
–R
+R
–jX

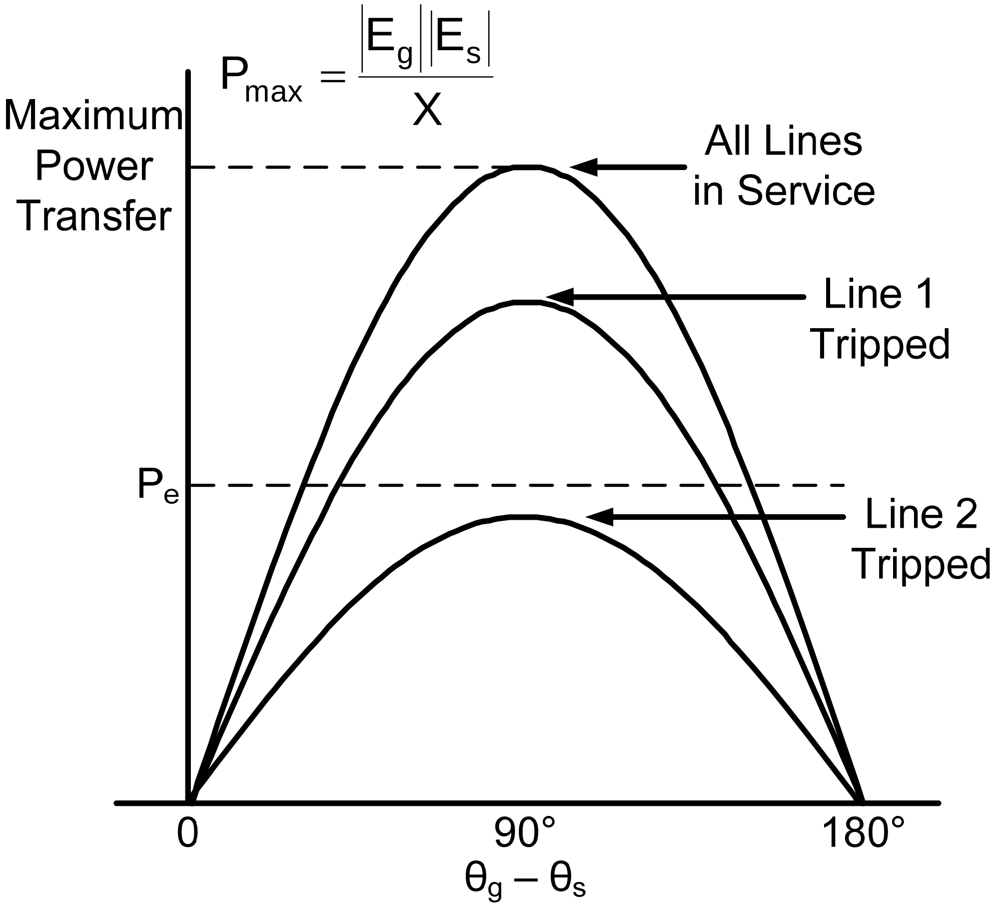
Generator Out-of-Step Protection (78)

- 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

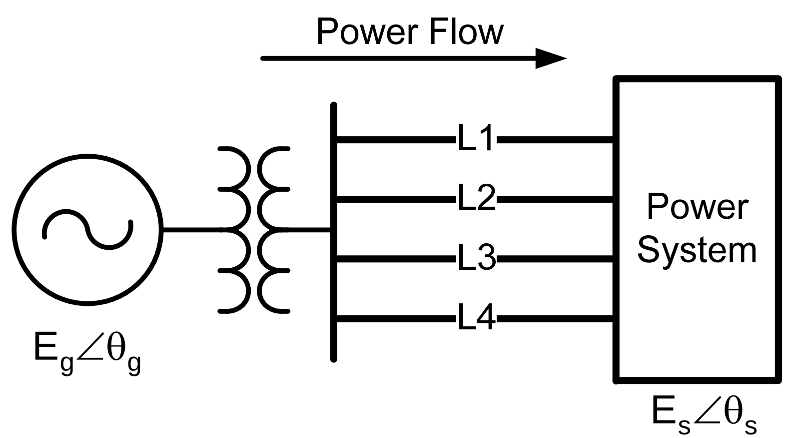
Stability



Power Transfer Equation

$$P_e = \frac{|E_g||E_s|}{X}\sin(\theta_g - \theta_s)$$

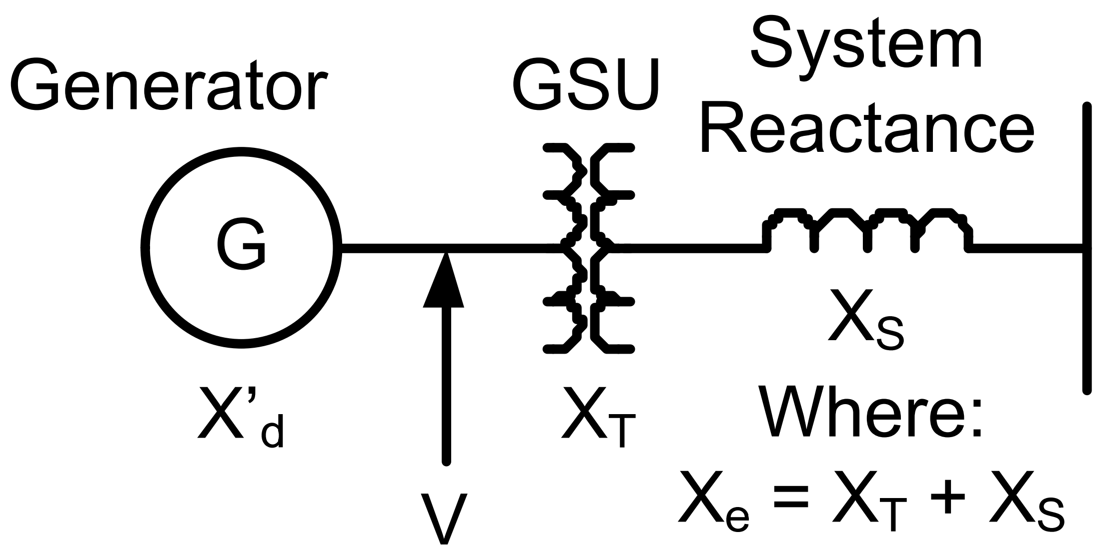
E_s - System Voltage
E_g - Generator Voltage
Θ_s - System Voltage Phase Angle
Θ_g - Generator Voltage Phase Angle
P_e - Electrical Power



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

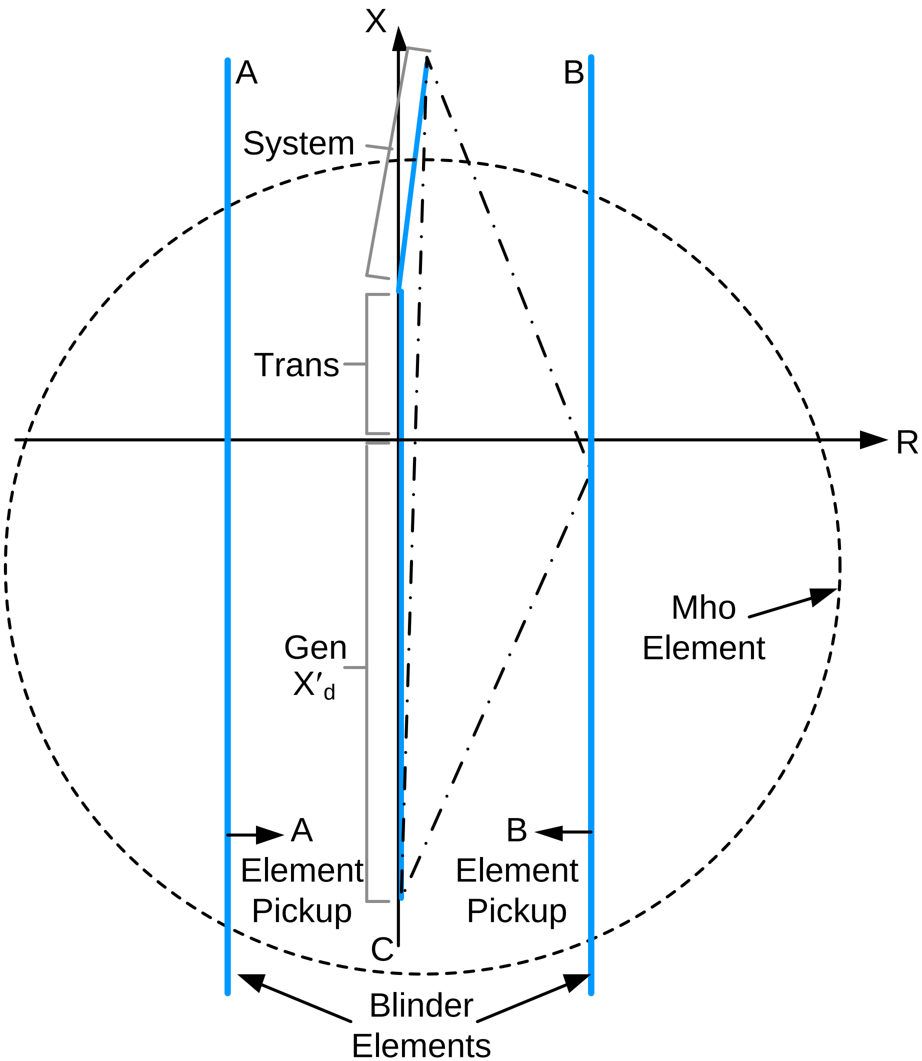
Out of Step: Generator and System Issue



Power Transfer Equation

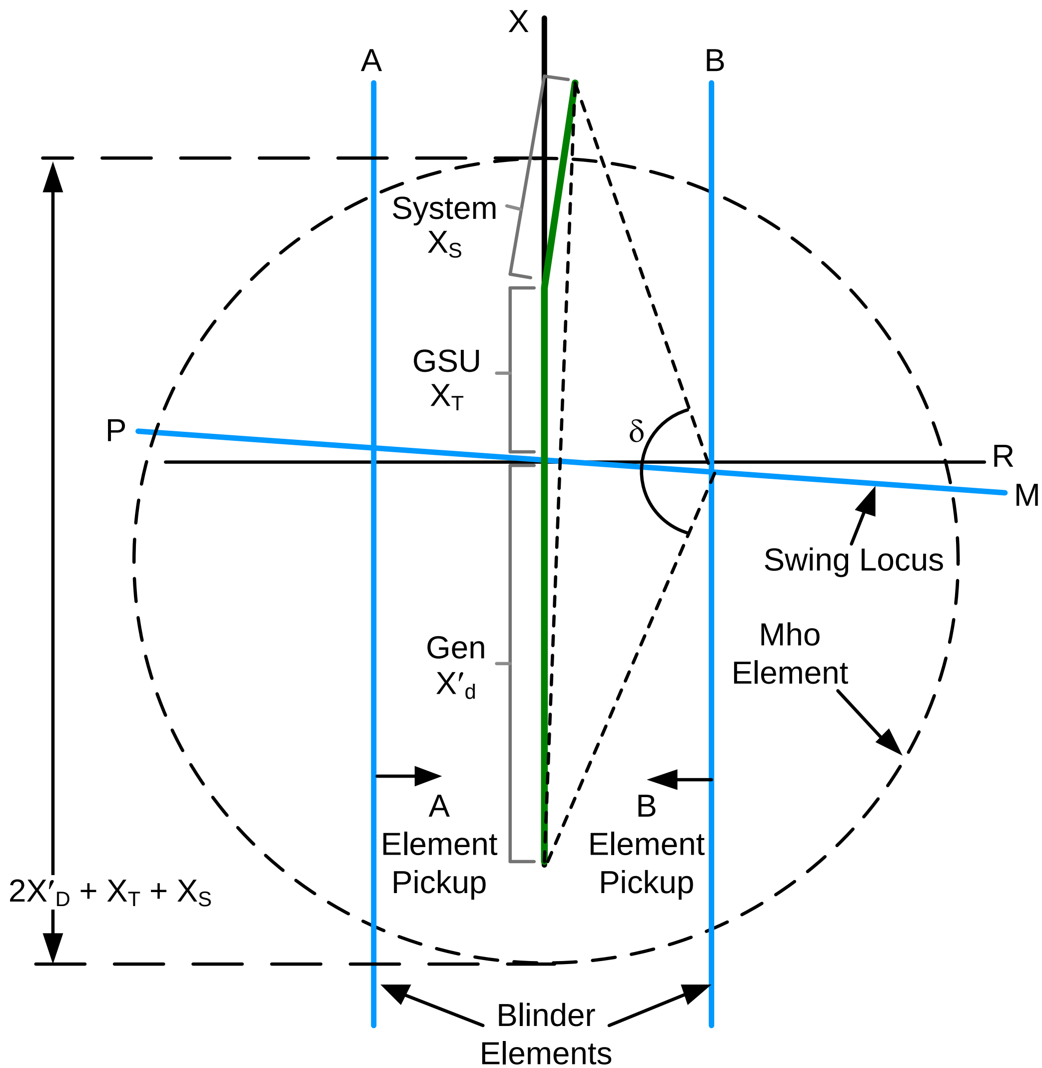
$$P_e = \frac{|E_g||E_s|}{X}\sin(\theta_g - \theta_s)$$

Single Blinder Scheme

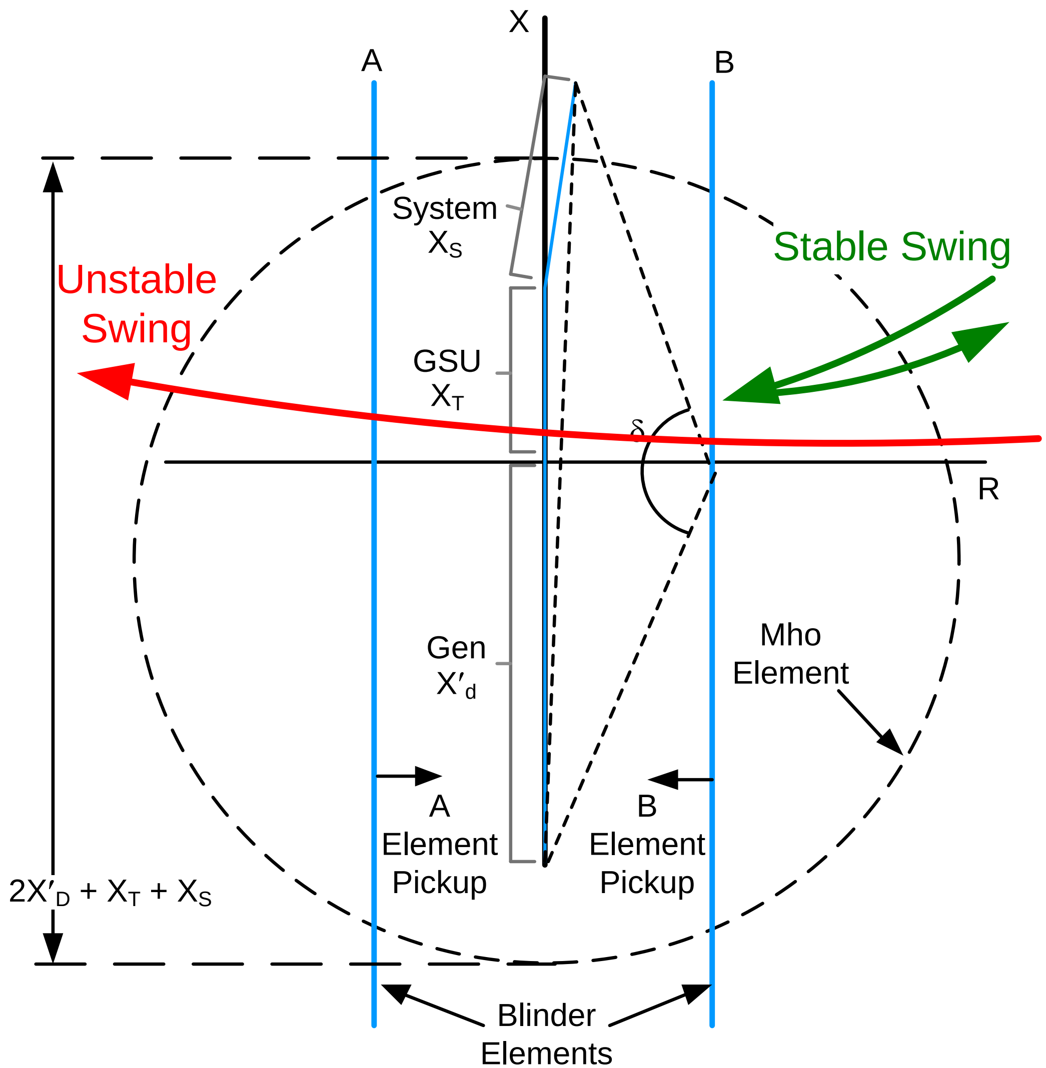


- One pair of blinders (vertical lines)
- Supervisory offset mho
- Blinders limit reach to swings near the generator

Graphical Method: 78

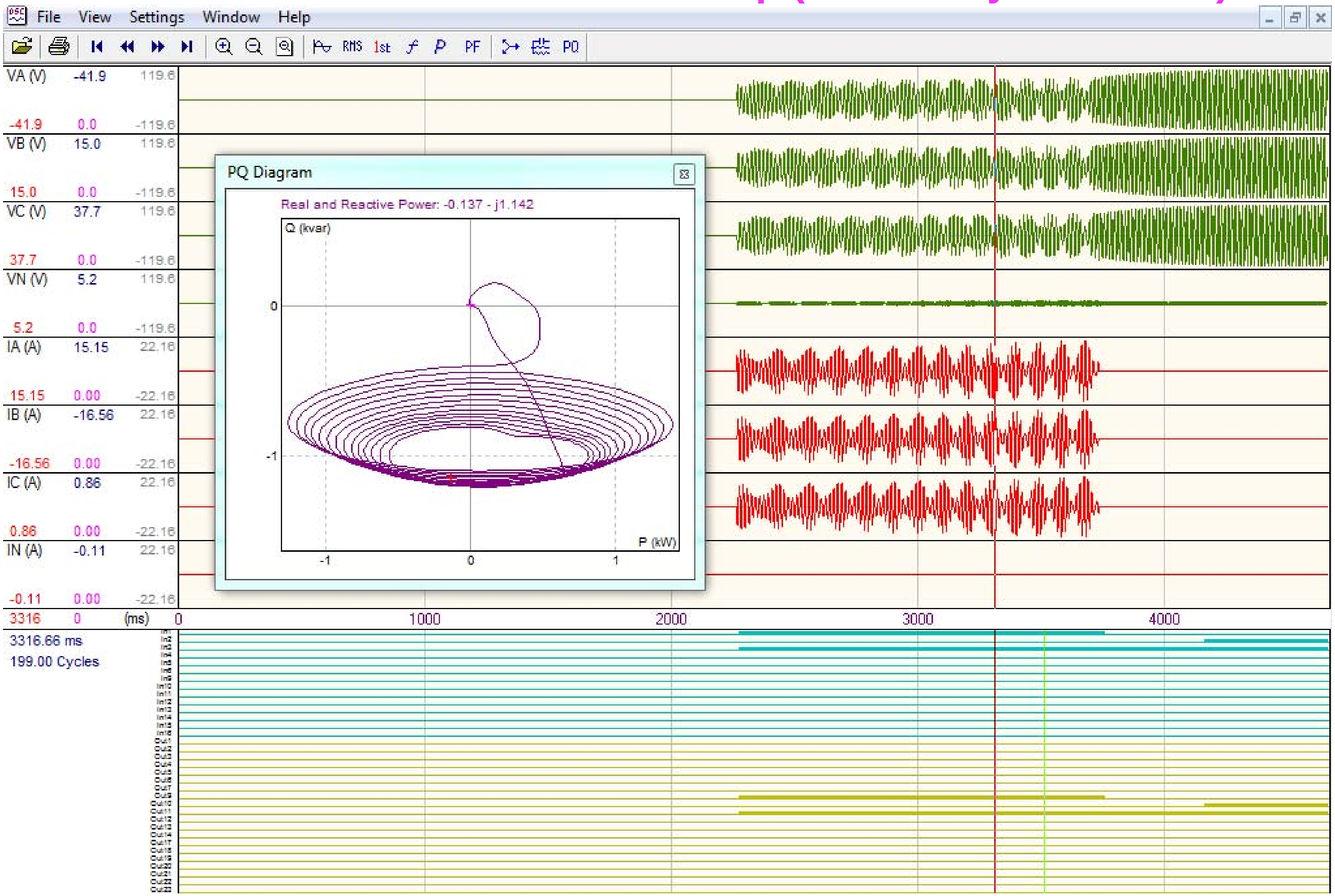


Graphical Method: 78



Generator Protection

Out-of-Step (Loss of Synchronism) Event

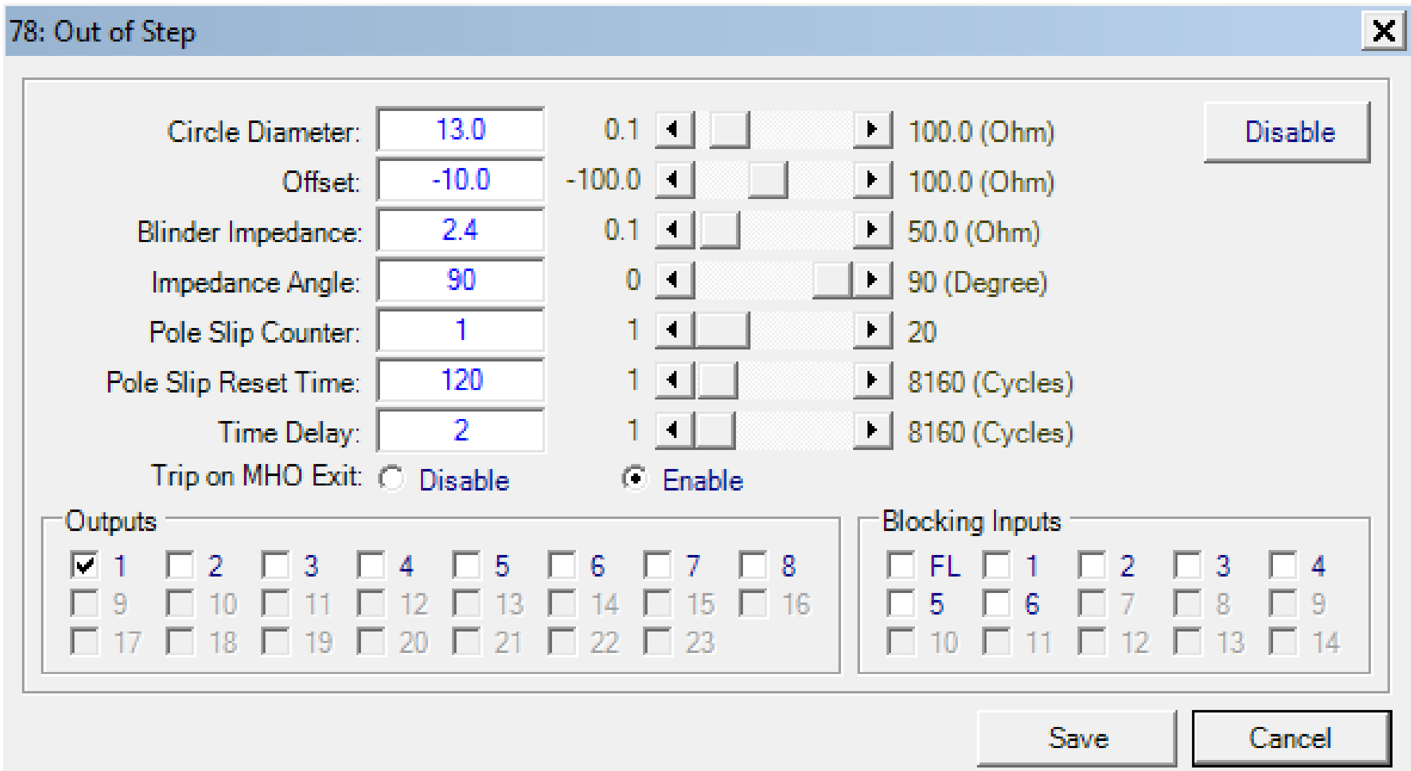


Generator Out-of-Step Protection (78)

