SERVICE MANUAL

INTEGRATED GENERATOR PROTECTION

RELAY TYPE LGPG111

R5942B

ALSTOM

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HANDLING OF ELECTRONIC EQUIPMENT

A person's normal movements can easily generate electrostatic potentials of several thousand volts. Discharge of these voltages into semiconductor devices when handling electronic circuits can cause serious damage, which often may not be immediately apparent but the reliability of the circuit will have been reduced.

The electronic circuits of ALSTOM T&D Protection & Control Ltd products are completely safe from electrostatic discharge when housed in the case. Do not expose them to the risk of damage by withdrawing modules unnecessarily.

Each module incorporates the highest practicable protection for its semiconductor devices. However, if it becomes necessary to withdraw a module, the following precautions should be taken to preserve the high reliability and long life for which the equipment has been designed and manufactured.

1. Before removing a module, ensure that you are at the same electrostatic potential as the equipment by touching the case.

2. Handle the module by its front-plate, frame, or edges of the printed circuit board. Avoid touching the electronic components, printed circuit track or connectors.

3. Do not pass the module to any person without first ensuring that you are both at the same electrostatic potential. Shaking hands achieves equipotential.

4. Place the module on an antistatic surface, or on a conducting surface which is at the same potential as yourself.

5. Store or transport the module in a conductive bag.

More information on safe working procedures for all electronic equipment can be found in BS5783 and IEC 147-0F.

If you are making measurements on the internal electronic circuitry of an equipment in service, it is preferable that you are earthed to the case with a conductive wrist strap.
Wrist straps should have a resistance to ground between 500k – 10M ohms. If a wrist strap is not available, you should maintain regular contact with the case to prevent the build up of static. Instrumentation which may be used for making measurements should be earthed to the case whenever possible.

ALSTOM T&D Protection & Control Ltd strongly recommends that detailed investigations on the electronic circuitry, or modification work, should be carried out in a Special Handling Area such as described in BS5783 or IEC 147-0F.

Number	Issue	Chapter Name
50005.1701.001	B	Title Pages
50005.1701.101	A	General Description
50005.1701.102	B	Handling And Installation
50005.1701.103	B	Application Notes
50005.1701.104	B	Functional Description
50005.1701.105	B	Hardware Description
50005.1701.106	B	User Interface
50005.1701.107	B	Fault Finding Instructions
50005.1701.108	B	Commissioning Instructions
50005.1701.111	A	Commissioning Test Results
50005.1701.109	B	Technical Data
50005.1701.110	B	Drawings

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AP	February 1995	Dave Banham	Original
BP	February 1995	Dave Banham	Commissioning Instructions updated.
CP	June 1995	Dave Banham	General update. NPS description changed. Technical data updated and expanded. Commissioning results record seperated from the commissioning instructions. This is now a seperate chapter.
A	July 1995	Dave Banham/ Publicity	Styles
B	Feb 1996	Dave Banham/ Publicity	General update

Contents

Publication R4106 forms part of this manual

CHAPTER 1 - GENERAL DESCRIPTION

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AP	February 1995	Tony Yip	Original
BP	June 1995	Dave Banham	Minor update.
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Contents

1. Introduction

A number of protection functions are required to fully protect generators against the adverse effects of the different types of faults and abnormal operating conditions that might occur. The exact forms of protection that are required are dependent on the type, design, size and purpose of the generating plant and on the form of power system which is to be supplied.

Traditional generator protection schemes have been made up of various discrete protective relays, in conjunction with auxiliary relays and other scheme components. A number of trip outputs are usually provided for initiating various plant actions, depending on the type of protection operation.

Digital protective relay technology has been gaining widespread acceptance over recent years. The benefits of standardised hardware, multiple functions, multiple/ hybrid characteristics, other enhancing features and remote communications are well recognised. It is the cost benefit and the fact that such power system devices can be made more useful for purposes beyond protection that is now becoming recognised outside the discipline of protection engineering.

When digital technology is applied to generator protection, a number of protection functions can be integrated into a single relay. This approach produces a reduction in both the physical size of the protection scheme and in the burdens imposed on the current and voltage transformers. If the integration is extended to include the scheme logic, the amount of inter-relay scheme wiring and auxiliary components is also reduced. This further minimises the design and installation costs, and simplifies maintenance and commissioning test procedures.

The use of digital technology and the integration of a number of protection functions offers further benefits: local and remote instrumentation, event, fault and disturbance recording, testing aids, self documentation of settings and serial communication facilities for remote access. All these features can simplify the tasks of commissioning, testing, trouble-shooting and post-fault analysis. Thus, by providing more information more readily, the protection unit is made more useful.

2. LGPG111 - INTEGRATED GENERATOR PROTECTION

The LGPG111 relay integrates a number of common generator protection functions and the scheme logic into the same relay case. The selection of the protection functions is designed to cover a wide range of generators, which avoids the need for application specific relay versions. From the user’s view point, this simplifies the relay specification, evaluation and project planning. From the development view point, the work is concentrated on a standardised model, thus allowing the relay to be more rigorously tested due to its internal fixed software architecture.

The mix of protection functions provided, Figure 1, is designed to produce a cost effective solution for a wide range of application problems. Each protection function can be enabled or disabled to suit individual requirements. Some functions, such as 100% stator earth fault and rotor earth fault, have not been provided in this relay, since they are not standard in the majority of applications. When these functions are specified, additional discrete relays will be required. With this in mind, the relay provides the ability to integrate external devices into its scheme logic, so that tripping facilities, together with local and remote alarm facilities can be utilised.

