NE9270
Power System Simulator

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SECTION 1.0 Introduction

Figure 1 TQ Power System Simulator NE9270

1.1 Overview: Design Philosophy

The majority of educational and training courses on power system engineering normally include laboratory work on individual components of the power system including:

- Generators
- Transformers
- Lines
- Protective relays

It is difficult to simulate in hardware form the performance and operation of the many combinations of components in an integrated power system. Software models provide a means for analysis of integrated system performance but cannot provide 'hands on' operational experience.

The **Power System Simulator (NE9270)** is a hardware, scale model of a power system, designed to mimic real systems and modern practice. It is flexible and has an extensive range of components to allow a wide range of experiments to be carried out. These experiments allow the study of essential aspects of both component and system operation and performance at undergraduate and postgraduate level. They also offer a means for operational training for industrial suppliers and utilities. The Simulator is, in effect, a small–scale, integrated power engineering laboratory, suitable for group experiments, in–class demonstrations, tutorials and training.

To maximise the capability and flexibility of the Power System Simulator, the design specification includes:

a) At least two generation or supply sources; switching and interconnecting systems; multiple lines and cables; and a distribution system and loads.

b) An integrated protection system whose operation and settings are dependent on system configuration and operation.

c) A centralized control panel for the application of faults and the measurement and record of fault currents at important points in the system.

d) Courier and Modbus communication systems for remote power system monitoring and connection to a SCADA system.

Central to the design is the selection and specification of system components which have similar per unit values to those of high voltage systems. Real systems can be set up on the Power System Simulator and calculated values of voltages, currents and power flows can be directly compared with measured values.

The voltages chosen for the Power System Simulator are 415 V/220 V/110 V (line–to–line). The choice of a 2 kVA base for the whole system gives a base current of 5 A at 220 V. The base current is suitable for the operation of commercial relays through current transformers with a 1 A secondary rating.

This choice of base current and the corresponding base impedance of 24.2 Ω assists, together with other practical features, in minimising errors in measurement due to junction resistances and relay burdens.

For general guidance in the selection of per unit values the Power System Simulator base values have been compared to a high voltage system of base values 275 kV/132 kV/66 kV and 100 MVA. Some compromises are made in the choice of per unit values.

A large number of experiments can be performed on the Power System Simulator, due to its flexibility and scope. Therefore, the experiments within this manual are specially chosen to demonstrate most of its capabilities. The experiments are described in a variety of forms, from short explanations to more prescriptive descriptions with calculations. It is anticipated that academic institutions and training establishments will wish to produce their own detailed instructions for carrying out experiments.

1.2 Outline Description of the Power System Simulator

The Power System Simulator is housed in a metal cabinet 5 m long × 2.2 m high × 1.4 m deep with rear access to all power components and bottom cable entry for a three–phase supply of 10 kW, 50/60 Hz.

The front panel of the cabinet contains a one–line schematic representation of the components within the Simulator, as well as means for their interconnection, operation and control. All components and connectors have a code description and address for identification within the SCADA system. The main components in the front panel schematic are shown in Figure 2. Section 2 describes and illustrates the main components in greater detail and a complete diagram of the front panel is included with this manual.

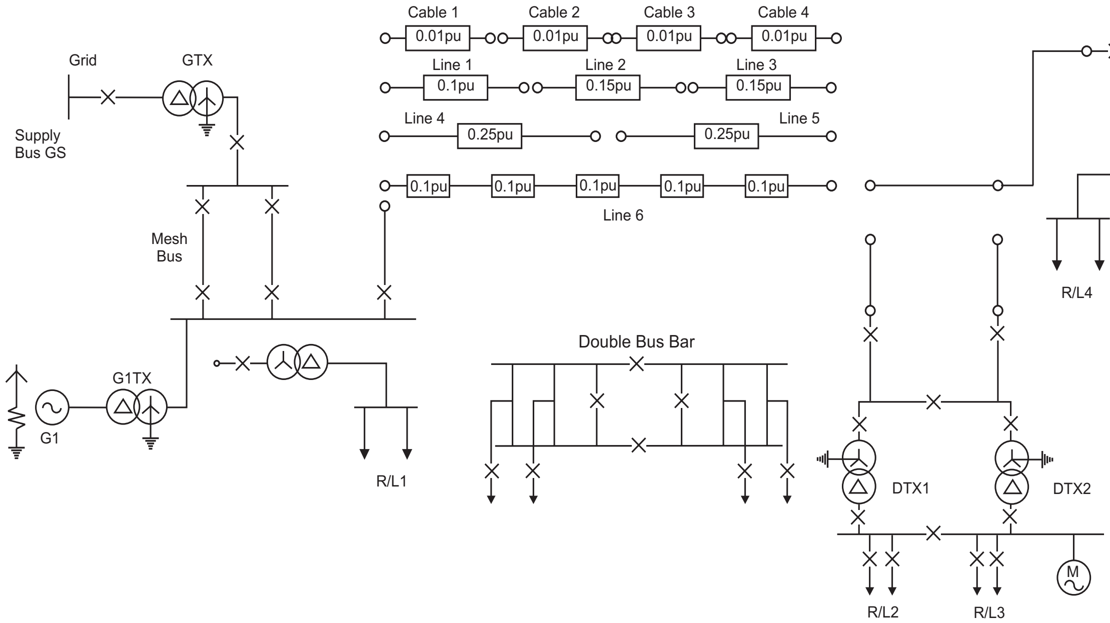


Figure 2 Schematic Diagram of Main System Components

Circuit breakers (or contactors) for system isolation or connection are shown in Figure 2. Each circuit breaker on the schematic has a manual close/open lever nearby.

The components of the main Power System Simulator are:

a) The Grid Supply, GS, and Grid Supply transformer, GTX.

b) A generator unit, G1, and generator transformer G1TX which may be connected to the Grid Supply through a mesh bus system.

c) A set of transmission lines (Lines 1 to 6) and cables of varying lengths for interconnecting between the power supply points and the loads. Line 6 differs from the others in being of several sections of shorter length. This arrangement is for studies specifically of the distance protection of transmission lines, but it can be used also as a general interconnecting line.

d) A distribution busbar which feeds, through two, parallel-connected transformers, DTX1 and DTX2, a utilisation busbar and a load centre consisting of resistance, inductance and capacitance, Load 2 and Load 3. An induction motor, M, may also be connected to the utilisation busbar to study the effects of dynamic as well as static loads.

e) A double busbar interconnector is placed centrally in the Power System Simulator panel. This provides not only convenient central connection points for the various components but also a study of busbar protection.

f) Placed centrally on the Power System Simulator panel (but not shown in Figure 2) are the 24 test points and alarms, the test switches which allow application of balanced and unbalanced faults and the synchronisation system and metering for paralleling the Grid Supply with generators G1 or G2, or for paralleling generators G1 and G2.

g) Each component of the Power System Simulator has an integrated protection system. These are not shown on Figure 2. The relays are placed into the front panel and their points of connection to the system are shown in the technical description of the protection system in Section 3. If a relay is taken out of the panel, contacts are closed so that the Simulator circuits are not open–circuited.

h) The Simulator Power System is 3 phase, 3 wire from supply to load. There is no neutral wire. A single solid earth bar provides earthing for the star points of transformers and other similar apparatus.

1.3 Parameter Values of Components: The Per Unit System

The parameter values of the components of the Power System Simulator represent, as far as possible, the parameter values of a real system. This can only be achieved on a proportional, or **per unit** basis, where the actual value of the parameter is expressed as the ratio of that parameter to a chosen **base value**. System representation is achieved by having the same per unit values as the actual system. Actual values are obtained by multiplying per unit values by the appropriate base values.

An understanding of the per unit system is essential to appreciate the theoretical significance of measurements made on the Power System Simulator. A summary of the per unit system is given in APPENDIX 1.

The base values of voltage and apparent power (voltamps) chosen for the Power System Simulator, and of the derived base values for current and impedance are given below:

Base voltages: 415 V/220 V/110 V (line values)

Base voltamps: 2 kVA

Base currents: 2.78 A/5.25 A/10.5 A

Base impedances: 86 Ω/24.2 Ω/6.05 Ω

For transmission lines, variation of the per unit value is possible by varying the length of the line, or by parallel connection. For a component such as a generator there is a need for compromise in the single per unit value chosen for electric parameters. However, variation of the angular momentum, M, is possible and a number of values are provided.

The per unit value of the components of the Power System Simulator are given in Table 1, all to a 2 kVA base. Individual component values are derived and discussed in later sections of this manual. The per unit values given are nominal values, which may differ slightly from the values measured on each Simulator. This is particularly true for the transmission line and cable reactances whose linearity is only within reasonable error limits up to about 20 A (see “Line and Cable Inductors” on page 13). Additionally, the current transformers have an accuracy of < 5% up to 10 times rated current. It is therefore advisable to keep system currents, at 220 V, less than 20 A and not greater than 30 A under fault conditions. The individual components are described briefly in the following sections.

System component	Identification (Refer to Figure 2)	Line volts (V)	3–Phase (VA) (50Hz/60Hz)	Parameter values			
				2 kVA base	2 kVA base	At 220 V	At 220 V
				Xpu (50Hz/60Hz)	Rpu	XΩ	RΩ
Grid supply	GS	415 V	5 kVA	–	–		
Grid transformer	GTX	415/220 V	5 kVA	0.048	0.016		
Generators	G1, G2	220 V	6.5/7.8 kVA	–	–		
X_d			(4 pole)	0.478/0.69	–		
X_q				0.167/0.24	–		
X_d'				0.047/0.068	–		
X_q'				0.167/0.241			
X_d''				0.039/0.056	–		
X_q''				0.191/0.276			
X_2				0.044/0.064			
X_0				0.017/0.025			
T_d' sec				0.028	–		
T_d'' sec				0.027	–		
T_{d0}' sec				0.75			
Transformer	G1TX	220/220 V	5 kVA	0.052	0.015		
Transformer	DTX1	220/110 V	2 kVA	0.13	0.054		
Transformer	DTX2	220/110 V	2 kVA	0.13	0.054		
Earthing		220/110 V	2 kVA	0.018	0.074	0.44	1.8
Transmission lines							
Line 1		220 V	2 kVA	0.10	0.008		
Line 2		220 V	2 kVA	0.15	0.013		
Line 3		220 V	2 kVA	0.15	0.013		
Line 4		220 V	2 kVA	0.25	0.021		
Line 5		220 V	2 kVA	0.25	0.021		
Line 6	x 5	220 V	2 kVA	0.10	0.008		
Cable	x 4	220 V	2 kVA	0.01	0.0008		

Table 1 Parameter Values of Power System Simulator Components. ***Note: The Generator does not have damper bars.***

Parameter Values:

Per Unit values are nominal as shown.

Columns for ohmic values are available for entry of values obtained by tests on each simulator (see section 2.4 and Section 5).

1.4 Outline of the Manual

The function of this manual is to provide a technical description of the Power System Simulator (PSS) and to demonstrate its use and range of capabilities by means of illustrative experiments.

The technical description and general operation of the PSS is contained within Sections 2, 3 and 4. The technical description of the individual components of the PSS follow in Section 2, with the technical description of the protection system for each component in Section 3. Information on the central test and control section and the general operation and use of the PSS is given in Section 4.

Sections 5, 6 and 7 together include a set of experiments that demonstrate the use of the Power System Simulator. The experiments include guidance on the procedures, calculations and sufficient information to set up relays and instrumentation. However, it will be necessary to refer to both this manual and the relay manuals when carrying out experiments on protection systems. In each section an outline of the required theory is given together with a list of references. A fuller treatment of relevant theory and practice is contained in 'A Course on Power System Engineering,' by Professor A. L. Bowden.

The experiments are divided into three broad areas: steady state operation (Section 5), fault studies (Section 6) and system protection (Section 7).

SECTION 2.0 Technical Description: Main Components

This Section provides a technical description, with specifications where necessary, for each of the main components of the Power System Simulator. Technical Drawings for all components of the Simulator and their controls are provided with the Simulator.

The main supply to the Console is 380/415 V, 3 phase plus neutral. The supply point is on the left hand side of the Console panel. Power supply is taken into the unit via terminals inside the case and through 20 A line fuses F1, F2 and F3. Technical Drawing 79960 details the main supply connections to the Simulator.

The main supply is switched on by a 30 A MCB. The MCB has emergency and under voltage trips and is interlocked through the Emergency Stop switches and door limit switches.

To switch on the supply to the Simulator, the MCB should be pressed up until it latches; but follow the directions given in Sections 4.8 and 4.9 before switching on the Simulator or the Generator Set. The Main Supply feeds the Grid Transformer and Grid Bus, the Vector Drive for the Generator 1 Set, the M230 and DH96 meters, and the MiCOM relays, CB Controls and the Transducers. A supply to 'External Equipment', through 10 A fuses, is also provided.

A large red 'emergency stop' button is situated near the right-hand edge of the Console desk. The MCB trips out when the emergency button is pressed. To restart the Simulator after an emergency button has been pressed, the button must first be turned to release it from the locked position.

The optional SCADA system also includes an emergency stop feature.

2.1 Grid Supply

The 415 V supply is fed to a Grid Supply busbar which feeds, through circuit breaker CB1 and further 16 A line fuses, a 5 kVA, 415 V/220 V three-phase Grid Transformer (GTX) with a phase connection of Dy11. The star point of the secondary winding can be earthed. Refer to Technical Drawing 79960 for details.

Figure 4 shows the schematic diagram of the Grid Supply Busbar and Grid Transformer, together with the test points TP1 and TP2, circuit breakers CB1 and CB2 and associated protection relay and meters as given on the front panel of the Power System Simulator.

The Grid Bus has two outgoing feeders connected to the Generator 1 Bus through circuit breakers CB3, CB4, CB5 and CB6 and six additional cable sockets. This 'Mesh' Busbar, or Substation, arrangement provides increased flexibility in the interconnection of power systems.

2.2 Generator Unit G1 and Transformer G1TX

On the front panel of the Power System Simulator is a schematic diagram of the generator unit G1 and Transformer, G1TX, including the location of test points TP3 TP4 and TP5, circuit breaker CB8 and associated protection scheme. This diagram is shown in Figure 5. The interconnection of the Generator, G1, and associated equipment is detailed in Technical Drawing 79961. The generator transformer is rated at 5 kVA, 220/220 V and has a phase connection of Dy11.

The generator stator winding is star connected. The neutral end of the winding may be connected to earth through an earthing resistor of 128 Ω. Current transformers (CTs) are provided at either end of each phase winding for connection of the Generator Protection relay, MiCOM P343. All protection functions shown are performed by this relay. This detail is shown in Figure 25.

The field winding of the generator, circuit breaker, and instrumentation for the generator and excitation is shown above the generator symbol: generator speed (RPM), load angle 'delta' (δ), field excitation volts and current. A three phase, M230 meter, Meter C, provides generator output data. Voltage, current and power meters are provided for the induction motor, or 'Prime Mover', driving the generator.

The control panel for Generator 1 is situated near the central Test and Control panel for the Simulator and is shown in Figure 3. 'Start' and 'stop' buttons are provided for the prime mover and control potentiometers for control of speed/power and field excitation current. Above the generator control panel are voltage and frequency meters for both Gen 1 Bus and Grid Bus. These meters, and the terminals alongside them, are used when synchronising the generator to the Grid Bus, or to Generator 2. The symbol ‘Y’ positioned below the terminals indicate the position in the circuit at which these voltage and frequency measurements are taken. For the Generator 1 the ‘Y’ symbol is shown after test point TP4.

CBF and CB8 are linked for ease of operation.

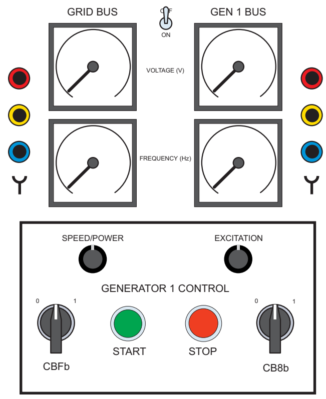


Figure 3 The Control Panel for Generator 1

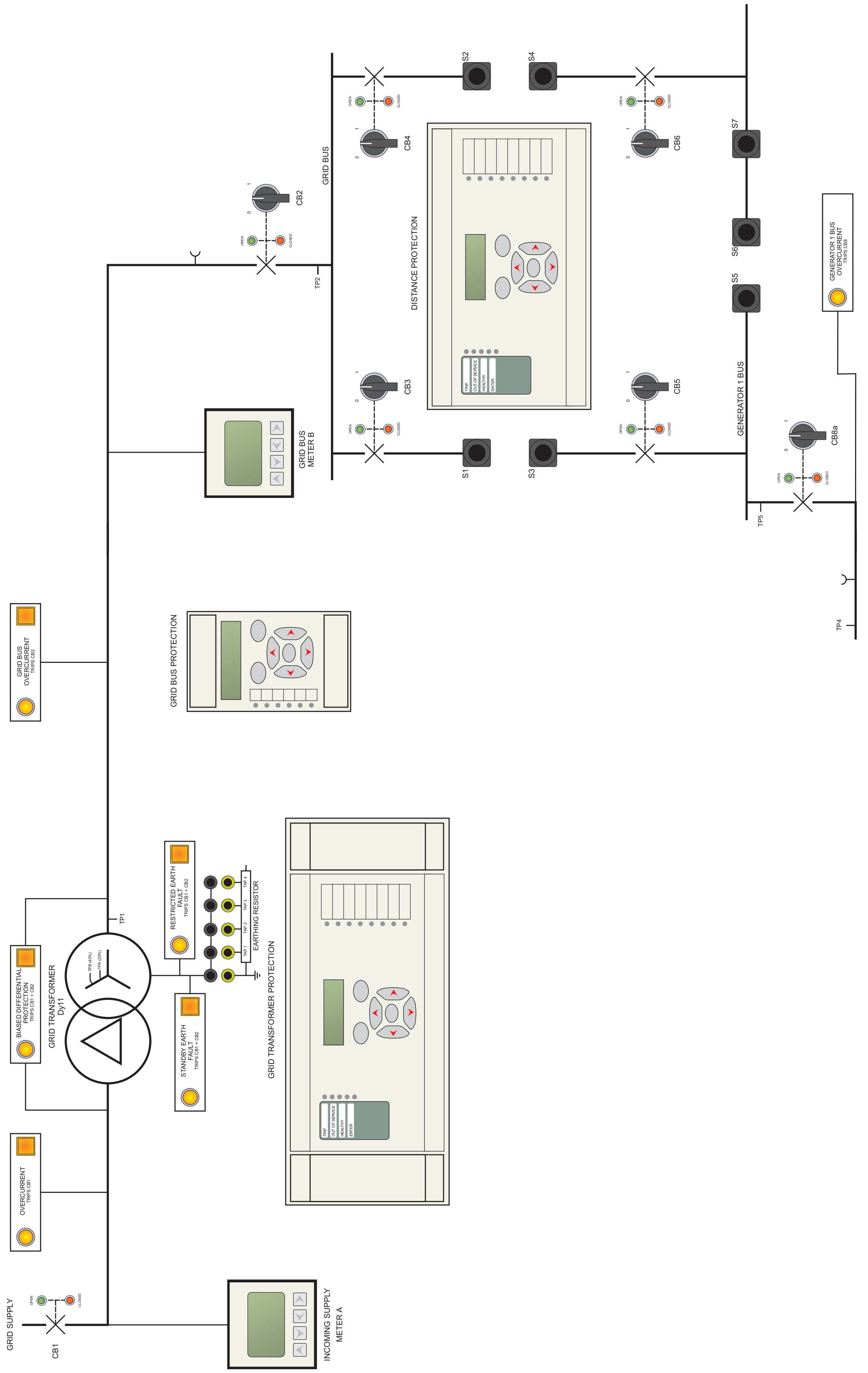


Figure 4 Schematic Diagram of Grid Supply Busbar and Grid Transformer

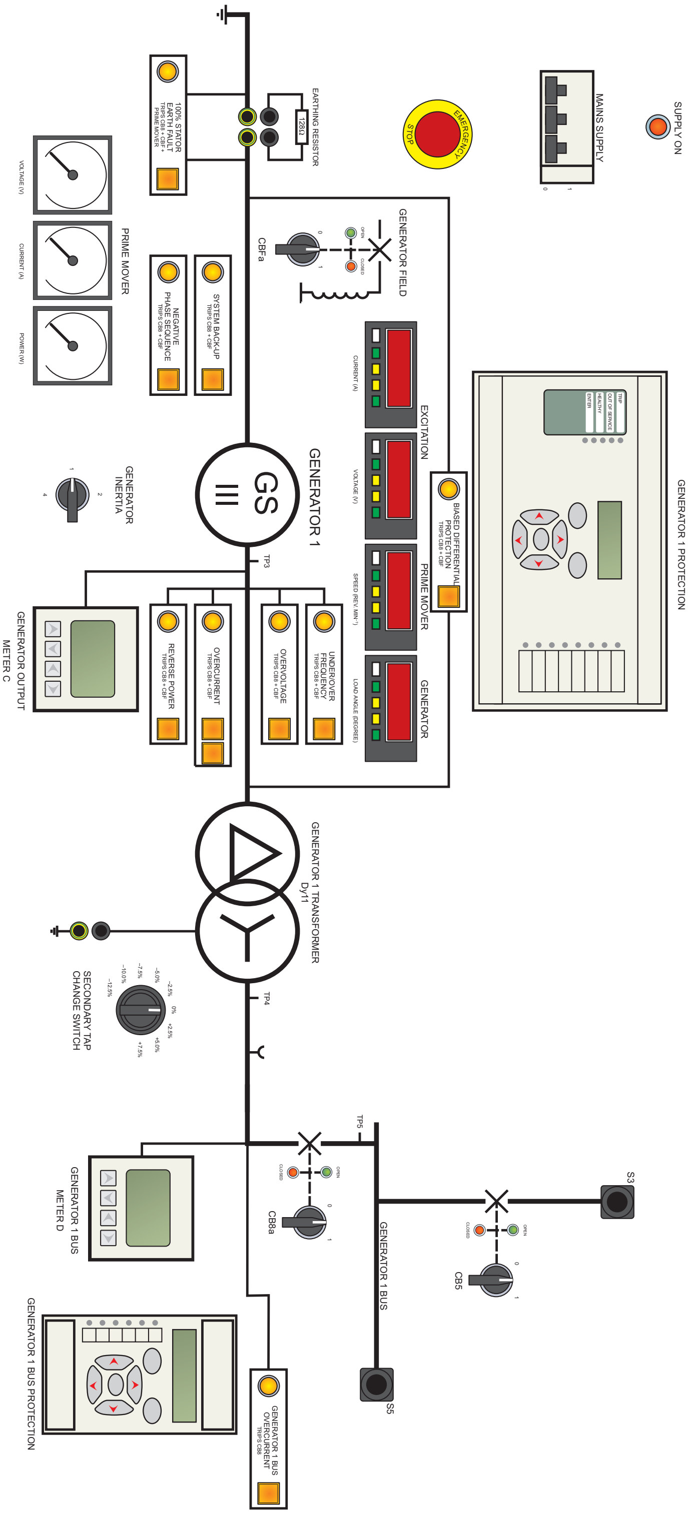


Figure 5 Generator Unit G1 and Transformer G1TX

The Generator Set

Actual generator units consist of a prime mover (usually a steam turbine in large power stations) driving an a.c. synchronous generator. In the Power System Simulator the prime mover is modeled by an induction motor drive with field-oriented control - a 'vector drive'.

The Generator Set is illustrated in Figure 6. It consists of an induction motor driving a salient, four-pole generator through a flexible coupling.

A shaft encoder, producing 2048 pulses/rev, is attached to the free end of the generator shaft for steady state and transient load angle measurement.

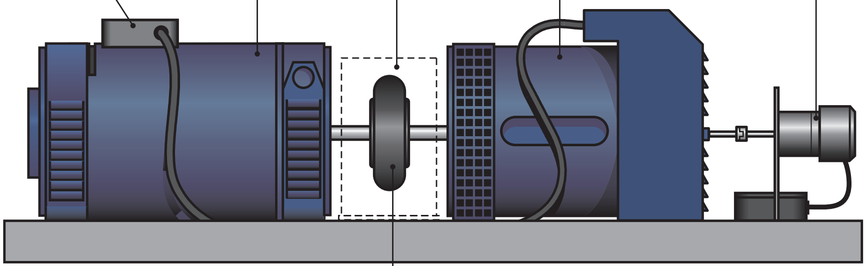


Figure 6 The Motor - Generator Set

The full specification of the brushless AC generator is:

Manufactured by Mecc Alte Spa, Type ECO 3-1S/4:

6.5 kVA, 0.8 pf, 3phase at 1500 rev/min, 50 Hz.

or 7.8 kVA, 0.8 pf, 3phase at 1800 rev/min, 60 Hz.

Excitation: 17 V; 1.08 A (without the rotor damping cage)

Each phase of the stator winding is split into two halves, with 4 ends, for series or parallel connection.

The rating of the generator is therefore;

Series connection: 230/400 V Star/Delta, 16.3/9.3 A at 50 Hz;

Or 276/480 V Star/Delta, 16.3/9.3 A at 60 Hz.

Parallel Connection: 115/200 V Star/Delta, 32.6/18.8 A at 50 Hz;

Or 138/240 V Star/Delta, 32.6/18.8 A at 60 Hz.

Main reactances, for both parallel and series connection, are Xd = 188%, Xq = 66%.

The specification of the Induction Motor is:

415V, 7.5kW, 50/60Hz supplied with a 690+ PWM Drive.

The motor has an automatic start/stop control initiated by push buttons on the front of the Console.

2.3 Modelling and Control of the Prime Mover

The 690+ Vector Drive

The 690+ PWM Drive Controller is a sophisticated speed-control unit for an induction motor. It possesses several modes of control: constant V/f control and field oriented or 'vector' control.

The basic building block of the 690+, unit is a PWM voltage source inverter. It uses advanced microprocessor technology for exciting the motor with controllable sinusoidal voltage source of variable voltage and variable frequency. The ratio V/f is kept constant up to the base speed of the motor. For low speed operation, voltage boost is provided to counteract the effect of stator impedance voltage drop since this becomes significant in low speed operation. The software of the Drive controls includes feedback loops with integral and differential control elements.

Field orientation in the Power System Simulator enables the stator current of the induction motor to be decoupled into flux producing and torque producing components by implementing a 90-degree space angle between specific field components. This process imparts dc motor characteristics to the induction motor with dynamic controls that are less complex and faster.

The software of the vector drive is configured to provide two separate controls for the prime mover:

- Control of speed
- Control of power delivered by the generator

Control of speed is used when the generator is operating as a single, separate supply unit.

Control of power is used when the generator is synchronised to the Grid supply, which has 'fixed' voltage and frequency. This control enables the motor-generator unit to accurately simulate the behaviour of a power station generator whose electrical power output to the Grid is determined only by the mechanical power control of the turbine. The excitation of the generator determines the reactive power output of the generator.

Speed and power are controlled on the Power System Simulator by a single 'speed/power' potentiometer situated in the central Test and Control area of the Simulator. See Figure 3.

A simplified diagram of the control circuit for the vector drive is shown in Appendix 4. This control circuit has a single input from the speed/power potentiometer. The full diagram may be found in Eurotherm Drives' 690+ Vector Drive, User Manual, which also contains information on the Drive menu and operation. The main difference between the power and speed control circuits is that the speed-control circuit has a speed feedback loop from the drive shaft encoder; and the power control circuit has a power-feedback loop from the generator output. The control circuit is automatically switched from speed feedback to power feedback when the synchronising switch is closed and the generator is synchronised to the Grid supply through circuit breaker CB8. Both feedback loops go to a summing junction within the control circuit.

Also seen in Appendix 4 is a 'generator inertia switch' input which is connected to the input PI circuit of the speed loop. This control enables variation of the angular momentum of the motor-generator to be achieved.

The generator G1 is not fitted with an automatic voltage regulator, and control of the excitation or field current of the generator is manual.

To the left of the generator unit is shown the connection between the neutral of the star-connected armature windings and earth, through an adjustable resistor. The resistor is set to limit the earth current to the rated current of the generator.

The generator-transformer G1TX is three-phase, 5 kVA, 220 V/220 V, star-delta wound with a phase connection of Dy11. The secondary star point of the transformer can be earthed.

2.4 The Transmission Lines

The six three–phase transmission lines modelled within the Power System Simulator are shown by one–line schematic diagrams at the top centre of the panel. The diagrams include test and connection points and are reproduced in Figure 7.

Neutral lines are not included in the Power System Simulator but a single solid earth bar is provided for the connection of earth faults and for earthing star points of transformers and generators. The earth bar has a single point connection to the external earth of the supply to the Power System Simulator.

The Power System Simulator lines operate at 220 V and the base impedance is 24.20 Ω. The per unit value of reactance for a 132 kV/275 kV overhead transmission line is typically 0.002 per km on a 100 MVA base. Thus, the per unit value of reactance for a 125 km line is 0.25 on a 100 MVA base. A per unit value of 0.25 at 220 V and 2 kVA is (0.25 × 24.2) which is 6.05Ω. So Lines 4 and 5 are represented by two inductors each of 6.0 Ω reactance (nominal). Each inductor is equivalent to 125 km of 132 kV line on a 100 MVA base.

In general, the Power System Simulator nominal (or base) voltages of 415 V/220 V/110 V and a rating of 2 kVA are equated approximately on a per unit basis to a 275 kV/132 kV/66 kV system on a 100 MVA base. If a higher voltage line with smaller per unit values is to be represented, the 6 Ω inductor will represent a longer length of line.

The **nominal** reactances of the line inductors are:

Lines 2 and 3	75 km	0.15pu	3.6 Ω
Lines 4 and 5	125 km	0.25pu	6.0 Ω
Line 1	50 km	0.10pu	2.4 Ω
Line 6	50 km × 5	0.10pu x 5	2.4 Ω × 5

The effective *X/R* value of the inductors is approximately 12 when connected into the system. This value is higher than that of real lines, which is good for fault and protection studies but not so good for load flow and line loss studies. For load flow and line loss studies, known values of resistance can be connected into the lines.

Line and Cable Inductors

Knowledge of the actual value of reactance and a.c. resistance of the line and cable inductors is important in calculating system currents. It is important to know how the reactances vary with increase of current. The inductors are steel–cored coils made with low–loss steel, large section windings and air gaps to achieve as linear a voltage/current characteristic as possible up to about 20 A. However, due to the non–linear nature of the magnetising curve of the steel there will be some variation in inductive reactance over the range of current.

Accuracy characteristics for the line inductors are given in Figure 8. These are based on many tests made on the line inductors for Simulators. The mean, linearised variation of reactance with current is shown based on measured values at 8 A. All inductors achieve an accuracy of ±5% from 0 to 16 A at least. The variation below 8 A is not greater than 3%. At 30 A the percentage variation varies between -10% and -14%.

The reactances of the line and cable inductors, although provided, should be measured at 8 A prior to carrying out any experiments on the Simulator. The a.c. resistance of the inductors should also be measured. The measured values of reactance (X) and resistance (R) should then be entered in the right–hand columns of Table 1. Figure 8 can then be used to determine the best value of reactance for a particular experiment.

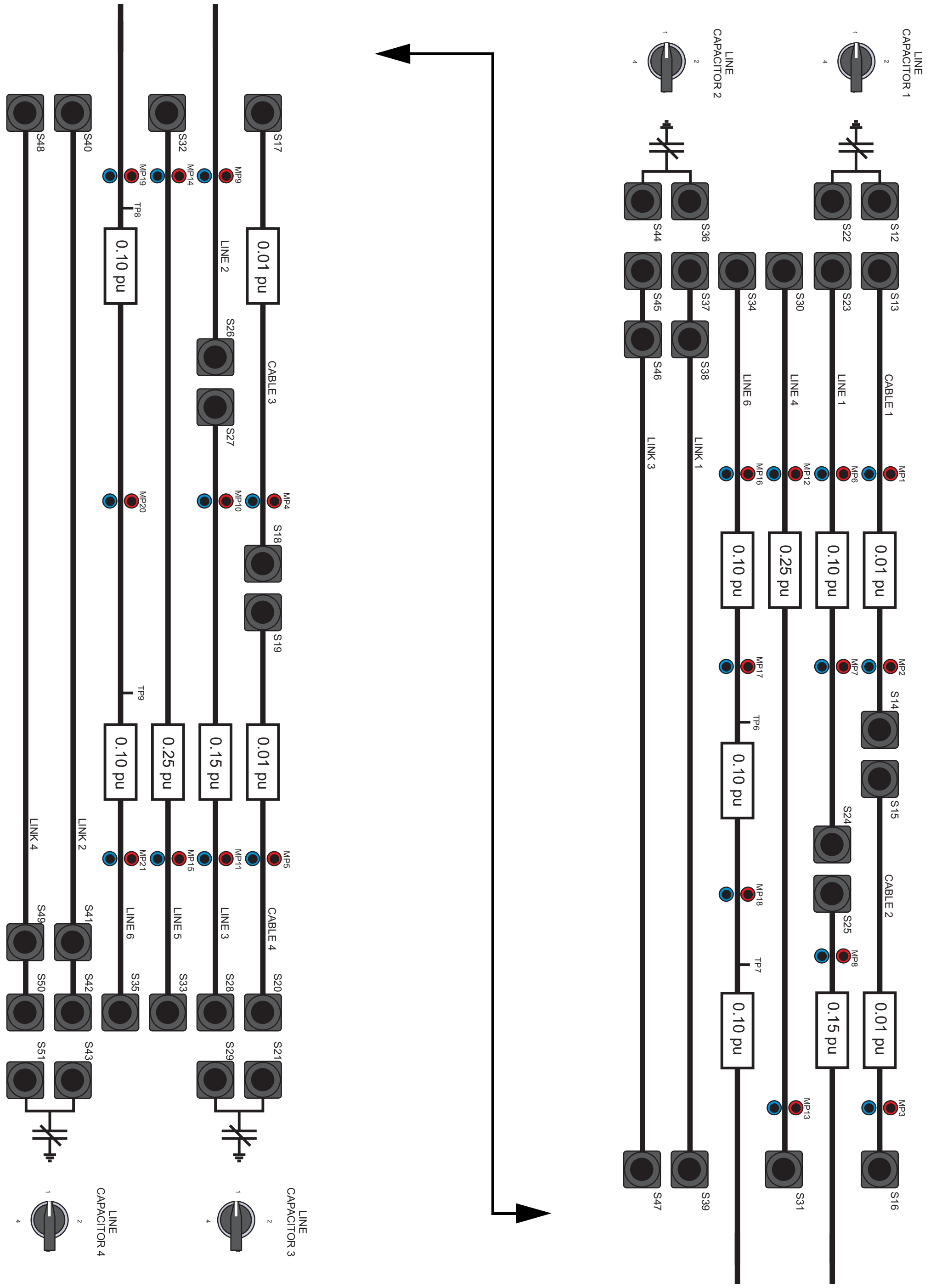


Figure 7 The Transmission Lines

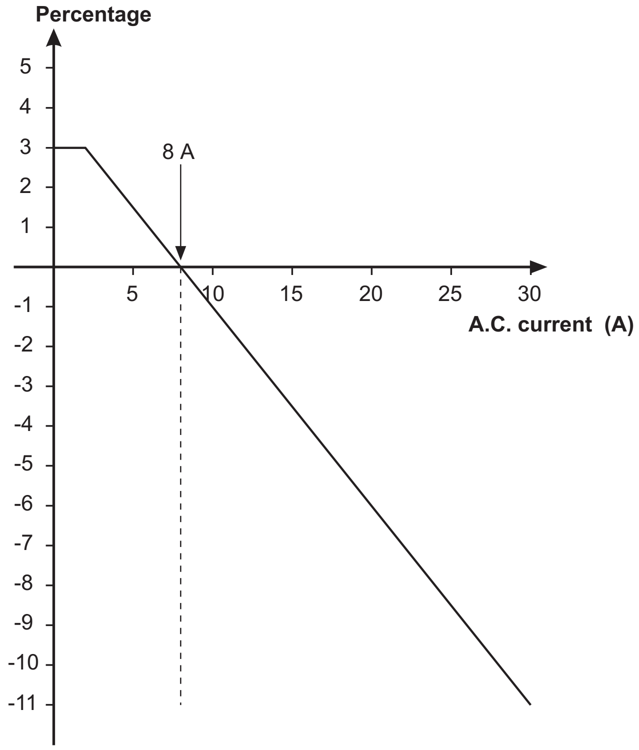


Figure 8 Mean Percentage Variation of Coil Reactance with Current Based on Value Measured at 8 A

Line Capacitances

Two switched line capacitors have been provided at each end of the lines, with two four–pin connectors. They may be connected into a line to form 'π'or 'T' sections.

The value of the switched line capacitors are:

Line Capacitor Number	1	2	3	4
Position 1 (μF)	0.5	2	0.5	2
Position 2 (μF)	1	3	1	3
Position 3 (μF)	2	4	2	4
Position 4 (μF)	3	5	3	5

Capacitors are connected between line and ground.

At 220 V, 2 kVA the base susceptance (B) is 0.0413 S. For 125 km of 132 kV line on a base of 100 MVA, the line susceptance is typically 0.06 pu. For a line of 220 V, 2 kVA, a susceptance of 0.06 pu is equivalent to a capacitance of approximately 8 μF at 50 Hz.

Cables

The cable has four equal sections. The cable per unit reactance, per section is 0.01 pu, which is equivalent to 10 km of 132 kV, 100 MVA cable. At 220 V, 2 kVA, 0.01 pu is equal to 0.24 Ω. The per unit susceptance of the cable is 0.25 pu, which is equal to 31.2 μF. Capacitors of 15 μF are connected at the end of each cable section. See technical drawing 79962.

2.5 The Distribution Busbar and Utilisation Busbar

The distribution system and load centre is shown on the right of the of the Simulator panel. The system consists of two transformers that can be supplied individually or in parallel by means of two switched, busbar interconnectors.

Switched and variable loads and a dynamic load are connected to a Utilisation Bus, which are fed via two parallel distribution transformers from a Distribution Bus. The schematic diagram of the distribution system, as it appears on the NE9270 front panel is reproduced in Figure 9 together with its associated protection system. Figures 10 and 11 show the enlarged left and right halves for easier viewing. The Technical Drawing for this section of the Simulator is number 79964.

Each distribution transformer is 2 kVA, three-phase, star-delta wound with a phase connection of Yd1.

Primary tappings on each transformer are at 2.5% intervals up to +/-10%. The two transformers have matched impedances. Primary star points can be earthed. The delta secondary of the transformers can also be earthed through an 'earthing transformer': a three-phase inductor with an interconnected star (or zig-zag) winding. The connection of this inductor on the delta side of the transformer is shown in Figure 12. Each phase winding is divided into two halves and one half is connected in reverse to the other. Thus, the inductor presents a high reactance to positive and negative sequence currents but presents a low reactance to zero sequence currents, as they are all in phase.

Protective relays, type MiCOM P142, and associated circuit breakers, together with M230 meters are connected into the system on the primary and secondary sides of both transformers. Six Test Points are included in this Section.

The loading on the Utilisation Busbar consists of:

a) Static Loads: variable and switched resistance, inductance and capacitance loads. Resistive, three-phase loads have ratings up to 3 kW. See Section 2.5.

b) Dynamic Load: The Dynamic Load consists of a cage induction motor driving a dc generator, which acts as a controllable load for the motor. The Dynamic load is connected to the Distribution Bus through circuit breaker CB34, positioned at the right hand end of the Distribution Bus. A red lamp indicates when the induction motor is running.

   The DC shunt-connected Generator supplies a resistive load. The field current of the DC Generator is varied by means of a thyristor whose firing angle is controlled by a 10 turn potentiometer, positioned on the panel below the Dynamic Load schematic. The potentiometer is motorized for remote control. A relay operated by the supply to the Induction motor prevents the field of the DC Generator being supplied when the motor is not running. See drawing 79964 for detail.

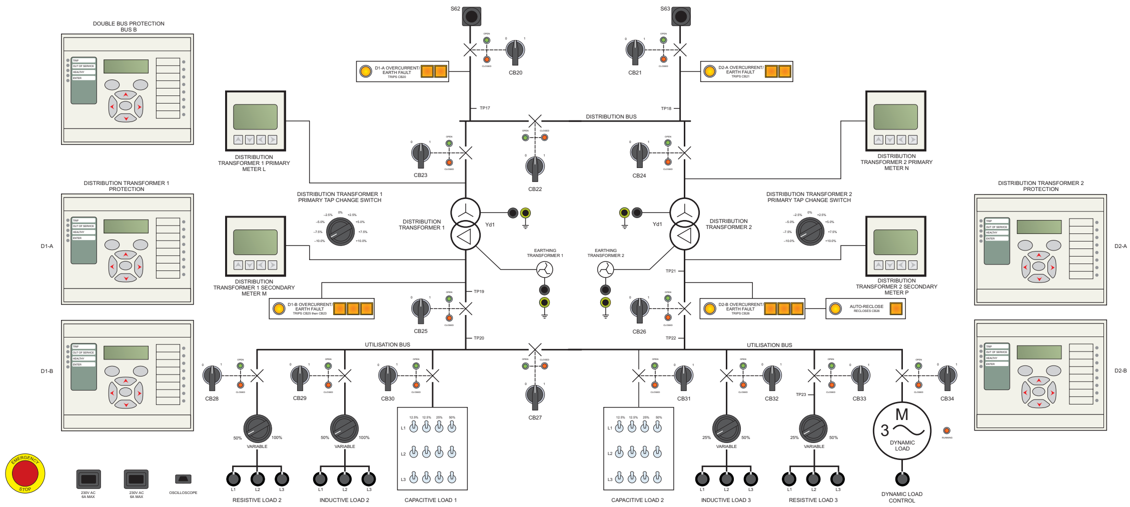


Figure 9 The Distribution and Utilisation Bus

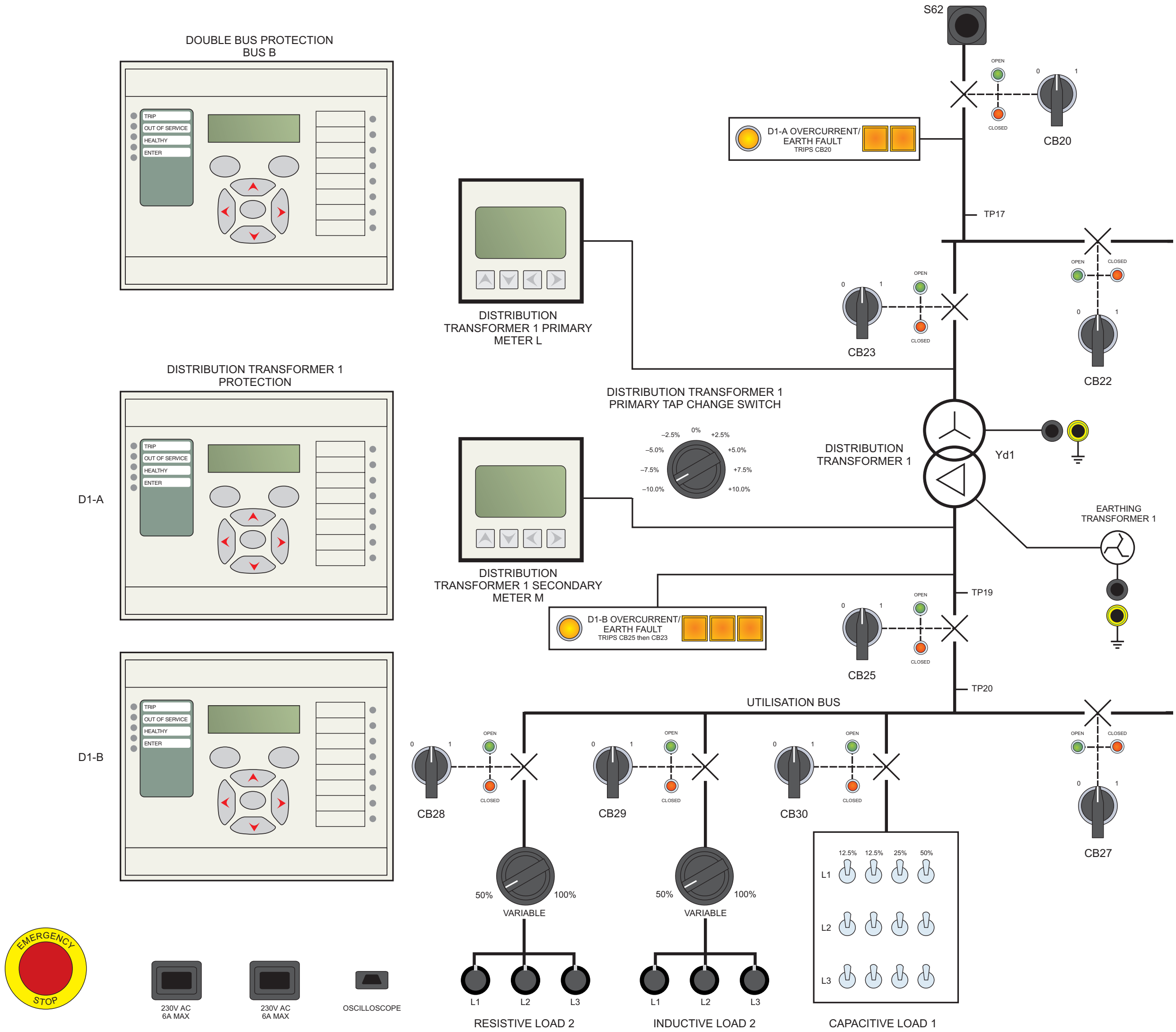


Figure 10 The Distribution and Utilisation Bus (Left Side)

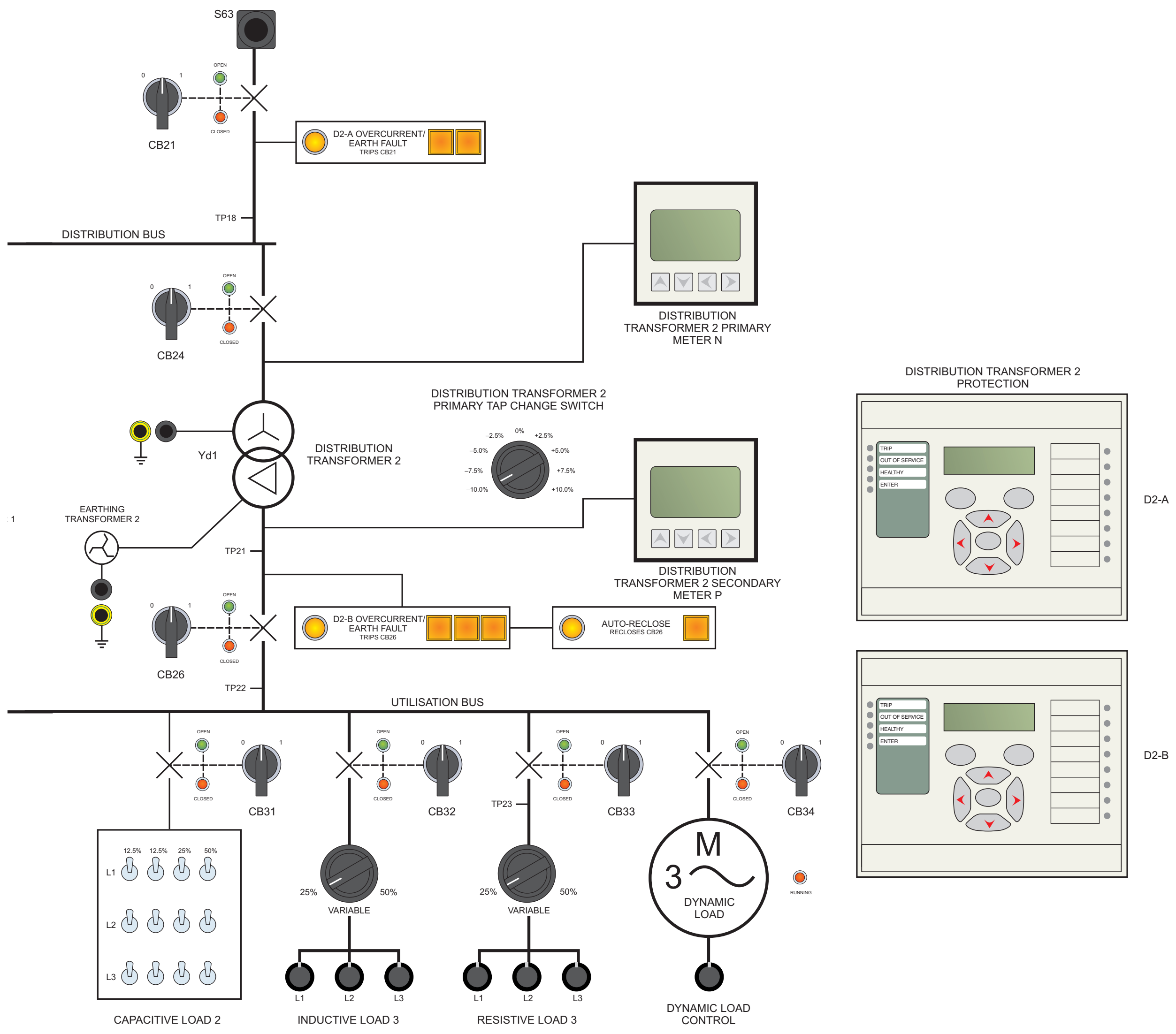


Figure 11 The Distribution and Utilisation Bus (Right Side)

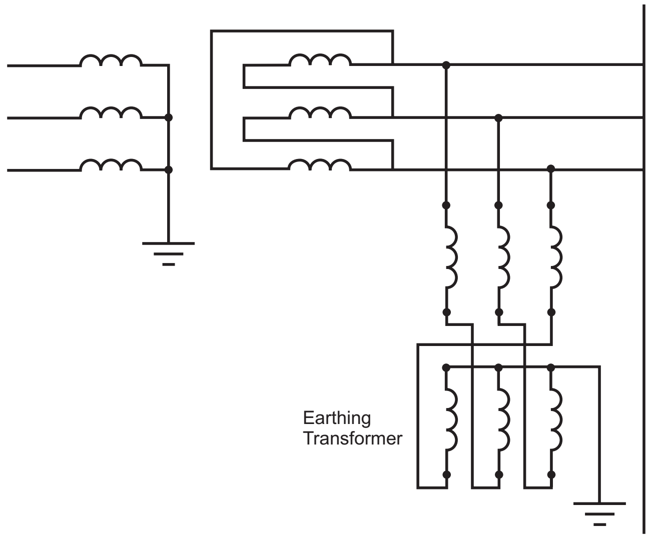


Figure 12 Earthing Transformer Connections

2.6 Resistive and Inductive Loads

The Resistive and Inductive, three-phase Load Banks in the Simulator are designated R1, L1; R2, L2; R3, L3; and R4, L4. All Load Banks are connected in delta. Each Load Bank has an isolating circuit breaker.

Resistive and Inductive Loads R1, L1 and R4, L4 are independent loads fed from 'dummy' transformers, i.e. the star-delta transformers shown on the panel do not exist. They are rated at 220 V line. R1 and L1 are situated near Generator 1; R4 and L4 are situated near the Generator 2 Bus on the right-hand side of the Simulator panel. The Simulator schematic for these loads are shown in Figure 13.

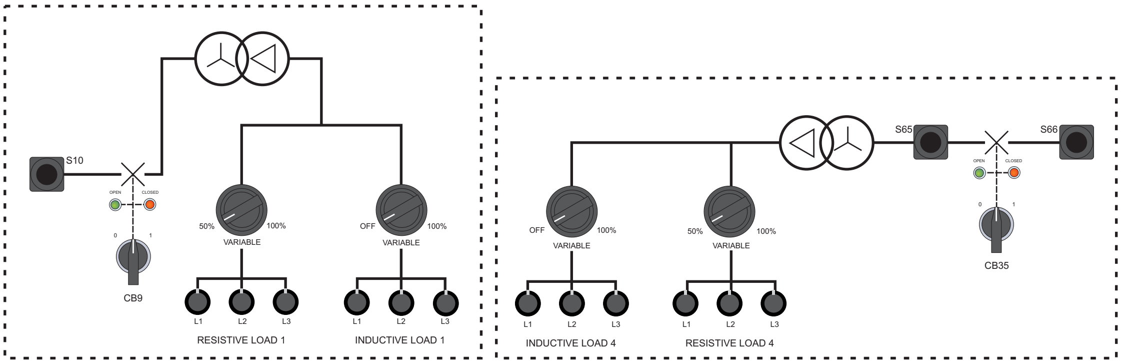


Figure 13 Resistive and Inductive Loads 1 and 4 (220V)

R2, L2 and R3, L3 are major loads for the Distribution Systems at the right hand end of the Simulator. L2 and R2 are shown in Figure 10, R3 and L3 are shown in Figure 11. They are rated at 110 V line. Each of these loads has an additional bank of switched capacitors. See Figure 14.

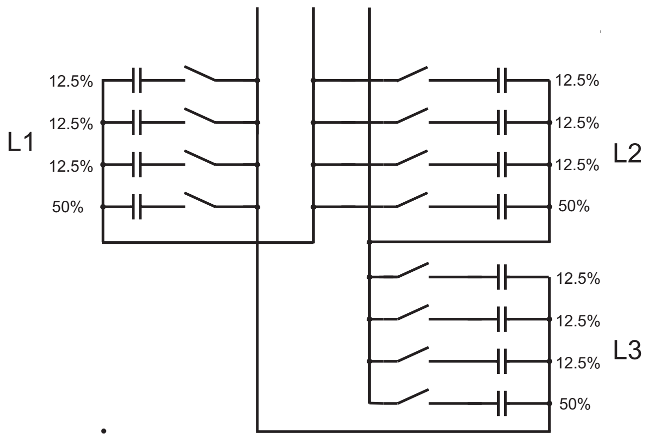


Figure 14 Delta Connected Switched Capacitive Loads

In each set of resistive and inductive loads are three potentiometers, or pots, designated L1, L2 and L3. All resistors and inductors are connected in delta. Each 'pot' controls the phase angle of two thyristors connected in inverse-parallel; the 'triac' connection. Figure 15 shows the connections for a three phase load.

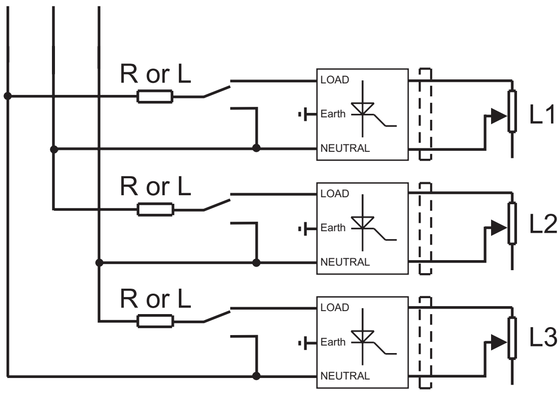


Figure 15 General Connection Diagram for Delta Connected Resistive and Inductive Loads

For the analysis of this circuit, see the textbooks mentioned in the References or others. The use of this circuit does of course result in the production of harmonics, namely the third, fifth seventh and ninth. Such harmonics occur in real power systems and affect measured readings, particularly of reactive power and power factor. However, the main reason for using them in the simulator is to enable the loads to be remotely controlled by a SCADA system. This is achieved by using motorized potentiometers to vary the value of resistance and inductance.

When using the thyristor- controlled loads, the power (P) and reactive power (Q) should be adjusted separately using the resistive (R) and inductive (L) loads. P and Q are then equal to the apparent power (S = VA) measured for the R and L loads, respectively. Power factor angle is given by Tan^{-1} Q/P.

To provide alternative 'clean' loads, with minimum harmonics, the resistors and inductors can be used independently from the thyristor controls. R1, L1 and R4, L4 have two values of resistance and one value for inductance, plus an 'off' position. R2, L2 and R3, L3 have two values of resistance and two values for inductance. These values are chosen at 25% and 50% for R3 and L3, and 50% and 100% for R2 and L2. This allows a selection of loads at 25%, 50%, 75%, 100% and 125%.

Three-position switches are provided for each Load Bank for changing from thyristor controls to fixed load. Tables 2 and 3 give the design currents for all loads, both switched and variable.

WARNING

Do not use the capacitor banks with the potentiometer-controlled loads, the capacitors have a lower impedance to the generated harmonics and may overheat.

Single or Combined Load	R2, R3 (or R2+R3) Line Current (A)	L2, L3 (or L2+L3) Line Current (A)	Power Factor
25%	3.17	1.61	0.89
50%	6.35	3.23	0.89
75%	9.52	4.84	0.89
100%	12.70	6.44	0.89
125%	15.87	8.05	0.89
Variable	0 to 15.24	0 to 12.32	Variable

Table 2 Design Currents and Powers for Loads R2, R3, L2 and L3

220 V	R1, R4 Resistive Line Current (A)	L1, L4 Inductive Line Current (A)	Power Factor
50% or Off	3.75	-	1.0
Variable	0-7.6	0-7.83	Variable
100%	6.35	3.27	0.94

Table 3 Design Currents and Powers for Loads R1, R4, L1 and L4

2.7 Double Busbar Interconnection and Switching System

The double busbar system shown in the centre of the panel is shown in Figure 16 together with its associated protection system. The double busbar system consists of a Main busbar and a Reserve busbar. Each busbar has two sections which may be connected by busbar section switches (CB10 and CB15). The Main and Reserve busbars may be connected by busbar couplers (CB13 and CB17).

Each section of the busbars has two incoming feeders with circuit breakers and isolators to select main or Reserve busbar. The isolators are black, two position, manual switches; when vertical the isolator is closed, when horizontal the isolator is open. A single outfeed is provided in each section, each provided with a circuit breaker and isolator in a similar way to the infeeds. All incoming and outgoing feeders are provided with MiCOM M230 meters.

The busbar interconnection and switching system reflects modern practice and provides the Power System Simulator with a flexible interconnection system. It also provides a means of demonstrating busbar zone protection.

Circuit breaker CB11 on one of the infeeds, is provided with a thyristor switch in each phase. These switches are for investigating transient voltages resulting from the interruption of fault current at a current zero.

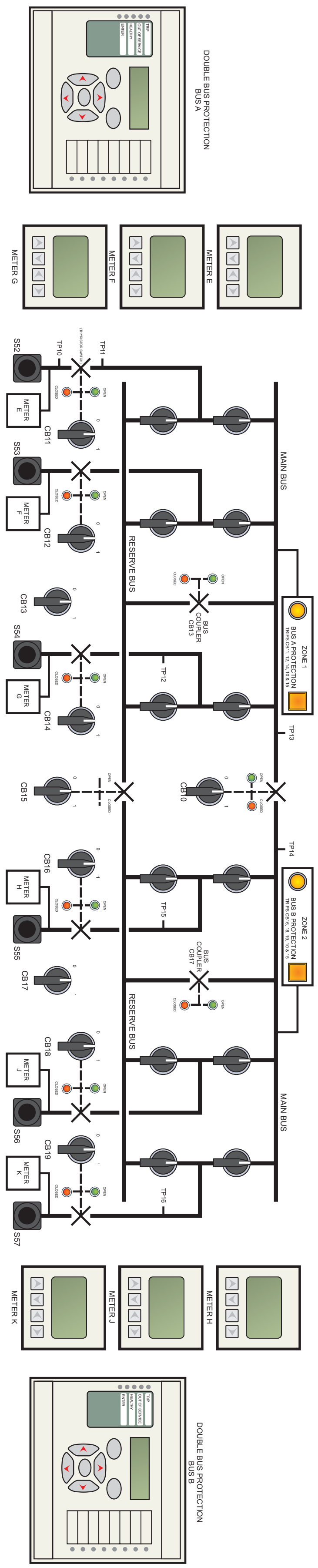


Figure 16 Double Busbar

2.8 Generator 2 Infeed

The Generator 2 Bus, situated on the far right of the Simulator panel, provides connection between the Simulator and external equipment, in particular Generator 2 Unit, NE9272. The schematic for this Section of the Simulator, shown in Figure 17 consists of a single main Bus with connection sockets S64, S67, S60 and S61. The last three of these sockets are positioned for easy connection to the Links 2 and 4, or to the Distribution Bus.

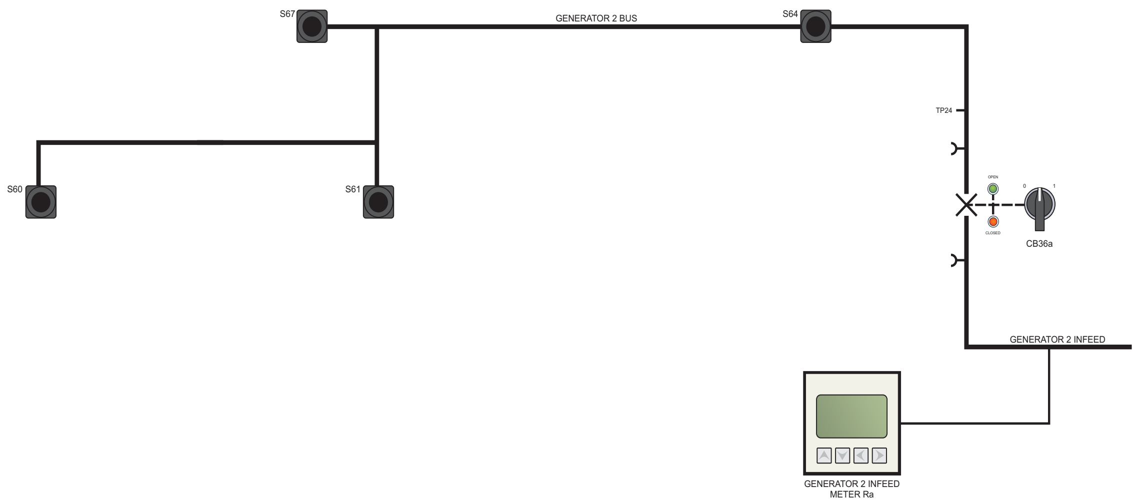


Figure 17 Generator 2 Bus

At the out-board end of the Generator 2 Bus, are situated circuit breaker CB36, control switch CB36a and M230 meter, Ra. Meters Ra and Rb have CTs at this point of the circuit, and are duplicate meters. Meter Rb is situated in the Generator 2 Control and Synchronising Panel within the central Test Area of the Simulator. This Panel is shown in Figure 18.

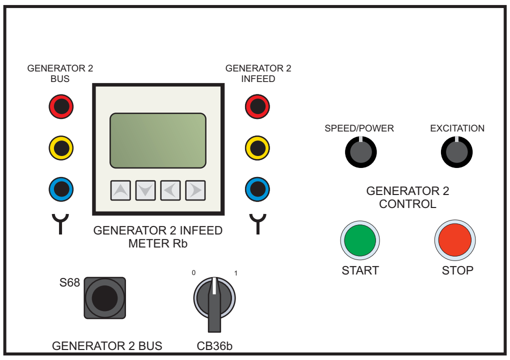


Figure 18 Generator 2 Control Panel

The symbols Y on either side of CB36 and in the Control Panel indicate the position of the line voltages to which 'Generator 2 Bus' and 'Generator 2 Infeed' in the Control Panel refer. CB36 is the synchronizing breaker and can be closed either by switch CB36a or switch CB36b. Socket S68 is connected in parallel with S67 of the Generator 2 Bus and is provided to make connections easier.

Having the Generator 1 and Generator 2 Control and Synchronizing Panels adjacent to each other and the Synchroscope enables the Generators to be synchronized either as parallel generators of as a separate, remote generator.

The connectors for linking Generator 2 with the Simulator are located on the side of the Simulator. A 37-way cable socket provides low voltage dc, and communicating and control links. A separate 16-way power socket provides supplies and main circuit connections. See Technical Drawing 79967.

SECTION 3.0 Technical Description of Protection and Measurement Systems

This Section is divided into two parts: the first describes the general features of the Areva numerical relays and their main features; the second part provides identification and a brief description of the protection schemes and their associated relays for each component or system of the Power System Simulator. A fuller explanation of the use of the protection schemes and the setting of the relays is given in Section 7.

3.1 The Areva Relays

Relay technology has advanced considerably since the 1980's. The first major advance was the replacement of electromechanical relays by 'static' relays, in which analogue electronic devices produced the relay characteristics. In the late 1980's and throughout the 1990's changes in relay construction became more rapid as digital technology replaced analogue. The first 'digital' relays contained microprocessors, but these were rapidly overtaken by 'numerical' relays, which use a specialised Digital Signal Processor (DSP) as the computational hardware, together with associated software tools. DSP technology has advanced so that relays such as the Areva range now include several relay functions, or elements, (overcurrent, differential protection, etc.) in one box, plus measurement and control functions. It is also possible for single relay functions to have up to four independent setting groups in one relay, although only one group is activated at a time. Because the functional requirements of relay elements are set by software, relays for different applications can have similar operational features, terminal arrangements and internal organization. They differ only in the nature and number of the relay elements inside them. Table 4 summarizes the features and capabilities of the numerical relays within the power system Simulator.

Relay Classification

All Areva Protection and Control relays have a 'P', or protection, number that defines their function and capability: e.g. P142

The first number defines their overall function: these are

P1xx Overcurrent protection

P2xx Motor protection

P3xx Generator protection

P4xx Distance protection

P5xx Current Differential protection

P6xx Transformer Differential protection

P7xx Busbar Differential protection

The second number defines the relay 'platform' – from the simplest Px20 to the most sophisticated Px40.

The final number indicates additional capabilities. For example:

P141 Feeder Management Relay.

P142 - plus auto-reclose

P143 - plus auto-reclose and check synchronizing.

Function	P142	P122	P343	P442	P632
Overcurrent (OC) Stages - Three Phase and Earth		3	2	2	2
Overcurrent (OC) Stages - Directional Three Phase and Earth	4				
Sensitive Earth Fault	✓		✓		
Restricted Earth Fault	✓		✓		✓
Voltage Controlled OC	✓		✓		
Negative Sequence OC/OV	✓	✓	✓	✓	
Under/ Over voltage	✓		✓	✓	✓
Neutral Displacement	✓		✓		
Under/ Over frequency	✓		✓		✓
Broken Conductor	✓	✓		✓	
Breaker Failure & Back Trip	✓	✓	✓	✓	
Auto-reclose (3ph)	✓			✓+1ph	
Check Synchronization				✓	
Setting Groups	4	2		2	
Blocking logic	✓	✓			
Distance Protection				✓	
Transformer Differential					✓
Generator Differential			✓		
100% Stator Earth Fault			✓		
Loss of Field			✓		
Reverse Power			✓		
Measurements (True RMS)	✓	✓	✓	✓	✓
Instantaneous Records	✓	✓	✓	✓	✓
Fault Records	✓	✓	✓	✓	✓
Event Records	✓	✓	✓	✓	✓
Disturbance Records	✓	✓	✓	✓	✓

P142: Feeder Management Relay
P122: Overcurrent Protection
P343: Generator Protection
P442: Full Scheme Distance Protection
P632: Transformer Differential

Table 4 Relays and Their Protection Functions

Relay System Overview

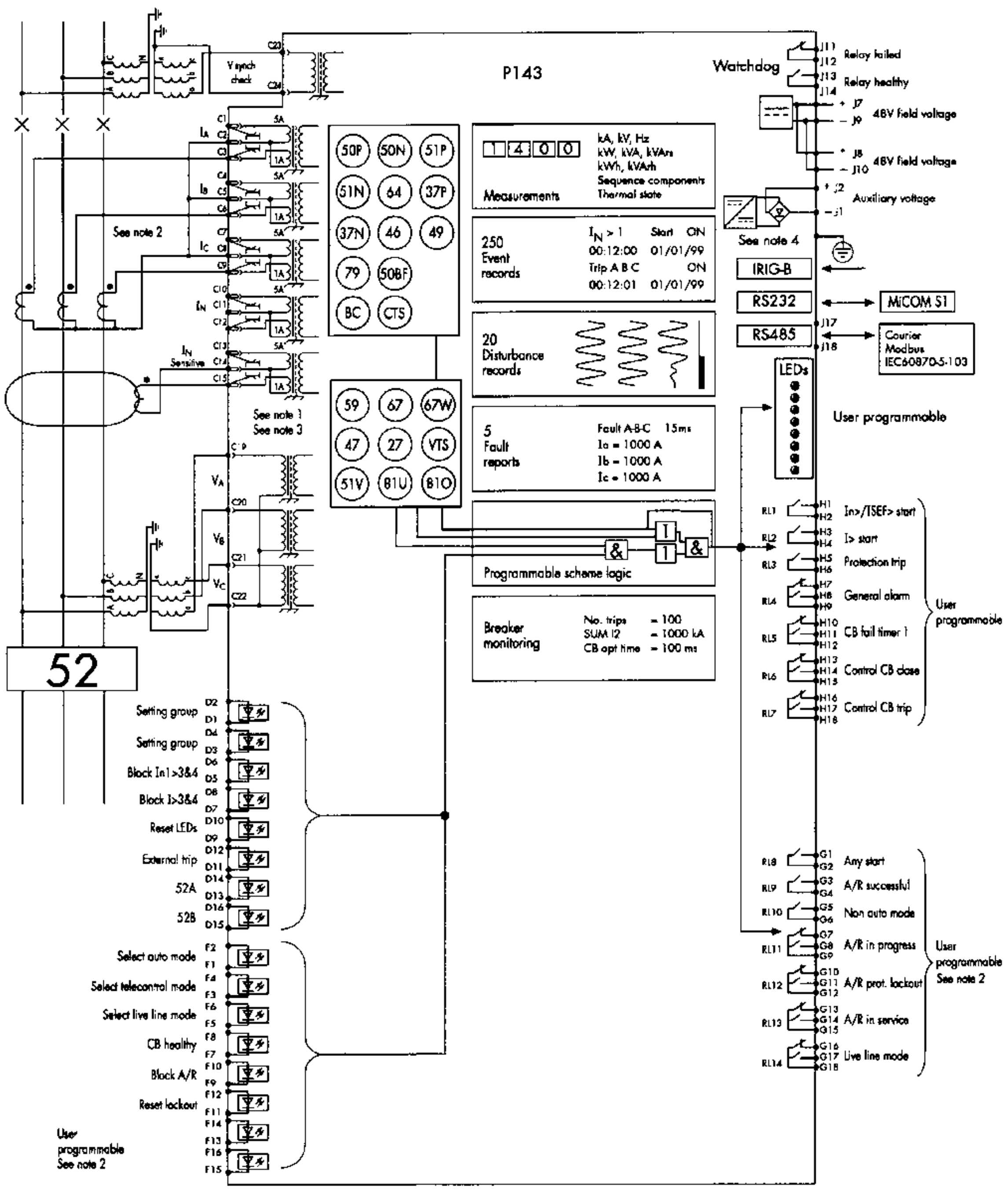
The System Overview for a P143 is shown in Figure 19 to illustrate the organization and component parts of MiCOM relays. On the left hand side are the inputs to the relay from CTS and VTs connected into the power system. These inputs go to the software protection elements, shown by their ANSI numbers. In APPENDIX 1 is the ANSI/IEC numbering and symbol systems for identifying relay functions.

The outputs from the two blocks of protection elements are taken to the Programmable Scheme Logic (PSL). The PSL allows the user to customise protection and control functions and to programme the operation of optically isolated inputs (shown on the bottom left of the diagram), relay outputs to CBs etc. and LED indicators (shown on the right hand side of the diagram).

The PSL is configured using the support software MiCOM S1, which is PC based. Settings can also be changed using the S1 software. The PC may be plugged into the front serial port of the relay to download to the relay new PSL arrangements and relay settings.

Many of the input and output relays, in all protection relays on the Simulator, have been used for additional control functions e.g. relay blocking and 'Accept' and 'Reset' buttons. This functionality must be included if the user needs to create their own PSL.

Also shown on the right hand side of the front panel is an RS485 connection for remote control/Communication via Courier or Modbus.



ANSI Numbers

67/50P	Instantaneous phase overcurrent	79	Autoreclose	81O	Overfrequency
67/51P	Time delayed phase overcurrent	67W	Wattmetric	47	Negative sequence overvoltage
37P	Phase undercurrent	51V	Voltage controlled overcurrent	50BF	Breaker failure and backtrip
67/50N	Instantaneous neutral overcurrent	67	Directional	25	Check synchronising
67/51N	Time delayed neutral overcurrent	59	Overvoltage	67/46	Negative sequence overcurrent
37N	Neutral undercurrent	59N	Residual overvoltage	BC	Broken conductor detection
64	Restricted earth fault	27	Undervoltage	VTS	Voltage transformer supervision
49	Thermal overload	81U	Underfrequency	CTS	Current transformer supervision

Note 1: All CT connectors have integral shorting. These contacts are made before the internal CT circuits are disconnected.

Note 2: Additional hardware for P143 only.

Note 3: 5A CT connections shown, 1A CT connections available on the terminal blocks.

Note 4: The bridge rectifier is not present on the 24 – 48V dc version.

Figure 19 P143 System Overview

Relay Front Panel

The front panels of all relays are very similar, with common features, although the relay boxes may differ in size. Figure 20 shows the front panel of the P142 with hinged covers at the top and bottom shown open. (Hold both ends of the covers when opening them as they break easily.)