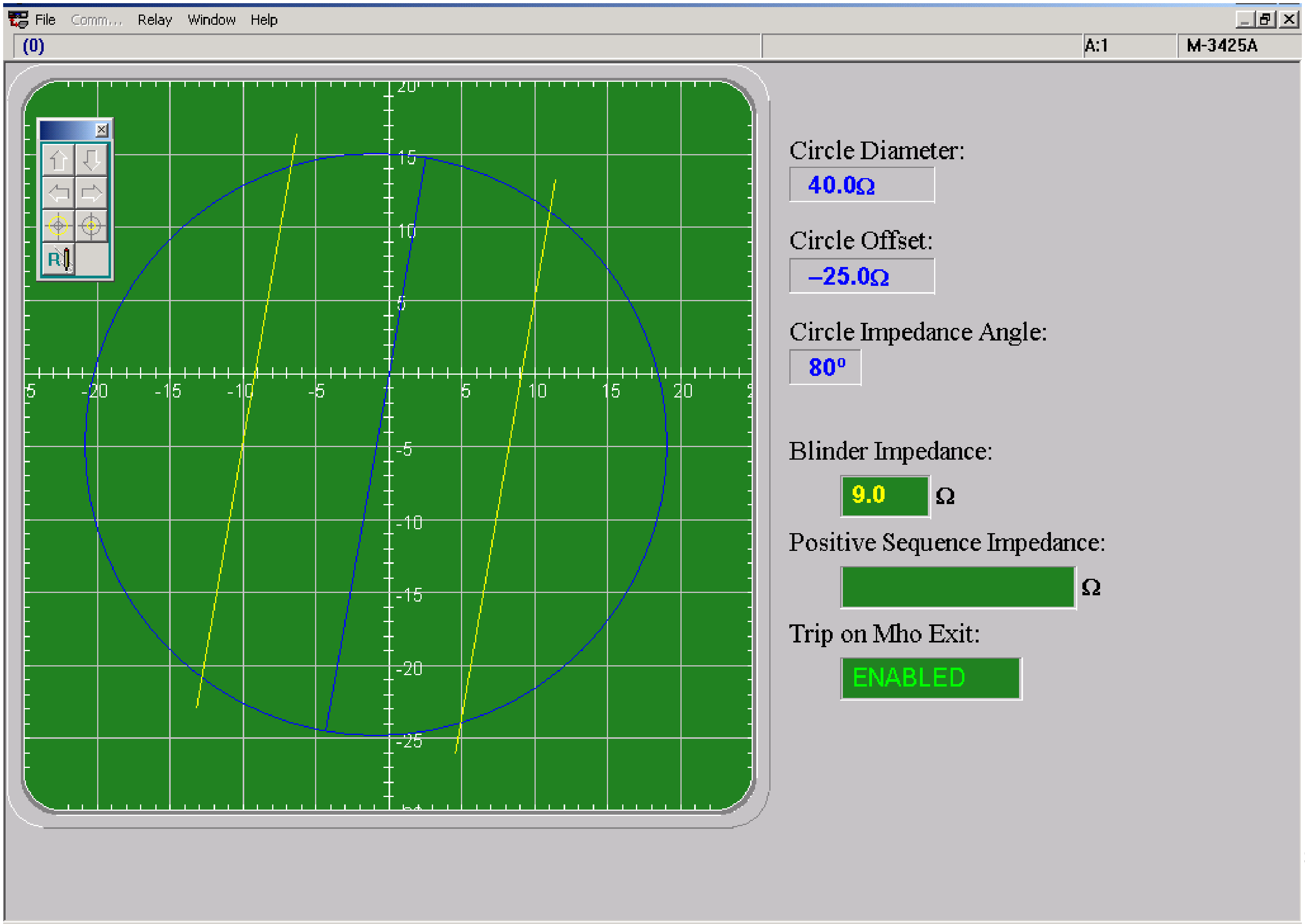
Dependability Concerns

- Positive sequence quantities used to maintain security and accuracy over a wide frequency range.
- Required to operate correctly (and not misoperate) with wide frequency variations possible during power swing conditions
  - Must work properly from 50 to 70 Hz (60 Hz systems).

Generator Out-of-Step Protection (78)



Generator Out-of-Step Protection (78)



Off-Nominal Frequency Impacts

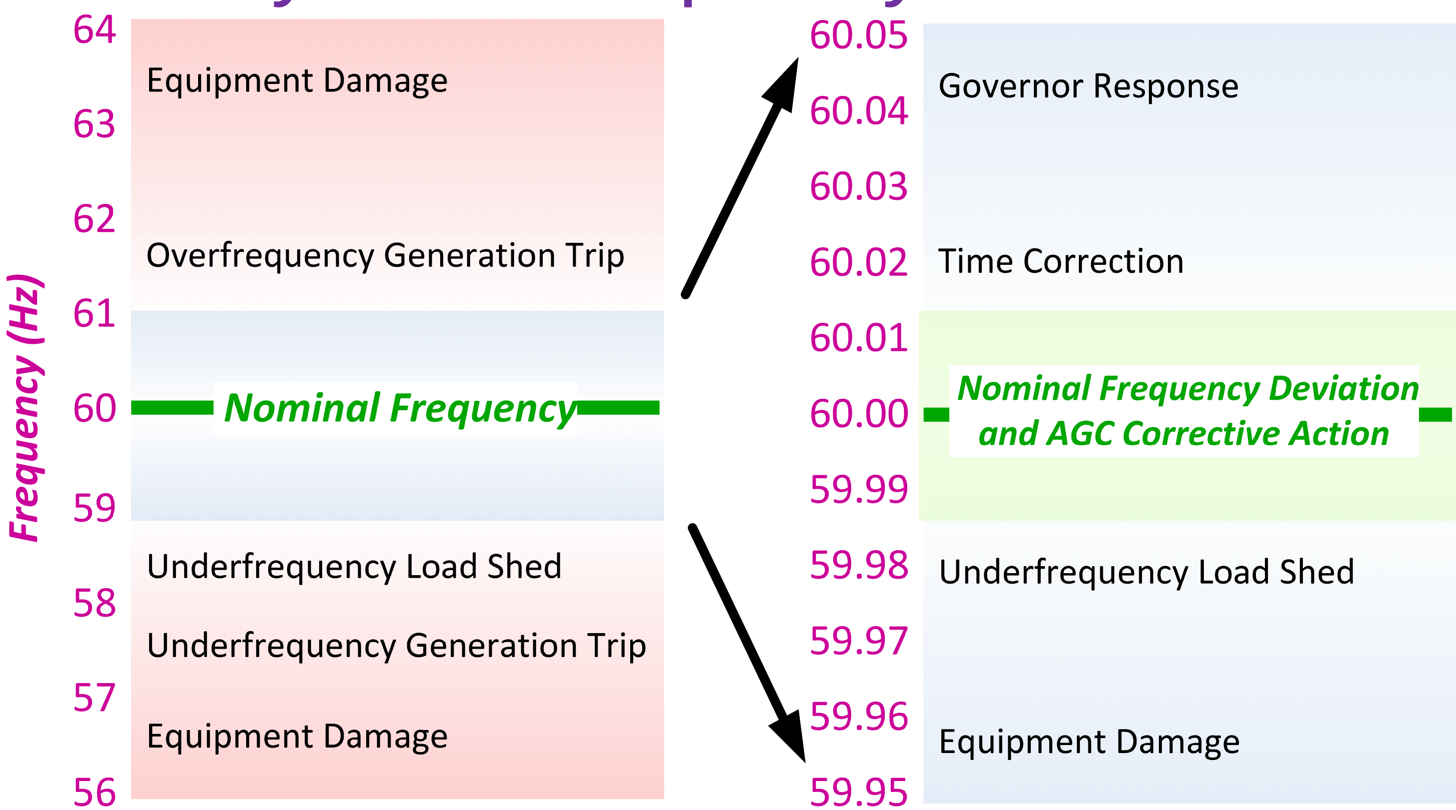
- Underfrequency may occur from system overloading
  - Loss of generation
  - Loss of tie lines importing power
- Underfrequency is an issue for the generator
  - Ventilation is decreased
  - Flux density (V/Hz) increases
- Underfrequency limit is typically dictated by the generator and turbine
  - Generator: V/Hz and loading
  - Turbine: Vibration Issues

81-U

- 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)

81-O

System Frequency Overview

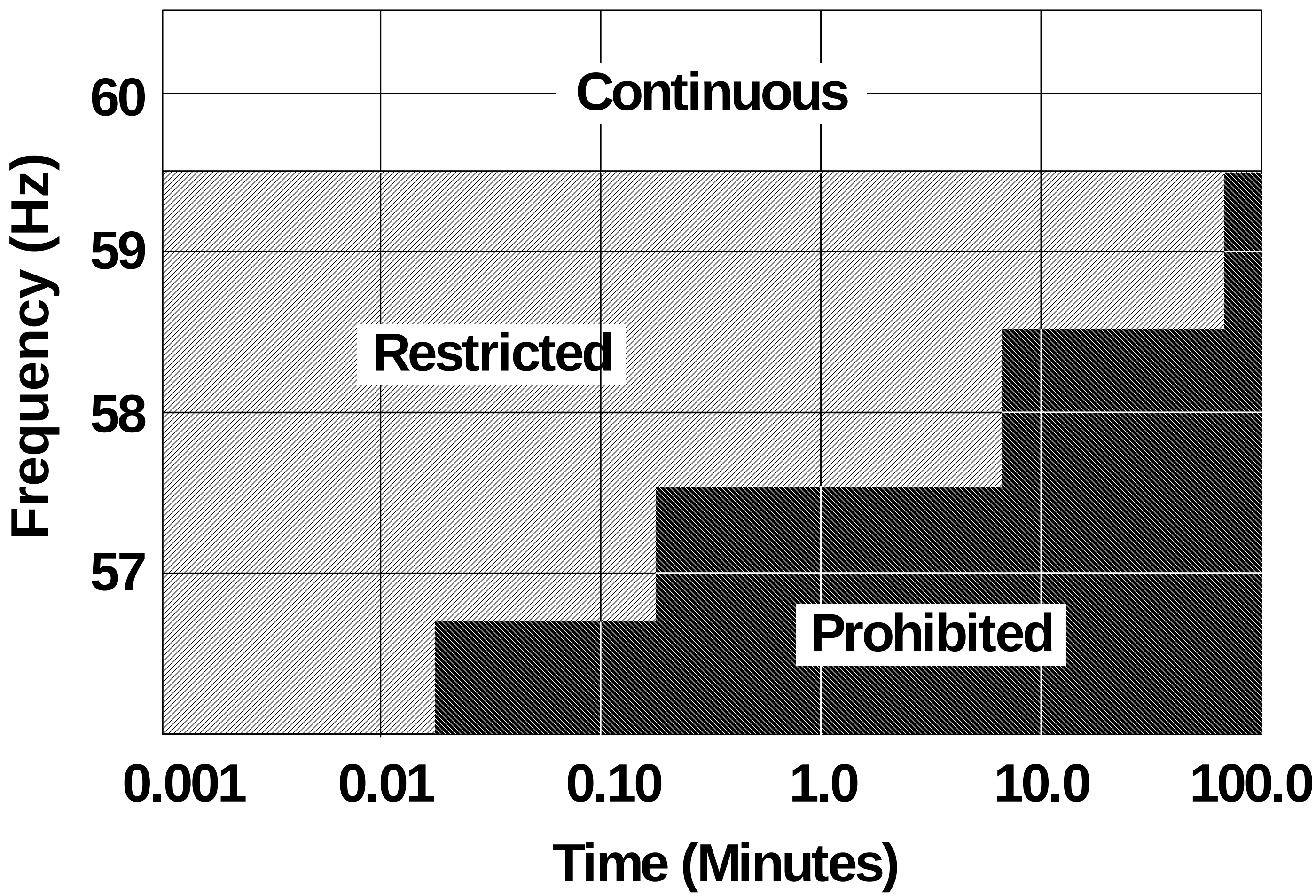


- For overfrequency events, the generator prime mover power is reduced to bring generation equal to load
- For underfrequency events, load shedding is implemented to bring load equal to generation
  - It is imperative that underfrequency tripping for a generator be coordinated with system underfrequency load shedding

Abnormal Operating Conditions

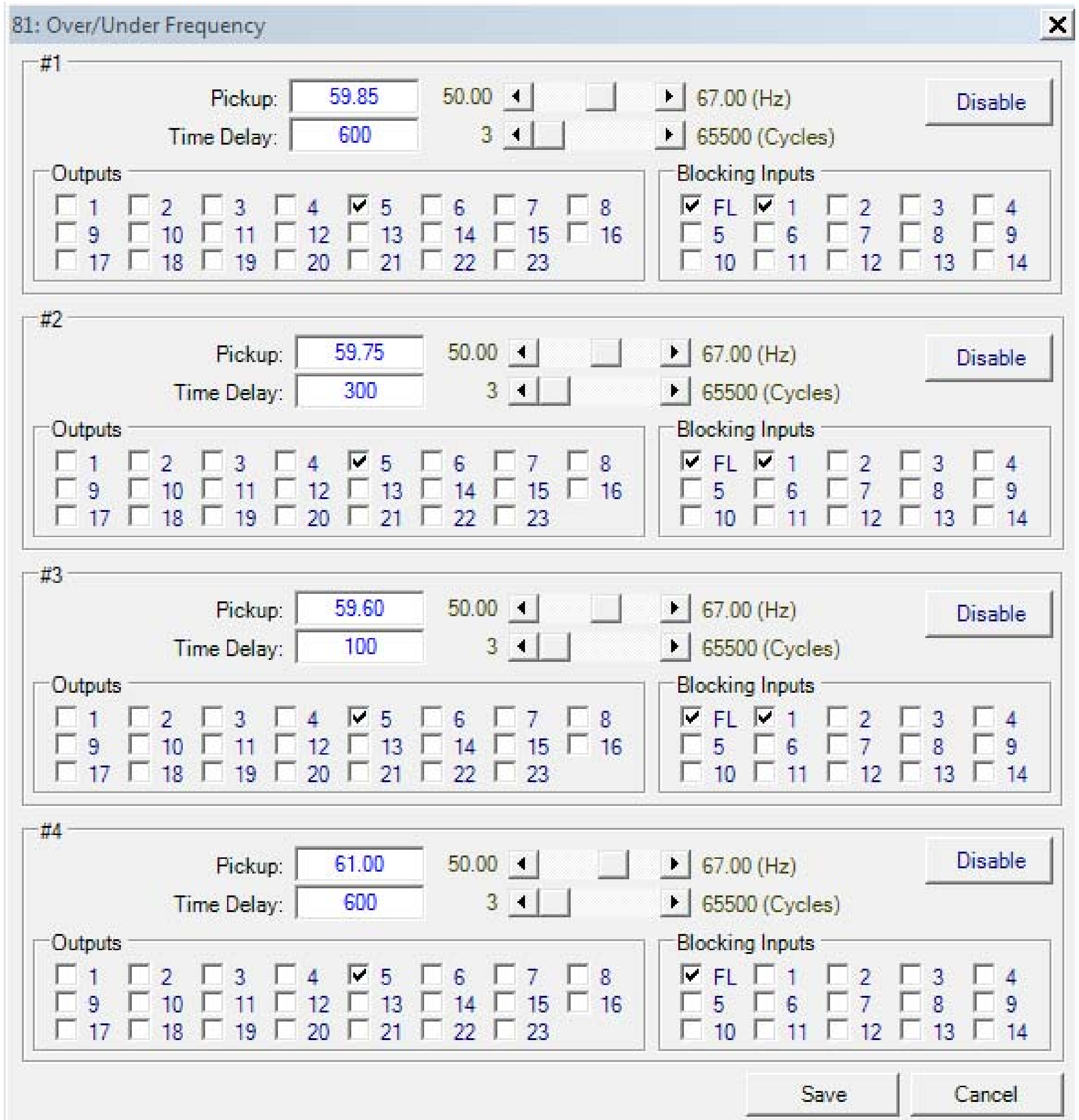
- **81 – Four Step Frequency**
  - Any step may be applied over- or underfrequency
  - High accuracy – 1/100th Hz (0.01 Hz)
  - Coordination with System Load Shedding
- **81A – Underfrequency Accumulator**
  - Time Accumulation in Six Underfrequency Bands
  - Limits Total Damage over Life of Machine
    - Typically used to Alarm
- **81R – Rate of Change of Frequency**
  - Allows tripping on rapid frequency swing