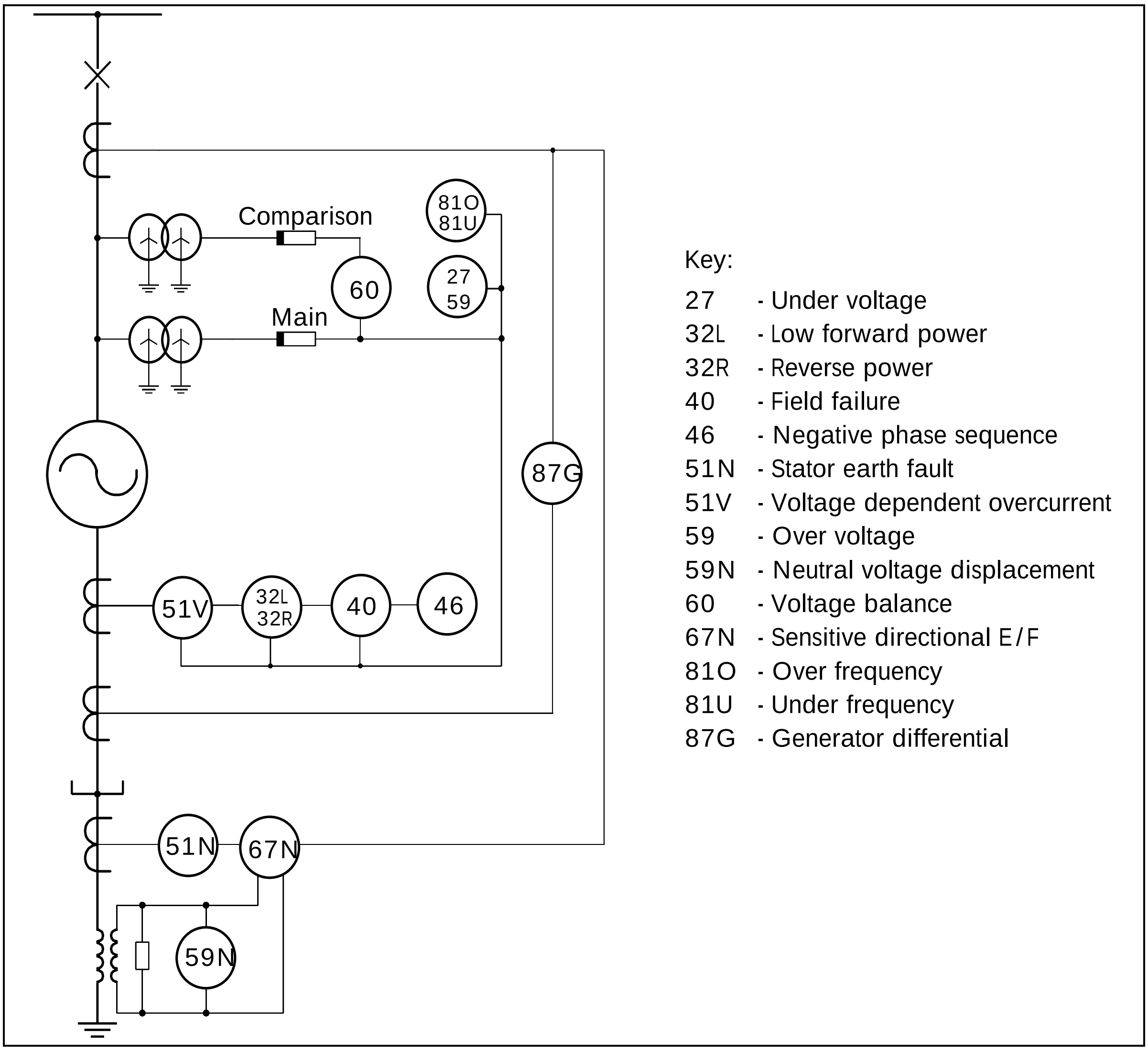

Figure 1 Protection functions provided by the LGPG111.

Chapter 2 - Handling And Installation

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ENGINEERING DOCUMENT NUMBER: 50005.1701.102

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AP	February 1995	Dave Banham	Original
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Contents

1. GENERAL CONSIDERATIONS

1.1 Receipt of product

Although the product is generally of robust construction, careful treatment is required prior to installation on site. Upon receipt, the product should be examined immediately, to ensure no damage has been sustained in transit. If damage has been sustained during transit, a claim should be made to the transport contractor, and a ALSTOM T&D Protection & Control Ltd representative should be promptly notified. Products that are supplied unmounted and not intended for immediate installation should be returned to their protective polythene bags.

1.2 Electrostatic discharge (ESD)

The product uses components that are sensitive to electrostatic discharges. The electronic circuits are well protected by the metal case and the internal modules should not be withdrawn unnecessarily. When handling modules, care should be taken to avoid contact with components and electrical connections. If removed from the case for storage, the module should be placed in an electrically conducting anti static bag.

There are no setting adjustments within the modules and it is advised that it is not unnecessarily disassembled. Although the printed circuit boards are plugged together, the connectors are a manufacturing aid and not intended for frequent dismantling; in fact considerable effort may be required to separate them. Touching the printed circuit boards should be avoided, since complementary metal oxide semiconductors (CMOS) are used, which can be damaged by static electricity discharged from the body.

1. HANDLING OF ELECTRONIC EQUIPMENT

A person's normal movements can easily generate electrostatic potentials of several thousand volts. Discharge of these voltages into semiconductor devices when handling electronic circuits can cause serious damage, which often may not be immediately apparent but the reliability of the circuit will have been reduced.

The electronic circuits are completely safe from electrostatic discharge when housed in the case. Do not expose them to risk of damage by withdrawing modules unnecessarily.

Each module incorporates the highest practicable protection for its semiconductor devices. However, if it becomes necessary to withdraw a module, the following precautions below should be taken to preserve the high reliability and long life for which the equipment has been designed and manufactured.

1. Before removing a module, ensure that you are at the same electrostatic potential as the equipment by touching the case.
2. Handle the module by its front plate, frame or edges of the printed circuit board. Avoid touching the electronic components, printed circuit track or connectors.
3. Do not pass the module to another person without first ensuring you are both at the same electrostatic potential. Shaking hands achieves equipotential.
4. Place the module on an anti static surface, or on a conducting surface which is at the same potential as yourself.
5. Store or transport the module in a conductive bag.

If you are making measurements on the internal electronic circuitry of an equipment in service, it is preferable that you are earthed to the case with a conductive wrist strap. Wrist straps should have a resistance to ground between 500kW-10MW. If a wrist strap is not available, you should maintain regular contact with the case to prevent a build-up of static. Instrumentation which may be used for making measurements should be earthed to the case whenever possible.

More information on safe working procedures for all electronic equipment can be found in BS5783 and IEC 60147-OF. It is strongly recommended that detailed investigations on electronic circuitry, or modification work, should be carried out in a Special Handling Area such as described in the above-mentioned BS and IEC documents.

3. UNPACKING AND INSTALLING

Care must be taken when unpacking and installing the products so that none of the parts are damaged, or the settings altered and they must only be handled by skilled persons.

The installation should be clean, dry and reasonably free from dust and excessive vibration. The site should be well lit to facilitate inspection.

CAUTION HEAVY AC INPUT MODULES - HANDLE WITH CARE

Modules that have been removed from their cases should not be left in situations where they are exposed to dust or damp. This particularly applies to installations which are being carried out at the same time as construction work.

3.1 Mounting

Products are dispatched, either individually, or as part of a panel/rack assembly. Modules should remain protected by their metal case during assembly into a panel or rack. The design of the relay is such that the fixing holes are accessible without removal of the cover. Dimensions, fixing details and cut-out sizes for the cases are shown in the case outline drawing GM0008, in chapter 11.

When installation is complete, the relay must be set-up and commissioned as described in chapter 8.

3.1.1 Rack Mounting

The rack mounting version of the relay is supplied in a case designed for mounting in standard 19 inch (483mm) racks.

3.1.2 Panel mounting

The panel mounting version of the relay can be supplied for either flush or semi-projecting panel mounting. Panels should be vertical to within 5°. Dimensions, fixing details and cut-out sizes for the cases are shown in the relevant case outline drawing.

The flush mounted relay is inserted from the front into the panel cut-out and secured by means of nuts and bolts through holes in the upper and lower flanges in the relay and corresponding holes in the panel.

The semi-projecting version of the relay is fitted with an extending collar and is fixed in a similar manner to the flush mounted version.

3.2 Auxiliary power supplies

The LGPG111 is designed to be powered from a DC auxiliary power supply within the limits of its Vx1 rated specification. Equally, the status inputs are designed to be energised from a DC auxiliary power supply within the limits of its Vx2 rated specification. The operative ranges for each nominal rating value of Vx1 and Vx2 is summarised in the table below.

The relay can withstand some AC ripple on its DC auxiliary supplies, however the peak value of the auxiliary supply should not exceed the maximum withstand value. Do not energise the relay from a supply with the batteries disconnected and the system run from the charger alone.

The LGPG111 is fitted with transient suppression circuits, which are designed to protect it from potential damage by intermittent spikes of short duration.

Nominal Rating of Vx1 and Vx2	24/27V	30/34V	48/54V	110/125V	220/250V
Operative Range	19.2 - 32.4 V	24 - 40.8 V	38.4 - 64.8 V	88 - 150 V	176 - 300 V
Maximum Withstand	36.5 V	45.9 V	72.9 V	168.8 V	337.5 V

4. STORAGE

If products are not to be installed immediately upon receipt they should be stored in a place free from dust and moisture in their original cartons. Where de-humidifier bags have been included in the packing they should be retained. The action of the de-humidifier crystals will be impaired if the bag has been exposed to ambient conditions and may be restored by gently heating the bag for about an hour, prior to replacing it in the carton.