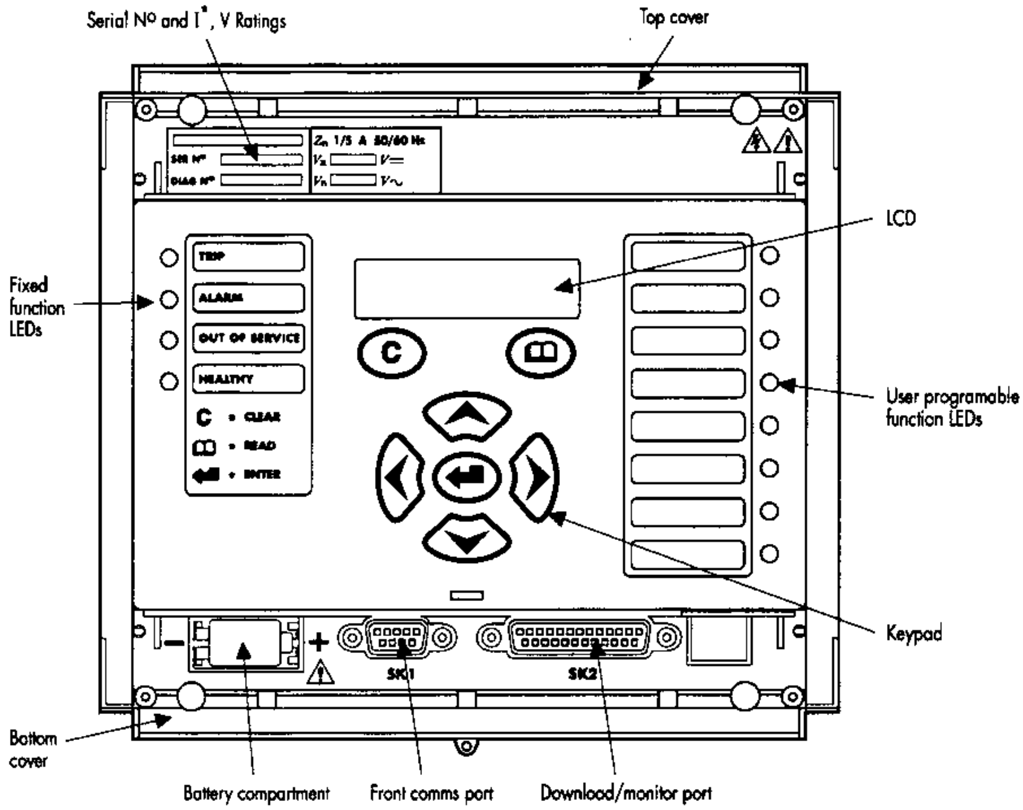


Figure 20 Front Panel of the P142

The front panel of the relay includes the following, as indicated in Figure 20:

- a 16-character by 2-line alphanumeric liquid crystal display (LCD)
- a 7-key keypad comprising 4 arrow keys (⇐, ⇒,⇑ and ⇓), an enter key (↵), a clear key © and a read key.
- 12 LEDs; 4 fixed function LEDs on the left hand side of the front panel and 8 programmable function LEDs on the right hand side.
- Under the top hinged cover:

  the relay serial number, and the relay's current and voltage rating information*.

- Under the bottom hinged cover:

  battery compartment to hold the ½ AA size battery that is used for memory back-up for the real time clock, event, fault and disturbance records.

- a 9-pin female D-type front port for communication with a PC locally to the relay (up to 15 m distance) via an RS232 serial data connection. This port supports the Courier communication protocol only.
- a 25-pin female D-type port providing internal signal monitoring and high speed local downloading of software and language text via a parallel data connection.

The fixed function LEDs on the left hand side of the front panel are used to indicate the following conditions:

Trip (Red) indicates that the relay has issued a trip signal. It is reset when the associated fault record is cleared from the front display. Alternatively the trip LED can be configured to be self-resetting. The trip LED is initiated from output relay 3, the protection trip contact.

Alarm (Yellow) flashes to indicate that the relay has registered an alarm. This may be triggered by a fault, event or maintenance record. The LED will flash until the alarms have been accepted (read), after which the LED will change to constant illumination, and will extinguish when the alarms have been cleared.

Out of service (Yellow) indicates that the relay's protection is unavailable.

Healthy (Green) indicates that the relay is in correct working order, and should be on at all times. It will be extinguished if the relay's self-test facilities indicate that there is an error with the relay's hardware or software. The state of the healthy LED is reflected by the watchdog contact at the back of the relay.

Relay Serial Numbers and Addresses

Each relay has a unique number printed beneath the top flap, i.e. P142 - - - - B1AO---C

This indicates that the software version B1 is used for the PSL.

User Interface

The relay has three user interfaces:

- front panel via LCD and keypad
- front port for local Courier communication to a PC with MiCOM S1 software.
- rear port for remote communication to a PC equipped with S10 SCADA software. This port can support either Courier or Modbus protocol (chosen on order and not user selectable).

Courier is the communication language developed by ALSTOM T&D Protection & Control to allow communication with its range of protection relays. Modbus is a universal protocol. The front port is particularly designed for use with the relay settings program MiCOM S1 that is a Windows NT based software package.

The keypad is the most limited method of access, as navigation through the menu is 'blind'.

Menu Structure

(for Px40 relays. There are small variations in display and navigation between Px40 ad Px30 relays. See the P632 Technical Manual)

The relay's menu is arranged in a tabular structure. Each setting in the menu is referred to as a cell, and each cell in the menu may be accessed by reference to a row and column address. The settings are arranged so that each column contains related settings, for example all of the disturbance recorder settings are contained within the same column. The top row of each column contains the heading that describes the settings contained within that column. Movement between the columns of the menu can only be made at the column heading level. A complete list of all of the menu settings is given in the relay Technical Manuals.

All of the settings in the menu fall into one of three categories: protection settings, disturbance recorder settings, or control and support (C&S) settings. One of two different methods is used to change a setting depending on which category the setting falls into. Control and support settings are stored and used by the relay immediately after they are entered. For either protection settings or disturbance recorder settings, the relay stores the new setting values in a temporary 'scratchpad'. It activates all the new settings together, but only after it has been confirmed that the new settings are to be adopted. This technique is employed to provide extra security, and so that several setting changes that are made within a group of protection settings will all take effect at the same time.

- Protection settings, scheme logic settings and fault locator settings, where appropriate.
- Control and support settings, including relay configuration, CT/VT settings, passwords.
- Disturbance recorder settings.

Navigation of the Menu and Settings

The ⇐, ⇒, ⇑ and ⇓ keys which are used for menu navigation and setting value changes, include an auto-repeat function that comes into operation if any of these keys are held continually pressed. This can be used to speed up both setting value changes and menu navigation; the longer the key is held depressed, the faster the rate of change or movement becomes.

The front panel menu has a selectable default display. The relay will time-out and return to the default display and turn the LCD backlight off after 15 minutes of keypad inactivity. If this happens any setting changes which have not been confirmed will be lost and the original setting values maintained.

Whenever there is an uncleared alarm present in the relay (e.g. fault record, protection alarm, control alarm etc.) the default display will be replaced by:

'Alarm/Faults Present'

Entry to the menu structure of the relay is made from the default display and is not affected if the display is showing the 'Alarms/Faults present' message.

Browsing the Settings Menu

The menu can be browsed using the four arrow keys, following the structure shown in Figure 21. Thus, starting at the default display the ⇓ key will display the first column heading. To select the required column heading used the ⇐ and ⇒ keys. The setting data contained in the column can then be viewed by using the ⇓ and ⇑ keys. It is possible to return to the column header either by holding the ⇑ key down, or by a single press of the clear key ©. It is only possible to move across columns at the column heading level. To return to the default display press the ⇑ key or the clear key C from any of the column headings. It is not possible to go straight to the default display from within one of the column cells using the auto-repeat facility of the ⇑ key, as the auto-repeat will stop at the column heading. To move to the default display, the ⇑ key must be released and pressed again.

Passwords

There are two levels in the Menu that require a password in order to proceed: level 1 and level 2. The instruction is simply 'Enter Password': xxxx. The default password at both levels is: A A A A if using the PC and front port, or ⇑ ⇒⇑ ⇒⇑ ⇒⇑ then 'Enter' using the keypad.

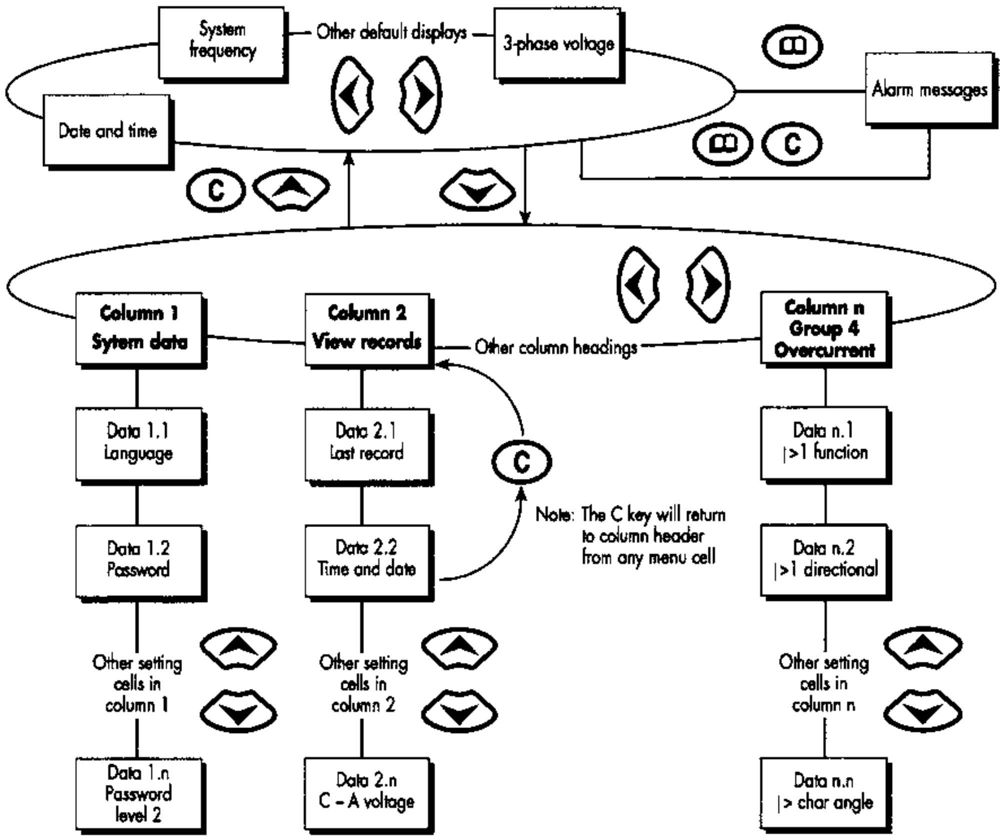


Figure 21 Settings Menu Structure

Relay Configuration

The relay is a multi-function device that supports numerous different protection, control and communication features. In order to simplify the setting of the relay, there is a configuration settings column (column 09) that can be used to enable or disable many of the functions of the relay. The settings associated with any function that is disabled are made invisible, i.e. they are not shown in the menu. To disable a function, change the relevant cell in the 'Configuration' column from 'Enabled' to 'Disabled'.

The configuration column controls which of the four protection settings groups is selected as active through the 'Active settings' cell. A protection setting group can also be disabled in the configuration column, provided it is not the present active group. Similarly, a disabled setting group cannot be set as the active group. When using the PC and front port only the active setting functions will be visible.

The configuration column also allows all the setting values in a group of protection settings to be copied to another group. To do this, first set the 'Copy from' cell to the protection setting group to be copied, then set the 'Copy to' cell to the protection group where the copy is to be placed. The copied settings are initially placed in the temporary scratchpad, and will only be used by the relay following confirmation.

3.2 Measurement and Data logging in MiCOM relays and Measuring Centres

Measurements with the MiCOM Relays

Although the main function of the Micom Relays is protection and control of the power system they are also capable of many other data management and data processing functions.

They divide in to two areas:

1) Event and fault records

2) Disturbance records and measurements

Event records provide date-and-time logged records of up to 250 events in which the relay is involved. Fault records include information on the last five faults, such as fault location, faulted phases, relay and CB operating time.

Disturbance records store typically 20 records each of 10.5 seconds long. Data is sampled 12 times a cycle. Up to 8 analogue channels, 32 digital channels and one time channel is available. The pre and post fault time can be set. These records are in graphical form and can be examined from the front port of the relay by PC and S1 MiCOM software.

Measurement records contain RMS and 'magnitude' values of quantities such as voltage and current as well as integrated quantities such as power, reactive power and energy. These records can be viewed on the relay or on a PC connected to the front port.

The RMS values are given for steady state power system operation and are calculated by the relay from the sum of the measured samples squared over a cycle of sample data. These values are referred to as 'true' r.m.s values as they include both fundamental and harmonic components.

'Magnitude' values of voltages are listed in the Measurement Sections of relay menus. Phase angles are also given as well as sequence values and earth currents. These values are produced directly from the Discrete Fourier Transform of measured samples of current and voltage. The 'magnitude' of a quantity refers to the RMS value of the Fourier fundamental component. The relay protection functions use these values. They are therefore important measurements for fault studies.

3.3 Communicating Measurement Centres, M230

A comprehensive measurement system is provided throughout the Simulator in addition to the measurements available from the relays. Communicating Measurement Centres in the form of the MICOM M230 unit are provided at key points.

Figure 23 shows their location and designation. The meters are connected into the power system with 7/1 CTs at 220 V and 15/1 at 110 V.

The front panel of the M230 contains a liquid crystal display with three lines of characters (for phases A,B,C for example) and four push buttons for navigating the Menu, two for up/down between Menu levels, two for left/right between measured quantities. See Figure 22 , taken from the M230 Manual

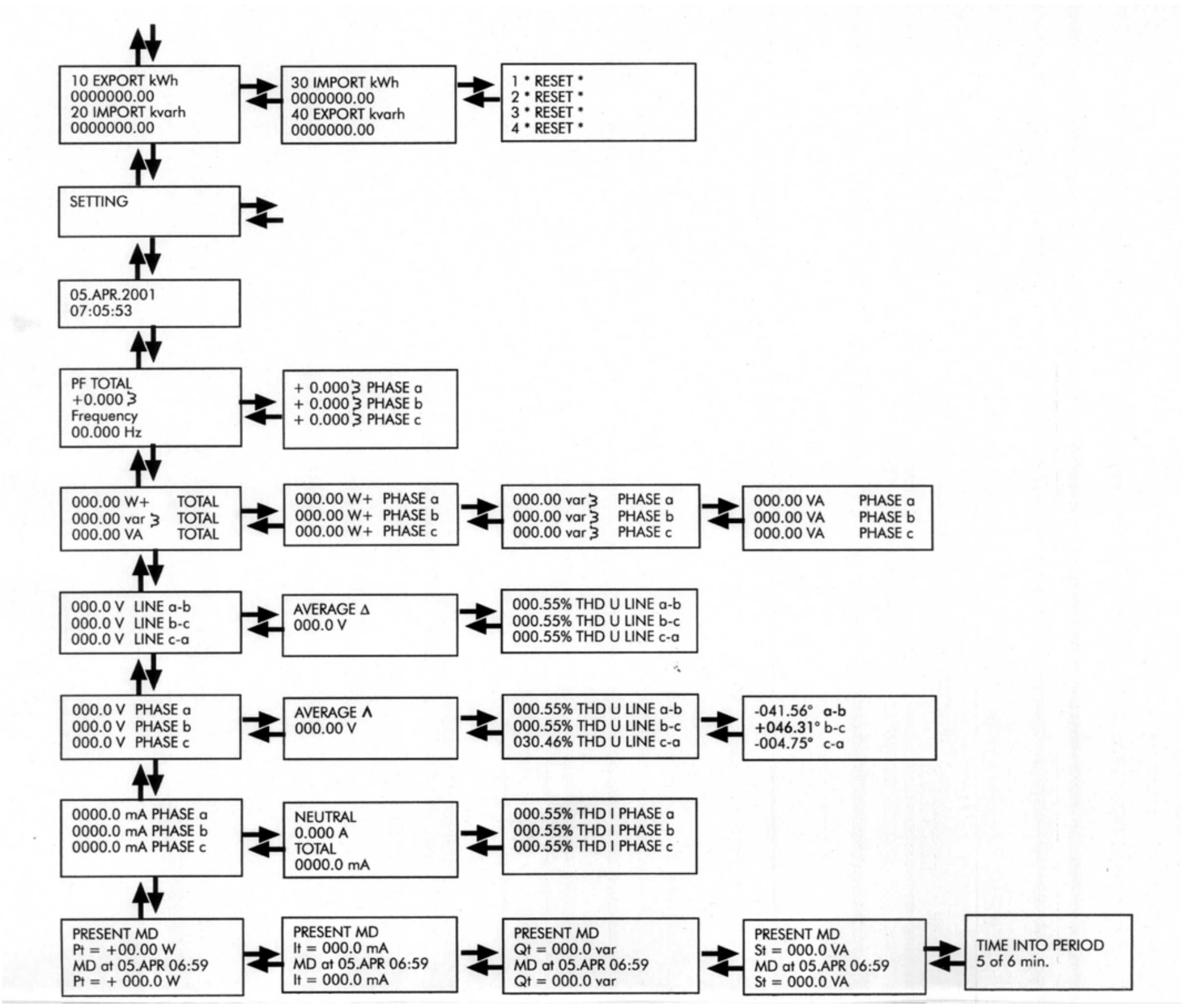


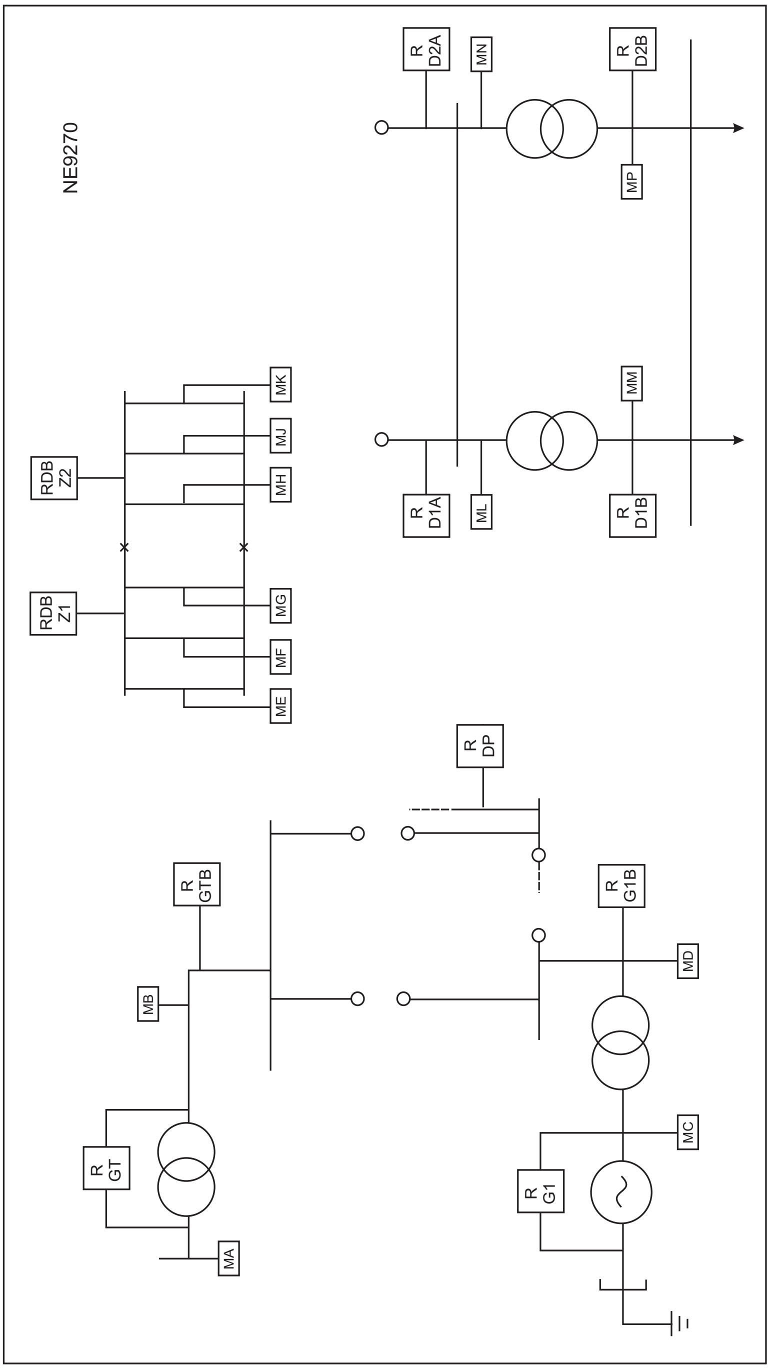
Figure 22 Measurements Menu of the M230

Table 5 shows the measurements obtainable from the M230 meters, including energy demand records. True rms measurements of voltage and current are given (i.e. fundamental components plus harmonics). However, for waveforms with significant harmonics content, the readings of power and reactive power, and power factor are incorrect. See "Resistive and Inductive Loads" on page 19.

Instantaneous Measurements	Parameters
Phase voltages	U_a, U_b, U_c
Average phase voltage	U
Line voltages	U_{ab}, U_{bc}, U_{ca}
Average line voltage	U_{Δ}
Current	I_a, I_b, I_c, I_t
Neutral current	I_n
Active power	P_a, P_b, P_c, P_t
Reactive power	Q_a, Q_b, Q_c, Q_t
Apparent power	S_a, S_b, S_c, S_t
Power factor	$\cos\varphi_a$, $\cos\varphi_b$, $\cos\varphi_c$, $\cos\varphi_t$
Frequency	Frequency
Total Harmonic Distortion	%THD Ia, %THD Ib, %THD Ic
Total Harmonic Distortion	%THD Ua, %THD Ub, %THD Uc
Total Harmonic Distortion	%THD Uab, %THD Ubc, %THD Uca
Integrated/ Maximum Demands	
Maximum demand	I_t, P_t, Q_t, S_t
Energy	Wh_t, $varh_t$

Table 5 Measured Parameters

The M230 has RS485 connections and a MODBUS communications protocol for remote viewing of measurements.



Relay Code	Indentification	Relay Description
RGT	P632	Grid Transformer
RGTB	P122	Grid Transformer Bus
RG1	P343	Generator 1
RG1B	P122	Generator 1 Bus
RDP	P442	Distance Protection

Relay Code	Indentification	Relay Description
RDBZ1	P142	Double Bus Z1
RDBZ2	P142	Double Bus Z2
RD1A	P142	Left Branch Primary Distribution
RD1B	P142	Left Branch Secondary Distribution
RD2A	P142	Right Branch Primary Distribution
RD2B	P142	Right Branch Secondary Distribution

MA to MP: Communicating Measurement Centres

Figure 23 Key Points for the Communicating Measurement Centres

3.4 Individual Protection Schemes and Relays

This section provides identification and a brief description of individual protection schemes and associated relays for each component of the Power System Simulator identified in Section 2. A fuller explanation of the application of the relays is given in Section 7 of this Manual. Figure 23 shows the location and designation of the relays.

The Grid Supply Transformer, GTX.

Protection for this transformer is provided by the P632, Transformer Differential Protection Relay.

The connection diagram for the transformer and relay are shown in Figure 24. Note that the correct polarity of the CTs is indicated by dot notation. Note also that there are no interposing transformers in the differential connections to balance, in magnitude and phase, the circulating currents between CTs. The relay achieves balance by calculations based on knowledge of CT ratios and the vector grouping of the transformer. It makes for a neater system, but information entered into the relay must be correct! This is discussed in detail in Section 7.

The relay possesses several elements in addition to that for the main biased differential protection for phase and earth faults. These are for back-up protection. The first of these is the Restricted Earth Fault Protection (REF) or Ground Differential scheme on the LV, star side of the transformer. This will protect a major proportion of the star winding, but not all of it. A second level of back-up is provided by standby earth fault protection. This is an overcurrent relay with a fairly long operating time. An overcurrent element is also connected to the primary CTs to provide back up for transformer faults fed from the Grid.

A P122 overcurrent relay is positioned on the secondary side of the transformer, outside the protected zone of the transformer. The CT ratios for the P122 relay are 10/1. This relay is graded with the P142 relays in the Distribution and Utilization System.

The P122 Overcurrent Relay is the simplest relay in the Simulator. It also has a clearly written Technical Manual. For those unfamiliar with the relays it may be the best relay to consider first. Whereas most relays are best accessed through the front port and settings changed on the PC with S1 software, the P122 Menu is simple enough to be accessed by the front key pad.

The Menu contents description is given in the Areva Technical Manual. The important sub-menus are 'Configuration', 'Protection' and 'Broken-Conductor'. To get to the 'Configuration' and the 'Protection' menus, press ⇓ (to 'Output Parameter' which requires the normal AAAA Password for entry) then ⇒ for 'Configuration' and, by further ⇒ to 'Protection'. Broken Conductor is found under the Automatic Ctrl Menu. Go ⇓ from this Menu and then ⇒ until 'Broken Conductor' is found. Go ⇓ to enter settings. For further information, see the Areva Technical Manual.

All protection elements trip Circuit Breakers CBs 1 and 2.

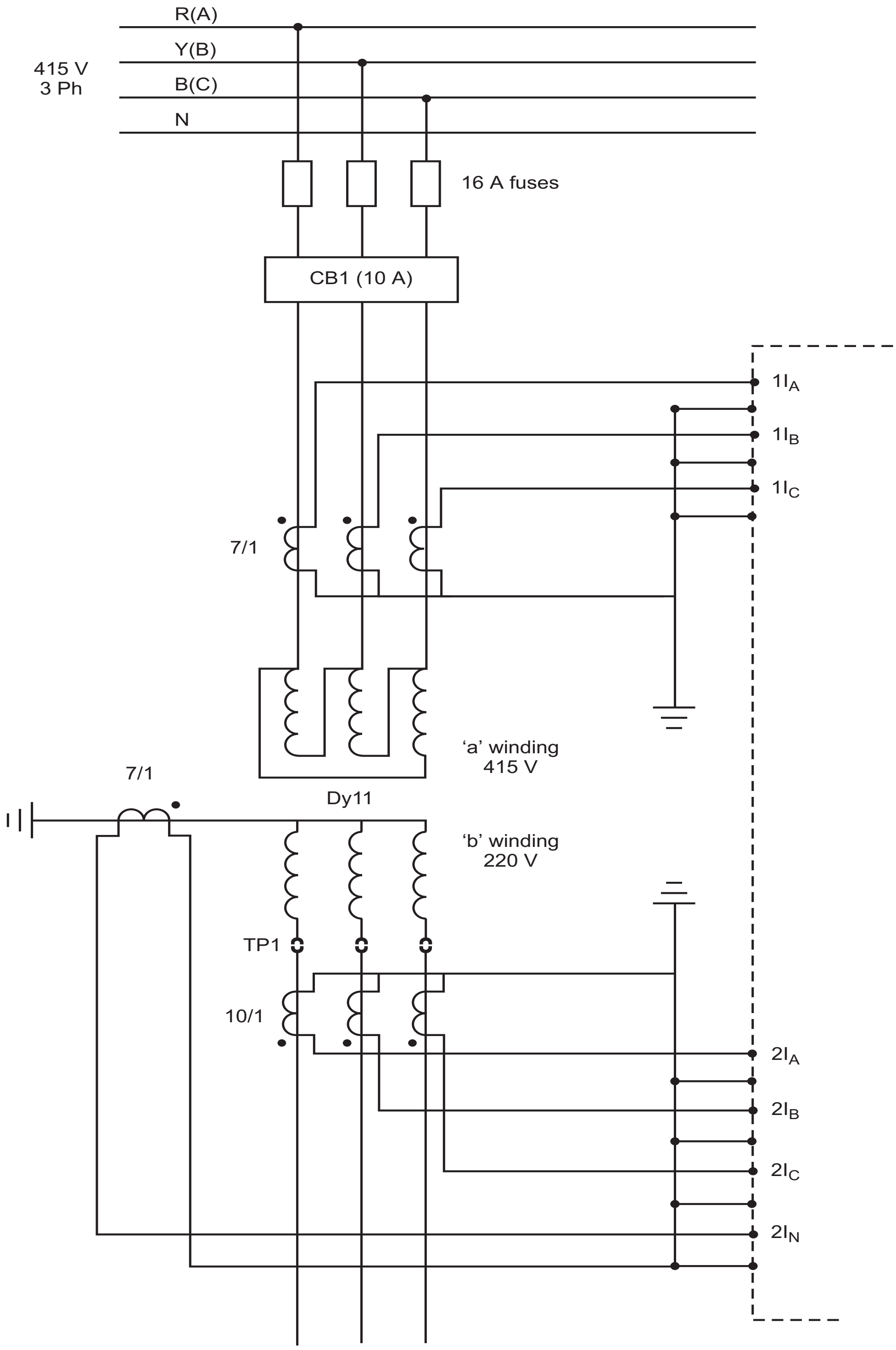


Figure 24 Relay P632 Grid Transformer (GTX) CT Arrangements

Generator Unit G1 and Generator Transformer, GITX

The P342 Generator Protection Relay provides protection of the Generator. The main protection for the generator is a biased, circulating current differential protection. It does not cover the generator transformer as well because the relay does not possess circuits to eliminate the effects of transformer transients, such a current inrush. Figure 25 shows the connection of the relay into the system.

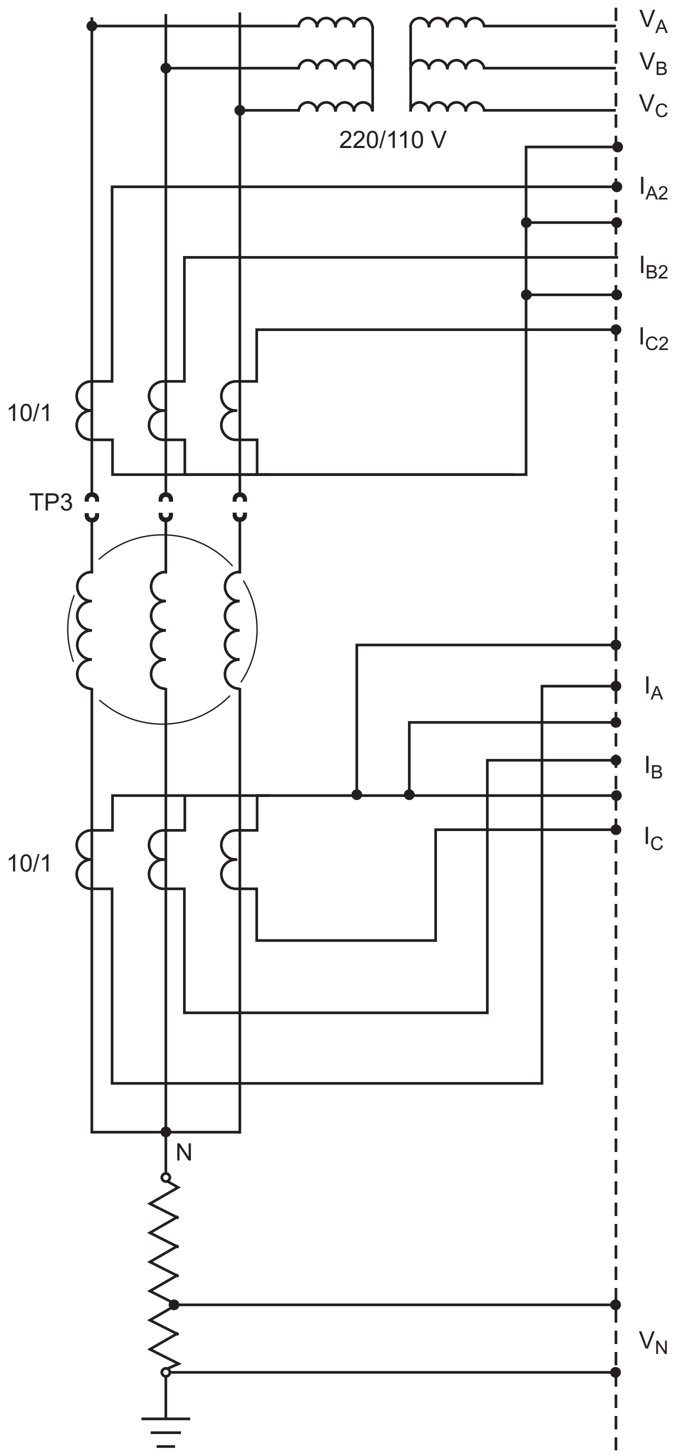


Figure 25 Relay P343 Generator (G1), CT, VT and Terminal Arrangements

Earth fault protection for the generator stator winding is provided, in addition to the differential protection, by inserting a resistor between earth and the star point of the stator winding. (Normally this resistor would be on the secondary side of a VT). The value of the resistor limits the earth current to 1 A for a fault at the generator terminal. The resistor is tapped to give a maximum of 50 V input to the relay neutral voltage input.

An overcurrent element is connected at the terminal end of the stator winding. It has a Definite Time, High Set, setting for instantaneous operation on the occurrence of a stator fault.

A further 'system backup' overcurrent element is provided at the neutral end of the winding. This is a voltage-controlled element. Normally this overcurrent element is set with a high threshold current. But if a fault occurs on the power system such that the voltage at the generator terminals drops below a settable threshold, the overcurrent element will switch to a lower and more sensitive setting. This element should be graded with other overcurrent elements on the power system. The overcurrent relay P122, 'Generator bus' relay, is one such relay.

Also connected into the neutral end of the stator winding is the negative sequence element. Negative sequence currents flowing in the power system can cause damaging overheating of the rotor surface. The setting of the relay is therefore dependent on both the magnitude and duration of the negative sequence current, the I_2^2t factor.

There are also several relay elements that warn of abnormal operation: over voltage and over/under frequency, and a reverse power element detects motoring power flow into the generator from the power system.

Most relays trip CBs 8 and F except Reverse power and under-frequency that trip CB8 only.

Transmission Line Protection

The P442 Full Scheme Distance Relay provides transmission line protection.

This relay provides single and three phase tripping for faults on overhead lines and cables. It also has single and three-pole auto-reclose with check synchronizing. Fault currents are calculated and impedances measured. Quadrilateral impedance characteristics define up to 5 Zones of protection.

Figure 26 shows the relay connection to the systems. The relay requires both CTs and VTs because it measures impedance and thereby, the distance to a fault on a line. The phase voltage input on the supply side of the circuit breaker is for check synchronization, i.e. for comparing the phase of the voltage on either side of the circuit breaker in order to determine the right time to reconnect the line to the supply.

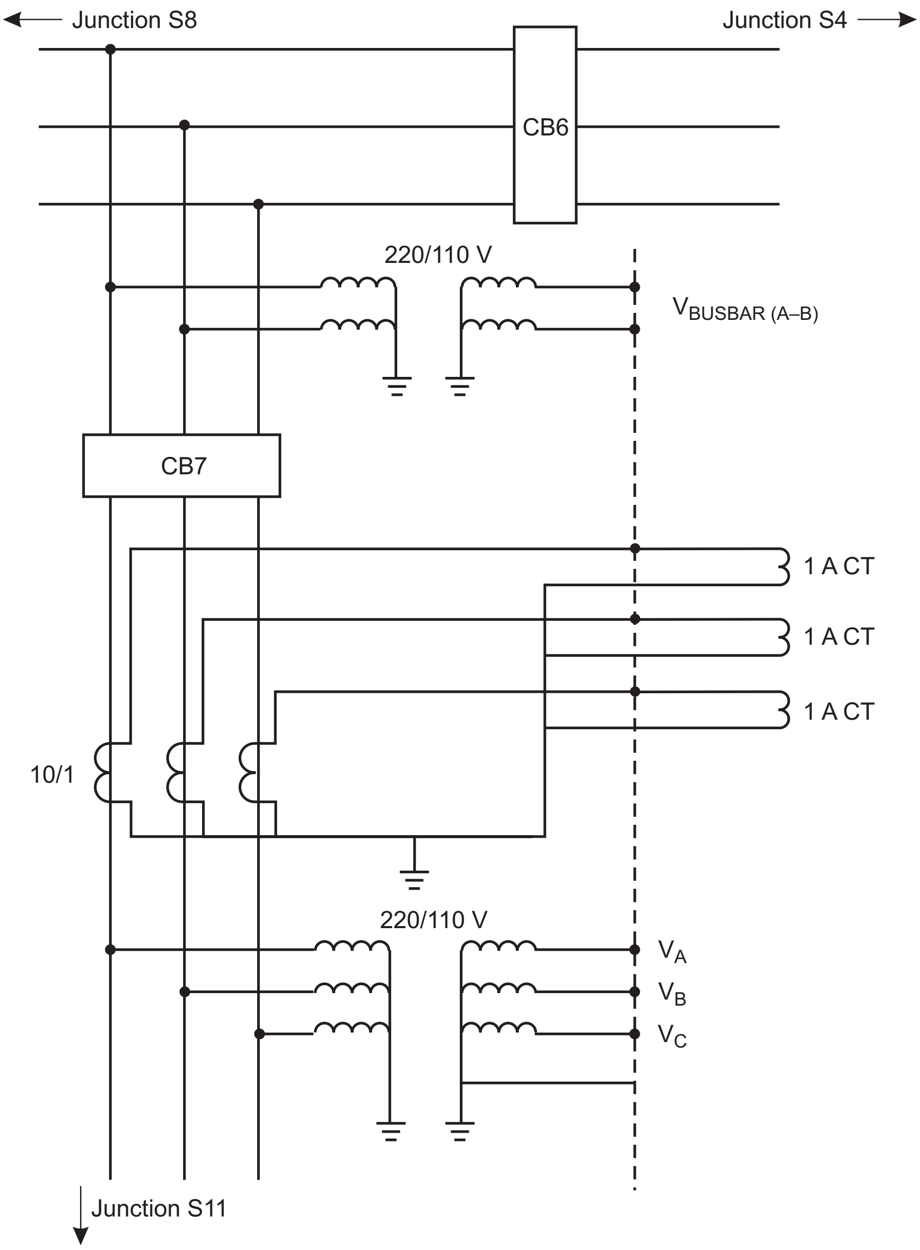


Figure 26 Relay P442 Distance Protection CT and VT Arrangements

Double Busbar Interconnection and Switching System (Refer to Figure 16)

Protection is provided for two zones of the busbars by a high impedance differential protection scheme. This arrangement enables the principles of busbar protection to be demonstrated. It does not fully represent a practical system, which would consist of four zones of protection plus a check protection scheme. See Section 7. Space does not permit the inclusion of a full system in the Simulator. The relays used for this protection are two P142 relays, one for the right–hand section, Zone 2, and one for the left–hand section, Zone 1.

These relays are connected to current transformers on either side of the bus section switch and on each incoming and outgoing feeder. All current transformers have a ratio of 7/1.

The Zone 1 relay trips CBs 10, 11, 12, 14, 15. The Zone 2 relay trips CBs10, 15, 16, 18, 19.

Distribution and Utilisation Bus

The main protection for the distribution system is provided by four P142 relays, two in each branch of the system, one on the primary side and the other on the secondary side of the distribution transformers. Figure 19 shows the connections for the P142 relays.

The four relays provide not only time–current characteristics but also a wide range of other features. Fault current, operating time and voltage data are amongst the information provided by the relay. The CTs for the P142 relays are 7/1 on the primary side and 14/1 on the secondary side.

The relays can be set to provide, together with the Grid Bus Overcurrent relay, graded protection for the system. Auto-reclose can be used in feeder protection and directional control of relays can be investigated in the protection of parallel transformers or feeders. Circuit breaker fail and back-trip can also be investigated.

3.5 Essential Operating Procedures

Reading Fault Records from a Relay Front Panel

When a relay trips, alarm messages will be indicated by the default display on the relay screen and by the yellow alarm LED flashing. The alarm messages can either be self-resetting or latched, in which case they must be cleared manually. To view the alarm message press the read key. When all alarms have been viewed, but not cleared, the alarm LED will change from flashing to constant illumination and the latest fault record will be displayed (if there is one). To scroll through the pages of this record, use the read key. When all pages of the fault record have been viewed, the following prompt will appear:

'Press clear to reset alarms'

To clear all alarm messages press C; to return to the alarm/faults present display and leave the alarms uncleared, press the read key. Depending on the password configuration settings, it may be necessary to enter a password before the alarm messages can be cleared (see section on password entry). When the alarms have been cleared the yellow alarm LED will extinguish.

Alternatively it is possible to accelerate the procedure. Once the alarm viewer has been entered using the read key, the C key can be pressed, this will move the display straight to the fault record. Pressing C again will move straight to the alarm reset prompt, where pressing C once more will clear all alarms.

Changing Settings from the Front Panel.

To change the value of a setting, first navigate the menu to display the relevant cell. To change the cell value press the enter key ↵, which will bring up a flashing cursor on the LCD screen to indicate that the value can be changed. This will only happen if the appropriate password has been entered, otherwise the prompt to enter a password will appear. The setting value can then be changed by pressing the ⇑ or ⇓ keys. If the setting to be changed is a binary value or a text string, the required bit or character to be changed must first be selected using the ⇐ and ⇒ keys. When the desired new value has been reached it is confirmed as the new setting value by pressing ↵. Alternatively, the new value will be discarded either if the clear button C is pressed or if the menu time-out occurs.

For protection group settings and disturbance recorder settings, the changes must be confirmed before they are used by the relay. To do this, when all required changes have been entered, return to the column heading level and press the key. Prior to returning to the default display the following prompt will be given: 'Update settings? Enter or clear'

Pressing ↵ will result in the new settings being adopted; pressing C will cause the relay to discard the newly entered values. It should be noted that, the setting values will also be discarded if the menu time out occurs before the setting changes have been confirmed. Control and support settings will be updated immediately after they are entered, without 'Update settings?' prompt.

Changing Settings by PC from the Front Port

The S1 Software and Settings program within the PC provided is accessed by connecting the PC to the front serial port of the relay, as shown in Figure 27. When the connection is made and the power switched on, the relay will run through a self-check. When the relay has finished its internal checks the following message should appear: 'Description, MiCOM Pxxx'.

1) Open the S1 program on the PC. The Start-up Screen will appear. See Figure 28. Click on the Relay. Using the on-Screen 'up', 'down', arrows choose the relay platform required, e.g. Px40, for front port access.

2) Click on the relay. The MiCOM application Screen appears. Click on the 'Settings and Records' button.

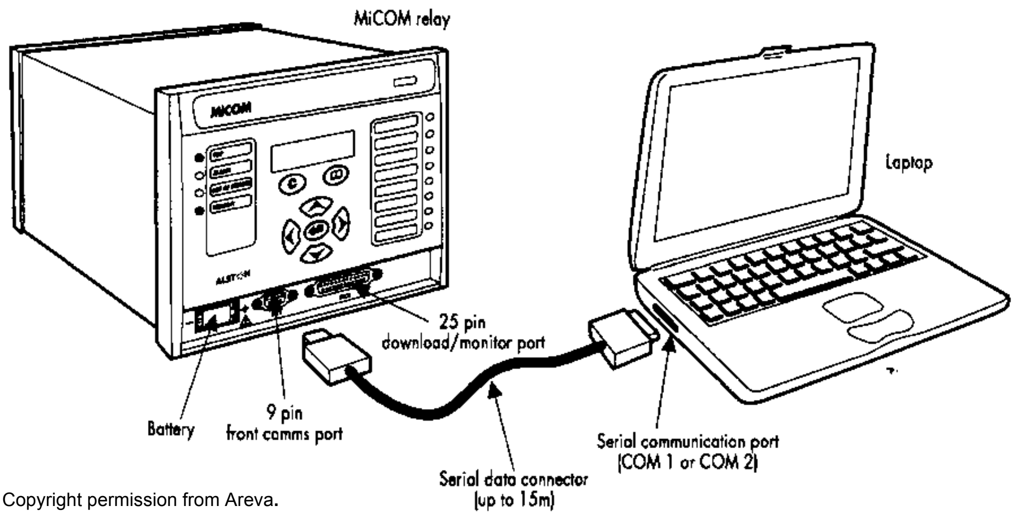


Figure 27 Front Port Connection

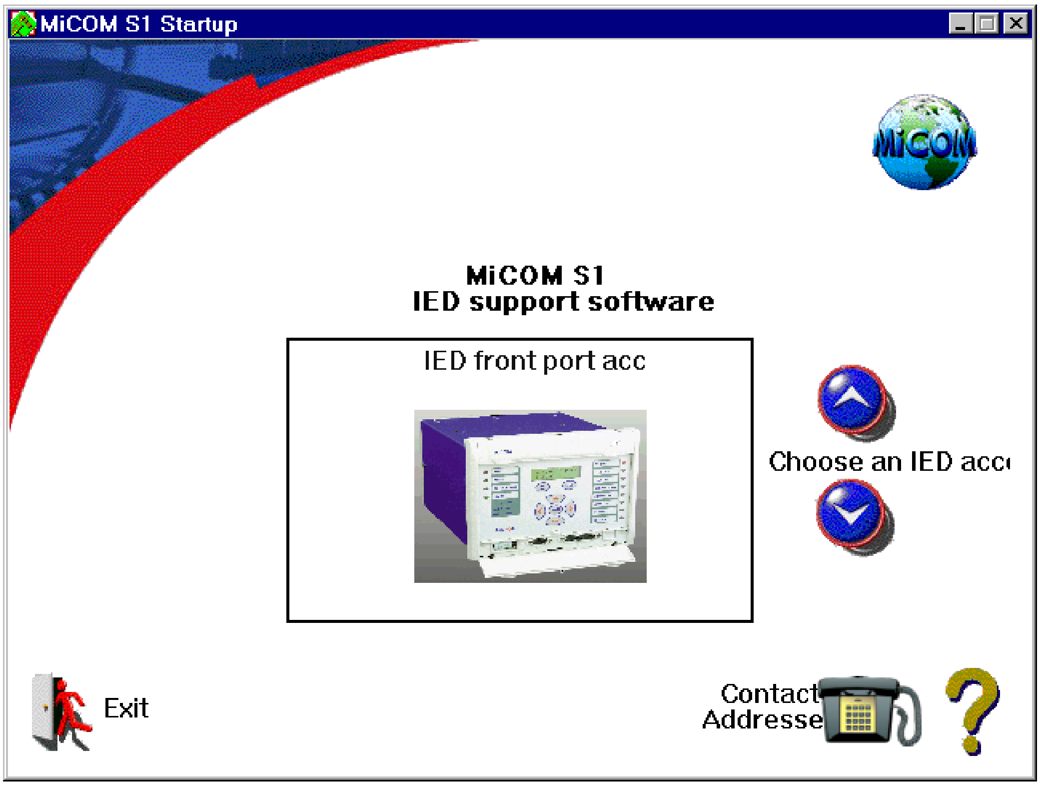


Figure 28 Start Up Screen

3) The Settings and Records blank page appears. The command options available in the tool bar are: File, View, Device, Help. This Screen enables the user to edit settings under 'File', or retrieve them from the relay using 'Device' and edit them. Edited files can then be sent back to the relay.

4) Click on File in the tool bar. A number of commands appear in the drop-down Menu: New and Open. Click on Open. A listing of settings files appears. Click on the one required for editing, according to its description.

For the Px40 range these are:

ne9270p142busa, 9270p142busb, 9270p142d1-a, 9270p42d1-B

9270p142d2-a, 9270p142d2-b, 9270p442 2dist, 9270p343 gen.

Click on the one to be edited. The P*30 and P*20 Settings and Records screens have to be similarly accessed for the P632 and P121 relays, respectively.

5) The Settings File for the P14x relay appears as shown in Figure 29.

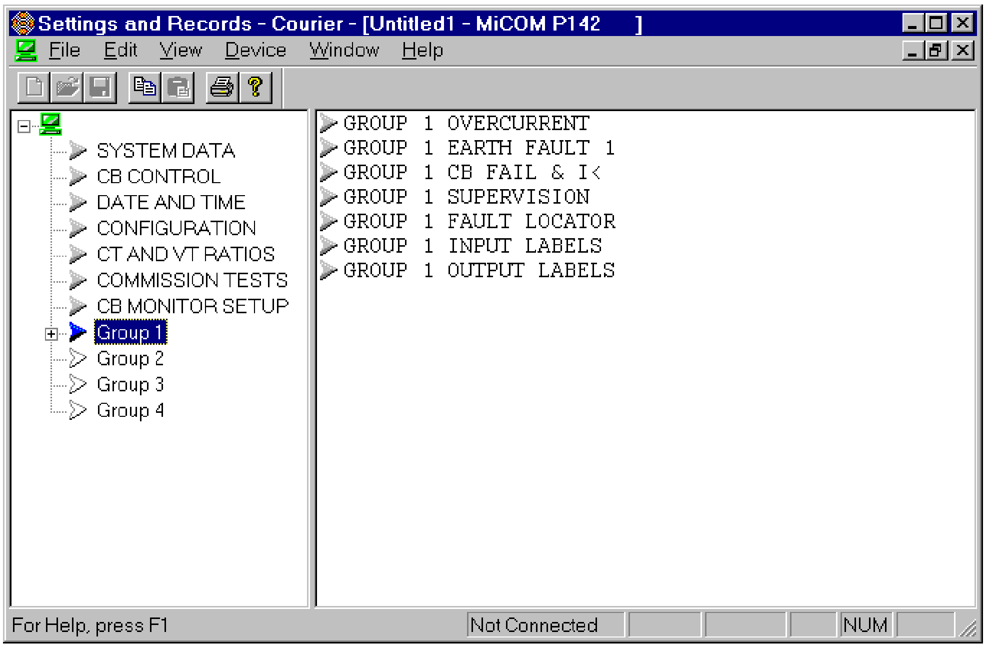


Figure 29 Settings

6) To modify individual settings click on ‘Group1’. Remember that ‘Configuration’ generally controls the ‘enable’ instructions for relay elements. Settings will appear as in Figure 29 with the Protection Settings in the right-hand pane.

7) To get at individual settings double click on ‘Overcurrent’, for example. All the individual settings will appear.

8) Double click on a setting to be changed. A setting selection screen will appear. Change the value or instruction and OK it.

9) When settings have been changed as required, save them, then go to the toolbar screen and click on ‘Device’, then ‘Open Connection’. Follow instructions to upload the existing file to the Relay.

10) There are now two relay-setting frames on the PC Screen, the Device Frame and the Modified Setting Frame.

11) Collapse the modified setting menu back to the PC icon. Click on the Green PC icon, and drag and drop onto the PC icon of the relay screen.

12) Wait until the PC finishes downloading to the relay. Follow any instructions necessary.

13) Refer to the S1 Software Guide for more detail.

SECTION 4.0 General Operation of the Power System Simulator

A number of general facilities are provided on the Power System Simulator panel to enable a power system to be set up and its operation investigated. The main functions of these facilities are to:

- Connect together the individual components to form the power system to be studied.
- Switch, manually and by protective relays, the various components in the system.
- Apply and time the duration of faults on the system.
- Measure and record voltages and currents throughout the system.
- Provide alarms and controls for the protection system.

Central Test and Control Panel

Means for connecting and switching components are distributed throughout the Simulator, but system monitoring and operational controls are provided collectively and centrally on the Simulator panel. These central facilities are shown in Figure 30 and include:

- Grid supply instrumentation and monitoring points.
- Generator instrumentation and monitoring points and generator speed, excitation and power controls.
- A synchroscope that allows two separately controlled power supply systems to be connected at specified busbars, called the reference bus and the incoming bus.
- A 'Test Points and Alarms' section for monitoring the system.

Use of the generator controls and synchroscope are described in Sections 2 and 5. All other general facilities are described in the following sections.

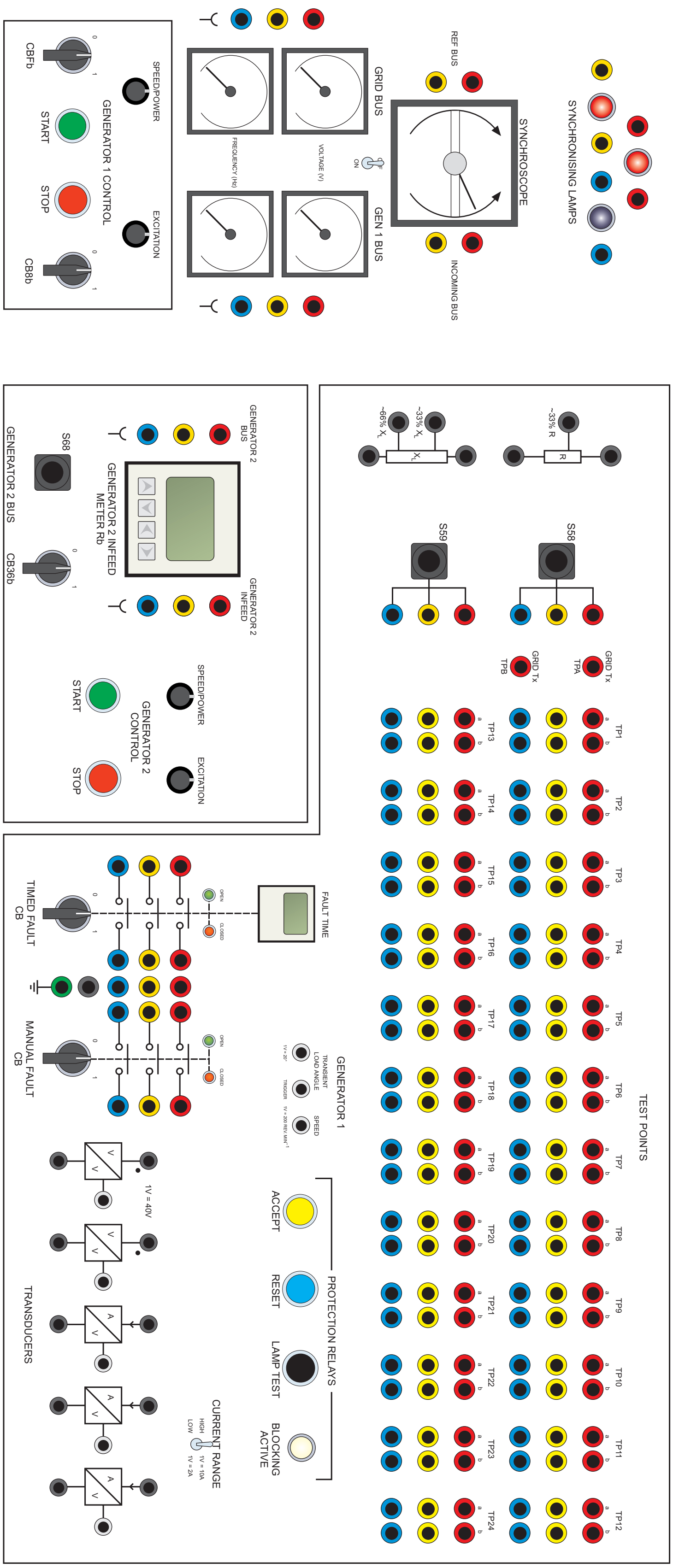


Figure 30 Central Test and Control Facilities on the Power System Simulator

4.1 Connections and Links

Four core cables (three–phase and earth) connect the components on the Simulator panel. The cables are of large diameter and have a gold–plated four–pin plug at each end to keep the resistance low.

At every point of termination of a line the cable plugs are inserted into four–pin sockets (black, square base) in the panel of the Simulator. The sockets are shown in the various component diagrams in Section 2. There is only one way to insert the cable plugs into the sockets - insert the plug into the socket and rotate the plug clockwise until its locking catch clicks into place. To remove the plug, slide the locking catch backwards and turn the plug anticlockwise until you can remove it.

The cables are supplied in several lengths to connect the lines and components together. However, to avoid long lengths of cable trailing across the front of the Simulator, four links have been included on the Simulator panel running parallel to the transmission lines. The links are simply connection cables fixed inside the Simulator. To make the circuits clearer and easier to follow, use the links instead of long lengths of flexible cable.

Use the test points S58 and S59 within the 'Test Points and Alarms' Section to connect to individual phases of the three–phase cables. These provide individual red, yellow and blue connection points from a cable socket.

4.2 Earth Connections

To study earth faults on a system it is necessary to be able to connect to earth star points of transformers and any phase at any test point throughout the system. Each transformer star winding is provided with an earth connection and an earth point is provided for the test points (see Section 4).

An earth bar runs across the Simulator behind the panel to enable earth connections to be made. The earth bar is connected to an external earth point and is separate to the earth bar for instrumentation and relay supplies within the Simulator.

4.3 Switches and Circuit Breakers (CBs)

Supply Switches and Emergency Trip

The main supply switch for the Simulator is near the left hand edge of the panel marked Main Supply MCB. To switch on the Simulator, press the MCB up until it latches. CB1 closes automatically when the relay has performed its self test. If the relay settings are not as recommended in this guide, the relay will come out of service and CB1 will not close.

Two large red 'emergency stop' buttons are available: one near the left hand edge of the panel and one at the bottom centre of the panel near the transducers. The MCB trips out when an emergency button is pressed. To restart the Simulator after an emergency button has been pressed, the button must first be turned to release it from the locked position.

Circuit Breakers

Figure 31 shows the arrangement for circuit connection or interruption by circuit breaker. Manual opening or closing of the breaker is achieved by the lever switch. 'O' indicates 'open' or 'out', '1' indicates 'closed' or 'in'. The red and green lights indicate the closed and open status respectively of the breaker.

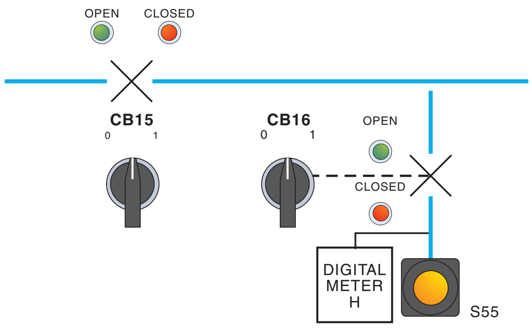


Figure 31 Manual Controls for the Circuit Breakers

Circuit breakers are closed manually, except CB1 which is closed automatically when the Simulator is switched on. Many of the circuit breakers are opened automatically by relay trip operation on the occurrence of a fault.

Indication of which circuit breaker is opened by a relay is stated in the outlined areas on the panel diagram, as shown in Figure 32. Note that the point at which the box is joined to the line indicates where the current transformers are placed within the three–phase system.

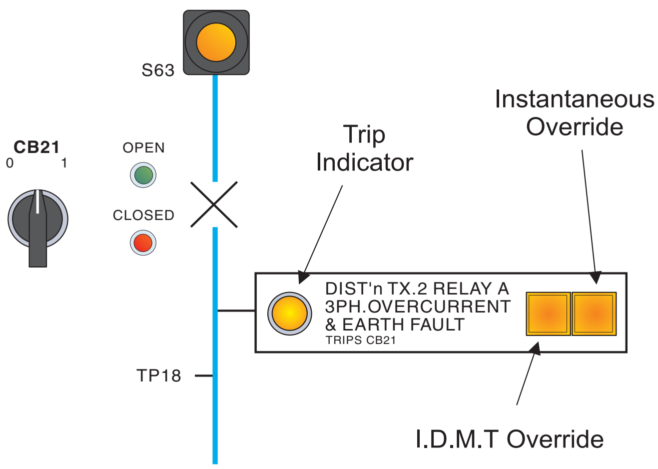


Figure 32 Relay Location Points Including Trip Indicators and Overrides

4.4 Simulator Control Systems and Relay Overrides

The relays within the Simulator have opto-inputs and output relays which are assigned to a variety of functions external to the relays and relating to the overall operation of the Simulator, regarding circuit breakers, alarms and interlocks. The input/output designations for each relay are shown on the drawings provided with the Simulator.

When studying the operation of the protection schemes it is desirable at times to override a relay operation (e.g. a protective relay may be overridden in order to time the operation of a back–up relay). The override function is set up at the relay concerned and the amber override button lights up when pressed (see Figure 32). Within the central control panel (shown in Figure 30), the relay override lamp comes on when any relay function on the simulator is overridden. The lamp test button allows all relay trip lights to be tested.

When a relay operates and its associated circuit breaker opens, the alarm sounds and the relay light flashes. The alarm can be switched off by pressing the yellow 'Accept' button (shown in Figure 30), which also stops the relay light flashing. The tripped circuit breaker however can not be manually closed again until the blue Reset button is pressed. The relay operate lights are also switched off when the blue Reset button is pressed.

4.5 Fault Application and Timer

The Manual Fault and Timed Fault circuit breakers are at the bottom centre of the 'Test Point and Alarms' section of the Simulator panel (see Figure 30).

Either of the Fault circuit breakers can be used to apply faults - three-phase, line to line or line(s) to earth - at a selected point in a system. For example, to apply a line to earth fault at the end of line 1, take a three-phase cable connector from the terminal socket of line 1 to test point S59. The red socket output from S59 is then connected to the primary side of the Fault circuit breaker, and the secondary side of the Fault circuit breaker is connected to the earth socket to the right of the circuit breaker. After the fault is applied (by closing the fault breaker), a protective relay should trip its associated circuit breaker after a set time.

If impedance is to be inserted in the earth connection then either the XL and R components in the panel above the fault circuit breaker, or an external impedance, could be used.

The Timed Fault circuit breaker can be used to clear a fault should a relay fail to trip. This function is a useful back-up when experimenting with relay operating (or trip) times. The timer is first set to a time greater than the expected operating time of the relay. Closing the Timed Fault breaker will apply the fault and start the timer. If the relay fails to trip within its set operating time, the timer will open the Timed Fault circuit breaker and remove the fault.

Setting the Timer

The timer has a digital time display. The timer has a reset, mode and display keys. The reset key resets the operating time indicator. The mode key shifts from 'Run' mode to 'Set' mode when it is required to enter a set time in the lower display. To go back to 'Run' mode from 'Set' mode press the Display key.

Using the four up-keys numbered 1 to 4 sets the time. Pressing any of these keys increases the digit displayed from 0 to 9, then to 0 again - i.e. cyclically. A decimal point is displayed initially between the fourth and third digit. In this position the maximum set time is 9.999 seconds. Trying to go above this value will move the decimal point to between the second and third digits. This process is repeated to move the decimal point further to the right. Note; TQ recommend that your fault times are less than 9.95 seconds.

4.6 Test Points, Transducers and Instrumentation

Test Points

There are twenty–four test points throughout the Simulator. They are invaluable not only for inserting, monitoring and recording equipment but also as additional points of interconnection between components. They increase considerably the flexibility of the Simulator.

The twenty–four test points are alongside the test points S58 and S59 so that connections can be easily made between three–phase cable connections and the test points. See Figure 30.

Each test point consists of six sockets connected into a three–phase line. They are divided into two sets: 'a' and 'b'. Each set consists of a red, yellow and blue socket. An external connection must be made between the 'a' sockets and 'b' sockets for current to flow between them. Special loop connectors are provided to link a and b sockets. Other leads and loop connectors are provided to enable external devices to be inserted between the a and b sockets.

There are in addition two single test points, TPA and TPB for tapping into the secondary winding of the Grid Transformer. Additional test points are also included on the line and are marked MP1 to MP21. These are tapping points only for use with the phase angle meter which is positioned just below Link 4 on the front panel.

Instrumentation

As well as the instruments used to monitor the operation of the Generator and its connection to the Grid, there are, throughout the Simulator, numerical measurement centres for voltage, current, power factor, frequency, power and reactive power, as considered appropriate. These are described in Section 3. The phase angle meter is used for looking at the line voltages and the phase shift across three–phase transformers or between lines, for which tapping points, 'MP', are provided in the lines across two phases.

Transducers and System Monitoring

At the bottom of the 'Test Points and Alarm' section there are five Hall–probe transducers: two are voltage transducers, three are currents transducers. Each has two sockets for connection through the test points into the circuit being studied. These transducers give instantaneous values of voltage proportional to system currents or voltages: 1 V ≡ 40 V and either 1 V ≡ 2 A or 1 V ≡ 10 A. The output terminals of the transducers are BNC sockets, as the transducers are normally used in conjunction with an oscilloscope or plotter. They are valuable for looking at and measuring transient currents and voltages following a fault application.

Two other BNC connectors for 'Load Angle' and 'RPM' are provided for recording the transient load angle and speed of generator GI.

4.7 Remote Access to the Relays and Measurement Centres

The menu tables of the MiCOM relays can be accessed, not only via the front port, but also via a communications link to a remote PC. This allows menu cells in setting files to be displayed on the screen of a PC using MiCOM S1 software, or access to the SCADA S10 program for carrying out remote operation and monitoring of the power system. The relays are interconnected via a shielded, twisted wire pair known as K–Bus. Up to thirty–two relays may be connected in parallel across the bus. The relay rear ports provide K-Bus/RS485 serial data transmission and are intended for use with a permanently wired connection to a remote control centre. The K–Bus is connected through a protocol converter known as KITZ, either directly or via a modem, to the RS232 port of a PC. The KITZ provides signals over the communications bus that are RS485 based and are transmitted at 64 kb (kilo bits) per second. The K-Bus and KITZ connections are shown in Figure 33. The KITZ and Modbus converters are small modules placed near to the remote PC. The interface to the converters and remote PC is located in the side panel on the right-hand side of the Simulator.

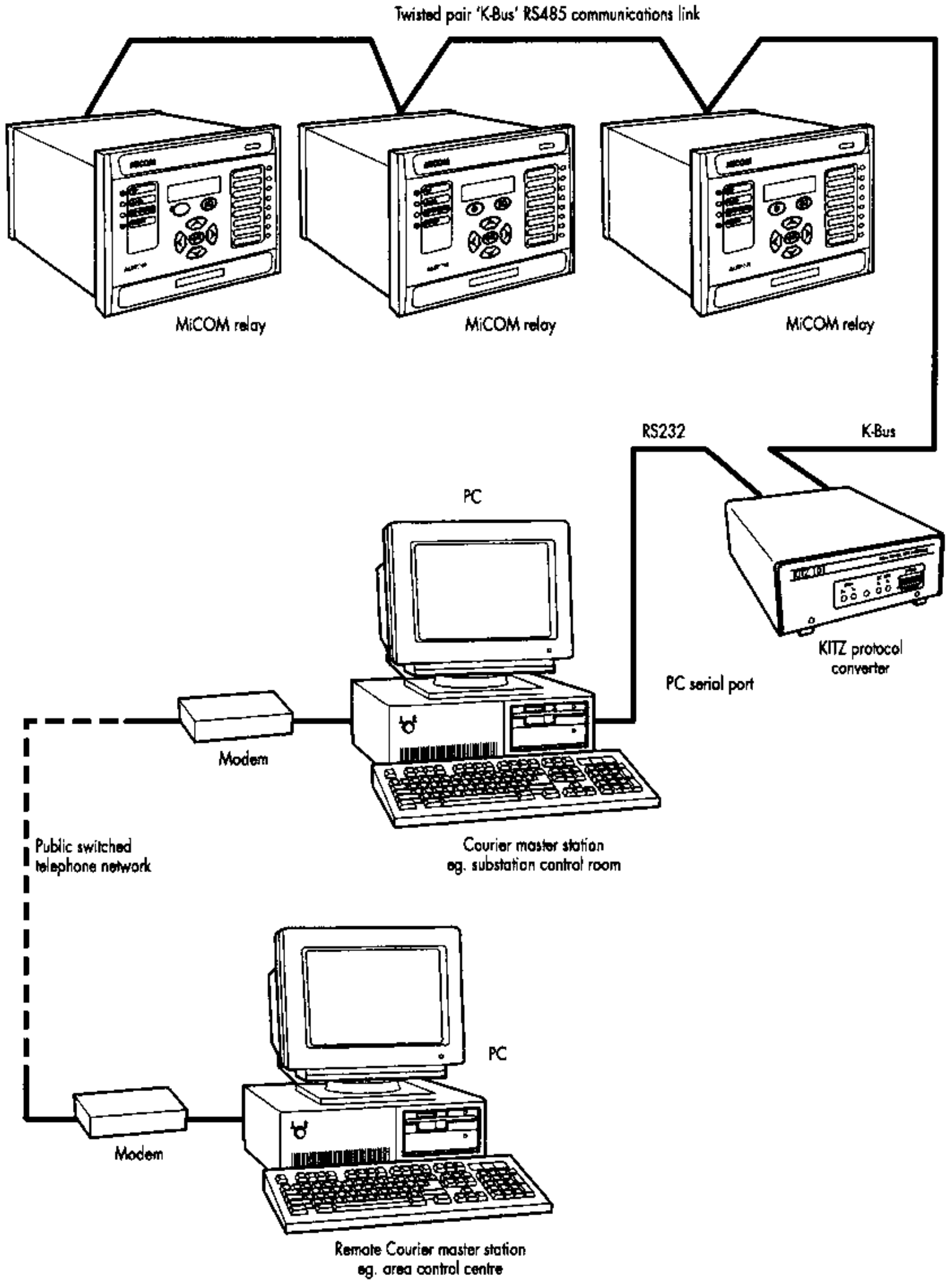


Figure 33 Remote Communication Connection Arrangements

Courier is the communications language used by Areva to allow remote interrogation of its range of relays via a K-Bus and KITZ protocol converters. In the Courier system, all information resides within the relay. Each time communication is established with the relay, the requested information is loaded to the PC. Each relay is directly addressable over the bus to allow communication with any selected relay. The protocol includes extensive error checking routines to ensure the system remains reliable and secure.

An alternative to the Courier protocol is Modbus: a similar master/slave communication protocol for network control. In the Simulator, Modbus is used for interrogating the M230 Communicating Measurement Systems. The interconnection bus for the M230 instruments also has an external connection port in the side panel on the right-hand side of the Simulator.

4.8 Simulator Start Up Procedure

1) Ensure both emergency stop buttons are out and rear cabinet doors are closed

2) Switch on the mains supply

3) Switch on the mains MCB of power system simulator

4) The grid transformer relay will perform a self-check for several seconds, then CB1 will close automatically. If this does not happen contact TQ or a representative

5) Check that generator inertia switch on panel 1 (left–hand side panel) is at Position 1

6) Check that all test point links (e.g. TP3, TP4, etc.) on panel 3 all have shorting plugs fitted

7) Check grid incoming volts across all phases (use MA)

8) Check transformer secondary volts across all phases on instruments adjacent to TP1 test point on the panel 1 schematic (use MB)

9) Press the reset button on the central control panel

10) Press lamp test button on the central control panel and check all lamps are working

4.9 Generator 1 Start Up Procedure (Use Generator 1 Control Panel)

1) Carry out 'Simulator Start Up Procedure'

2) Check field circuit breaker CBF is open

3) Check speed/power control pot is at its minimum setting (500 rev.min^{-1})

4) Check excitation control pot is fully anti–clockwise (000)

5) Press Start button

6) Increase speed/power control to give 1500 rev.min^{-1} (50 Hz) or 1800 rev.min^{-1} (60 Hz)

7) Close field circuit breaker CBF

8) Adjust excitation control to give 220 V

9) Check voltages across all generator phases on MC or MD

NOTE

- *Circuit breaker CBF and CB8 cannot be closed until the drive motor for Generator 1 has started.*
- *The motor will only start if the generator protection is operative and the inertia switch is in position 1.*

4.10 Generator Shut Down

1) Adjust the generator output to near zero and open the field circuit breaker CBF.

2) Press the stop button and allow the prime mover motor fan to continue cooling for at least one minute before you switch off the simulator.

SECTION 5.0 Theory and Experiments: Steady State Operation

This section considers the operation of a power system under steady state conditions, when symmetrical three–phase voltages are applied to three–phase balanced loads resulting in identical currents in each phase of the system. Basic knowledge of balanced three–phase systems is assumed, and the experimental studies concentrate on three main areas of system operation: generation, transmission and distribution and utilisation. In each area a review of the relevant fundamental theory is given together with some illustrative experimental studies.

5.1 Commissioning Experiments

Unless specifically asked for, manufacturers normally supply only nominal values for equipment parameters. It is desirable therfore that the actual values of parameters should be obtained by tests before system studies are carried out. Parameters of the following components should be measured:

- Generator G1: Series reactance by open circuit and short circuit test
- Generator Transformer G1TX: Series reactance and resistance by open circuit and short circuit test
- Transmission lines and cables: Reactance and resistance measurement by a.c and d.c voltage and current up to 30 A
- Distribution transformers DTX1 and DTX2: Series reactance and resistance by open circuit and short circuit test

Values obtained by TQ should be entered into Table 1, using the columns provided so that actual measured values are used rather than nominal values.

5.2 Generator steady-state operation

The generator operation discussed in this initial section assumes that the machine has a cylindrical round, rotor and uniform air-gap and there is no saturation of its magnetic circuits.

Generator units consist of two elements: a prime mover (turbine or diesel engine) and an electrical a.c generator as shown in Figure 34. Mechanical energy is produced by the prime mover and converted to electrical energy by the a.c. generator. Control of the prime mover therefore controls the electrical power supplied to the power system; this is usually achieved by a governor mechanism.