Steam Turbine Underfrequency Operating Limitations

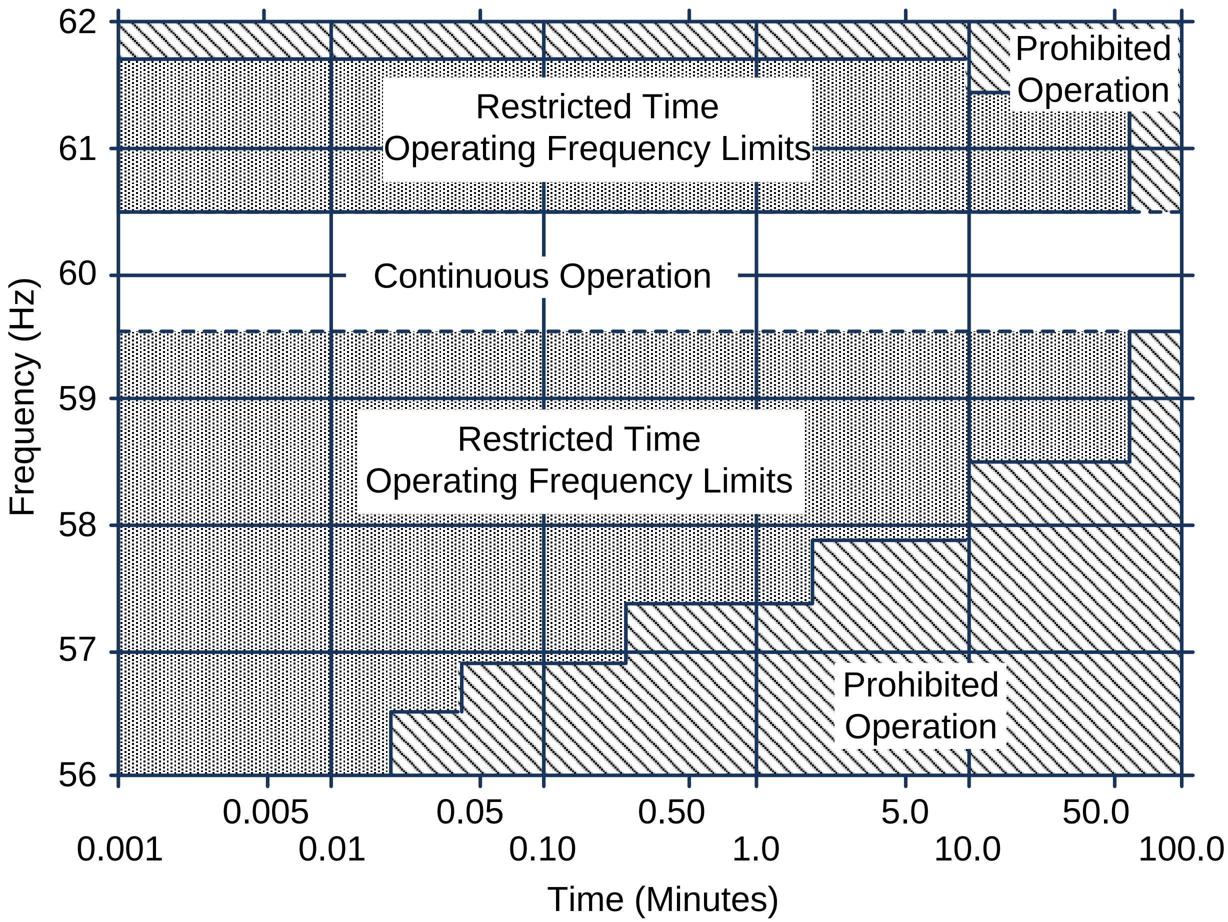


Typical, from C37.106

81U – Underfrequency



Turbine Over/Underfrequency



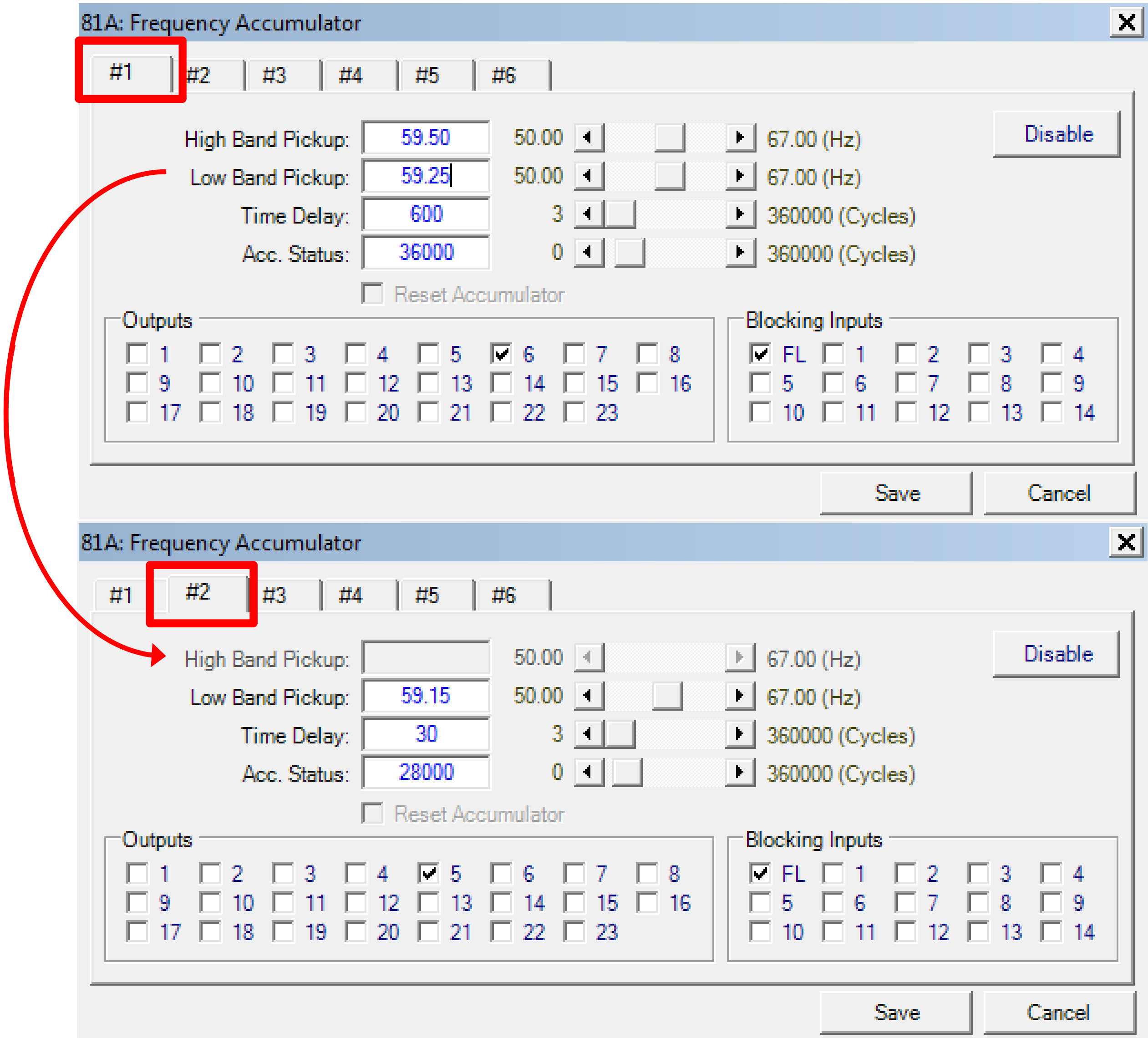
Typical, from C37.106

81A – Underfrequency Accumulator

- 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

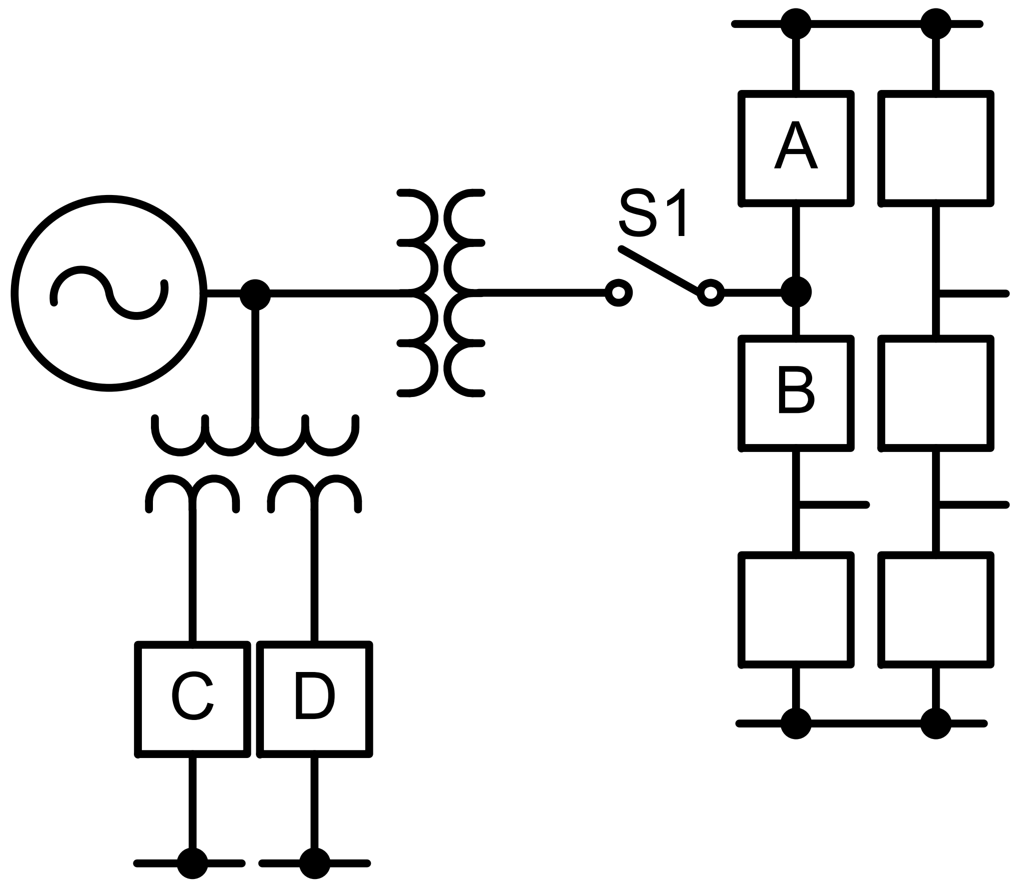
  - In 60 Hz machines, the typical operating frequency range:
    - 18 to 25 inch blades = 58.5 to 61.5 Hz
    - 25 to 44 inch blades = 59.5 and 60.5 Hz
  - Accumulated operation, for the life of the machine, not more than:
    - 10 minutes for frequencies between 56 and 58.5 Hz
    - 60 minutes for frequencies between 58.5 and 59.5 Hz

81A – Underfrequency Accumulator



Causes of Inadvertent Energizing

- Operating errors
- Breaker head flashovers
- Control circuit malfunctions
- Combination of above



Inadvertent Energizing: Protection Response

- 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

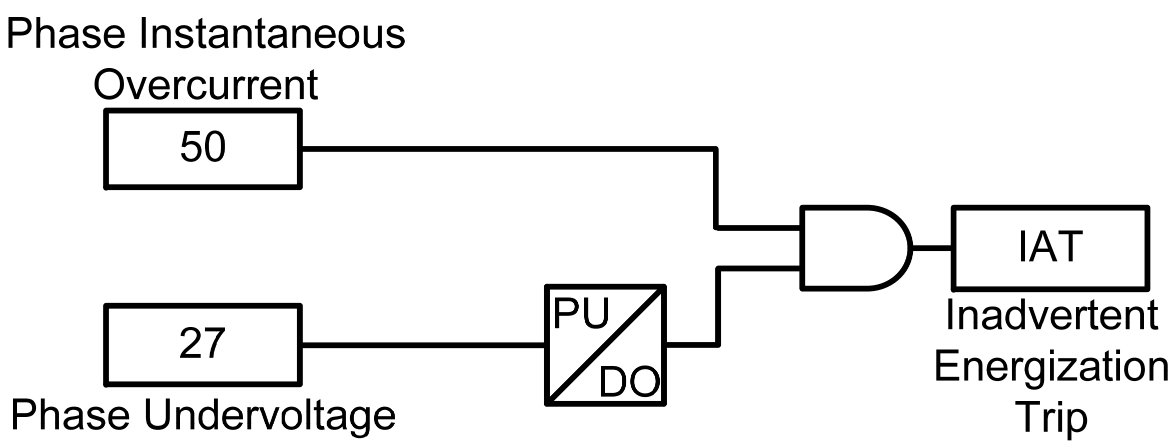
- When inadvertently energized from <u>3-phase source</u>, the machine acts like an induction motor
  - Rotor heats rapidly (very high I_2 in the rotor)
- Current drawn
  - Strong system: 3-4x rated
  - Weak system: 1-2x rated
  - From Auxiliary System: 0.1-0.2x rated

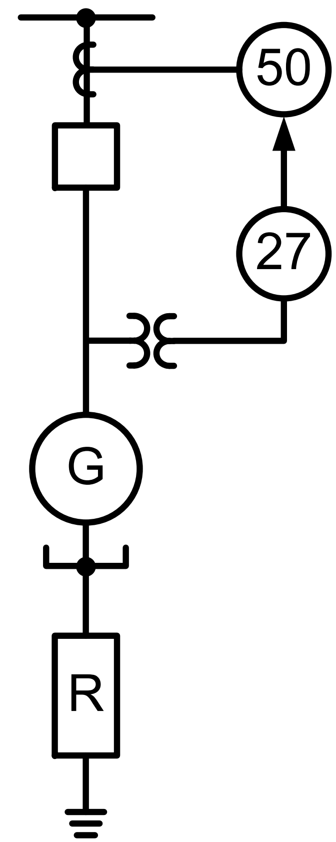
- When inadvertently energized from <u>1-phase source</u> (pole flashover), the machine does not accelerate
  - No rotating flux is developed
  - Rotor heats rapidly (very high I_2 in the rotor)