Dust which collects on a carton may, on subsequent unpacking, find its way into the product; in damp conditions the carton and packing may become impregnated with moisture and the de-humidifier will lose its efficiency.

Storage temperature -25°C to +70°C.

CHAPTER 3 - APPLICATION NOTES

Issue control

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AP	February 1995	Paul Hindle & AlanTrow	Original
BP	June1995	Dave Banham	Minor corrections. NPS protection notes updated to reflect change in LGPG111 functionality for version 18LGPGOO2XXXEA onwards. The NPS reset characteristic was an exponential decay, now the thermal replica is used. Kreset was the time constant of the exponential now it is the thermal capacity constant for cooling. CT requirements expanded to include all current inputs.
A	July1995	Dave Banham/ Publicity	Minor amendments and styles
B	Feb 1996	Chris Hodgson/ Publicity	Protection summaries added. Stator earth fault CT requirements corrected.

CONTENTS

1. INTRODUCTION

1.1. Generating plant

A generator forms the electromechanical stage of an overall energy conversion process that results in the production of electrical power. Except for very special circumstances, e.g. for some types of railway locomotives, AC electrical power is normally produced. A reciprocating engine or one of many forms of turbine acts as a prime mover to provide the rotary mechanical input to an alternator.

Whilst induction machines are sometimes used for generation, in parallel with a main public supply system (e.g. in the case of some mini-hydro schemes), the synchronous machine is normally used for production of AC electrical power. The LGPG111 caters for the protection requirements of synchronous generators. The term ‘generator’ is generally used to describe the complete energy conversion system whilst the term ‘alternator’ is sometimes used as a more specific description of the electromechanical conversion unit.

The running speed of a prime mover, which is ultimately dependent on the original source of energy for the conversion process, greatly influences the mechanical and electrical design aspects of the generating system. In the case of a very high speed prime mover, for instance, a reduction gearbox would be used to transmit mechanical power to a 2-pole, cylindrical rotor alternator. In the case of a very slow speed prime mover, a salient-pole alternator with multiple pole-pairs would be directly driven. During electrical power system changes, the type of prime mover, and its associated speed governing facilities, will have great influence on the dynamic performance of the generating plant.

There are many forms of generating plant that have evolved to exploit the common sources of energy available, e.g. combustion of fossil fuels, hydro dams and nuclear fission. Generation schemes may be provided for base-load production, peak-lopping or for providing standby power.

Whilst large-scale generating schemes still meet the base-load needs of most national power utilities, there is a growing move towards smaller-scale schemes to utilise otherwise redundant heat, gases or combustible material resulting from many modern industrial processes. Changing national legislation and utility tariff structures can also create an economic environment whereby large industrial consumers of electrical power find encouragement to operate their own generating plant to contribute to, or to offset the demand on, a utility supply at certain times of national peak demand for electrical power.

As a result of environmental concerns, much effort is currently being expended with research into the efficient reliable and economic generation of electrical power using new forms of renewable energy. All the above factors, coupled with traditional industrial power generation requirements, result in wide-ranging demands for generator protection that are conveniently and economically addressed by the LGPG111 integrated protection package.

1.2. Protection of generators

Electrical protection is required to quickly detect and initiate shutdown for major electrical faults associated with the generating plant and, less urgently, to detect abnormal operating conditions which, if sustained, may lead to plant damage.

Abnormal electrical conditions can arise as a result of some failure with the generating plant itself, but can also be externally imposed on the generator. Common categories of faults and abnormal conditions to be electrically detected are listed as follows: (Not all conditions have to be detected for all applications.)

MAJOR ELECTRICAL FAULTS

* Insulation failure of stator windings or connections

SECONDARY ELECTRICAL FAULTS

- Insulation failure of excitation system
- Failure of excitation system
- Unsynchronised over voltage

ABNORMAL PRIME MOVER OR CONTROL CONDITIONS

- Failure of prime mover
- Over frequency
- Over fluxing
- Dead machine energisation
- Breaker Flashover

SYSTEM RELATED

- Feeding an uncleared fault
- Prolonged or heavy unbalanced loading
- Prolonged or heavy overload
- Loss of synchronism
- Over frequency
- Under frequency
- Synchronised over voltage
- Over fluxing
- Under voltage

In addition to the range of electrical protection required for a generator, varying types and levels of mechanical protection are necessary, such as vibration detection, lubricant and coolant monitoring, etc.

The action required following response of an element of electrical or mechanical protection is often categorised as follows:

- Urgent shutdown
- Non-urgent shutdown
- Alarm only

An urgent shutdown would be required, for example, if a phase to phase fault occurred within the generator electrical connections. A non-urgent shutdown might be sequential, where the prime mover may be shutdown prior to electrically unloading the generator, in order to avoid over speed in the case of a steam turbine. A non-urgent shutdown may be initiated in the case of continued unbalanced loading. In the event of unbalanced loading, it is desirable that an alarm should be given before shutdown becomes necessary, in order to allow for possible operator intervention to remedy the situation.

For urgent tripping, it may be desirable to electrically maintain the shutdown condition with latching protection output contacts, which would require manual resetting. For a non-urgent shutdown, it may be required that the output contacts reset without intervention, so that production of power can be recommenced as soon as possible.

1.3. LGPG111 integrated protection

The LGPG111 incorporates the commonly required protection functions for a wide variety of generating plant applications in a single integrated package, see Figure 1. Flexible scheme logic is also provided to allow the protection output contacts of the package to be configured to execute required categories of action. Optically-isolated logic inputs are provided to allow the status of external plant to be monitored and to exercise control over the protection functions. It is also possible for mechanical protection functions to initiate alarms or action via the LGPG111 scheme logic and to be monitored via the serial communications facility provided with the protection package.