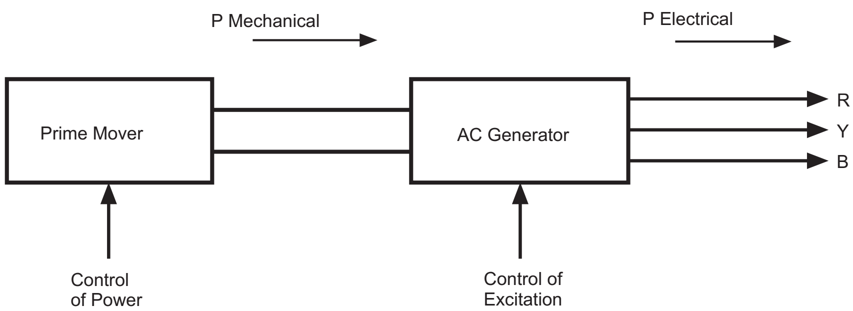


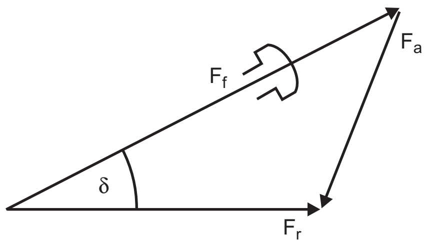
Figure 34 A Generator Set

Large a.c generators have a multi-pole rotor 'excited' by d c current to produce a magnetic field. The strength of the magnetic field is given by the magneto-motive force (mmf), F_f which produces a flux density, B_f. The rotor is driven by the prime mover to induce an emf ,E_f, in each phase of the stator winding. When the stator phase windings carry load current, I_a, they produce together a magnetic field, F_a, which rotates in synchronism with the rotor. This magnetic field, which is called the armature reaction mmf, interacts with the mmf of the rotor to produce a resultant magnetic field, F_r. This mmf produces the flux density, B_r, in the air-gap of the machine which will induce the internal emf per phase of E_i.

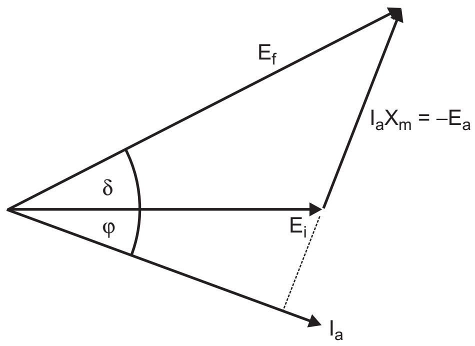
The phasor relationship between the mmfs is shown in Figure 35a for a lagging power factor load. The position of the mmf, F_a, with respect to F_f is determined by the load power factor, as shown in Figure 35b.

If the magnetic circuits of the machine are assumed to be linear, so that $B \propto F$, each of the mmfs can be considered to produce, by superposition, a proportional emf in each phase of the stator winding.

The mmf and emf phasor diagrams are therefore similar triangles. Remember, however, that the mmf diagram is a space diagram and the emf diagram is a time diagram.



(a)
MMFs in air gap of generator



(b)
EMFs and current in an armature phase

Figure 35 MMF and EMF Diagrams

The armature reaction mmf, F_a, can be considered to produce an emf, E_a, or an equivalent voltage drop of I_aX_m in each phase. X_m is the magnetizing reactance of the stator winding, per phase.

The voltage phasor diagram leads to a generator equivalent circuit representation, per phase, shown in Figure 36. The actual emf induced in the stator windings is E_i. Further voltage drops in the winding due to resistance (I_aR_a) and leakage reactance (I_aX_l) result in a final terminal voltage of V. The full phasor diagram is shown in Figure 37. The combination of X_l and X_m is called X_s, the synchronous reactance of the machine.

The load angle 'δ' is a space and a time angle; it can be measured, approximately, as the angular change in the pole position from no-load to load.

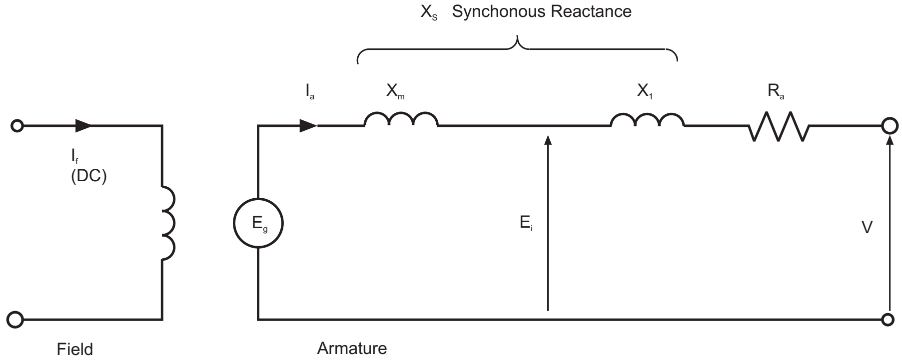


Figure 36 Equivalent Circuit for the Generator

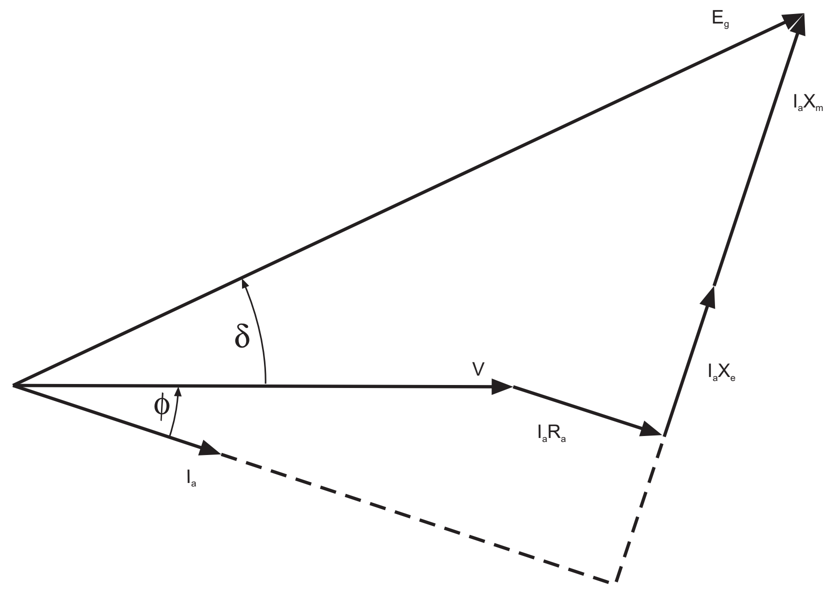


Figure 37 Phasor Diagram for the Generator

Saliency: Direct and Quadrature Axis Reactances

In practical generators the air-gap is never uniform (ie of equal length all around the machine). It is certainly not true of salient-pole machines, as shown in Figure 38, and even cylindrical rotor machines have a degree of saliency. Saliency means that there are two axes of symmetry for the magnetic circuit of the machine: one along the pole or direct axis and one along the inter-polar or quadrature axis. These axes are shown in Figure 38 together with the flux paths associated with them. Note that, for the same value of mmf, the flux produced on the quadrature axis would be much smaller than that on the direct axis because its magnetic circuit contains much more air. For any axis in between the direct and quadrature axis an mmf would produce a flux somewhere between the maximum d-axis flux and the minimum q-axis flux. In the previous section it was seen that the position with respect to the pole axis of the resultant mmf, F_r, is dependent on the power factor of the load (Figure 35). Thus the magnitude of the flux produced by F_r, and the flux pattern in the machine will vary with load power factor.

As a means of analysing this situation, the armature reaction mmf, F_a, is divided into two components at right angles: F_{ad} along the d-axis and F_{aq} along the q-axis. These mmfs are shown in Figure 38. Figure 39 shows the mmf and corresponding emf diagrams for a uniform air-gap generator with lagging power factor load.

In this case the flux produced by an mmf would be the same on both axes, so the stator winding reactances on both axes, X_{md} and X_{mq} are equal. However, for a salient pole machine, X_{mq} is much less than X_{md} and the voltage phasor diagram changes, as shown in Figure 40. For comparison, the voltage ON is the voltage E_f for a uniform air-gap generator for which $X_{sq} = X_{sd}$. The direct-axis synchronous reactance, $X_{sd} = (X_{md} + X_l)$ and the quadrature-axis, synchronous reactance, $X_{sq} = (X_{mq} + X_l)$.

Note that, for a given power, saliency reduces the load angle, δ, at which the generator operates.

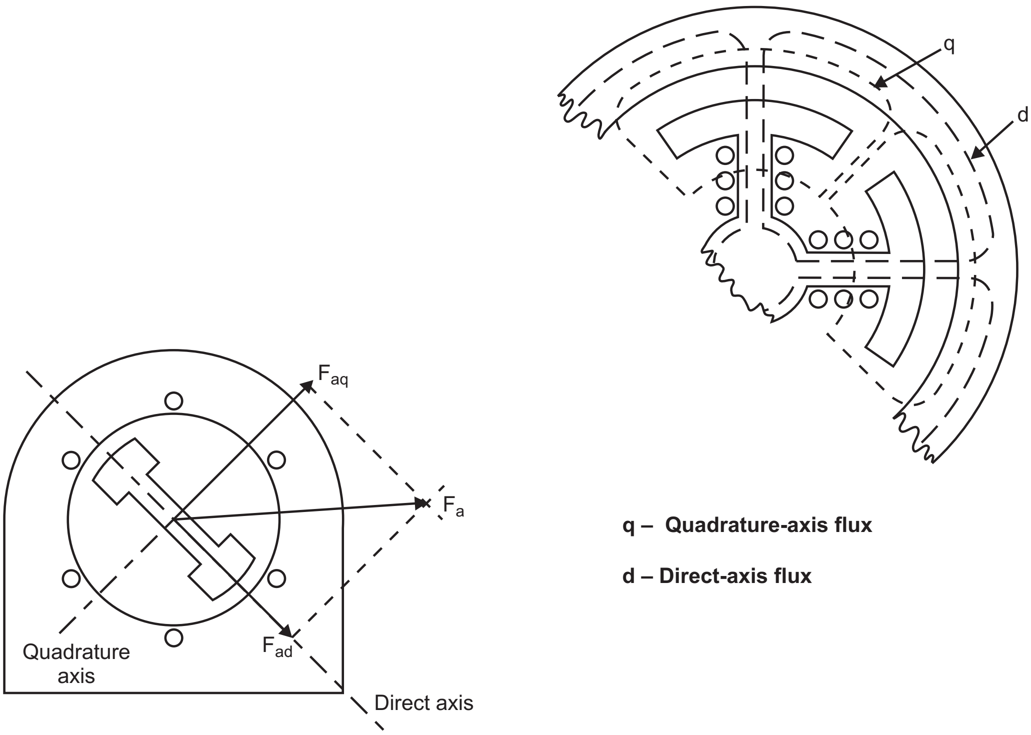


Figure 38 Flux Paths and Axes of Symmetry for a Salient Pole Machine

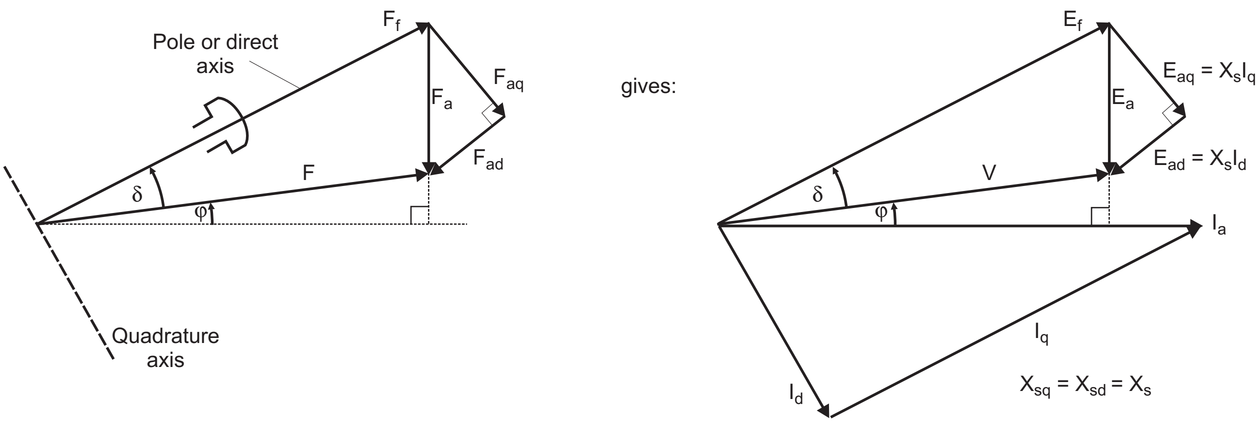


Figure 39 MMF and EMF Diagrams for a Round Rotor Generator

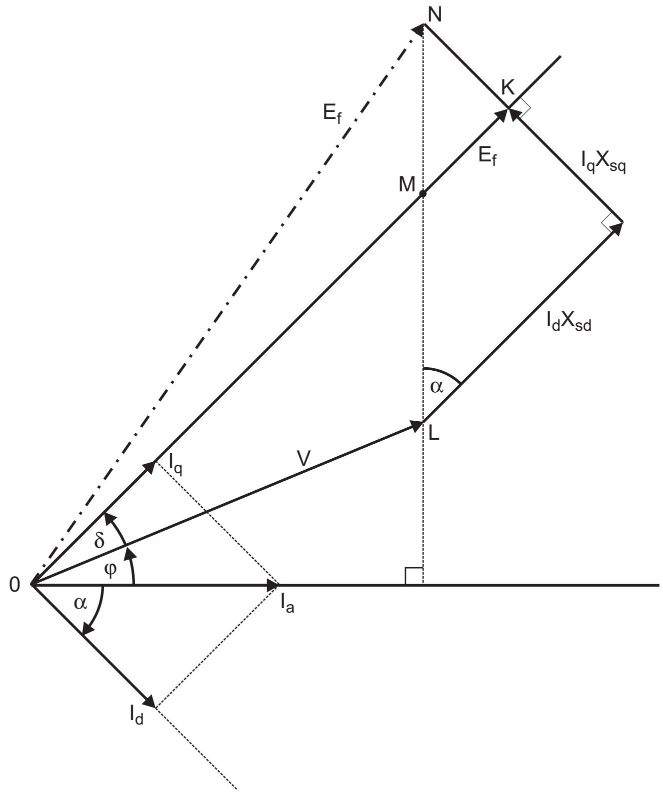


Figure 40 Phasor Diagram For a Salient Pole Generator

The Performance Chart for a Round Rotor Generator

The voltage phasor diagram of Figure 37 can be converted to a power diagram or capability chart by multiplying each phasor by (V/X_s), and neglecting resistance. The resulting capability chart is shown in Figure 41. Note the specification on this chart of stator current limit, rotor current limit and turbine power limit.

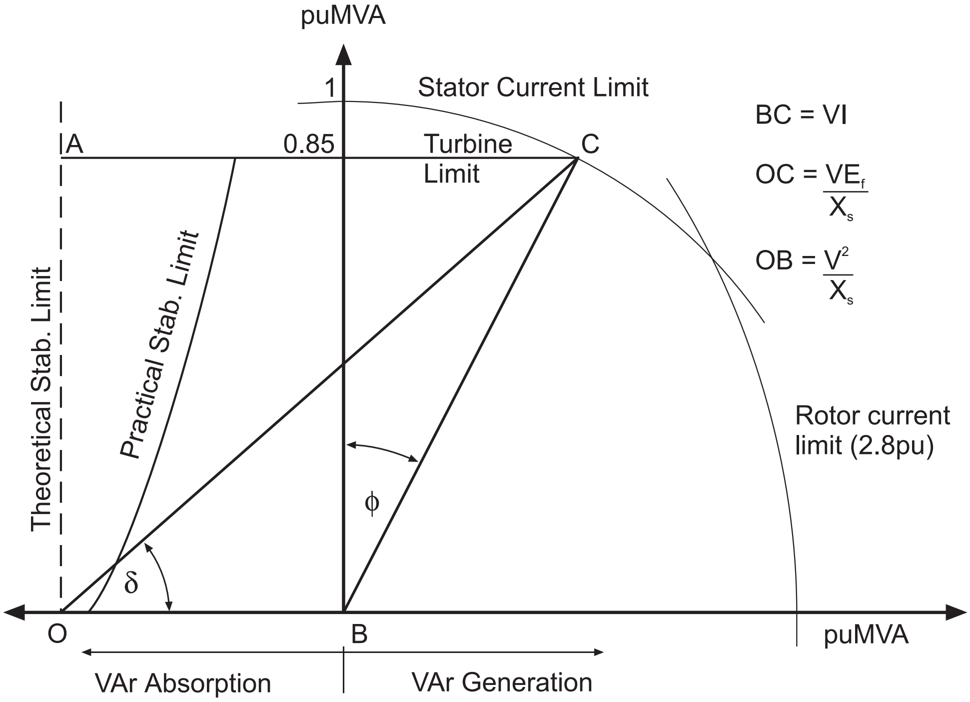


Figure 41 Capability Chart for Turbine Generator

The power factor is equal to the ratio of (turbine power limit/generator apparent power rating) and is stated in the description of the machine i.e. 588 MVA, 22 kV, 0.85 pf, three–phase, 50 Hz a.c. generator, 1 pu generator MVA rating is 588 MVA. Thus, the turbine power limit is (588 × 0.85) MW. The rotor current (or excitation) limit is typically 2.8pu.

When the generator delivers power at a lagging power factor it 'generates' reactive power (VArs) but when delivering power at a leading power factor it 'absorbs' reactive power. The active power per phase of the generator is:

$$P = VI_a \cos\phi$$

From the phasor diagram of Figure 37 but neglecting R_a, P may also be expressed in terms of the load angle δ:

$$P = \frac{V \cdot E_g}{X_s} \sin\delta \qquad (1)$$

Figure 42 shows the variation of P with δ: the Power Angle Curve (PAC). Under steady state operation this curve indicates the power–conversion capability of the generator. If a certain mechanical power P_m is supplied to the generator, this curve indicates the angle δ at which the generator will operate (e.g. P_m and δ_O in Figure 42).

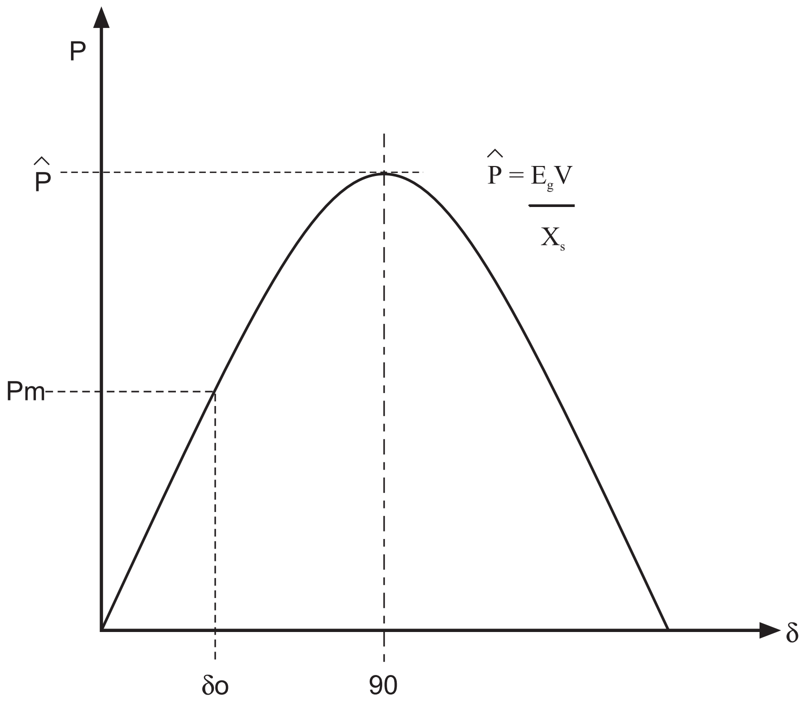


Figure 42 Power Angle Curve for Generator

The maximum power in Figure 42 at δ = 90° corresponds to the theoretical stability limit indicated by line 'AO' in Figure 41.

A practical power limit is shown in Figure 41. This is obtained from the requirement that there should be, typically, 12.5% power (MW) 'in-hand' or 'in reserve' to allow for transient stability swings, δ_t, at any power level. In a 0.80 power factor generator this requirement would mean 0.125x 0.80 = 0.10 MVA. Hence a practical stability limit may be constructed as shown in Figure 43.

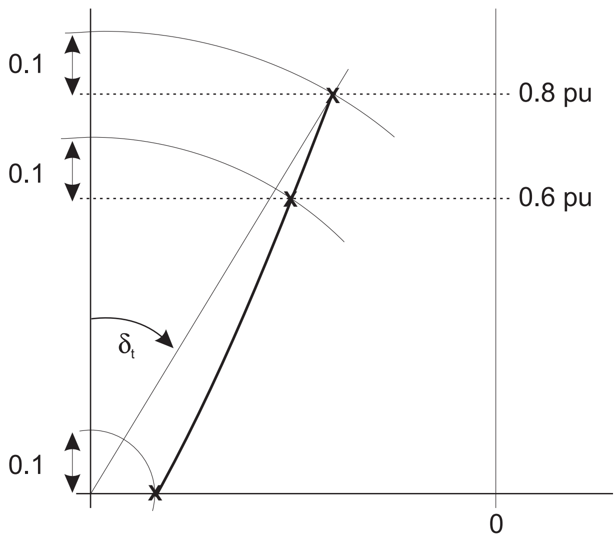


Figure 43 Practical Power Limit

Performance Chart for a Salient Pole Generator

From the phasor diagram for the salient pole generator, Figure 40, it may be shown that

$$P = \frac{E_f V}{X_{sd}} \sin\delta + \frac{V^2}{2}\left(\frac{1}{X_{sq}} - \frac{1}{X_{sd}}\right)\sin 2\delta \qquad (2)$$

Figure 44 shows the variation of P with δ, obtained from equation 2.

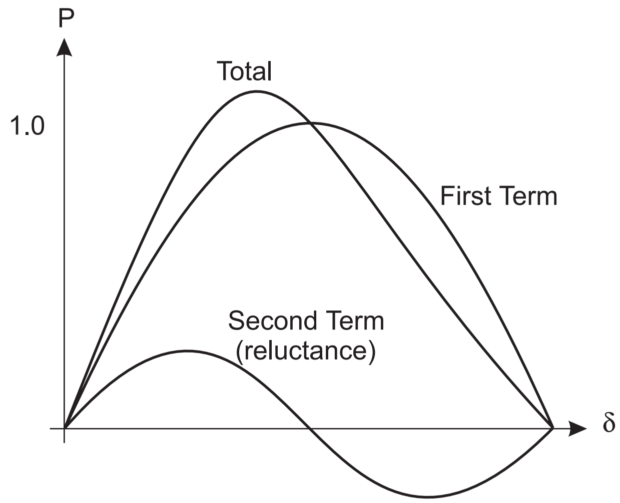


Figure 44 Variation of P with δ

Figure 44 shows that saliency causes a reduction in δ for a given power, compared with a round-rotor generator. The machine is 'stiffer'.

It is not possible to construct a circle diagram about the point 'A' in the phasor diagram Figure 40, because the saliency effect varies with power factor. The locus of point Z in Figure 45 is thus obtained by drawing rays from point X and marking of (E_fV)/Xsd from the circumference of the saliency circle. The locus obtained for point Z is not a circle but a limacon. See references by J Walker and R.M Gove.

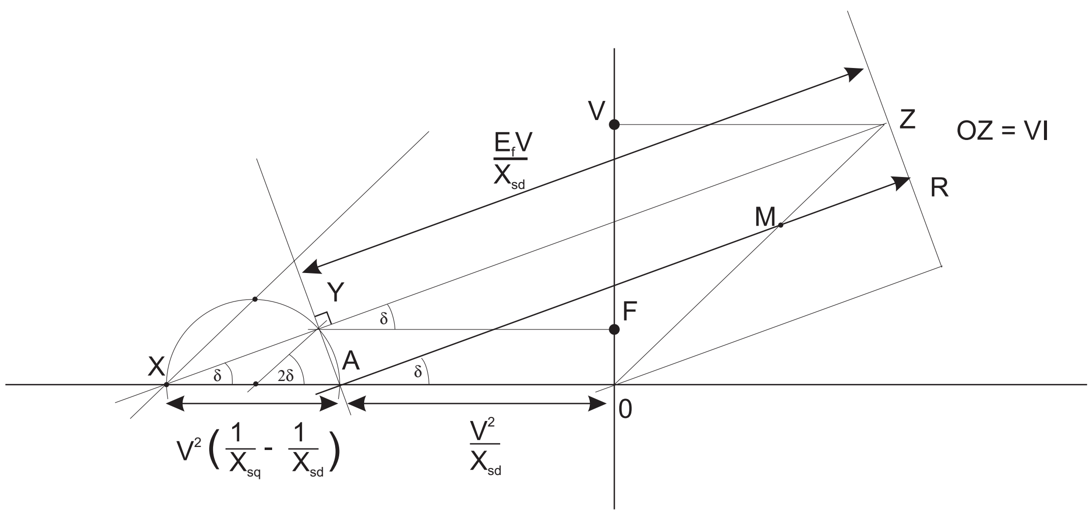


Figure 45 Operating Chart For A Salient Pole Machine

Note that in Figure 45, VO = Total Power = VF+FO

Where (from equation 2 on page 64):

$$VF = \frac{E_f V}{X_{sd}} \mathrm{Sin}\delta \text{ and } FO = \frac{V^2}{2}\left(\frac{1}{X_{sq}} - \frac{1}{Xsd}\right) \mathrm{Sin}2\delta$$

FO is the Saliency or Reluctance Power, obtained without excitation (E_f).

The construction of the theoretical stability limit may also be obtained geometrically (Reference by RM Gove)

See Figure 46. Note the additional area gained due to saliency.

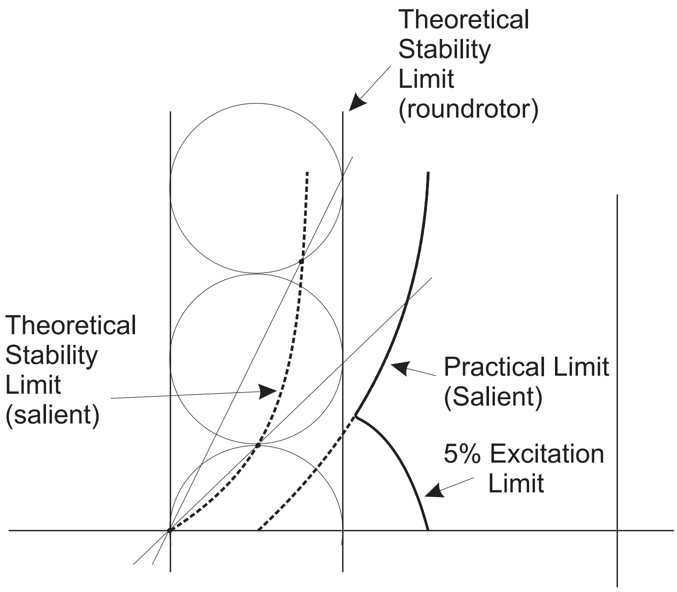


Figure 46 Theoretical Stability Limit

Note that if the reference voltage for the construction of the Power Chart is taken from the secondary side of the Generator Transformer, then the reactance of the transformer should be added to X_{sd}.

Typical Values of Generator Parameters

Typical values of synchronous reactance are given in Table 6. For a more complete explanation of generator reactances, refer to the textbooks shown in the References section of this manual.

	Large T.G. (2 pole)	Gas T.G. (2 pole)	Slow speed salient pole	Medium speed salient pole	Salient pole (4 pole)
X_d	2.01	1.80	1.35	2.05	2.25
X_q	1.91	1.67	0.89	1.17	1.22
X_d'	0.291	0.165	0.38	0.42	0.37
X_d''	0.231	0.112	0.238	0.278	0.22
X_q''	0.231	0.112	0.242	0.282	0.32
T_d'	0.95	0.55	1.13	0.9	1.2
T_d''	0.026	0.013	0.03	0.019	0.03
T_q''	0.026	0.013	0.044	0.035	0.12

Table 6 Typical Range of Values - Synchronous Generators

Experiment 1: Synchronisation

Theory

The process of connecting a generator in parallel with another generator, or with busbars to which a number of generators are already connected, is known as *synchronising.* The process is necessary because of the possible difference in frequency of the two machines or of the incoming machine and the system. Connection can only be made if the frequencies are nearly the same, and must be made at or near an instant when the two sets of voltages are in phase.

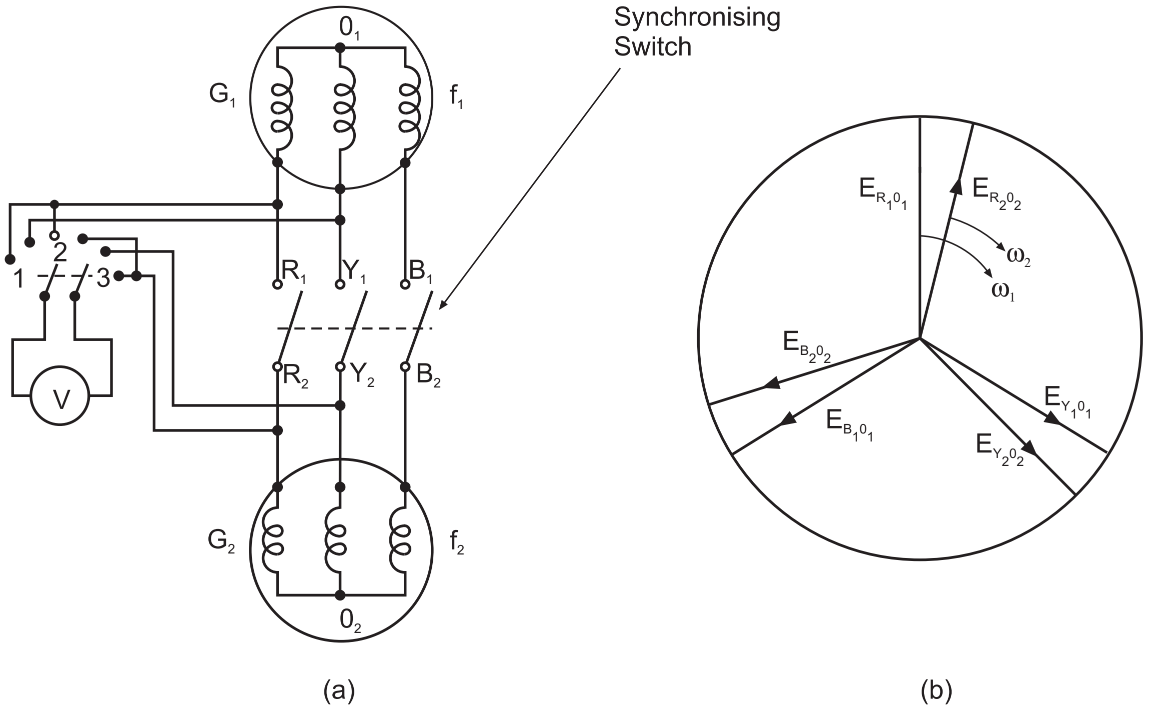


Figure 47 Synchronising of Two Generators

Consider the synchronising of two three-phase generators as illustrated in Figure 47. This can be done with the aid of a voltmeter and a three-way switch. The phase sequence of the generators must be the same otherwise short circuits will result. First, with the speed of each machine adjusted approximately to the required values (different only if the machines have different numbers of poles) the field current of each is adjusted until the voltages of the machines are nearly equal. Positions 1 and 3 of the voltmeter selector switch may be used for observation of the voltages of the two machines. By changing now to position 2, the voltage variations between the two red phases can be observed. Since the difference in frequency, $f_1 - f_2$, will be small, the frequency of the voltage variation will be small and, if necessary, can be made still smaller by a slight adjustment of the speed of one machine.

The synchronising switch may be closed as the voltmeter reading is passing through zero. If the two voltages are not exactly 'in-phase', but the difference is small, the generators will normally 'pull into' synchronism. If the two voltages are not in-phase, or the difference in their frequencies is too great, the two machines will pull out of synchronism.

Synchronising Instruments:

To synchronize generators, the following instruments are normally used:

- Voltmeters
- Lamps, one for each phase
- A synchroscope.

The voltmeter method is described on the previous page. The voltmeter method is not often used.

The use of three lamps, one for each phase, allows both phase sequence determination and synchronizing to be carried out.

A synchroscope is an analogue instrument with inputs f_1 and f_2 that enables $(f_1 - f_2)$ to be observed in a convenient way. The faster the instrument pointer rotates the greater the difference between f_1 and f_2. If f_2 is greater then f_1 the pointer rotates clockwise. If f_2 is less than f_1 the pointer moves anti-clockwise. The synchroscope is in fact an analogue of the vector diagram shown in Figure 47(b).

The process of synchronizing must be preceded by confirmation, or a test to confirm, that the generators or systems have the same phase sequence of R-Y-B.

Synchronising Methods:

a) Synchroscope

A synchroscope has a rotating hand and a dial indicating “slow” and “fast” that refers to the frequency of the incoming generator relative to that of the existing supply. The slow (anticlockwise) indication means that the incoming frequency is too low; a fast (clockwise) indication means the incoming frequency is too high. The speed of the incoming supply should be adjusted until the rotating hand is rotating very slowly in the 'fast' direction. When it points to the vertical index mark the synchronising switch can be closed.

b) Dark lamp method

As the frequency of the incoming generator approaches that of the existing supply, the flashing of the lamps becomes slower. The middle of the dark period is the point of the “in phase” condition when the synchronising switch can be closed, with safety.

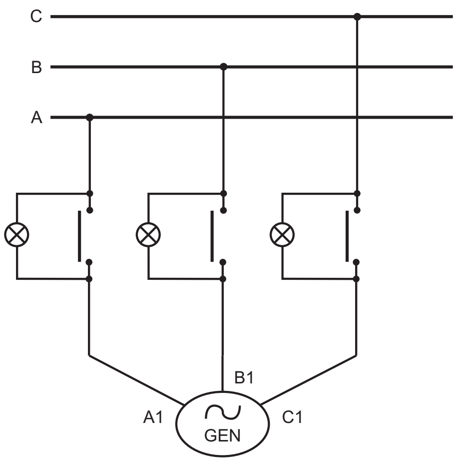


Figure 48 Dark Lamp Method

c) Bright lamp method;

The dark method of synchronising has a disadvantage - it is very difficult for the human eye to determine the exact period of darkness. In addition, the lamp filament may not be hot enough to radiate in the visible spectrum but may still have a voltage across it. Bright lamp synchronising will pulse bright and dim just as in the dark lamp method, but the synchronising switch is closed at the brightest point of the illumination cycle. With single phase circuits this method produces the maximum voltage at exactly the correct phase angle.,

The bright lamp method has a disadvantage - in a three phase circuit there could be a 60° error when the lamps are emitting full light output. This is a major factor in not using bright lamp synchronising for three phase circuits.

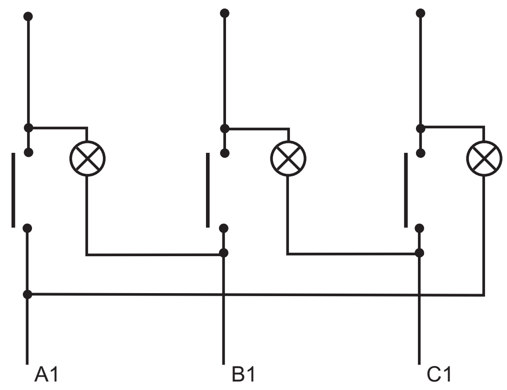


Figure 49 Bright Lamp Method

d) Rotating lamps or cross-connected method

The circuit shown in Figure 50 is known as two-bright-one-dark synchronisation, rotating lamps synchronisation, or the cross-connected Siemens-Halske method. It can be seen that two sets of lamps are cross-connected between phases while the third lamp is connected across one phase only. With this circuit the lamps will vary in brightness in sequence and the speed of the variation will indicate if the incoming generator is running too fast or too slow. The synchronising switch can be closed when the lamp connected across phase C is extinguished and the other two lamps are of equal brightness. This is the most commonly used lamp method.

If the phase sequence is incorrect, all the lamps will be dark simultaneously. Note that the lamps must be able to withstand twice the normal phase voltage.

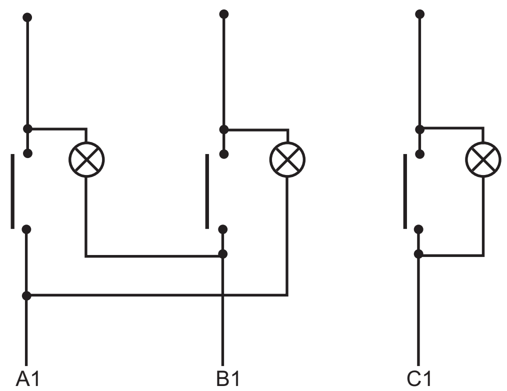


Figure 50 Rotating Lamps - Siemens Halske Method

Synchroscope Procedure

The control panel and synchroscope for this procedure is shown in Figure 30. Connection is made initially between the GRID supply and the GEN 1 Bus by connecting the GRID TRANSFORMER Bus to the GEN 1 bus. Either the left or right-hand routes between the busbars is used (see Figure 4).

This procedure is for connecting Generator 1 to the main, or GRID supply at the GEN 1 Busbar. The synchronizing switch is therefore CB8 that is duplicated in the central control panel.

1) Before switching the supply on, check that the Generator Inertia switch is in position 1, and the excitation and power pots are wound down to minimum position.

2) Above the Generator 1 Control Panel there is a synchroscope that has two inputs: 'Reference Bus' and 'Incoming Bus'. The synchroscope also has an on-off switch that should be normally in the 'off' position except when synchronising.

3) To synchronise Generator 1 to the main or GRID supply the Grid red and yellow terminals (next to the GRID instruments above the GEN 1 controls) should be connected to the REF bus terminals of the synchroscope. Similarly the red and yellow terminals of GEN 1 should be connected across to the INCOMING bus terminals of the synchroscope.

4) Link sockets S1 to S3.

5) Switch on the Mains Supply MCB on the left of the Simulator panel.

6) Close circuit breakers CB2, CB3, and CB5.

7) Press the green START button for the motor.

8) Quickly bring up the speed to 1500 rev.min^{-1} for 50 Hz, or 1800 rev.min^{-1} for 60 Hz (if you are too slow, the under/over frequency system will trip).

9) Close the circuit breaker CBFb in the Generator 1 Control panel. Increase the excitation to give a voltage equal to that of the Grid supply.

10) Switch on the synchroscope. Watching the synchroscope, gently alter the speed so that the red LEDs of the synchroscope are indicating slow clockwise rotation. Just before top dead centre of the synchroscope (at 11 o'clock), positional indication changes to the green LEDs. Close the duplicate circuit breaker control switch CB8b, in the Generator 1 Control panel when the green LED illumination approaches top dead centre. Circuit breaker CB8 closes to connect the Generator 1 to the GEN 1 BUS.

11) Generator 1 is now synchronised to the Grid supply. The speed/power pot now controls the power output of the generator. Generator excitation controls reactive power.

When switching off, reduce the power output and the reactive power to as near zero as possible before opening the circuit breaker CB8.

Procedure with Rotating Lamps

Connection should be made initially between the GRID supply and the GEN 1 Bus by connecting the GRID TRANSFORMER Bus to the GEN 1 bus by using either the left or right-hand routes between the busbars. This procedure is for connecting Generator 1 to the main, or GRID supply at the GEN 1 Busbar. The synchronising switch is therefore CB8 that is duplicated in the central control panel.

1) Before switching the supply on, check that the Generator Inertia switch is in position 1, the excitation and speed/power pots are wound down to minimum.

2) Above the synchroscope there are three lamps (R-Y-B) in triangular formation. Each lamp has two connecting sockets.

3) To synchronise Generator 1 to the main or Grid supply, connect the lamps between the GRID TX BUS and GEN 1 BUS R-Y-B sockets as shown in Figure 50. This circuit is for the rotating lamp method of synchronizing.

4) As an additional visual aid, connect the synchroscope as in the last experiment.

5) Switch on the Mains Supply MCB on the left of the panel.

6) Close CBs2, 3 and 5. Switch on the synchroscope.

7) Wind down the speed/power pot before pressing the green START button for the motor.

8) Bring up the speed to 1500 rev.min^{-1} for 50 Hz, or 1800 rev.min^{-1} for 60 Hz.

9) Close the circuit breaker CBF in the Generator field circuit. Increase the excitation to give an output voltage equal to that of the Grid supply.

10) Watching the lamps, gently alter the speed so that the lamps change in sequence more slowly. Note which two lamps glow as the synchroscope is at top dead centre. When these two lamps are of equal brightness close the duplicate circuit breaker CB8, (which is just below the excitation pot). Circuit breaker CB8 connects the Generator 1 to the GEN 1 BUS.

11) Generator 1 is now synchronised to the Grid supply. The speed/power pot now controls power output of the generator. Generator excitation controls reactive power.

Experiment 2: Variation of Armature Current with Excitation (Vee Curves)

Theory

As stated in the General Theory a generator unit connected to a large power system has two controls: a prime mover control (a governor) and a generator excitation control (a voltage regulator). The governor on the prime mover is the only control of power produced by the generator unit; excitation control cannot affect the power output. However, excitation control does control directly the reactive power delivered by the generator.

This experiment is intended to demonstrate this aspect of generator control, by varying the excitation of a generator and observing the magnitude and power factor of the armature current. The phasor diagrams in Figures 51, 52 and 53 illustrate the result of variation of excitation for constant power output.

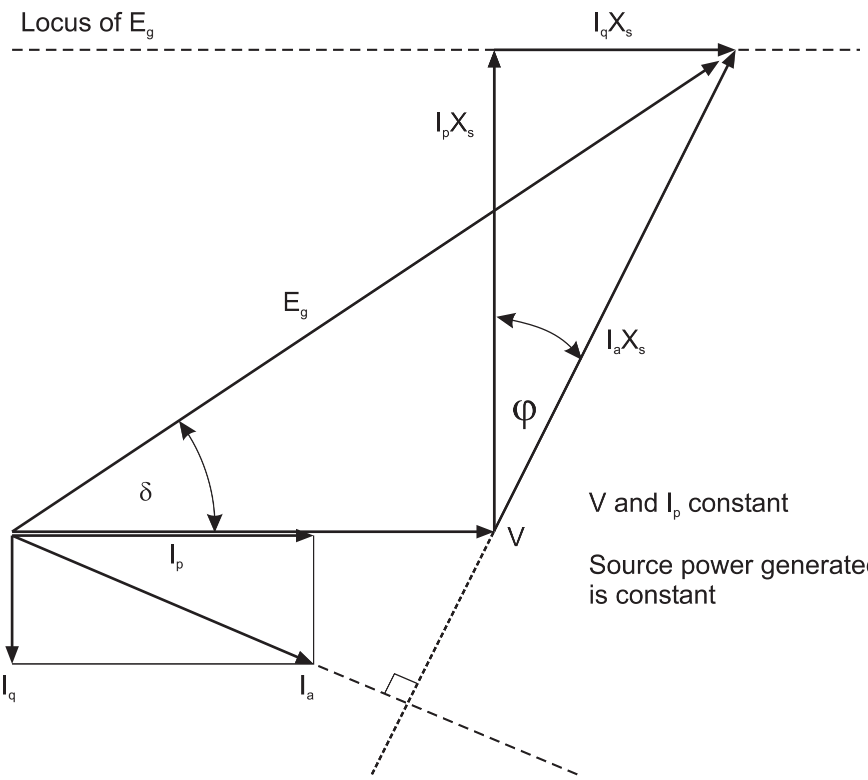


Figure 51 Phasor Diagram for the Variation of E_g with I_q

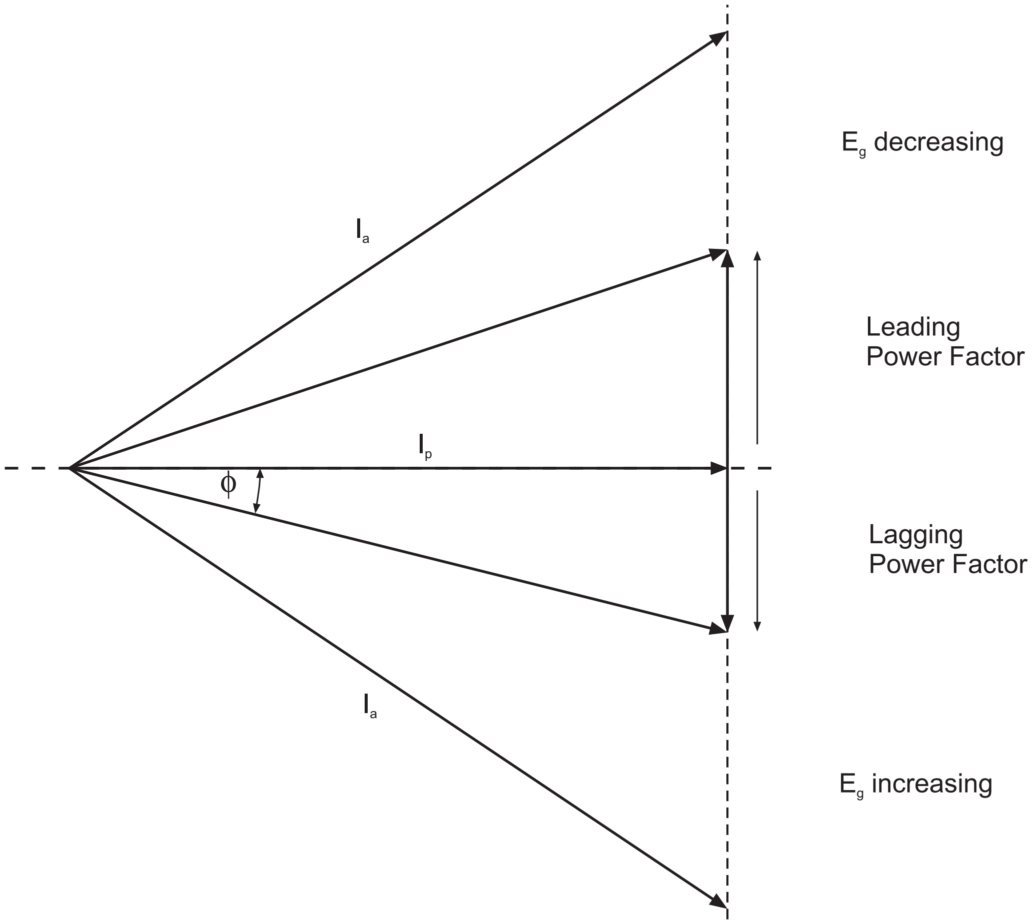


Figure 52 Phasor Diagram: Variation of I_a with E_g

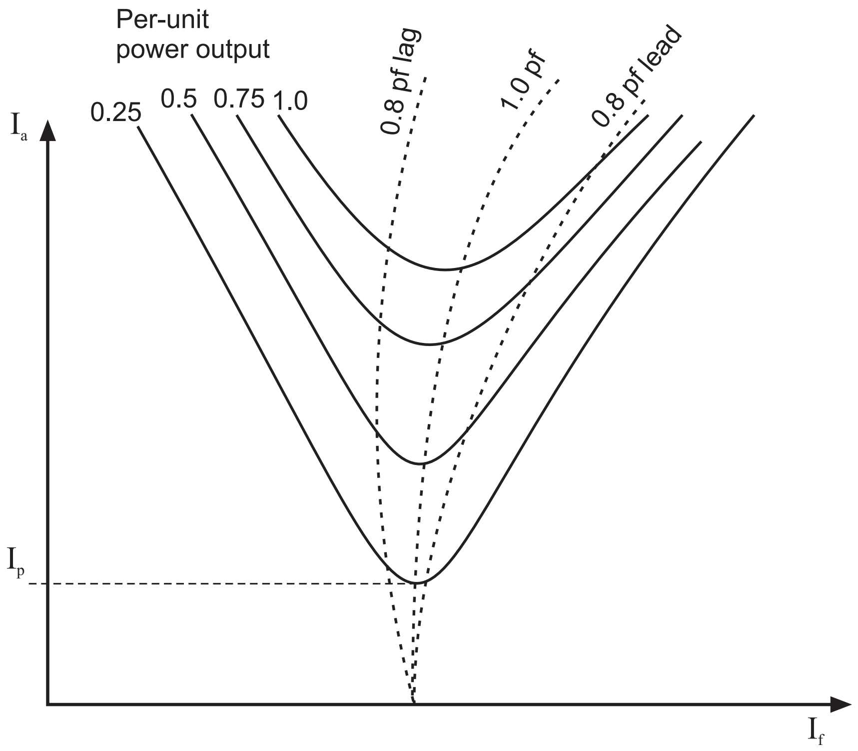


Figure 53 Synchronous Generator Vee Curves

Procedure

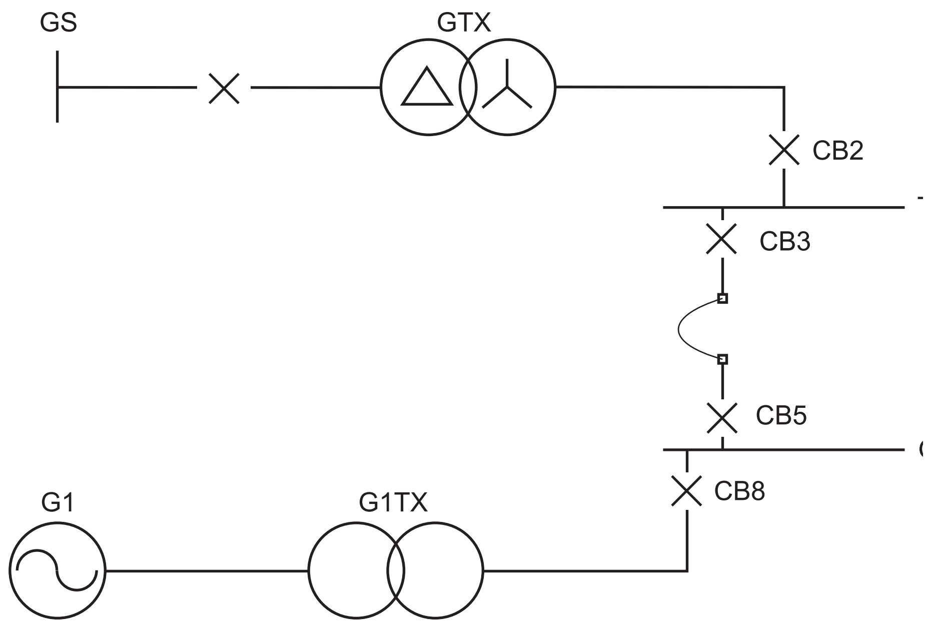


Figure 54 Generator Connection Diagram for Experiment 2

1) Carry out the experiment on Generator 1, connected to the Grid Supply as shown in Figure 54.

2) Generator 1 should be synchronised to the mains as described in Experimental Study 1.

3) Measurement should be taken at meter MC. Meter MD includes the generator transformer.

4) The power output of the generator unit is set at 500 W by adjustment of the power control. Values of armature current and power factor should be recorded for various values of excitation current. Repeat for other values of power output: 1 kW, 1.5 kW and 2 kW.

5) Plot a graph of the armature current, (I_a) against the field or excitation current, (I_f) for the three values of power generated, as shown in Figure 53.

NOTE: For correct results, do not use generator excitation levels below 80 mA or above 600 mA.

Experiment 3: The Generator Performance Chart

The Performance Chart of a synchronous generator provides information on the power (P) and reactive power (Q) delivered to a constant voltage, constant frequency busbar. Figure 41 (earlier) shows a typical chart for a 588 MVA generator. The chart produced is scaled in per unit on the machine rating. Thus, 1 per unit VA is equal to 588 MVA. This base VA applies equally to the P and Q axes.

The length of line OB is equal to V^2/X_{sd}. As V = 1pu, line OB is $1/X_{sd}$ pu. Line OC is equal to $V.Ef/X_{sd}$. Thus the ratio of lines OC/OB is Ef/V, and the per unit excitation of the generator is equal to (length OC)/(length OB).

The chart enables variation of both power and reactive power to be observed. Experiment 2 was concerned with variation of excitation only at constant power and observing variation of armature current.

Experimentation in this study is intended to illustrate:

a) Variation of reactive power Q and the load angle δ, due to variation of generator excitation at constant prime mover power;

b) Variation of power P, reactive power Q and the load angle δ, due to variation of prime mover power at constant generator excitation.

It is first necessary to construct a Performance chart for the Salient Pole Generator in the Simulator.

Construction of the Performance Chart.

As Generator 1 is a Salient-pole machine, the performance chart should be constructed as shown in Figure 45. Two quantities have to be calculated first: the base value V^2/X_{sd} , and the diameter of the saliency circle,

$$V^2\left(\frac{1}{X_{sq}} - \frac{1}{Xsd}\right)$$

The pu values of X_{sd} and X_{sq}, must first be converted to the Simulator base values of 2 kVA and 220 V line from those for the Generator, given in Section 2.

Hence, for 50 Hz:

$$X_{sd} = 1.88 \times \left(\frac{200}{220}\right)^2 \times \frac{2}{6.5} = 0.478\text{pu}$$

$$X_{sq} = 0.66 \times \left(\frac{200}{220}\right)^2 \times \frac{2}{6.5} = 0.167\text{pu}$$

And for 60 Hz:

$$X_{sd} = 1.88 \times \left(\frac{240}{220}\right)^2 \times \frac{2}{7.8} = 0.69\text{pu}$$

$$X_{sq} = 0.66 \times \left(\frac{240}{220}\right)^2 \times \frac{2}{7.8} = 0.242\text{pu}$$

Use these values to construct a chart. Use a base value of 2 kVA (= 1pu), and take the y axis to 4 kW.

Values of load angle obtained from the performance chart are :

At 60 Hz $\delta \approx 19^{o}$ at 2 kW and -2 kVAr

At 50 Hz $\delta \approx 13^{o}$ at 2 kW and -2 kVAr.

Procedure

Note that during this experiment, as the reactive power approaches 2 kVAR, generator output protection will activate.

1) Construct a chart for Generator G1 to a 2 kVA base as described.

2) Synchronise the generator to the Grid Supply as described in Experiment 1.

3) Using meter MC, set the power output at 2.0 kW increasing the excitation to keep the power factor at unity. Note the field current and the load angle (δ) of the generator.

4) Keeping the power constant, increase the excitation from the value obtained in (3).

NOTE: For correct results, do not use generator excitation levels below 80 mA or above 600 mA.

Note the load angle δ and reactive power at various excitations and draw on the operating chart a locus of the points on the chart defined by the values of P, Q and δ. Return to the unity power factor setting, and then decrease the excitation taking measurements as before.

5) Keeping the excitation constant at the value set in (3), vary the power, P, and note the variation of the load angle δ, and reactive power Q, at various values of P. Draw on the chart a locus of the points defined by P, Q and δ.

6) The results obtained from (3), (4) and (5) are illustrated in Figure 40.

7) Why might the measured load angles differ from the predicted load angles?

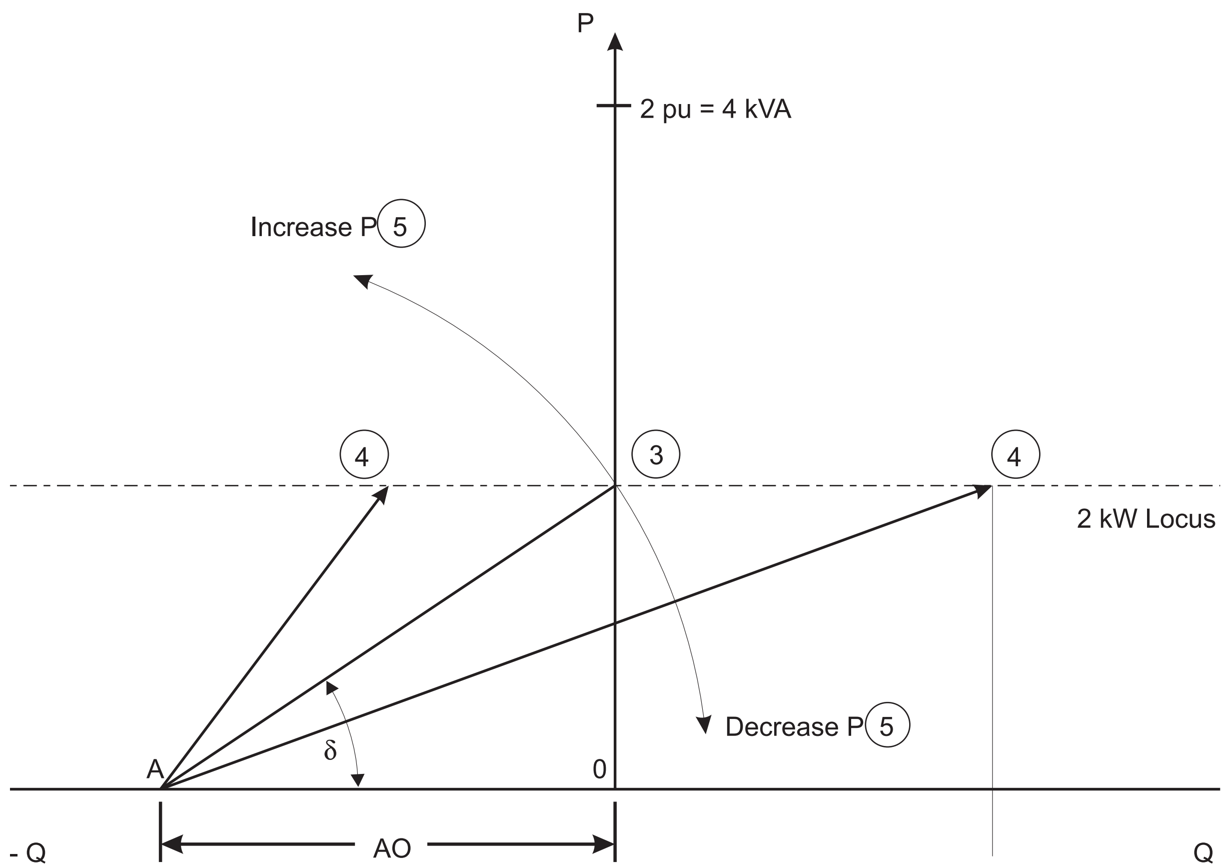


Figure 55 Results Obtained from Experiment 3 (Ringed numbers on the diagram refer to procedure numbers from Experiment 3)

$$AO = \frac{V^2}{X_{sd}} + V^2\left(\frac{1}{X_{sq}} - \frac{1}{X_{sd}}\right) \text{ (For a salient pole generator)}$$

$$AO = \frac{V^2}{X_{sd}} \text{ (For a round rotor generator)}$$

5.3 General Theory of Transmission of Power and Reactive Power

Equivalent Circuits

Transmission lines and cables possess inductive reactance and resistance per unit length - these are series parameters. They also possess capacitive reactance and conductance; these components are connected between the line and neutral and are called shunt parameters.

An equivalent circuit representing the series and shunt parameters per unit length of transmission lines is given in Figure 56. Equations for the voltage, *V*, and current *I*, on the line can be obtained, based on this equivalent circuit. These equations may be reduced to give only the voltages and currents at the ends of the lines: V_r, I_r, V_S and I_S. The impedances between the ends of the lines can also be 'lumped' together to form the equivalent circuits shown in Figure 57.

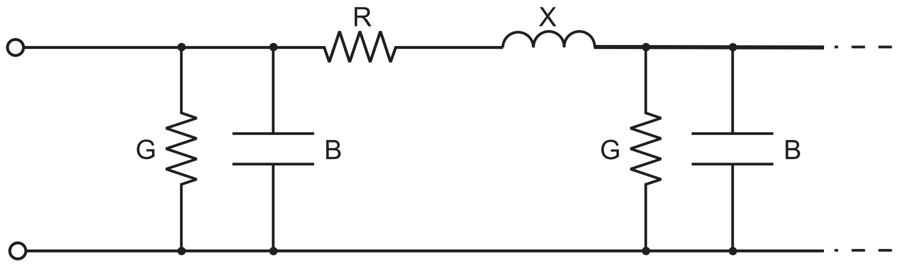


Figure 56 Equivalent Circuit: Series and Shunt Parameters per Unit Length of Transmission Line

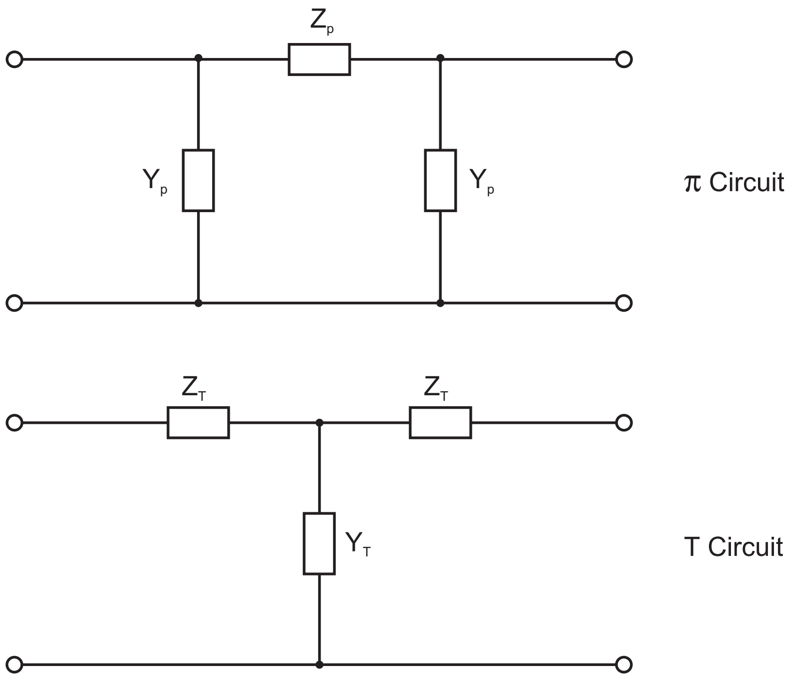


Figure 57 Equivalent Circuit: Impedances between Ends of Lines

Power and Reactive Power Flow in Power Systems

By convention the complex power *S* is defined as:

$$S = VI^* \text{ for a load}$$

and

$$S = EI^* \text{ for a generator}$$

So that, in either case, by convention,

$$S = P + jQ \text{ if the current lags the voltage}$$

and

$$S = P - jQ \text{ if the current leads the voltage}$$

where *P* is the (real) power and *Q* the reactive power.

These equations can be used to develop general equations for power and reactive power flow in power systems if the impedances of the system are known. Note that a load ‘absorbs’ reactive power if it is inductive and ‘generates’ reactive power if it is capacitive.

Power Transmission and Voltage Regulation for Lines where Capacitance is Neglected

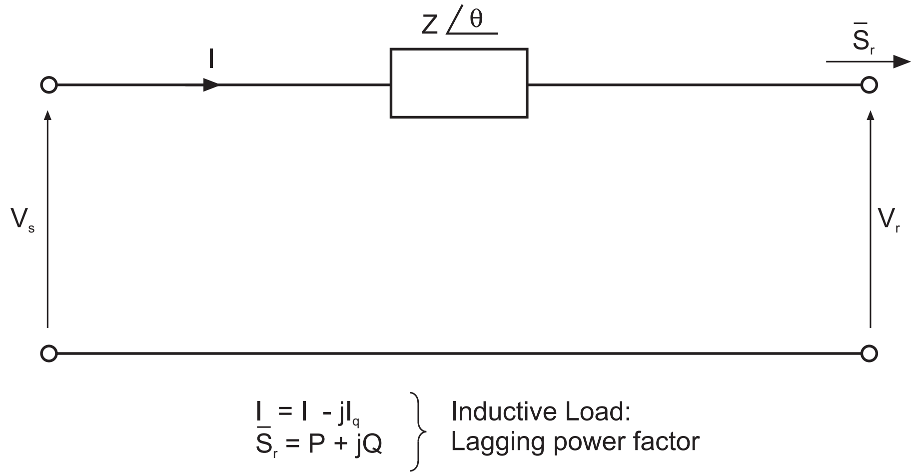


Figure 58 Equivalent Circuit: Series Impedance Only

Consider the line represented by the equivalent circuit in Figure 58, only the series impedance is included. For this line, it may be shown that

$$P = \frac{V_s \cdot V_r}{Z}\cos(\theta - \delta) - \frac{V_r^2}{Z}\cos\theta$$

δ is the angle between V_s and V_r.

Now let $\varepsilon = 90 - \theta$

$$P = \frac{V_s \cdot V_r}{Z}\sin(\delta + \varepsilon) - \frac{V_r^2}{Z}\sin\varepsilon$$

This is a more convenient form in which to write the equation because when $Z \rightarrow X$, $R \rightarrow 0$, i.e. the X/R ratio is large,

$$P = \frac{V_s \cdot V_r}{Z} \sin\delta$$

Similarly it may be shown that:

$$Q = \frac{1}{X}(V_r \cdot V_s \cos\delta - V_r^2)$$

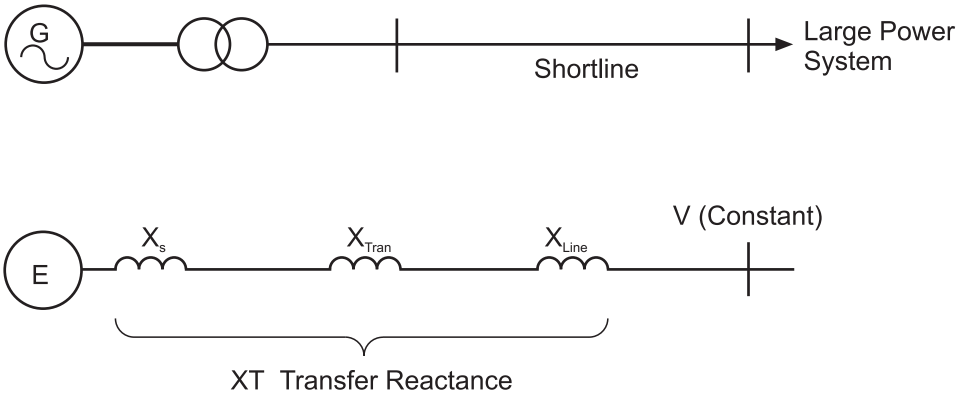


Figure 59 Generator Feeding a Large Power System

The equation for P is similar to that for the power delivered to a system by a generator. If a generator feeds a large power system through a transformer and a short line, as shown in Figure 59 then:

$$P = \frac{EV}{X_T} \sin\delta$$

where X_T is the total or transfer reactance of the system and δ is the overall load angle between the rotor axis and the system–bus reference axis.

Thus, for a generator feeding a large system or for a generator feeding a large system through a transmission system, or for a simple transmission system, the form of the power flow equation and of the phasor diagram is the same. It must be noted that in all cases there is a maximum value for the power that can be delivered by a power system and that, if resistance and capacitance is neglected this occurs when $\delta = 90°$.

Voltage Regulation

A voltage phasor diagram can be drawn for the equivalent circuit shown in Figure 59, by considering the current, I, to be equal to the sum of two currents, I_p and I_q, that are at right angles to each other. I_p is in phase with V_r and I_q lags V_r by 90°. The resulting phasor diagram for a lagging p.f. load is shown in Figure 60.

From this diagram:

$$V_S^2 = V_r + \Delta V_p^2 + \Delta V_q^2$$

If δ is small

$$(V_s - V_r) = \Delta V_p = RI_p + XI_q$$

$$= \frac{PR + QX}{V_r}$$

If the load is capacitive, or a leading p.f. load, the plus sign becomes a minus sign. Similarly, it is seen that:

$$\Delta V_q = XI_p - RI_q$$

$$= \frac{PX - QR}{V_r}$$

If the load is a capacitive, or leading p.f. load, the minus sign becomes a plus sign. Thus if $X/R > 1$,

a) The flow of reactive power, Q, determines the volt drop and,

b) The flow of power, P determines the transmission angle.

and these statements are substantially independent of each other.

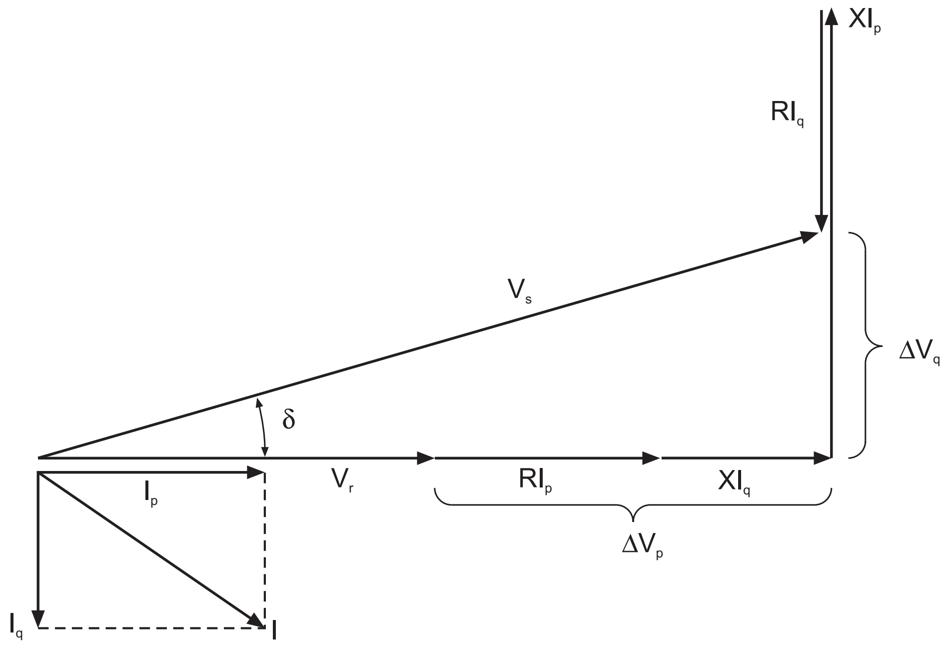


Figure 60 Resulting Phasor Diagram for a Lagging p.f. Load

Since X/R increases with voltage, statements (a) and (b) are particularly true at 400 kV and 275 kV; the error in neglecting R altogether is < 3% at 275 kV and < 10% at 33 kV.

Power Flow and Voltage Regulation for Lines where Capacitance is Included

A transmission line, or cable absorbs an increasing amount of reactive power as the load current increases; it is given by:

$$(I^2X)$$

The line or cable will also generate reactive power equal to (V^2/X_c).

If the resistance of the line may be neglected (X/R large) and the voltage is considered constant, there will be a load on the line for which:

$$I^2X = \frac{V^2}{X_C}$$

i.e. net VArs absorbed or generated by the line is zero. From this expression:

$$\frac{V}{I} = \sqrt{XX_C} = \sqrt{\frac{L}{C}}$$

From the general equations for a transmission line, it may be shown that when the line is terminated by a load equal to $\sqrt{L/C}$, the characteristic or surge impedance, the voltage and current are everywhere on the line in phase and there is no voltage drop:

i.e. $V_r = V_s$

the power delivered by the line under these conditions is

$$P_N = \frac{V^2}{\sqrt{L/C}}$$

the Natural Load or surge–impedance load of the line.

	$\frac{X}{R}$	Reactive Power (MVAr/km)	
	Ratio	No–Load	Full–Load
400 kV line	14	+0.65	–5.0
400 kV cable	18.4	+33	+30.6
132 kV line	3.4	+0.07	–0.62
132 kV cable	4.5	+2.63	+2.3
33 kV line	1.9	+0.005	–0.24
33 kV cable	0.78	+0.21	+0.16

(+ sign means reactive power generated; - sign means reactive power absorbed)

Table 7 Reactive Power Generated and Absorbed by Lines and Cables

For loads greater than P_N the line absorbs reactive power; for loads less then P_N the line generates reactive power. Table 7 gives values of (MVAr/km) absorbed and generated by lines and cables for no–load and full–load conditions.

Lines generally absorb reactive power except when very lightly loaded. Cables however generate reactive power even when fully loaded. The P_N for cables is of the order of ten times that for lines and is always greater than the corresponding thermal rating.

It must be noted therefore that in a power system with an extensive transmission and distribution system, considerable reactive power can be absorbed or generated by the transmission system itself with a consequent drop or rise of system voltage.

Voltage Regulation at Constant Load Power Factor

At the receiving end of a transmission system there may be connected loads of varying power factor. If the sending end voltage of a transmission line V_s is considered constant it is of interest to determine the variation of V_r for varying load at fixed power factors. These calculations can be carried out from the line equations.