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

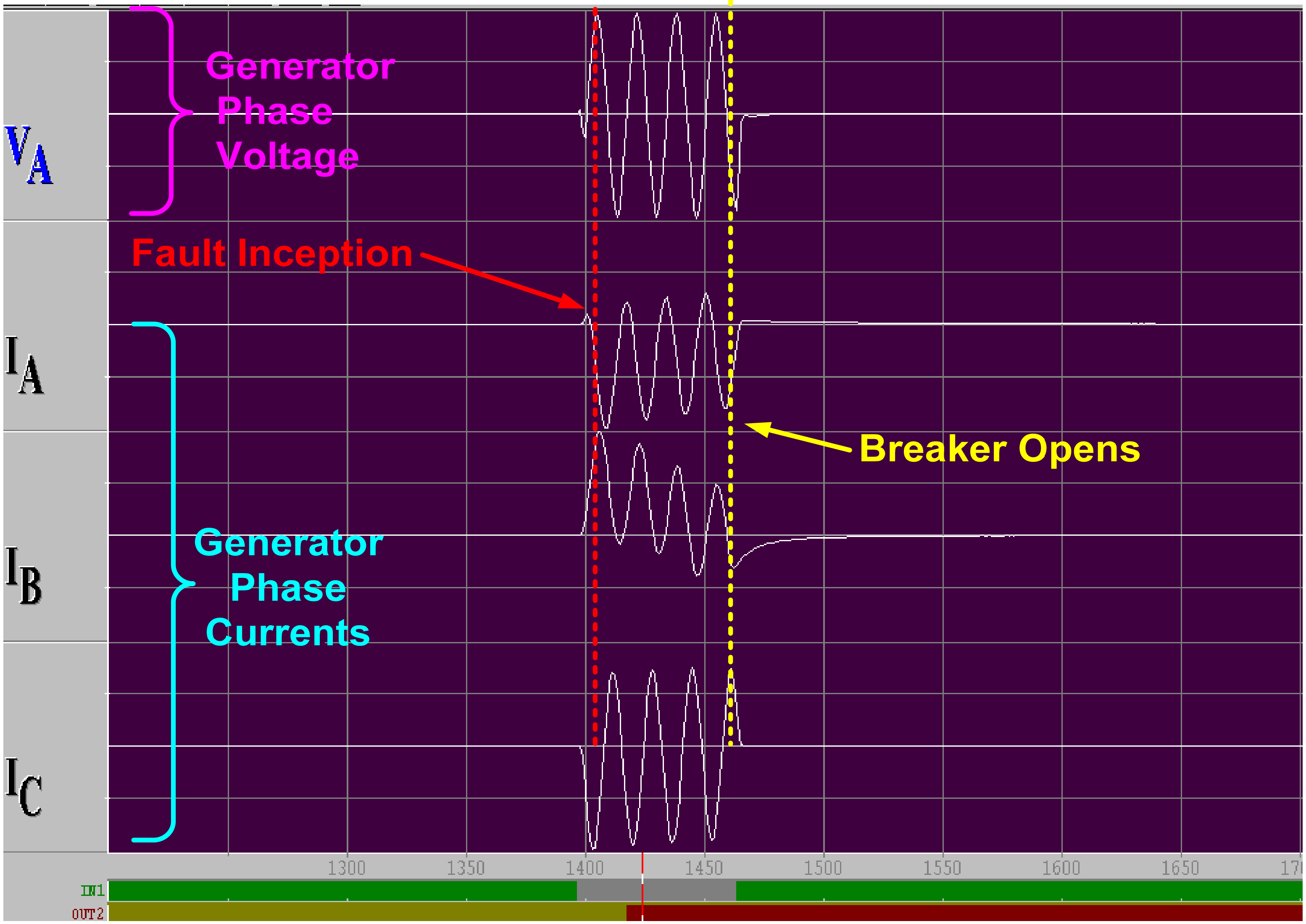
Inadvertent Energizing Scheme

- 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

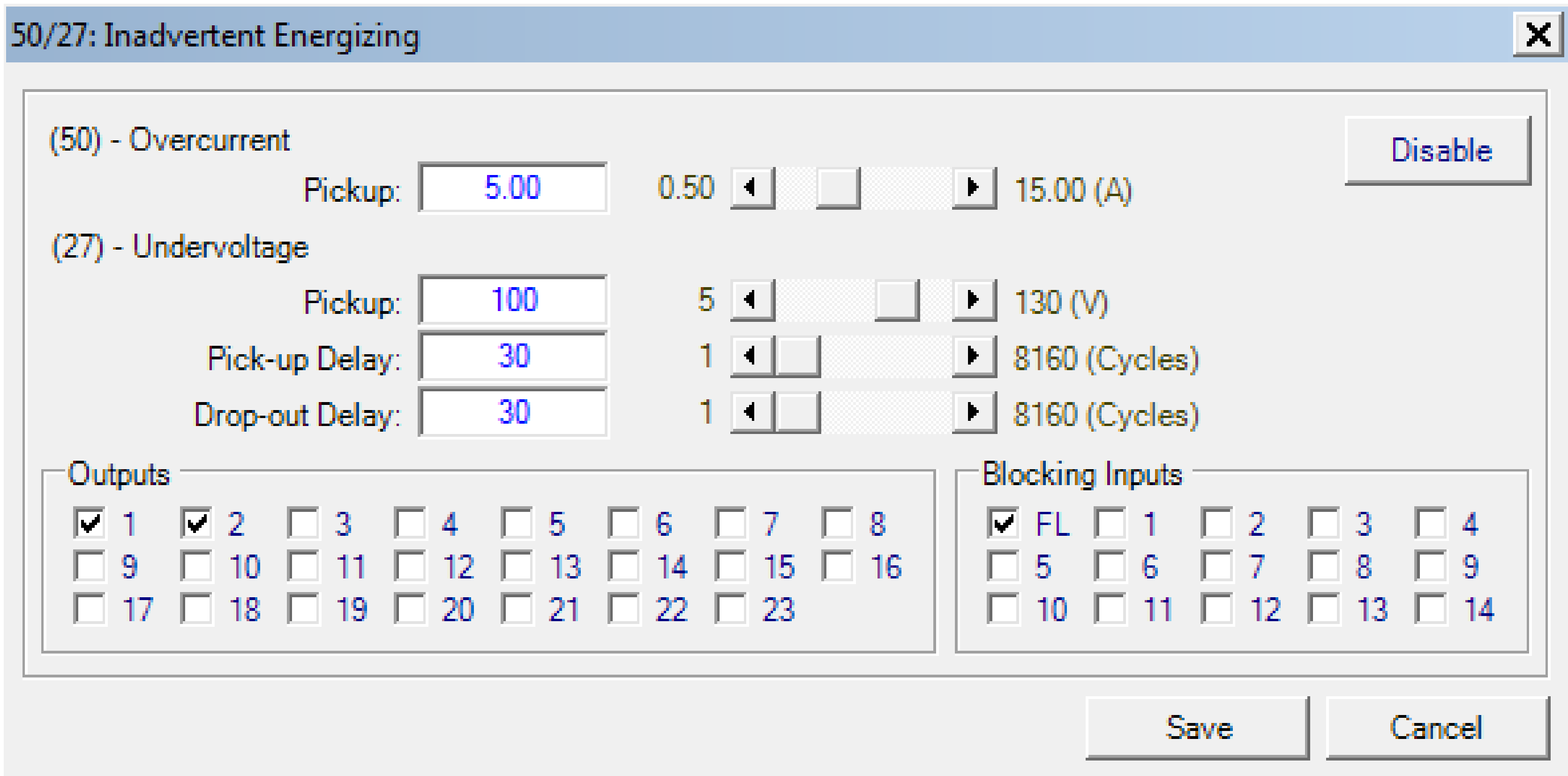




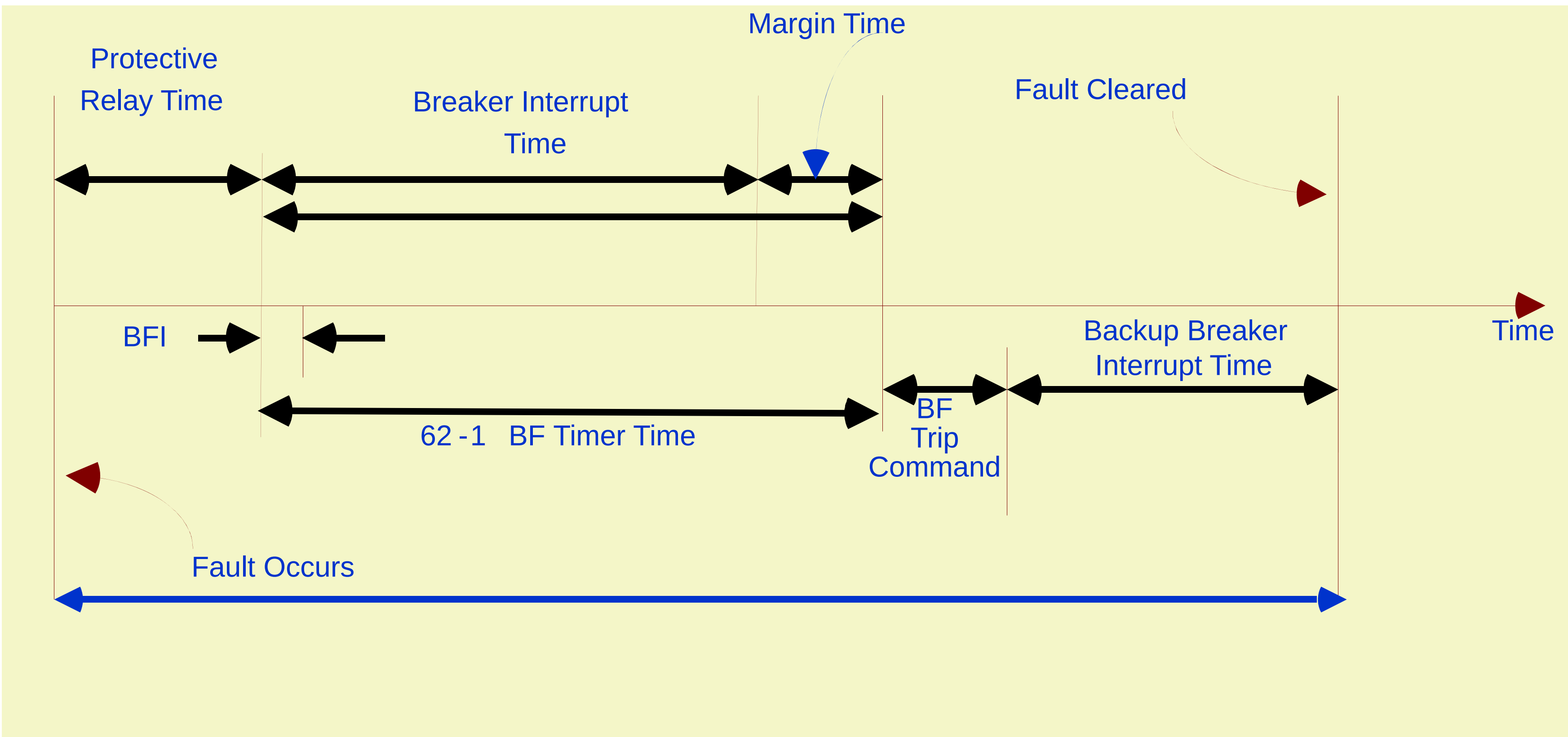
Inadvertent Energizing



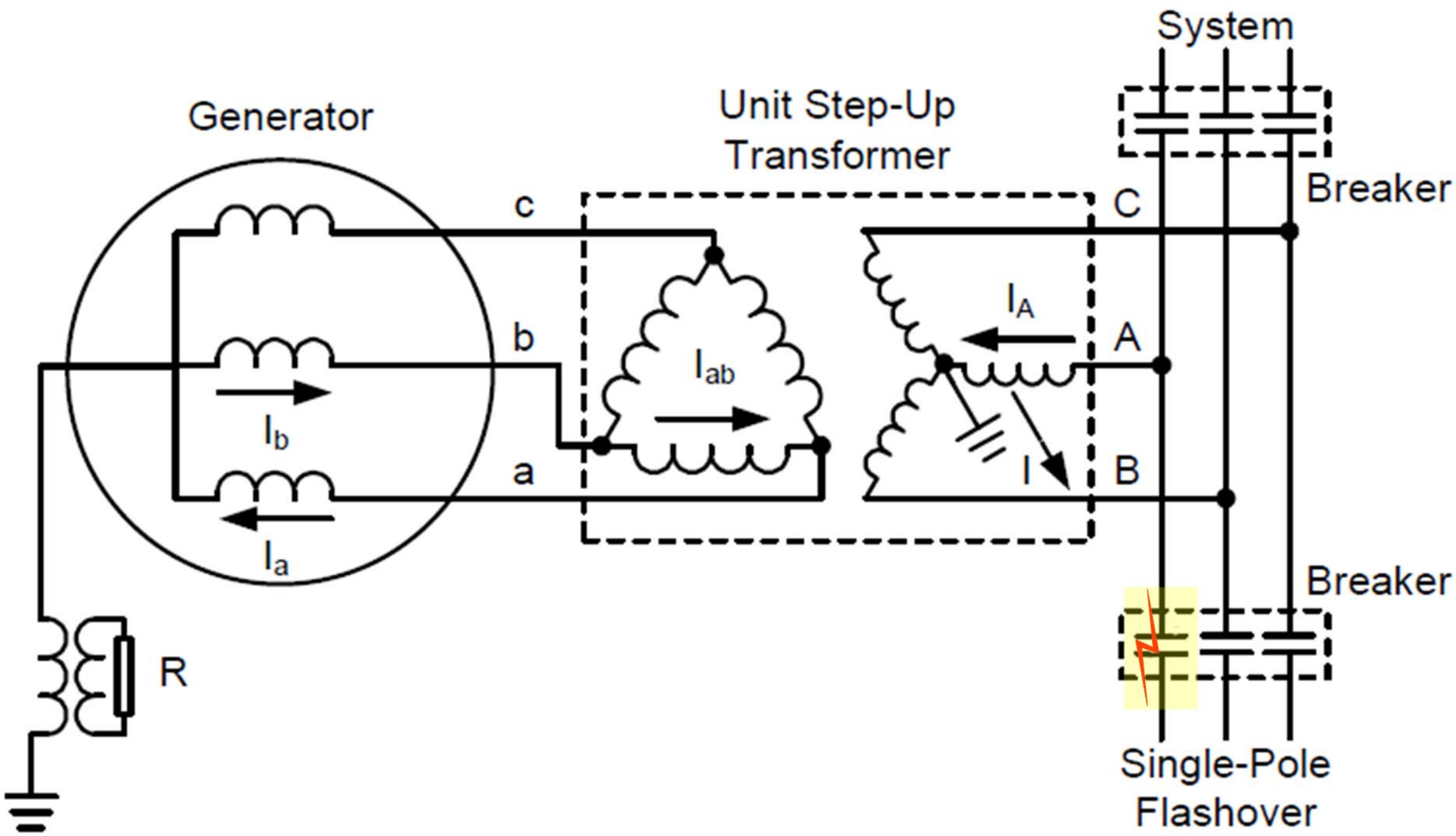
Inadvertent Energizing



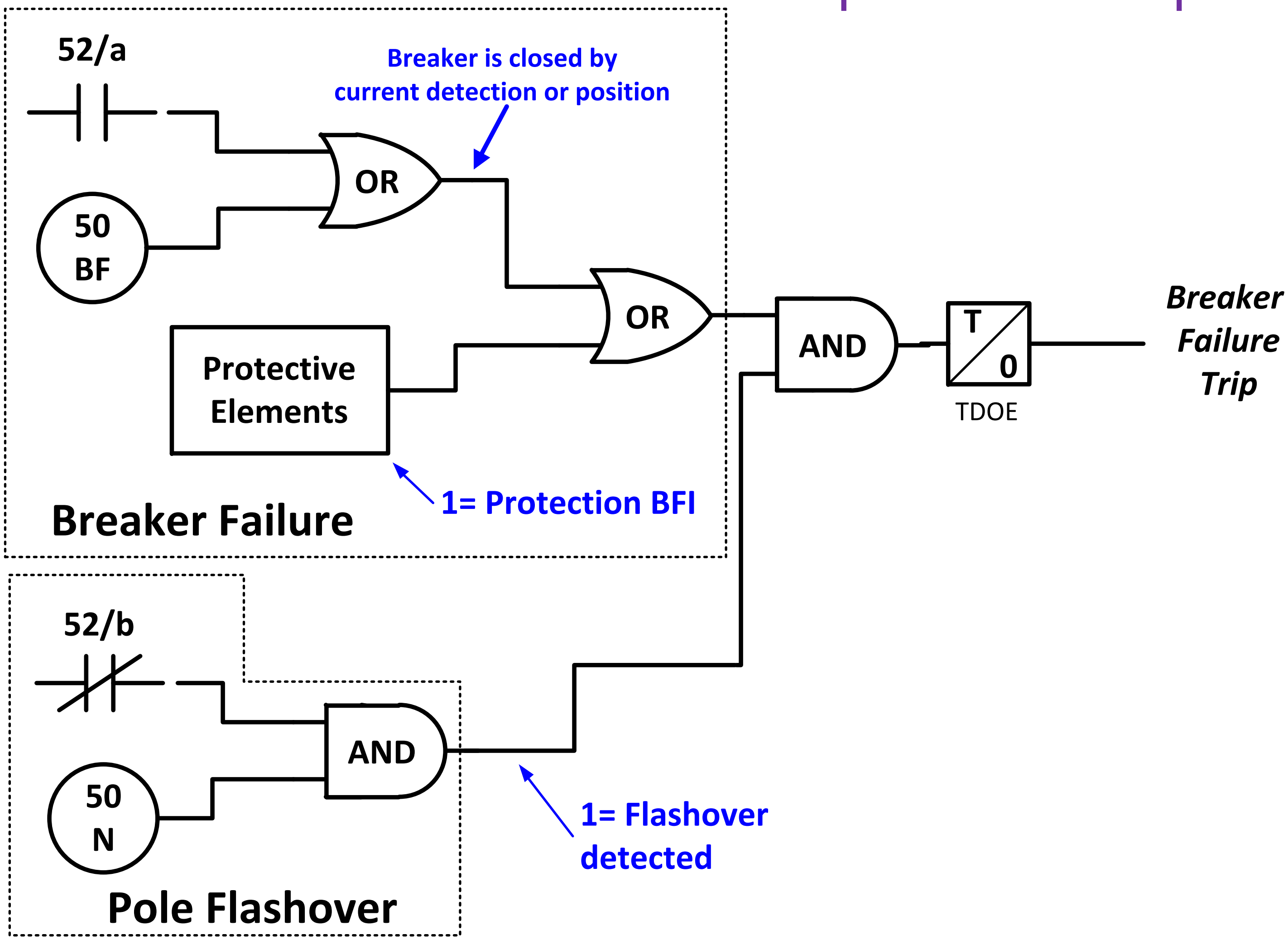
Breaker Failure Timeline



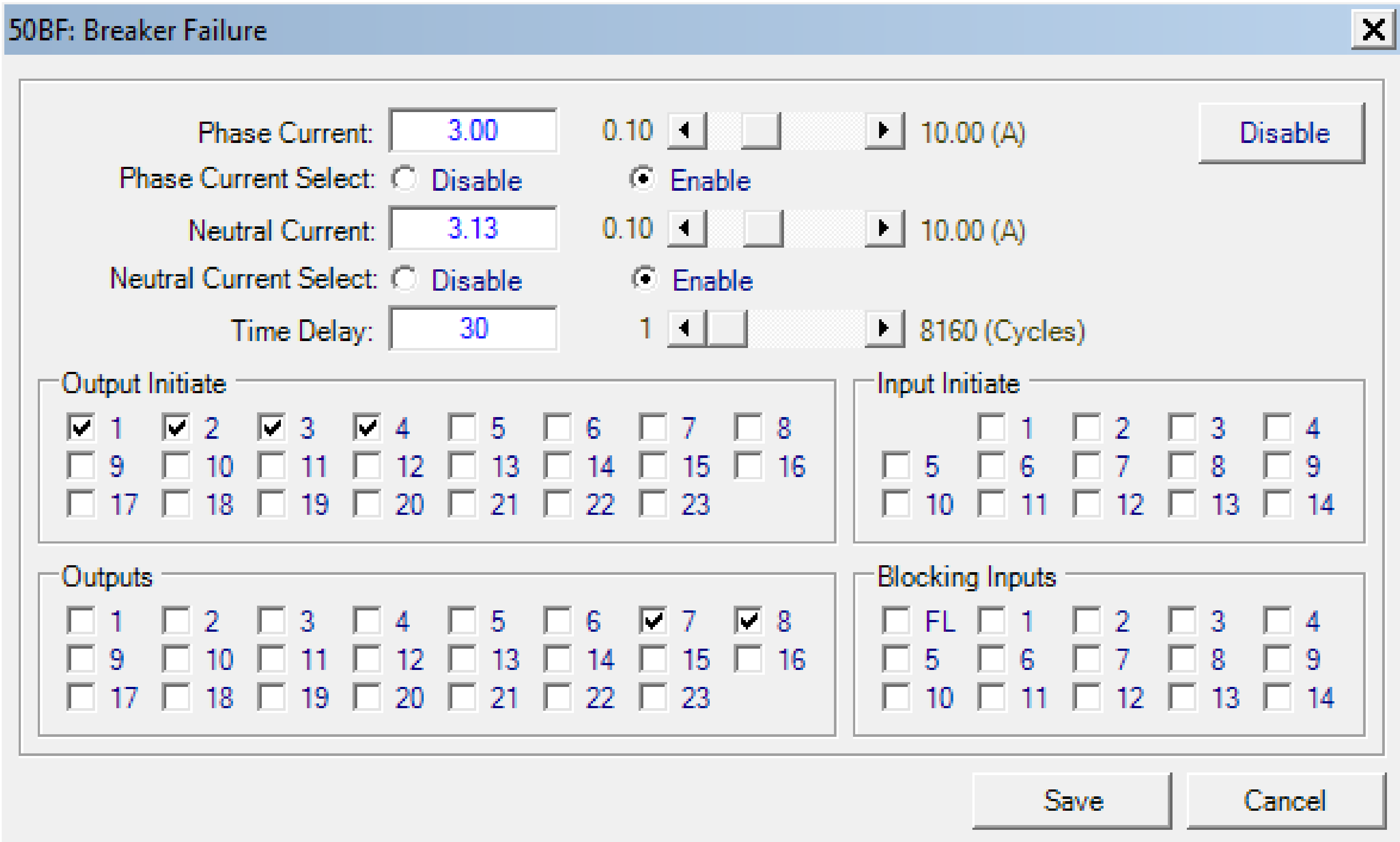
Breaker Pole Flashover & Stuck Pole



Generator Breaker Failure and Pole Flashover Scheme: Simplified Conceptual View



Generator Breaker Failure and Pole Flashover



- “Phase Initiate Enable” is made from software selection and enables breaker failure protection
- Output Initiates (Trip Output Contacts) or External Contact Signal Initiates are used to start the breaker failure element
- “Neutral Initiate Enable” is made from software selection and enables pole flashover protection
- 52b contact used to supervise the pole flashover protection

Fuse Loss

- **Fuse loss (loss of voltage potential) can cause voltage sensitive elements to misoperate**

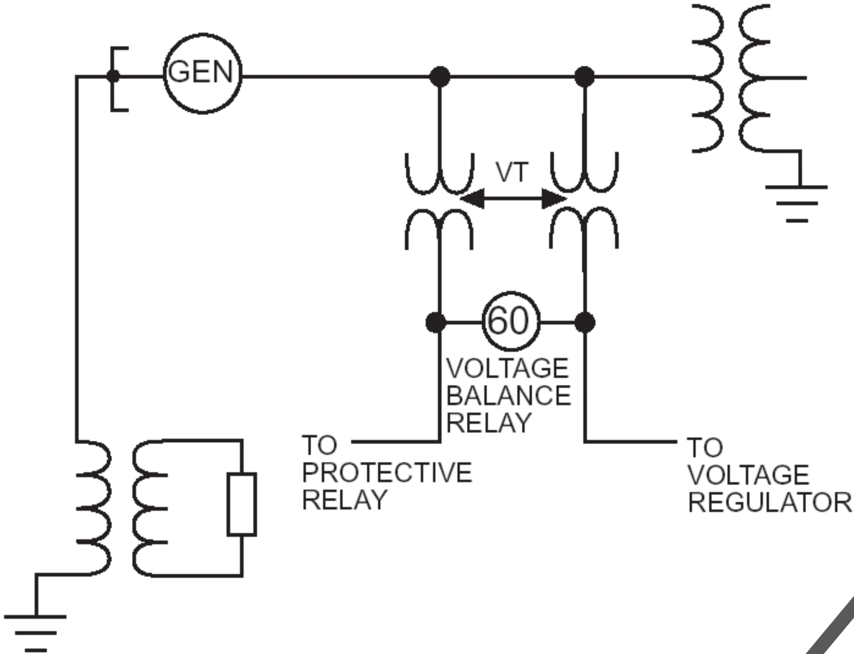
  - 51V, 21, 78, 32, 67, 67N, 40

- **Typically performed using two sets of VTs and a voltage balance relay**

- **Some small hydro installations may only have one set of VTs**

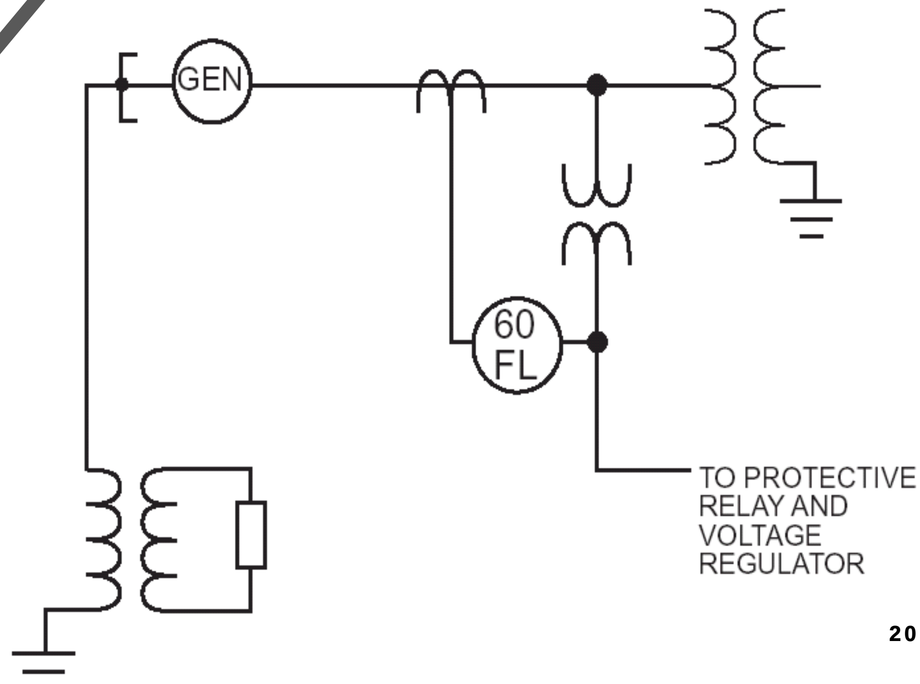
- **Use Symmetrical Component and 3-Phase Voltage/Current methods to provide fuse loss detection on a single VT set**

Fuse Loss



Two VTs

One VT



Fuse Loss (LOP) Detection:

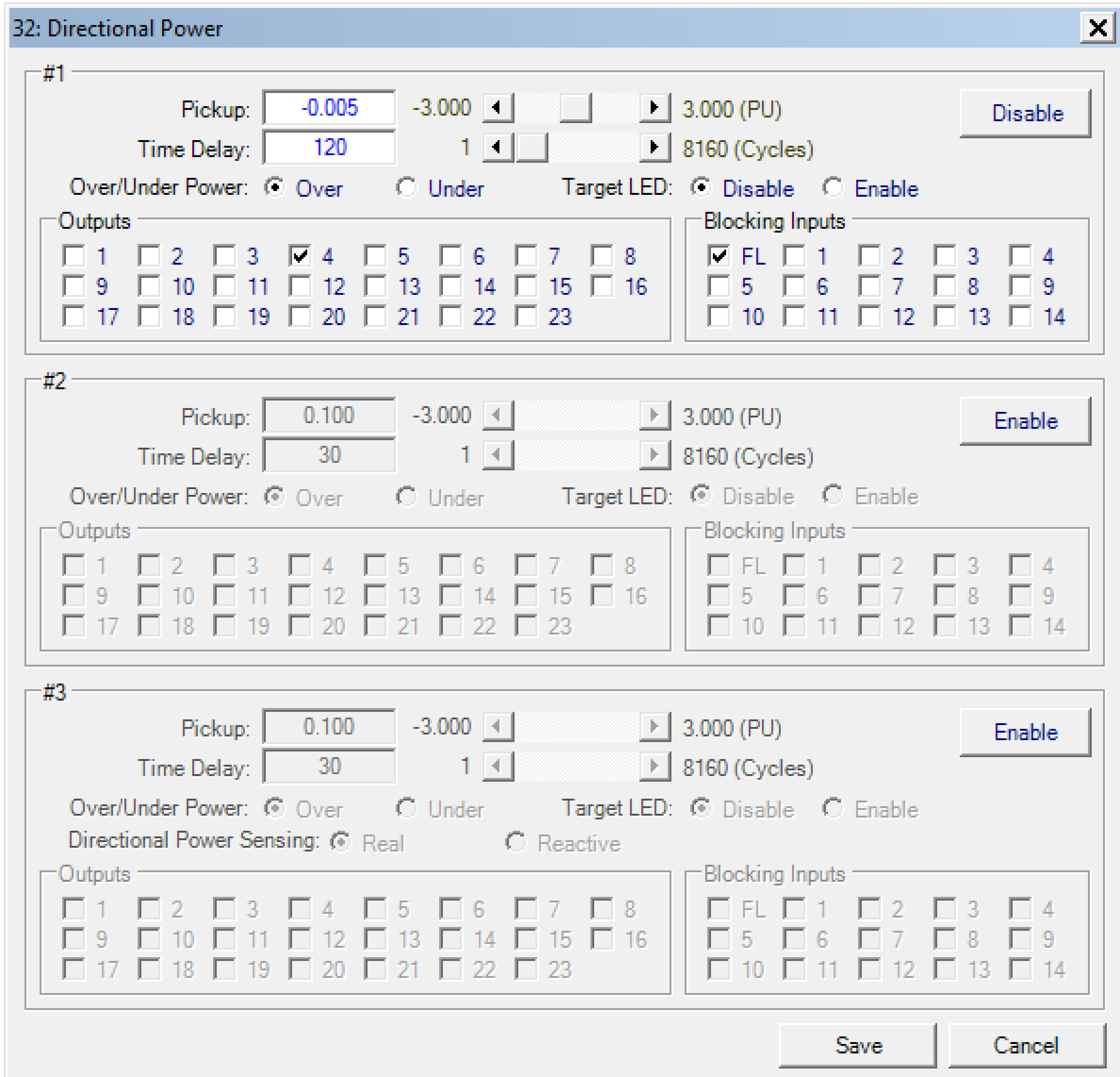
Symmetrical Components & 3-Phase Voltage/Current Monitoring

- **Use to block voltage dependent elements from misoperating and to alarm**
  - Stops nuisance tripping and attendant full load rejection on LOP
- **1 and 2 phase LOP detection by symmetrical component comparison**
  - Presence of Negative Sequence Voltage and Negative Sequence Current indicates a Fault
  - Presence of Negative Sequence Voltage and <u>absence</u> of Negative Sequence Current indicates a Fuse Loss
- **3 phase LOP detected by voltage and current monitoring**
  - Low 3-Phase Voltages and High 3-Phase Currents indicates a Fault
  - Low 3-Phase Voltages and Low 3-Phase Current indicates a Fuse Loss

Anti-Motoring: 32

- 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; <=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

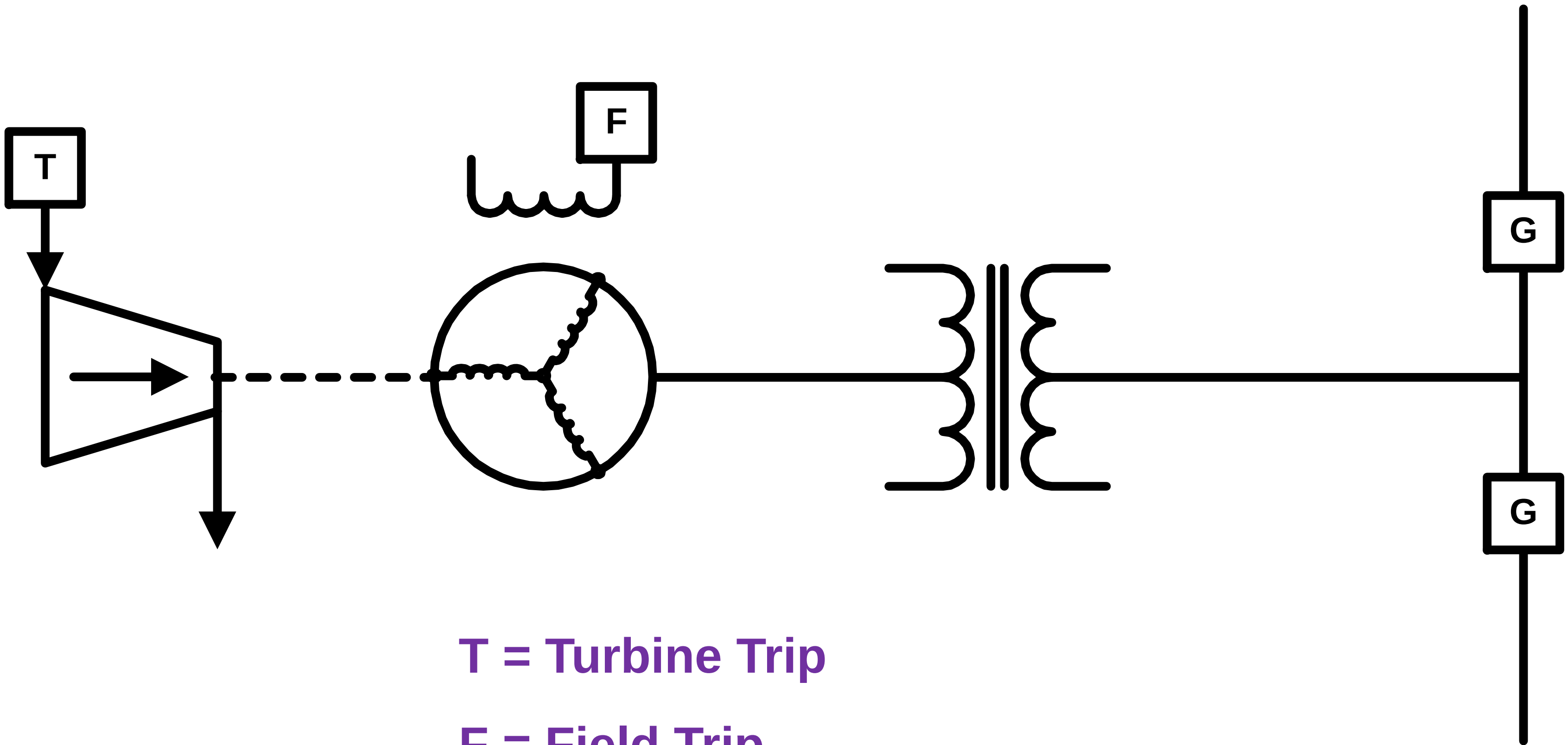
Directional Power (32F/R)