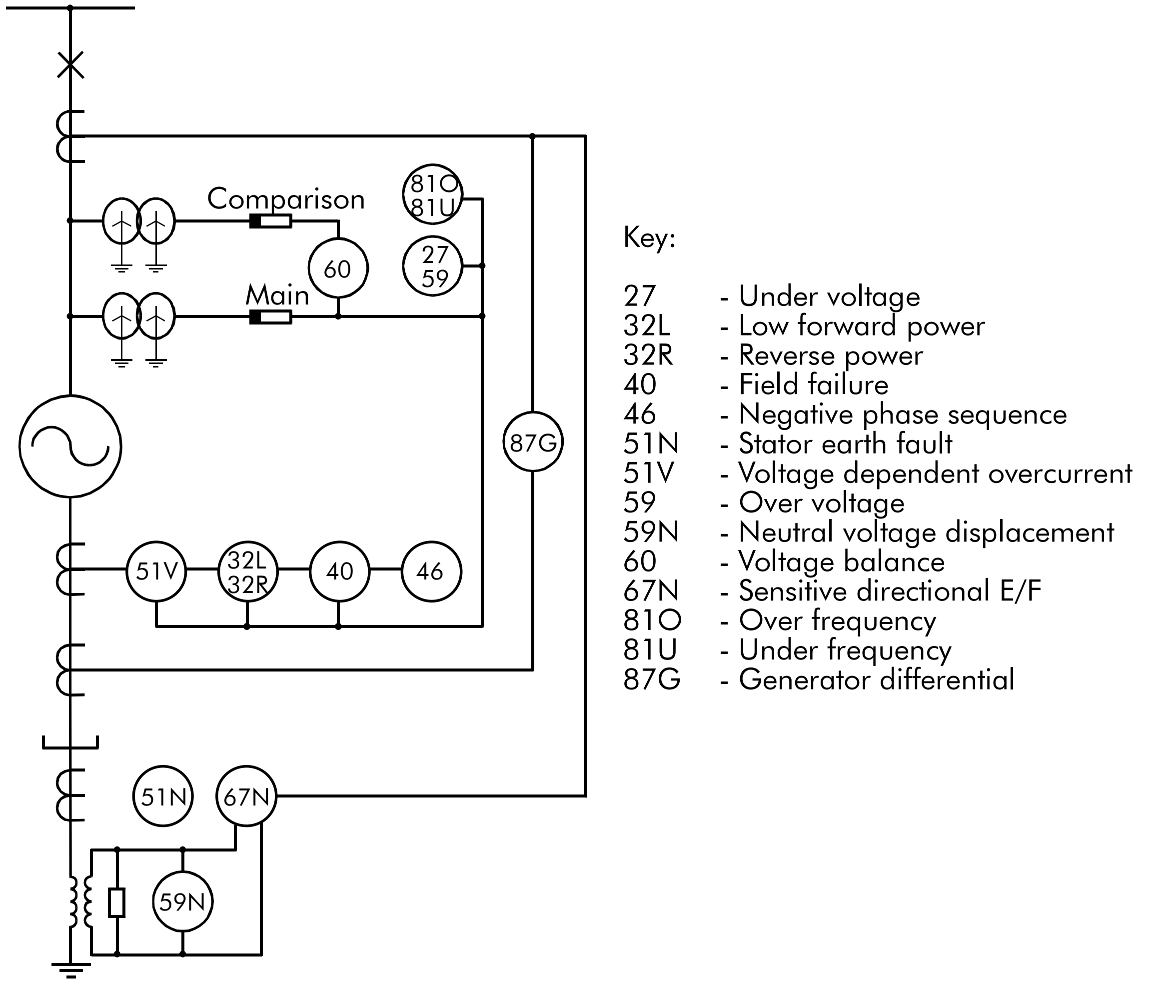


Figure 1 Protection functions provided by the LGPG111 relay.

With its frequency tracking system, the LGPG111 is able to maintain all protection functions in service over a wide range of operating frequency. It should not be necessary, for instance, to disable the negative phase sequence thermal protection when running a generator at low frequency; as might be necessary with existing discrete relay schemes. This LGPG111 capability will be of especial interest for pumped storage generation schemes, where synchronous machines would be operated from a variable frequency supply when in pumping mode. Additionally, in the case of combined cycle generating plant, it may be necessary to excite and synchronise a steam turbine generating set with a gas turbine set at low frequency, prior to running up to nominal frequency and synchronising with the power system.

When LGPG111 protection functions are required to operate accurately at low frequency, it will be necessary to use CT's with larger cores. In effect the CT kneepoint voltage requirements will be multiplied by f_n/f,where f is the minimum required operating frequency and f_n is the nominal operating frequency.

In the case of a synchronous machine at a pumped storage plant being operated in the motoring mode, it would be necessary to disable reverse power protection in this mode. This could be accomplished by switching to the LGPG111's alternative group of settings where the reverse power protection function would not be enabled.

When applying the LPG111, the traditional scheme engineering and inter-relay wiring costs associated with traditional discrete relay protection schemes are eliminated and a significant economy is made in required panel space.

For some applications, not all the protection functions of the LGPG111 would be applied. For other applications some specialised additional protection might be required in addition to those functions provided by the LGPG111. For example, when refurbishing the protection on some old designs of generator with external excitation connections to the rotor winding, there would be a requirement for rotor earth fault protection. Thermal overload protection is also not catered for in the LGPG111 package, since direct-acting resistance temperature devices are usually applied with a monitoring unit supplied with the generator. Where there exists the possibility of over fluxing a generator transformer, over fluxing protection should be incorporated with the transformer protection.

For large generator applications, the integration of the LGPG111 may be seen as a potential disadvantage in terms of the small, but finite, probability of the complete package failing. Although the probability of failure is small, the ensuing costs of plant downtime could be high in relation to the cost of providing the protection for a large base-load generator. In such applications, it would be prudent and economically viable to duplicate the protection packages and operate them from independent auxiliary power supplies, see Figure 2. Such an arrangement would offer the full protection redundancy that is normally provided for primary transmission systems, but which has not been traditionally provided for generating plant. The past strategy for avoiding outages, due to protection problems, has been to rely on multi-function discrete relays, rather than on complete protection redundancy.

1.4. LGPG111 non-protection functions

In addition to being a versatile protection package, the LGPG111 offers additional facilities by virtue of its digital design. These facilities are listed below:-

- Electrical instrumentation with local/remote display
- Fault records (summary of reasons for tripping, status of logic inputs/relay outputs and fault measurements)
- Event records (summary of alarms and relay events)
- Disturbance records (record of analogue waveforms/operation of logic inputs and relay outputs)
- Date and time-tagging of all records
- Commissioning aids
- Remote communications
- High level of continuous self-monitoring and diagnostic information

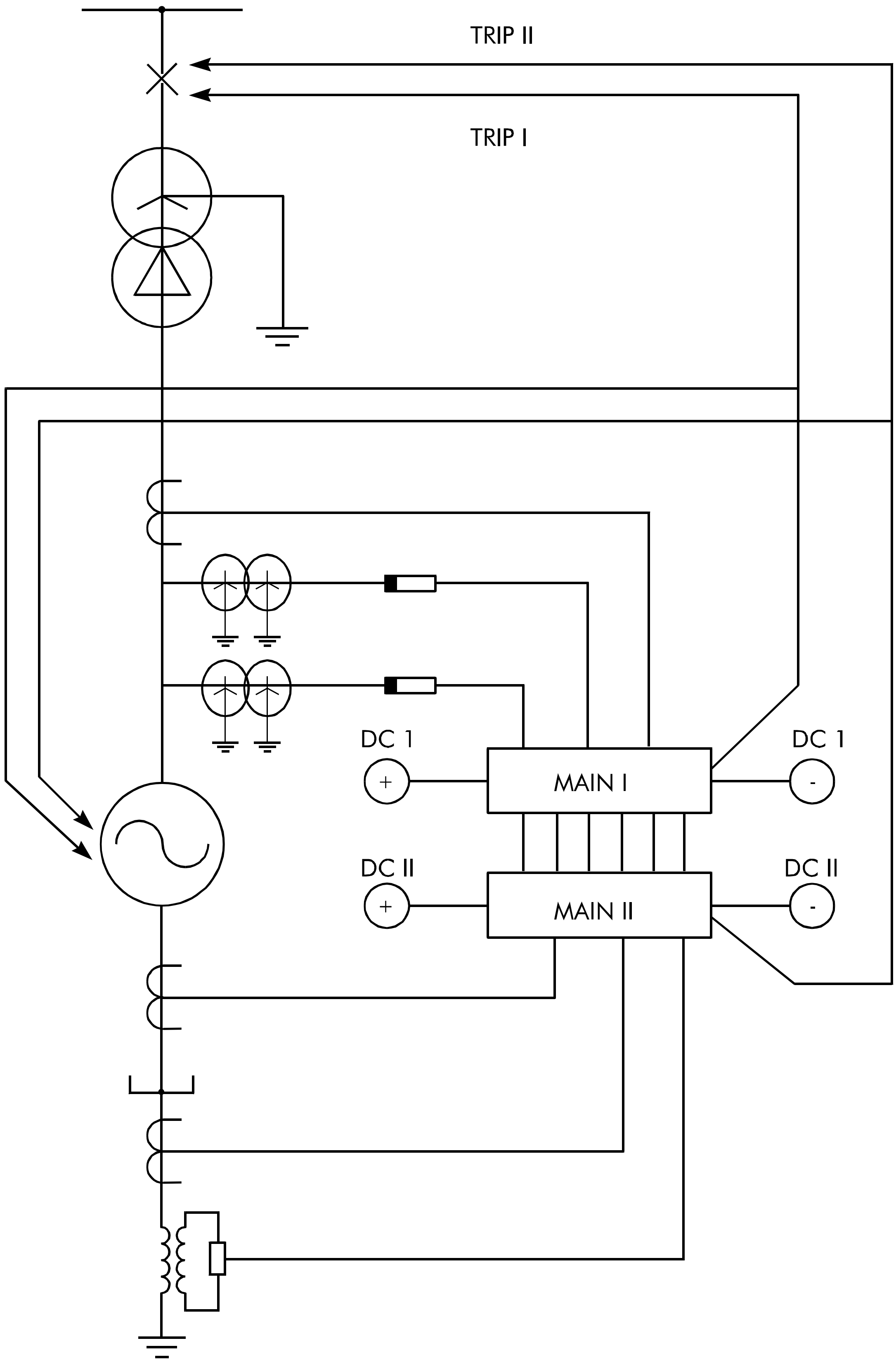


Figure 2 Complete protection redundancy using duplicate relays.