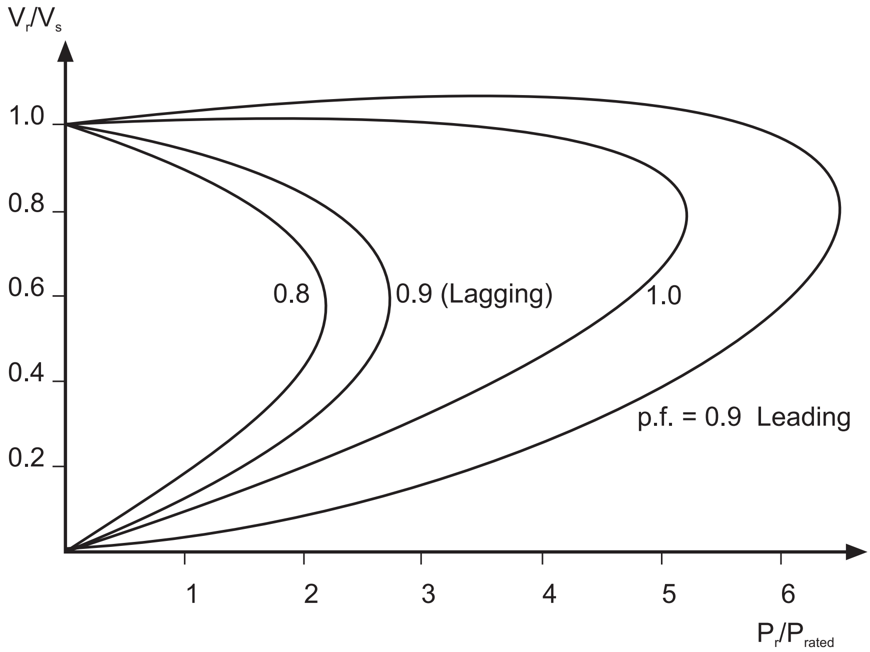


Figure 61 Voltage Regulation at Constant Load Power Factor

Figure 61 shows the result of such calculations. As might be expected from earlier discussion, leading power factor loads cause an increase in voltage whilst lagging power factor loads can cause a severe reduction not only of voltage but also of the maximum power that can be delivered. Clearly, for maximum power transfer and maintenance of voltage near 1.0 pu it is necessary for high power factors to be maintained.

Experiment 4: Voltage Variation and Control

This study is intended to demonstrate that the voltage difference between the sending end of a line and the load or receiving end depends mainly on the flow of reactive power, *Q*, and not the power, *P*, providing the X/R ratio of the system is relatively large. However, the decrease in voltage at the receiving end due to reactive power flow limits the power that can be delivered.

Procedure

1) On the Power System Simulator use Line 2 (0.15pu) and set up the system shown in Figure 62 and as shown in APPENDIX 3.

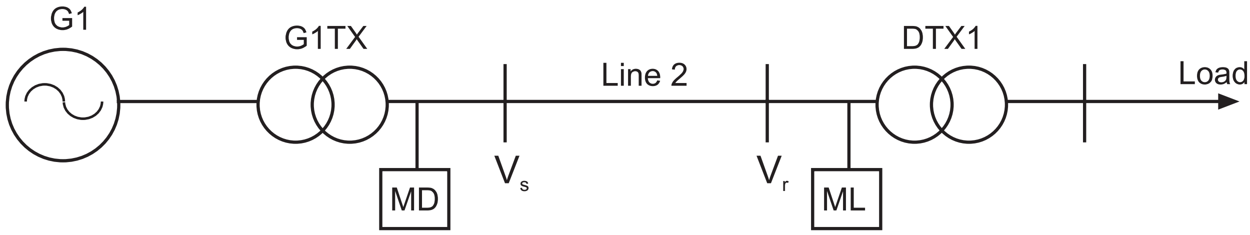


Figure 62 Set Up for Experiments 4 and 5

2) For no-load condition set the excitation of generator G1 to produce 220 V at the Distribution Bus (Meter ML). This voltage is designated V_r. Note the voltage at the Generator Bus (Meter MD). This voltage is designated V_s.

3) Connect a 50% switched resistance load to the utilization bus. Increase the generator excitation to produce a voltage of 220 V line at Vr (Distribution Bus) and note the voltage Vs at the Generator Bus, the line current Ip, kW, kVA and power factor. Do not increase the generator excitation current above 1.3 A.

4) Construct a voltage phasor diagram for this load, as shown in Figure 63 and compare measured and calculated values of Generator Bus voltage (V_s).

5) Now connect a 25% switched inductive load to the utilization bus, in parallel with the resistive load. Adjust the generator excitation to maintain 220 V at the Distribution Bus, V_r. Record, current, power factor kVAr, KVA and kW at the Generator Bus.

6) Repeat this procedure for a 50% switched inductive load and a 75% switched inductive load.

   Note that the line current should not be increased above 7.0 A nor the generator excitation current above 1.3 A. These are the limiting conditions for this and other, similar experiments.

7) Construct phasor diagrams for the loads as shown in Figure 63.

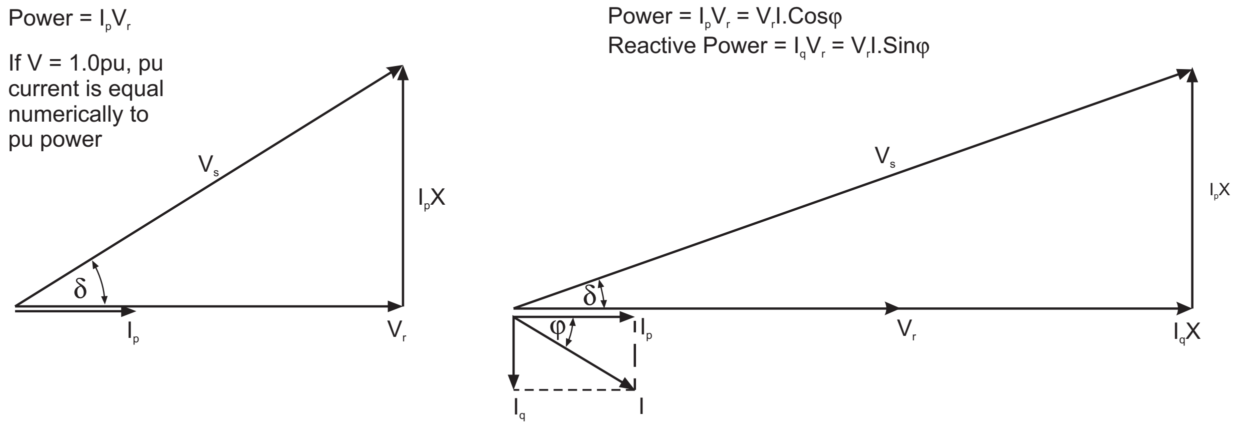


Figure 63 Phasor Diagrams

Experiment 5: Voltage Regulation for Constant Power Factor Load

This experiment is similar to the Experiment 4 but the power factor at each step must be kept constant.

A value of 0.89 is chosen for the power factor so that the switched loads of Table 2 on page 21 can be used.

1) Set up on the Power System Simulator the system shown in Figure 62.

2) For no-load condition set the excitation of Generator G1 to produce 220 V at the Distribution Bus (V_r). Note the voltage at the Generator Bus (V_s).

3) Connect a load of 25% resistance and 25% inductive reactances to the system. Keep the generated voltage Vs constant for this increase in load and note the value of the Distribution Bus voltage Vr. Measure the load current and power factor.

4) Repeat this procedure for equal resistive and inductive loads of 50%, 75% and 100%.

5) Plot the variation of distribution voltage against power (kW) delivered and compare the curve obtained with the curves in Figure 61.

6) Repeat for a resistive load only (power factor $\approx$ 1) 25% to 100%, as a reference for comparison.

5.4 Distribution System: Three–Phase Transformers

Two or three–winding transformers that are used in power systems, are 'voltage' transformers, as their applied primary voltage is nominally constant. Three single–phase transformers can be used, but since the sum of symmetrical, three–phase currents and flux is zero, there is no need for a common 'return' limb in the magnetic circuit and a 3–limb, core type transformer is normally used. The primary and secondary windings for each phase are wound with the HV winding around the low voltage winding, as shown in Figure 64.

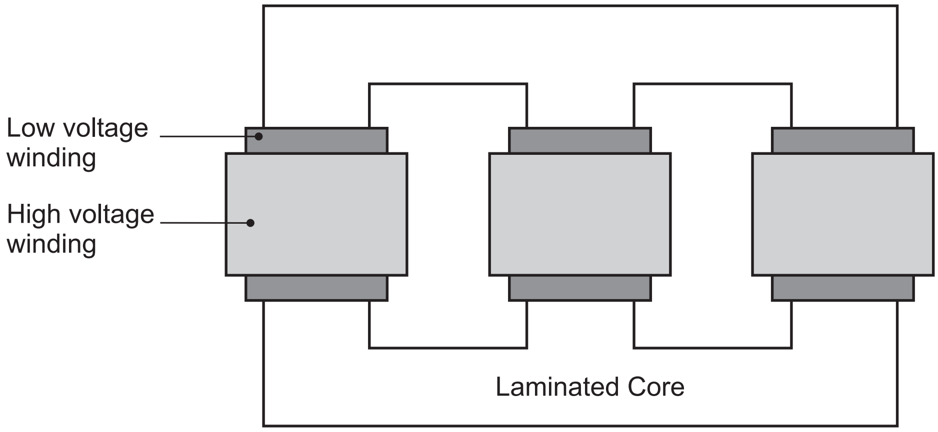


Figure 64 Three-limb, Core Type Transformer

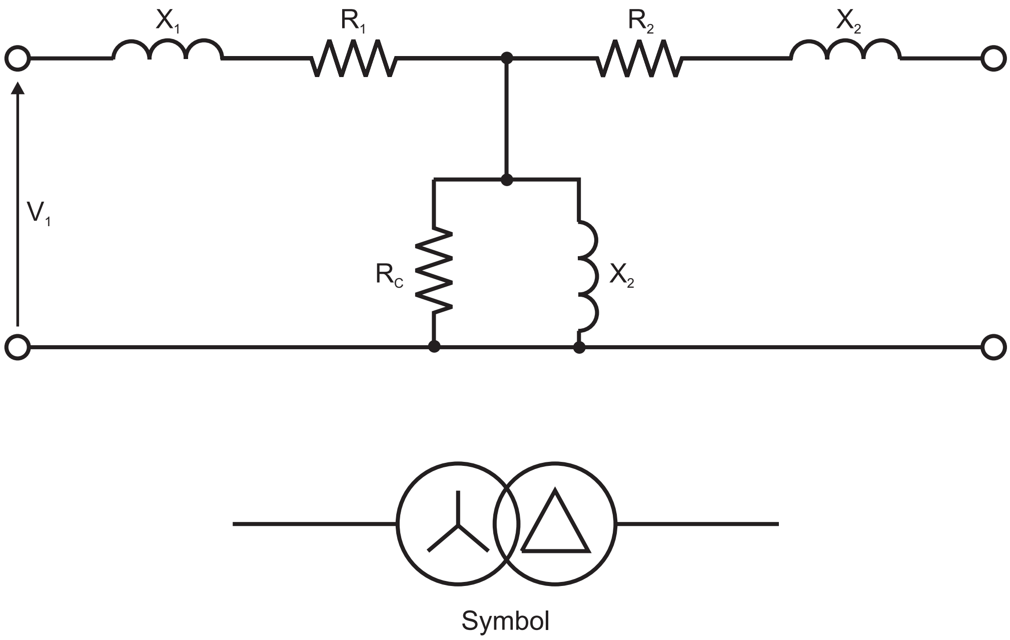


Figure 65 T-Equivalent Circuit for a Two-Winding Transformer

The T–equivalent circuit for a two–winding transformer is shown in Figure 65. The relative values of the total series impedance and the magnetising reactance (X_m) are of the order of 10% and 2000% respectively. They rarely have to be considered together and in most load and fault calculations the transformer may be represented by only the series impedance.

Windings of three–phase transformers may be connected in Star or Delta. Depending on the primary and secondary connections, phase shifts of 0°, +30° and 180° can be produced between the primary and secondary phase–to–neutral voltages. It is therefore necessary to have standardisation of nomenclature and connection procedure as shown in Table 7.

The distribution transformers in the Power System Simulator are phase connected Yd1. This means that the secondary phase voltage lags the primary phase voltage by 30°.

The winding connections to produce this phase shift are shown in Table 8. In this diagram the winding between A2 and YN of the Star is wound on the same limb of the transformer as the winding 'a' of the delta. Hence, these voltages are in phase, as shown, so causing the -30° phase shift between primary and secondary phase voltages.

Tap Changing

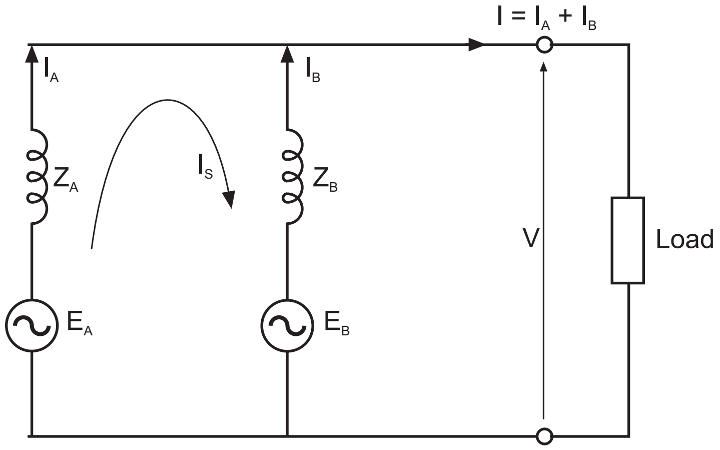


Figure 66 Circulating Produced by Unequal Taps of Two Parallel Transformers

If the taps of the two parallel connected transformers are unequal, $\bar{E}_A \neq \bar{E}_B$, a circulating current will be produced as shown in Figure 66. The circulating current I_S is given by:

$$I_S = \frac{\bar{E}_A - \bar{E}_B}{\bar{Z}_A + \bar{Z}_B}$$

I_S is mainly reactive. The relationship between the voltage *V* and the currents flowing in the circuit are given by the 'parallel generator theorem' or Millman's theorem (see 'References').

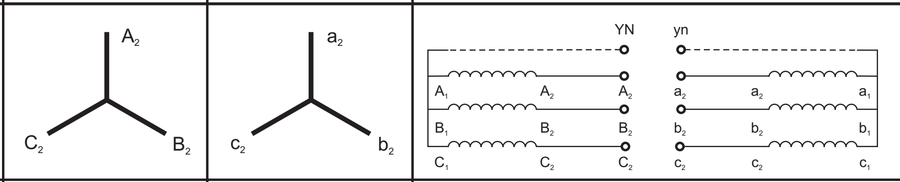
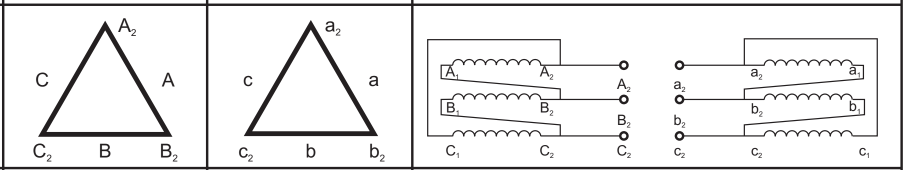
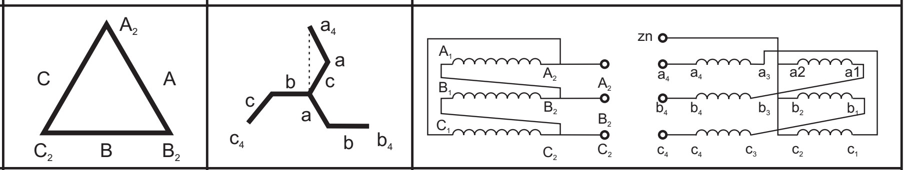
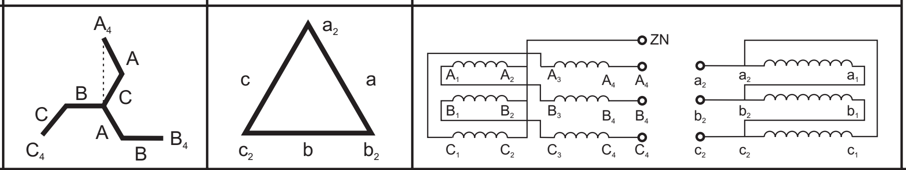
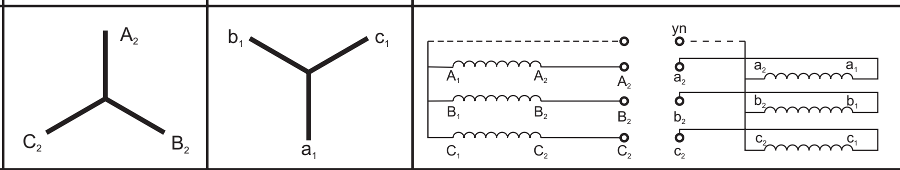
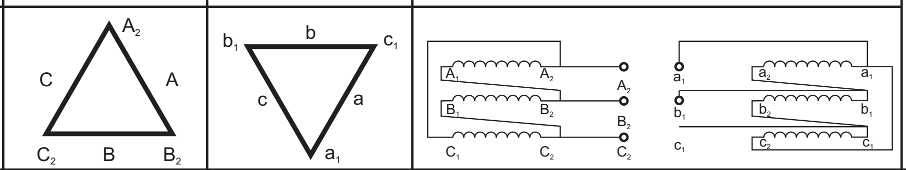
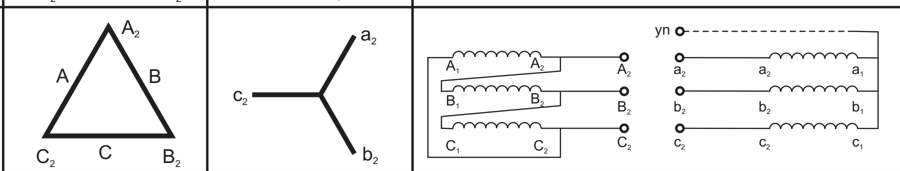
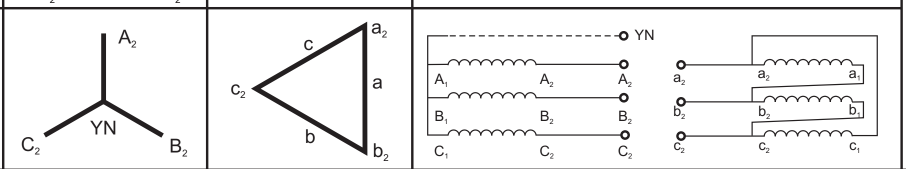
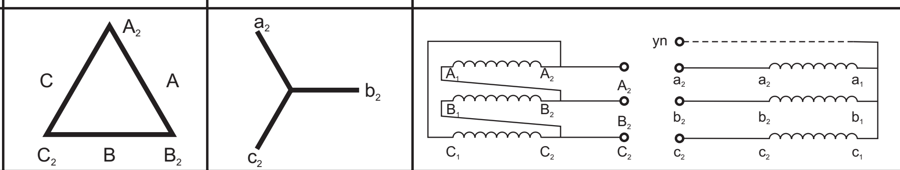
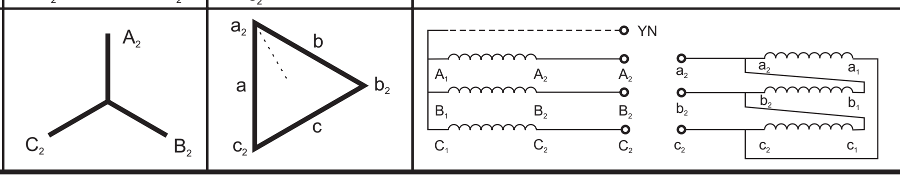
Vector Symbols	Line terminal markings and vector diagram of induced voltage: HV Windings	Line terminal markings and vector diagram of induced voltage: LV Windings	Winding Connections	Phase Displacement	Main Group Number
Y y 0				0º	1
D d 0					
D z 0					
Z d 0					
Y y 6				180º	2
D d 6					
D y l				-30º	3
Y d l					
D y ll				+30º	4
Y d ll					

Table 8 Time–Phasor Diagrams for Three–phase Transformers

Experiment 6: Three–Phase Transformer Operation

The following studies may be carried out on the Power System Simulator's distribution transformers. The parallel-connected distribution transformers can be fed from the Grid supply through Line2. The overall circuit connection diagram for experiment 6 is shown in Appendix 3.

Part A is a simple introductory experiment. Parts B and C are investigations of the conditions to be satisfied for efficient operation of transformers in parallel. Part D is relevant to more advanced studies on unbalanced loads or faults supplied by three-phase transformers.

Part A: Primary to Secondary Phase Changes in three phase transformers

Use an oscilloscope and the phase angle meter to confirm that the phase angle between the primary and secondary line voltages of a distribution transformer is -30°. Similarly look at the primary and secondary winding voltages of the generator transformer. The phase difference in this case is +30°, since the transformer is phase connected Dy11.

Part B: Unequal taps

Unequal ratios in parallel-connected transformers are equivalent to a small voltage generator circulating current only around the transformer 'loop'. Investigate the effect of unequal ratios by setting unequal taps on the two distribution transformers. The smallest difference in percentage taps should be considered initially and the transformers should not be supplying a load. Currents, power and reactive power should be measured by the M230 meters in each transformer primary and secondary. Compare measured and calculated values of current. Why do the two primary currents have different measured values?

Part C: Unequal impedances

Two transformers will not share a total load in proportion to their ratings if the per unit impedances of the two transformers are not identical, and one transformer will become overloaded before the total output reaches the sum of their individual ratings. Set up the distribution system to supply a total load of say, 50% Resistive and 50% Inductive. Insert a 0.1 pu transmission line in the secondary of one of the transformers and investigate the effect its inclusion has on the division of load between the two transformers. Repeat, if possible, with transmission lines of different values.

Compare measured and calculated values of power, reactive power, currents and voltages for the two transformers. How would you insert an inductance of 0.06 pu?

Part D: Unbalanced loads

This is an exercise in symmetrical component analysis to determine the magnitude and paths of primary currents. It requires knowledge of the fact that for positive sequence currents the transformer is Yd1 but for negative sequence currents it is Yd11. Investigate the current flow in the primary and secondary lines of a distribution transformer when the delta secondary supplies a single load connected between any two lines.

A similar experiment can be carried out on the grid transformer for a single-phase load on the star-connected secondary side.

See Figure 127 on page 183 for the current distribution in the transformer windings.

5.5 Load Flow Studies

Since the Power System Simulator can have two controllable generators G1 and G2, and a grid supply, and has five lines and several load points, it can be used as a tutorial support for more studies of load flow analysis. These studies are normally carried out in the more advanced stages of power engineering courses.

Load flow analysis is the solution of non–linear equations relating the complex power at each 'node' or busbar to system impedances and voltages. At each node there are four variables; P, Q, V and δ. To solve the equations two of these variables must be specified at each node. At a generator node the P and $|V|$ are specified and Q and δ are unknown; at a load node P and Q are specified V and δ being unknown. At the 'slack' node (or reference node) V and δ are specified. The slack or swing bus takes up the 'slack' in the system due to unknown (line) loses.

Since the equations are non–linear, numerical methods of solution are required, the two most commonly used being the Gauss–Seidel (GS) method and the Newton–Raphson (NR) method. To solve the equations the following data must be available:

a) The impedances between nodes and admittances to ground

b) The active power generated and/or consumed at all buses but one

c) The reactive power consumed at all load buses

d) The voltage magnitude at all voltage control buses

e) The magnitude and angle of the voltage at one node of the network, the reference bus

Experiment 7: Load Flow Study

It is possible to set up on the Simulator a system as shown in Figure 67.

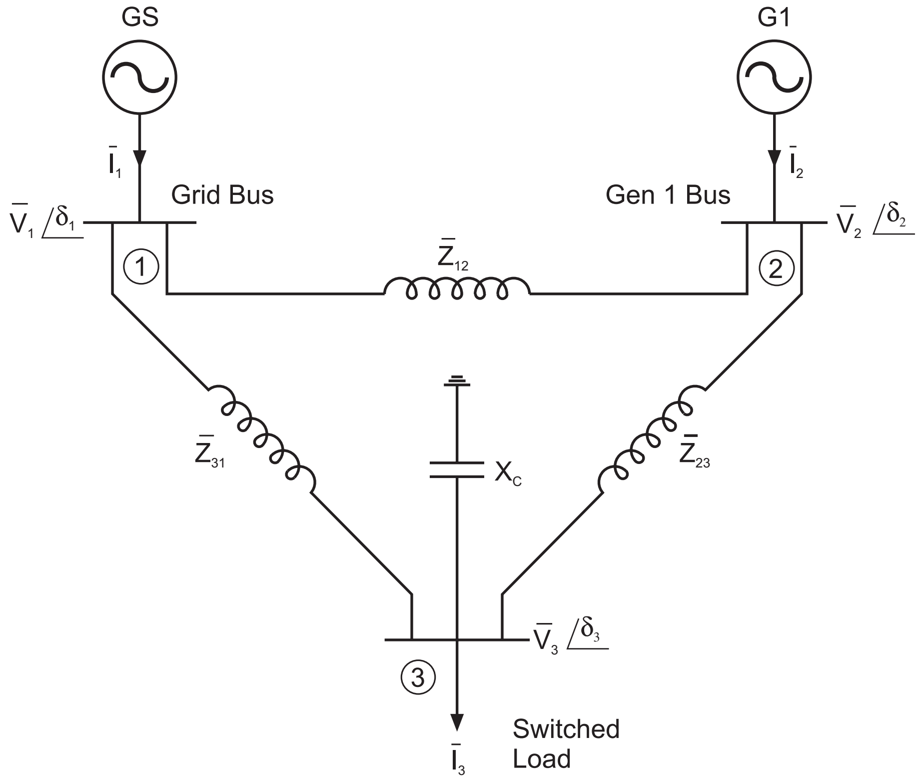


Figure 67 Three Bus System

It is suggested that the experiment is carried out first, so that computation can be based on measured values of V_1, V_2 and V_3. Knowledge of the magnitude and angle of the three bus voltages defines uniquely the load flows from which the injected currents and complex powers at the buses can be calculated. The load flow problem may be formulated by specifying bus 1 as the reference bus, thus define V_1 and δ_1 (usually 0°, as reference), node 2 as the Generator Bus thus defining V_2 and P_2 and node 3 as the load bus, thus defining P_3 and Q_3. Examples of load flow studies are given in Section 8 of this Manual.

The connection diagram for experiment 7 (shown in Appendix 3) shows how the system can be set up so that quantities in all lines can be measured by M230 meters. Generators G1 and G2 can be used or GS and G1. Note that the system should be set up between G2 or GS and G1 Bus before G1 is synchronised onto the G1 Bus using the duplicate CB8, as described in Section 5. The angles $\delta 2$ between V_2 and V_1 and $\delta 3$ between V_3 and V_1 can be measured using the phase angle meter. The capacitor need not be included, but is in the system to raise the voltage V_3.

Set up V_1 and V_2 initially at approximately 1puV (220 V) and switch in a 50% resistive load at Bus 3. Adjust the generator excitation to increase V_2 as the load increases to 1.0 pu (220 V) and measure I_1, I_2 and I_3, P_2 and Q_2, and P_3 and Q_3. This is intended to get a feel for the circuit behaviour and its control. Eventually it is suggested that the switched loads might be used at the Utilization Bus and capacitance added as required, but the generator excitation current must never exceed its maximum ratings of 1.3 A.

SECTION 6.0 Experiments: Fault Currents, Transient Over Voltages and Transient Stability

Transient conditions are produced in a system immediately after a fault has occurred. The balanced flow of energy around the system under steady–state conditions has been disturbed and the disturbance takes time to fade away and the system to return, hopefully, to normal. A fault, or short circuit, on the system causes transient currents and can cause transient instability. There is usually a secondary disturbance following a fault and this is caused by the opening of circuit breaker contacts to isolate the faulted section of the system. This causes transient over-voltages. In most circumstances the circuit breaker will automatically reclose after a set time in the hope that the fault has been cleared. If the fault has not been cleared the breaker will 'make' (i.e. contacts close) onto a fault.

The series reactances and resistances of power system components in steady–state operation have been described in an earlier section. These parameters are not always applicable for transient current calculations, particularly for a.c. generators and motors; these new parameters are described briefly below.

Shunt impedances, consisting of the capacitances and insulation resistance of lines, machines and switchgear may be ignored in calculating short circuit currents since they are greater by some order of magnitude than the series impedances. They are, however relevant to calculations of transient over voltages.

6.1 Symmetrical Faults

This section considers the effects of three–phase, or symmetrical short circuits on power system performance, leading primarily to the calculation of the resulting balanced currents that flow in the system. These fault currents depend on the location of the fault and the distribution and nature of the power system components. In the faulted section the short circuit current is between 10 kA and 40 kA in high voltage systems.

Transient Reactances of A.C. Generators

When a three–phase short circuit is applied to the terminals of an unloaded a.c. generator the current that flows initially is much greater than that calculated from the steady–state equivalent circuit. Figure 68 shows the current in a phase of an a.c. generator; it shows that between the large initial current and the 'steady state' short circuit current, the fault current decays over many cycles.

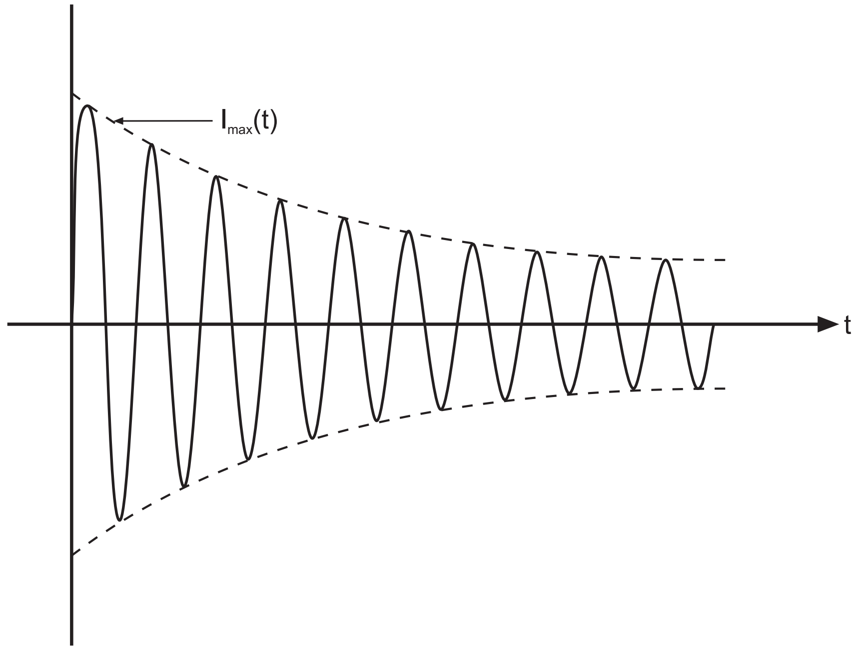


Figure 68 Current in a Phase of an a.c. Generator

Initially, the sudden change of current in the stator windings will create a magnetic field which will try to reduce the flux in the machine. This change in flux, however, induces a current in the rotor field winding which opposes the change. The increased field current 'cancels out' the field–reducing effect of the stator field; therefore the flux in the machine and the induced emf in the stator phases remain the same. The only reactance in the circuit to limit the current is a leakage reactance X_d' which is called the transient reactance of the machine (on the direct or 'd' axis).

The initial transient current is therefore:

$$I_d' = E_g / X_d'$$

This decays exponentially as the additional current in the field dies away. It has a time constant of T_d'. Typical values are shown in Table 6 on page 66.

Additionally, extra currents opposing the sudden increase of stator current occur as eddy–currents in the rotor iron. These currents cause a further increase in the initial current since the effective leakage reactance of the machine is further reduced. This new reactance is X_d'', the sub–transient reactance, so that:

$$I_d'' = E_g / (X_d'')$$

In modern, high–speed circuit breakers (2 cycle breakers), contact separation takes place about 40 ms after short–circuit initiation, depending on the speed of the protection system. This time is slightly longer than the sub–transient time constant for small and medium–sized generators and is about as long as that for very large turbine–generator sets. The transient reactance X_d' is therefore acceptable in calculations of short circuit currents for determining circuit breaker 'contact break' requirements. For the calculation of the initial short circuit current, however, X_d'' should be used.

When a generator is supplying load current at the time the fault occurs, a further modification to the equivalent circuit of the generator is required; this time to the generated emf.

When the generator is delivering load circuit I_L under steady state conditions:

$$E_g = V + I_L X_S$$

When a fault occurs the reactance of the generator suddenly changes from X_S to X_d' so that the generated voltage becomes:

$$E' = V + I_L X_d'$$

E′ is called the voltage behind the transient reactance and is approximately equal to the actual emf induced in each phase of the stator winding. The equivalent circuit for the generator under transient conditions is shown in Figure 69. Similarly if the initial, sub–transient period is considered.

$$E'' = V + I_L X_d''$$

Where E'' is the voltage behind the sub–transient reactance.

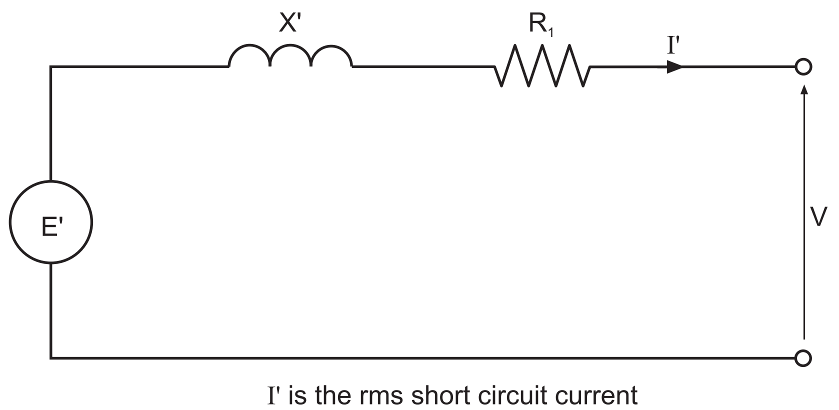


Figure 69 Equivalent Circuit

Balanced Fault Currents

Balanced fault currents (i.e. same a.c. current in each phase), flow when a three–phase short circuit occurs on a system and may be calculated from a network diagram of the system drawn in per unit. A simple system is shown in Figure 70.

If it is assumed that there is no circulating current between the generators, they must be of equal magnitude so Figure 71 can be reduced to Figure 72. Since it is also assumed that *X/R* > 1 throughout, so that the resistances may be neglected, the fault current I_F may be calculated as:

$$I_F = \frac{E'}{\Sigma X} \text{ pu current}$$

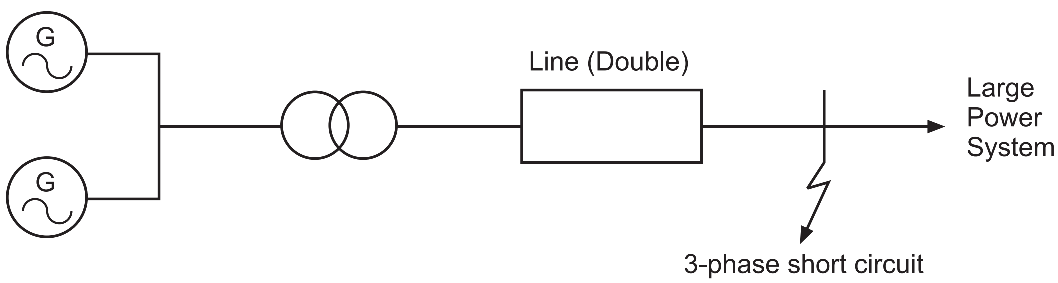


Figure 70 A Simple System

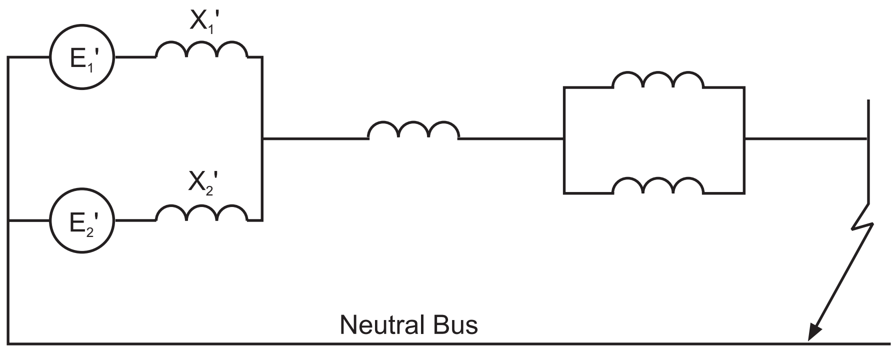


Figure 71 Balanced Fault Currents - Circuit A

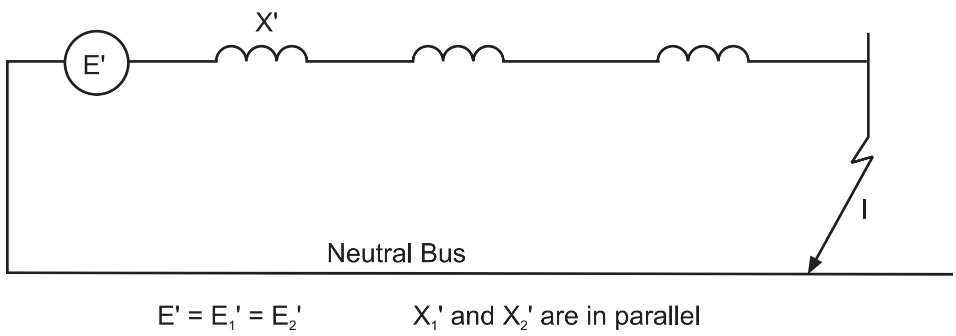


Figure 72 Balanced Fault Currents - Circuit B

If the voltage in the faulted section is 1.0 pu voltage, then the fault level (VA) at the fault point is (1.0 pu voltage $\times I_F$ pu current) i.e. equal numerically to I_F pu.

Sometimes the faulted section of the system is connected through a busbar to a larger power system. If the fault level at the busbar is known, then the power system which produced that fault level may be made equivalent to a 1.0 pu voltage generator and a series reactance *X* pu.

The fault level for the equivalent system is:

$$1.0 \times \frac{1.0}{X} \text{ pu}$$

which is equal to $\frac{1}{X}$ pu

Thus if the fault level or infeed from the power system is known and is equal to (VA) pu on the system base values, then:

$$X \,\text{pu} = 1/(\text{VA}) \text{ pu}$$

D.C. Components of Fault Current

So far it has been assumed that the only currents that flow on the occurrence of a three–phase short circuit are a.c. currents. This is not so, d.c. currents are also produced.

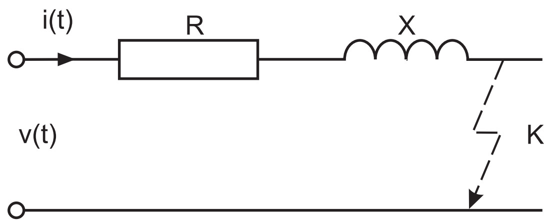


Figure 73 Single Line Circuit Diagram

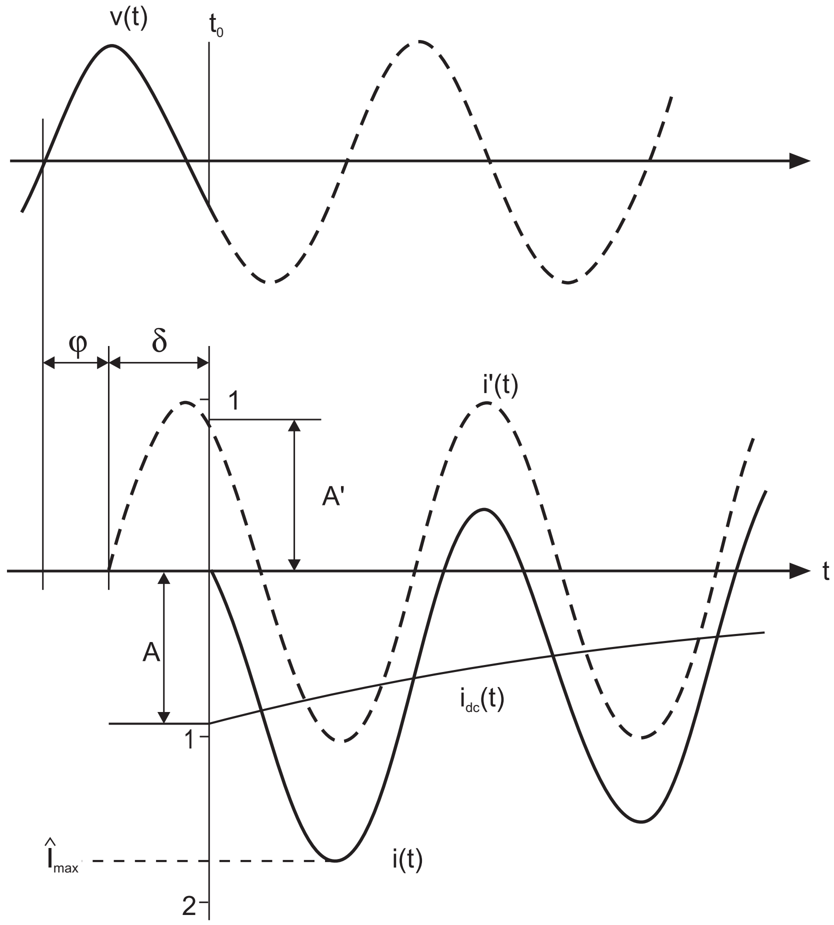


Figure 74 Curves of Voltage and Current

A = A' = D.C. component at t_0	K = Short–circuit
R = Resistance	X = Reactance
i(t) = Current	i'(t) = Curve of balanced components of the current
i_{DC}(t) = Curve of d.c. component	v(t) = Applied voltage
t_0 = Moment of short–circuit	φ = Phase angle
δ = Closing angle related to i(t) = 0	

In Figure 74, waveforms *v* and *i '* represent 'steady state' short circuit conditions, the phase angle φ being dependent on the *X/R* ratio. However, if the short circuit occurred at t_0, the current could not instantaneously have the value *A'* so it must in fact be zero. So, a direct current *A* equal but opposite to *A'* must be superimposed at t_0. Since this d.c. current is not supported by a voltage it will decay with a time constant *T* = *L/R*. The highest value of *A* is obtained when the fault occurs at or near a voltage zero so *i'* is a maximum at t_0. For this condition, the maximum peak current I_{max} occurs 10 ms after t_0, and if T = 45 ms is obtained from:

$$I_{max} = I_F\sqrt{2}(1 + \exp-10/45) = I_F\sqrt{2}(1.8) = I_F 2.55$$

where I_F is the rms value of the balanced short circuit current. This is the maximum current that should flow between the contacts if the circuit breaker closed onto a three–phase short circuit; it is called the 'making peak'.

Some four cycles (80 ms) after t_0, the short circuit current ceases at a current zero. At this point the d.c. current is much less than *A*, but it effectively increases the a.c. current to be interrupted. Breakers are therefore given an unbalanced short circuit current rating which is a multiple of the balanced short circuit current rating, I_F for *T* = 80 ms and *X/R* = 30. The unbalanced rating exceeds the balanced rating by some 25%.

It must be remembered that if *i'* is a maximum at t_0 for one phase it will not be necessarily so for the other phases. This may be seen in Figure 75 in the phase currents for a short circuited generator. Since the steady–state short circuit currents for the three phases must add to zero at t_0 so must be corresponding d.c. components in the three phases.

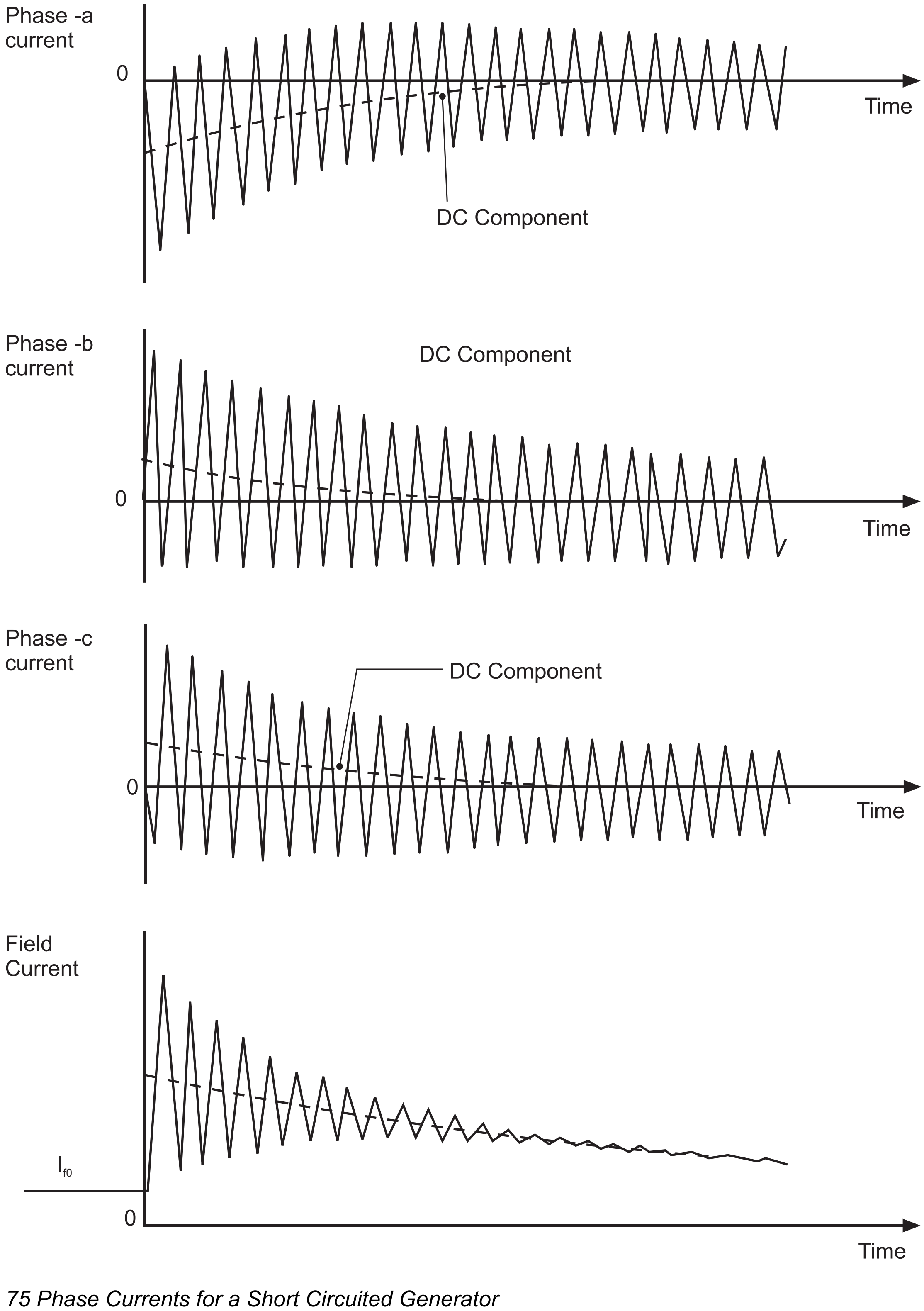


Figure 75 Phase Currents for a Short Circuited Generator

Further Phenomena caused by Machine Operation

Induction Motors

Although induction motors are primarily loads they are able to generate current into faults for short periods. The problem was recognised in the UK in the late 1960's and was highlighted through measurements. The curves shown in Figure 76 were obtained following tests on a large induction motor.

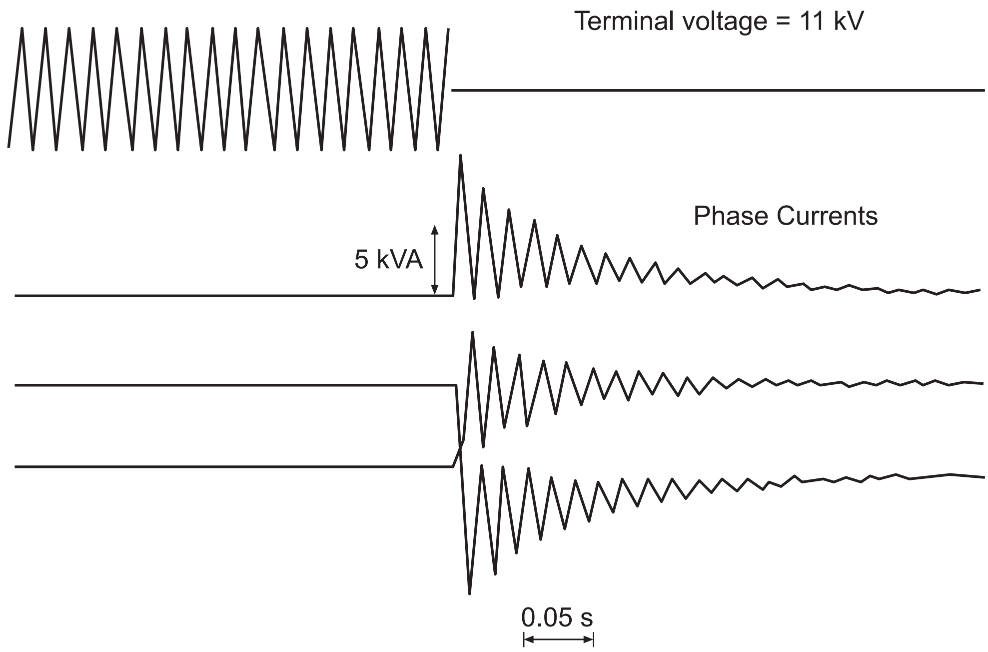


Figure 76 Test Curves

The simplest method of handling induction motor fault currents is to consider the a.c. component only, which starts off at a high value and decays rapidly. Initial fault currents are close to motor starting currents and can be estimated by taking the inverse of the starting reactance. Decay rates vary from motor to motor and also depend on the exact location of the fault. On some large machines it may be possible to obtain accurate data of time constants, particularly for motors under construction. However, for the majority of machines data will be unobtainable.

A.C. current decrements are usually included by using various rules of thumb and by considering the effect on the make and break duty separately. To calculate the make contribution, the full fault contribution of the induction motor is considered. However, for the break duty it is usually assumed that the induction motor current has decayed to one third of the peak a.c. value.

Induction motors have little effect on transmission system faults but may influence fault currents within distribution systems. Power station auxiliary supplies contain large numbers of induction motors that have a significant effect on fault current.

Effect of AVRs

Most synchronous machines contain automatic voltage regulators (AVRs) to stabilise the terminal voltage when the load fluctuates. Often, AVRs are fast enough to influence fault currents and the principal effect is to reduce the rate of a.c. current decay. Since fault level calculations often ignore the a.c. decrement, the effect of an AVR is to make the calculation more accurate.

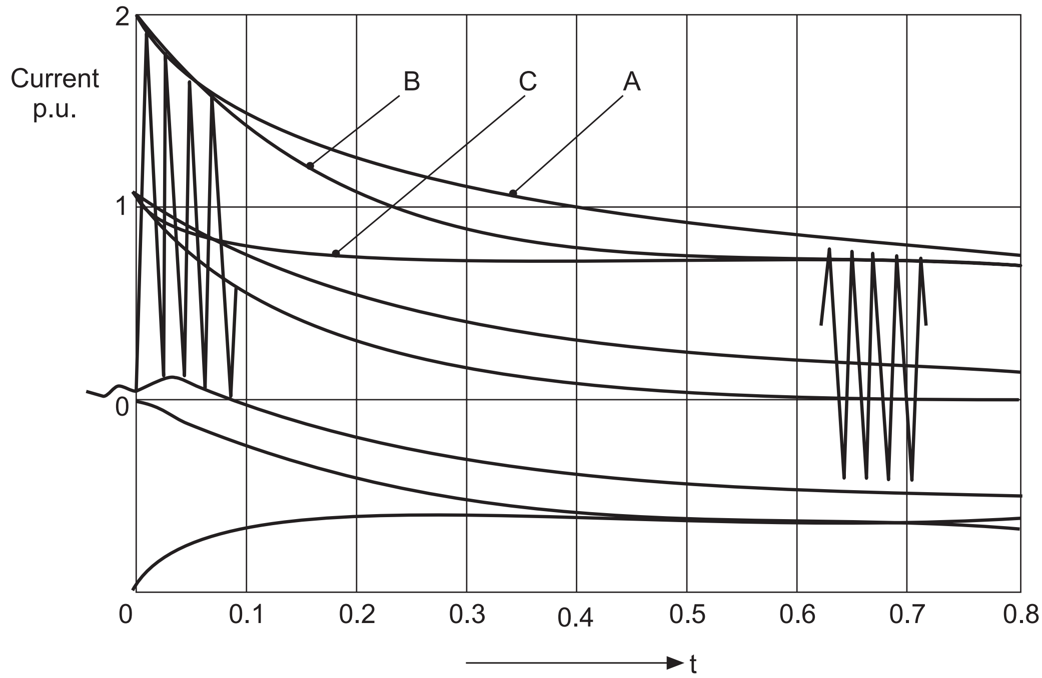


Figure 77 Curve of Short–Circuit Current in the Proximity of a Slightly Under-Excited Generator

Current curve envelopes:

A: Short–circuit on the 525 kV side of the transformer of a 1000 MVA generator–transformer unit. Time constant of decay of the d.c. component τ = 300 ms.

B: As shown in A, but with short circuit on the line at a distance of 50 km, τ = 135 ms.

C: Curve of balanced current.

Small generators without AVRs can produce rapid a.c. decrement resulting in fault currents not much bigger than load currents. Faults are very difficult to detect under these circumstances. If AVRs are fitted the fault current can be maintained at a higher value for longer and the fault is then simpler to detect.

A further complication associated with decrement occurs on switchgear close to generators. If the a.c. decrement is more rapid than the DC decrement then the first few cycles of current do not pass through zero. See Figure 77.

Experiment 8: Symmetrical Faults

The following are examples of studies that can be carried out on the Simulator. In all cases the values measured are to be compared with those calculated. The connection diagrams for Parts A to D are given in Appendix 3.

Part A: Faults on an Unloaded System

Connect Line 2 between the Grid Supply and the distribution transformer DTX1 as shown in the connection diagram for experiment 8a in Appendix 3. Phase-phase-phase faults can be applied, via the timer (set to 0.3 s) and its circuit breaker, at test point TP20 on the secondary side of the distribution transformer.

This is a system that will be considered later in Section 7 for grading overcurrent protection. The overcurrent settings in the relays RD1A, RD1B and RGTB need not be blocked for this experiment. The fault duration will be long enough for records and measurements of fault current to be made in these relays. Comparison should be made between calculations of fault current and recorded data in the P142 and P122 relays, that can be found in the Measurement 1 menu and the Disturbance Records. Refer to Section 3 of this Manual and the Relay Manuals.

Part B: Faults on a Loaded System

1) Connect lines 2 and 3 between the grid supply and the distribution transformer DTX1. Connect test point TP13 between the lines using the Double Bus system to include meters MF and MG in the circuit. See the connection diagram for experiment 8b in Appendix 3.

2) Close all CBs except the load CB25. Measure the voltage at the fault point.

3) Apply through the timer and its CB, a phase-phase-phase fault at the test point TP13. Referring to the Measurement 1 menu and Disturbance Records of the relays, record the values of the phase currents in the lines.

4) Now supply a three-phase 50% switched resistive load at the 110 V utilization busbars. Measure the voltage at the fault point.

5) Again apply through the timer and its CB, a three-phase fault at the test point TP13. Referring to the Measurement 1 menu and Disturbance Records of the relays, record the values of the phase currents in the lines.

6) Compare the currents measured in steps 3 and 5 above. Is there any significant difference? Note that in practice prefault load currents are often neglected in calculations.

Part C: Contribution Made to the Total Fault Current by an Induction Motor Load

As discussed in Section 6, an induction motor can make a significant contribution to the initial fault current at a busbar. An example is given in Figure 78 to illustrate this point. A system similar to that given in Figure 78 can be set up on the Power System Simulator as shown in experiment 8 part c connection diagram in Appendix 3. The Grid Supply feeds the utilisation bus through a short line (0.15 pu) and the distribution transformer DTX2. With no load on the Utilisation Busbar, apply a short duration three–phase to earth fault (say 0.3 seconds) at test point TP23a and record the fault current on an oscilloscope connected across a transducer inserted into a phase at TP23a.

Now start and run the induction motor from the utilisation bus and again apply a three–phase fault at test point TP23.

Compare the recorded fault current traces for the two load conditions. The fault current trace with the induction motor will be greater at t = 0 but should decay within about four cycles.

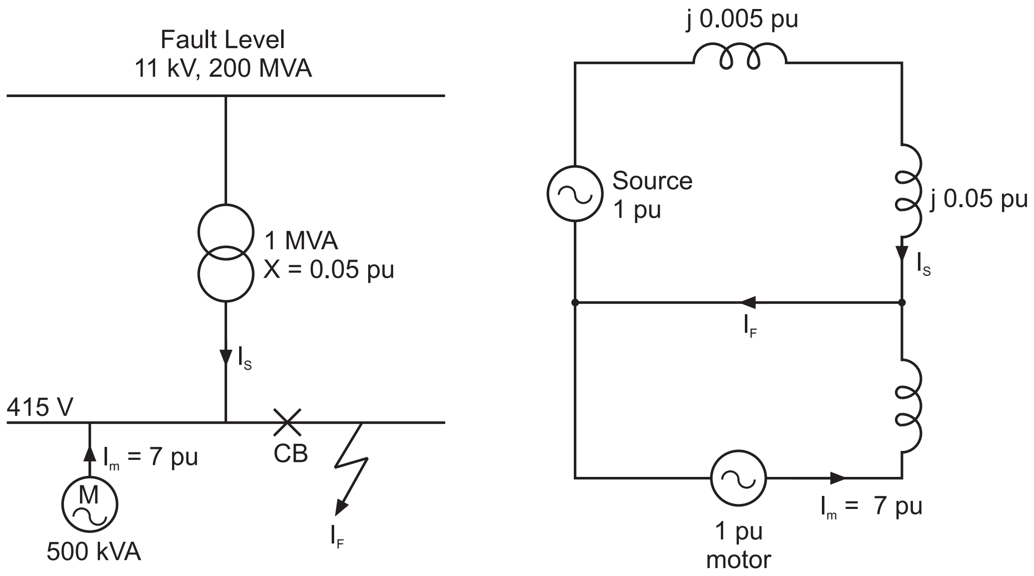


Figure 78 Contribution of induction motor to initial fault current at busbar

I_s = Current from source

I_m = Current from motor

Base MVA = 1 MVA

So, source equivalent X pu = 1/200 = j0.005 pu

$$I_{make} = I_s + I_m = \frac{1}{0.055} + \left(7 \times \frac{0.5}{1.0}\right) = 21.68 \text{ pu}$$

$$I_{break} = \frac{10}{0.055} + \left(\frac{7}{3} \times \frac{0.5}{1.0}\right) = 19.35 \text{ pu}$$

Part D: Fault Analysis using Bus Impedance Matrices

More complicated systems involving generator G1 and the grid supply GS and six lines can be set up on the Power System Simulator. Such systems, as shown in Figure 79, will have 3 or 4 busbars.

The diagram for setting up this system on the Simulator is shown in the connection diagram for experiment 8d in Appendix 3. The double Busbar is used to interconnect the lines. The fault point is at TP17; no load is supplied by the system.

Calculations of the fault current at the faulted bus and from the two generators, using the bus impedance (Z_{bus}) method, can be compared with measurements recorded in the Disturbance Records and Measurement 1 sections of the relays RD1A, RG1B and RGTB.

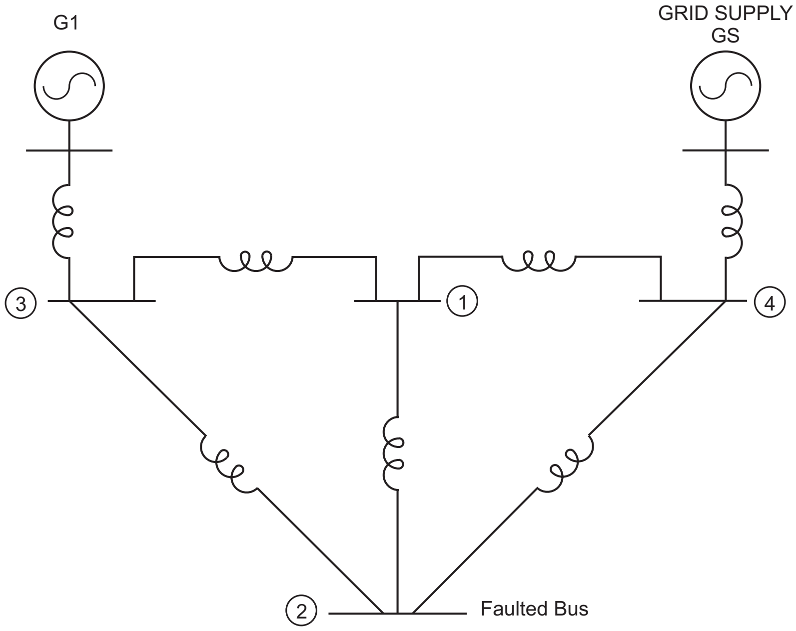


Figure 79 Fault Analysis Using Bus Impedance

6.2 Unbalanced Fault Currents

Most systems and loads are reasonably well balanced and may be analysed using a single phase representation. Measurements taken of system voltages support this view. However, there are situations where the level of imbalance is severe, the most common being system faults. To cater for system unbalance, a different set of analysis techniques is required.

Simple configurations of unbalanced load can be handled by conventional circuit theory representing each phase in detail. The method is tedious and can only be extended to a small range of systems without introducing interphase mutual effects. To avoid these and other problems the method of symmetrical components has been devised.

The Method of Symmetrical Components

Any set of unbalanced three phase phasors can be resolved into three sets of balanced phasors to simplify the analysis. The three sets of balanced phasors used by symmetrical components are:

1) Positive phase sequence phasors which are three equal phasors 120° spaced. Phase rotation = a, b, c.

2) Negative phase sequence phasors which are three equal phasors, 120° spaced. Phase rotation = a, c, b.

3) Zero phase sequence phasors which are three equal phasors, all in phase.

These components are shown in Figure 80. The sequence component phasors are combined in the following way:

$$I_a = I_{a0} + I_{a1} + I_{a2} \quad I_b = I_{b0} + I_{b1} + I_{b2} \quad I_c = I_{c0} + I_{c1} + I_{c2} \tag{3}$$

To aid algebraic operations use is made of the 120° operator a, where:

$$a = 1\angle 120$$

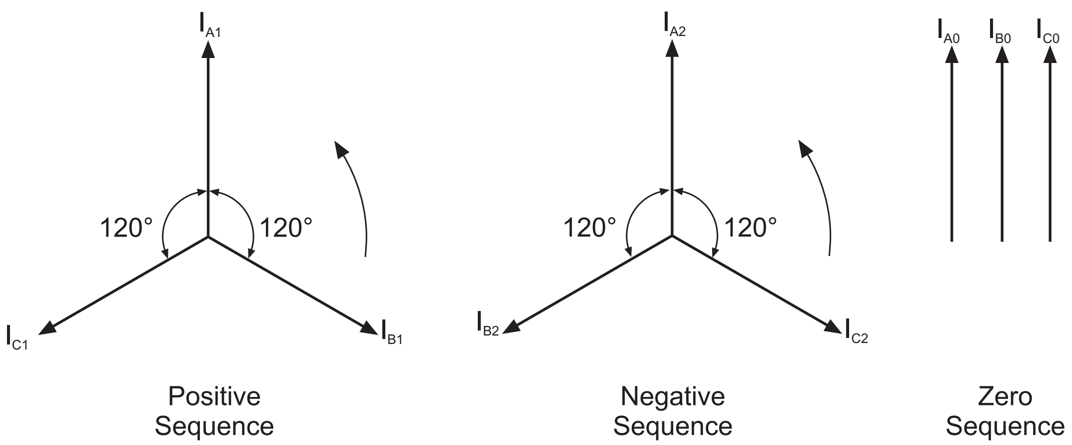


Figure 80 Symmetrical Components

When a vector is multiplied by a, the magnitude remains unchanged but the phase angle is advanced by 120°. Using this operator all the phase currents may be defined in terms of the a phase symmetrical components since:

$$I_{c1} = a \times I_{a1} \quad I_{b1} = a^2 \times I_{a1} \quad I_{c2} = a^2 \times I_{a2} \quad I_{b2} = a^2 \times I_{a2}$$

$$I_a = I_{a0} + I_{a1} + I_{a2} \quad I_b = I_{a0} + a^2 I_{a1} + a I_{a2} \quad I_c = I_{a0} + a I_{a1} + a^2 I_{a2} \tag{4}$$

Solving the equations gives the symmetrical component values in terms of the phase values:

$$I_{a0} = \frac{1}{3}[I_a + I_b + I_c] \quad I_{a1} = \frac{1}{3}[I_a + aI_b + a^2 I_c] \quad I_{a2} = \frac{1}{3}[I_a + a^2 I_b + aI_c] \qquad (5)$$

By applying Equations (5), the symmetrical component values may be derived from any three unbalanced phasors.

Having derived the symmetrical component values, each component is assumed to flow in a separate network containing only that component. When a solution is obtained for each component separately, they are superimposed, using Equation (4), to form the unbalanced phase values. Since each of the symmetrical components is a balanced set of vectors a single phase calculation can be conducted for each network. The technique therefore enables an unbalanced problem to be resolved into three problems each within a self contained balanced circuit.

In a three wire system the three–phase currents sum to zero. In a four wire system the neutral current is given by:

$$I_n = I_a + I_b + I_c$$

but since

$$I_{a0} = \frac{1}{3}[I_a + I_b + I_c]$$

$$I_n = 3I_{a0}$$

Neutral currents are therefore directly related to zero phase sequence currents.

Sequence Impedances of Power System Components

In general different power system devices have different circuits and impedances to the different sequence components. The negative impedances of lines and transformers are equal to their positive sequence impedances. The negative sequence impedance of a generator is approximately equal to its sub–transient reactance.

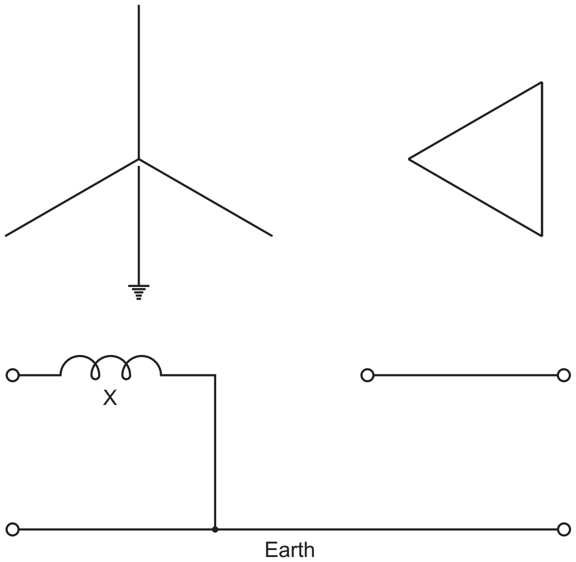


Figure 81 Equivalent Circuit

The zero sequence impedance of lines may be two to three times larger than the positive sequence impedance. The zero sequence reactance of a core type transformer is equal approximately to its positive sequence leakage reactance but the zero sequence equivalent circuit of a transformer depends on its winding and earthing connections (see Figure 81 and References). The zero sequence impedance of a generator is very small and often neglected.

Analysis of Unbalanced Fault Currents

The analysis of unbalanced faults based on symmetrical components is included in most textbooks on power system analysis, and will not be summarised here (see References).

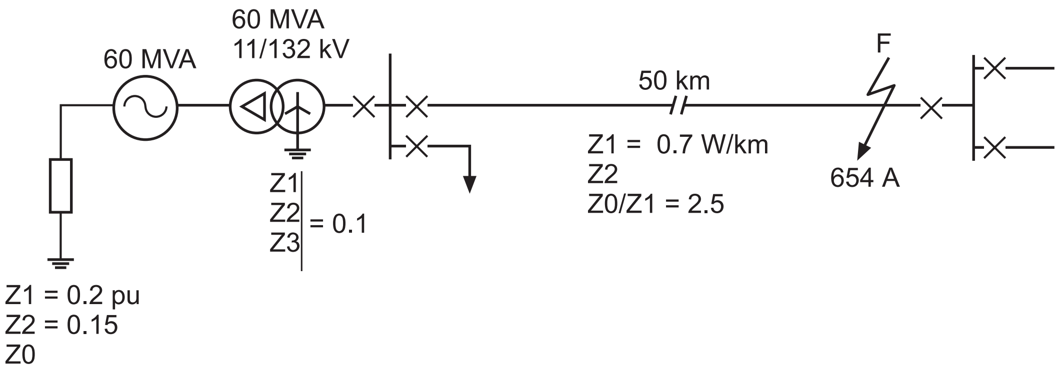


Figure 82 Schematic Diagram - Analysis of a line to Ground fault on an Elementary Power System (Load Current Neglected)

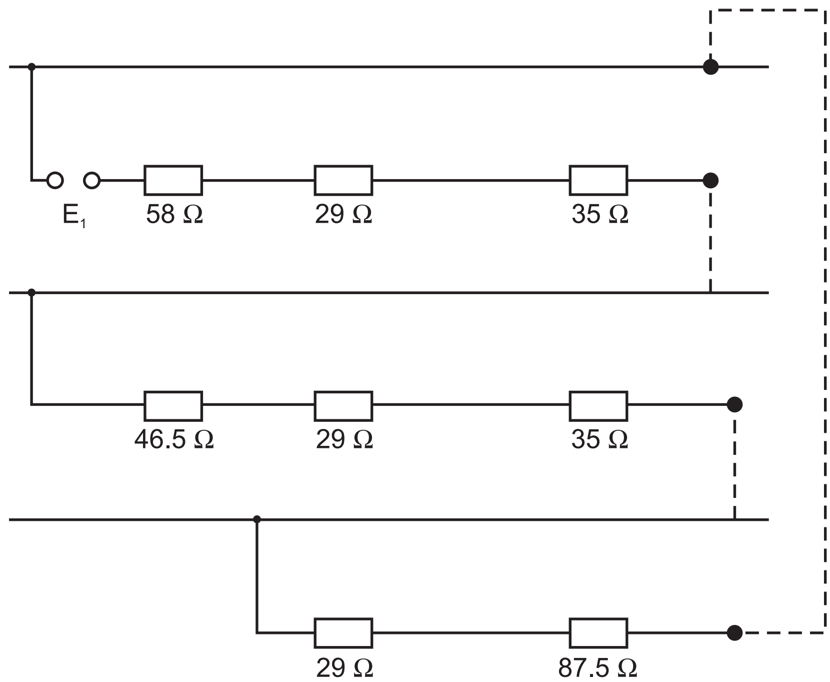


Figure 83 Circuit Diagram - Analysis of a Line to Ground Fault on an Elementary Power System (Load Current Neglected)

The analysis for each type of fault may be represented by a specific interconnection of the sequence networks for the system, from which fault currents may be determined. Figures 82 and 83 illustrate the analysis of a line to ground fault on an elementary power system. Note that the load current is neglected, i.e. system and the load impedance beyond the fault point are not shown.

For the transformer and line, the rated current is:

$$I_N \equiv \frac{60 \times 10^6}{\sqrt{3 \times 132 \times 10^3}} = 262\ \text{A}$$

$$\therefore\ 0.1\ \text{pu Z} \equiv \frac{0.1 \times 132000}{262 \times \sqrt{3}} = 29\Omega$$

Total impedances, referred to 132 kV, 60 MVA are:

$$Z_1 = 122\ \Omega$$

$$Z_2 = 110.5\ \Omega$$

$$Z_0 = 116.5\ \Omega$$

$$\therefore\ I_1 = I_2 = I_0 = \frac{132000}{\sqrt{3}(122 + 110.5 + 116.5)} = 218\ \text{A}$$

$$\therefore I_F = I_1 + I_2 + I_0 = 218 + 218 + 218 = 654\ \text{A}$$

Experiment 9: Unsymmetrical Faults

Experimental and analytic studies of varying degrees of complexity can be carried out on the Power System Simulator for a variety of faults; for example line-to-ground, line to line, line to line to ground, and open circuit.

The following are a few examples of experiments that can be carried out. The connection diagrams for Parts A, B, C, and D are given in Appendix 3. Outline descriptions are given below. In all cases the values measured are to be compared with those calculated. The P122 and P142 relays connected into the system enable data on both fault currents and steady state currents, including sequence currents. See Section 3 of this Manual and the relay Manuals.

Part A: Negative Sequence Current Measurement

This experiment is a simple exercise in symmetrical component analysis. It does not involve fault application; only steady state measurement of current. A line-to-line load is fed by a radial system and measurements of current compared with analysis.

On the Power System Simulator, set up a system in which the Grid supply feeds a load through Line 4 and a distribution transformer. Connect a switched three phase load resistance (R3) at the end of the line and use TP23 to break one phase with the manual circuit breaker. Measure the line current to the load.

For line-to-line faults, or loads, symmetrical component analysis gives $I_{line} = \sqrt{3} \cdot I_2$, where I_2 is the negative sequence current. In this case I_2 = approximately 2.8 A or 58% of the line current. The relay RD1B should indicate these values in the Measurements section of the relay menu.

Part B: Faults on a Transmission Line fed from a Single Source

A system similar to that of the example given in Figure 83 can be set up on the Simulator by connecting Line 4 to the Grid Transformer Bus. Line-to-ground, line-to-line or line-to-line-to ground faults can be applied at the far end of Line 4, at TP17. Remember that the timer and its CB should be included in the fault circuit as 'back up'.

The fault currents should be recorded in relay RD1A. Look in the Disturbance Records of this relay for traces of the fault currents and in Measurement 1 Menu for the magnitude of phase currents. Symmetrical component analysis should be used to calculate the fault current for each type of fault. Compare the calculated values with measured values.