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

Generator Tripping



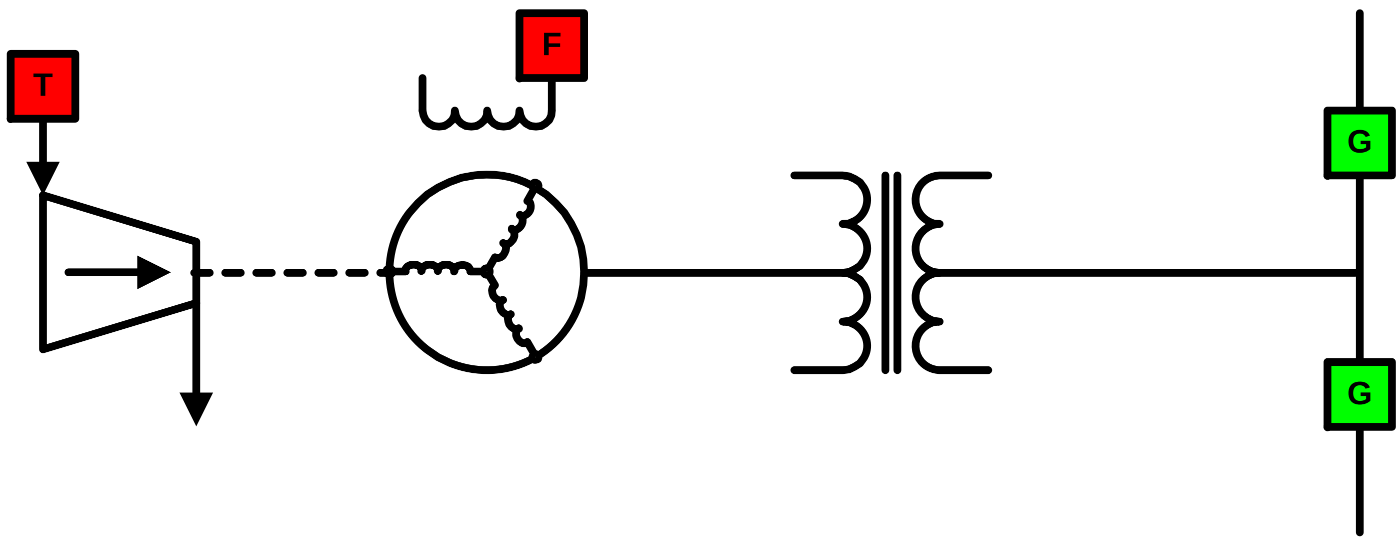
T = Turbine Trip

F = Field Trip

G = Generator Breaker Trip

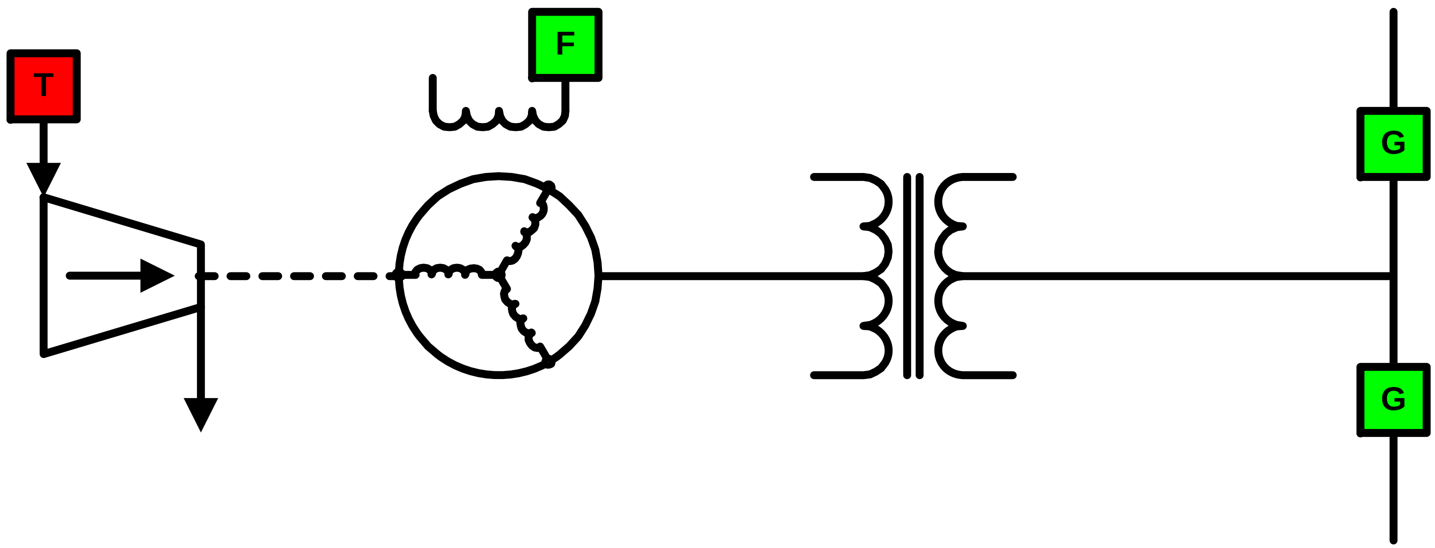
Tripping Philosophy & Sequential Tripping

– 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



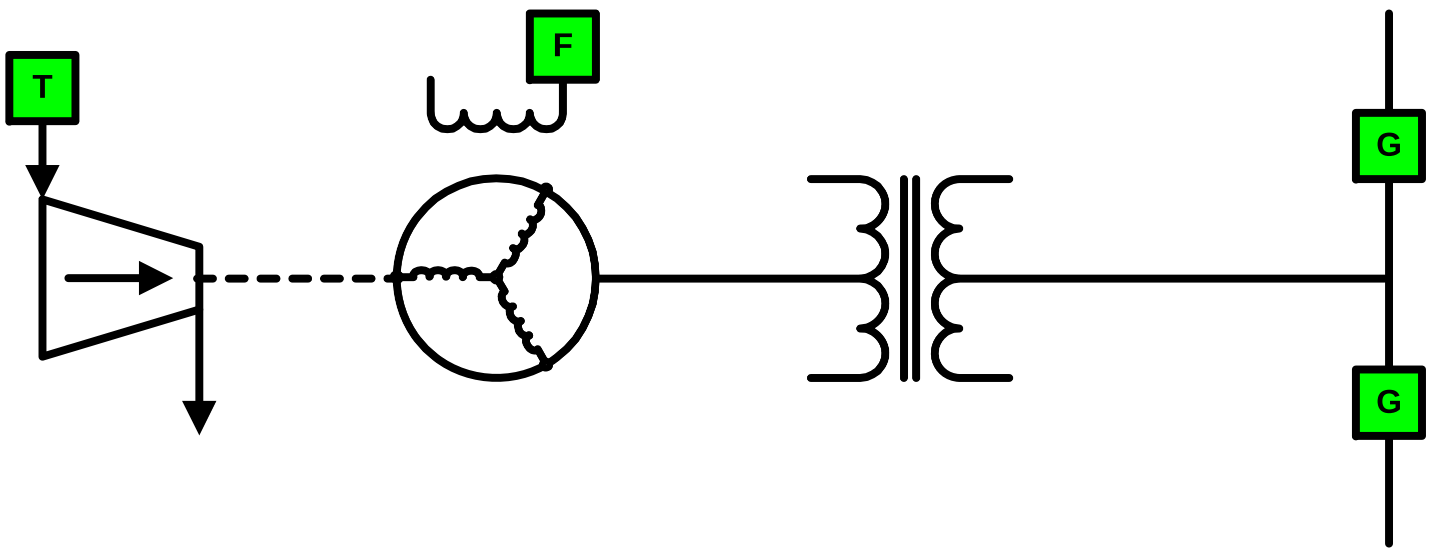
Tripping Philosophy & Sequential Tripping

- Generator Trip
  - Used when machine is isolated and overexcitation trip occurs
  - Exciter breaker is tripped (LOR) with generator breakers already opened



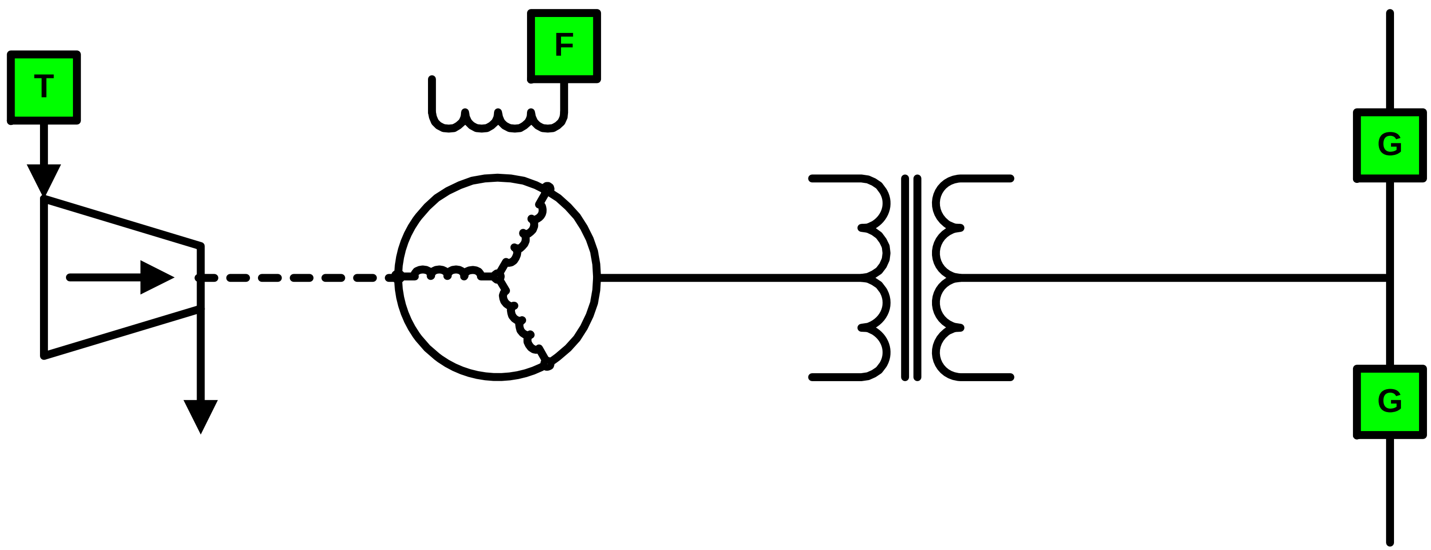
Tripping Philosophy & Sequential Tripping

– 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

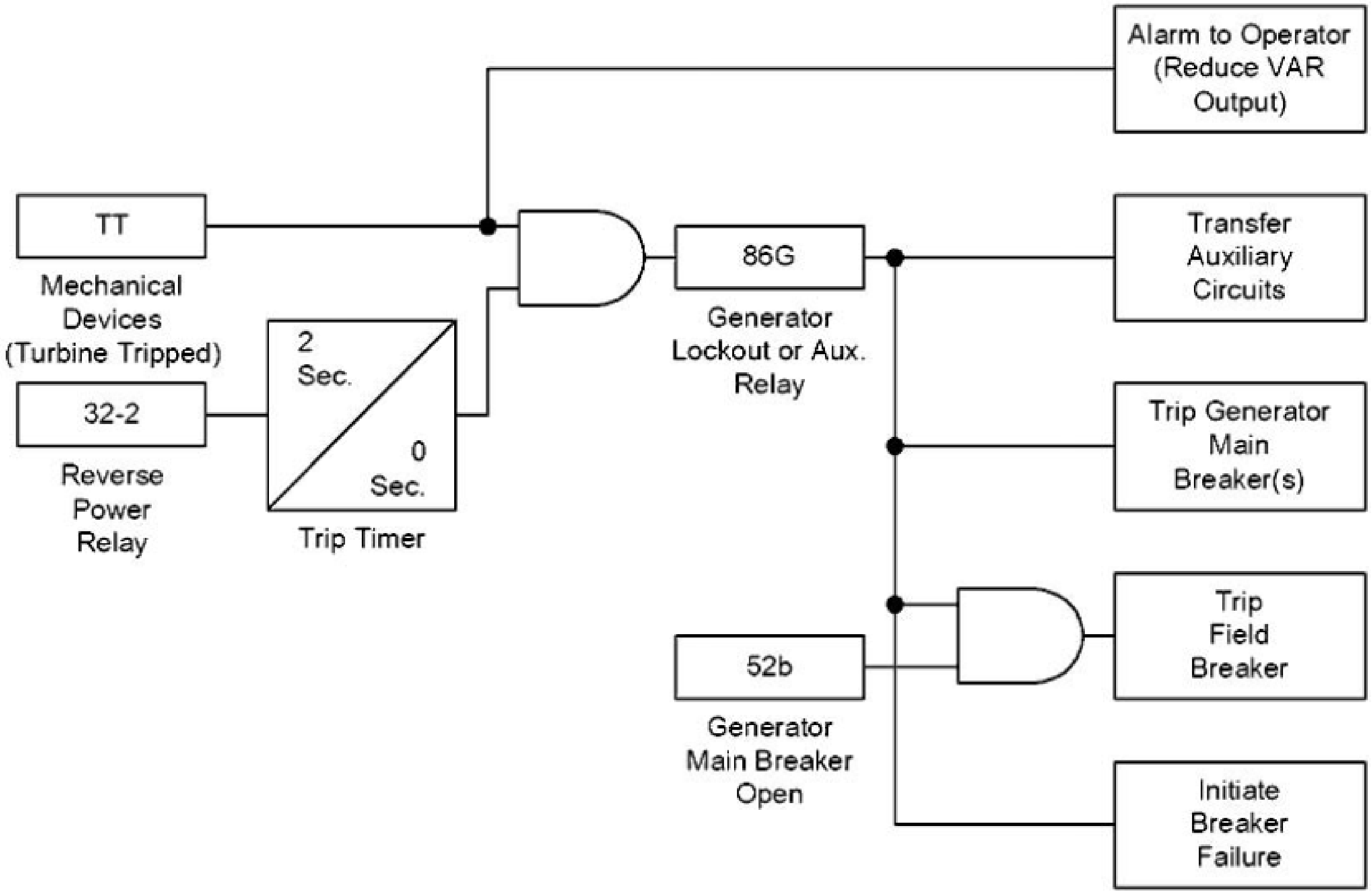


Tripping Philosophy & Sequential Tripping

– 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



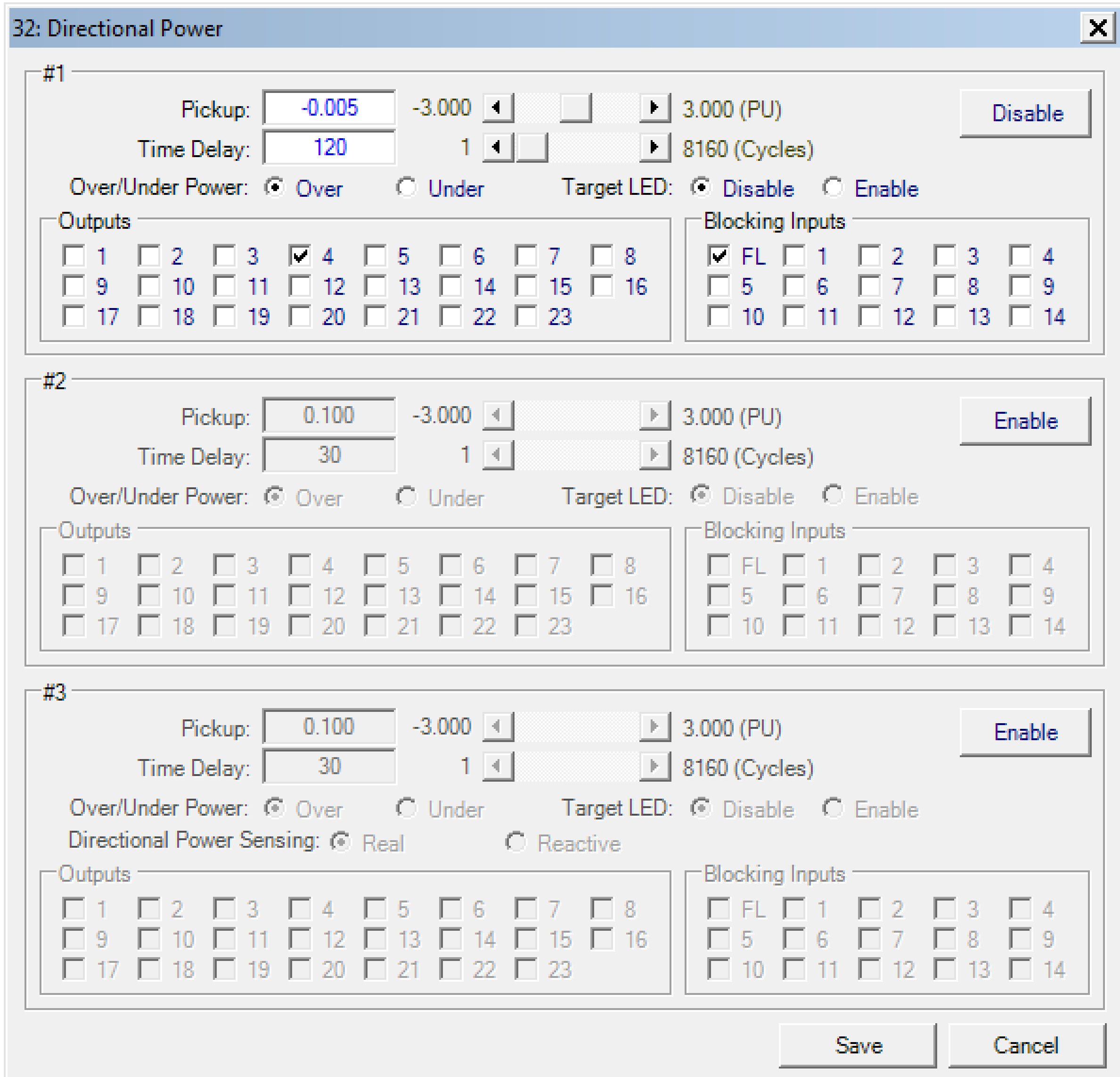
Sequential Tripping



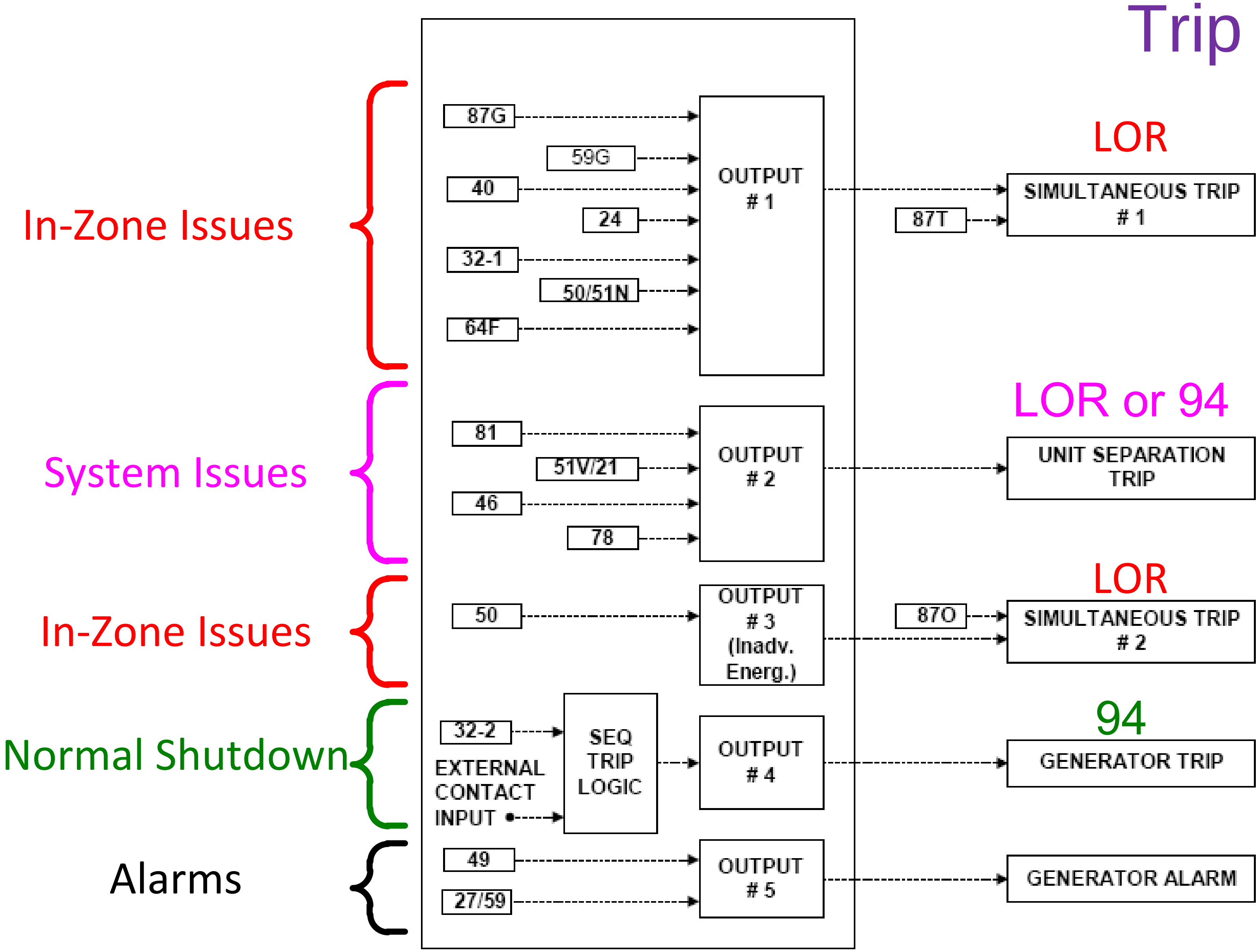
Tripping Philosophy & Sequential Tripping