2. APPLICATION OF INDIVIDUAL PROTECTION FUNCTIONS

2.1. LGPG111 protection functions

The following protection functions are provided within the LGPG111 package:

- Generator Differential protection (87G)
- Stator Earth Fault protection (51N)
- Neutral Voltage Displacement protection (59N)
- Sensitive Directional Earth Fault protection (67N)
- Voltage-Dependent Overcurrent protection (51V)
- Negative Phase Sequence Thermal protection (46)
- Field Failure protection (40)
- Reverse Power protection (32R)
- Low Forward Power protection (32L)
- Over Voltage protection (59)
- Under Voltage protection (27)
- Over Frequency protection (810)
- Under Frequency protection (81 U)
- Voltage Balance protection (60)

The single line diagrams in Figures 3 and 5 illustrate how the relay might be applied for various generator configurations and ratings. Figures 4 and 6 show the respective relay connections.

2.2. Generator differential protection function (87G)

Summary:

- Protects against failure of the stator winding insulation.
- Compares the current on the neutral side of the generator with the current on the line side.
- Requires the use of matched CT's.
- Uses a low impedance dual slope bias characteristic to achieve high sensitivity for internal faults but stability for external faults.
- Where an in zone unit transformer, or in-zone variable frequency starting unit exists, additional CT's may be required.
- Can be arranged to offer high impedance type protection using an external stabilising resistor.
- Can be arranged to provide interturn protection for certain stator winding arrangements.

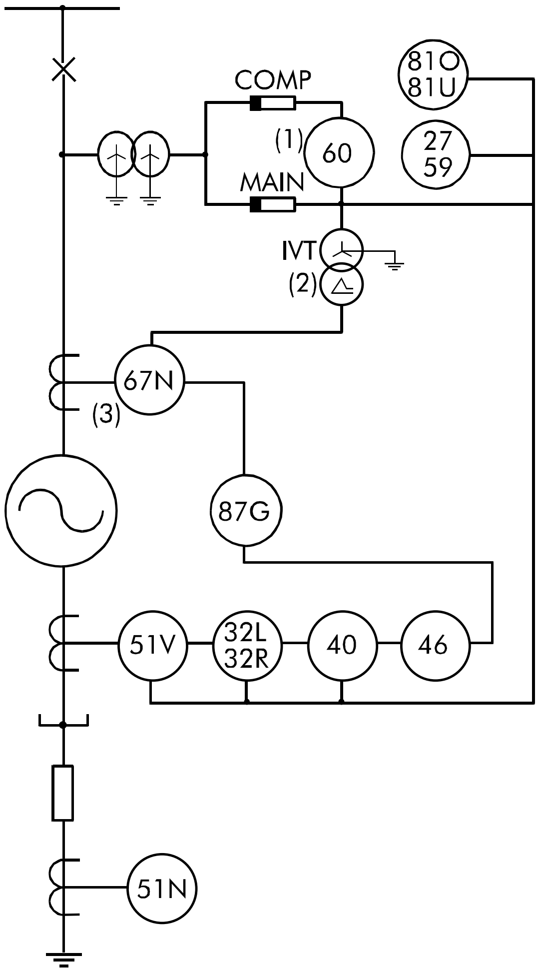
The generator differential protection function compares the signals from the LGPG111 neutral-end and terminal-end three-phase CT inputs to detect faults within the stator winding. A dedicated set of neutral-end CT inputs is provided to allow the option of using a dedicated set of main CT's for differential protection. The input CT's for other protection functions could either share a set of differential protection main CT's or use another set.

Where a significantly rated unit transformer is teed-off within the required zone of generator differential protection, such that an LV auxiliary system fault would yield sufficient primary current to cause unwanted differential protection operation, it will be necessary to cover the additional primary connection with an additional set of differential protection CT's. This additional set of CT's should be connected in parallel with the generator terminal CT's, see Figure 5.

All CT's used for the differential protection function must be of equal ratio. Any deviation in tee-off CT ratios must be dealt with using adequate interposing CT's of suitable ratio. In the case of some pumped storage arrangements, or gas turbine start-up arrangements, an in-zone variable frequency supply connection would also need to be addressed in the same manner.

Failure of stator windings or connection insulation can result in severe damage to the windings and stator core and more widespread damage to winding insulation. The extent of the damage will be a function of the fault current level and the duration of the fault. Protection should be applied to limit the degree of damage in order to limit repair costs. For primary generating plant, high-speed disconnection of the plant from the power system is also necessary to maintain system security.

For generators rated above 1 MVA, it is usual to apply generator differential protection. This form of unit protection allows discriminative detection of winding faults, with no intentional time delay, where a significant fault current arises. The zone of protection, defined by the location of the CT's, should be arranged to overlap protection for other items of plant such as a busbar or a step-up transformer.



Notes:

(1) Where only a single VT is available, the voltage balance protection function (60) should be connected to the VT via a main set of protection fuses and via a reference set.

(2) The voltage polarising signal for the directional sensitive earth fault protection function (67N) could be derived from a main VT broken delta secondary winding or via a set of interposing VT's as shown. In either case, the main VT must be 3 single phase or a 3 phase, 5 limb transformer with the primary star-point earthed.

(3) To provide very sensitive earth fault protection, with stability for external 2 phase to earth faults, where the spill current from the 3 line CT's may cause false operation, a dedicated core balance CT should be used for the directional sensitive earth fault protection function.

Key:

27	- Under voltage	50	- Over voltage
32	- Reverse power *	60	- Voltage balance
40	- Field failure *	67N	- Sensitive directional earth fault *
46	- Negative phase sequence	81O	- Over frequency
51N	- Stator earth fault	81U	- Under frequency
51V	- Voltage dependent overcurrent	87G	- Generator differential

* Only applicable with a parallel source present.

Figure 3 Protection of directly connected generator (in isolation or in parallel).