Part C: Faults on a Transmission Line Terminated in a Transformer

If Line 2 is connected to Line 3 and then terminated in one of the distribution transformers, any line-to-ground fault at the junction of the two Lines would result in ground current flowing to the star points of both the grid supply transformer and the distribution transformer. The disposition of sequence currents for a line to ground fault on such a system is shown in Figure 84. Additionally, Figure 85 shows the interconnection of the sequence networks and the analysis for determining the currents in such a system.

Carry out the following experiment.

Set up a system on the Simulator as described above and shown in the Experiment 9c Connection Diagram in Appendix 3. Connect the reactance of 9.6 Ω on the Simulator panel between the fault point and the 'earth' of the grid supply to distribution transformer system (not the actual earth connection). Measure using the M230 meters the steady state 'fault currents' flowing throughout the system and compare measured and calculated values of current in each section of the circuit. Note that when calculating the currents using a circuit similar to that in Figure 85, a reactance of (3 x 9.6 Ω) should be inserted in the dotted line leading from the zero sequence network. The three ammeters in meter K are all connected and measure the fault current and the currents flowing back to the transformers.

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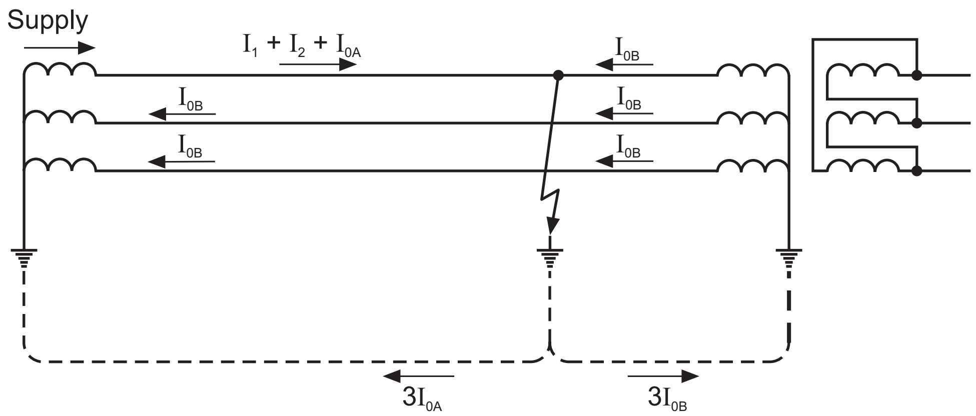


Figure 84 The Disposition of Currents for a Line–to–Ground Fault on a Multiple Earthed System

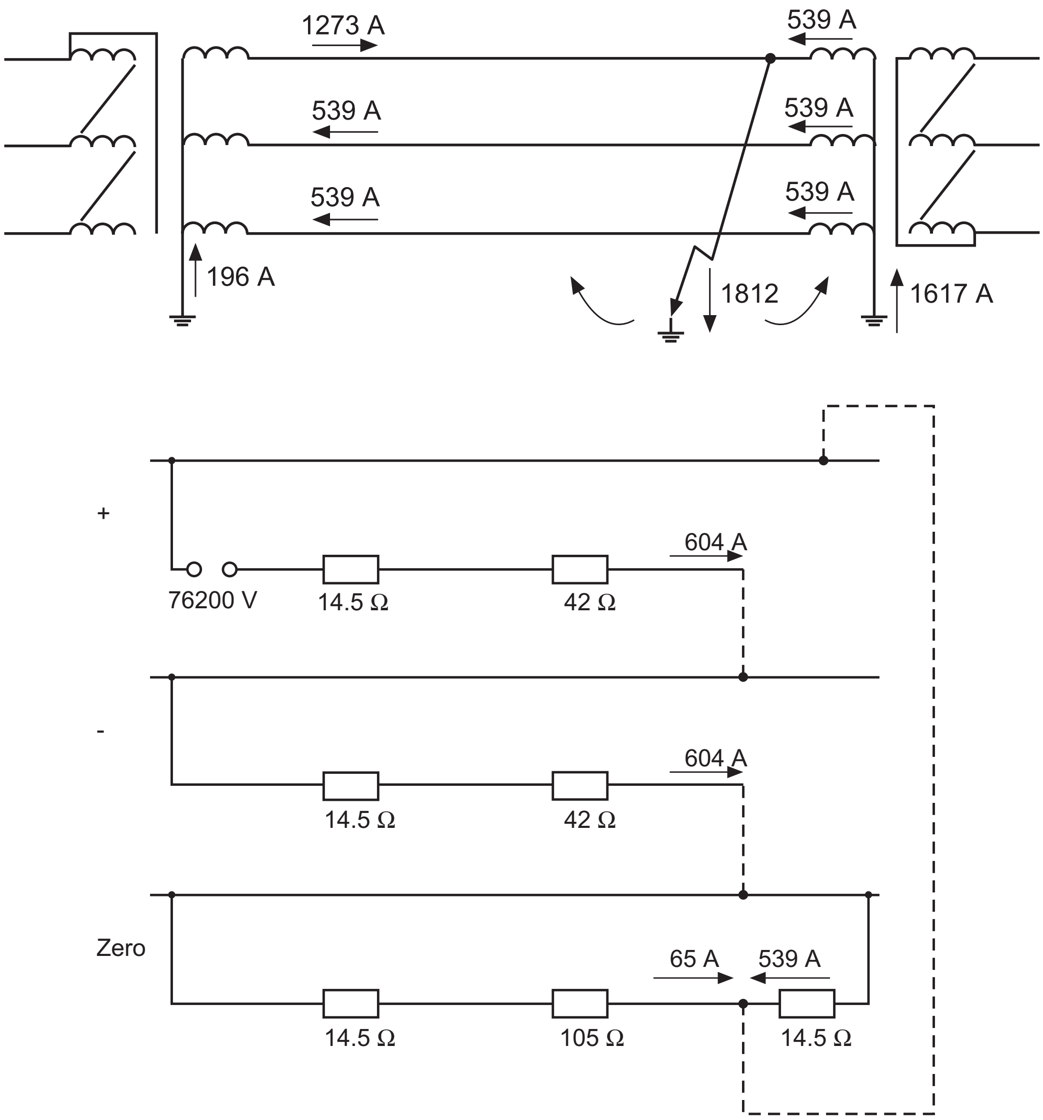


Figure 85 Interconnection of the Sequence Networks (Load Current Neglected)

Analysis

For Figure 85:

$$I_1 = I_2 = I_0 = \frac{76200}{2(14.5+42)+\left(\frac{119.5 \times 14.5}{134}\right)} = 604 \text{ A}$$

End A

$$I_a = 604 + 604 + 65 = 1273 \text{ A}$$

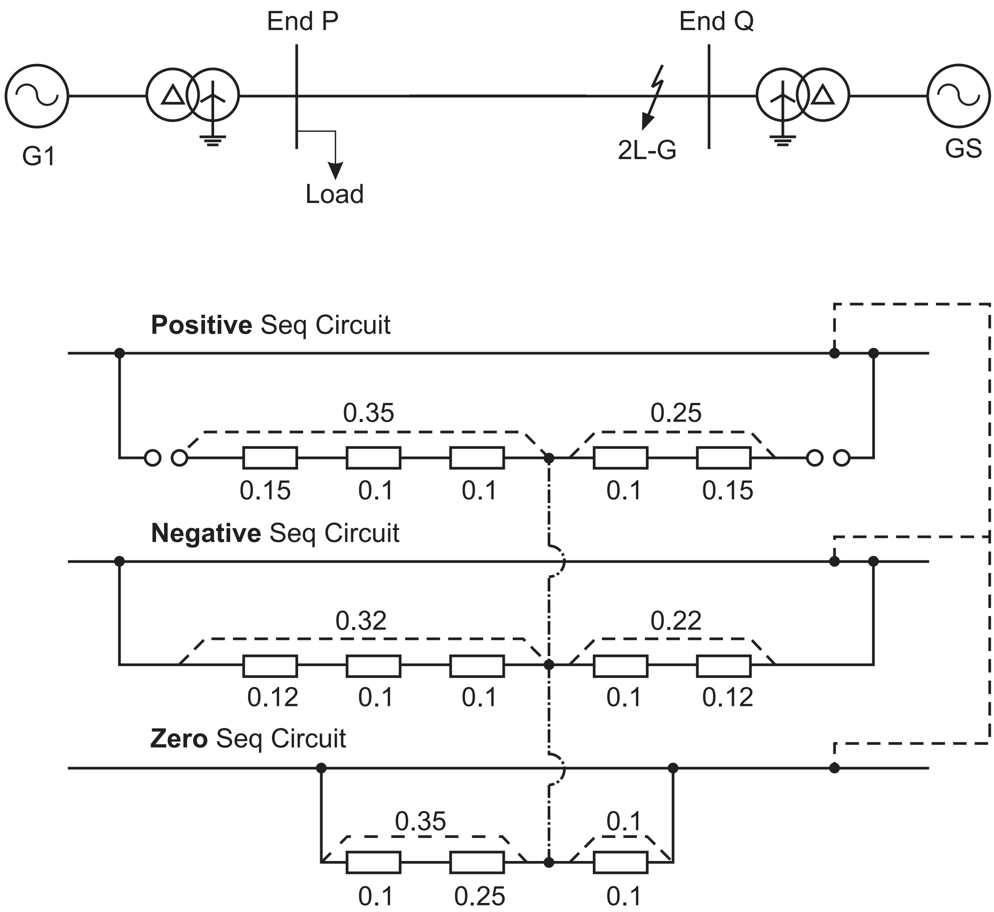
$$I_b = a^2 \cdot 604 + a604 + 65 = -539 \text{ A}$$

$$I_c = a604 + a^2 \cdot 604 + 65 = -539 \text{ A}$$

Part D: Faults on a Transmission Line with a Double–End Feed

Faults on a transmission line between two busbars, each busbar connected to a generator, will be fed from both ends. Such a system and its analysis for a Line-to- line-ground fault is shown in Figure 86.

This system arrangement can be set up on the Power System Simulator by connecting Line 4 and line 2 between generator G1 and the grid supply, GS. This system is shown in the connection diagram for experiment 9d of Appendix 3. Connect a load at the Gen 1 Bus (End P), supplied mostly by G1 by increasing its excitation and power. A two line fault can be applied between lines 2 and 4. Measurements of fault currents can be extracted from the 'Measurement 1' menu and 'Fault Records' in the relays at either end of the lines.



Notice Seq Circuits connected in parallel.
Each Seq Circuit has two parallel paths of
varying impedance ratios, i.e.

Positive	0.35/0.25	=	1.4
Negative	0.32/0.22	=	1.45
Zero	0.35/0.1	=	3.5

Figure 86 Faults on a Transmission Line between two Busbars and Analysis for a Line to Line–Ground Fault

Part E: Advanced Fault Studies

More complicated networks can be set up, as shown in Figure 79, to which unbalanced faults can be applied. The experimental procedure for these experiments is the same as those given in Part D of Experiment 8.

For these Experiments, analysis will involve the specification of the Zbus matrices for each of the three sequences, positive, negative and zero. See the references in section 8.

6.3 Transient Over voltages: A.C. Circuit Interruption

Introduction

When a fault is detected by a protective scheme it causes a circuit breaker to trip and to break or interrupt the fault current. A.C. circuits are interrupted at a current zero because the current in the arc between the opening contact of the circuit breaker is zero at this time, making it the most convenient time to 'blow' the arc out.

In HV transmission systems the *X/R* ratio is high and therefore the resistance can be neglected in a first analysis. Thus the fault current lags by nearly 90^{o} behind the applied voltage, so that the voltage will be at its peak value when the is current zero. Figure 87 and Figure 88 illustrate the most common situation for circuit breakers in transmission systems.

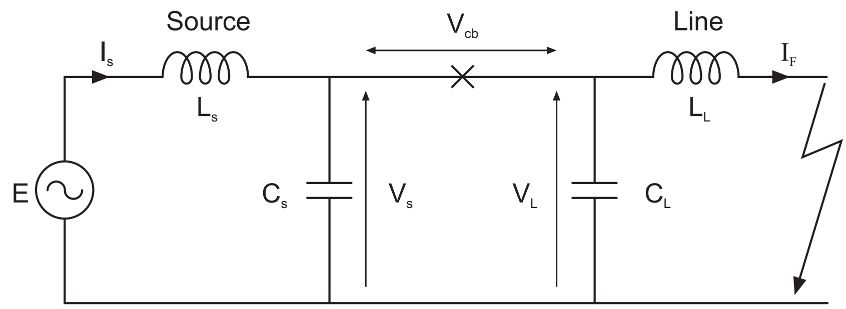


Figure 87 Fault Conditions for a Circuit Breaker - Circuit Diagram

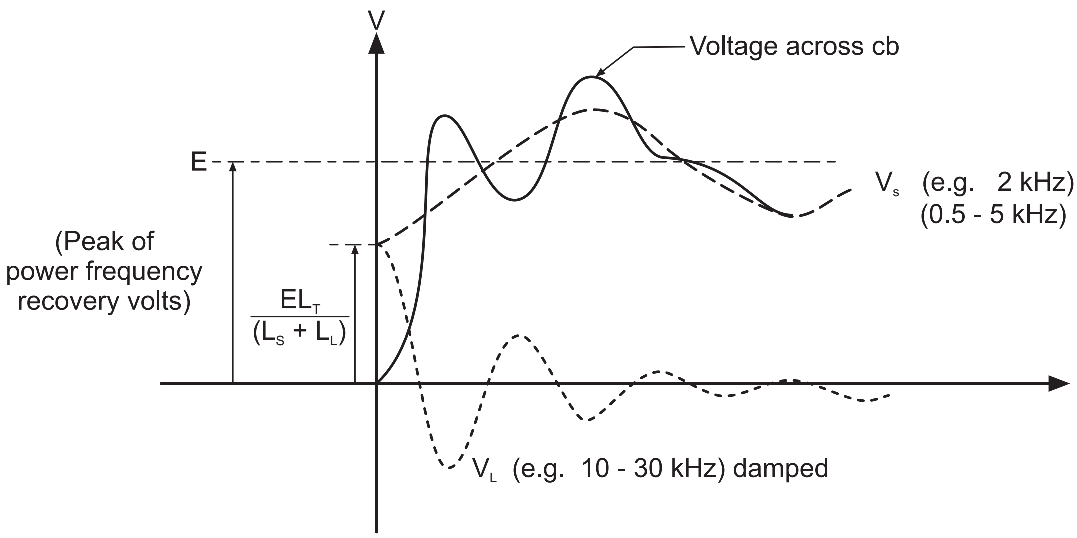


Figure 88 Fault Conditions for a Circuit Breaker - Graph

The generator or supply side of the circuit breaker is called the ***source side*** and the load or power transmission side is called the ***line side*** of the breaker. The system on each side of the breaker will have inductive and capacitive reactance, the latter being associated mainly with insulating bushings. Before the fault current is interrupted, the voltage at the circuit breaker is:

$$V_s = V_L = \frac{EX_L}{X_S + X_L}$$

When the fault current is interrupted the line side voltage V_L returns to zero while the source side voltage V_S becomes equal to the supply voltage. However, before this final steady state voltage is reached there is a transient voltage oscillation. This oscillation occurs because of the energy exchange between the inductances and capacitances of the system following sudden circuit interruption.

The natural frequency of oscillation is:

$$f = \frac{1}{2\pi}\sqrt{\frac{1}{LC}} \text{ Hz}$$

and is higher for the line side voltage V_L: see Figure 88.

The final value of the voltage between the circuit breaker contacts, V_{cb} is the difference between V_L and V_S. This also is shown in Figure 88. The maximum theoretical value of V_{cb} is twice the supply voltage, but the actual value is less due to system losses that cause damping.

Experiment 10: Demonstration of Transient Over voltages on the Simulator

Circuit breaker CB11, which is connected to the Double Bus Switching Scheme, is a solid state, thyristor switch. When the CB11 lever is closed the firing circuit to the thyristor gate is switched on and the thyristor is triggered and held in a conductive state so that current can flow through it. When the CB11 lever is opened, the firing circuit is switched off and the thyristor becomes open–circuited at the next current zero. Additionally, the firing circuit of the thyristor can be switched off by operation of the double bus relay at position BUS A. Figure 89 shows a system which can be set up on the Simulator. Figure 146 in APPENDIX 3 shows the connection diagram. Line capacitors are used to provide C_S and C_L (see Section 2).

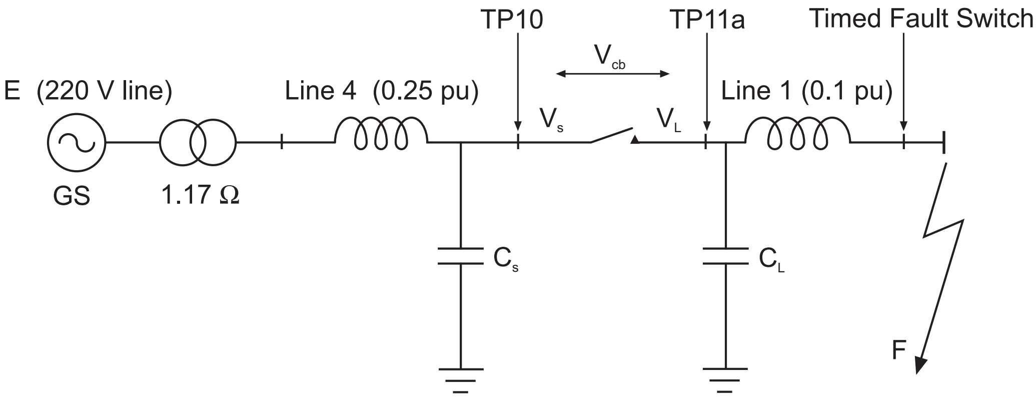


Figure 89 A.C. Circuit Interruption Test

C_S = 3 μF, calculated frequency of V_S ≅ 560 Hz

C_L = 0.5 μF, calculated frequency of V_L ≅ 2.5 kHz

Line 4 is connected to a line capacitor and then to the thyristor switch CB11. Line 1 is connected between the 'a' sockets of test point TP11 and the timed fault. The source end of Line 1 is first connected to a line capacitor before being connected to terminals 'a'.

The fault is single–phase to earth and is connected at the end of Line 1, at the 'a' terminal of TP11 and the timer CB. The timer acts as back–up and may be set to 0.2 s.

The voltages V_{cb} can be captured and recorded by connecting a voltage transducer and associated oscilloscope between TP10 and TP11a. The source and line side voltages, V_s and V_L, can be similarly and simultaneously recorded by connecting two voltage transducers across the capacitors C_s and C_L, respectively. The transducers are connected to the two channels of an oscilloscope.

When the fault is switched on the P142 relay at BUS A will trip almost instantaneously, switching off the triggering circuit to the thyristor and subsequently the fault current at the next current zero. Figures 90 and 91 show the voltage waveforms obtained for the circuit in Figure 89. Various values of capacitance or line length can be used to change the natural frequency of the oscillations.

Note: You may need several attempts before you obtain a satisfactory waveform.

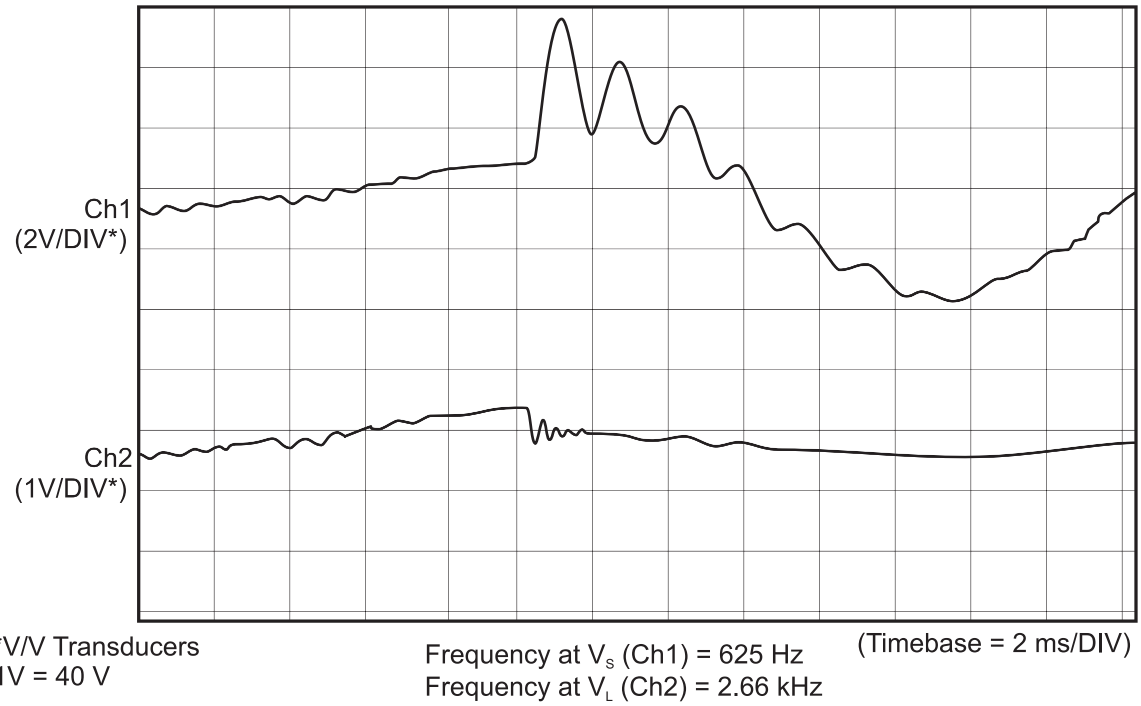


Figure 90 A.C. Interruption Test Source Side and Line Side Voltages

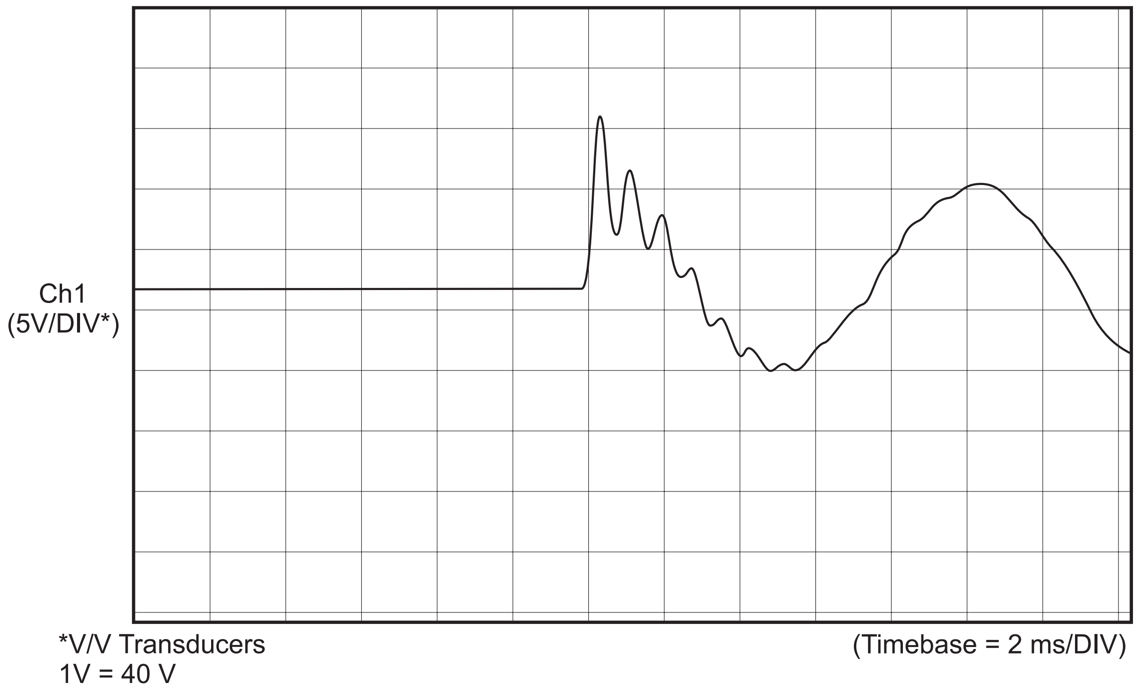


Figure 91 A.C. Interruption Test Voltage Across Breaker (V_{cb})

6.4 Transient Stability Studies

Introduction

When a fault occurs on a system it causes not only transient currents but also electromechanical transients associated with the generator units connected to the system.

A generator unit consists of a prime mover and a generator. Under normal steady state conditions of operation the electrical power supplied to the system by the generator, P_e is equal to the mechanical power produced by the prime mover, P_m if losses are neglected.

When a fault occurs on the system P_e will be suddenly reduced. Thus $P_m > P_e$. As P_m cannot change instantly the power (P_m - P_e) causes the generator unit to accelerate and the surplus mechanical energy is stored in the rotating mass of the generator unit.

When the fault is cleared the capability of the generator to supply electrical power may be such that $P_e > P_m$. The generator unit would then decelerate towards its original steady state operating point as energy is taken out of the rotating mass to supply the electrical power. However, the generator unit will not suddenly stop decelerating at the operating point; its momentum will take it past this point. Eventually deceleration will cease and the generator will then be accelerated again back towards the operating point. The generator unit will therefore oscillate or swing about the steady state point until the oscillation is damped out and the generator unit returns to stable running.

If however, the fault causes the initial swing to be so large that even after the fault is cleared P_e is still smaller than P_m, there is no way the generator unit can decelerate back to its original operating point. The speed of the generator will continue to increase so that the rotor poles slip past the stator poles. When pole slipping occurs, the generator unit has become unstable and has lost synchronism with the other generators in the power system.

Reference to the load angle, δ, is made when discussing the swing of a generator unit. Figure 42 shows the increase of P_e with δ for a generator, discussed previously in Section 5, and known as the Power Angle Curves. This is a very important characteristic in stability studies. The ideal curve shown gives $P_e = P_{max} \sin \delta$.

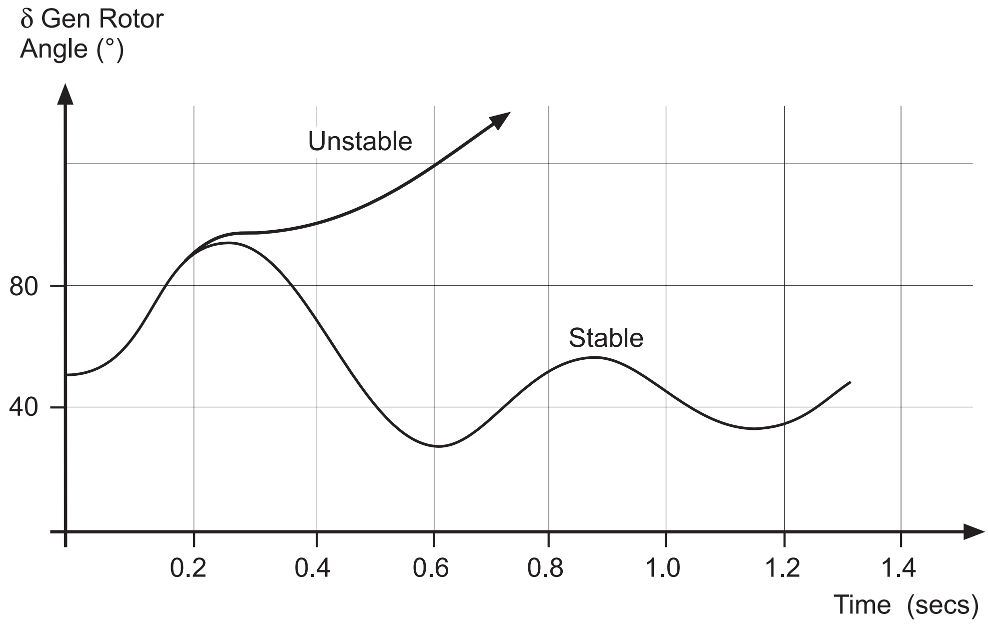


Figure 92 Transient Stability: The Swing Curve

Figure 92 shows a typical swing curve of a generator for both stable and unstable conditions. This curve describes the variation of δ with time and can be solved numerically by computer. It is expressed mathematically in its simplest form as:

$$P_m - P_e = M\left(\frac{\mathrm{d}^2\delta}{\mathrm{dt}^2}\right)$$

where M is the angular momentum of the generator unit.

This is a simple description of the fundamental concepts of stability analysis, which is a very large subject. Further study of the subject may be made using the books mentioned in ‘References’.

Experiment 11: Stability Studies

Scaling the Angular Momentum of the Generator Unit

The motor–generator set has a closed–loop control consisting of an inner torque or current loop and an outer speed loop. The speed loop has set inputs including feedback from a digital encoder fitted to the drive shaft of the motor set. The digital encoder has 1024 pulses/rev. which allows the transient variation of δ to be obtained by means of a specially designed electronic circuit. The angle δ may be obtained from the BNC terminal marked Load Angle in the Transducer section of the main panel.

When the generator is synchronised to the mains a set input to the speed loop determines the electrical power output from the generator, which is maintained constant by means of a wattmetric feedback from the generator (See Appendix 4). The encoder still provides feedback to the speed loop but is ineffective when the generator is synchronised to the mains.

To achieve a load angle swing when a fault is applied to the generator, the tight closed–loop monitor control needs to be removed or reduced. Hence it is necessary to remove the integral function (I) from the speed loop and to provide a means of varying the proportional gain (P) so that swings of varying severity can be produced. This can be achieved electronically within the control circuitry of the vector drive and is switched into operation by means of a Generator Inertia Switch on the front panel of the Simulator. See the diagram in Appendix 4.

The Generator Inertia Switch under GEN 1 on the main panel has four positions. Positions 2, 3 and 4 are used for stability studies. Position 1, which includes the integral function, is used for all other operations on the Simulator. With the inclusion of proportional gain for both speed feedback and power input to the speed loop the Swing Equation for the motor–generator becomes:

$$K_I(P_m - P_e) = M\frac{\mathrm{d}^2\delta}{\mathrm{dt}^2} + K_I\frac{\mathrm{d}\delta}{\mathrm{dt}}$$

or

$$(P_m - P_e) = \left(\frac{M}{K_I}\right)\frac{\mathrm{d}^2\delta}{\mathrm{dt}^2} + K_I\frac{\mathrm{d}\delta}{\mathrm{dt}} \qquad (6)$$

$\left(\frac{M}{K_I}\right)$ = Effective inertia of the motor–generator set and K_I is the proportional gain of the speed loop

$\frac{\mathrm{d}\delta}{\mathrm{dt}}$ = Damping due to the speed feedback

P_m = Set power

P_e = Electrical power output

Also, the angular momentum M is given by:

$$M = J\omega_s$$

where J is the total inertia of the motor, generator and coupling and ω_s is the synchronous angular speed.

The total inertia of the motor–generator set in the simulator

$$J = 0.0894 \text{ Kg.m}^2$$

Values of K_I may be set within the software of the Vector Drive. Three values of K_I have been set and may be selected by the Generator Inertia Switch. The values of K_I that correspond to the switch positions are:

Position 2: $K_I = 2.05$

Position 3: $K_I = 0.87$

Position 4: $K_I = 0.45$

Thus, as K_I decreases, the effective inertia of the generator set increases. Equation (6) does not include electrical time constants. The time constants of the rotor of the motor is approximately 200 ms. However, the current controller of the drive boosts the current output to achieve close tracking of the current demand with minimum delay.

Position 1 of the Inertia Switch is the 'Start' and 'Run' setting for the drive.

Generator Protection for Power Swinging Conditions

During power swinging not only does the load angle oscillate but the voltage, current and power factor vary as well. If the oscillations disappear in a few seconds it is desirable that the generator protection does not trip. This is achieved by, for example, the overcurrent relay being set for faults only within the generator protection zone and the operation of the reverse power relay being delayed for a few seconds. However, if pole slipping occurs, power oscillations between the system and generator can cause large torque oscillations. Under these conditions it is necessary to isolate the generator from the system. This is achieved by means of a pole slipping detection relay which can allow without tripping, power swings up to but not greater than ±90°.

Procedure for Demonstration of Power System Instability

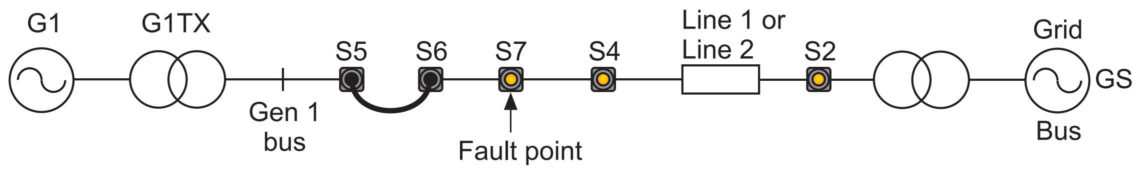


Figure 93 System for Demonstrating Power System Instability

Consider the system shown in Figure 93, which may be set up on the Simulator. Note that the system must be first connected from the Grid Bus to the Gen 1 Bus before Gen 1 is synchronised onto the Gen 1 Bus as described in Section 5. Apply a phase–phase-phase fault at connection S7 via the timed fault circuit breaker.

Use the timed fault circuit breaker to remove the fault after a set time. Connect the oscilloscope to the transient Load Angle BNC connector. Connect the 'Trigger' connection to the external input of the oscilloscope. Set the oscilloscope for single shot capture of the waveform.

After synchronisation, inhibit the under–frequency relay and over–voltage relay (or set them at an acceptably high value). The overcurrent relay can be inhibited or set at an operating time of 1 second for a fault at S7 to act as back–up for the timer.

Increase the power output of Generator 1 to approximately 1 kW.

First switch the Inertia Switch from position 1 to position 2, 3 or 4 and then apply the fault by switching the fault breaker. As soon as the fault is concluded, switch back through the switch positions to Position 1.

Typical traces are shown in Figures 94, 95 and 96. The results depend greatly on the fault times. Generator swing increases with inertia switch position and increase of power output and line length. In the above system extra lines can be inserted either in place of the S5 to S6 link or in series with Line 1. Pole slipping will be identified both by the sound of the motor drive and the absence of a return swing on the oscilloscope trace. Pole slipping should not occur, but if it does, the Inertia Switch should be quickly returned to Position 1 or stop the generator. However, pole slipping is unlikely, as the generator is salient pole and its rating is relatively large.

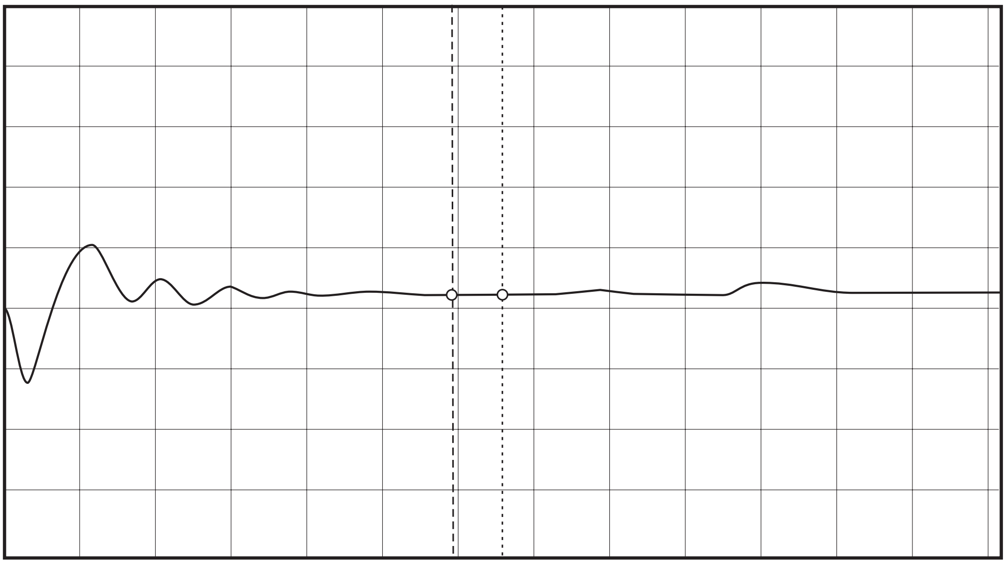


Figure 94 Transient Load Angle: Inertia Position 2, Fault Time 0.2 s, Line 1 (0.1 pu)

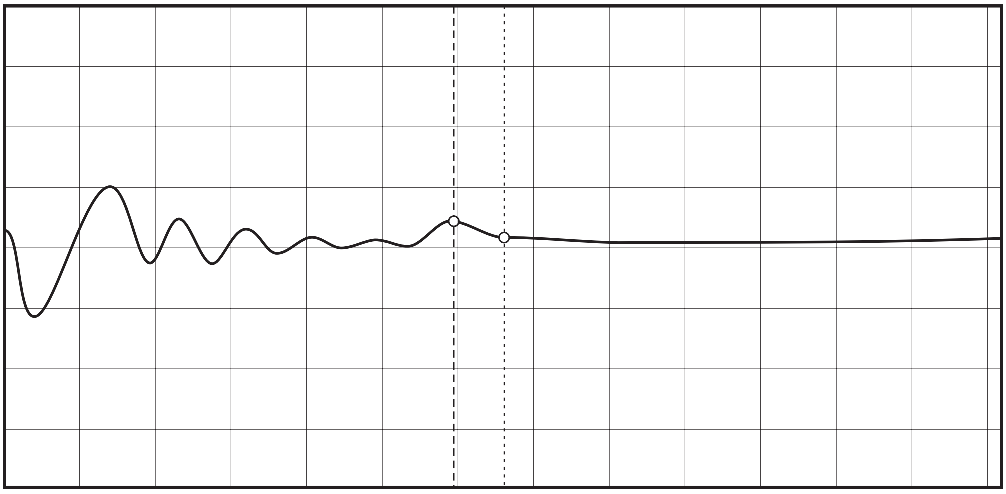


Figure 95 Transient Load Angle: Inertia Position 3, Fault Time 0.3 s

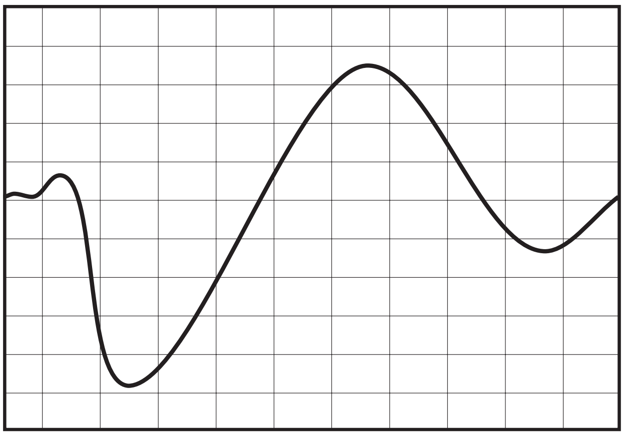


Figure 96 Transient Load Angle: Recorded Swing Curve; Fault Time 0.12s, Inertia Switch Position 4

SECTION 7.0 Experiments: Protection Systems

7.1 Introduction

Power system protection covers a wide range of application areas and the Power System Simulator contains a majority of them. Each application area is a subject for study in its own right. Whilst each application draws on a fundamental knowledge and understanding of power system analysis and engineering, the protection systems, techniques and relays used can vary greatly. This manual is not intended to provide a course in system protection, although such courses can be designed around the Power System Simulator, but to demonstrate the use of the Simulator in studying the main application areas. Thus guidance is given on system and scheme operation and related theory together with illustrative examples using the Power System Simulator. Guidance is also given on the use and setting of all the relays, but the user should refer to the relay Technical Manuals for further, more detailed information. Books listed in the References are particularly relevant to this section.

7.2 Principles of Power System Protection

This section discusses the principles underlying the design of protective systems rather than describing individual systems or schemes. Definitions and terminology used are given in Appendix 2. The components of electrical power systems are susceptible in varying degrees to faults of various kinds, caused by internal failures or by external factors. Faults include insulator flashover and busbar faults, overheating of plant, etc. Also included are those system conditions that would develop into a fault if allowed to persist, as for example negative phase sequence heating of generators. Protective systems have been developed to detect fault conditions in individual components and to initiate the opening of circuit breakers that isolate the faulted section, while keeping as much of the power system in operation.

Early power systems were radial in layout. Protection was required to limit the damage caused by short circuit currents. Short circuit currents cause overheating that destroys insulation, welds core laminations, and produce electromagnetic forces which distort windings. Speed of operation of the protection was required to reduce the duration of the fault. Discrimination, i.e. restricting isolation to the faulted section only, was relatively easy. It was generally achieved by time–grading: by deliberately delaying the operation of protection on sections nearer the source. This method has obvious limitations but the power levels and fault levels by present standards were low.

The interconnection of power systems by extensive transmission and distribution systems, with generating sources operating in synchronism, demanded more rigorous performance requirements of protective systems, because;

a) Current could be fed in either direction through a given section of a power system, and directional sensing was therefore necessary.

b) Power and hence fault levels were enormously increased as were the importance and cost of equipment involved.

c) Isolation of faulted lines, etc. was required to maintain system stability.

Basic Types of Protective Scheme

There are two basic types of protective scheme, 'Unit' and 'Non-unit'.

Non–Unit Protection

These schemes do not protect a particular element of the power system, the limit of their **reach** depends on the accuracy with which the protective equipment is designed, manufactured and applied; the complete set of protective gear is applied at one point only in the system. This group includes the fuse and overcurrent relay; their components can in most cases be generalised as shown in Figure 97. The quantity or quantities in the power system are too large to be measured directly, so sensing devices reproduce each quantity faithfully on a much reduced level: these devices include the current transformer and the linear coupler, the voltage transformer and capacitor voltage transformer.

The components of information that best determine the condition of the system are then chosen. This may be done by a summation transformer, a sequence network or by mixing transformers in a distance relay scheme. The information is fed to a measuring device or relay element that produces an output when the fault setting is exceeded. In numerical relays much of this logic is carried out in software and digital signal processors. The output is small and is amplified until it is sufficient to trip the circuit breaker, interrupting the fault current in the primary circuit or power system.

Unit Protection

Unit protection, or restricted protection schemes respond only to fault currents particular to one system component or clearly defined **zone.** They compare the value of some quantity at the input of the zone with its value at the output of the zone. Protective equipment must be applied at all boundaries of the protected zone so that the scheme can readily discriminate between internal and external faults. In this group are the circulating current and voltage balance differential schemes together with the phase–comparison carrier–

current systems. Unit protection can be applied throughout a system and since it does not involve time grading, can be relatively fast in operation. Relays in a unit protection scheme operate almost instantaneously.

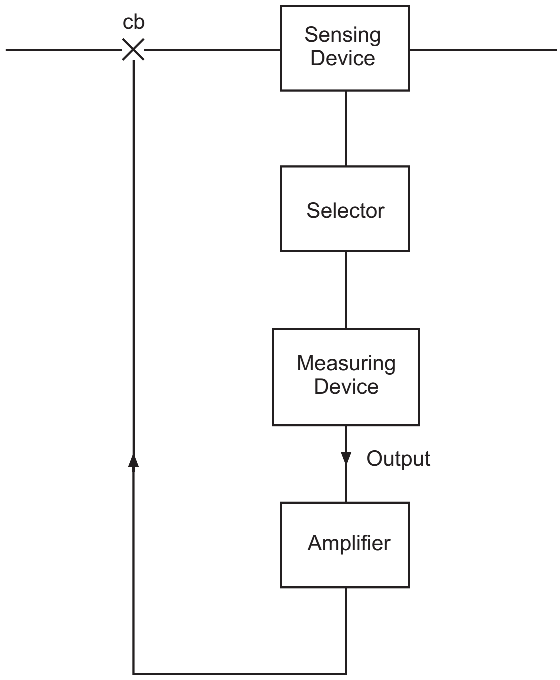


Figure 97 General Components of Non–Unit Protection Scheme

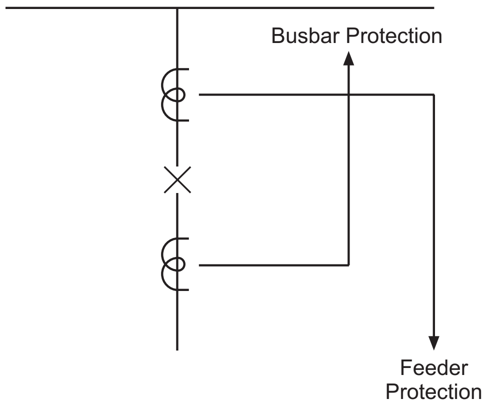


Figure 98 Overlapping Protection Zones-a

Zones of Protection

Ideally, system zones protected by unit (fully discriminative) schemes should overlap, as shown in Figure 99.

The location of the current transformer (CT) usually defines the zone boundary. Where zones do not overlap, as in Figure 100, protection is obtained by a back–up scheme, or by an extension of the zone boundary.

A fault between the CB and CT would not be detected by feeder protection and the fault would continue to be fed through the feeder.

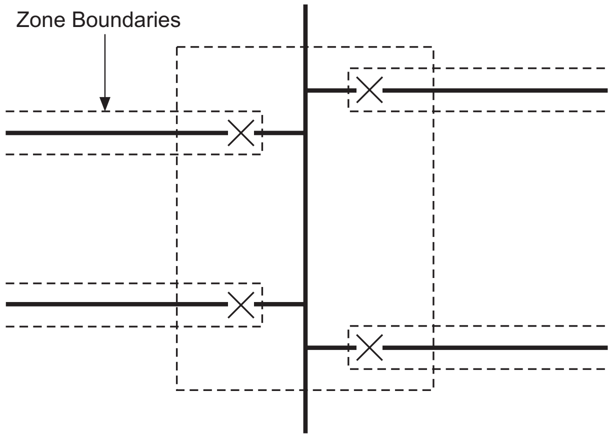


Figure 99 Overlapping Protection Zones-b

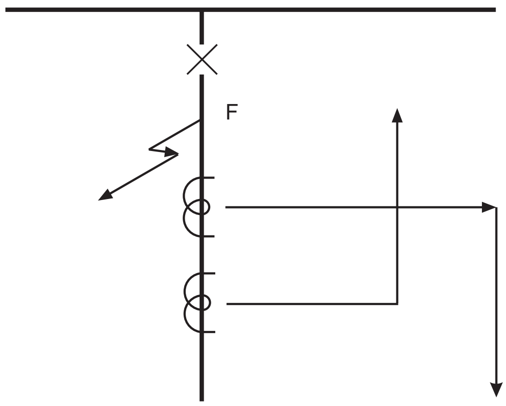


Figure 100 Protection Zones, No Overlap

Back–up Protection

Both main and back up protection is provided on all primary plant and feeder circuits, the main protection being a fully discriminative type. Below 275 kV back up protection is provided by IDMT Overcurrent relays; at 275 kV and 400 kV a 'second main protection' is provided, which is fully discriminative. Back up protection possesses its own CTs and relays.

7.3 Overcurrent Protection

As pointed out in the introduction to the previous section, when power systems increase in extent and capability fault currents become large and it is no longer sufficient to discriminate between distant faults and faults close–up to the source of supply simply on a time basis. Equipment close to the source would carry too large a current for too long a time.

It is therefore necessary to combine current grading with time grading to achieve minimum operating time for all the relays on the system. This is achieved by having relays with an inverse time–current characteristic so that the larger the fault current the shorter the time of operation. Overcurrent relays can have characteristics of various shapes from normal inverse to extremely inverse to assist grading between relays and to grade with fuses, which also have an inverse characteristic.

Typical relay inverse time–current characteristics are shown in Figure 101. A one–line diagram of the system and its protection is combined with time against fault current for each of the three relays, R1, R2 and R3.

For example, relay R3 operates in 0.23 s for a fault current of 1100 A at the relay point. Further down the line protected by R3, the operation time is 0.34 s for 500 A. The real significance of the inverse characteristic however is seen in comparing the operating times for R3, R2 and R1. Relay R2 can also operate for a fault of 1100 A at relay point R3, but in 0.48 s. The difference in time between operation of the relays R3 and R2 is 0.25 s for a fault at relay point R3. This time allows for operation of the relay and circuit breaker at R3. The operating time of relay R2 at relay point R2 is 0.33 s for a fault of 2300 A, which is less than 0.48 s but greater than the shortest operating time of 0.23 s for relay R3.

A more dramatic reduction in operating time due to the inverse time characteristic is seen by comparing relays R1 and R2. A maximum operating time for relay R1 is defined by taking the minimum time of operation of relay R2 and adding 0.25 s, say, to allow for circuit breaker operation. Thus, at relay point R2 and a fault current of 2300 A relay R1 has a maximum operating time of (0.33 + 0.25) s, which is 0.48 s. But due to the inverse characteristic of relay R1, the minimum operating time at relay point R1, for a fault current of 13000 A, is 0.24 s. This time is less than the minimum operating time of R2 and comparable to that of R3.

In some cases the minimum operating time at relay point R1 may not be considered short enough. In such cases an additional relay will operate due to the decrease in voltage at relay point R1 for close–up faults. These relays are called voltage controlled Overcurrent relays.

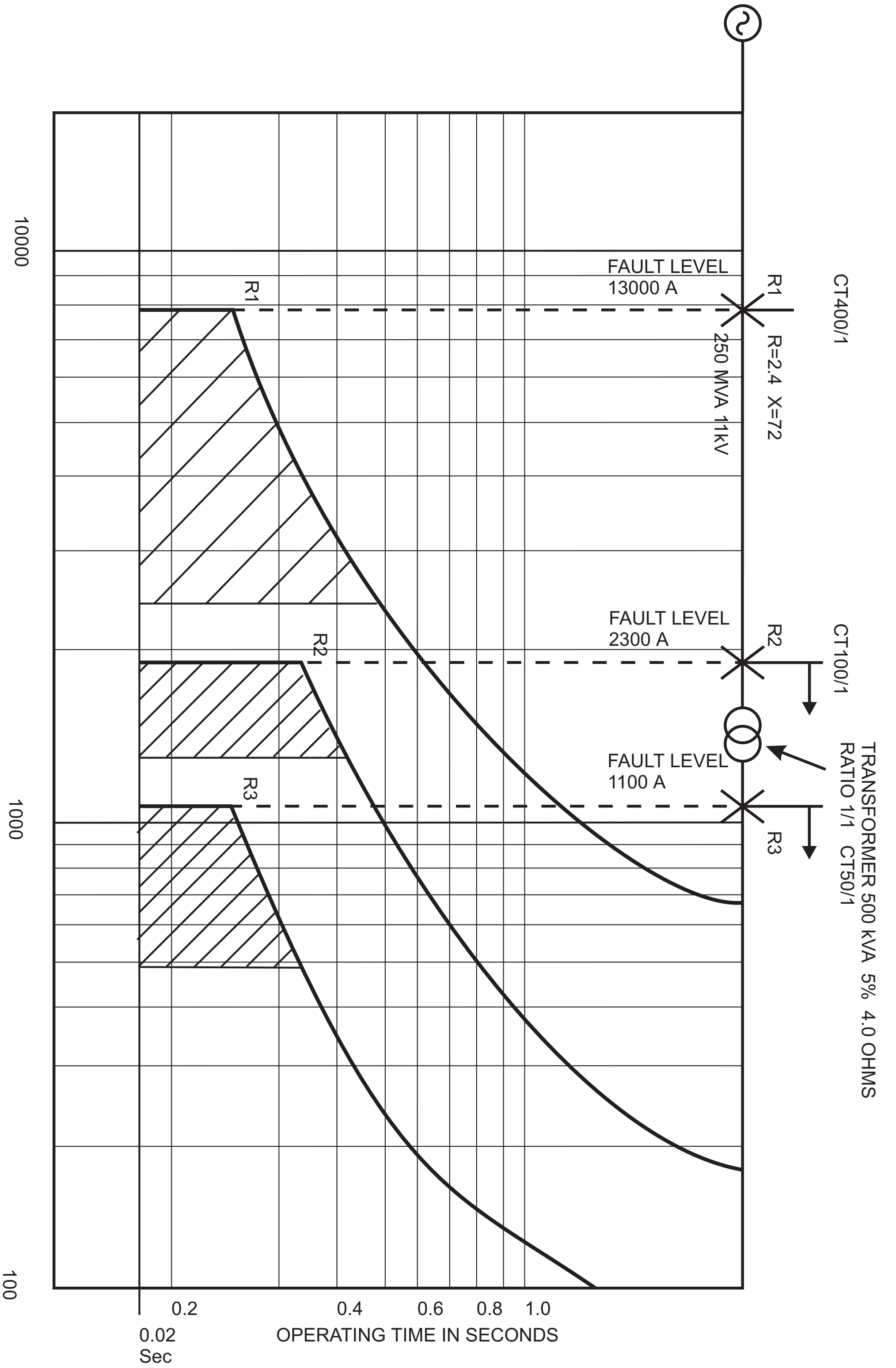


Figure 101 Overcurrent Grading

Experiment 12: Grading of Overcurrent Protection for Three–Phase Faults

A system similar to the system illustrated in Figure 102 can be set up and studied on the Power System Simulator. A one line diagram of the system on the Power System Simulator is shown in Figure 102.

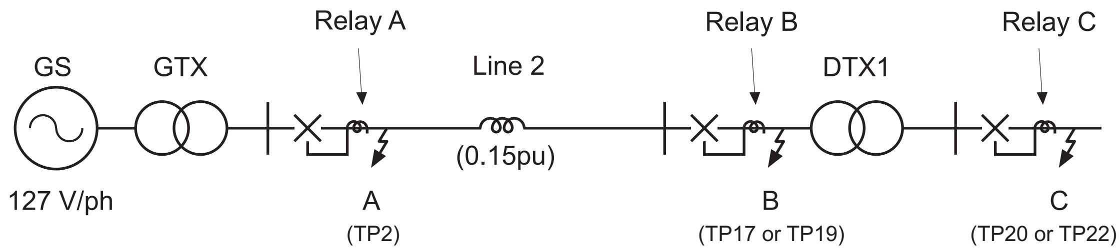


Figure 102 Experimental Study 12

All impedances are represented by reactances. System quantities referred to 220 V, are typically:

Grid supply voltage	: 127 V/phase	
Grid transformer reactance	: 1.38 Ω	
Line 2 reactance	: 3.70 Ω	
Distribution transformer reactance	: 3.60 Ω	Total = 8.70 Ω (TXs)

Note that the reactances of the Line and Transformers are not exactly the same for each Simulator. Given values of reactances are approximate or mean.

Relays:

The relays within the system and associated current transformers (CTs) are:

Relay C	:	MiCOM P142. Position RD1–B.
		Voltage 110 V(line), CT ratio 14/l
Relay B	:	MiCOM P142 Position RD1–A
		Voltage 220 V(line), CT ratio 7/1
Relay A	:	MiCOM P122 Position RGTB
		Voltage 220 V(line), CT ratio 10/1

The standard inverse curve for the MiCOM relays in all relay manuals as the IEC Standard Inverse Curve, is reproduced in Figure 103.

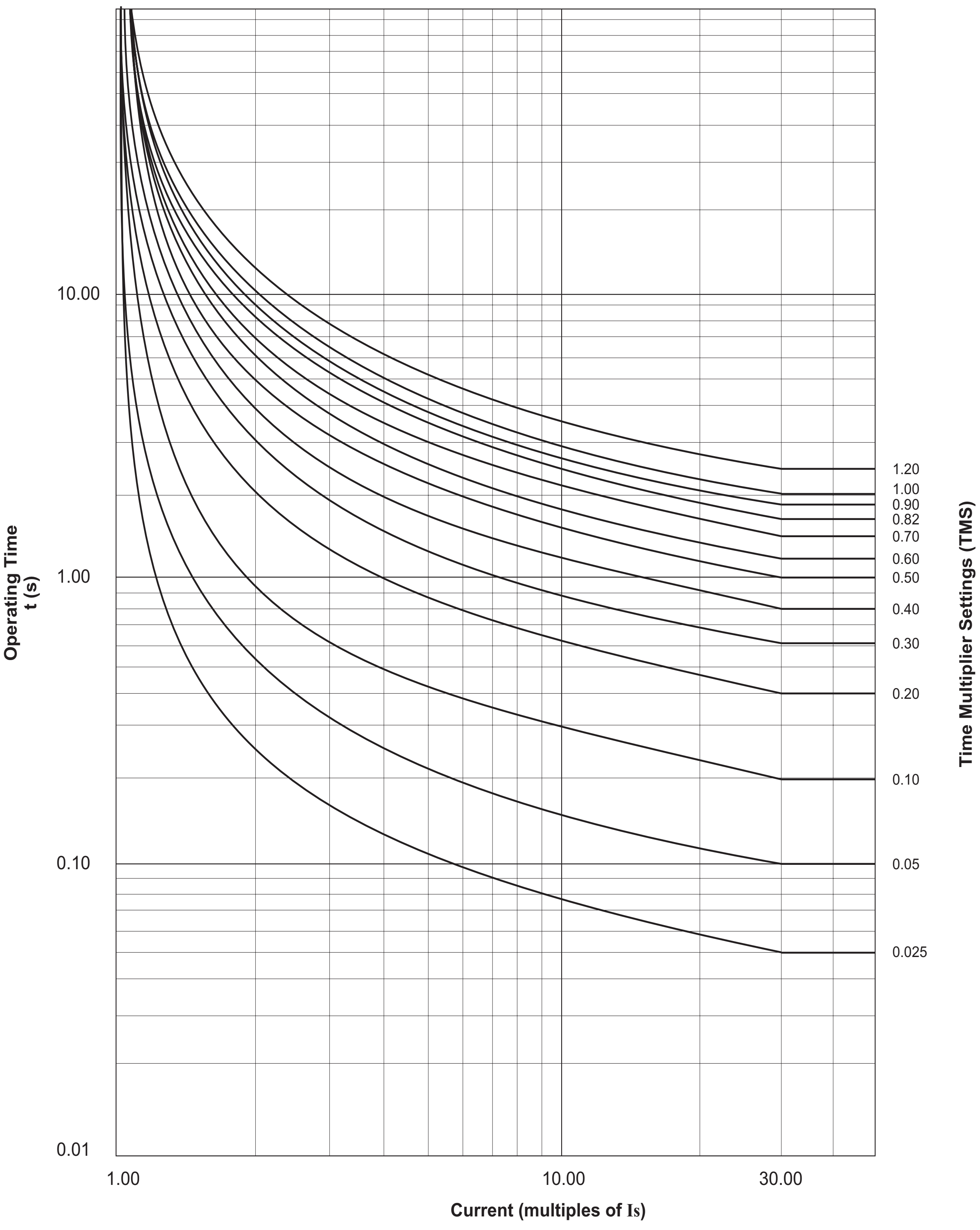


Figure 103 Characteristic Curve SI x 30DT Standard Inverse (moderately inverse) – Definite Time Above 30×Is

Procedure for Setting the Relays

Part (A) Phase Faults

Phase–phase-phase faults normally give the maximum fault current for which the relays should operate in the shortest possible time and with satisfactory grading with other relays. Other phase faults will produce less fault current and slower operating times.

Relay point C (Fault Point TP20)

The total reactance to the point of fault is: 8.7 Ω

Thus the fault current at C = (127/8.7 Ω)

= 14.60 A at 220 V

= 29.20 A at 110 V

∴ CT secondary current = 29.20/14 = 2.09 A

Consider the relay characteristics in Figure 103. On the right hand side vertical axis are given the **Time Multiplier settings** (TMS). These are settings within the relay which enable the calculated setting for a TMS = 1.0 to be proportionally reduced (i.e. TMS = 0.5 indicates operation in half the time calculated).

Note that the axes of the characteristic are log–log. The numbers along the X–axis are multiples of the threshold current, or setting current, Is, on the secondary side of the CT. The relay will operate only above the setting current. This current is obtained by finding the maximum steady load current in the system. The CT secondary current is then found by dividing the load current by the CT ratio. This should come to about 1 A for a 1 A rated CT. The value obtained is normally increased by 20% to give a margin of safety. However, in this case a setting current of 1.0 A would be acceptable, which means the CT primary threshold current is 14.0 A. Hence find the operating time for a secondary current multiplier of 2.09 (= 2.09/1.0), and a TMS of 1.0. The value obtained is about 9.5 s. For a minimum operating time choose the lowest TMS of 0.025. Thus the actual operating time of the relay is (9.5 s x 0.025) which is 0.24 s.

Summary

CT ratio	:	14/1
Current threshold for CT secondary	:	1.00 A
Setting multiplier	:	2.09 A
Time multiplier setting	:	0.025
Calculated operating time	:	0.24 s

Relay Point B

Relay B acts as a back-up to relay C for a fault at C.

The fault current at B due to a fault at C is 29.20/2, which is 14.60 A

The CT ratio at B is 7.0/1. ∴ CT secondary current = 14.60/7.0 = 2.09 A, which is also the setting multiplier if the threshold current is 1 A.

Time read from the relay characteristics for a setting multiplier of 2.09 and a TMS of 1.0 is 9.5 s

Allowing 0.3 s time grading between relay point C and relay point B to allow for relay and CT errors and circuit breaker operation, (see page 132 of N-PAG, ref 16) the calculated operating time for the relay at B is (0.24 + 0.30) s which is 0.54 s.

∴ The TMS setting required for relay at point B is = 0.54/9.5 = 0.057

The nearest TMS setting is 0.050, giving and actual operating time of 0.48 seconds.

Summary for Relay B

CT ratio:	7/1
Current threshold for CT secondary:	1.0 A
Setting multiplier:	2.09
TMS:	0.05
Operating time:	0.48 s

Relay point A (Fault Point TP2)

Relay A acts as a back-up to relay B for a fault at B (TP17).

The fault current at A due to a fault at B is (127 V/5.08 Ω), which is 25 A.

At point A the CT ratio = 10/1 ∴ CT secondary current = 25/10 = 2.5 A.

At point B the fault current is also 25 A. For relay B the secondary current threshold is 1.0 A (i.e. a primary current of 7 A), and the setting multiplier on the x-axis of the relay characteristics (Figure 103) is calculated as (25 A/7 A) = 3.57 A.

Thus the time of operation of relay B, for a fault at B, may be obtained from the relay characteristics for a TMS of 0.05 as approximately 0.28 s.

For relay A, also with a secondary current threshold of 1.0 A, a setting multiplier of 2.5 and a TMS of 1.0, the operating time is seen form Figure 103 to be about 8 s. Hence, allowing once again 0.30 s time grading between relays, the actual operating time of relay A should be (0.28 + 0.3)s which is 0.58 s. The TMS setting required for the relay at point A is, therefore = 0.58/10 = 0.058. The nearest TMS is 0.05.

This value of TMS can be entered into the P122 relay.

Summary

CT ratio:	10/1
Current threshold for CT secondary:	1.0 A
Setting multiplier:	2.5
TMS:	0.05
Operating time:	0.40 s

Note that the operating time of relay A for a fault at A would be much smaller than 0.40 s.

Part (B) Earth Faults

These tests are to be carried out with relays D2A and D2B

For correct relay operation in the case of an earth fault on any phase at test point TP22, new values of TMS have to be calculated and entered together with other information as above, into the Earth Fault (2) menu of relays D1A and D1B at relay points B and C, respectively.

The current thresholds and TMS values are obtained by calculating the fault current by the method of symmetrical components.

Relay Point C

Calculation of the fault current I_F, should be carried out as shown in the worked example of Section 6 Figure 83.

The fault current is given by:

$$I_F = \frac{3 \cdot E}{Z_0 + Z_1 + Z_2}$$

For a fault at relay point C, $Z_1 = Z_2 = 8.7\ \Omega$, as before. Z_0 is equal only to the zero sequence reactance of the earthing transformer, which is negligibly small.

Thus,

$$Z_{total} \approx Z_1 + Z_2\ \Omega = 2Z_1 \text{ and } I_F = 3E/2Z_1 = 1.5\ E/Z_1$$

Hence, I_F is equal approximately to 1.5 times the three phase fault current.

The three phase current, from initial calculations is 29.20 A. Hence I_F = 1.5 x 29.20 = 43.80 A. Hence the CT secondary fault current is (43.80 A/14), which equals 3.13 A. From the relay characteristic in Figure 103, the operating time for the relay is 0.28 s for a secondary threshold current of 1 A and a fault current of 3.13 A at a TMS of 0.025.

A fault current of 43.80 A is a very large current and it is recommended that a 1 Ω resistor on the front panel of the simulator is inserted in the earth connection of the earthing transformer to reduce the fault current to about 30.0 A. The relay will still operate very positively in a time of about 0.30 s.

Relay Point B

This relay should be set as a back up to Relay C for a fault at C, TP22.

In this case only the positive and negative components of current, I_1 and I_2, can flow through the Relay at B. The zero phase sequence current circulates only through the earthing transformer on the secondary side of the distribution transformer.

Symmetrical component analysis shows that at the point of fault, $I_1=I_2=I_0$, so that on the primary side of the distribution transformer the current in the faulted line is (I_1+I_2), which is equal to $2/3I_F$. The fault current on the primary side of the distribution transformer is (30 A/2) which is 15 A. Thus the fault current at Relay B is 2/3 of 15 A, which is 10 A.

The CT secondary current is (10.0/7) A, which is 1.43 A. The relay characteristics in Figure 103 give an operating time for the relay of approximately 1.0s for this value of current, a threshold current of 1.0 A and a TMS of 0.05.

Note that Relay A will not act as a 'distant' back up as the CT ratio for A is 10/1. So the relay current may be below threshold of 1 A.

Relay Point A

The relay at A should act as back up to Relay B for a fault at B (TP18).

Symmetrical component analysis for this fault situation is given in Part C of Experiment 8: Unbalanced Faults. If a fault to earth is applied at TP18, fault current can circulate through the star points of both the grid transformer and the distribution transformer. But only the current from the Grid transformer will flow through the CTs for the Relay D1A at Position B.

Analysis of the faulted circuit gives $I_1 = I_2 = I_0 = 11.6$ A. It also shows that a ground current of 16 A flows to the star point of the distribution transformer, and a ground current of 15 A flows to the star point of the grid transformer.

Relay B has an earth fault setting threshold of 1.0 A, a TMS of 0.05 and CTs of 7/1, so that the operating time for a relay current of (15 A/7) = 2.14 A is, therefore 0.48 s. Allowing 0.30 s time grading between relays B and A, the operating time for Relay A is 0.70 s. Relay A has 10/1 CTs. A trip time of 0.90 s can be obtained for a relay current of 15/10 A = 1.50 A with an earth setting threshold of 1.0 A. and a TMS of 0.05.

For a fault at TP2, close to Relay A, the estimated, total earth fault current is 56.0 A and the Grid transformer earth current is 40 A. The estimated trip time for relay A with the above settings is 0.070 s! Earthing resistance or reactance should always be used to limit fault current for close-up faults to the Grid supply.

Setting the P142 Relays for Overcurrent Protection

Refer to Section 3 of this Manual for a general description of the P142 Relay and for accessing the relay menu via the relay front port.

Enter the following settings into the relays. RD1B and RD2B have the same overcurrent settings. RD1A and RD2A have the same overcurrent settings. On the PC provided with the Simulator, access MiCOM S1 and open the Settings screen. Under ‘File’ find the relay address and double click to enter the menu. The main headings required are ‘Configuration’, ‘CT and VT Ratios’ and ‘Group1’.

Configuration Settings

The following settings should be entered for all four relays:

Active Settings	Group 1
Settings Group 1	Enabled
Earth Fault 1	Disabled
Earth Fault 2	Enabled

Note: for Earth fault 1 the residual current is measured directly from the system by a CT in the earth connection. For Earth fault 2 the residual current is calculated from the measured three phase currents. There are no CTs on the Distribution transformer earth connections, so Earth Fault 2 is used.

CT and VT Ratios

	RD1B + RD2B	**RD1A + RD2A**
Main VT Primary	110V	220V
Main VT Secondary	110V	110V
Phase CT Primary	14A	7A
Phase CT Secondary	1A	1A

Group 1.

Click on 'Group1' to show Application Headings. Select 'Overcurrent' – double click to show settings.

Enter the following:

Function	IEC S Inverse	IEC S Inverse
I>1 Direction	Non Directional	Non Directional
I>1 Current Set (Prim)	14 A	7 A
I>1 TMS	0.025	0.05

Earth Fault 1

Function	IEC S Inverse	IEC S Inverse
IN>1 Current	14 A	7 A
IN>1 TMS	0.025	0.05

Setting the P122 at position RGTB

The P122 Overcurrent Relay is the simplest relay on the Simulator. It has a simple, clearly written Technical Manual. It is best to start with this relay if you are unfamiliar with the relays on this apparatus. Most of the relays are accessed by the front port and their settings changed on the PC with S1 software, the P122 Menu is simple enough to be accessed by the front key pad.

The Menu contents description is presented in the Areva Technical Manual. The important sub menus are Configuration, Protection and Broken-Conductor. To get the Configuration and the Protection press ⇓ (to Output Parameter which requires the normal AAAA Password for entry) then ⇒ for Configuration and, by further ⇒ to Protection. Broken Conductor is found under the Automatic Ctrl Menu. Go ⇓ from this Menu and then ⇒ until Broken Conductor is found. Go ⇓ to enter settings. See Chapter 3-2 of the Areva Technical Manual.

P122 Settings

See Section 3 for an introduction to this relay.

Configuration Settings

<table>
<tr><td>Group Select</td><td colspan="2">Group1</td></tr>
<tr><td rowspan="2">CT Ratio</td><td>Line CT primary</td><td>10A</td></tr>
<tr><td>Line CT Sec</td><td>1A</td></tr>
<tr><td colspan="3">Check phase rotation is ABC</td></tr>
<tr><td colspan="3">I >? Yes, I> 1.0In</td></tr>
</table>

Earth Fault 1

Function Ie>	Yes
Ie>	1.0 Ien
Delay Type	IDMT
Idmt	IEC S1
TMS	0.05

Broken Conductor

Broken Conductor?	Yes
Broken Conductor Time	2s
Ratio I2/I1	20%

Now set one of the 4 selectable LEDs (5 to 8) to Broken Conductor. Find 'Led Broken Conductor' under 'Configuration'. Say 'Yes' and enter. See page 21/22 of Chapter 3-1 of the P122 Technical Manual.

Procedure

Phase Faults (Use Distribution Transformer 1 circuit)

1) Set up the three relays in accordance with the settings calculated above and with reference to the relay manuals.

2) Connect the timer CB at test point TP20. Set the timer to, say, 1.5 s. Block the instantaneous trip at relay D1A and Instantaneous trip >2 at D1B.

3) Close CB20, CB23 and CB25.

4) Apply a fault at TP20 (fault point C). The relay at C(D1B) should operate.

5) If relay at C is blocked, applying a fault at C should cause relay at B (D1A) to operate.

6) If both relays C and B are blocked, applying a fault at C will cause A to operate.

7) In steps 5 and 6 it is possible to sense from the relay operational LEDs the time grading between relays B and C! From the Disturbance Measurements and Records 1 records within the menus of relays B and C it is possible to check the fault current duration, CB operating time and relay trip time.

8) If a fault is applied at B (TP17), relay B should operate.

9) If relay at B is inhibited, applying at fault at B should cause the relay at A to operate.

Earth Faults (Use Distribution Transformer 2 circuit)

10) Block I>1, I>2 and close CB24. Applying a fault at TP22 will cause relay C to operate.

11) Blocking relay C (In>1) and applying a fault at TP22 should cause relay B to operate.

12) Applying a fault at TP18 should cause relay B to operate (block I>2).

13) Applying a fault at TP18 and blocking relay B should cause relay A to operate.

Experiment 13: Multi–Shot Auto–Reclose

Auto-reclosing of circuit breakers helps to maintain continuity of supply in the event of transient faults. 80-90% of faults on any overhead transmission line are transient. Only a single reclosure ('single shot') is used in EHV transmission systems due to considerations of system stability, but in distribution systems, 'multi–shot' reclosures are used, as 80% of all faults are transient. In an auto–reclose cycle the circuit breaker may open and reclose a specified number of times before 'locking out' (staying open, reclosure prevented). Figure 104 shows the time sequence and events in a single shot auto-reclosure scheme. Refer to Chapter 14 of Reference 16 for a fuller discussion of auto-reclosing.

The initial trip by the circuit breaker is usually instantaneous to minimise damage at the fault location. After a set time delay, a 'dead time', the circuit breaker recloses automatically, the instantaneous protection is inhibited and IDMT protection is made operative, to try and 'burn off' the cause of the fault.

If the fault is still on, the IDMT relay operates and the breaker opens again. A second reclosure follows after another 'dead time'. If the fault has been removed the second reclosure is successful. If the fault is still on, the IDMT operates once again. For a 'two shot' cycle, operation of the IDMT is followed by a lock out.

Procedure and Setting the RD2B Relay

The MiCOM P142 relay in the right hand branch of the distribution system, position RD2B, possesses an auto-reclose element. The auto-reclose relay operates circuit breaker CB26. A 'transient' line fault is applied at test point TP23. To use the auto-reclose, press the auto-reclose button. For further information, see chapter 2 of the P142 Technical Manual.

Settings can be entered into the RD2B relay via the PC and relay front port. TQ suggest that the following settings are entered:

Configuration

Auto-reclose	Enable

Group 1 Auto-reclose

Number of shots	3
Dead Time 1	3s
Dead Time 2	5s
Dead Time 3	5s
CB Healthy Time	20s
Start Dead Time on	Protection resets
Reclaim Time	5s
Trip1 Main	No Block
Trip 2 Main	No Block
Trip 3 Main	Block Inst Prot.
I>1 and I>2 (Idmt)	Initiate Main AR
IN2>1 IN2>2 (DT)	Initiate Main AR
Note: The operation of (DT) is instantaneous	

The reclaim time is the reset time of the relay following a successful reclosure. Dead times vary according to application, from 0.3 s for motors up to 10 s for industrial and domestic consumers.