- 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

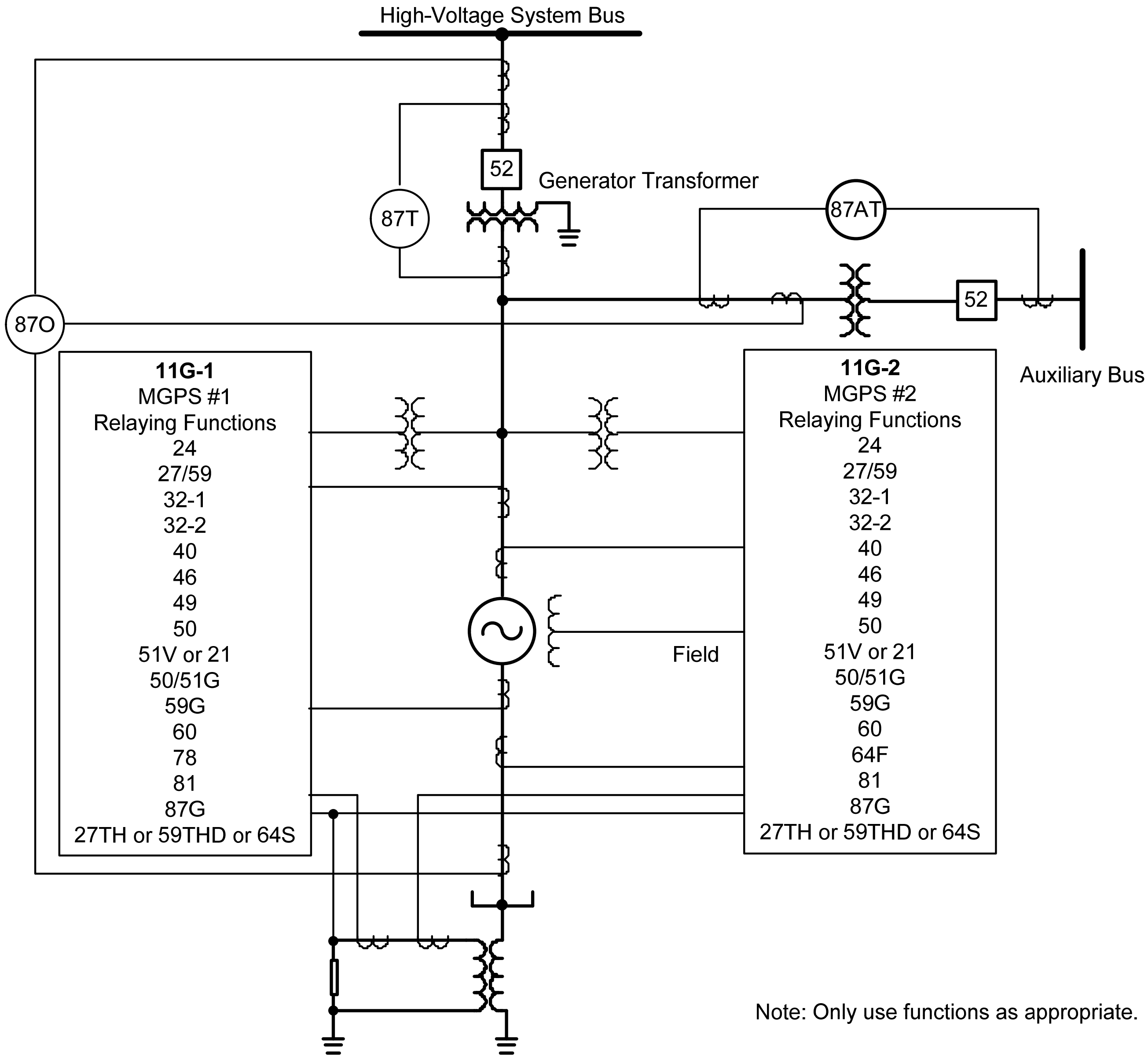
Directional Power (32F/R)



Trip Logic


In-Zone Issues
System Issues
In-Zone Issues
Normal Shutdown
Alarms
87G
59G
40
24
32-1
50/51N
64F
OUTPUT # 1
81
51V/21
46
78
OUTPUT # 2
50
OUTPUT # 3 (Inadv. Energ.)
32-2
EXTERNAL CONTACT INPUT
SEQ TRIP LOGIC
OUTPUT # 4
49
27/59
OUTPUT # 5
LOR
87T
SIMULTANEOUS TRIP # 1
LOR or 94
UNIT SEPARATION TRIP
LOR
87O
SIMULTANEOUS TRIP # 2
94
GENERATOR TRIP
GENERATOR ALARM

Typical Protection Functions for a Large or Important Generator



Note: Only use functions as appropriate.

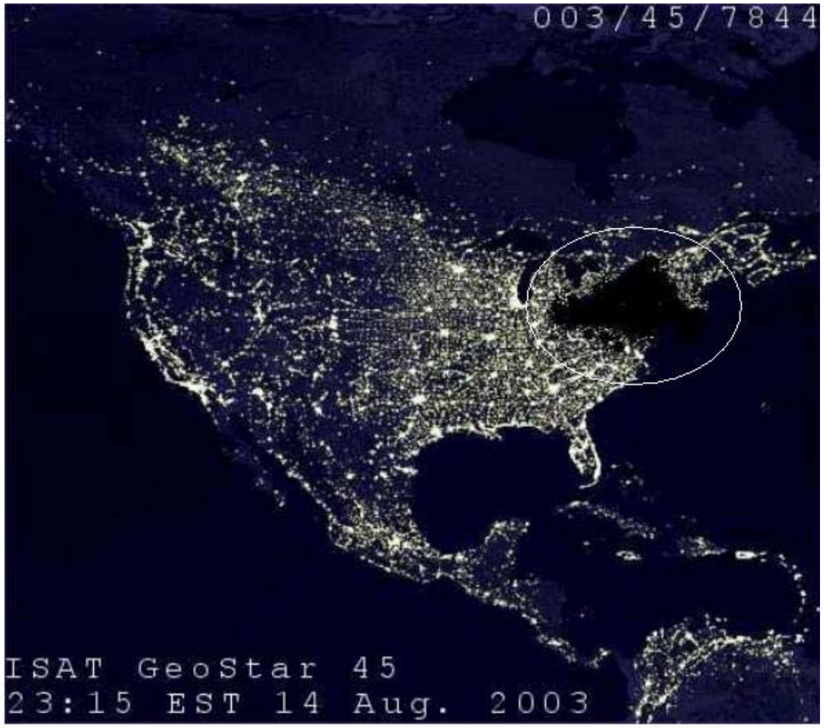
Mitigating Reliability Concerns

- 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)

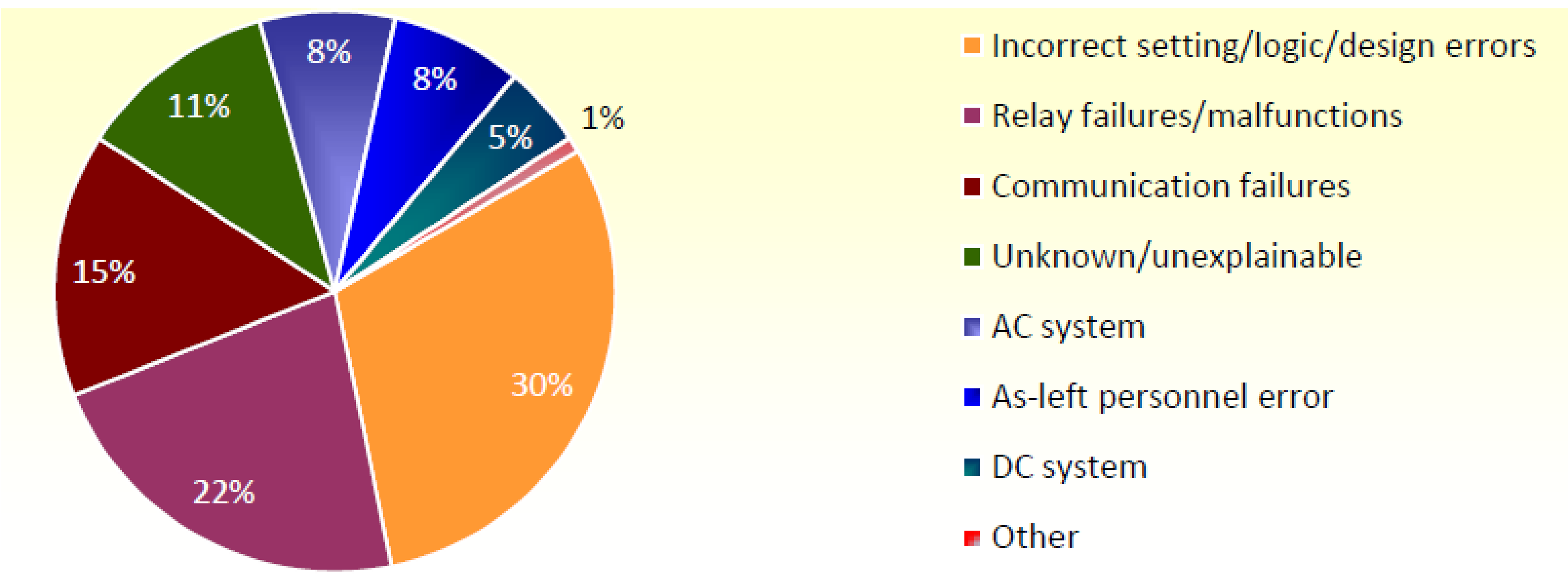
Protection Upgrade Opportunities

- **New protections**
  - Inadvertent energizing
  - VT fuse loss (integrated)
- **Special applications**
  - Generator breaker failure
    - Pole flashover (prior to syncing)

Interface and Analysis Software: Desirable Attributes

- NERC "State of Reliability 2013"
- 30% of Relay Misoperations are due to human interface error
  - Programming too complex
  - Commissioning difficult
  - Period Testing difficult

Figure 4.8: NERC Misoperations by Cause Code from 2011Q2 to 2012Q3



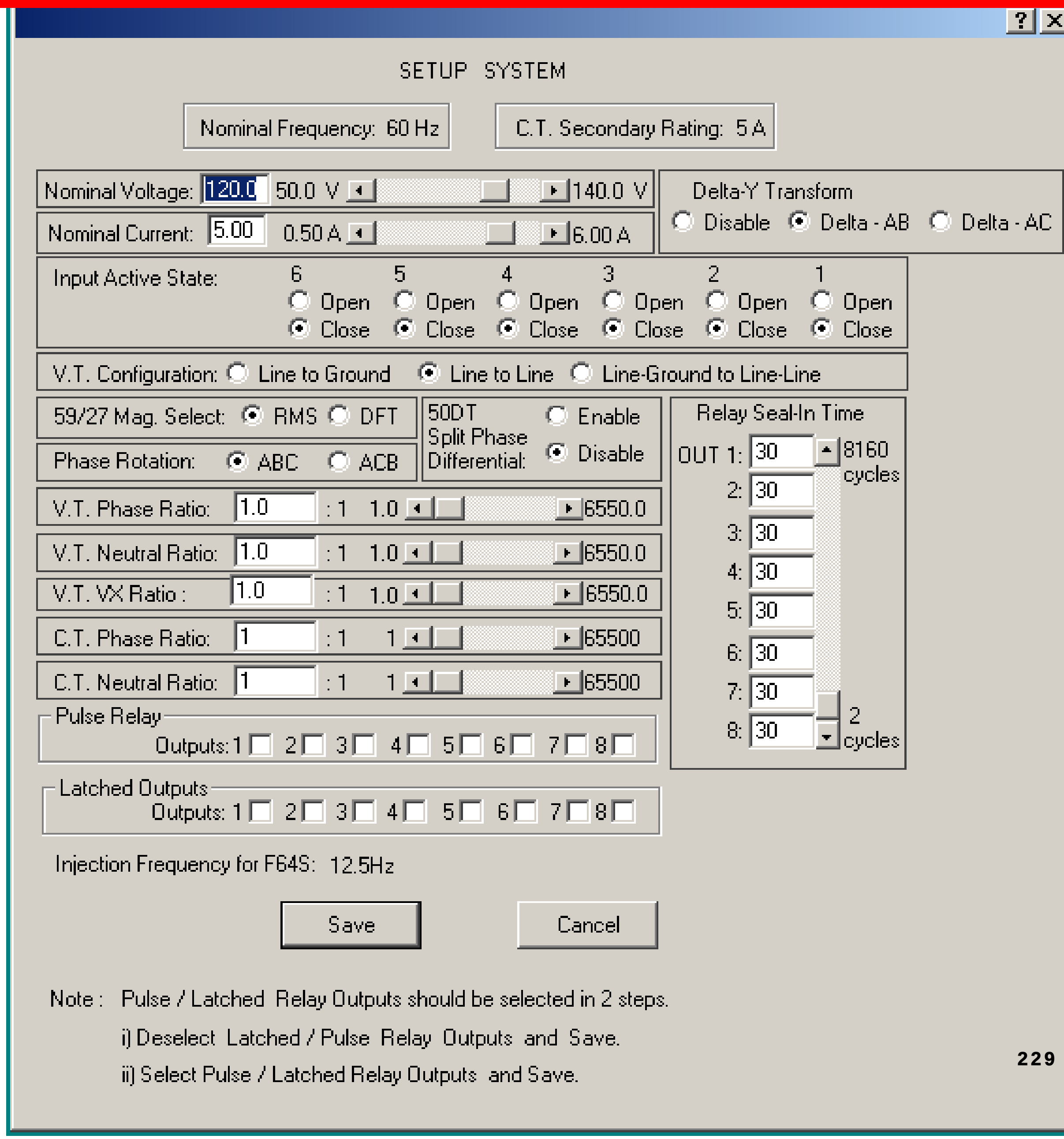
Interface and Analysis Software: Desirable Attributes

- PC Software package for setpoint interrogation and modification, metering, monitoring, and downloading oscillography records
- Oscillography Analysis Software package graphically displays to facilitate analysis, and print captured waveforms

  Be menu-driven, graphical, simple to use
- Autodocumentation to eliminates transcription errors

Example:

Relay Configuration

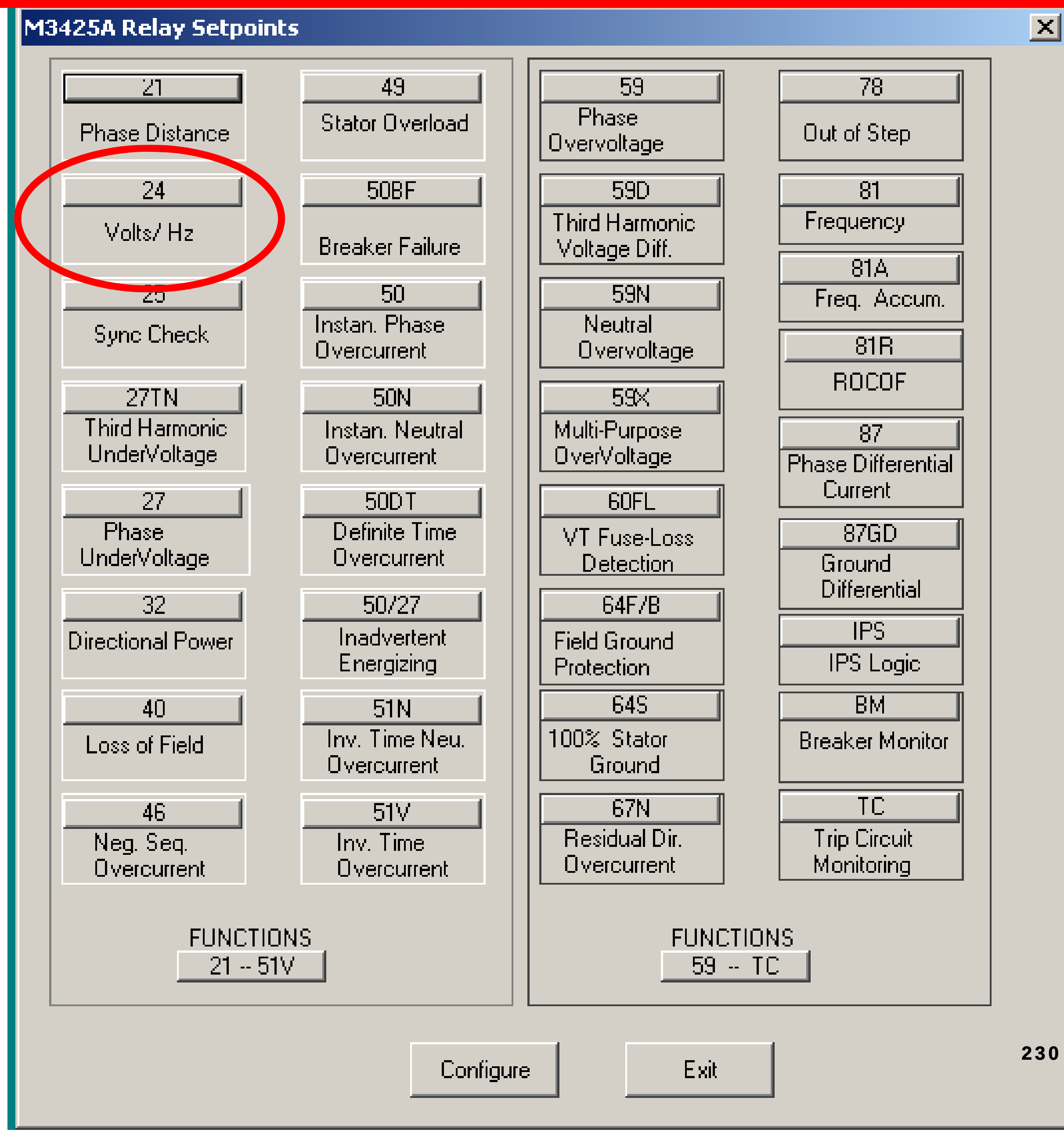


33RD ANNUAL HANDS-ON Relay School
MARCH 14–18, 2016
PULLMAN, WASHINGTON

Generator Protection

Example:

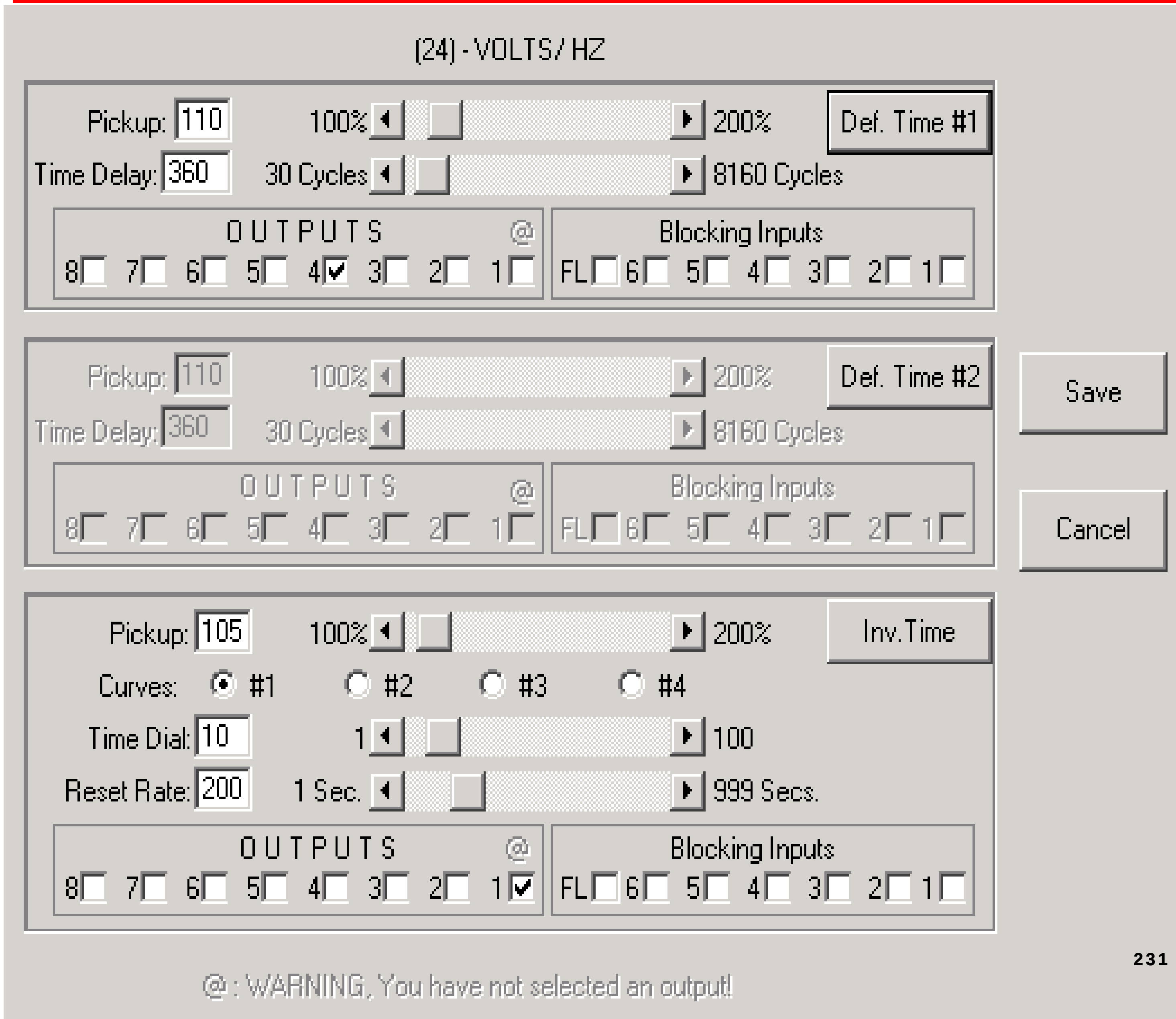
Element Selection



Generator Protection

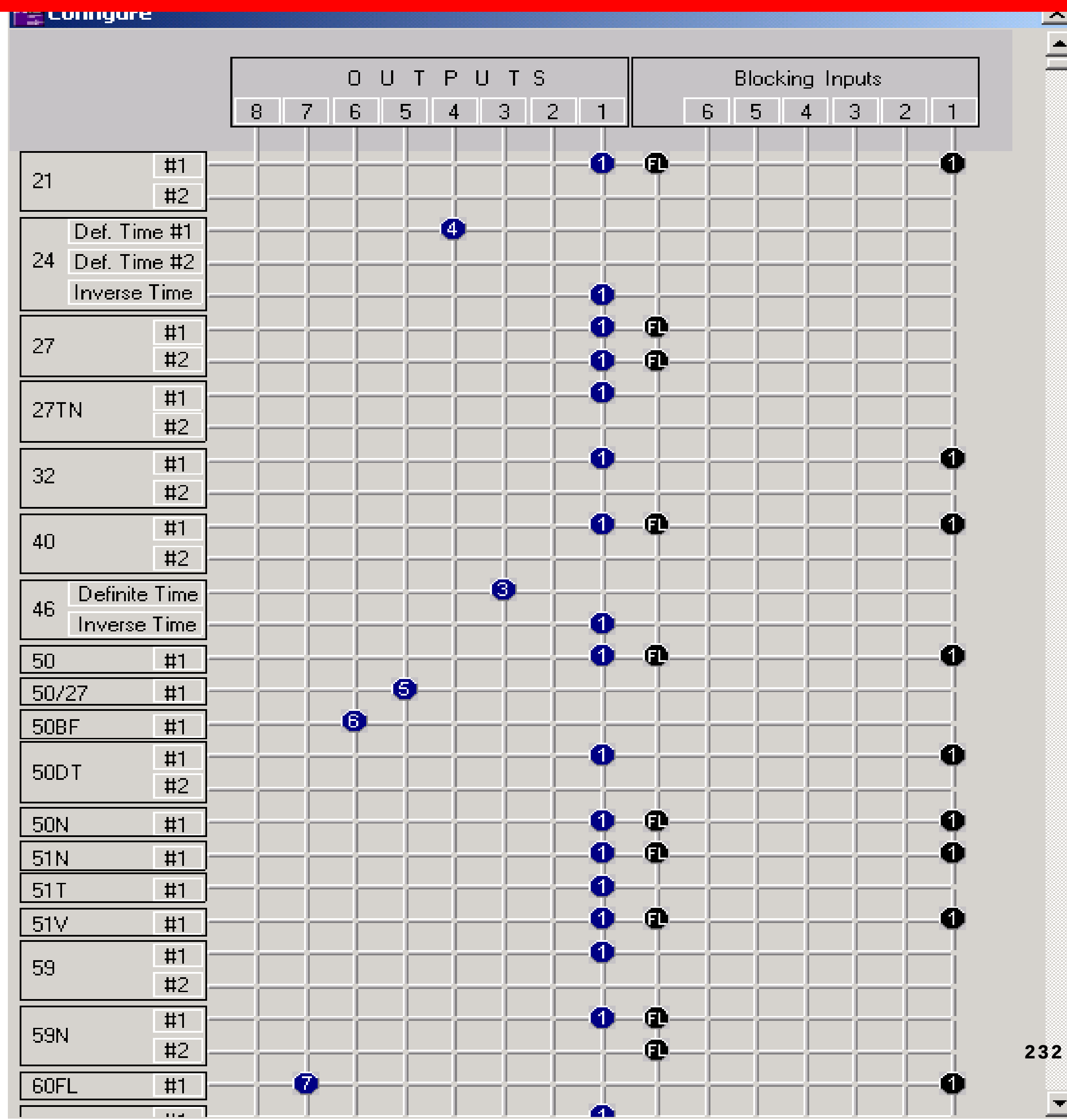
Example:

Element Setting



Example:

I/O Assignment



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Generator Protection

Example:

Settings Summary

IPScom - [All Setpoints Table]

File Comm Relay Tools Window Help

(27) Undervoltage

#1 Pickup: 90.0 %
Delay: 60 Cycles

#2 Pickup:
Delay:

(32) Directional Power

#1 Pickup: -0.02 PU
Delay: 60 Cycles
Overpower: Enable

#2 Pickup:
Delay:

(40) Loss of Field

#1 Circle Diam.: 1.00 PU
Offset: 0.10 PU
Delay: 10 Cycles

#2 Circle Diam.: 1.50 PU
Offset: 0.10 PU
Delay: 30 Cycles

Voltage Control: Disable

(46) Neg. Seq. Overcurrent

Definite Time
Pickup: 5 %
Delay: 600 Cycles

Inverse Time
Pickup: 10.0 %
Time Dial: 1
Max Time: 10000
Curves: (I square)*t=K

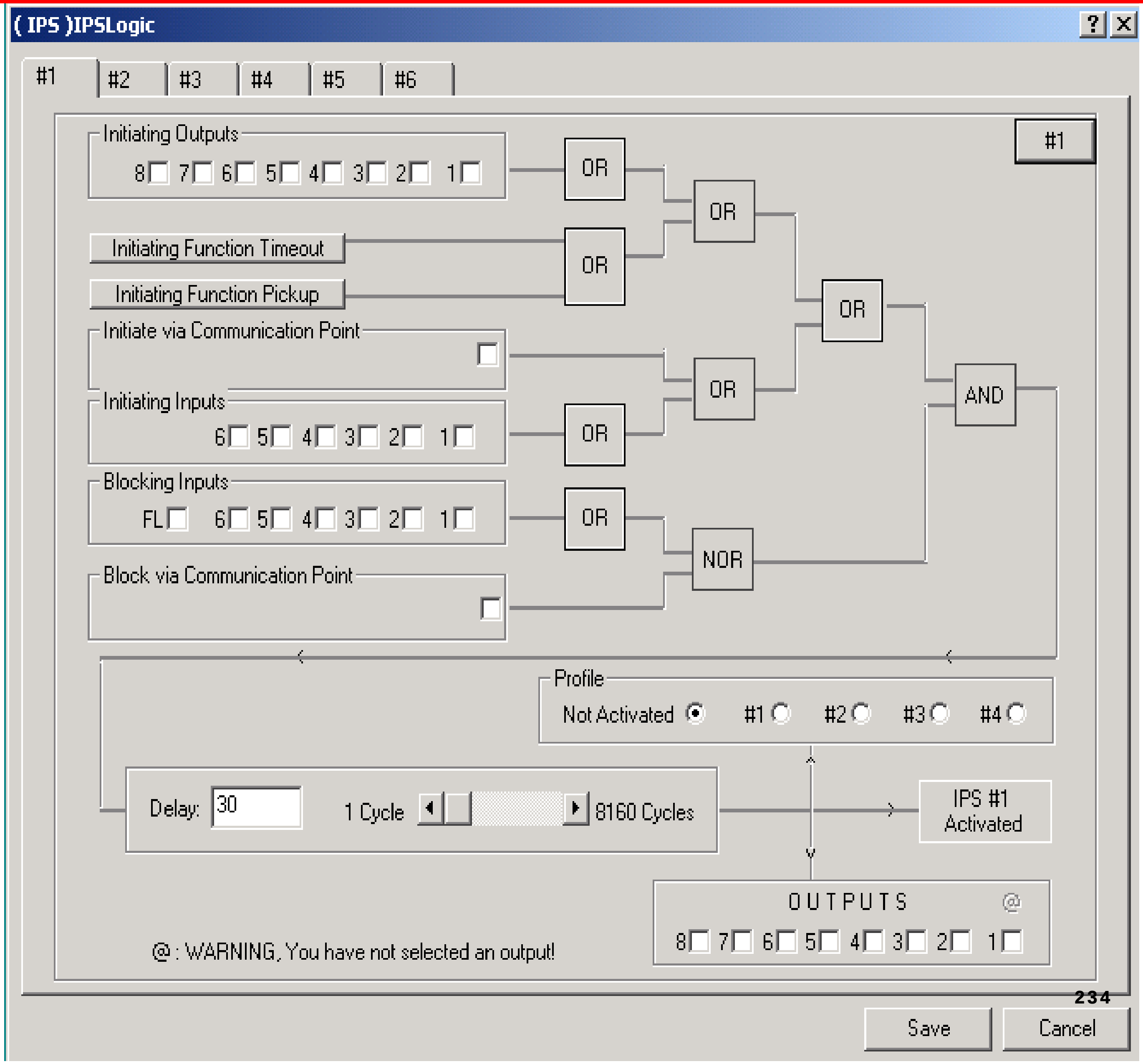
(47) Neg. Seq. Overvoltage

#1 Pickup: 25.0 %
Delay: 60 Cycles

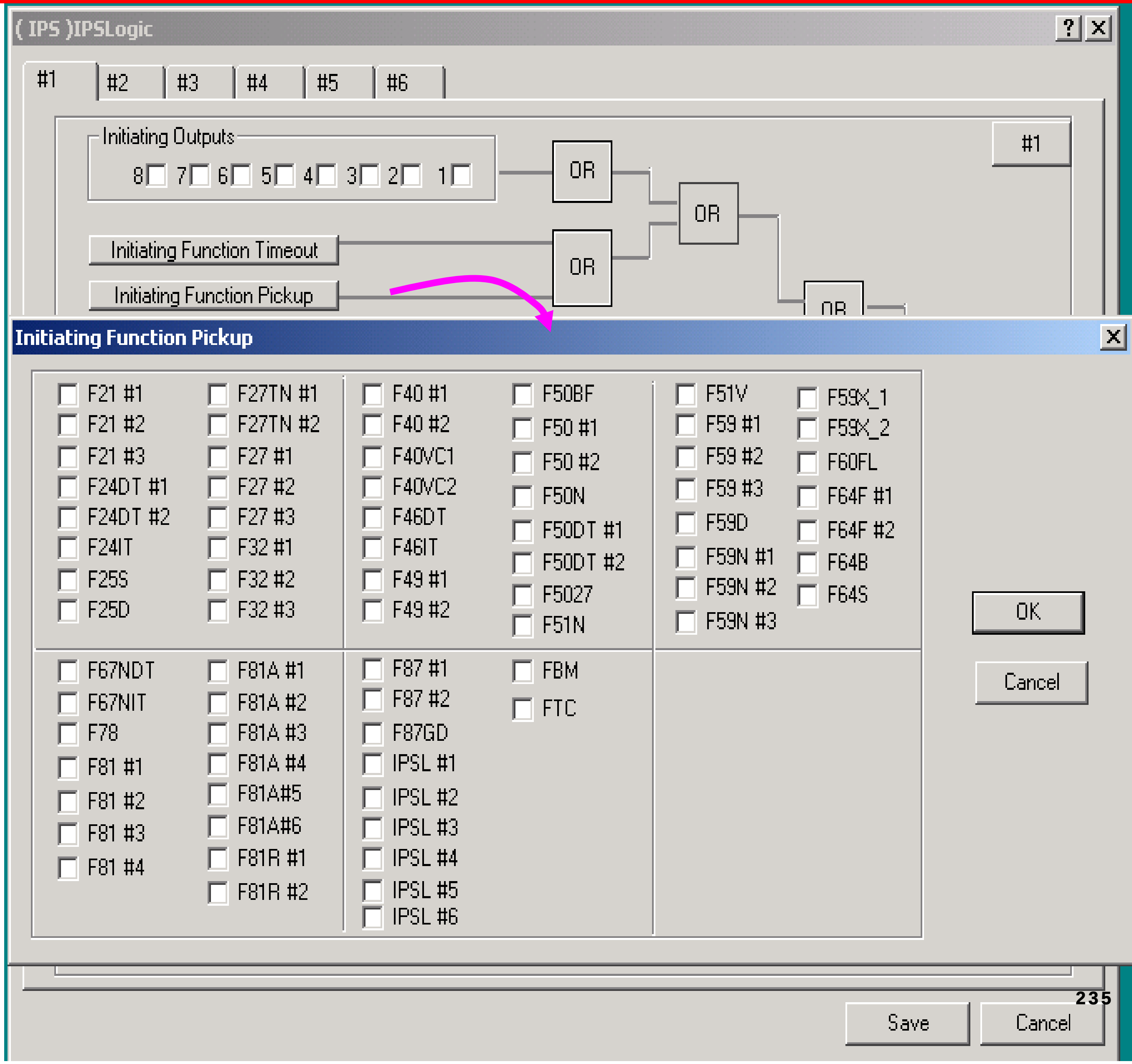
#2 Pickup:
Delay:

Generator Protection

Programmable Logic



Programmable Logic

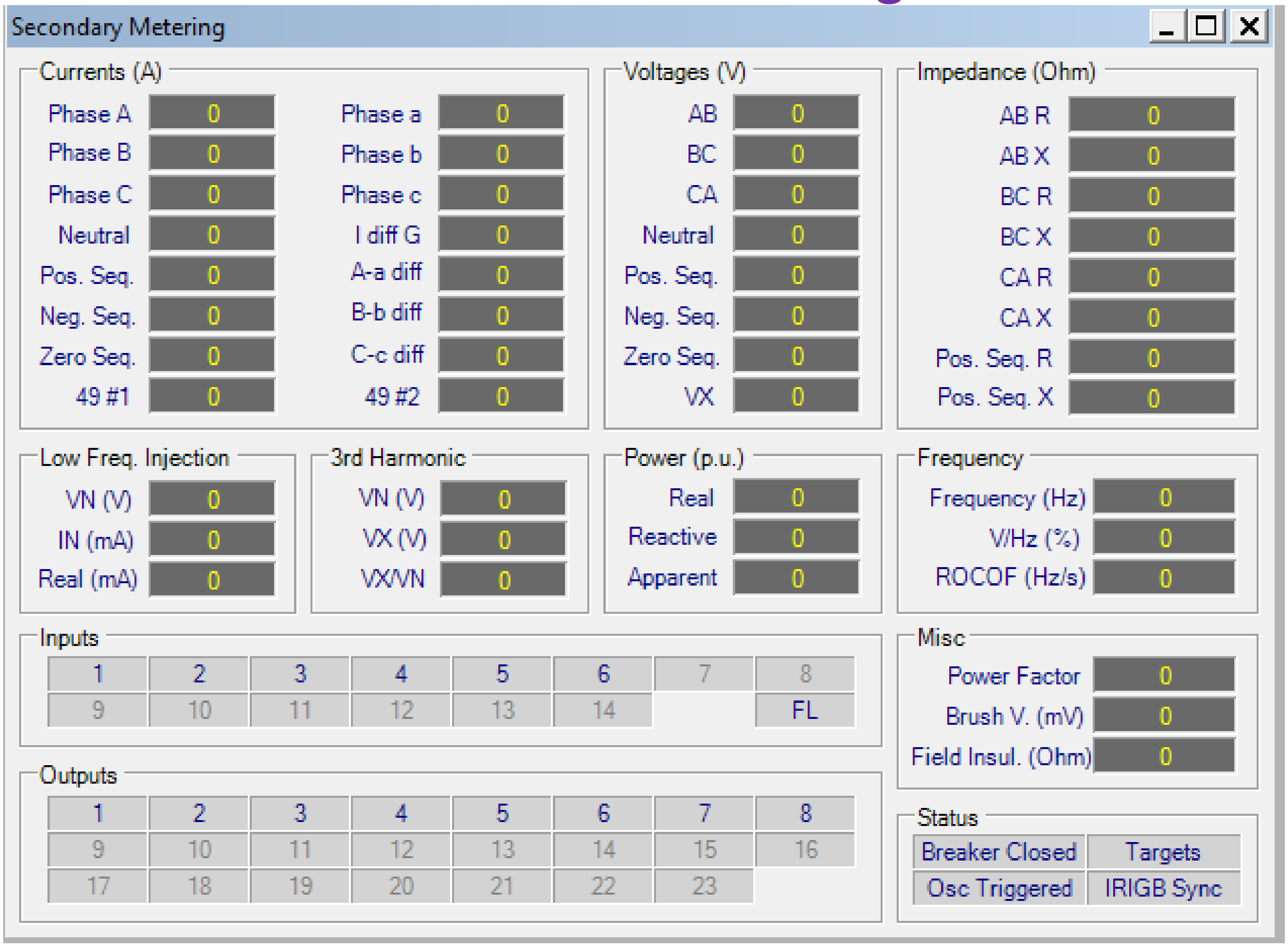


Graphic Metering and Monitoring

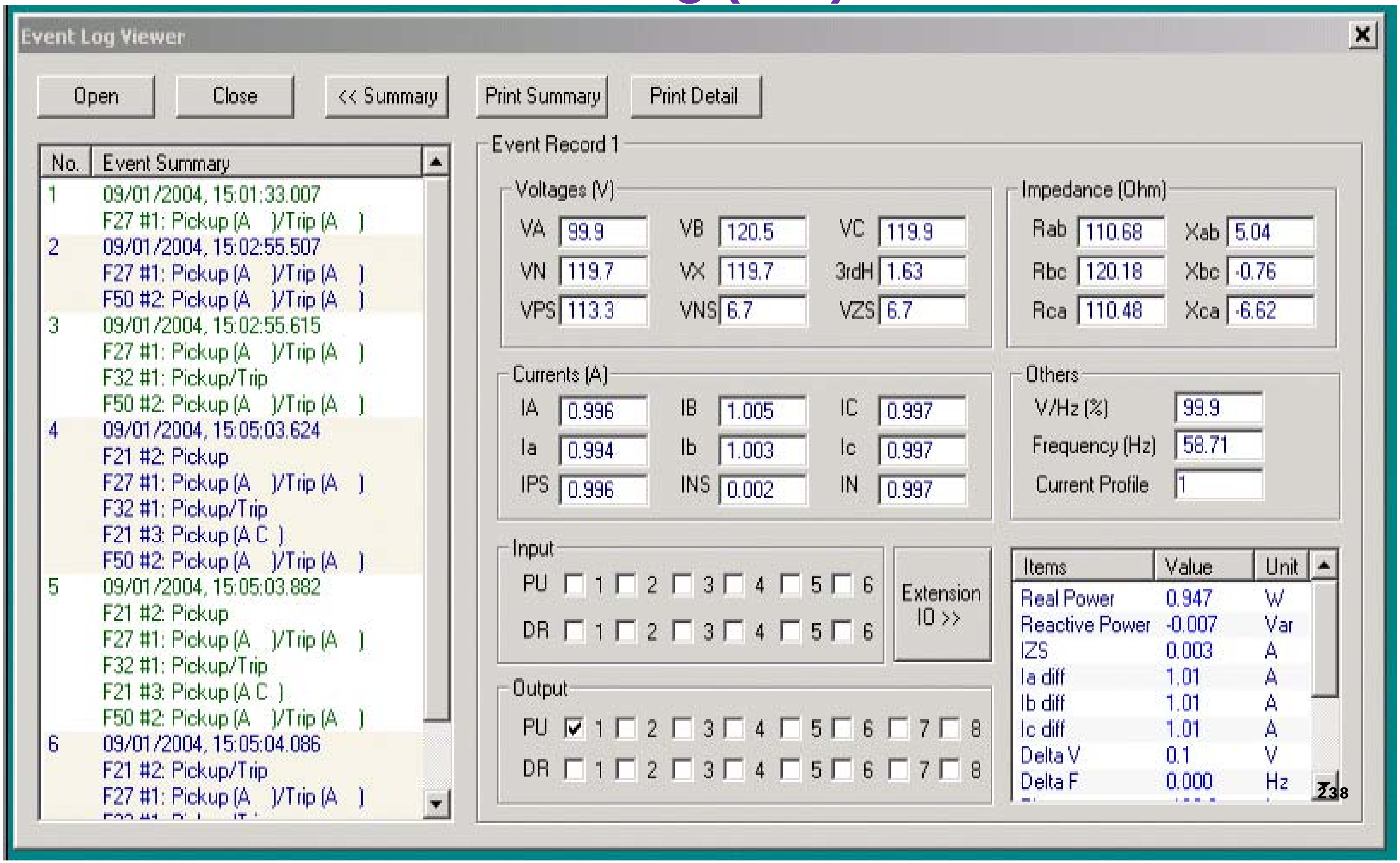
- **Metering of all measured inputs**
  - Measured and calculated quantities
    - Instrumentation grade

- **Commissioning and Analysis Tools**
  - Advanced metering
  - Event logs
  - Vector meters
  - R-X Graphics
  - Oscillograph recording