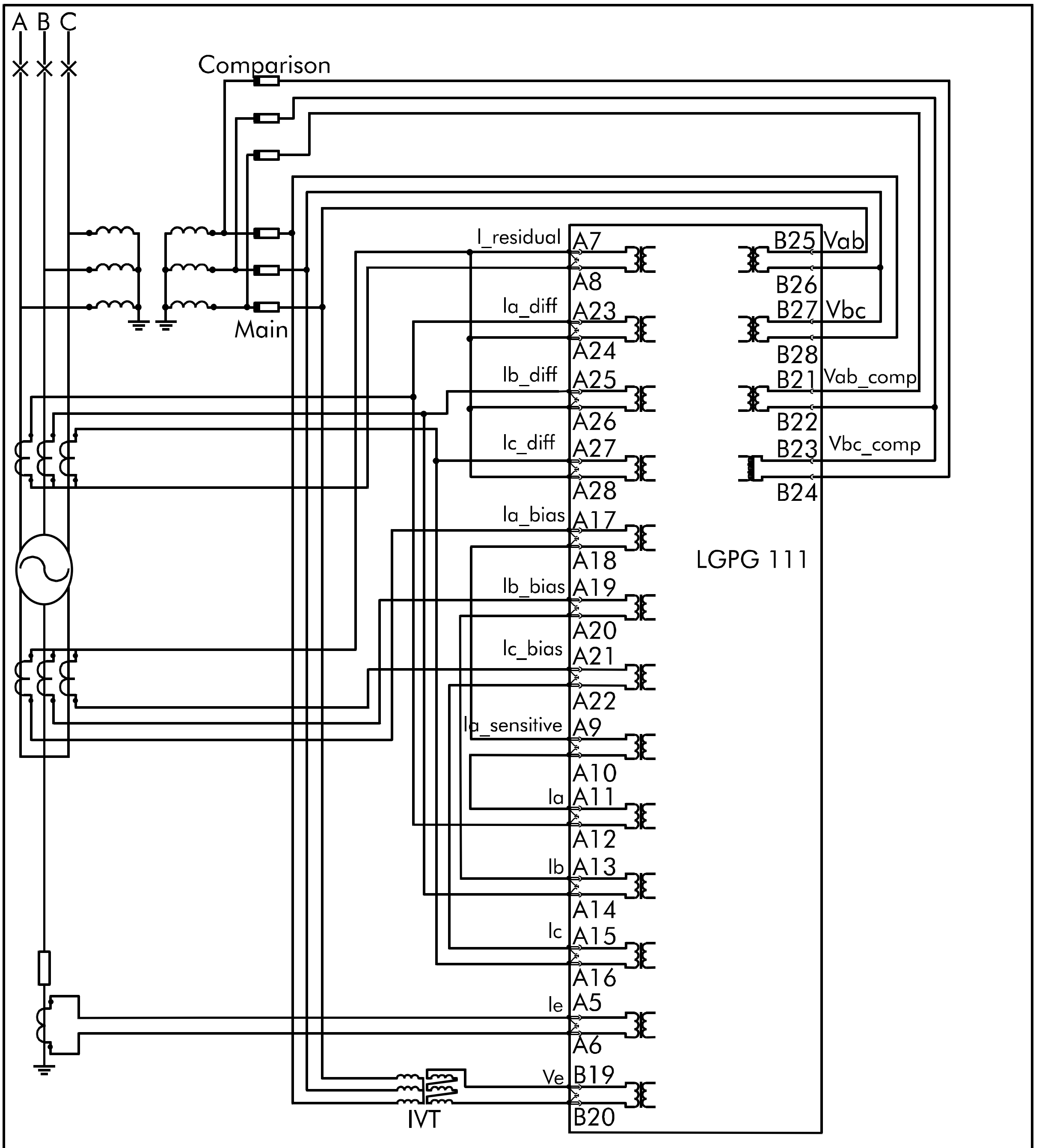
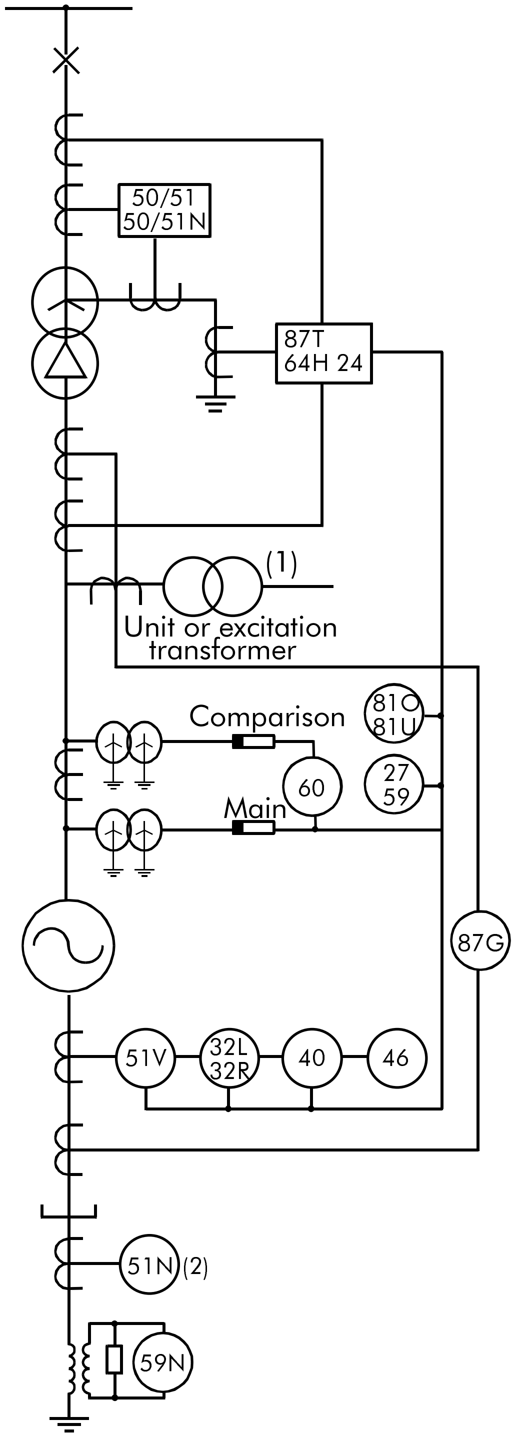


Figure 4 LGPG 111 connections for a directly connected generator (in isolation or parallel).



Key:

50/51	- Instantaneous high set/delayed HV overcurrent	KCGG140
51N	- HV standby earth fault	
50N	- HV breaker flashover (enabled when Cb is open)	
87T	- Transformer differential	KBCH
64H	- HV restricted earth fault	
24	- Generating plant overfluxing	
27	- Under voltage	LGPG111
32L	- Low forward power	
32R	- Reverse power	
40	- Field failure	
46	- Negative phase sequence	
51N	- Stator earth fault	
51V	- Voltage dependent overcurrent	
59	- Over voltage	
59N	- Neutral voltage displacement	
60	- Voltage balance	
81O	- Overfrequency	
81U	- Under frequency	
87G	- Winding differential	

Notes:

(1) The unit transformer connection must be covered by a CT where the current to a LV fault would be high enough to cause operation of the winding differential protection function (87G).

(2) The current operated stator earth fault protection function could be connected to a CT on the earthing transformer primary, as shown, and set to provide instantaneous high-set protection. Alternatively, this protection function could be driven from a CT on the earthing transformer secondary.

Figure 5 Protection of an indirectly connected generator for parallel operation.