To demonstrate the automatic operation of the relay, manually remove the fault by switching the fault application breaker, during either of the two dead times.

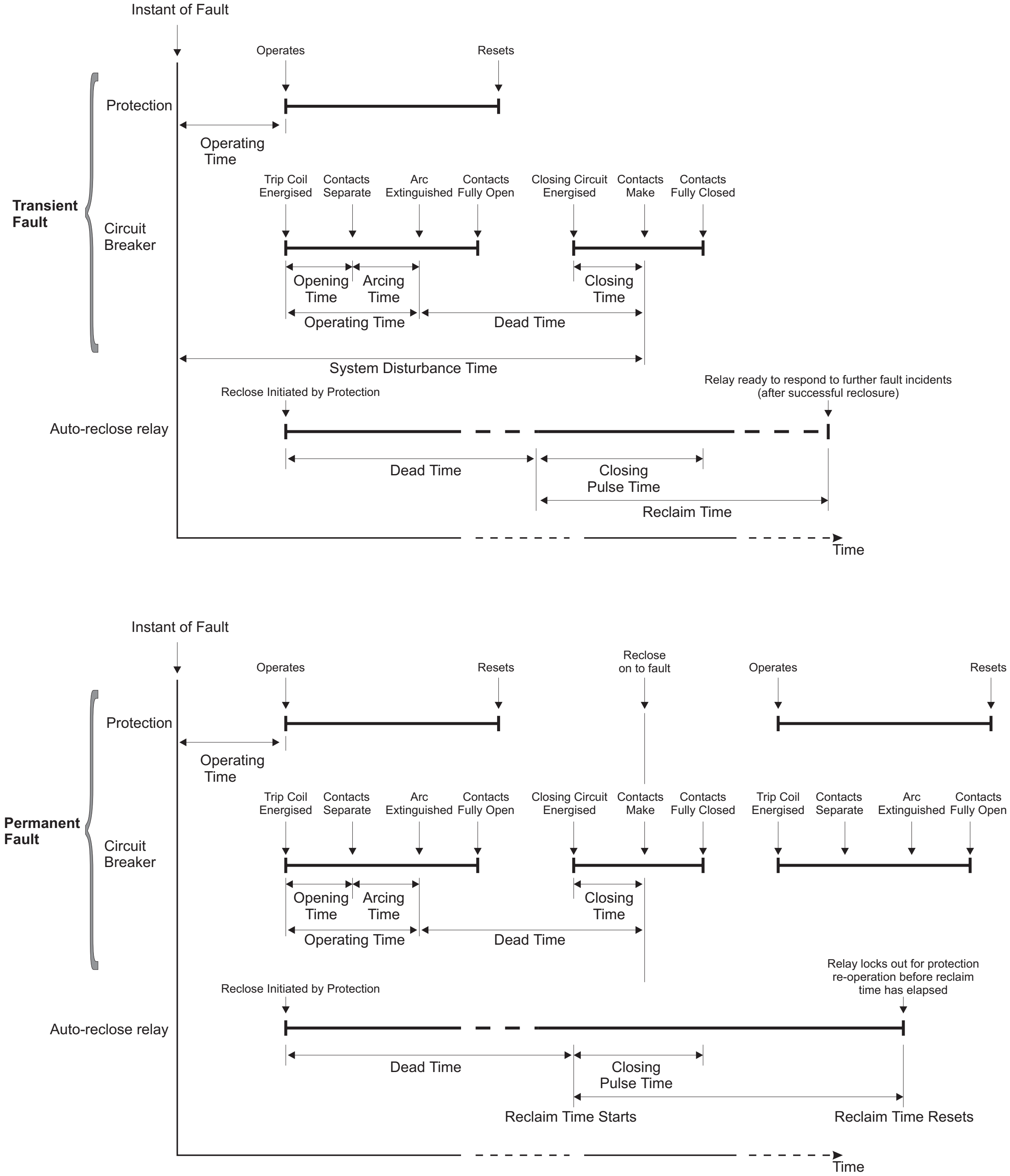


Figure 104 Single Shot Auto Reclose Schemes for a Transient Fault and a Permanent Fault

Experiment 14: High Set Instantaneous Settings

The MiCOM P142 relays have four stages of overcurrent settings, which can be set to a variety of IDMT or DT settings. By using a combination of these settings, it is possible to shorten the operating time of all relays in a graded sequence, such as Relays A, B and C in Figure 102. One such application takes advantage of the change in fault level between the LV and HV sides of a transformer. For example, the through fault current for a phase–phase-phase fault on the utilisation bus is about 29 A. This is the maximum current that will be obtained for a through fault on the LV side. The equivalent current on the HV side is 15 A. Therefore, if a fault occurred on the HV winding of the transformer, the relay can be set for instantaneous operation at a fault current higher than 16 A, normally about (1.3 x 16 A) = 20.8 A. The shorter time setting can limit fault damage to the transformer.

This operational situation can be investigated on the Simulator by setting a Definite Time element of relay RD1A, on the primary side of the distribution transformer DTX1, to about 20 A or a CT secondary current of 20 A/7 = 2.86 A. The operating time of the relay element should be set at zero. Relay A, at position RGTB, could now be graded with the instantaneous element of Relay B, thus considerably reducing the operating time.

If a fault is applied at TP20, with relay RD1B inhibited, relay RD1A will operate after a delay (i.e. time graded). However if a fault is applied at TP17, relay RD1A should operate instantaneously.

Setting the RD1A Relay for High Set Operation

Group 1 Overcurrent	
I>2 Function	DT (Definite Time)
I>2 Current Set	20 A

Group 1 Earth Fault 2	
IN2>2 Function	DT (Definite Time)
IN2>2 Current	20 A

Experiment 15: Back Tripping

In the previous experiment it should be noted that if a fault occurs at TP20, with the IDMT element of relay RD1B blocked, CB25 will not operate to clear the fault. In this event relay RD1A should operate to clear the fault, but after a longer delay due to time grading.

To overcome this 'malfunction' of CB25, a back–trip signal can be sent from relay RD1B to the next circuit breaker towards the source, in this case CB23. Thus set relay RD1B to produce a back–trip signal after a time of, say, 20% longer than the calculated normal operating time.

Note: To use the back-trip function, press the back-trip enable pushbutton on RD1B.

When these settings have been made, CB23 will open for a fault at TP19 in a shorter time than the calculated time–graded operating time of relay RD1A and CB 20.

Back Trip Settings RD1B, RD1A relays

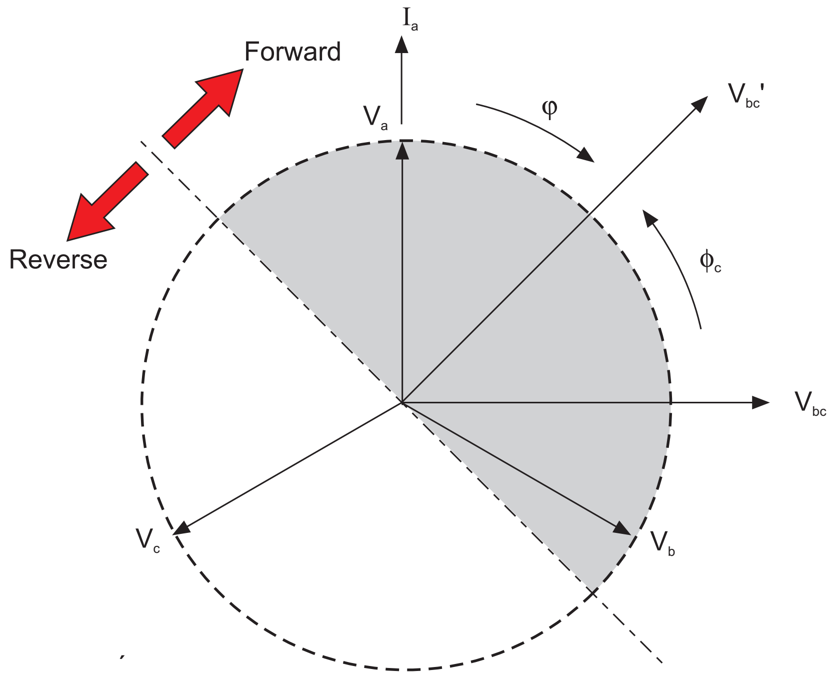
Back Trip RD1B to CB23	
Configuration	
CB Fail	Enable

Group 1 CB Fail	
Configuration	Enabled
CB Fail 1 Timer	100 ms

Experiment 16: Directional Control of Relay Tripping

Overcurrent relays are made directional by multiplying the current by a 'polarizing' voltage. The product of the two quantities has a maximum value along an axis coincident with the direction of the polarizing voltage phasor and decreases to zero 90° either side of that axis. The directional decision given by the product of these quantities is applied in the relay software after the current threshold and before the following associated time delay.

In the Micom relays, as in most other relays, phase fault directional elements are polarized by the quadrature line voltage and the earth fault elements are polarized by the zero sequence voltage.



$V_{bc'}$: Axis of maximum directional sensitivity
ϕ_c : Characteristic angle
φ : Lagging phase angle of I_a

Figure 105 Directional Characteristics of Overcurrent Relays

Thus, for the line current Ia in Figure 105, the polarizing voltage is V_{bc}. For most system loads Ia lags the phase to neutral voltage Va by -45°to -60°. It is therefore desirable that the axis of the directional element is phase shifted to achieve a maximum directional signal along the actual current axis. This is obtained by phase shifting the polarizing voltage V_{bc} within the relay software.

The phase angle between the line current I_a and the polarizing voltage V_{bc} is called the characteristic angle setting, ϕ_c. This is the angle through which V_{bc} is phase shifted. Thus for most practical purposes ϕ_c will be set to an angle of +30° or +45° for the phase elements. The angle ϕ_c for earth faults depends on the method of earthing and the chapter entitled Application Notes in the Technical Manual for the relays should be consulted. For phase faults the polarizing voltage threshold is fixed at 0.5 V but is variable for earth faults.

Application to Parallel Feeders

Figure 106 shows a typical distribution system using parallel transformers.

Relays R3 and R4 may both have a non-directional overcurrent stage set to trip for a fault on the low voltage (LV) busbar, or as back-up to relays on outgoing feeders. The HV, upstream relays will have a longer operating time than the LV, downstream relays that are closer to the fault. However, if a fault occurs between the LV winding of a transformer and the relay, both transformers will still trip. This can be prevented by use of a second overcurrent stage with directional control. If relays R3 and R4 have a second stage set to operate very rapidly for fault current flowing towards the transformer LV windings, only the faulted transformer branch will trip.

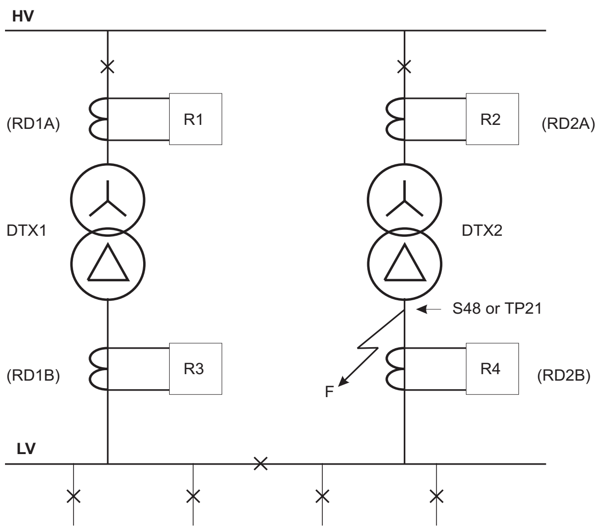


Figure 106 Typical Parallel Transformer Distribution System

Directional control of relays in the protection of parallel feeders, without transformers, can be demonstrated on the Simulator. Connect the Grid Supply to Line 2 and 3 as shown in the connection diagram for Experiment 16. Lines 2 and 3 can represent either transformer reactances or feeder reactances. CB22 is to remain closed and CB23 and CB24 are to remain open throughout this experiment.

Within the overcurrent menu of relay RD1A and relay RD2A select settings of 'direction reverse'.

Apply a phase-phase-phase fault at line 3, via the timed fault CB. The Timed Fault CB acts as an upstream relay and CB in removing the faulted transformer or feeder. Set the Timer to 1.0 s. The Relay RD2A should operate but not RD1A.

It may be interesting to try 'forward' and 'non-directional' settings in one or both relays, for comparison.

Alternative Experiment

This experiment can also be carried out on the Distribution Transformers by applying a phase-phase-phase fault at TP21 (see Figure 106). The Grid supply transformer is connected to both Distribution Transfomers by means of Line 2. TP21 is located between the relay RD2B and the transformer DTX2. Relay RD2B trips the circuit breaker CB26, located downstream of relay RD2B.

If, therefore relays RD1B and RD2B were set for non-directional overcurrent, both CB25 and CB26 would open for a fault at TP21. Both transformer branches would then be open circuit. But, if both relays were set for reverse direction overcurrent, only relay RD2B would trip, preventing further fault current flowing through transformer DTX1. Relay RD2A should then trip, opening CB24 and removing transformer DTX2 from the system. The Utilisation Bus could still be supplied through transformer DTX1.

7.4 Distance Protection

Distance protection of transmission lines and feeders may be classed as either unit or non unit protection. Tripping is for the most part instantaneous on detection of a fault, yet its reach, like overcurrent protection, can extend into other zones. Generally it is classed as non–unit since there is no comparison of quantities at zone boundaries.

Theory

The distance relay in its simplest form consists of a unit which divides the voltage at the sending end terminal by the current at the same location, on a phase–by–phase basis, via the appropriate instrument voltage and current transformers. This function is indicated in Figure 107, albeit by an outdated electromechanical balanced–beam type relay. The balanced beam will swing over to the right–hand side to close a contact (not shown) leading to circuit breaker tripping where:

$$\frac{V}{Z_{\mathrm{R}}} \leq I \text{ or } \frac{V}{I} \leq Z_{\mathrm{R}}$$

Thus, relay operation gives a direct indication of the fault position, measured in ohms of line impedance, from the relay location. Figure 107 illustrates this system overall operation. It ought to be mentioned however that the relay determines only whether the ohmic distance to the fault is less than a given value, i.e., the relay setting, and operation to trip occurs only when this measured value is less than the setting. It would be desirable to select this relay setting to coincide with the distance to the end of the protected feeder. Unfortunately this is not possible due to the extraordinary high measurement accuracy that would be required.

Consider a feeder of 20 km long having an impedance of 0.37 Ω per km. The impedance from the relay location to the distant line extremity would be:

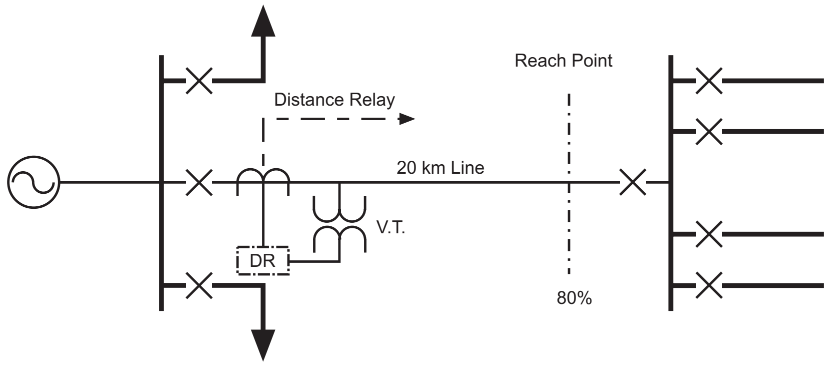
Z_L = (20 x 0.37) = 7.4 Ω

An error of even 1% would correspond therefore to a physical distance of:

1/100 x 20 km = 200 metres

This shows that an overreaching error could cause incorrect operation for faults in the first 200 metres of those feeders connected to the remote end busbar. This risk is unacceptable and indeed the actual accuracy of a typical distance relay system approaches 10–15% when the accuracy of the associated current and voltage transformers is also taken into account. It is thus customary to set the distance relay to operate for faults up to only 80% of the protected line length. This is referred to as the 1st zone.

It is apparent however that the amplitude type comparator described has no directional properties (Figure 107). Whether the current flows from busbar to line, or from line to busbar the relay will operate. To make the relay directional an additional directional relay may be added. However, a better solution exists. The 'MHO' type relay combines distance measuring and a directional feature in one unit. This is achieved in the Mho relay by comparing not simply V/I with Z_R, as before, but by comparing (V/I - Z_R), or (Z_F - Z_R) with Z_R. Z_R is the replica or relay impedance, which is fixed. Z_F is the fault impedance. The **threshold** of the relay occurs when (Z_F - Z_R) = Z_R and the locus of the threshold is a circle radius Z_R. This is shown in Figure 108.



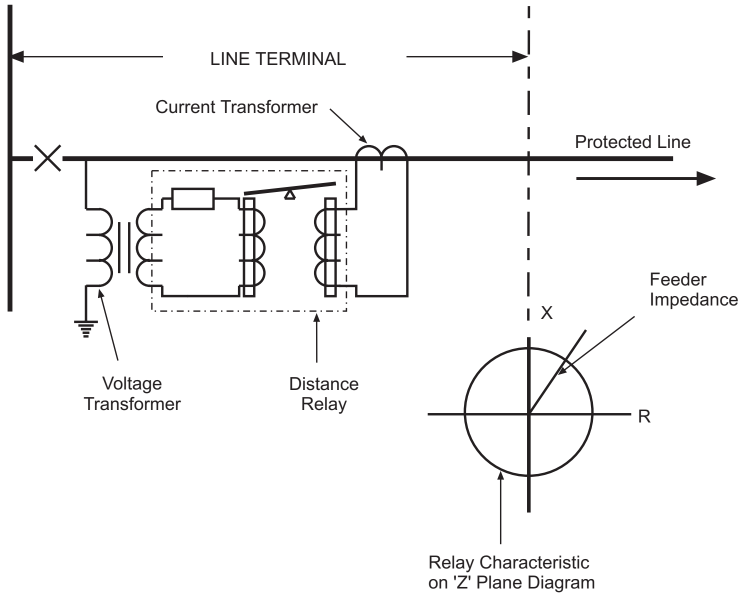


Figure 107 Distance Relay Function

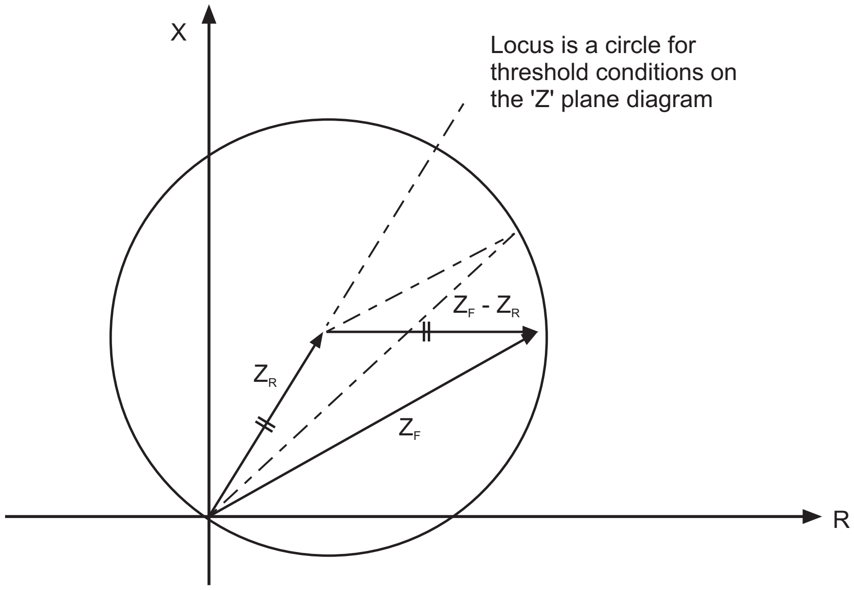


Figure 108 Locus of the Threshold

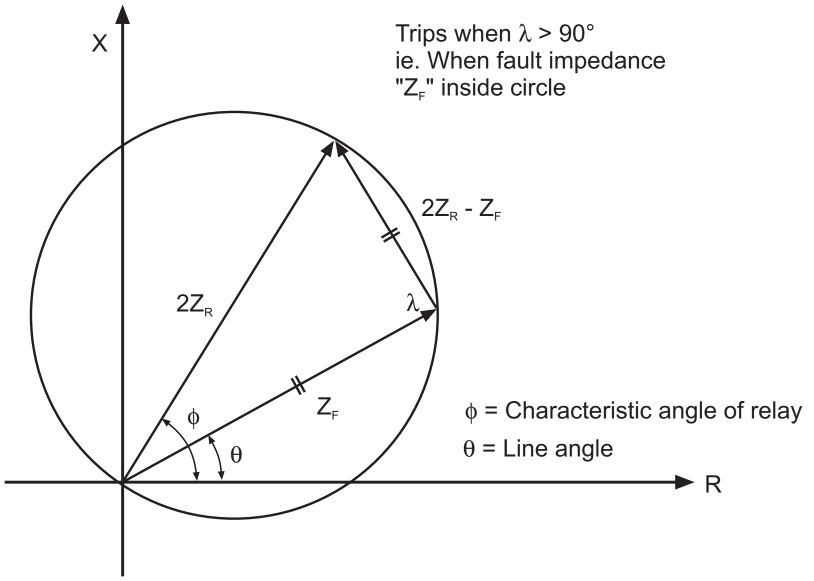


Figure 109 A Comparison of the Phase Angle λ Between Two Quantities

The phase angle λ between two quantities, Z_F and ($2Z_R$ - Z_F) are compared as shown in Figure 109. The threshold is given by $\lambda = 90°$. The relay operates when $\lambda > \pm 90°$.

Static and digital relays, such as the Quadramho and Optimho, which replaced electromechanical relays, are phase comparators. In these relays, the two inputs are called S_1 and S_2 where:

$$S_1 = V - IZ_n$$

$$S_2 = V$$

I is the fault current. Z_n is the impedance setting of the relay and equals $2Z_R$.

In all impedance relays the variable arc resistance at the point of fault causes difficulties in achieving consistency and accuracy of measurement and causes the relay to under-reach (i.e. length of line protection is less than the relay setting). See References 9 or 16. This can be overcome by using a reactance relay, which measures only the reactive component of the line.

However, when the fault resistance is of such a high value that load and fault current magnitudes are of the same order, the reach of the relay is modified by the value of the load and its power factor and it may either over-reach or under-reach.

The reactance relay has been superseded now by relays with quadrilateral characteristics, as shown in Figure 110. Most digital and numerical relays now offer this form of characteristic. The polygonal impedance characteristic is provided with forward reactive reach and resistive reach settings that are independently adjustable. In addition, the reactance characteristic of Zones 1 and 2 is arranged to swing about the reach point in such a way as to compensate for effects of pre-fault load flow and allow correct Zone 1 measurement. Note that Zone 3 is offset from the zero-reactance axis to cover the busbars behind the distance relay, as back-up to other protection. This region of Zone 3 is often referred to as Zone 4.

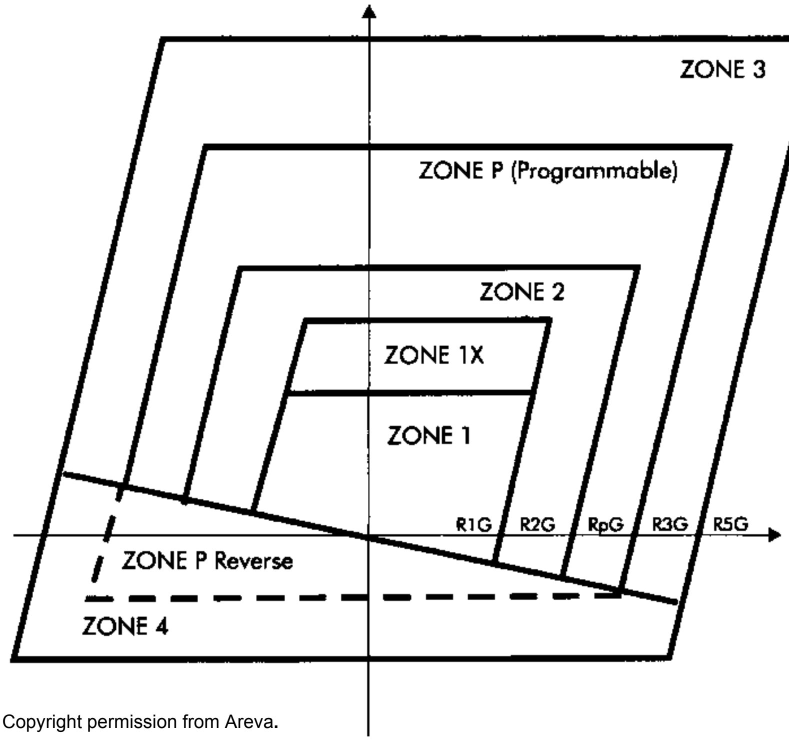


Figure 110 Earth Fault Quadrilateral Characteristics

The Three Zone Scheme

The most economical distance relays possess measuring elements only for Zone 1. These elements will trip instantaneously.

Earlier it was stated that for reasons of accuracy, the relay reach for the first zone of operation was set to 80% of the line length. In order to provide protection for the last 20% of the feeder a typical distance protection system would be provided with a detector (or starter) element to reach to the end of the following feeder as shown in Figure 111. The detector would not trip directly but would start a timer and would, after typically 0.4 second, extend the reach of the measuring element, if the latter had not already operated.

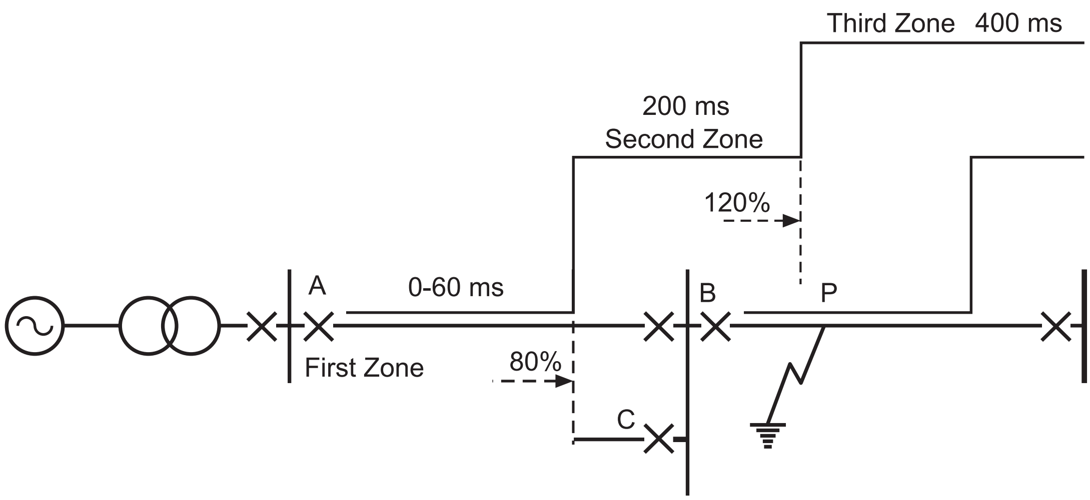


Figure 111 Three Zone Distance System

This zone extension process would increase the measuring unit's reach to typically 120–150% of the feeder length. This Zone 2 would cover faults occurring in the last 20% of the feeder and also in the first section of the next feeder. In the latter case the instantaneously acting measuring unit of the next feeder ought to have already operated to trip its own circuit breaker. The delayed action of the distance relay for the previous feeder may be regarded as back–up protection, as illustrated in Figure 111. Remote back-up protection for faults on adjacent lines can be provided by a third zone of protection that is further time delayed to discriminate with Zone 2. See Figure 111. On interconnected systems, fault current in-feed at the remote busbars will cause an increase in the impedance 'seen' by the relay and needs to be taken into account when setting Zone 3.

In modern digital and numerical relays, such as the MiCOM P442, timers are not used and each zone has 6 measuring elements: three for phase–phase faults and three for earth faults. This gives greater flexibility and speed of operation. The relay has, therefore, 18 measuring elements and is known as a 'full scheme' distance relay. Such relays can be used on EHV and HV lines.

In interconnected power systems, a distance relay is rarely applied to a single, long line. It is more likely to be parallel lines, multiple infeeds at busbars, and 'teed' feeders. The challenge to protection engineers is how mathematically to apply the relay to provide accurate discriminatory protection. Modern distance protection schemes are often greatly assisted by communication links between relays, forming, in effect, unit protection schemes.

As an example, a common problem is the shortening effect of the second zone coverage of the following feeder due to parallel infeeds. Consider for example a fault occurring on the second feeder a short distance in front of the distance relay at B, say point P in Figure 111. A voltage drop will occur from the breaker B to the point of fault due to any other fault current via breaker C as well as the current fed directly from A.

The additional voltage drop due to current from C will not be seen by the relay A, but the voltage contribution itself from B to P will be seen by the relay A. Thus a fault at P may be seen as being closer to relay A than is actually the case. The relay is said to under-reach.

Residual Compensation For Earth Faults

Distance relays operate for three–phase faults, line–line (or phase) faults or earth faults. For phase faults it is necessary to measure line voltages and delta currents so that the relay may 'see' the positive sequence impedance of the line. Thus, for phase faults,

$$Z_{\text{seen}} = \frac{V_{\text{a}} - V_{\text{b}}}{(I_{\text{a}} - I_{\text{b}})} = Z_1$$

For earth faults the determination of Z_{seen}, is not so straightforward because of the unknown nature of the 'fault loop' from the faulted end of the line to the supply earth(s). The current in the fault loop depends on the total impedance of the fault loop, determined by the method of earthing, the number of earthing points and the sequence impedances of the fault loop.

The voltage drop to the fault point is the sum of the sequence voltage drops between the relay point and the fault,that is

$$\mathrm{V_a = I_1Z_{L1} + I_2Z_{L1} + I_0Z_{L0}}$$

The current in the fault loop is given by:

$$\mathrm{I_a = I_1 + I_2 + I_0}$$

And the residual current, I_N , at the relay point is given by:

$$\mathrm{I_N = I_a + I_b + I_c = 3I_0}$$

Where I_a, I_b and I_c are the phase currents at the relaying point. From the above expressions the voltage at the relaying point can be expressed in terms of the phase currents at the relaying point, the transmission line zero sequence to positive sequence impedance ratio K, equivalent to Z_{L0}/Z_{L1}, and the positive sequence line impedance Z_{L1}.

$$\text{Thus } V_a = Z_{L1}\left[I_a + (I_a + I_b + I_c) \times \frac{K-1}{3}\right]$$

This analysis shows that the relay can only measure an impedance which is independent of infeed and earthing arrangements if a proportion $K_N = (K - 1)/3$ of the residual current, I_N, is added to the phase current I_a. This technique is known as 'residual compensation'.

Most distance relays compensate for the earth fault conditions by inserting an additional, replica impedance (Z) within the CT side of the measuring circuits. Whereas the phase replica impedance Z_1 is fed with the phase current at the relaying point, Z_N is fed with the full residual current. This is shown in simplified form in Figure 112.

It is shown in Reference 9, that if Z_N in Figure 112 is put equal to [(K - 1) Z1]/3, the sum of the voltages developed across Z_1 and Z_N equals the measured phase-to-neutral voltage in the faulted phase.

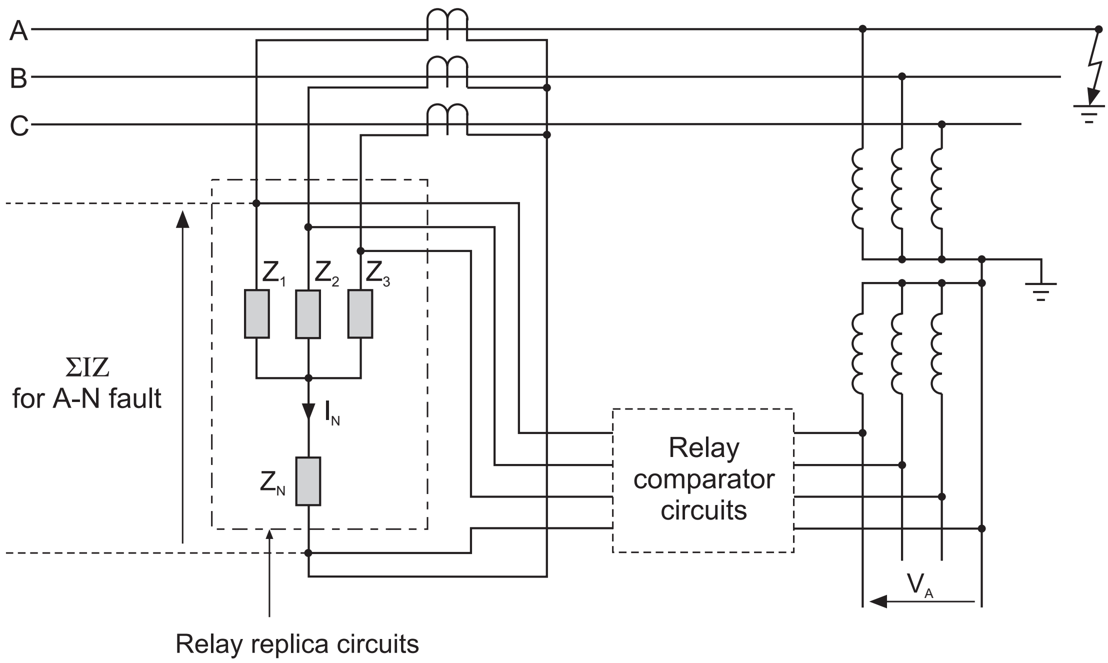


Figure 112 Earth Fault Relay Current and Voltage Circuits

Experiment 17: Three Zone Distance Protection Scheme

The MiCOM P442 distance relay is a very sophisticated numerical relay with 18 measuring elements, or comparators, which enables a variety of characteristics to be obtained and information on fault quantities and the distance to the fault to be given. The relay has separate measuring elements for each zone and for phase to phase and earth faults.

Before commencing any experimental study the user must become familiar with the operation of the Menu system in the relay Technical Manual and in the S1 Software in the PC provided. Locate the Group 1 Settings section.

The following study on the Power System Simulator illustrates the determination of the base or scheme settings. Sections 2, 3,and 4 in the Areva Technical Manual are particularly relevant.

Part A:Phase Faults

Zone Settings

Figure 113 shows a one–line diagram that should be set up on the Power System Simulator. Line 2, together with the impedance of the grid transformer represents the source impedance. The line to be protected is the first two sections of Line 6 (0.20 pu).

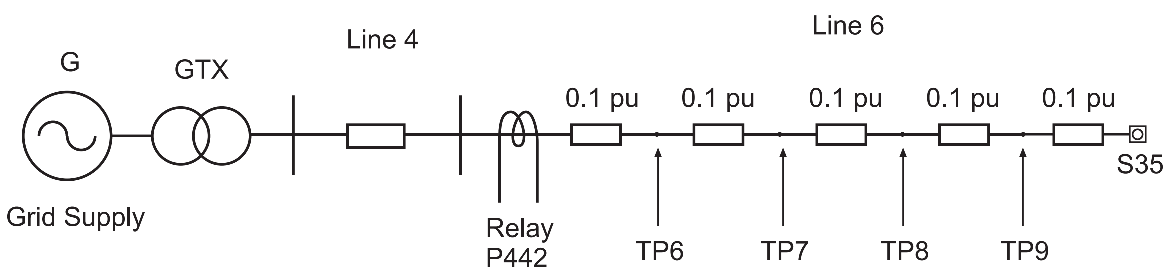


Figure 113 One–line Diagram; Three Zone Distance Protection Scheme

The line length = two sections of line 6 = 100km (assumed)

The line impedance = 4.8 Ω

The line angle = 80°

The required Zone 1 reach of the relay is:

Z 1 = (80% x 4.8 Ω) = 3.84 $\angle 80°$ Ω

This is a primary impedance.

The relay will use secondary values of impedance in its calculations, obtained by multiplying the primary impedance by the (CT/VT) Ratio

The CT Ratio = 10/1

The VT Ratio = 220 V/110 V

So (CT/VT Ratio) = 5.

Primary or Secondary values can be entered into the relay settings file. If primary values are entered, the relay calculates the secondary values from the CT and VT ratios. Thus primary values will be given here.

The Zone 2 reach is:

Z2 = (150% x 4.8 Ω) = 7.20∠80°Ω

The Zone 3 reach is:

Z3 = (220% x 4.8 Ω) = 10.56∠80°Ω

Resistive Reach Calculations

All distance tripping elements must avoid the heaviest system loading. Taking a 1 A CT secondary current as an indication of maximum load current, the minimum load impedance presented to the relay would be

$$[V_n(ph-n)/I_n]$$

Typically, phase fault distance zones would avoid the minimum load impedance by a margin of ≤40%. Earth fault zones would use 20% margin. This allows maximum resistance reaches of 38 Ω and 50.8 Ω If quoted on the primary side, the values above are divided by the CT/VT ratio, which is 5. Hence the required maximum primary values are 7.6 Ω and 10.16 Ω.

The minimum values are dependant on arc resistance (see Table 1, Paragraph 2.4.4 of the Areva Technical Manual) which are not relevant in this application.

Hence, select the following.

	Minimum	Maximum	Zone 1	Zone 2	Zone 3
Phase (Rph) Ω	0	7.6	R1Ph = 3	R2Ph = 5	R3Ph = 7
Earth (RG) Ω	0	10.2	R1G = 1	R2G =2	R3G = 3

Part B: Earth Faults

In Section 7, it is stated that 'residual compensation' is necessary if the relay is to see correctly the impedance of the line (Z_1). To achieve this for the P442 relay, a 'residual compensation factor', *KZ*O, has to be inserted into the relay software so that the replica impedance is correctly specified. The replica impedance is equal to ($KZ\text{O}\times Z_1$). See 'Residual Compensation For Earth Faults' in the relay manual.

The residual compensation factor (KZO) is equal to:

$$KZ\text{O} = \frac{K-1}{3}$$

Where

$$K = \frac{Z_0}{Z_1}$$

For a 0.20 pu section of line in the simulator, *KZ*0 = 0 (i.e., $Z_0 = Z_1$). However, *K* is typically about 2.5. This can be obtained on the Simulator by inserting an additional impedance, Z_E, in the circuit between the fault point and earth.

Z_E may be determined in the following way:

As the earth loop impedance Z_0 is equal to KZ_1, it is also equal to:

$$(K-1)Z_1 + Z_1$$

Thus the additional line impedance required is $(K\text{-}1)Z_1$; which must be equal to $3Z_E$, as $3I_0$ flows through Z_E whilst I_0 flows through Z_1.

Thus,

$$Z_E = \frac{(K-1)Z_1}{3}$$

From this expression, if $K = 2.5$, $Z_E = Z_1/2$. Thus, if the line length is 0.20 pu, $Z_E = 0.10$ pu. This may be achieved on the Simulator by connecting Line 1 between the fault point and earth at TP7. Note that for a line–to–ground fault, only one phase of Line 1 is connected to earth.

A residual compensation setting has to be entered into the relay Menu, which, for $K = 2.5$, is:

$$KZO = 0.50\angle 80° \text{ pu}$$

Part C: Power Swing Blocking

Power swing blocking is only required when carrying out stability tests when Line 6, in full or in part, is connected between the Gen.1 Bus and the Grid Bus. Although 100% Zone 1 is equal to 0.20 pu in the above example, it is recommended that a 0.30 pu length of line is used for stability tests.

A general description of the blocking process and relay requirements is given in Chapter 2 of the Areva Technical Manual. Power swings follow a much slower impedance locus than that measured for a fault. Thus the relay measures the time taken for the impedance seen by the relay (the impedance locus) to 'swing' through the ΔR or ΔX bands to the Zone 3 threshold. See Figure 114. A power swing is detected if the time in the ΔR band is more than 5ms and Power Swing Blocking is executed. Typically the ΔR and DX band settings are both set between 10-30% of R3Ph. Refer to Section 3 of the Areva Technical Manual.

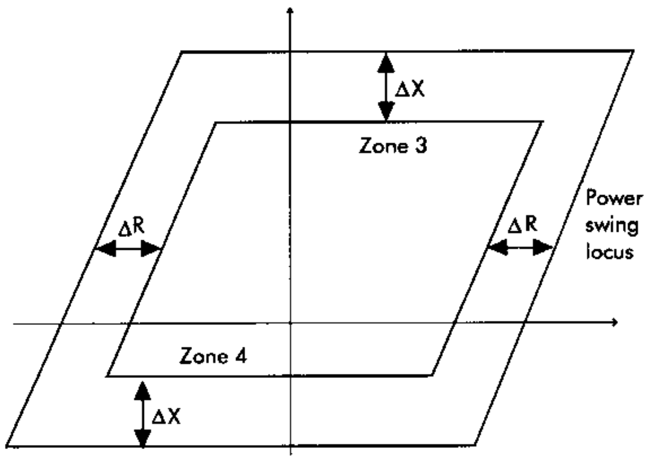


Figure 114 Power Swing Detection Characteristics

Three additional settings are required for power swing blocking (see Chapter 2 of the Areva Technical Manual):

1) A biased residual current threshold is exceeded.

2) A biased negative sequence current threshold is exceeded.

3) A phase current threshold is exceeded.

Relay Menu Settings

The following configuration data and settings should be entered into the relay Menu as they are given below. Refer to Sections 2 and 4 of the Areva P442 Technical Manual for further data and explanation.

Configuration

Active Setting	Group 1
Setting Group 1	Enable
Disable 2,3 and 4	
Power Swing	Enable
Setting Values	Primary

CT and VT Ratios

Main VT Primary	220 V
Main VT Secondary	110 V
Phase CT Primary	10.0 A
Phase CT Secondary	1.0 A
C/S Input	A – B
Main VT location	line

Group 1 Distance

Group 1 Line Setting	
Line Length	100.0 km
Line Impedance	4.800 Ohm
Line Angle	80.00 deg

Group 1 Zone Setting	
Zone Status	01010
kZ1 Res Comp	0.5
kZ1 Angle	80 deg
Z1	3.840 Ohm
R1G	1.0 Ohm
R1Ph	3.0 Ohm
tZ1	0.060 s
kZ2 Res Comp	0.5
kZ2 Angle	80 deg
Z2	7.200 Ohm
R2G	2.0 Ohm
R2Ph	5.0 Ohm
tZ2	0.20 s
kZ3/4 Res Comp	1.000

kZ3/4 Angle	0 deg
Z3	10.56 Ohm
R3G-R4G	3.0 Ohm
R3Ph-R4Ph	7.0 Ohm
tZ3	0.4 s

Note: 'Zone status' indicates that Zones 2and 3 are enabled; others are blocked. See Chapter 2 of the Areva Technical Manual.

Procedure

1) Enter into the menu Settings of the relay the values determined above.

2) Apply a three–phase fault at TP6, between the first two 0.10 pu sections of the Line 6.

3) The relay should operate and the distance to the fault given in the Fault Records section of the Menu should be approximately 50 km.

4) Apply three–phase faults similarly at TP7 and TP8. The relay should operate for a fault on TP7 (zone 2), at TP8 (zone 2/zone 3), and at TP9 (zone 3), but not at S35, as it is outside the zone 3 reach. Both the fault distance and fault zone can be found in Fault Records

5) For earth faults connect TP7 between one line and earth, via the fault CB, and apply a fault to earth. The relay should operate and the fault location should be 100 km of Line 6.

7.5 Differential Protection

Differential protection systems are the most widely used type of unit protection where instantaneous relay operation is required due to the magnitude of fault current.

There are two possible sub–divisions:

1) Circulating current schemes, for short zones, which includes most power systems plant.

2) Balanced voltage systems, used for physically long zones such as feeders and transmission lines.

These notes refer only to circulating current schemes.

Biased Differential Protection Schemes

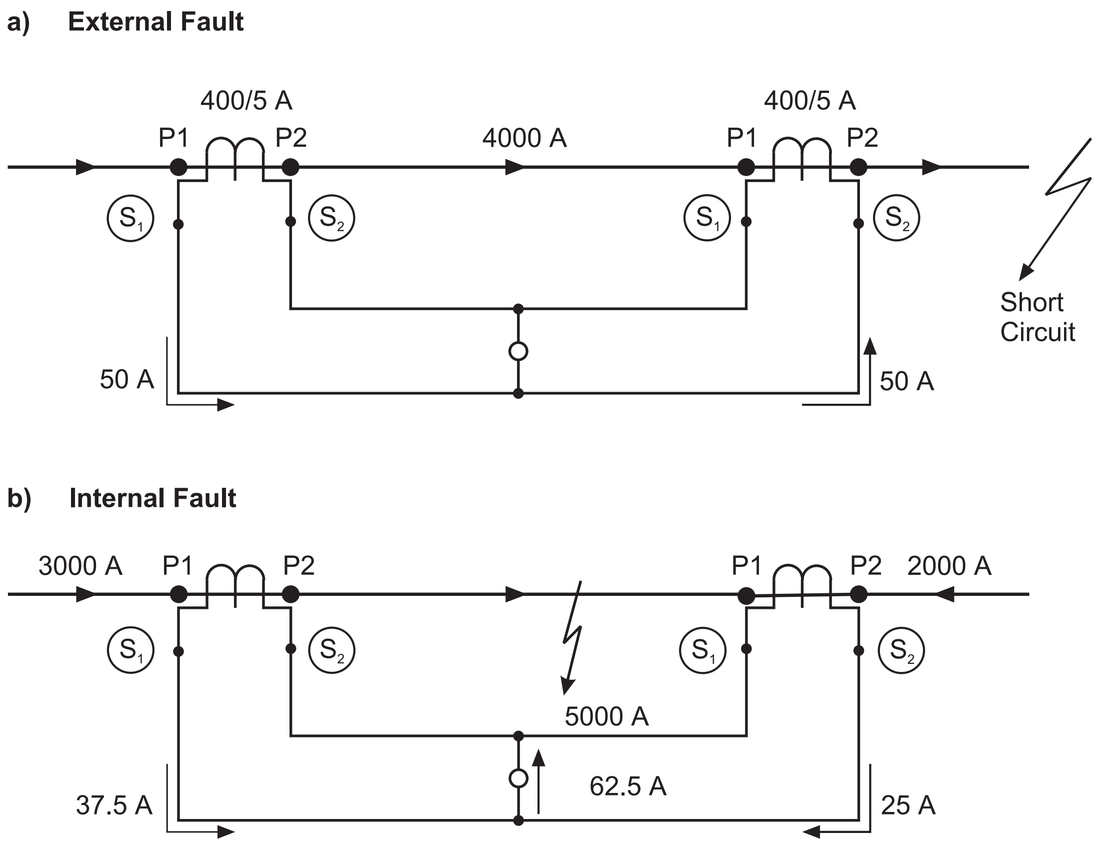


Figure 115 Differential Protection

Note: the CT polarity designation (P1,P2,S1,S2) and associated current directions.

The principles of operation of biased differential protection schemes are common to most unit type protection systems. Stated briefly, the current entering a protected zone, e.g. feeder, transformer, generator, busbar, etc. is compared with the current leaving the same zone. This basic principle is indicated in Figure 115 where it is seen that during a 'through' fault condition the corresponding current transformer secondary currents circulate via the interconnecting pilots, resulting in no relay current flowing. However, for a fault within the protected zone, current transformer output currents do not sum to zero resulting in relay current and thus (correct) tripping of the line circuit–breaker.

In practice the associated current transformers tend to saturate due to the higher value of fault current. Thus for through fault conditions the comparison of in–going and outgoing currents tends to be imperfect, giving rise to some appreciable spill current flowing in the relay, with the attendant risk of malfunction. This risk is normally overcome by using a fraction of the through fault current to restrain the relay from operating. In the case of transformer protection the percentage restraint used may be typically 20% of through fault current at low values of fault current, increasing to 80% at the higher current values. A circuit diagram for a three–phase transformer with a biased differential system is shown in Figure 116.

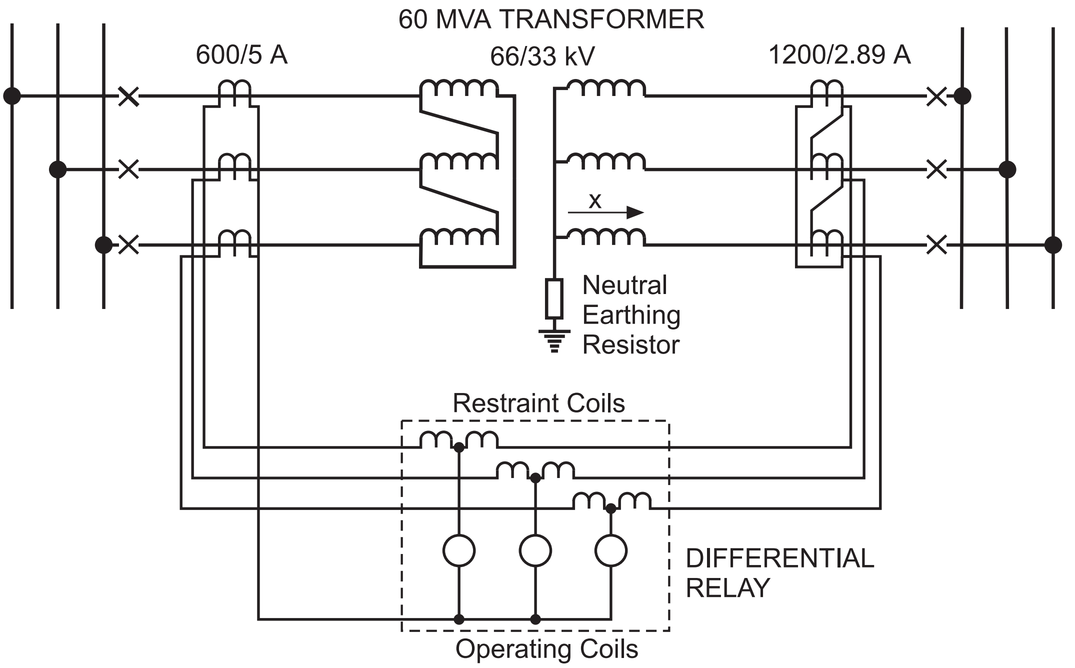


Figure 116 Three–Phase Transformer Differential System

Most three–phase power transformers are delta–star and therefore the primary and secondary line currents are 30° out of phase. To bring the CT secondary currents in phase, the star side of the power transformer should have a delta connected set of CTs and the delta side of the power transformer should have a star connected set of CTs. This form of CT connection also prevents unbalanced CT secondary currents due to zero sequence currents on the occurrence of an earth fault external to the protected zone. However, the ratio of the delta–connected CTs must be divided by $\sqrt{3}$ to obtain a balance of secondary circulating currents under through fault conditions, as shown in Figure 116.

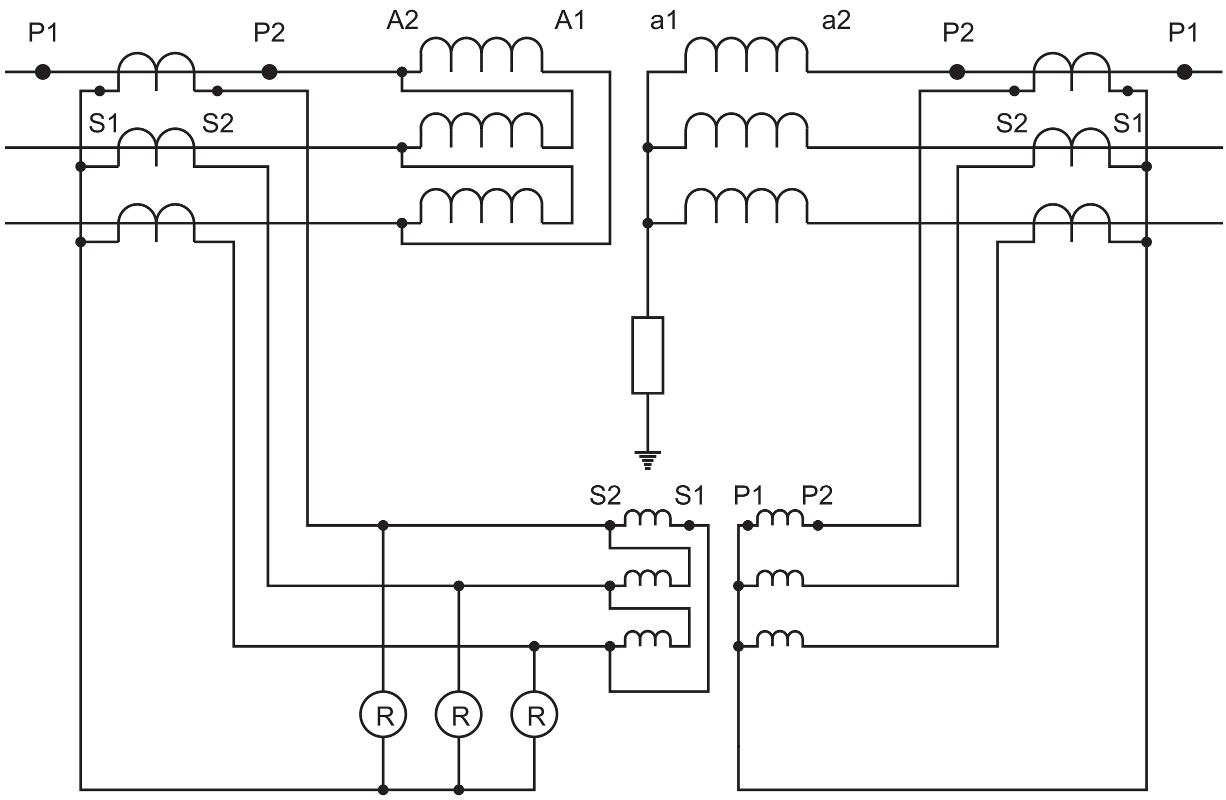
Transformer differential protection schemes have higher settings, both for pick up and restraint (or bias) than, for example, generator differential protection. Expressed as a percentage of rated current the setting are, typically, a (pick–up) setting of 40% and bias of 20%, compared with corresponding settings of, say, 20% and 10% for a generator. The reasons for this are several:

a) When the transformer is on no–load, the no–load current is seen as an internal fault current. The relay setting current must therefore be greater than the no–load current, expressed as a percentage of primary current. The energising current is also dependent on the type of fault.

b) The two sets of CTs differ in current and voltage ratings and it is therefore difficult to match them. Large out of balance current may flow during heavy through fault conditions.

c) The transformer may be fitted with on–load tap changers. It is not practical to alter CT ratios to match the varying ratio of the transformer. CT ratios are chosen to suit the nominal ratio of the transformer, so that out–of–balance current must flow for off–nominal taps.

Problems of CT ratio correction (the √3 factor) and mismatch can often more conveniently be dealt with by the use of an interposing delta–star transformer as shown in Figure 117. The interposing CT allows standard ratio line CTs to be used and provides vector correction, ratio correction and zero–sequence compensation. The interposing CT ratio is again chosen to correspond with the mid point of the tap–changer range.



Interposing CT provides: Vector correction, Ratio correction, Zero sequence compensation.

Figure 117 Interposing Delta–Star Transformer

High Impedance Relays

An alternative means of achieving tripping stability for through faults in differential or circulating current protection schemes is to use a high impedance relay rather than relay restraint coils. This relay is used extensively in busbar protection schemes and for restrictive earth fault protection where through fault current can vary considerably for the zone boundary CTs.

In the upper equivalent circuit in Figure 118, there is little or no current flowing through the relay if current circulates between the CTs. The voltage across the relay is very small. But if the CT,'X', becomes saturated due to a large, transient through-fault current, the other CT, 'Y', is the only CT to circulate secondary current, as the saturated CT is effectively short circuited on the secondary side. A relatively large voltage, V_s, is then produced across the relay, causing it to trip. In this circumstance the current can be reduced below the setting value of the relay by inserting extra resistance in series with the relay. This resistance is known as the stabilising resistance, R_{ST}. This is shown in the lower diagram. The voltage V_R, across the resistor R, must be larger than V_S to produce the required trip current, I_R, in the relay. However V_R should be no more than half the CT knee point voltage V_K.

The relay trip current is usually selected between 0.05 A to 0.20 A (5% - 20% of CT secondary current) although the relay may be unstable at the lower settings. The value of the stabilising resistor R_{ST} to obtain the relay setting voltage V_S can be calculated as shown in Figure 118. If a higher setting current is needed, a shunt resistor may have to be connected across the relay and R_{ST} to obtain the required V_S.

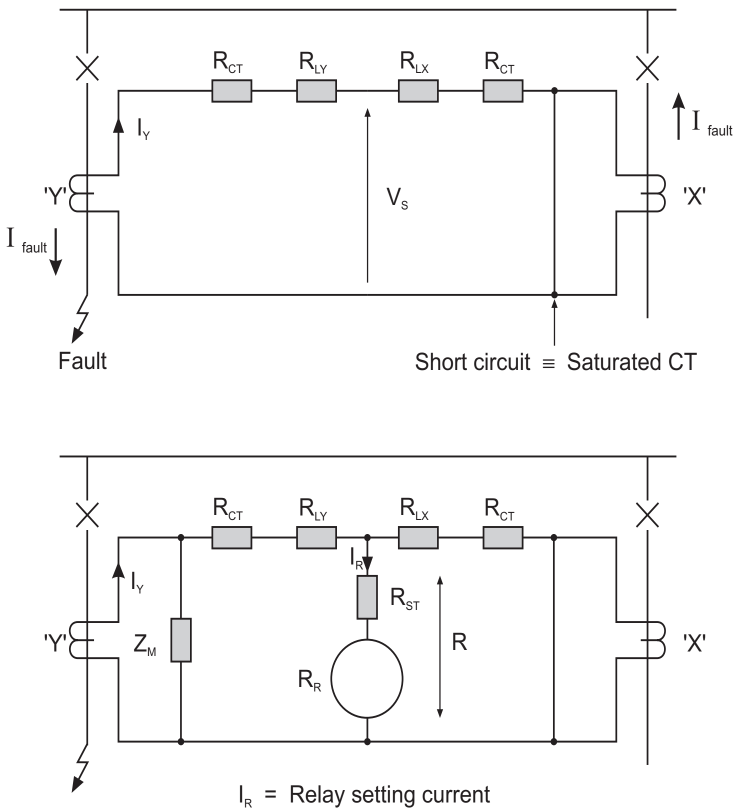


Figure 118 Principle of High Impedance Protection

For Figure 118:

$$V_s = I_Y(R_{LX} + R_{CT}) \text{ (Upper Diagram)}$$

$$\text{and } V_R = I_R \cdot R \geq I_Y(R_{LX} + R_{CT}) \text{ (Lower Diagram)}$$

$$\text{So } R \geq \frac{I_Y}{I_R}(R_{LX} + R_{CT})$$

$$\text{Also, } R_{ST} = R - R_R \text{ and } I_R R_R = \frac{VA \text{ Burden}}{I_R}$$

$$\therefore R_{ST} = \frac{V_s(\text{VA Burden}/\text{I}_\text{R})}{I_R}$$

Winding Faults

As with generator protection, the differential protection should include earth faults on the windings themselves. Consider the delta–star transformer shown in Figure 116. The star point of the secondary winding is earthed through an earthing resistor of resistance $R\,\Omega$. If an earth fault occurs on one phase of the star winding at a distance ‘x’ from the star point, the voltage behind a circulating earth current is:

$$\frac{xV_s}{\sqrt{3}}$$

where V_S is the star line voltage.

The circulating fault current in the star winding is therefore:

$$\frac{xV_s}{R\sqrt{3}}$$

Referring this current to the delta side of the transformer, I_d is obtained as:

$$I_d = \frac{xV_s}{R\sqrt{3}} \times \frac{V_s x}{V_d\sqrt{3}}$$

where V_d is the primary line voltage (see Figure 127 on page 183).

The current I_d flows through the CTs (two) on the primary (delta) side. No fault current flows through the secondary CTs. Thus, the secondary CT current which flows through the relay is:

$$I_{relay} = \frac{x^2 V_s^2}{3RV_d} \times \frac{1}{k}$$

where k is the CT ratio on the delta side. Thus:

$$I_{relay} = \frac{x^2 V_s^2}{3RkV_d}$$

This equation enables the relay setting, or x, or R to be determined. With a reasonably high value of resistance, say 1 pu, it is difficult to protect more than 40% of the winding, for a relay setting of 20%.

Differential Protection in Numerical Relays:

Instead of using interposing CTs or star/delta main CT connections, numerical relay such as the P632, implement ratio and vector correction, or matching, within the relay software, thus enabling most combinations of transformer winding arrangements and CT connections to be catered for.

However, page 3–39 of the Areva P632 Technical Manual gives a ‘standard configuration’ of two star-connected CTs, whatever the connection of the main transformer primary and secondary. The theory on amplitude and vector groups matching on pages 3-95 to 3–115 applies only to this standard configuration. Selection of other CT connections requires changes in the vector group matching.

Amplitude Matching

The requirements for amplitude matching and the determination of the amplitude matching ‘K’ factors are given on p3-97 of the Areva P632 Technical Manual. The reasoning behind the process is not given, but can be explained simply from the diagram in Figure 119.

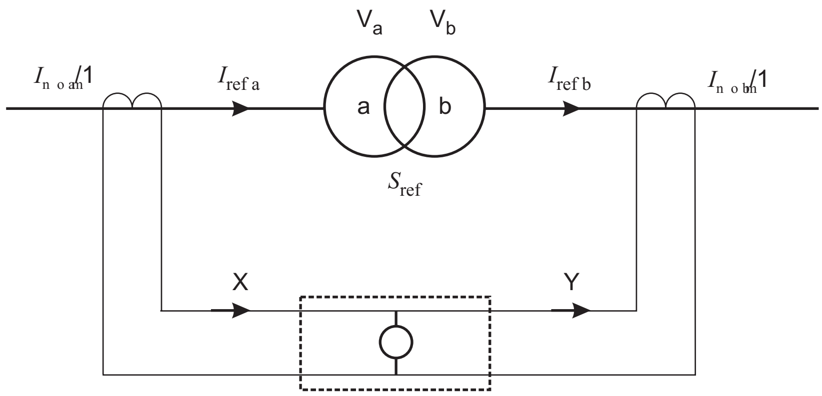


Figure 119 Principle of Amplitude Matching

It is known that

$$I_{refa} = \frac{S_{ref}}{\sqrt{3} \times V_a} \text{ and } I_{refb} = \frac{S_{ref}}{\sqrt{3} \times V_b}$$

where S_{ref} is the nominal rating of the transformer and I_{refa} and I_{refb} are the individual reference currents for the windings. These currents are calculated by the relay. V_a and V_b are the nominal line voltages of the transformer.

The CT secondary currents, X and Y are given by:

$$X = \frac{I_{refa}}{I_{noma}} \quad \text{and} \quad Y = \frac{I_{refb}}{I_{nomb}}$$

Where I_{noma} and I_{nomb} are the primary nominal currents of the CTs

For a balanced System X = Y

If now X and Y are multiplied by the factors k_{ma} and k_{mb} where

$$k_{ma} = \frac{I_{noma}}{I_{refa}} \text{ and } k_{mb} = \frac{I_{noma}}{I_{refa}}$$

$$(X \times k_{ma}) = (Y \times k_{mb}) = 1$$

For any other line current ($X \times k_{ma}$) and ($Y \times k_{mb}$) will not equal 1.

K_{ma} and K_{mb} are the amplitude–matching factors for the 'a' and 'b' windings, respectively.

They remove dependance on the nominal currents of the transformers. And the numbers compared and processed by the relay software are smaller.

The matching factors must satisfy the following conditions:

- The matching factors must always be ≤ 5
- The ratio of the highest to the lowest matching factors must be ≤ 3
- The value of the lower matching factor must be ≥ 0.7

Vector Group Matching

'Vector group matching' is required within the relay software to bring the primary and secondary relay currents 'into phase'. This is achieved by rotating the secondarylow-voltage 'b' side currents with respect to the primary high-voltage 'a' side currents, according to the vector group of the transformer to be protected, and, for odd vector groups, by multiplying by (1/√3) to retain amplitude matching.

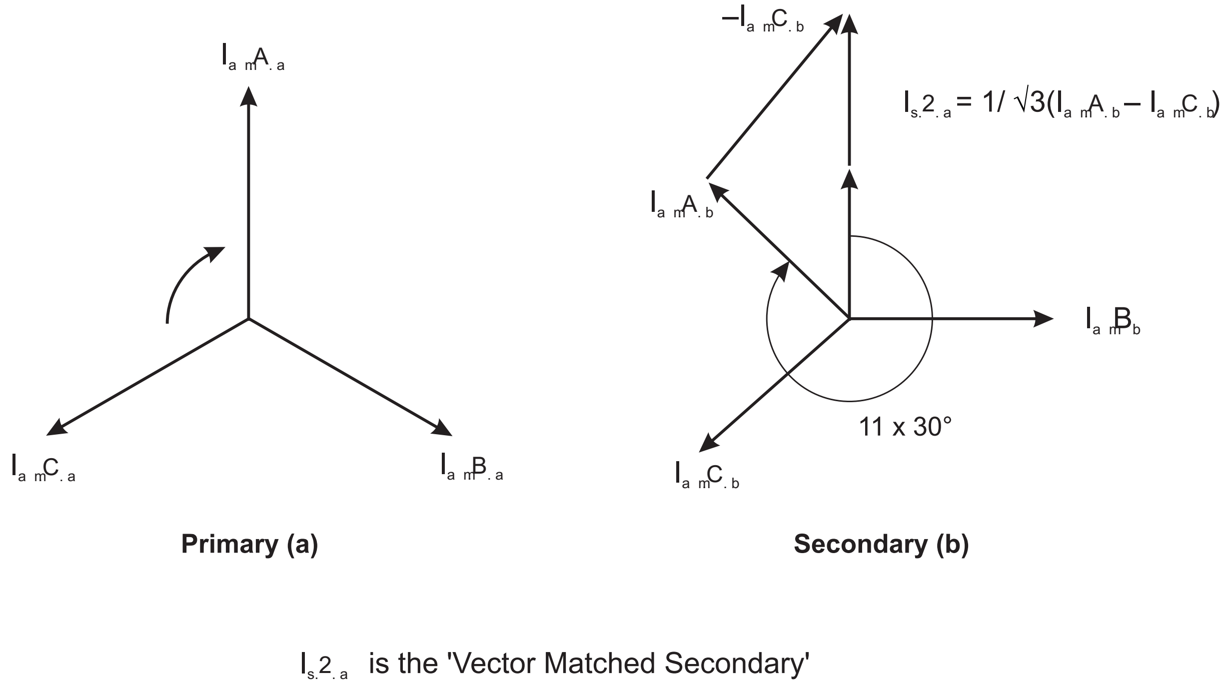


Figure 120 Vector Group Matching for a Dy11 Transformer, Vector Group 11

The relay software computes $I_{s.2.a}$ by the process illustrated in Figure 120. The only setting information to be input to the relay is the vector group identification number, provided that the phase currents on both sides of the transformer are connected in 'standard configuration'. There are 11 groups altogether, given on pages 3-101 to 3-103 of the Areva P632 Technical Manual. No vector group matching operation is carried out on the primary, high voltage side.

Zero – Sequence Current Filtering

However, suppose that the primary phase windings are connected in a star (or Y) configuration, the star-point of which is grounded. In the event of system faults to ground, the circuit for the zero-sequence component of the fault current would close via the grounded star-point that lies within the transformer differential protection zone, and would thus appear in the measuring systems as differential current. The consequence would be undesirable tripping. For this reason the zero-sequence component of the three-phase system must be eliminated from the phase currents on the high-voltage side by filtering. In accordance with its definition, the zero-sequence current is determined from the phasor sum of the amplitude-matched phase currents.

If the secondary, low voltage side is connected in star, as it is in the Simulator, zero sequence filtering must also be applied. This is illustrated in Figure 121.

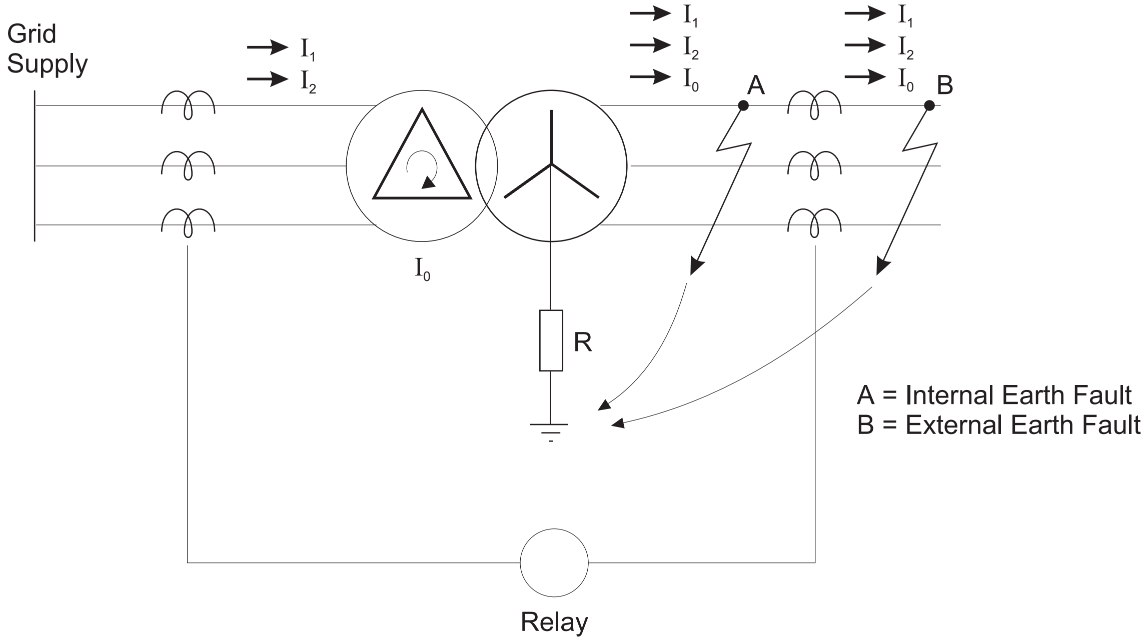


Figure 121 Zero Sequence Current Filtering

For an internal earth fault on the star-winding side of the transformer, equal co-phasal I_1, I_2 Io components of current flow into the fault. I_0 circulates through the earthed star point of the transformer, but I_2 and I_1 are supplied on the primary side from the Grid supply. As no currents flow through the secondary CTs of the transformer, it is the I_1 and I_2 components of current on the primary side that cause the relay to trip.

For an external fault on the secondary side of the transformer, the Io component circulates, as before, through the star point of the transformer, but the secondary CTs see all three components of current, I_1, I_2 and I_0. However the primary CTs of the transformer only see the I_1 and I_2 components. There is therefore an imbalance in the currents circulating between the primary CTs and the secondary CTs, and the relay trips. Hence the need for zero-sequence filtering on the secondary side of the transformer.

On a low-voltage delta side, the zero-sequence line current is automatically filtered out, based on the mathematical phasor operations. This is not always necessary and also not always desirable, but is always the result of any subtraction of two phase current phasors.

Tripping Characteristic

After the currents of the individual ends of the transformer have been matched, the sum of the current phasors of all ends is equal to zero in fault-free operation under idealized conditions. Only an internal fault in the protection zone of differential protection will generate a phasor sum of end currents that differs from zero, namely the differential current, I_d.

In practice, however, differential currents occur even in fault-free operation and can be attributed essentially to the influencing factors given under 'Biased Differential Protection Schemes', namely magnetizing current, unbalanced CTs and on-load tap-changers.

Whereas the magnetizing current is determined by the level of the system voltage and can therefore be viewed as constant, irrespective of load level, the transformation errors of the current transformer sets are a function of the through-current level. The threshold value of a transformer differential protection device is therefore not implemented as a constant differential current threshold, but is formed as a function of the restraining current I_R. The restraining current corresponds to the current level in the protected transformer. The function $I_d = f(I_R)$ is represented as the tripping characteristic.

The tripping characteristic for the (biased) differential protection provided by the relay is shown in Figure 122.