Advanced Metering



Event Log (512) Events



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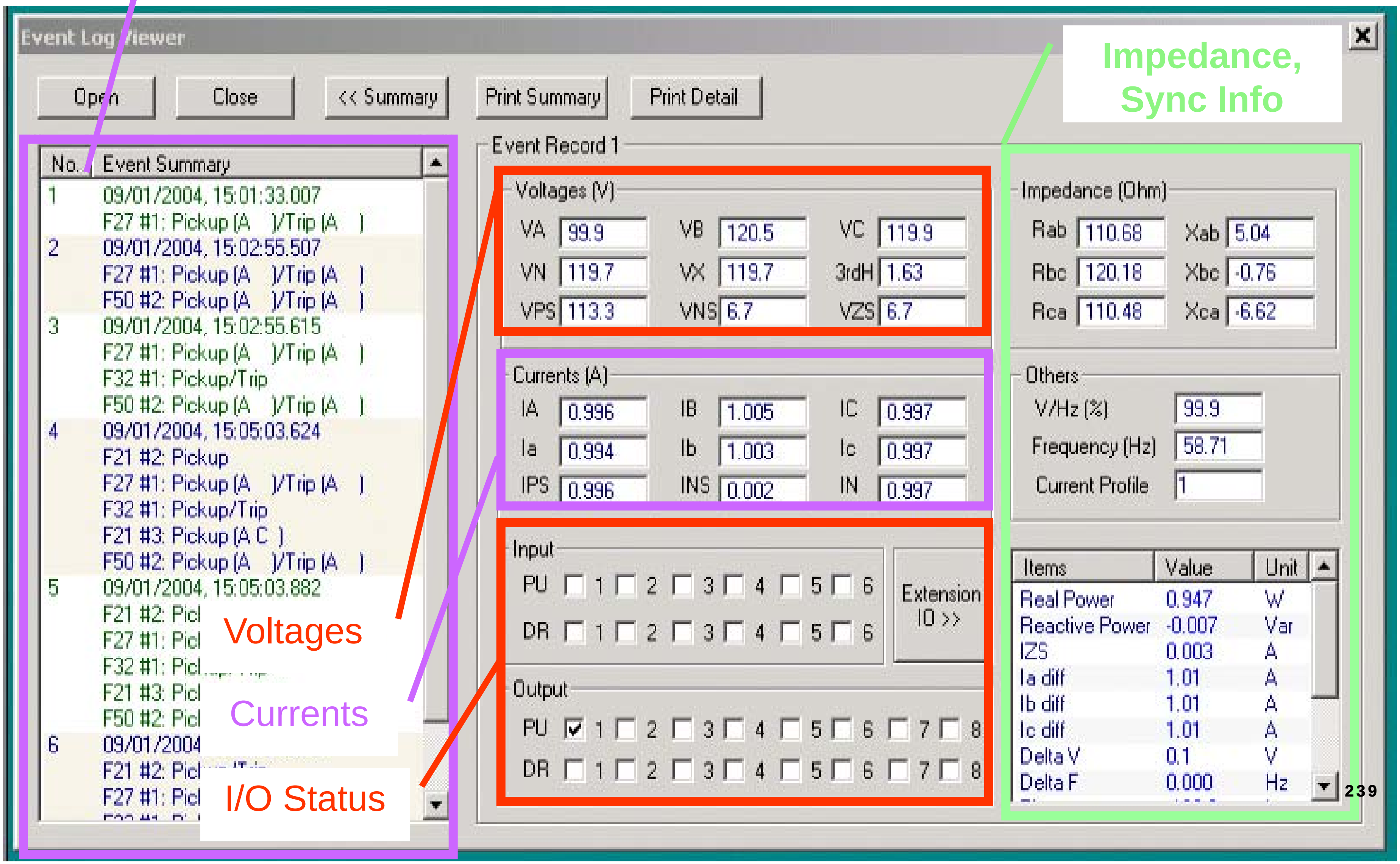
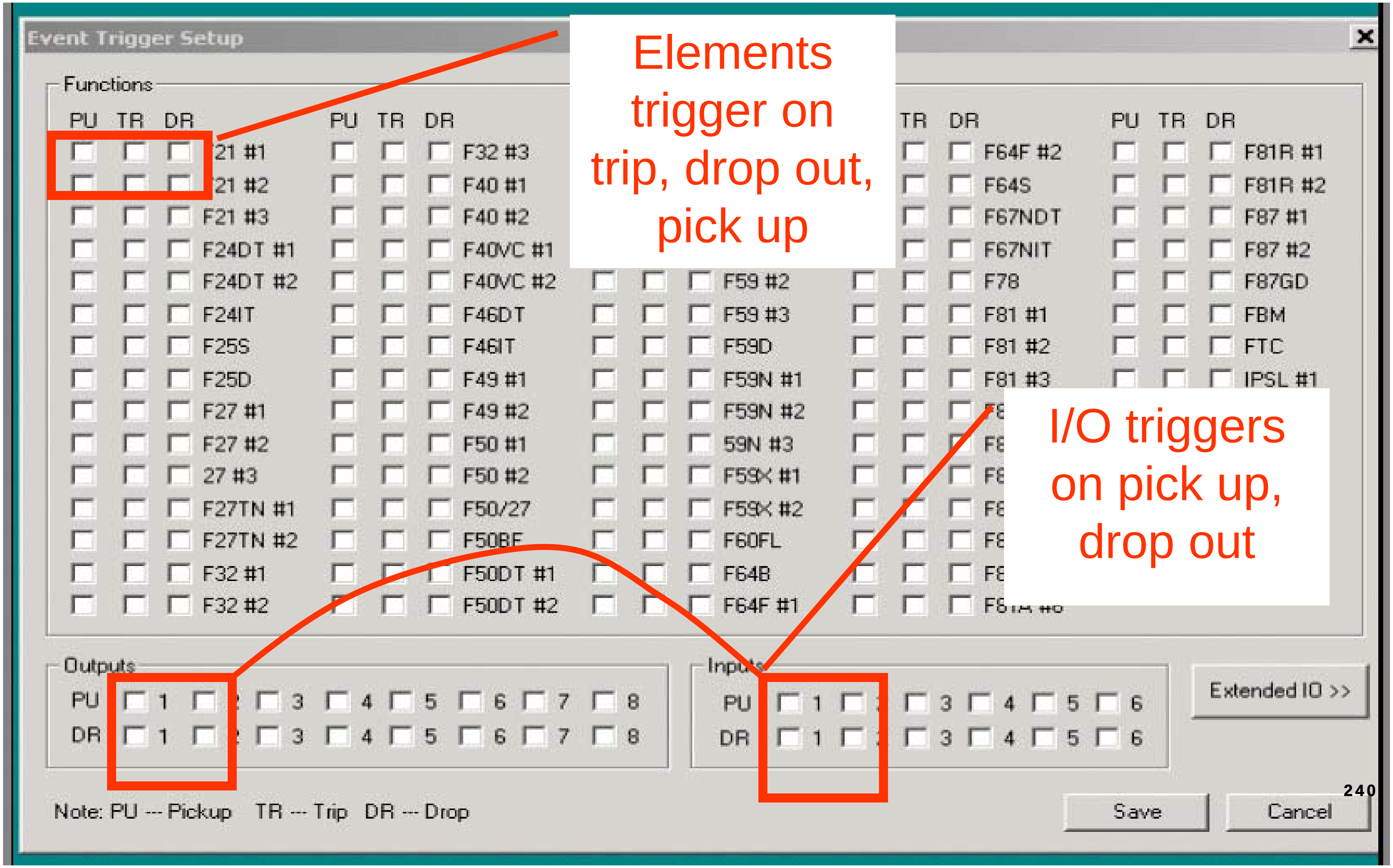
Event Log (512) Events

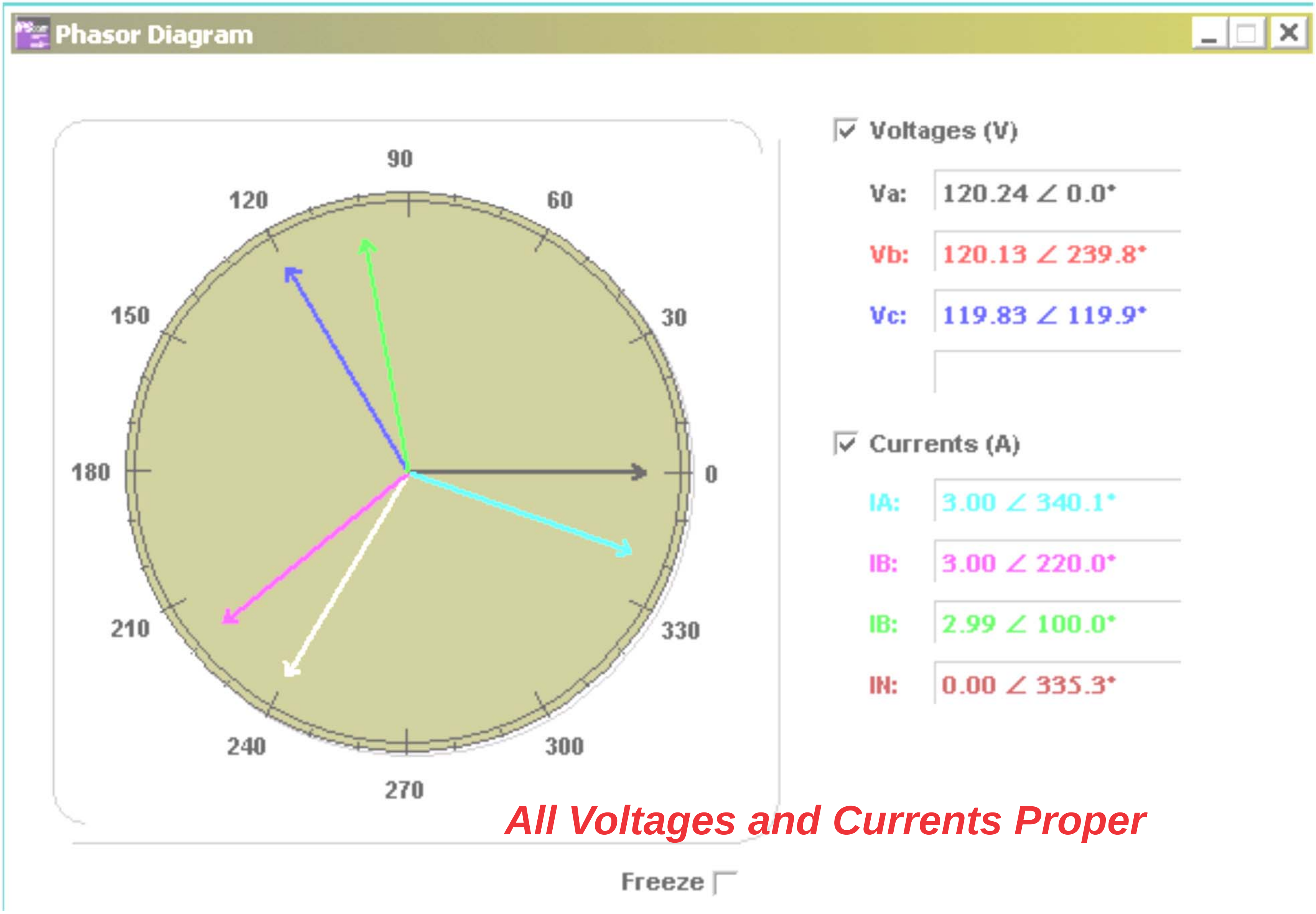
Pick up, drop out, trip
Event #, Date, Time



Event Log Trigger

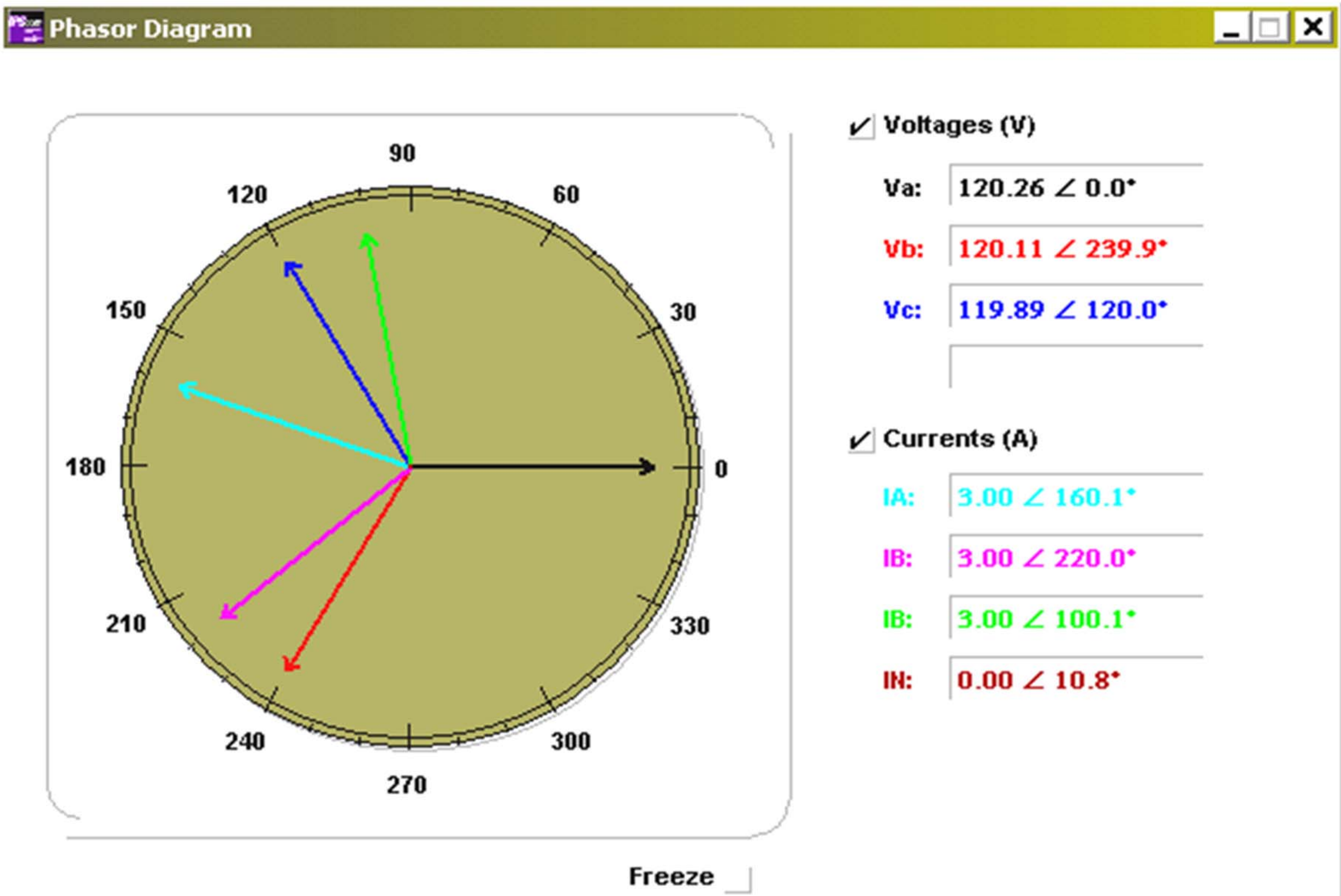


Phasor Display (Vectors)



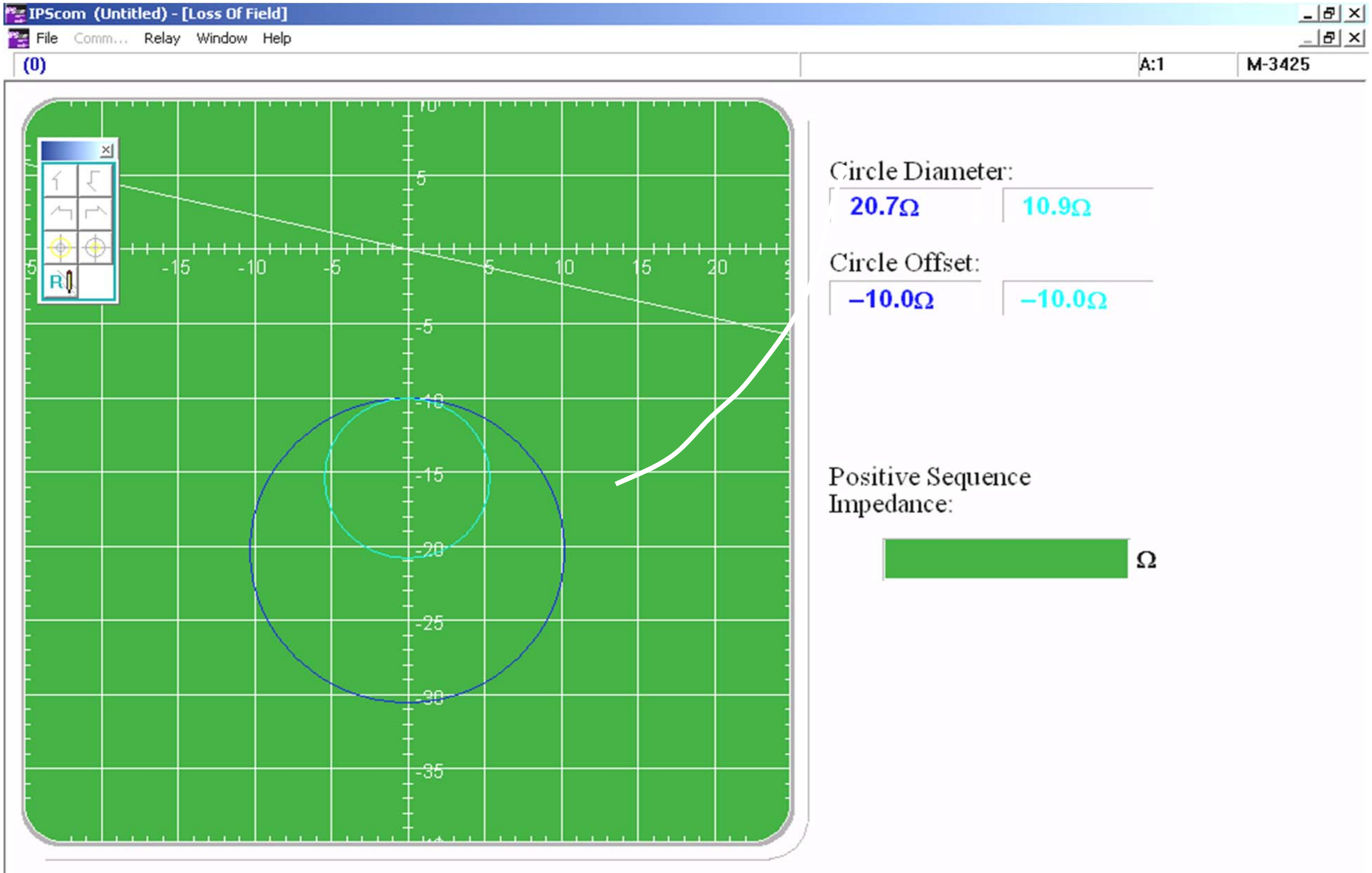
All Voltages and Currents Proper

Phasor Display (Vectors)



Phase A Current "Rolled"

R-X Graphics: Loss of Field (40)



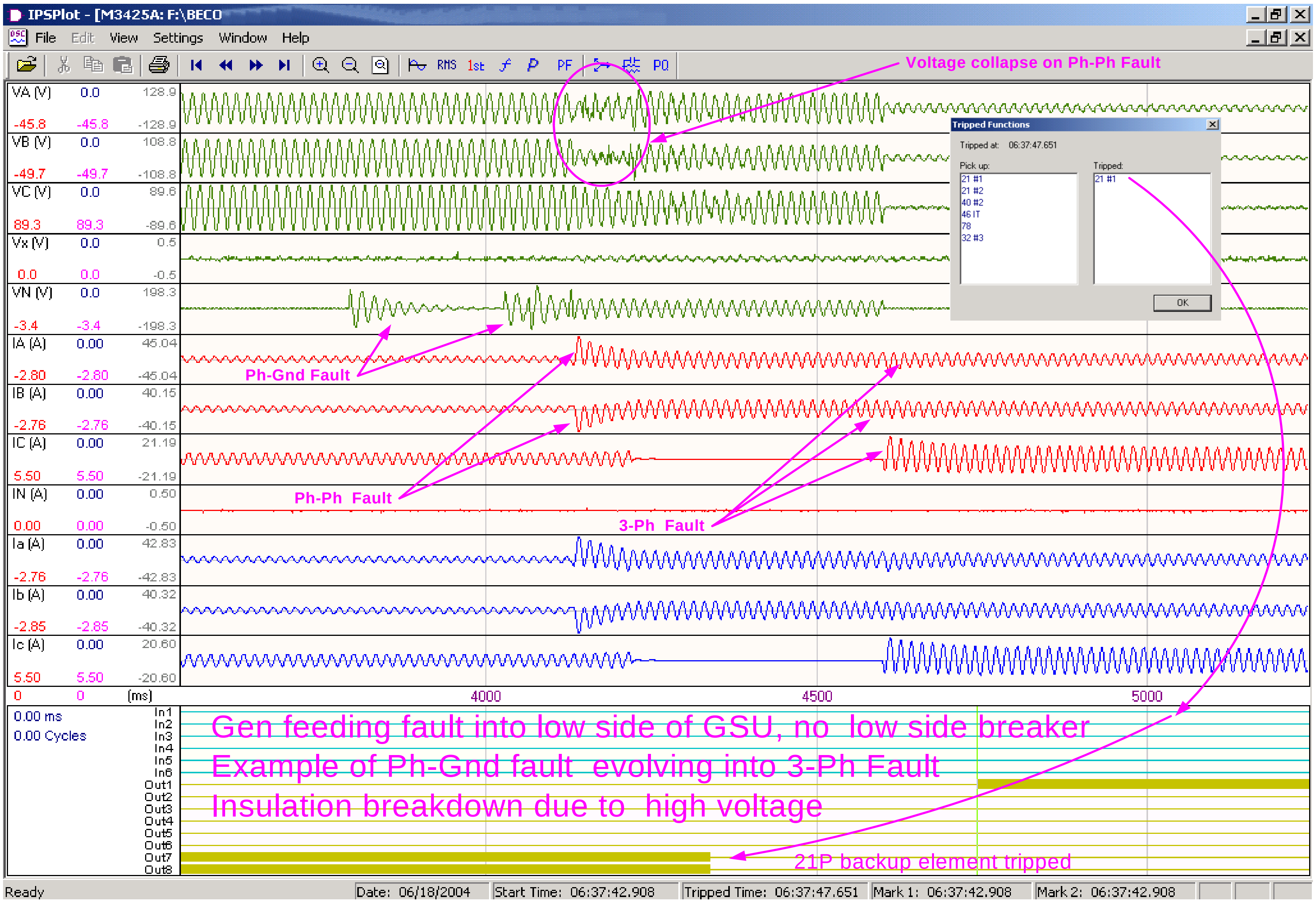
Provides the ability to check settings and view testing

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

Comtrade Format Oscillographs (*.cfg)
Record Length: 416 cycles, up to 16 records

Long Records Let You See the Issue – 416 cycles



Summary

- 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

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4. *IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems*, IEEE Std. 142-1991.
5. *Protection Considerations for Combustion Gas Turbine Static Starting*; Working Group J-2 of the Rotating Machinery Subcommittee, Power System Relay Committee.
6. *Protective Relaying for Power Generation Systems*; Donald Reimert, CRC Press 2006; ISBN#0-8247-0700-1.
7. *Practical Improvement to Stator Ground Fault Protection Using Negative Sequence Current*; Russell Patterson, Ahmed Eltom; IEEE Transactions Paper presented at the Power and Energy Society General Meeting (PES), 2013 IEEE.
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.
9. *Advanced Generator Ground Fault Protections; Wayne Hartmann, presented at the Western Protective Relay Conference, October 2015.*