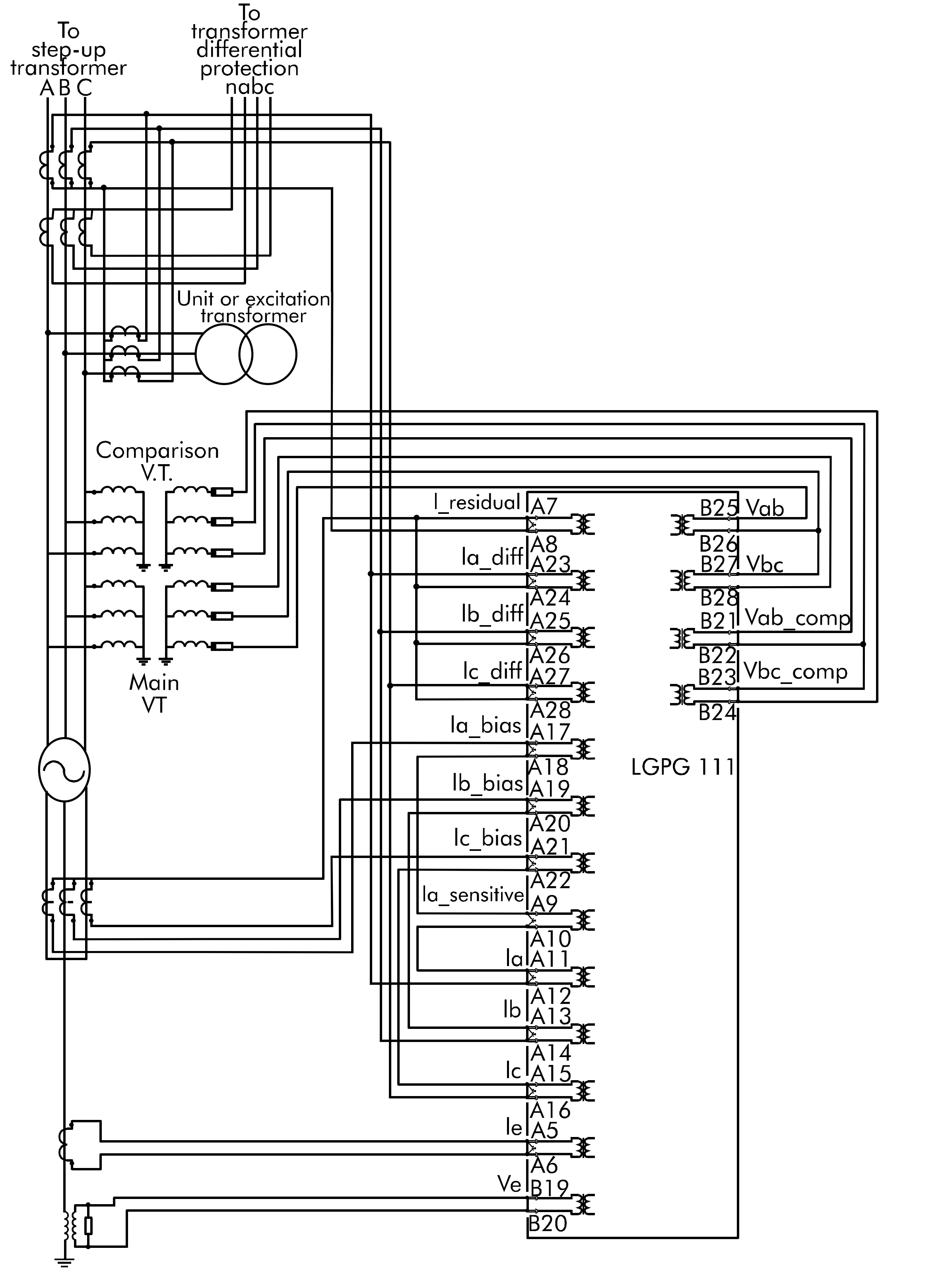
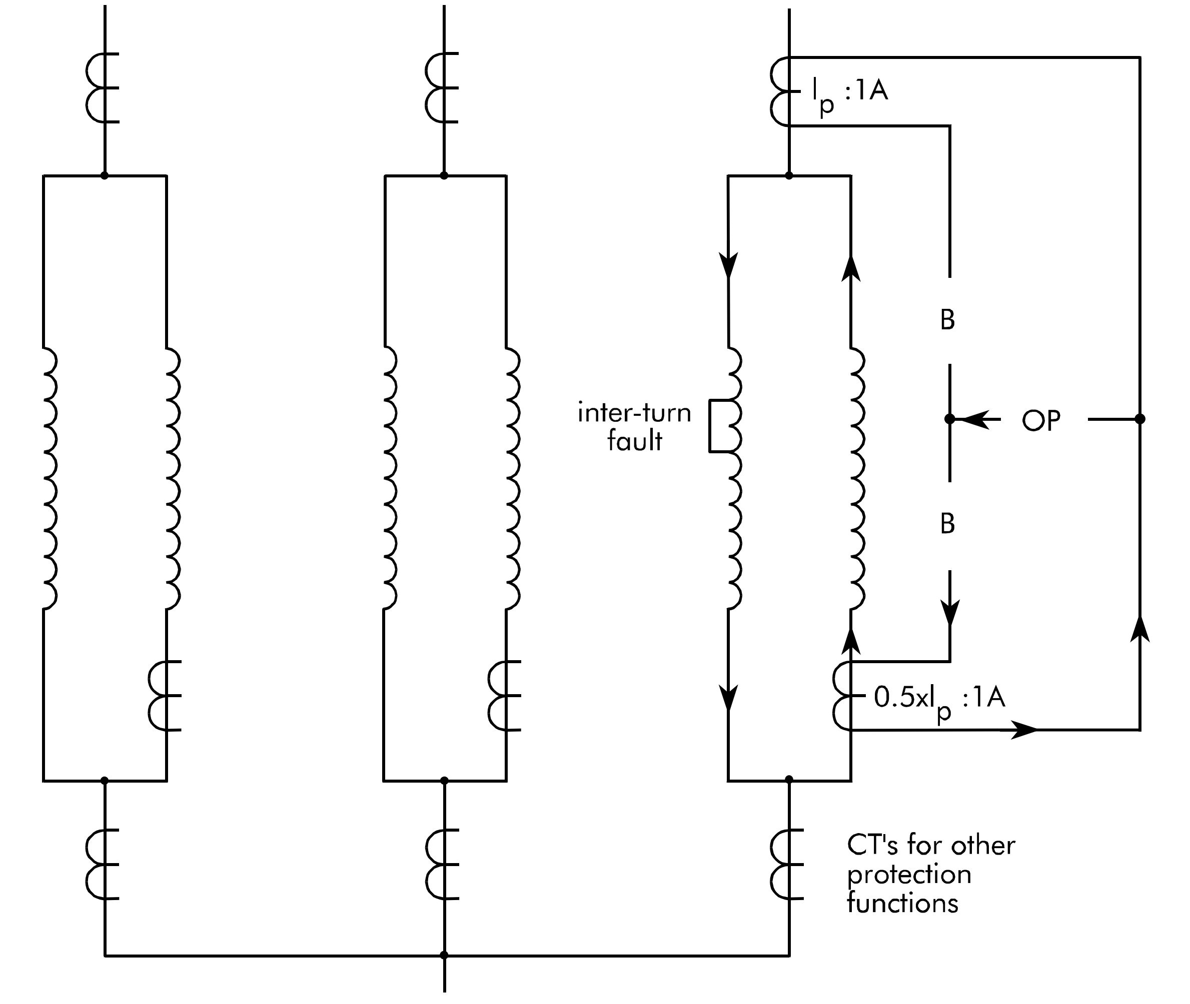


Figure 6 LGPG 111 connections for indirectly connected generator for parallel operation.

The most likely mode of stator winding insulation failure will be between a winding conductor and the stator core, resulting in a stator earth fault. Such a fault would be detected by the generator differential protection if the current is high enough. To further limit stator winding fault damage, the stator windings of generators are commonly earthed through an impedance to limit stator earth fault currents (see Section 2.3.). In the case of very high impedance earthing, the stator generator differential protection will only respond to a phase-phase fault or an earth fault with the earthing impedance short-circuited. A phase-phase fault is most likely to occur within the machine connections. The probability of such a fault occurring would be dependent on the way in which winding connections are brought out and insulated. Although the probability of such a fault would be low, it is possibly the most serious electrical fault that could occur.



Note: Bias slope of differential protection must be low up to 1_{flc} to give inter-turn fault sensitivity.

Figure 7 Generator differential and inter-turn fault protection.

For generators with multi-turn stator windings there is the possibility of a winding inter-turn fault occurring. Unless such a fault evolves in nature to become a stator earth fault, it will not otherwise be detected with conventional protection arrangements. Hydrogenerators usually involve multi-turn stator windings with parallel windings. For such applications, the parallel windings could be grouped into two halves and the generator differential protection could be applied as illustrated in Figure 7, to provide generator differential protection and a degree of inter-turn fault protection. The sensitivity of the protection for inter-turn faults would be limited by the fact that the two CT ratios applied must be selected in accordance with generator rated current. A more sensitive method of providing inter-turn fault protection, using an additional single CT, is discussed in Section 2.3.2.