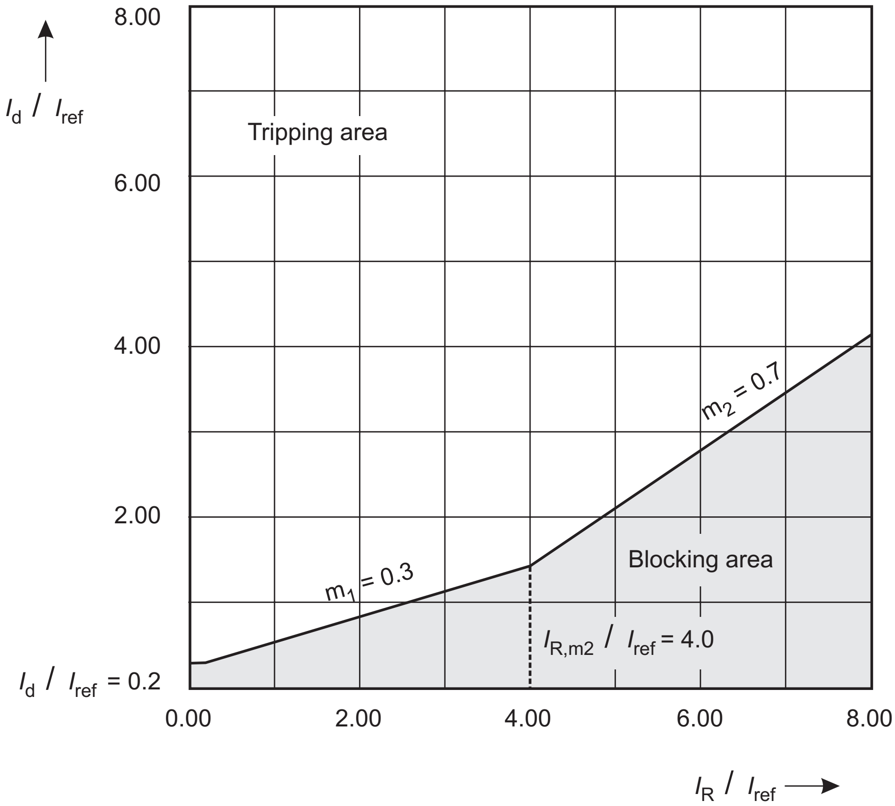


Figure 122 Tripping Characteristics of Differential Protection

The differential current is defined as the phasor sum of the matched currents on the primary and secondary sides of the transformer.

The restraining or bias current is defined as half the phasor difference between the currents on the primary and secondary sides of the transformer.

When the in-feed to an internal fault from both ends is exactly the same in amplitude and angle, then both currents cancel one another out, i.e., the restraining current becomes zero and the restraining effect disappears. Disappearance of the restraining effect when there is an internal fault is a desirable result since in this case transformer differential protection has maximum sensitivity.

The first section of the tripping characteristic is the most sensitive region with the lowest selectable threshold value I_d>. The default setting of 0.2 takes into account the magnetizing current of the transformer, which flows even in a no-load condition and is generally less than 5% of the nominal transformer current. The first section of the tripping curve runs horizontally until it reaches the fault current line for single side feed.

The second section of the tripping curve covers the load current range, accounting for not only the transformer magnetizing current, which appears as differential current, but also for differential currents that can be attributed to the transformation errors of the current transformer sets.

The second knee point of the tripping characteristic determines the end of the overcurrent zone in the direction of increasing retraining current in fault-free operation. It can be as high as four times the normal current in certain operating cases – such as when a parallel transformer has failed. Therefore, the second knee point can be set (I_r,m_2) for a default setting of 4.I_{ref}.

Tripping Current

The tripping current I for which the relay responds for single-side feed can be determined for the primary or secondary side of the transformer from the kam.z amplitude matching factors:

For primary 'a' side:

$$I = [(I_d > I_{\mathrm{noma}})/k_{\mathrm{ama}}]$$

I_d> I_{nomz} is the nominal setting, or trip value (e.g 20% x 1 A).

A vector-group matching factor has to be included with the amplitude matching factor for one-phase or two-phase feed. Depends on Differential Measuring System (1,2 or 3) and Zero Sequence Current filtering See pages 9-7 to9-9 of the Areva Technical Manual.

Restricted Earth–Fault Protection (or Ground Differential Protection)

To protect a greater percentage of the winding than is possible with differential protection, restricted earth–fault protection is used, as shown in Figure 123. For external earth faults the residual current produced by the three line CTs is balanced by the CT current in the earth connection. Thus all CTs must have the same ratio. For internal faults no residual current is produced by the line CTs; only the earth connection CT is energised. The relay setting can be low, say (10%), since this system does not suffer from any of the disadvantages of overall transformer protective systems. A high impedance relay may be used to prevent imbalance of the CTs due to saturation.

Restricted earth fault protection on the delta side is possible using the system described for the star winding, when an earth connection is provided by means of an earthing transformer. Alternatively, a simple residual current scheme can be connected into the delta lines. See Figure 124. Residual current (zero sequence current) will flow in the delta supply lines due to a fault on the delta winding.

As a backup for the restricted earth fault protection, a standby earth fault protection is provided in the earth connection. This is an overcurrent (IDMT) relay with a long inverse time characteristic that must be time-graded with other IDMT relays on the system.

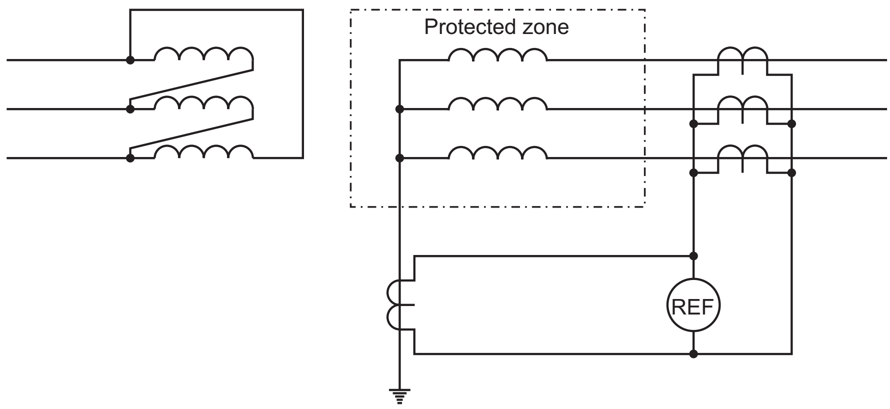


Figure 123 Star Winding Restricted Earth–Fault Protection

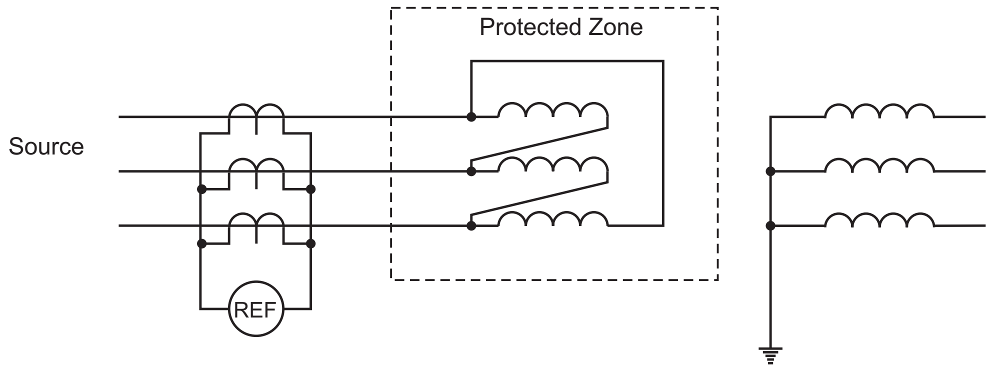


Figure 124 Delta Winding Restricted Earth–Fault Protection

Restricted Earth Fault Protection with Numerical Relays

Numerical relays, such as the P632, can be used for restricted earth fault protection as shown in Figure 123. However, a biased differential scheme is used, which does not require stabilizing resistors. The protection function is determined by comparing the phasor sum, I_N, of the phase currents of the relevant transformer winding, to the neutral-point current, I_Y. The P632 generates in its software the phasor sum of the phase currents.

Amplitude matching is required, as before, of the currents from the two ends of the differential system. But vector group matching is not required. The two amplitude factors are calculated as before by the expressions:

$k_{am,N.b} = I_{nom.b}/I_{ref,N.b}$ and $k_{am,Y\ b} = I_{nom,Y\ b}/I_{ref,N.b}$

The matching factors must always be ≤5. In addition, the following conditions apply;

- The ratio of the matching factors must be ≤ 3
- The value of the smaller matching factor must be ≥ 0.5

The tripping characteristic is shown in Figure 125. The threshold current $I_{d,N}$ is equal to the magnitude of the phasor sum of the amplitude matched resultant currents, $I_{am,N,b}$ and $I_{am,Y,b}$. The restraining current, $I_{R,N,b}$ is equal to the magnitude of the calculated current $I_{am,N,b}$

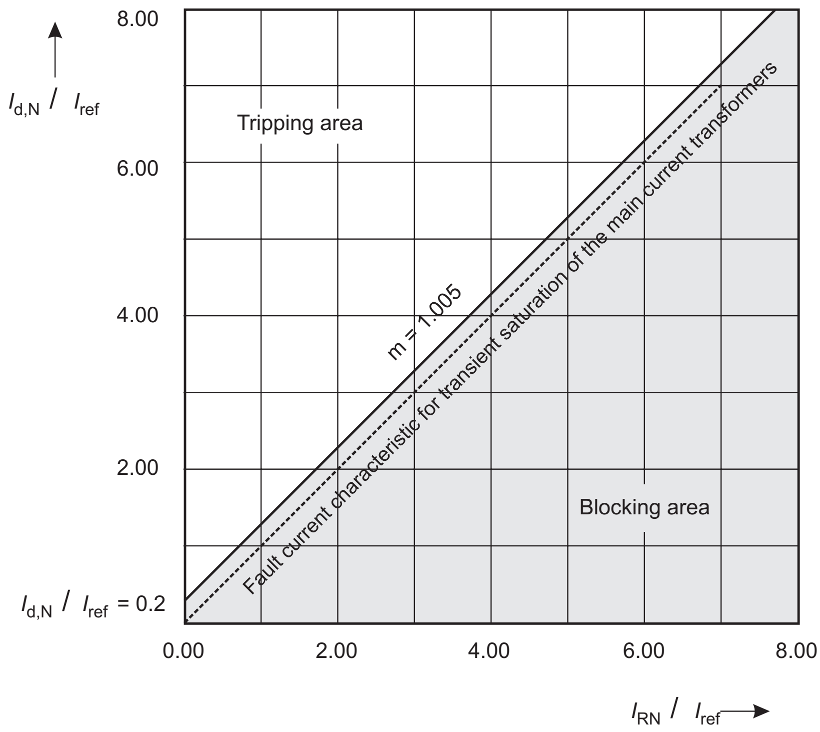


Figure 125 Tripping Characteristics of Ground Differential Protection

7.6 Setting the P632 Transformer Differential Protection

The P632 has the most complicated Setting Menu of all the relays in the Simulator. Care is needed in completing the several sections of the Menu, and particularly in finding 'enables' required for the relay to function.

Four application areas have to be completed:

DIFF, REF2, IDMT1 and IDMT2.

REF2 & IMD2 refer to End (or winding) 'b' of the transformer IDMT1 refers to the end 'a' of the transformer.

IDMT2 is for standby earth fault protection, and IDMT1 is for Overcurrent back-up protection, on the primary side of the transformer.

The relay Menu tree is shown in Figure 126. The tick marks indicate where the 'enables' have to be made.

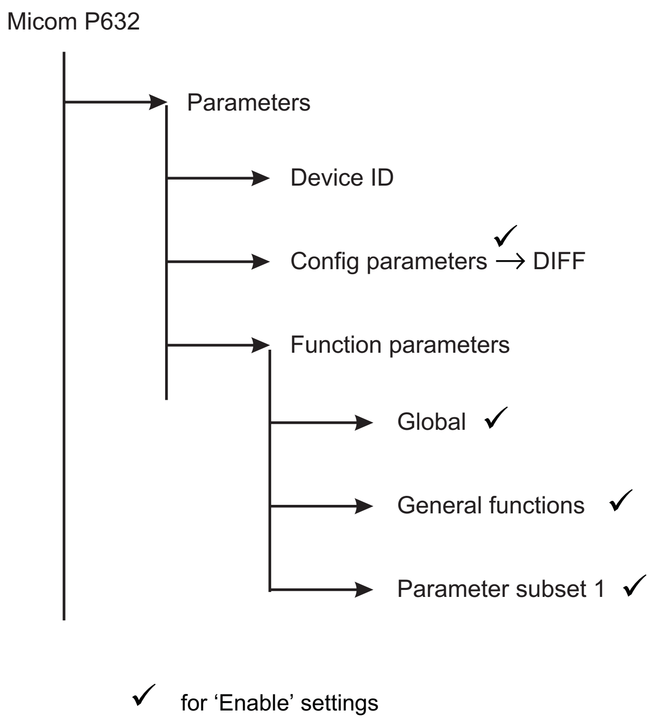


Figure 126 Setting Menu for the Micom P632 Biased Differential Relay

Differential Protection (DIFF)

The calculations carried out by the relay have been discussed earlier, namely that of the amplitude matching factors $k_{am.a}$ and $k_{am.b}$. But these have to be calculated first to check that they meet the three conditions specified. However the relay will only accept a reference power, S_{ref}, of 100 kVA or over. Thus, to obtain acceptable amplitude factors and a threshold, or tripping, current, 'artificial' values of Sref and V_a and V_b must be used. The values chosen are:

S_{ref} = 0.40 MVA

$V_{nom.a}$ = 0.40 kV

$V_{nom.b}$ = 0.20 kV

Thus

$$I_a = 400,000/(\sqrt{3} \times 400) = 577A$$

$$I_b = 400,000/(\sqrt{3} \times 200) = 1154A$$

If the CT ratios are 1000/1 and 700/1, instead of 10/1 and 7/1,

k_b = 1000/1154 = 0.8665

and k_a = 700/577 = 1.2124 These are acceptable values.

The actual tripping current is given by the expression in the earlier section 'Tripping Current' , which gives for a setting current of 20%:

I_{trip} = 0.2x1A/1.2124 = 0.165 A, without zero sequence filtering.

Thus enter the following settings in the Menu:

Goto - Config. parameters/DIFF/Function Group DIFF and enable by entering 'with'

Parameters/ Function Parameters/Global/MAIN		
Protection enabled	Yes	
Inom C.T.prim.,end a	700 A	
Inom C.T.prim.,end b	1000 A	
Inom C.T.Yprim.,end b	700 A	
Inom device, end a	1 A	
Inom device, end a	1 A	Leave other value entries as the default entries.

Function Parameters/ General Functions/MAIN		
Vnom prim., end a	0.40 kV	
Vnom prim., end b	0.20 kV	Leave other value entries as the default entries.

Function Parameters/General function/DIFF		
General enable USER	Yes	
Reference power Sref	0.40 MVA	
Ref.curr.Iref,a	not measured (0.577 kA) (******)	
Ref.curr.Iref,b	not measured (1.154 kA) (******)	
Matching fact. Kam, a	not measured (1.2124) (******)	
Matching fact. Kam, b	not measured (0.8665) (******)	
Vector grp.ends a-b	11	Leave other value entries as the default entries. (******) values are calculated by the relay.

Function Parameters/ Parameter Subset 1/DIFF		
Enable	Yes	
Idiff>	PS1	0.20 Iref
m1	PS1	0.3
m2	PS1	0.7
Ir,m2	PS1	4.0 Iref
0-seq. filt.B.enable.	Yes	Leave other value entries as the default entries.

Restricted Earth Fault, REF2(end b)

As with the DIFF Settings, ‘artificial’ settings for Sref, Vb and the CTs must be used to obtain satisfactory amplitude matching factors. The same values as before are acceptable, plus the CT ratio for the star point, or ‘Y’, connection is set at 700/1. Settings are entered as:

Parameters/Function parameters/General functions/REF2		
General enable USER	Yes	
Select. Meas. Input	End b	
Reference power Sref	0.40 MVA	
Ref.curr.Iref	not measured (1.154 kA) (******)	
Matching fact. Kam, Nb	not measured (0.8665) (******)	
Matching fact. Kam, Yb	not measured (0.6066) (******)	
Leave other value entries as the default entries. (******) values are calculated by the relay.		

Standby Earth Fault Protection, IDM2

This is back-up for earth faults and has a long operating time of seconds

Parameters/Function parameters/General functions/IDM2:	
General enable USER	yes

Parameters/Function parameters/Parameter subset 1/IDMT2	
Enable	yes
Iref, P	Blocked
Iref, P dynamic	Blocked
Iref, N	0.2 Inom
Iref, N dynamic	0.2 Inom
Characteristic N	Standard Inverse
Factor kt, N	1.2 s
Leave other value entries as the default entries.	

Overcurrent Protection on Primary, IDMT1

Primary Back-up to Differential Protection

Parameters/Function parameters/General functions/IDMT1:	
General enable USER	yes

Parameters/Function parameters/Parameter subset 1/IDMT1	
Enable	yes
Rush restr. enabl	Yes
Iref, P	1.0 Inom
Iref, P dynamic	1.0 Inom
Characteristic P	Standard Inverse
Factor kt, P	0.07
Min Trip Time	0.05 seconds
Leave other value entries as the default entries.	

Experiment 18: Grid Transformer Differential Protection

It is difficult to describe set procedures for specific experiments in this application area. Procedures are more investigative, and the following are recommended. In all experiments the Timer CB should be connected in series with the fault CB with a set time of about 0.25 s.

Part A: Phase Fault Settings for the Differential Protection

Various fault conditions can be applied at TP1 within the zone of the differential protection. Using the inductor of 9.6 Ω in the fault path to limit the fault current, apply phase–to–phase faults and phase–to–earth faults at TP1. Investigate the settings required to operate the relays in the three phases. The relay setting should not be reduced below 20% of the relay rated current, to retain stability for through faults. Through fault stability can be tested by applying a fault out side the differential relay zone at the far end of say, Line 2. Make sure the Grid Bus Protection relay is set correctly.

Part B: Earth Faults on the Star Winding

Differential Protection.

a) For this initial experiment it may be necessary to inhibit both the restricted earth relay and the standby relay. The Overcurrent relay on the primary side of the transformer should have an operating time of 0.30 s. This is as a back up for the differential protection. Now apply a fault to earth at TP1 through the 9.6 Ω inductor provided. The differential element of the relay should trip.

b) The star winding has two tapping points at which earth faults can be connected: they are at 20% (TAP A) and 40% (TAP B) of the star winding, measured from the star point. Their connections are at the central test area of the PSS - marked 'TPA' and 'TPB'. Apply an earth fault at the 40% and 20% winding tap points through the 9.6 Ω inductor. The relay should not trip.

The equation given in the earlier Section 7.5; 'Winding Faults', can be used to calculate the the maximum value of earthing resistor, R, that will allow the relay to trip for internal earth faults .

For the Grid Transformer,

$$\mathrm{I\ relay} = \frac{X^2 \times 220^2}{3R \times 415 \times 7/(1A)} = 5.55 \times X^2/R$$

For a nominal setting current of 20%, the actual tripping current is 0.165 A, as given earlier,

Thus $R = 33.84 \times X^2$

Hence R may be calculated for various distances from the star-point of the winding :

For 20% of the winding, Tap A; R = 1.35 Ω.

For 40% of the winding, Tap B; R = 5.41 Ω.

Various values of R can be used, above and below these values, to test the theory. Use the 3 ohm resistor, with 33% tap, in the central test area. As the values of resistance are small, it may be difficult to determine accurately the boundary between trip and non-trip. A similar experiment carried out for the Restricted Earth Fault Protection with higher values of resistance may be more conclusive. Note that the 9.6 ohm inductor is not used in addition to these resistors.

Part C: Restricted Earth Fault Protection

As the differential protection may not operate effectively for earth faults at the 20% winding tap the restricted earth fault protection can be set to operate for faults at this point.

For an internal fault on the transformer winding the Restricted Earth fault element of the relay may be tripped by a relay current produced only by the 7/1 CT in the earth connection of the star-connected secondary winding.

The tripping current can be calculated using the expression given in the earlier 'Tripping Current' Section.

Thus

$$\text{I Trip} = \frac{0.20 \times 1\text{A}}{0.6066} = 0.33\text{A or } 2.3\text{ A primary}$$

This current is produced by a value of earthing resistance R given by:

$$2.3\text{A} = \frac{124\text{V}}{\text{R}} \times 20\% \text{ or } 40\% \text{ for tapping points A and B respectively}$$

The actual value of secondary voltage (124 V) is slightly less than the nominal value (about 3%) due to the drop in secondary voltage when the fault is applied. This will cause a decrease in R for both restricted and differential protection.

The values of R calculated to achieve the tripping current at Tap A and Tap B are:

R = 11Ω, at Tap A (20% of winding),

R = 22Ω, at Tap B (40% of winding)

The box provided has four resistors, above and below these two values. Try these resistors for the faults at Tap A and Tap B. Do not use the 9.6Ω inductor in the earth connection! View the earth-fault current values in the relay measurement section.

If differential and restricted earth fault relays do not operate, the ‘standby’ overcurrent relay should operate, but not before the overcurrent relay RGT for a fault at TP1. The time of operation of standby or unrestricted relays is normally seconds, and as many as 10 s in practice.

Note the fault current paths and magnitudes shown in Figure 127 for phase and earth faults. Note from the relay ‘operate’ LEDs which of the phases are tripped for the faults shown.

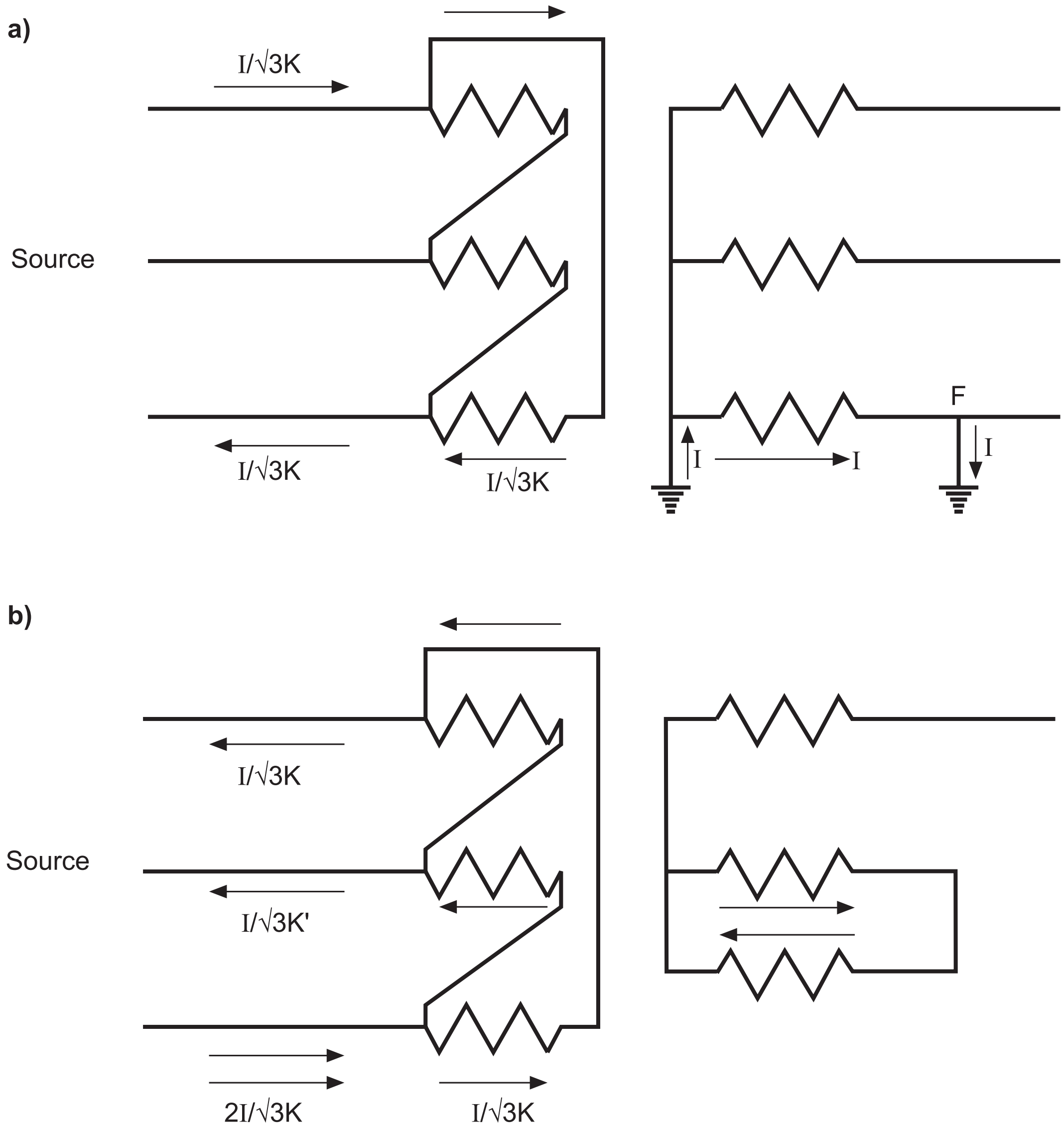


Figure 127 Fault Current Paths and Magnitudes for Phase and Earth Faults; K = Line Voltage Ratio

7.7 Busbar Protection

Within an integrated protection scheme overcurrent or distance protection provides back–up protection for unit protection of feeders and expensive plant, such as transformers. Differential protection schemes can also be applied to busbars, single or multi–section. In simple, low voltage bus–bar systems it is not considered necessary, but for more complex, high voltage systems the consequences of prolonged loss of connection to generation or important loads could be severe.

Multi–section busbars provide complex interconnection of lines or feeders. An external, fault on one line may be fed from any number of lines connected to the busbar system. The loading on the CT in that line may therefore saturate causing severe imbalance in the differential protection system. Thus the stability of differential protection systems for busbars under through–fault conditions is a serious problem. However, it can be overcome by using a high impedance relay with a series stabilising resistor. The relay–setting voltage and stabilising resistor are calculated from through fault stability considerations (see 'High Impedance Relays').

Figures 128 and 129 show the grouping of the three CTs for each line for the measurement of earth faults and phase and earth faults. For earth faults (Figure 128) three parallel connected CTs produce a residual current; for phase faults (Figure 129) the currents in individual phases are compared by means of a fourth or neutral bus wire.

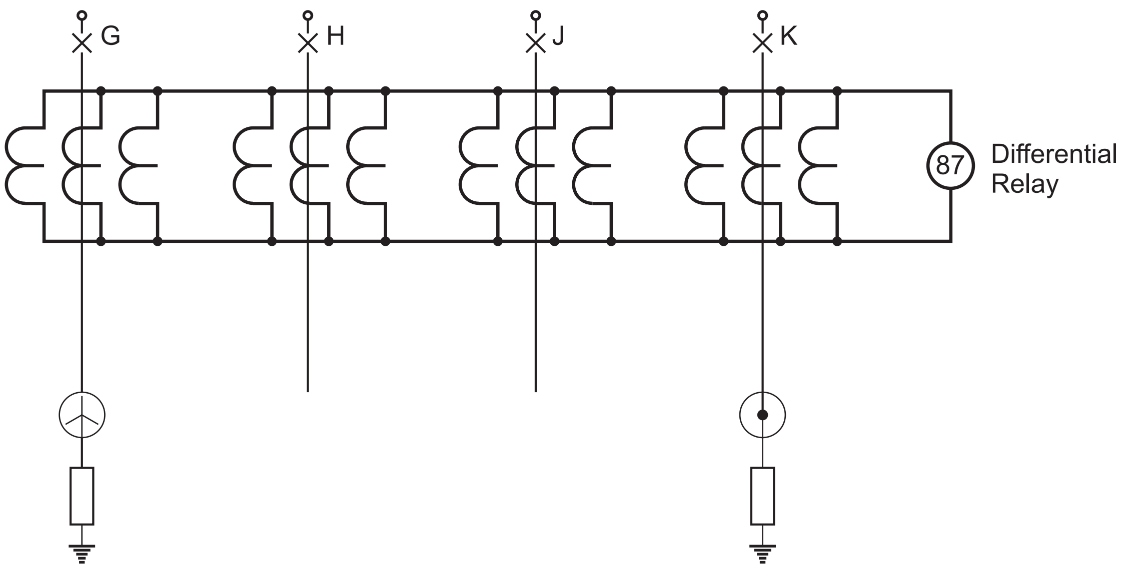


Figure 128 Grouping of the Three CTs for the Measurement of Earth Faults

In Figure 129 the relay has three elements and therefore responds both to earth and phase faults. This is essentially the system used in the Power System Simulator and Figure 130 shows the interconnection of CTs for earth fault detection in a two section, busbar system. Note that the CTs mark the boundaries of the zones and that the zones overlap across the Section breaker.

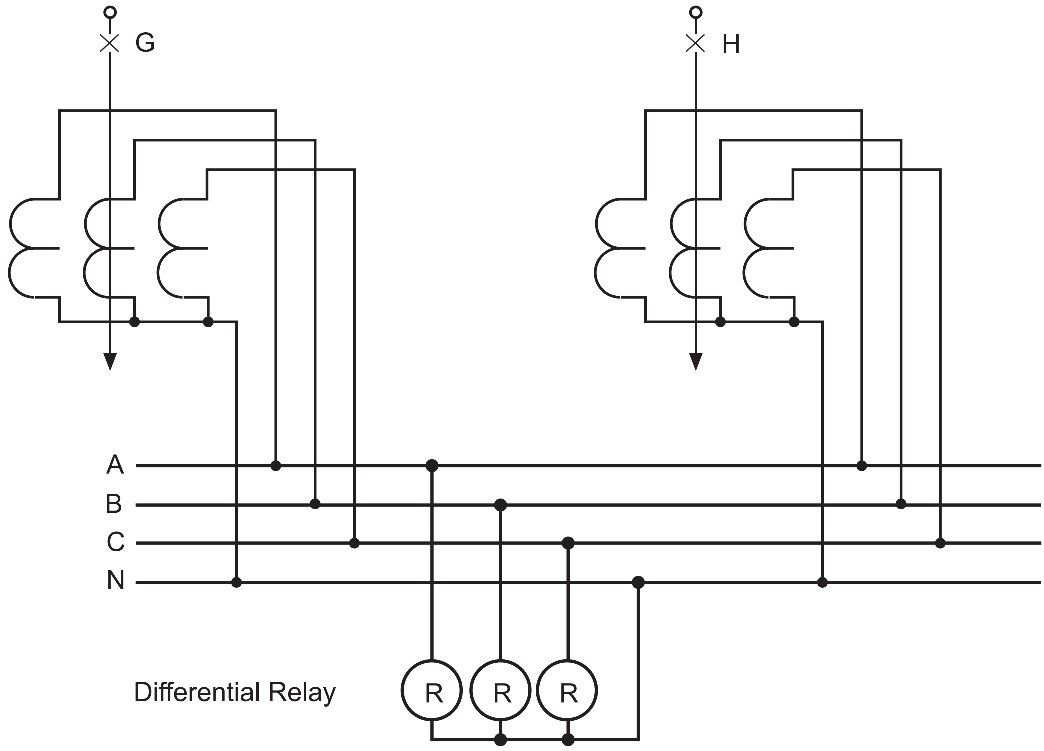


Figure 129 Grouping of the Three CTs for the Measurement of Phase <u>and</u> Earth Faults

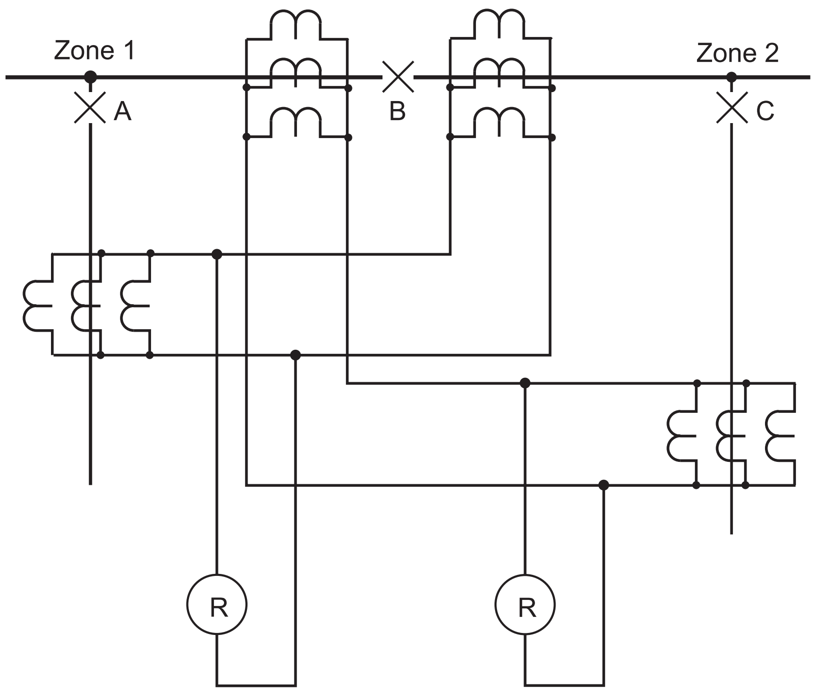


Figure 130 Interconnection of CTs for Earth Fault Detection in a Two Section Busbar System

Figure 131 shows a full double busbar scheme with three protective zones. The CTs on either side of the bus coupler CBs define the separation of zone C from zones A and B. In addition to the three zones there is a check system which looks at both busbars as a single zone. The protection for both the check system and a zone must operate for the zone relays to trip. This ‘two–out–of–two’ arrangement ensures that critical plant is not inadvertently tripped due to failure of the protection system rather than the plant itself. Note the supervision relays which operate if a CT connection is broken.

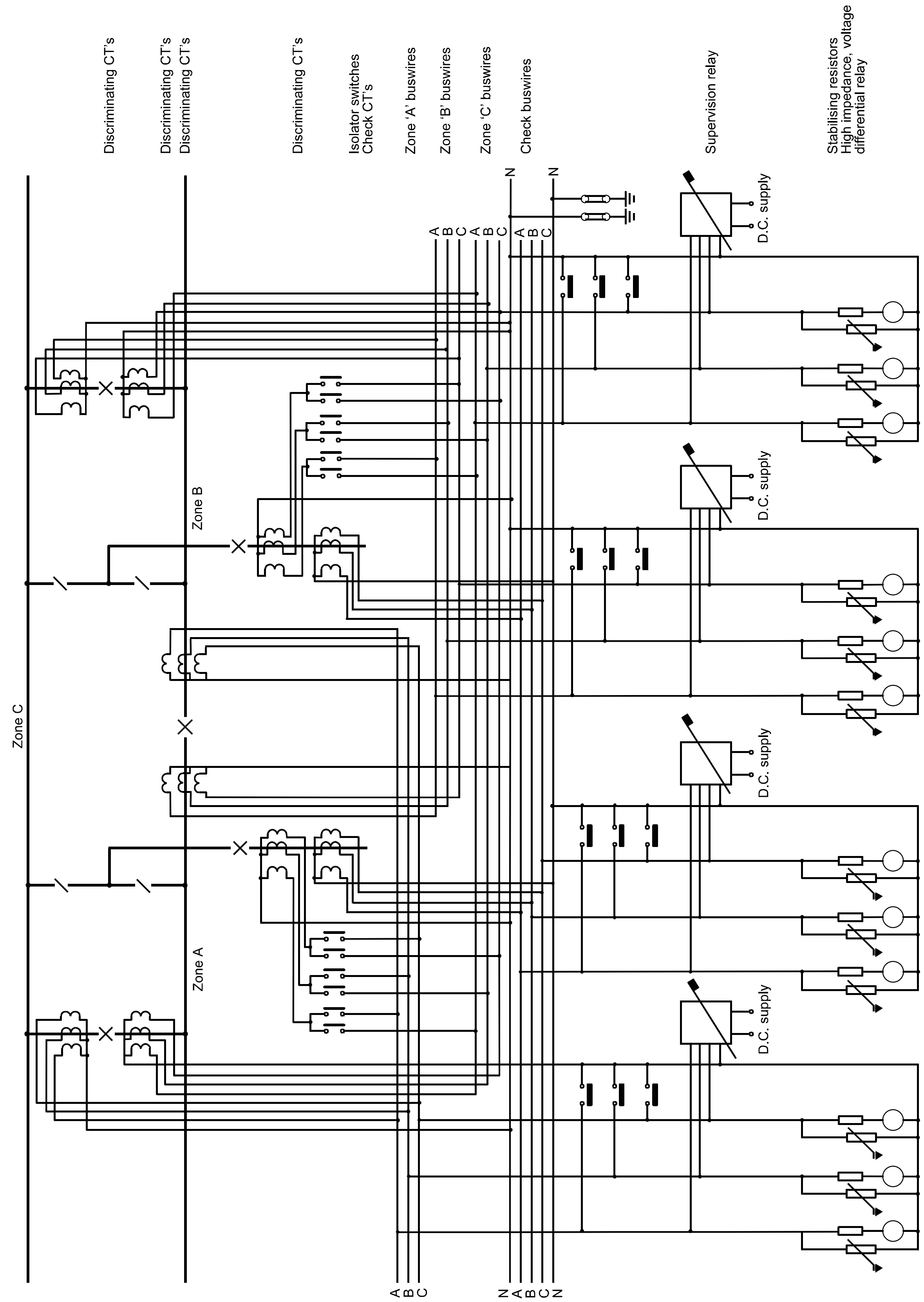


Figure 131 Full Double Busbar Schematic

Experiment 19: Busbar Protection

Study of References 9 and 10 together with the relay manuals is advised in order to determine the setting current for these relays.

The stabilising resistor of these relays has been set to 180 Ω. Calculations using the equation $R_{ST} = \{(V_S - VA/I_R)/I_R\}$, obtained from Figure 118, show that for a setting current of 0.20 A the stabilising resistor is 178 Ω. The maximum available value of this resistor is 220 Ω; at setting currents much lower than 0.20 A the resistor required is greater than 220 Ω. The CT knee voltage, V_K, is 81 V; the VA burden is 1 VA; and the minimum setting voltage V_S is assumed equal to V_R and to $V_K/2$.

Two test points are available for applying faults to the two sections of the main busbar: TP13 and TP14. TP13 is positioned near the section breaker and should therefore operate for both overlapping zones. Faults at TP14 should operate the right hand section only (Zone 2). Also within the section zones are TP11, 12, 15 and 16, on the feeders. The TQ PSS Drawing 'HV Bus' (79963) should be consulted for full details.

Apply phase-phase (not phase-phase-phase) faults via the test inductor X_L and the timed ciruit breaker set at 0.3 seconds.

The relays should not operate for through faults, and is very unlikely in this system even if the setting current is very low. Through current means in at one feeder and out at either another feeder in the same zone, or through the bus section CB (CB10). Zone 1 and Zone 2 include the reserve bus (or back bus), provided the bus section CB (CB15) in the reserve bus is open. If CB15 is closed, current can flow into one zone and out at the other zone, so that both zone relays would trip, illustrating the purpose of the bus section CTs.

It is suggested that a simple single line (Line 42) and load system is set up to investigate the operation of the protection scheme and the effects of varying the relay settings on the operation and stability of the relays

7.8 Generator Protection

The protection system for the generator and generator–transformer, within the Power System Simulator (G1 and GTX1, respectively) is shown in Figure 5 and the connection diagram in Figure 25. The system contains most of the electrical protection normally associated with generators and generator transformers. Prime mover protection is not included, with the exception of a reverse power relay.

Generator Unit faults can be divided into two broad categories:

a) Insulation failure, resulting mostly in earth faults.

b) Abnormal running conditions.

The main protection system is associated with category (a) faults. A generator/generator transformer unit in which the primary winding of the transformer is delta connected is isolated from the transmission system so far as earth faults are concerned. The earthing policy for the generator unit can therefore be made independently from that for the transmission system. Normally the generator star point is earthed, through a resistor or a transformer and resistor to limit the fault current to a value no greater than the rated current of the generator.

7.9 A) Main Protection Systems

1) Biased Differential Protection

The main protection of the stator winding for phase-phase and phase-earth faults is provided by a biased, circulating current differential current scheme. In practice, both circulating current and high impedance schemes are used.

The principles of Biased Differential Protection are described in Section 7.5 of this Manual. The operating characteristic for P343 generator protection is shown in Figure 132 and illustrates the settings factors to be defined in the relay menu. The Differential Current setting, 'Gen Diff Is 1', is set as low as possible normally 5% of rated current. 'Gen Diff Is 2', the threshold above which the second bias is applied, is set to 120% of rated current. The initial bias slope, 'Gen Diff k1', should be set to 0% for optimum sensitivity for internal faults and the slope of the second bias slope, 'Gen Diff k2', is typically 150%.

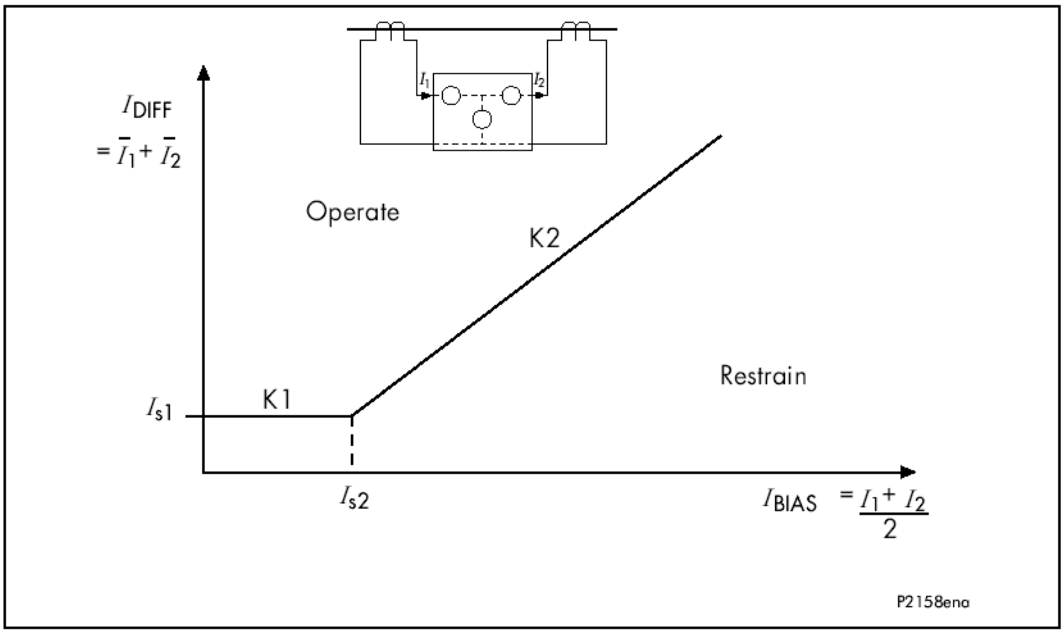


Figure 132 Relay P343 Biased Differential Protection Operating Characteristic

2) Stator Earth Fault Protection

As back-up protection to the Differential Protection for earth faults, standby earth fault protection may be provided by either a CT-coupled relay in the earthed neutral connection, or a voltage-operated relay element connected across an earthing impedance or coupled into the earth connector through a transformer.

There is considerable variation in the earthing arrangements for generators. Earth fault currents can range from 10 A to 200 A depending on the impedance in the star-point to earth path. For minimum damage, high impedance is preferred and often the fault current is set with a maximum value equal to the rated current of the generator. There is a limit to the percentage of the stator winding that can be protected by this method. It is difficult to protect the last 5% of the stator winding, as the voltage driving the fault current is too small. However, limiting the damage to the generator is a priority, and other methods can be used to protect the whole winding.

Residual overvoltage/neutral voltage displacement protection

On a healthy three-phase power system, the addition of each of the three phase voltages to earth is nominally zero. However, when an earth fault occurs on the system this balance is upset and the sum of the phase voltages to earth is equal to a 'residual' voltage, V_R. This condition causes a rise in the neutral voltage with respect to earth, which is referred to as "neutral displacement voltage" ,V_{NE}. It may be shown that V_{NE} is equal to 3 V_R.

Hence, a residual-voltage measuring relay can be used for earth fault protection. If the system is impedance or distribution transformer earthed, the neutral displacement voltage can be measured directly in the earth path via a single phase VT. This type of protection can be used to provide earth fault protection irrespective of whether the generator is earthed or not, and irrespective of the form of earthing and earth fault current level. For faults close to the generator neutral the resulting residual voltage will be small. Therefore, only 95% of the stator winding can be reliably protected.

For the Generator 1 in the Simulator, the current is limited to 1 A for full phase voltage by inserting a 128 Ω resistor between star point and earth. A voltage-operated relay element, is used in the Simulator, the 128 Ω resistor being tapped to provide a maximum input of 50 V.

100% Stator Earth Fault Protection

Full, or 100%, stator winding protection can be obtained in the MiCOM P343 relay by measuring tne amplitude of the third harmonic component in the voltage between star point and earth.

Most generators produce third harmonic voltage due to non-linearities in the magnetic circuits of the generator. Under normal operating conditions the distribution of the third harmonic voltage along the stator windings varies linearly from a negative maximum at the star, or neutral point, N, to a positive maximum at the winding terminal. For a stator earth fault at the star point the amplitude of the third harmonic in the voltage at the terminals is approximately doubled both when the generator is off load prior to the fault, and when it is fully loaded. This is also true for the amplitude of third harmonic measured in the star point voltages for an earth fault at the generator terminals.

The third harmonic threshold has to be set above the normal level in the system, due mainly to magnetic circuit non-linearities in transformers. This threshold is given as VN3H> in the relay Menu.

3) Overcurrent Protection

A two-stage, non-directional overcurrent element is provided in the P343 relay. This element is used to provide time-delayed back-up protection for the system and high-set protection for fast tripping for internal machine faults. The relay element uses phase current inputs from CTs at the terminal end of the generator.

The first stage has a time-delayed characteristic that can be set as either Inverse Definite Minimum Time (IDMT) or Definite Time (DT). The second stage has a definite time delay, which can be set to zero to produce instantaneous operation. Each stage can be selectively enabled or disabled. The first stage can provide protection for system faults, and as such should be co-ordinated with downstream protection.

The current setting of the second stage, 'I > 2 Current Set', should be set for the maximum fault rating of the generator. The operating time, 'I > 2 Time Delay', should be set to 340 s to give instantaneous operation. The stage will therefore be stable for external faults where the fault current from the generator will be below the stage-2 current setting. For faults within the machine, the fault current will be supplied from the system and will be above the stage-2 current setting, resulting in fast clearance of the internal fault.

System Backup Protection

A generator will supply system faults until they are cleared by system protection. Time-delayed overcurrent protection can also act as back up for system faults, if it is graded with other system overcurrent protection.

However, there may be a pronounced fault current decrement for faults close to generators, resulting in a lower current than the relay setting. Therefore the relay may take an unacceptably long time to operate. To overcome this effect, voltage controlled relay characteristics are used. This characteristic is illustrated in Figure 133. If the voltage at the terminals of the generator drops below 'V<1 set', the current threshold of the relay switches automatically from 'I> set' to a much lower setting, 'KI>set', thus ensuring quicker operation.

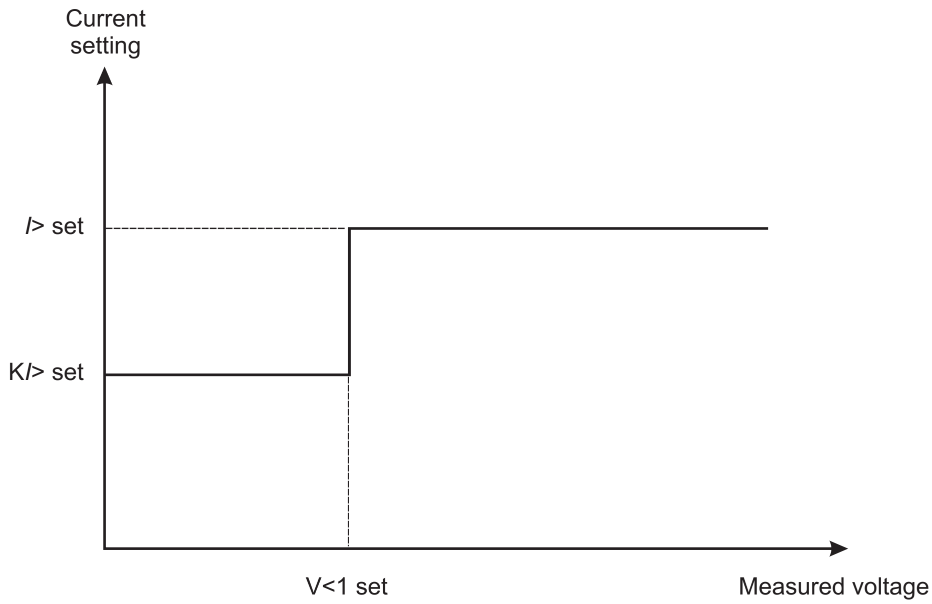


Figure 133 Modification of Current Pickup Level for Voltage Controlled Overcurrent Protection

4) Reverse Power Protection

If the prime mover power output fails or is reduced, the generator may take power from the system (or a parallel generator) to motor the prime mover. This is a serious situation and can cause considerable damage. A wattmetric relay element is used, set below the motoring level, to initiate tripping.

B) Indication of Abnormal Operation

The protection system includes a number of indicators or alarms for abnormal operation of the unit. These are:

- Over-voltage
- Under or over frequency
- Negative phase sequence

1) Negative Phase Sequence Protection

Negative phase sequence protection differs from all other forms of protection for the unit in that the need for protection is due to faults on the transmission system rather than in the generator unit. Faults on the system can cause negative-sequence current I_2 to flow in the generator. These 100 Hz currents can cause intense surface heating of the solid rotor of the generator that can cause severe damage.

Indication of excessive negative sequence current (I_2) is given by a negative sequence relay, which can, if the condition persists, trip the main breaker.

Manufacturers give generators two ratings:

1) For low values of negative sequence current. The continuous I_2 the machine can withstand (I2C).

2) For high values of negative sequence current. The short-time thermal withstand, in the form $K = (I_2)^2.t$.

The negative sequence relay has two settings: an alarm setting, $I_2>1$, related to (I2C), and a current trip setting related to the $(I_2)^2.t$ thermal characteristic for the generator. The trip time is calculated by the relay by matching the thermal, $(I_2)^2.t$ characteristics with specified values of K_g, the generator thermal capacity constant. K_g factors vary between 20 and 5: for smaller air-cooled generators to large, hydrogen cooled generators, respectively.

Within the relay Menu the I_2>1 settings refer to the alarm stage and I_2>2 settings to the trip time. Both have current settings. The I_2>1 alarm current setting should be less than the I_2>2 thermal current setting. The alarm stage time setting 'I2>1' Time Delay must be chosen to prevent operation during system fault clearance. A maximum operating time for the negative sequence thermal withstand protection may be set, 'I2>2 tMAX', where a machines thermal characteristics are uncertain.

Reference to the relay Technical Manual, Section 2.11, should be made for further information.

2) Tripping Sequence

For large generator units complete tripping (main breaker, field breaker and turbine) is only carried out for internal faults. For all external faults the generator back-up protection trips only the H V breaker.

In the Simulator, operation of main protection trips, in all cases, the main circuit breaker, CB8. However, for an earth fault on the stator winding the generator can still supply current to the fault even when the main breaker is open. Thus it is important to trip the field circuit of the generator, by circuit breaker CBF, which is normally connected via a make–before–break contactor to a field suppression resistor to dissipate the stored energy in the field.

The prime mover should be shut down as quickly as possible for internal faults. However this is not executed for Generator 1 as faults are simulated.

Setting the P343

The following settings should be entered into the settings files for Group 1 only.

To assist in defining the quantities listed, in greater detail than given above, the page numbers in the Areva P343 Technical Manual are given in each section.

Configuration (page 17 Ch2)

Active Settings	Group 1
Setting Group 1	Enabled
Setting Values	Primary

Group 1

Group 1 Gen Diff (page 17)	
Gen Diff Function	Percentage Bias
Gen Diff Is1	500.0 mA
Gen Diff k1	0%
Gen Diff Is2	10.00 A
Gen Diff k2	150.0%

Group 1 Power (page 62)	
Operating Mode	Generating
Power1 Function	Reverse
-P>1 Setting	80.00W
Power1 Time Delay	5.00s
Power1 DO Timer	0s
P1 Poledead Inh	Enabled
Power2	Disabled

NPS Thermal (page 57)	
I2>1 Alarm	Enabled
I2>1 Current Set	500.0 mA
I2>1 Time Delay	20.00 s
I2>2 Trip	Enabled
I2>2 Current Set	1.00 A
I2>2 k Setting	5.0 s
I2>2 kreset	5.00 s
I2>2 tMAX	400 s
I2>2 tMIN	1.0 s

Group 1 System Backup (page 35)	
Backup Function	Volt Controlled
V Dep OC Char	IECS1 TMS 0.025
V Dep OC I>Set	16 A
V Dep OC Delay	0.5
V Dep OC tRESET	0 s
V Dep OC V<1 Set	<140.00 V
V Dep OC k Set	250.0e-3

Group 1 Overcurrent (page 32)	
I>1 Function	IEC S Inverse
I>1 Current Set	7.00 A
I>1 TMS	250.0e-3
I>2 Function	DT
I>2 Current Set	15.00 A
I>2 Time Delay	0 s

Group 1 Residual O/V NVD (page 72)	
V_N Input	Measured
V_N>1 Function	DT
V_N>1 Voltage Set	5.00 V
V_N>1 Time Delay	1.00 s
V_N>1 Status	Disabled

Group 1 100% Stator EF (page 80)	
100%St EF Status	VN3H>Enabled
100%St EF VN3H>	10.00 V
VN3H> Delay	5.00 s

Group 1 Volt Protection (page 47 and 49)	
V<1 Function	Disabled
Group 1 Overvoltage	
V>1 Function	IDMT
V>1 Voltage Set	250.0 V
V>1 TMS	2.5

Group 1 Freq Protection (page 49 and 52)	
F< setting	47.00 Hz
F>1 Setting	53.05 Hz

Experiment 20: Generator Protection

There are two test points on the simulator, TP3 and TP4. These points are for investigating the protection of generator G1 for phase and earth faults. TP3 is close to the Generator terminals; TP4 is on the secondary side of the Generator Transformer.

Figure 5 shows the positioning of the protection functions discussed in the previous section. There are nine individual protection functions and elements available. The function not shown is the Neutral Volt Displacement protection that is combined with 100% Earth Fault. Both these relay functions require the measurement of voltage, VN, between earth and the neutral (or star point).

The position of the CTs and VTs for the protection functions are positioned as shown in Figure 25. The ratio of the VTs is 220/110 V line. Note that test point TP3 is positioned between the Generator and the system side (or downstream) CTs and VTs .

Testing of Individual Relay Functions

Before testing the Generator, make sure the 128Ω earth resistor is connected into the earth connection, and all links are inserted into TP3 and TP4.

1. Under/Over Frequency and Over Voltage.

Run the Generator without load and not synchronised. (CB8 open). Over voltage and frequency can be tested by excitation and speed control of the Generator. Over and underfrequency should trip at +/- 5% after approximately 15 seconds. Overvoltage starts at 250 V and an IDMT curve. Both will trip the generator field.

2. Differential and Overcurrent Protection Phase Faults

First set up on the Timer Circuit Breaker a line to line fault through the 9.6Ω inductor on the central control panel. Set the Timer for 0.1s. Run the Generator, unsynchronized, at normal frequency and a terminal voltage of 150 V.

Apply the line-line fault at TP3. The Differential Protection should operate and the start LED for Overcurrent may flicker.

If the voltage is increased to 220 V line, the Overcurrent could trip instantaneously as well, if the fault current is greater than the I > 2 Current Set of the relay, presently 15.0 A. Lower this setting and inhibit the Differential relay to test the instantaneous stage operation of the Overcurrent element.

3. Earth Fault Protection

First set up the Timer Circuit Breaker for a line to ground fault without the inclusion of the 9.6 Ω inductor.

Set the Timer at 1s. Run the Generator, unsynchronized, at normal frequency and a voltage of 230 V. These values are necessarily high due to the current limiting effect of the generators earthing resistor.

Apply a line-ground fault at TP3. The Differential Protection should trip. The Neutral Voltage Displacement protection should only show a start. If it does start, inhibit the differential trip protection and reapply the fault to prove tripping in 0.5 (see settings).

It will be found that if the voltage setting for 100%St EF VN3H>, in the 100% Stator EF protection, is lowered below 10.0 V, the protection will trip due to third harmonic voltages under normal running and load conditions.

4. System Back-up Protection.

The voltage sensing VT for the voltage-controlled Overcurrent Protection VT is positioned downstream of test point TP3. Connect into TP3 a 0.10 pu line to limit fault current and provide additional volt-drop between the Generator terminals and the voltage sensing VT. The present voltage setting for operation of the relay-(switching the Overcurrent IDMT characteristic to a more sensitive DT setting) is 130 V primary line voltage.

Measure the fault current and the line voltage at TP5 using Meter D, and the voltage at the location of the voltage sensing element using Meter C.

A line-line fault should be applied at TP5 by means of the Timer Circuit Breaker with the 9.6 Ω inductor connected between two phases; set the timer to 0.4s. Close CB8, before closing the Timer CB. The Generator relay should trip. If, at this point of the line, the voltage has dropped below 130 V the trip time should be <0.5s; if above 130 V the trip time will be >0.5s.

5. Negative Sequence Thermal Protection

The Negative Sequence Protection can be tested by connecting the Generator to a variable, phase-phase resistive load.

Connect Resistive Load 1 to Generator 1 by linking S10 to S5. Close CBs 8 and 9. Supply the load at 220 V and, using only one pot of the resistive load, adjust the current flowing in two phases to 2.6 A.

For line-line faults, or loads, symmetrical component analysis gives $I_{line} = \sqrt{3} \times I2$, where I2 is the negative sequence current. In this case I2 = 1.5 A or 58% of 2.6 A

The first indication that the NPS Thermal Protection is operating is the switching-on of the NPS Alarm LED after 20 s, the 'I2>1 Time Delay'. After 500 s, the 'I2>2 tMax' setting, the relay should trip.

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APPENDIX 1 ANSI/IEC Relay Symbols + The Per Unit System

ANSI/IEC Relay Symbols

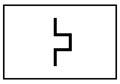
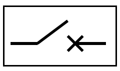
Description	ANSI	IEC 60617	Description	ANSI	IEC 60617
Overspeed Relay	12	$\omega >$	Inverse Time Earth Fault Overcurrent Relay	51G	I ⏚ $>$
Underspeed Relay	14	$\omega <$	Definite Time Earth Fault Overcurrent Relay	51N	I ⏚ $>$
Distance Relay	21	$Z <$	Voltage Restrained/ Controlled Overcurrent Relay	51V	U $I >$
Overtemperature Relay	26	$\theta >$	Power Factor Relay	55	$\cos\varphi >$
Undervoltage Relay	27	$U <$	Overvoltage Relay	59	$U >$
Directional Overpower Relay	32	$P >$	Neutral Point Displacement Relay	59N	$U_{rsd} >$
Underpower Relay	37	$P <$	Earth Fault Relay	64	I ⏚ $>$
Undercurrent Relay	37	$I <$	Directional Overcurrent Relay	67	$I >$
Negative Sequence Relay	46	$I_2 >$	Directional Earth Fault Relay	67N	I ⏚ $>$
Negative Sequence Voltage Relay	47	$U_2 >$	Phase Angle Relay	78	$\varphi >$
Thermal Relay	49		Auto Reclose Relay	79	O $\rightarrow$ I
Instantaneous Overcurrent Relay	50	$I >>$	Under Frequency Relay	81U	$f <$
Inverse Time Overcurrent Relay	51	$I >$	Over Frequency Relay	81O	$f >$
Circuit Breaker	52		Differential Relay	87	$I_d >$

Table 9 ANSI/IEC Relay Symbols

ANSI = American National Standards Institute. IEC = International Electrotechnical Commission.

The Per Unit System

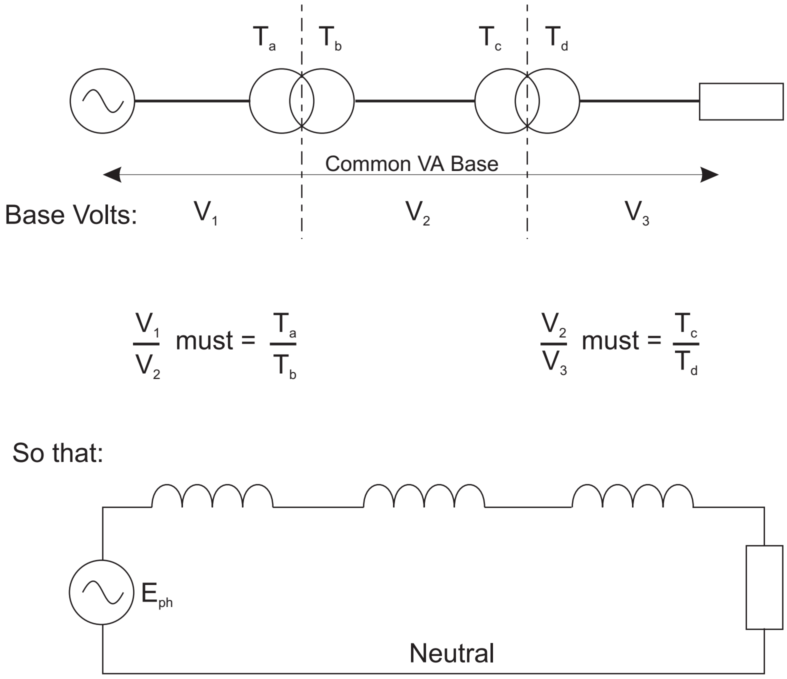


Figure 134 The Per Unit System

$$\text{p.u volts} = \frac{\text{Single phase volts}}{\text{Single phase base volts}} = \frac{\text{line volts}}{\text{base line volts}}$$

$$\text{p.u VA} = \frac{\text{Single phase VA}}{\text{Single phase base VA}} = \frac{\text{3 phase VA}}{\text{3 phase base VA}}$$

$$\text{Base current} = \frac{\text{Single phase base VA}}{\text{Single phase base volts}} = \frac{\text{3 phase base VA}}{\sqrt{3} \times \text{base line volts}}$$

$$\text{Base Impedance} = \frac{\text{Single phase base volts}}{\text{base line current}} = \frac{(\text{ single phase base volts})^2}{\text{single phase base VA}}$$

$$= \frac{(\text{base line volts})^2}{\text{3 phase base VA}} \left[\frac{(\text{kV})^2}{\text{MVA}}\right]$$

$$\text{Zpu}_2 = \text{Zpu}_1\left(\frac{\text{VA}_2}{\text{VA}_1}\right) \times \left(\frac{\text{V}_{b1}}{\text{V}_{b2}}\right)^2$$

APPENDIX 2 Protection: Definitions and Terminology

Back–up protection

A Protective system intended to supplement the main protection in case the latter should be ineffective, or to deal with faults in those parts of the power system that are not readily included in the operating zones of the main protection.

Biased relay

A relay in which the characteristics are modified by the introduction of some quantity other than the actuating quantity, and which is usually in opposition to the actuating quantity.

Burden

The loading imposed by the circuits of the relay on the energising power source or sources, expressed as the product of voltage and current (volt–amperes, or watts if d.c.) for a given condition, which may be either at 'setting' or at rated current or voltage.

The rated output of measuring transformers, expressed in VA, is always at rated current or voltage and it is important, in assessing the burden imposed by a relay, to ensure that the value of burden at rated current is used.

Characteristic curve

The curve showing the operating value of the characteristic quantity corresponding to various values or combinations of the energising quantities.

Discrimination

The ability of a protective system to distinguish between power system conditions for which it is intended to operate and those for which it is not intended to operate.

Drop-out

A relay drops out when it moves from the energised position to the un–energised position.

Earth fault protective system

A protective system which is designed to respond only to faults to earth.

Earthing transformer

A three–phase transformer intended essentially to provide a neutral point to a power system for the purpose of earthing.

Electrical relay

A device designed to produce sudden predetermined changes in one or more electrical circuits after the appearance of certain conditions in the electrical circuit or circuits controlling it.

Note: The term 'relay' includes all the ancillary equipment calibrated with the device.

Electromechanical relay

An electrical relay in which the designed response is developed by the relative movement of mechanical elements under the action of a current in the input circuit.

Embedded generation

Generation that is connected to a distribution system (possibly at LV instead of HV) and hence poses particular problems in respect of electrical protection.

Energising quantity

The electrical quantity, either current or voltage, which alone or in combination with other energising quantities, must be applied to the relay to cause it to function.

Independent time measuring relay

A measuring relay, the specified time for which can be considered as being independent, within specified limits, of the value of the characteristic quantity.

Instantaneous relay

A relay which operates and resets with no intentional time delay.

NOTE: All relays require some time to operate; it is possible, within the above definition, to discuss the operating time characteristics of an instantaneous relay.

Inverse time delay relay

A dependent time delay relay having an operating time which is an inverse function of the electrical characteristic quantity.

Inverse time relay with definite minimum time (I.D.M.T.)

An inverse time relay having an operating time that tends towards a minimum value with increasing values of the electrical characteristic quantity.

Knee-point e.m.f.

That sinusoidal e.m.f applied to the secondary terminals of a current transformer, which, when increased by 10% causes the exciting current to increase by 50%.

Main Protection

The protective system which is normally expected to operate in response to a fault in the protected zone.

Measuring relay

An electrical relay intended to switch when its characteristic quantity, under specified conditions and with a specified accuracy attains its operating value.

Operating time

With a relay de-energised and in its initial condition, the time which elapses between the application of a characteristic quantity and the instant when the relay operates.

Operating time characteristic

The curve depicting the relationship between different values of the characteristic quantity applied to a relay and the corresponding values of operating time.

Operating value

The limiting value of the characteristic quantity at which the relay actually operates.

Pick-up

A relay is said to ‘pick-up’ when it changes from the de-energised position to the energised position.

Protected zone

The portion of a power system protected by a given protective system or a part of that protective system.

Protection gear

The apparatus, including protective relays, transformers and ancillary equipment, for use in a protective system.

Protection relay

A relay designed to initiate disconnection of a part of an electrical installation or to operate a warning signal, in the case of a fault or other abnormal condition in the installation.

A protective relay may include more than one unit electrical relay and accessories.

Protection scheme

The coordinated arrangements for the protection of one or more elements of a power system.

A protective scheme may comprise several protective systems.

Protection system

A combination of protective gear designed to secure, under predetermined conditions, usually abnormal, the disconnection of an element of a power system, or to give an alarm signal, or both.

Rating

The nominal value of an energising quantity which appears in the designation of a relay. The nominal value usually corresponds to the CT and VT secondary ratings.

Residual current

The algebraic sum, in multi-phase system, of all the line currents.

Residual voltage

The algebraic sum, in a multi-phase system, of all the line-to earth voltages.

SCADA

Supervisory Control and Data Acquisition.

Setting

The limiting value of a 'characteristic' or 'energising' quantity at which the relay is designed to operate under specified conditions.

Such values are usually marked on the relay and may be expressed as direct values, percentages of rated values, or multiples.

Stability

The quality whereby a protective system remains inoperative under all conditions other than those for which it is specifically designed to operate.

Stability limits

The r.m.s. value of the symmetrical component of the through fault current up to which the protective system remains stable.

Static relay

An electrical relay in which the designed response is developed by electronic, magnetic, optical or other components without mechanical motion.

It should be noted though that few static relays have a fully static output stage, to trip directly from thyristors for example. By far the majority of static relays have attracted armature output elements to provide metal-to-metal contacts. which remain the preferred output medium in general.

System impedance ratio (S.I.R)

The ratio of the power system source impedance to the impedance of the protected zone.

Time delay

A delay intentionally introduced into the operation of a relay system.

Transducer

A device that provides a d.c. output quantity that has a definite relationship to the a.c. input quantity being measured.

Unit protection

A protection system which is designed to operate only for abnormal conditions within a clearly defined zone of the power system.

Unrestricted protection

A protection system which has no clearly defined zone of operation and which achieves selective operation only by time grading.

APPENDIX 3 Connection Diagrams

Experiments 2 and 3: Generator Control

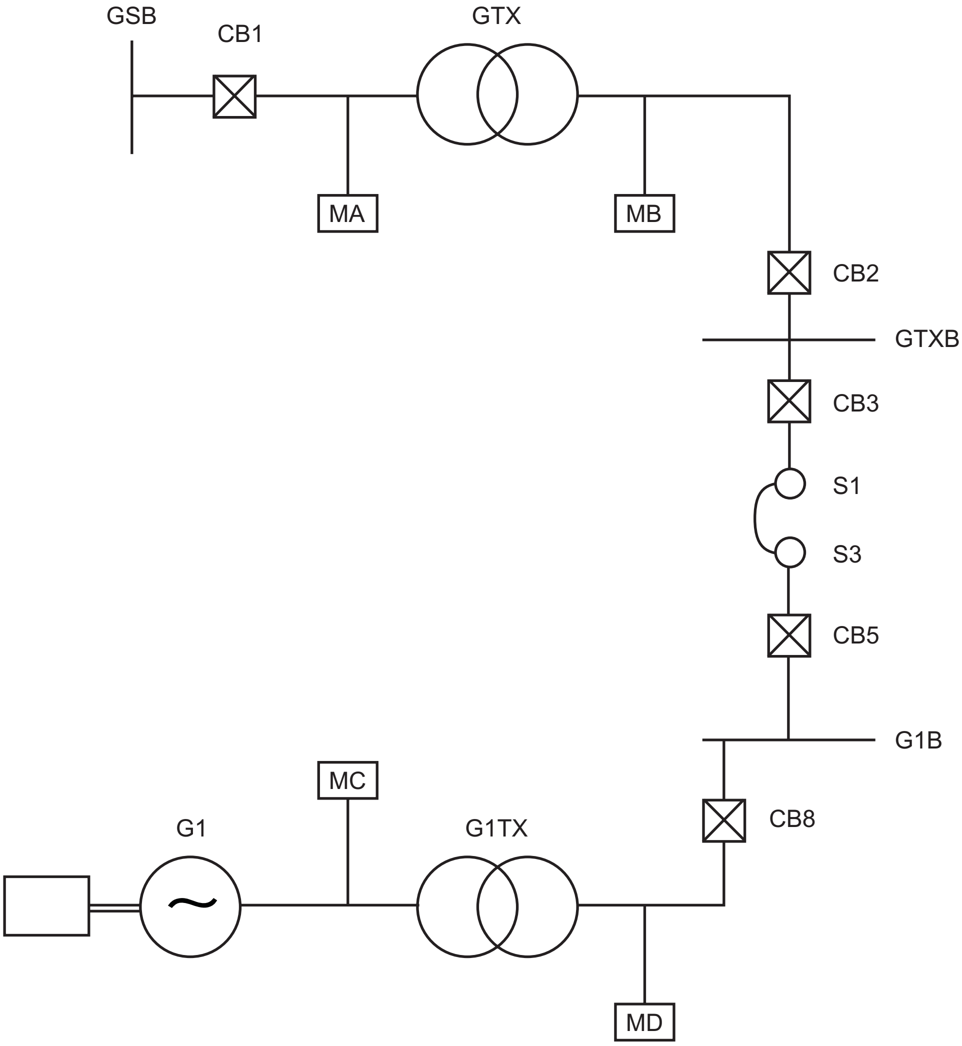


Figure 135 Connection Diagram for Experiments 2 and 3

Experiments 4 and 5: System Voltage Regulation

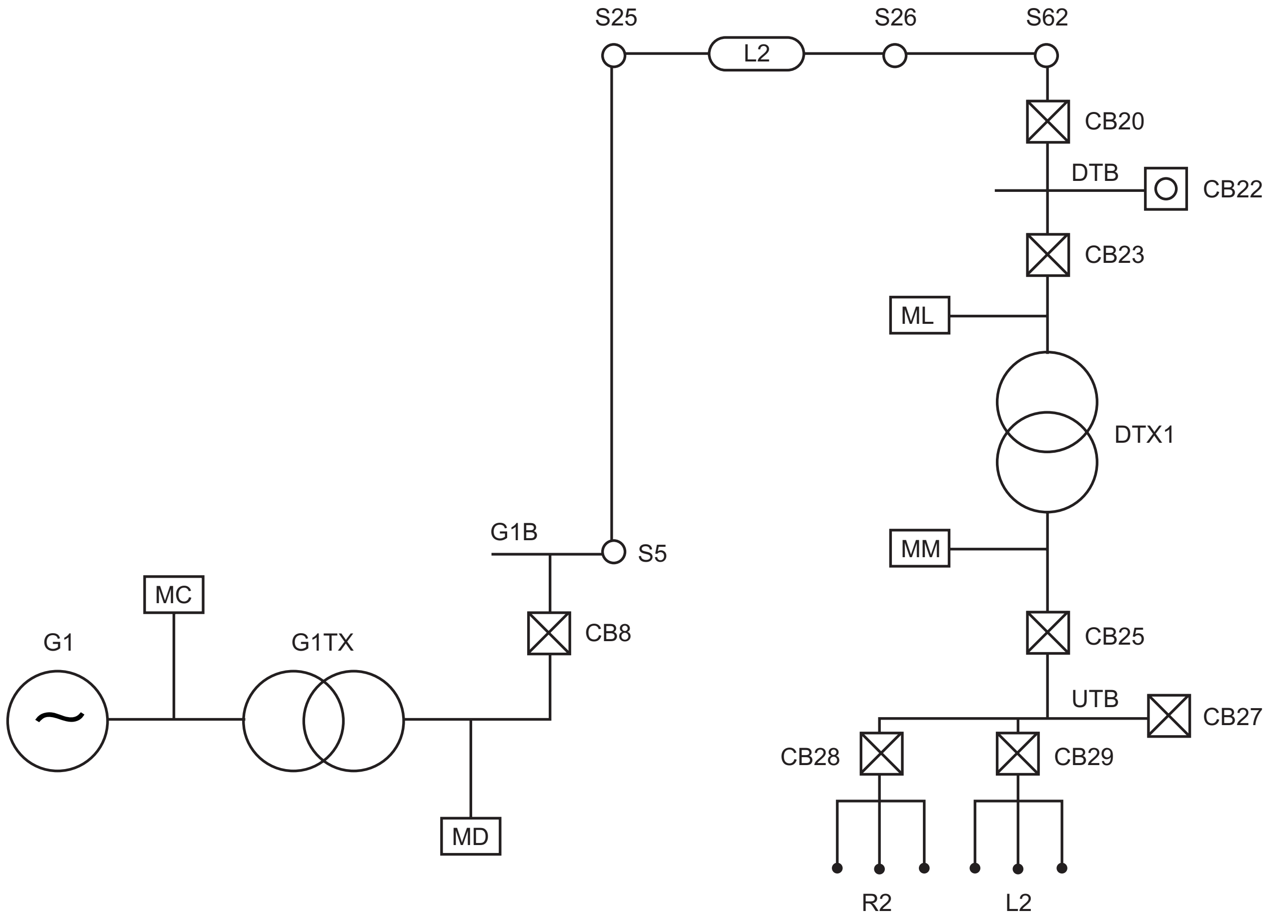


Figure 136 Connection Diagram for Experiments 4 and 5

Experiment 6: Three Phase Transformers - Parts A, B, C and D

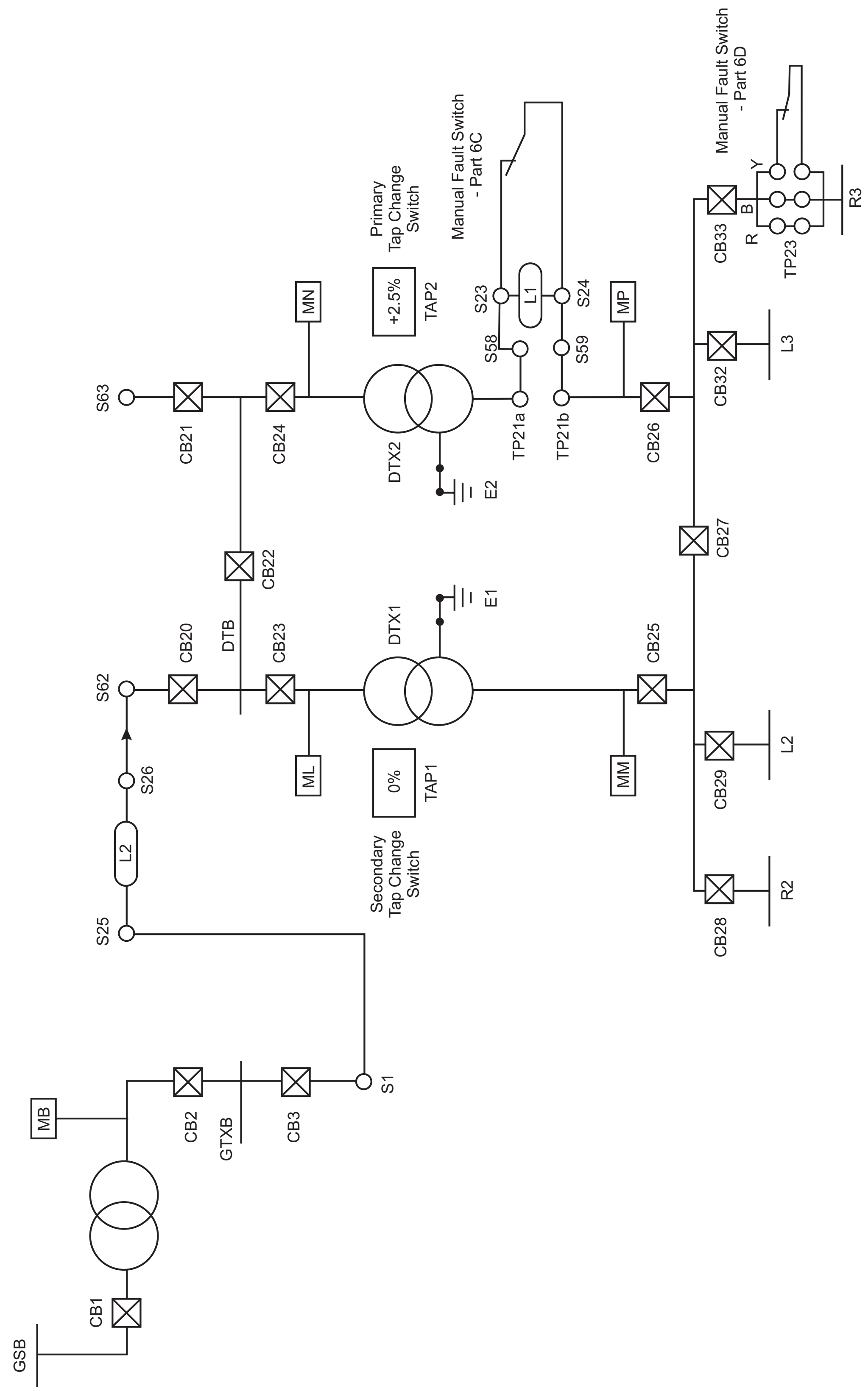


Figure 137 Connection Diagram for Experiment 6

Experiment 7: Load Flow

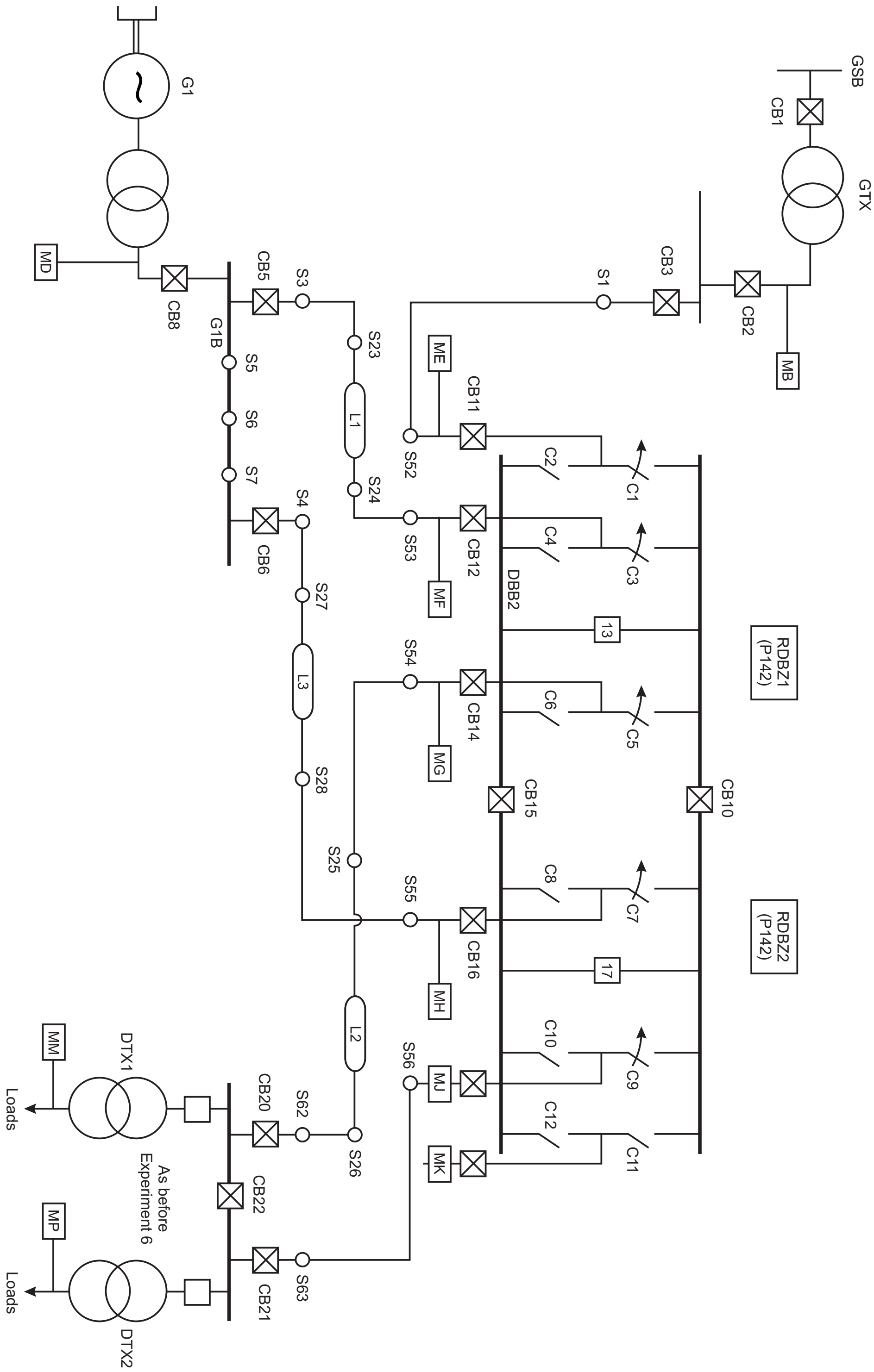


Figure 138 Connection Diagram for Experiment 7

Experiment 8 Part A: Symmetrical Faults - Unloaded System

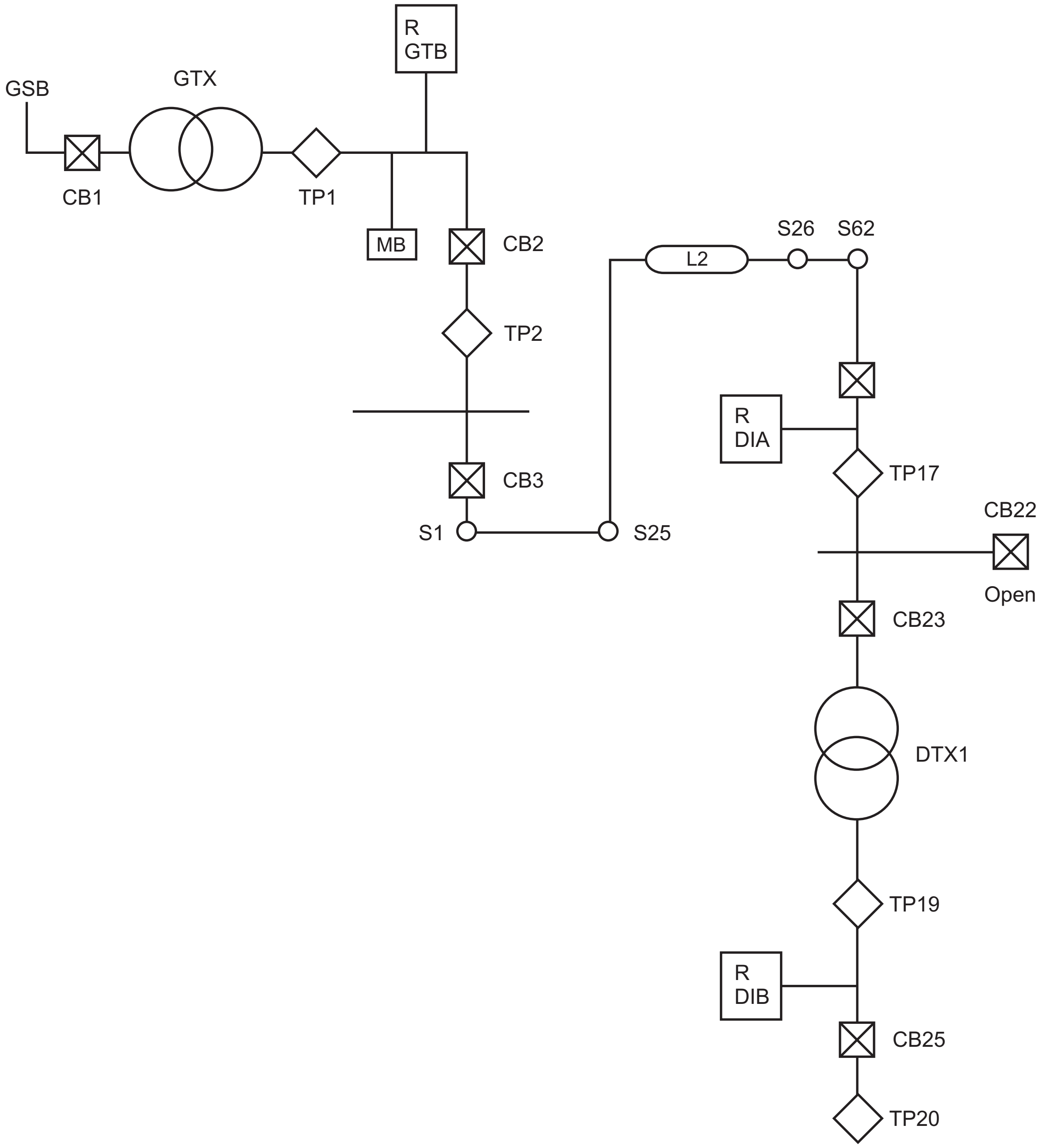


Figure 139 Connection Diagram for Experiment 8a

Experiment 8 Part B: Symmetrical Faults - Loaded System

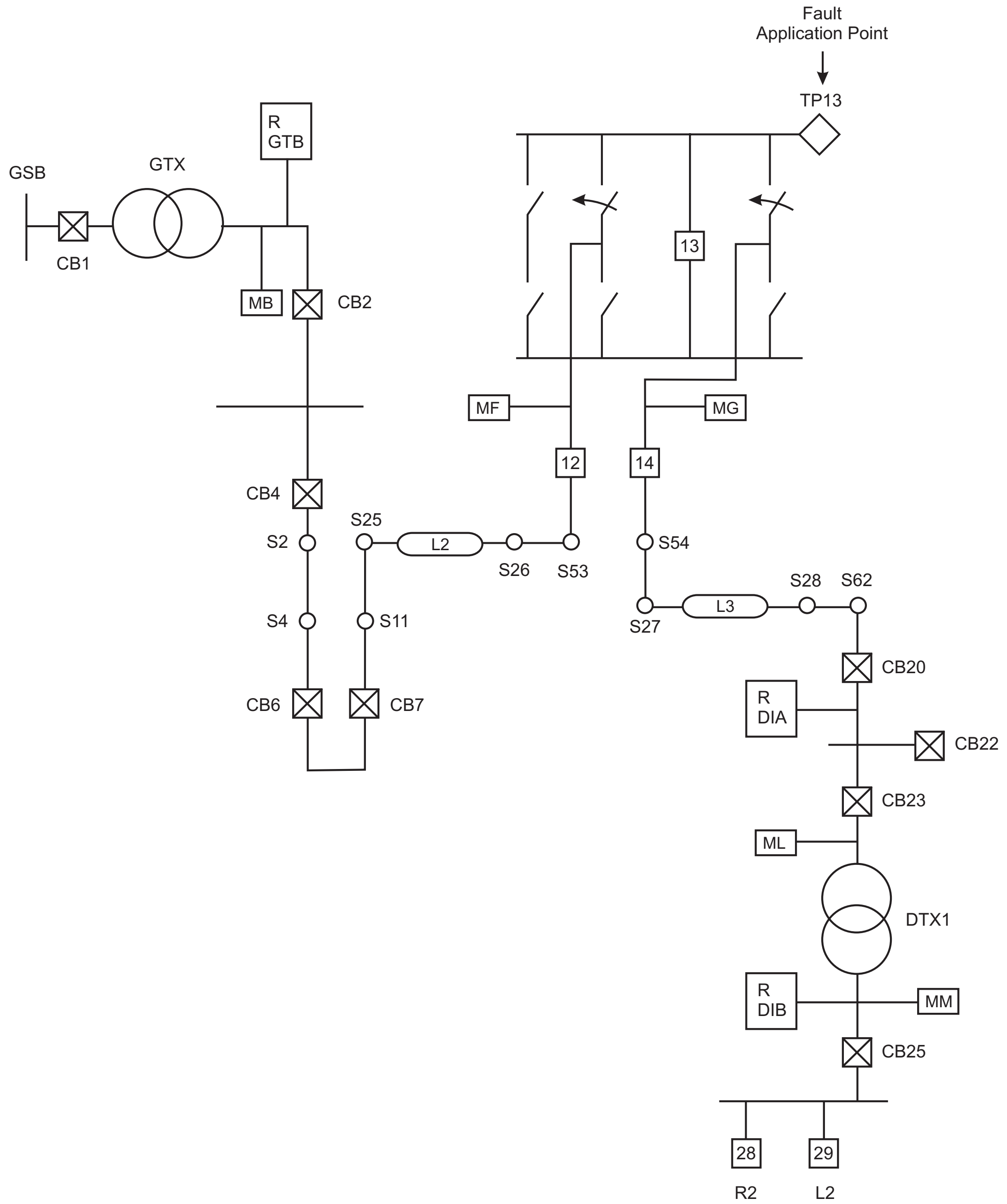


Figure 140 Connection Diagram for Experiment 8b.

Experiment 8 Part C: Symmetrical Faults - Induction Motor Contribution

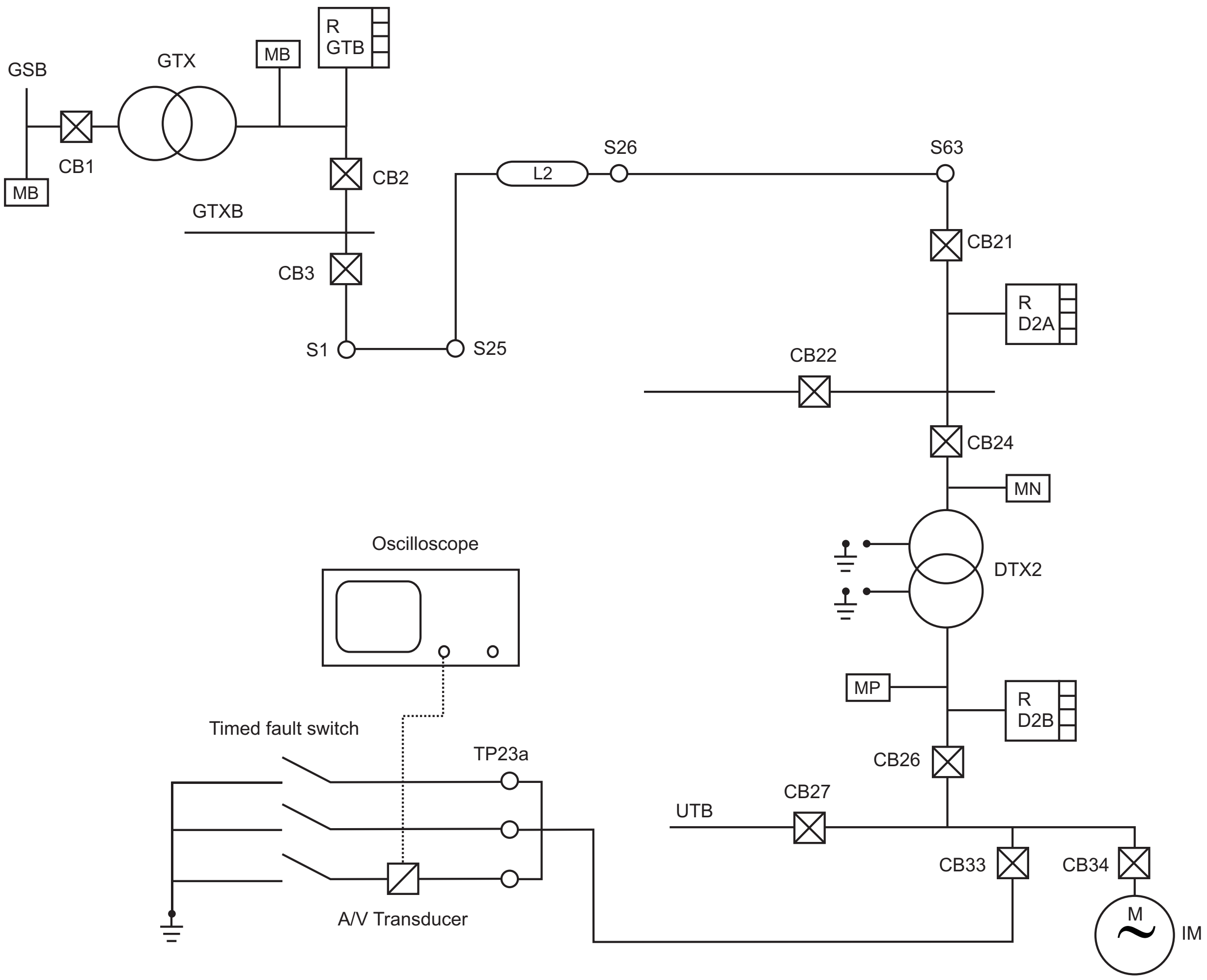


Figure 141 Connection Diagram for Experiment 8c

Experiment 8 Part D: Symmetrical Faults - Four Bus System

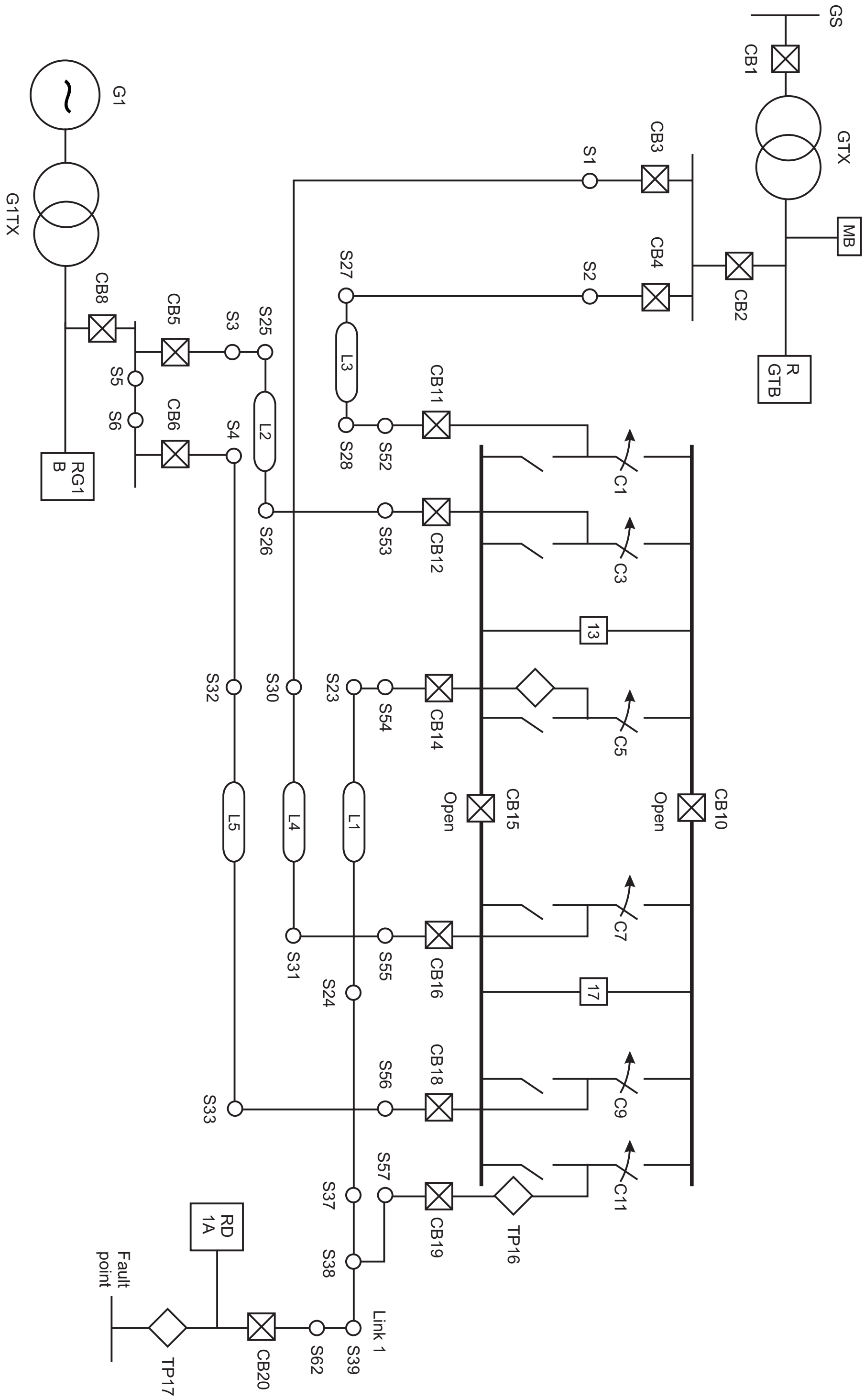


Figure 142 Connection Diagram for Experiment 8d

Experiment 9a and 9b: Unsymmetrical Faults - I2 Measurement and Transmission Line Faults

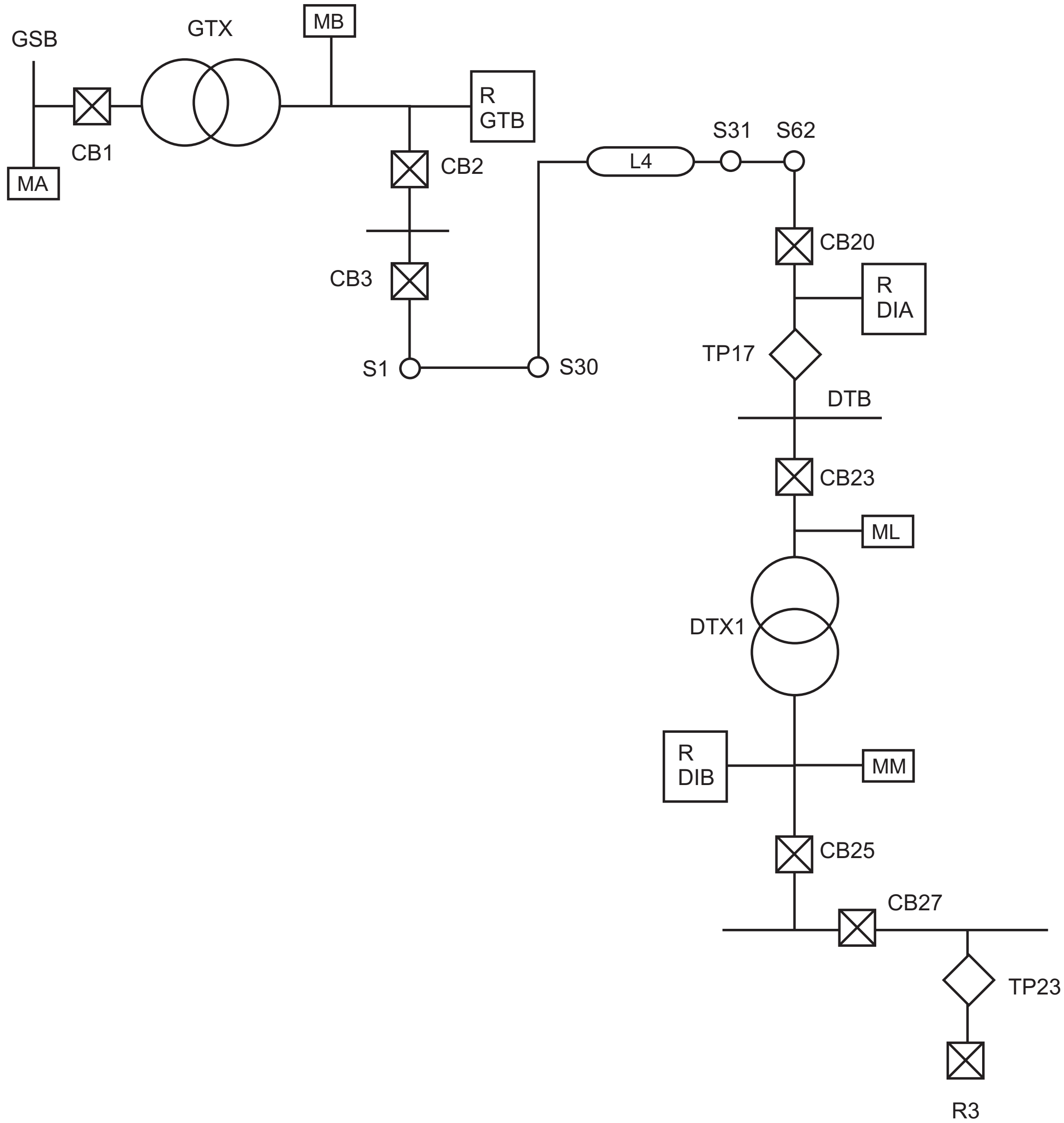


Figure 143 Connection Diagram for Experiments 9a and 9b

Experiment 9c: Unsymmetrical Faults - Transformer Terminated Line

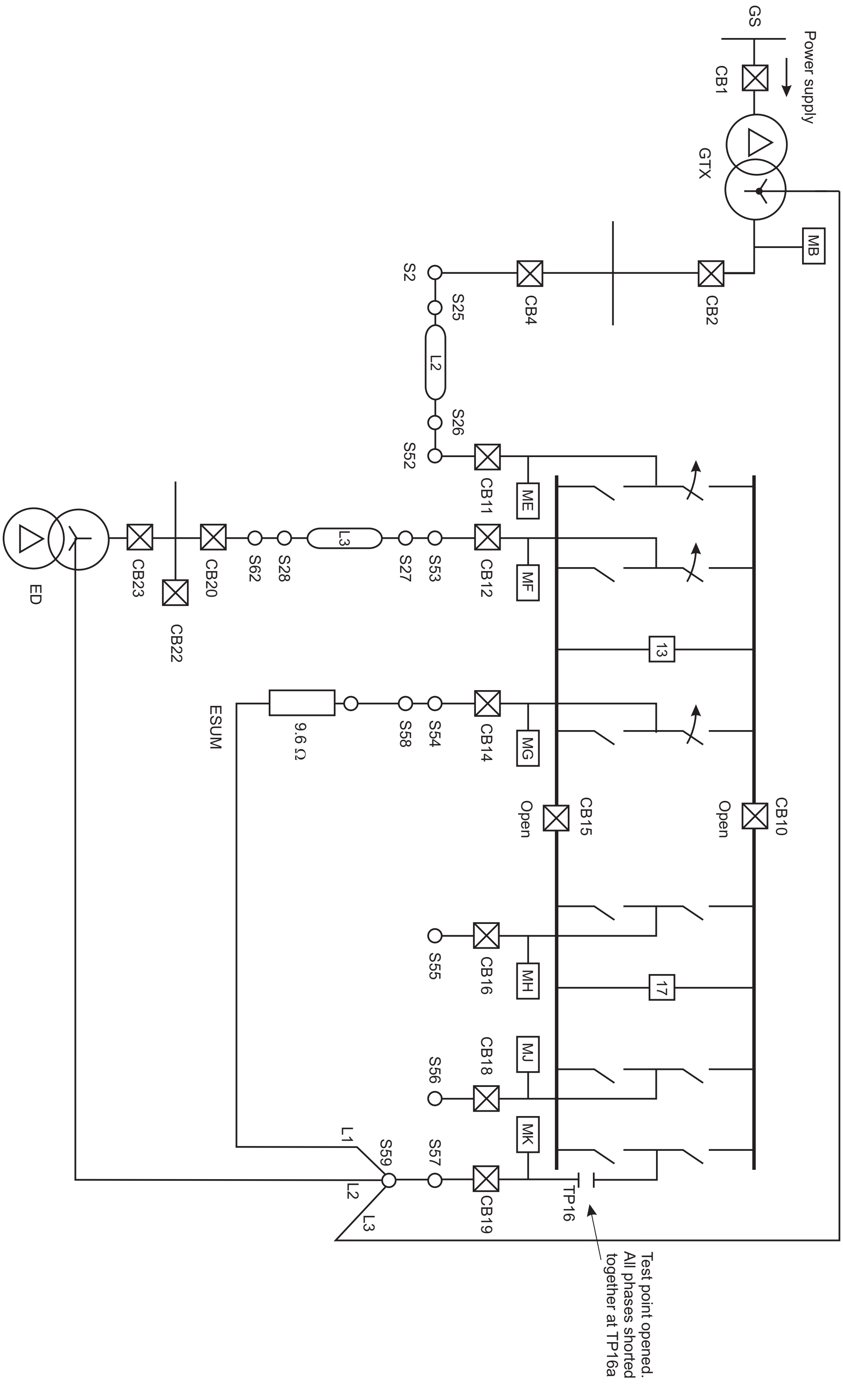


Figure 144 Connection Diagram for Experiment 9c

Experiment 9d: Unsymmetrical Faults - Double End Feed

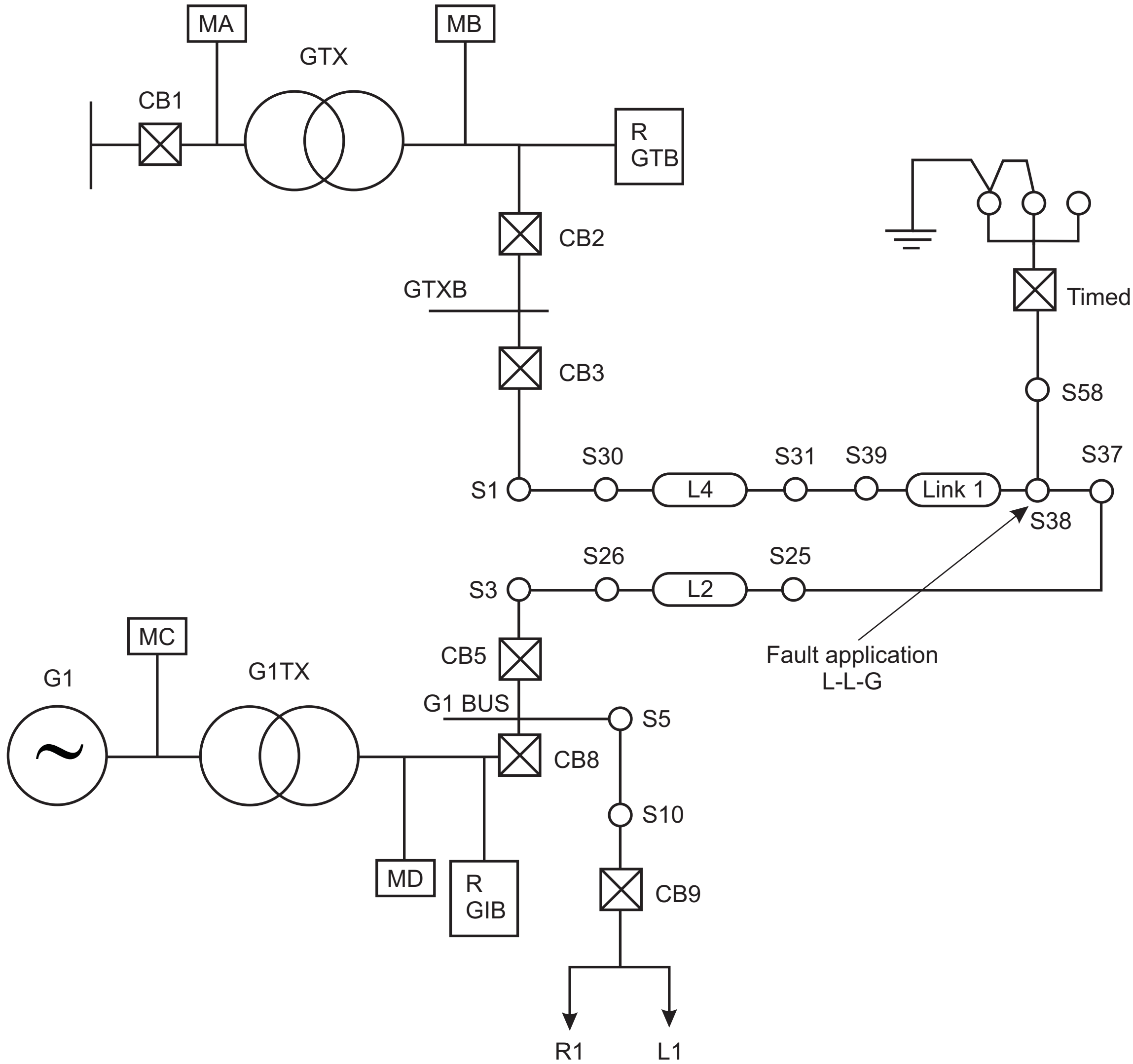


Figure 145 Connection Diagram for Experiment 9d.

Experiment 10: Transient Over voltages

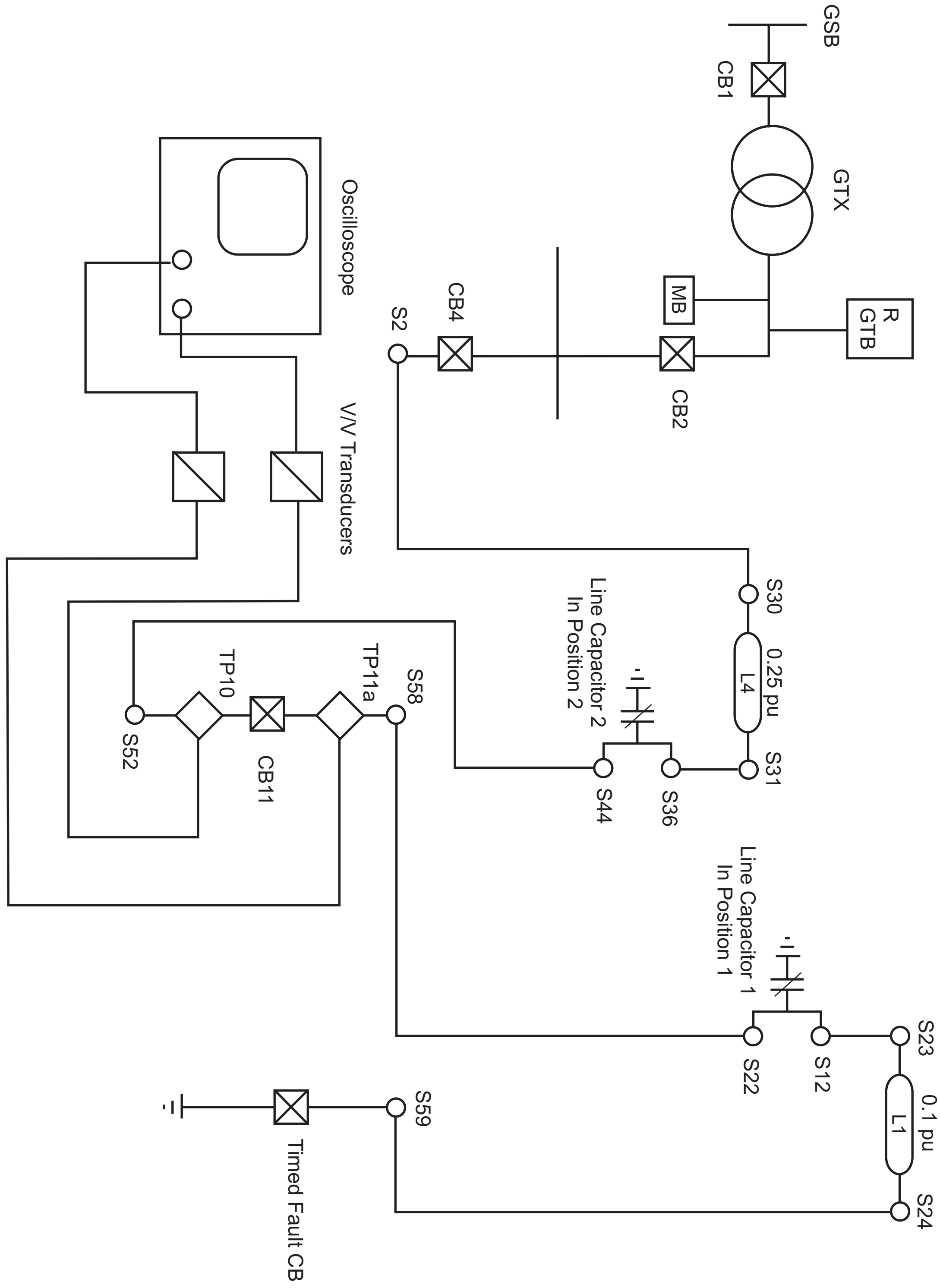


Figure 146 Connection Diagram for Experiment 10.

Experiments 12, 14 and 15: Overcurrent Protection - Relay Grading, High Set and Back Trip

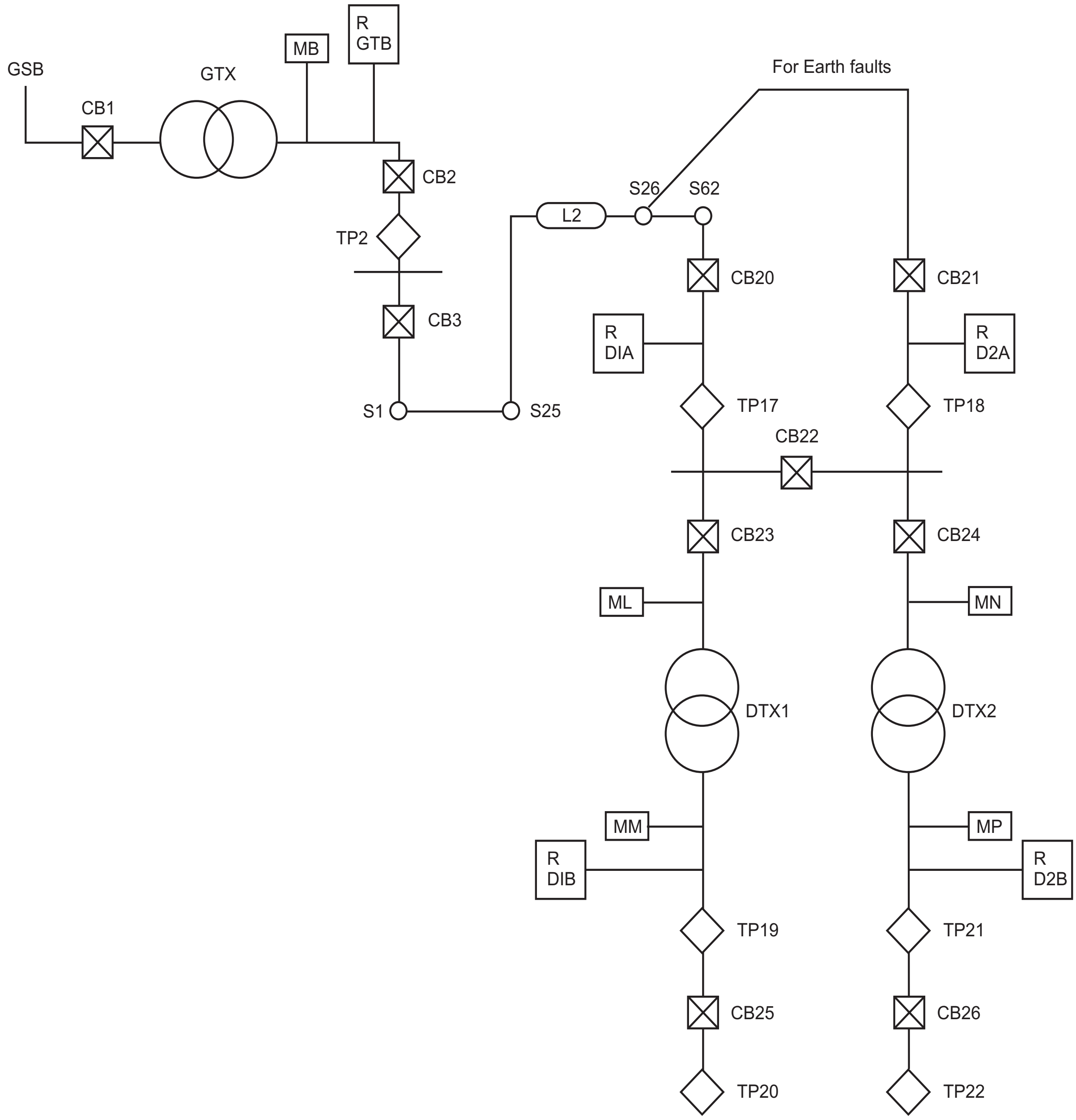


Figure 147 Connection Diagram for Experiments 12, 14 and 15.

Experiment 13: Overcurrent Protection - Auto Reclose

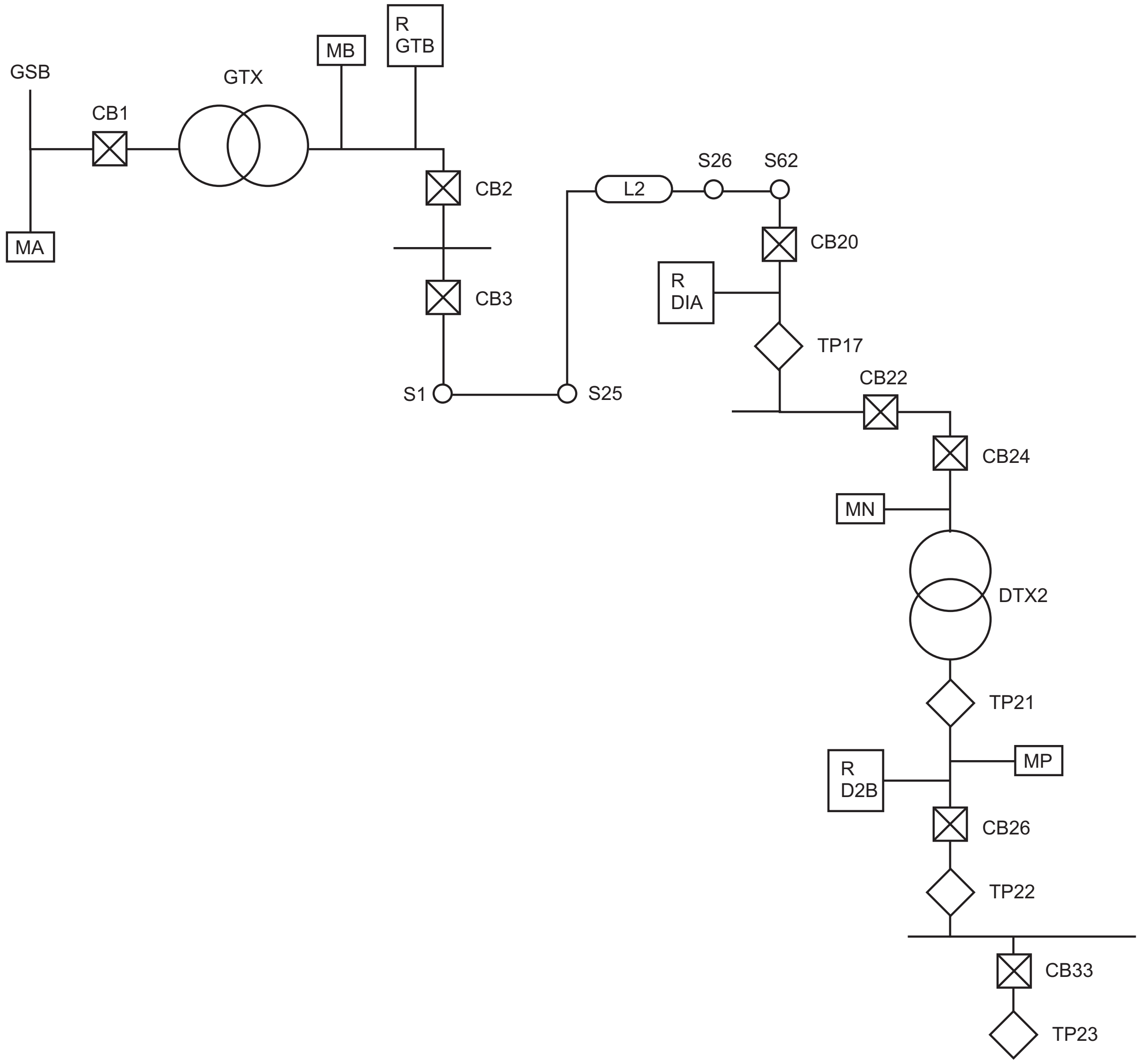


Figure 148 Connection Diagram for Experiment 13.

Experiment 16: Overcurrent Protection - Directional Control

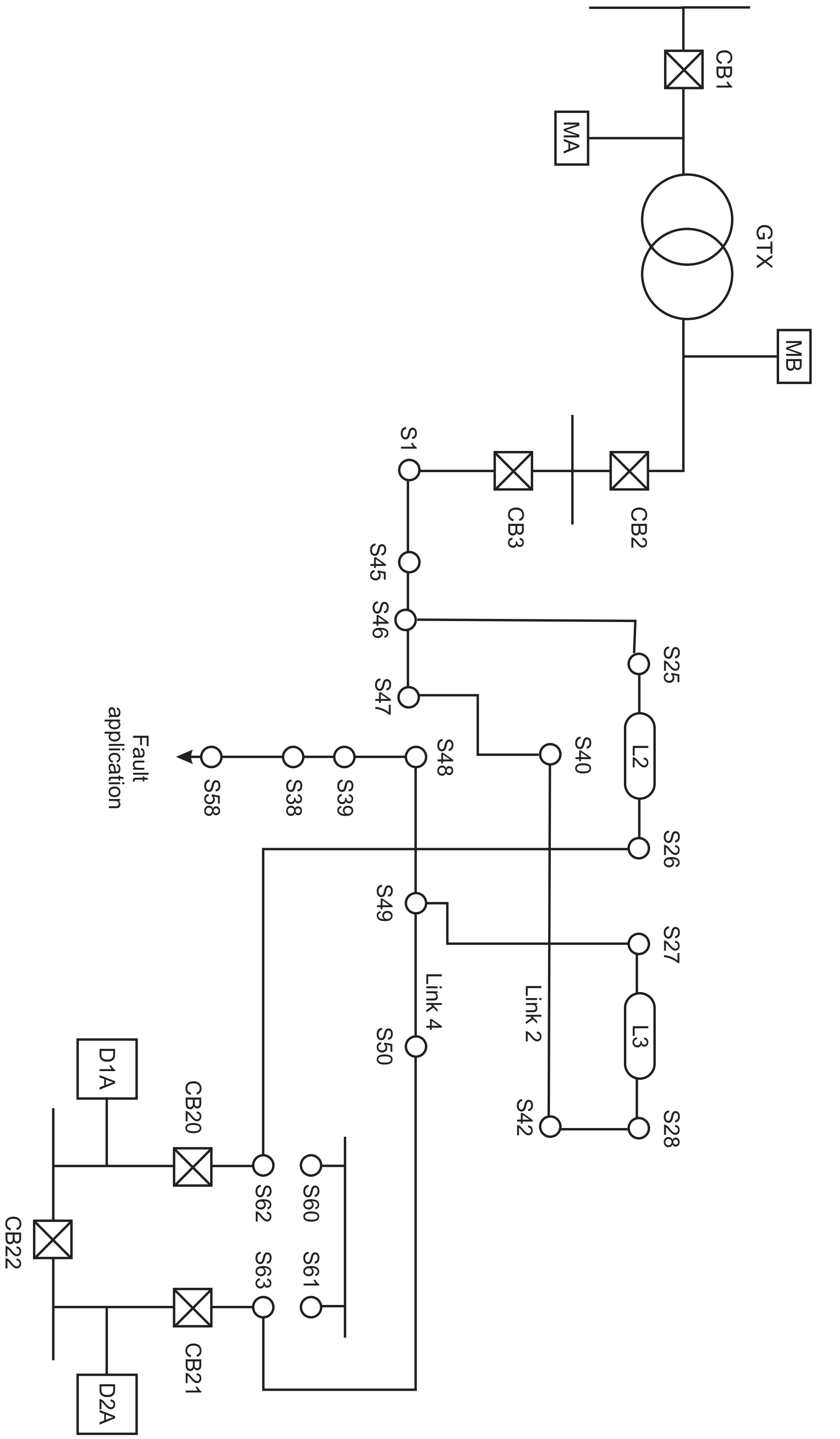


Figure 149 Connection Diagram for Experiment 16.

Experiment 17: Distance Protection

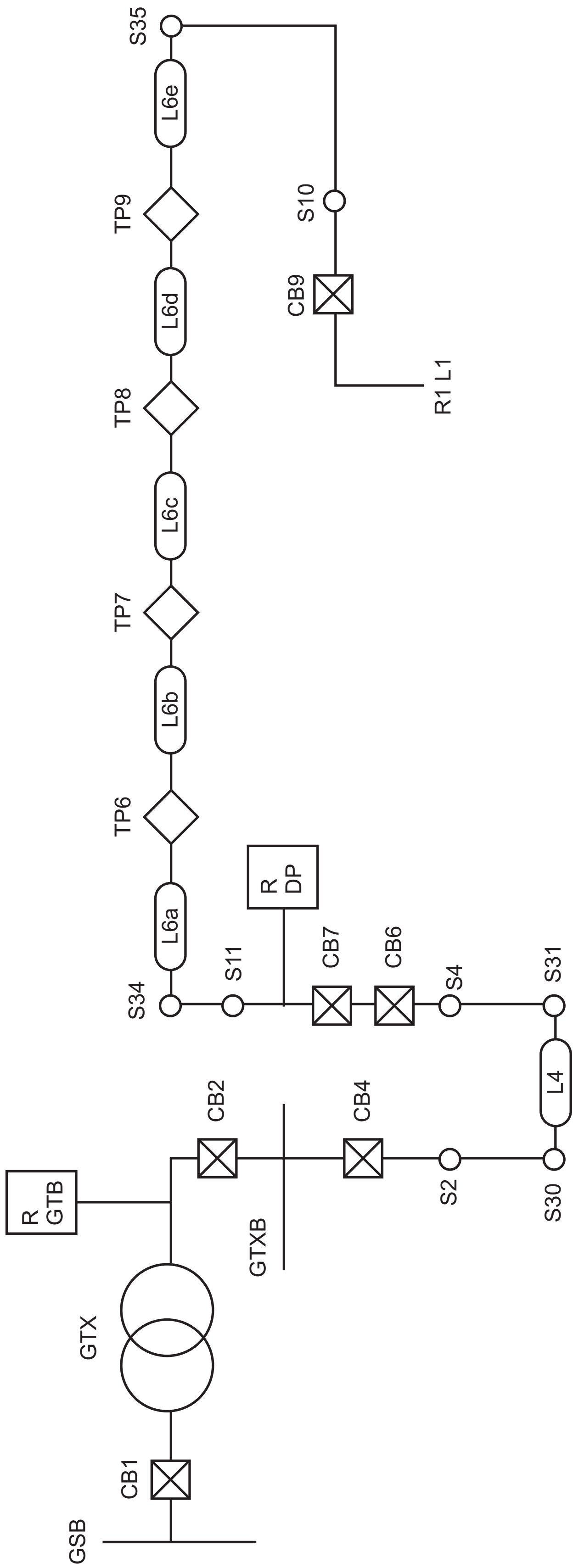


Figure 150 Connection Diagram for Experiment 17

Experiment 18: Grid Transformer Protection

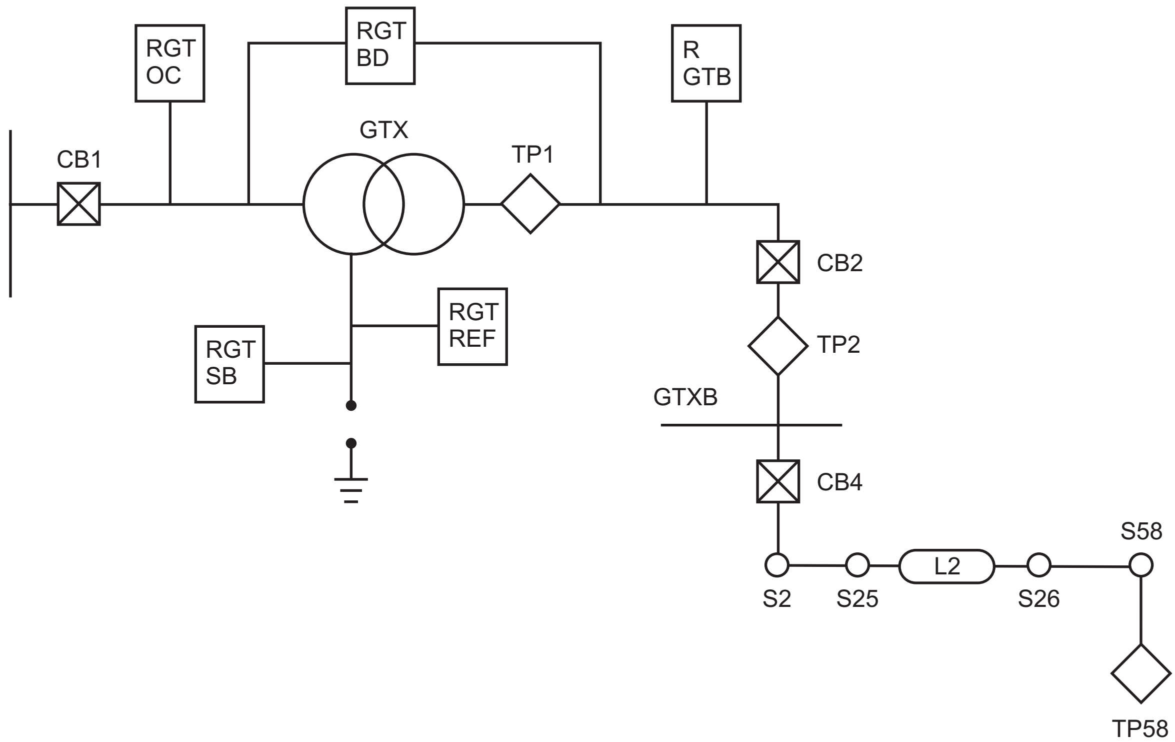


Figure 151 Connection Diagram for Experiment 18.

Experiment 19: Busbar Protection

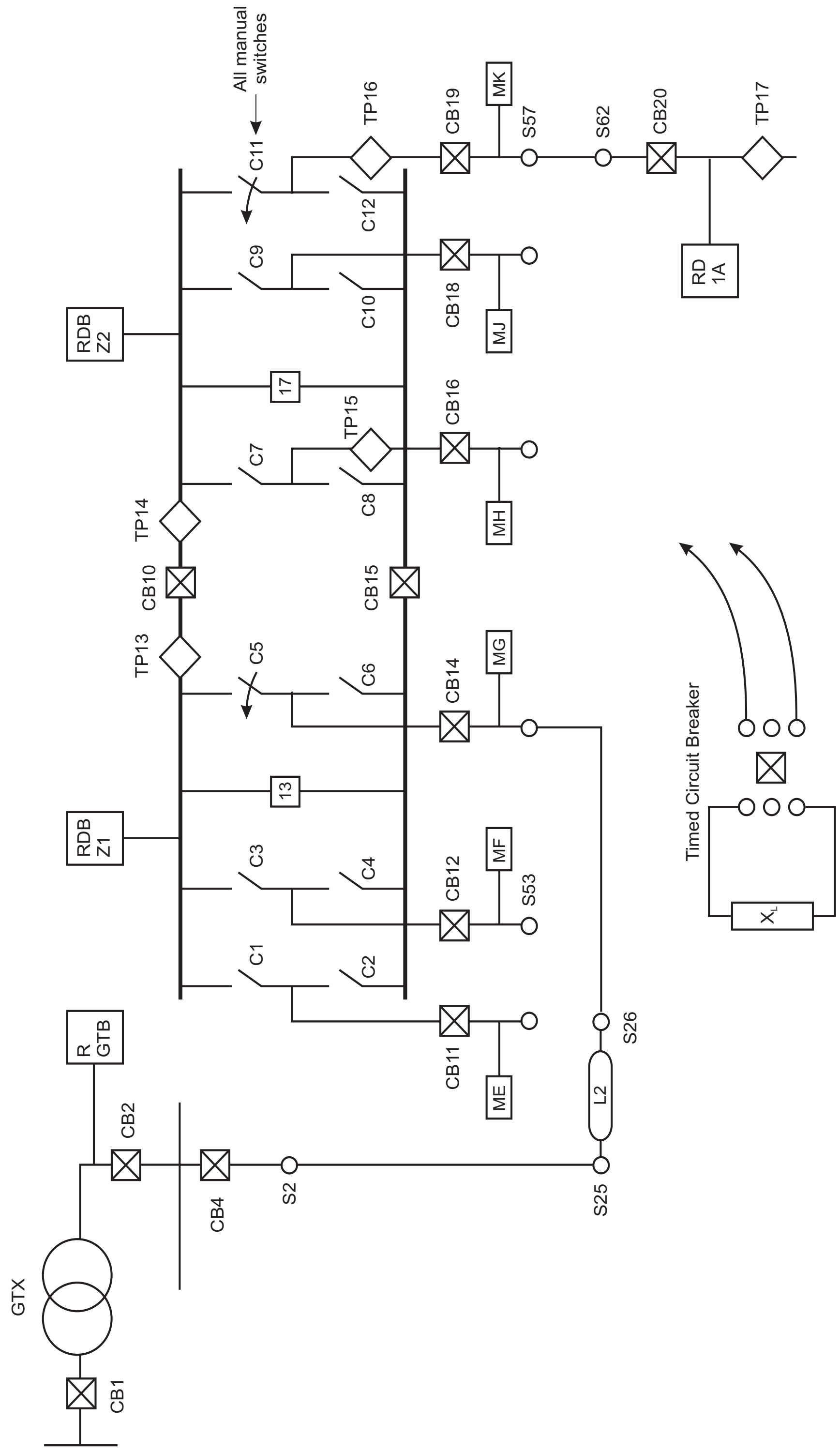


Figure 152 Connection Diagram for Experiment 19

Experiment 20: Generator Protection

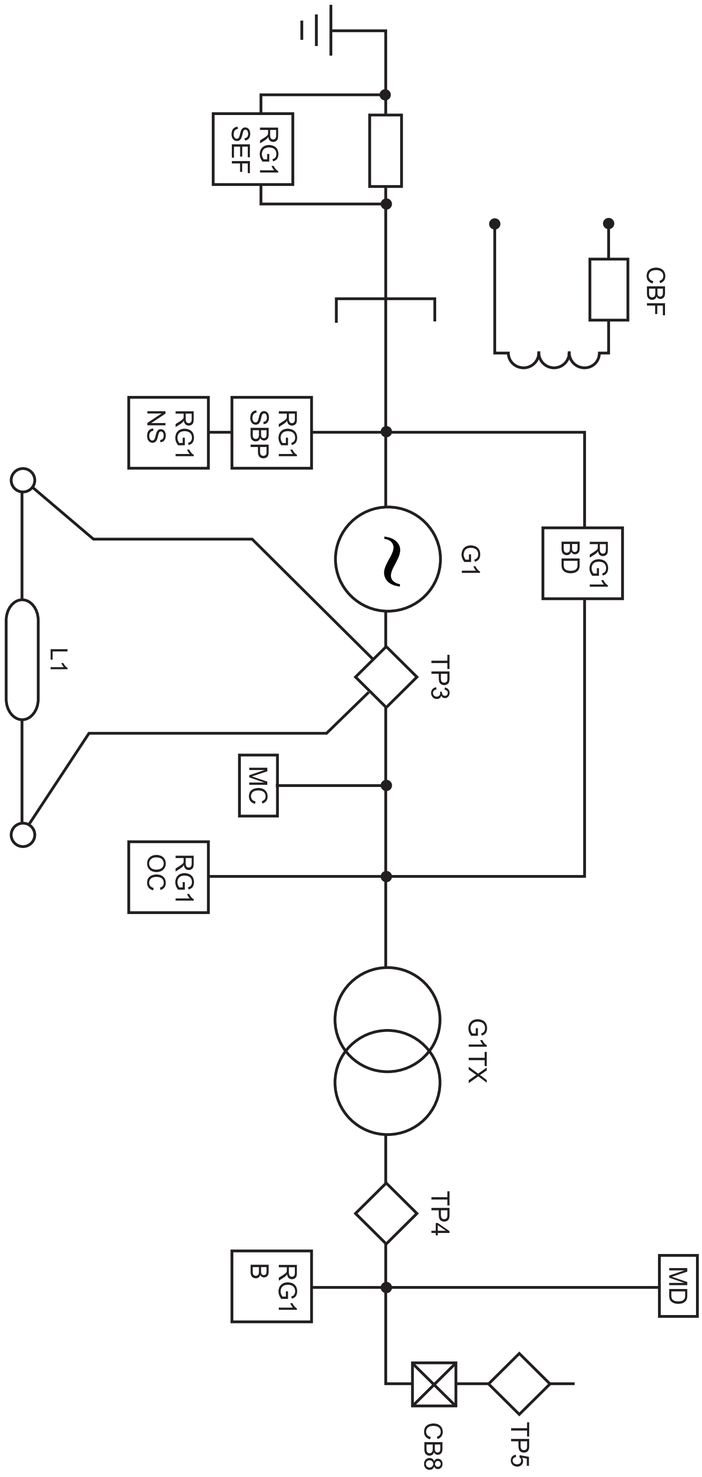
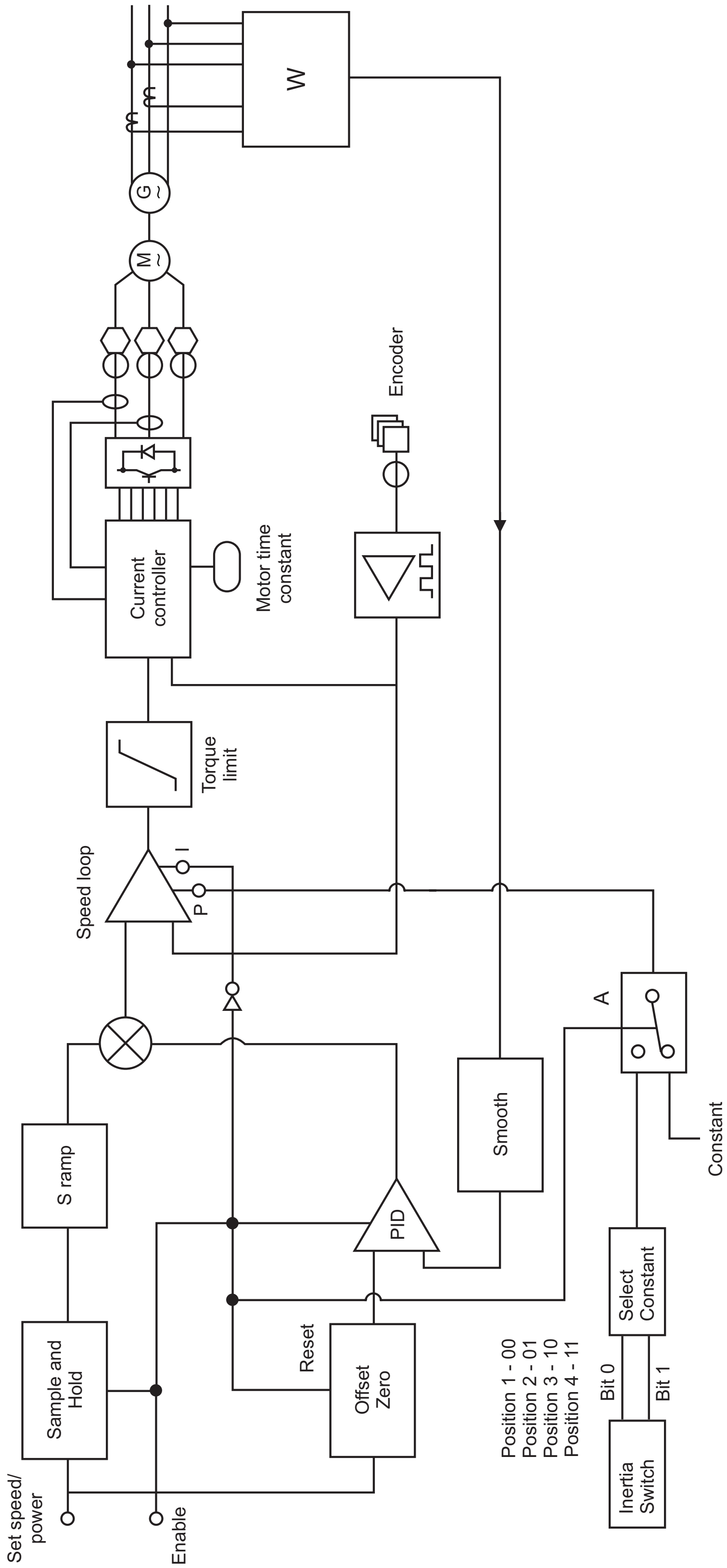


Figure 153 Connection Diagram for Experiment 20.

APPENDIX 4 Control Circuit for the Vector Drive



Note:

An input to the enable terminal occurs when Gen1 is synchronised by closing CB8. The PID is thus enabled and switch A closed. Enabling the PID connects the power feedback 'W' into the circuit.

Figure 154 Control Circuit for the Vector Drive

Relay Override (O/R) and Enable Buttons

Grid Transformer Relay P632

- Grid Overcurrent (O/C) Override (O/R)
- Grid Diff O/R
- Grid Standby Earth Fault (E/F) O/R
- Grid Restricted E/F O/R

Gen 1 Relay P343

- Stator E/F O/R
- System Backup O/R
- Neg Phase Sequence O/R
- Gen Diff O/R
- Overvolts O/R
- Under/Over Frequency (Hz) O/R
- O/C I> O/R, O/C I>> O/R, Rev Power O/R

Distance Relay P442

- Distance Override

Busbar Protection P142 (2)

- Bus A O/R
- Bus B O/R

Distribution Bus P142 (4)

- RD1A - D1A IDMT O/R, D1A Inst O/R
- RD1B - IDMT O/R, D1B Inst O/R, D1B Bk Trip Enable
- RD2A - D2A IDMT O/R, D2A Inst O/R
- RD2B - IDMT O/R, D2B Inst O/R, D2B Bk Trip Enable and Auto Reclose

Grid Bus P122

- Grid Overcurrent Override

Generator Bus P122

- Generator Overcurrent Override

Micom Relays - Programmable LED Assignments

P632 - Grid Transformer	
LED 1	FT_RC Id>Triggered
LED 2	FT_RC IR>STriggered
LED 3	IDMT 1 Iref>Starting, A
LED 4	IDMT 1 Iref>Starting, B
LED 5	IDMT 1 Iref>Starting, C
LED 6	IDMT 2 Starting
LED 7	Ref 2 Trip
LED 8	Diff Trip
LED 9	IDMT1 tIref, P>elapsed
LED 10	IDMT1 tIref, N>elapsed
LED 11	General Starting
LED 12	DIFF Starting

P442 - Distance Protection	
LED 1	Zone 1
LED 2	Zone 2
LED 3	Zone 3
LED 4	Zone 4
LED 5	Distance Trip A
LED 6	Distance Trip B
LED 7	Distance Trip C
LED 8	Any Start

P343 - Generator Protection	
LED 1	I> Start
LED 2	V >1 Start
LED 3	Rev pwr Start
LED 4	Stator EF Start
LED 5	Freq Start
LED 6	NPS Alarm
LED 7	V Dep O/C Start
LED 8	Any Start

P142 - Bus A	
LED 1	I>Start
LED 2	Status CB11
LED 3	Status CB12
LED 4	Status CB14
LED 5	Status CB13
LED 6	Status CB10
LED 7	Status CB15
LED 8	

P142 - Bus B	
LED 1	I>1 Start
LED 2	Status CB16
LED 3	Status CB18
LED 4	Status CB19
LED 5	Status CB17
LED 6	Status CB10
LED 7	Status CB15
LED 8	

P142 - D1-A	
LED 1	I>1 Start
LED 2	I>2 Start
LED 3	IN>1 Start
LED 4	I>1 Trip
LED 5	I>2 Trip
LED 6	IN>1 Trip
LED 7	
LED 8	

P142 - D1-B	
LED 1	I>1 Start
LED 2	I>2 Start
LED 3	IN1>1 Start
LED 4	I>1 Trip
LED 5	I>2 Trip
LED 6	IN>1 Trip
LED 7	Any Start
LED 8	Backtrip to CB23

P142 - D2-A	
LED 1	I>1 Start
LED 2	I>2 Start
LED 3	IN>1 Start
LED 4	I>1 Trip
LED 5	I>2 Trip
LED 6	IN>1 Trip
LED 7	
LED 8	Any Start

P142 - D2-B	
LED 1	I>1 Start
LED 2	I>2 Start
LED 3	IN>1 Start
LED 4	I>1 Trip
LED 5	I>2 Trip
LED 6	IN>1 Trip
LED 7	Successful (Auto) close
LED 8	

P122 - Generator Bus	
LED 1	TRIP
LED 2	ALARM
LED 3	WARNING
LED 4	HEALTHY
LED 5	I>Iref
LED 6	I>>Iref
LED 7	Ie>
LED 8	Broken Conductor

P122 - Grid Bus	
LED 1	TRIP
LED 2	ALARM
LED 3	WARNING
LED 4	HEALTHY
LED 5	I>Iref
LED 6	I>>Iref
LED 7	Ie>
LED 8	Broken Conductor

All the relays except the P122 units have five separate fixed function LEDs on their front panel. These functions are:

- Trip
- Alarm
- Out of Service
- Healthy
- Enter

The first four LEDs in the P122 units perform most of these functions.

APPENDIX 5 Miscellaneous Information

For future reference, record the serial number of your NE9270, and the serial numbers of major ancillary components in the table below. Use the following pages to record any other information which you feel may be of use.

Product Description	Product Number	Serial Number
Power System Simulator	NE9270	

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