The LGPG111 differential protection function is stabilised against unwanted operation for external faults, which may lead to a transient differential current as a result of transient asymmetric CT saturation. Stability is assured through the use of a through-current bias (percentage-restraint) technique. The differential protection function operating characteristic is depicted in Figure 8.

For general applications, the load current bias slope (K1) should be set to zero and the through fault bias slope (K2) should be set to 150%. The general CT requirements have been determined on this basis, through conjunctive testing. This will ensure constant differential protection function sensitivity with varying load current. The recommended setting for the break-point in the bias characteristic (Is2) is 1.2In, so that sensitivity will be maintained under full load conditions with a low-level winding fault.

There can be a traditional preference for applying high-impedance generator differential protection, as opposed to biased protection. This preference may be based on maintaining a constant protection sensitivity with varying load current and on being able to use smaller CT's, with earlier relay designs. With the LGPG111 load current bias slope (K1) set to zero, there would be no advantage in using high impedance protection from a sensitivity point-of-view. If however, high impedance protection is a specified requirement for a particular application, it would be possible to implement this form of protection using the LGPG111, by virtue of the fact that it is possible to access the differential current paths of the differential current protection function externally. The addition of an external stabilising resistor would be necessary to create a high-impedance differential protection scheme.

For general application, it is recommended that the most sensitive differential current setting (Is1) of 0.05In is applied. This setting can be raised up to 0.1In, in 0.01 In steps, for applications where a relatively small unit transformer or excitation supply transformer, is teed-off within the zone of differential protection. In such cases, the differential setting should be based on preventing operation for faults on the LV side of the transformer or to try and grade the LGPG111 operating time with transformer fuse protection.

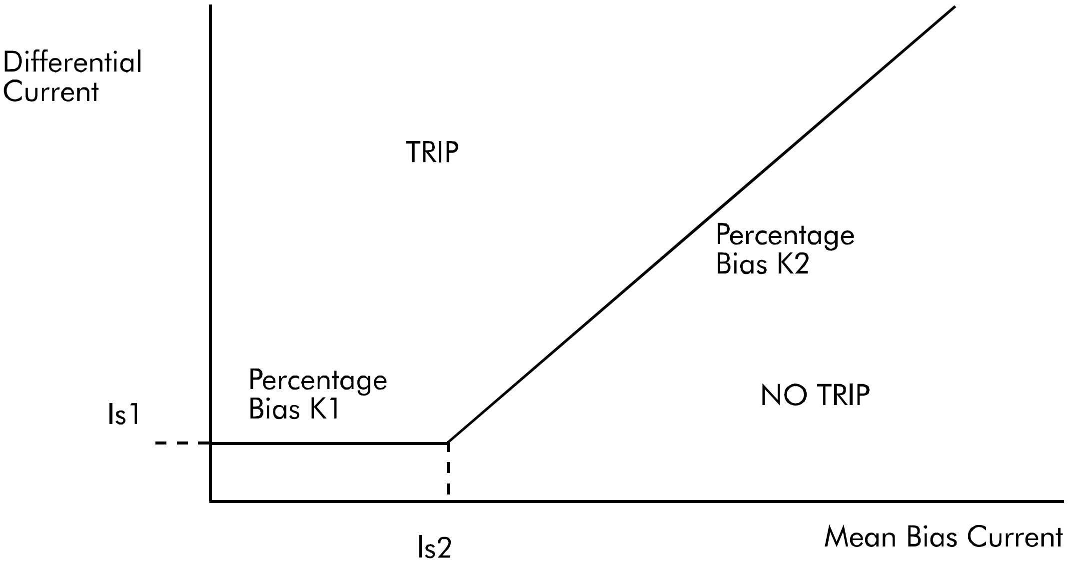


Figure 8 Differential protection function operating characteristic.

2.3. Stator earth fault protection function (51 N)

Summary:

- Current operated from a CT in the neutral earth path.
- Two independent tripping stages.
- First stage tripping can incorporate either a definite time or standard inverse type IDMT delay.
- Second stage tripping can be instantaneous or definite time delayed.
- Can be used to provide inter-turn fault protection.
- Immune to third harmonics.
- **Applied to directly connected generators.**

  The protection must be time graded with other earth fault protection.

  The setting employed should be less than 33% of the earth fault level.

  A setting of 5% of the earth fault level should be applied for applications where the differential protection provides less than 95% coverage of the stator winding.

- **Applied to in-directly connected generators.**
  (with the generator earthed via a distribution transformer)

  Can be supplied from a CT in either the primary or secondary circuit of the distribution transformer.

  With a CT in the primary circuit, the protection has the advantage of being able to detect an earth fault which causes flashover of the primary winding of the distribution transformer.

  With the CT in the secondary circuit the protection has the advantage of detecting a short circuit across the loading resistor.

  A sensitive 5% setting can be applied to the first tripping stage, a short time delay can be applied to stabilise the protection against small earth currents due to VT failures or earth leakage during HV system faults.

  The second tripping stage can be utilised as a high set. A 10% setting and instantaneous operation ensures fast clearance of generator earth faults.

The current operated stator earth fault protection function consists of two independent elements. The main element (Ie>) can be set with an adjustable standard inverse-time operating characteristic or a definite-time delay. The additional element (Ie>>) is provided for instantaneous protection or for adjustable definite-time operation. This element has an independently adjustable current setting and may be used as a high-set element in some applications. A dedicated single-phase current input is provided for this protection function. The current applied to this input can also act as a polarising signal for the sensitive directional earth fault protection function (67N).

The inverse-time operating characteristic of the main protection element is governed by the following formula:

$$t = TMS \times \frac{0.14}{\left(\frac{I}{Ie>}\right)^{0.02} - 1}$$

2.3.1. Application to a directly connected generator

For this application, illustrated in Figure 3, the time-delayed, main earth fault protection element (Ie>) should be set with a current setting and time characteristic (inverse or definite- time) to co-ordinate with the fast, sensitive, directional earth fault protection (67N) of any parallel generators. It must also co-ordinate with the time-delayed earth fault protection of the outgoing feeders from the generator bus. The current setting should also be less than 33% of the earth fault current contribution of the protected machine.

Where the generator differential protection function would not offer 95% coverage the stator windings for earth faults, the setting Ie> should be as close as possible to 5% of the machine contribution to a solid terminal earth fault. This is unless the neutral voltage displacement protection function is used to provide this coverage with a long time delay (see Section 2.4.1.). Figure 9 shows the single line diagram of the system used for the co-ordination example given in Figure 10.

Where difficulty is experienced in co-ordinating the generator stator earth fault protection function with outgoing feeder earth fault protection, and where KCGG/ KCEG relays are used to protect outgoing feeders, it may be possible to eliminate the co-ordination problems by interlocking the feeder protection with the generator protection, as described in Section 3.4.

In the case of direct generator connection, it is common that only one generator of a parallel set is earthed at any one time, with the earth connections of other machines left open. If the generating plant can also be run directly in parallel with a medium voltage public supply, it is a common requirement that all generator earth connections are left open during parallel operation. In such circumstances, the main earth fault protection element (Ie>) will only be operational for an earthed machine. It will provide primary earth fault protection for the associated machine, backup earth fault protection for other machines and the rest of the power system and thermal protection for the earthing resistor.

For directly connected generators, that could be earthed, there is no need to employ the additional earth fault protection element (Ie»).

2.3.2. Application to an indirectly connected generator

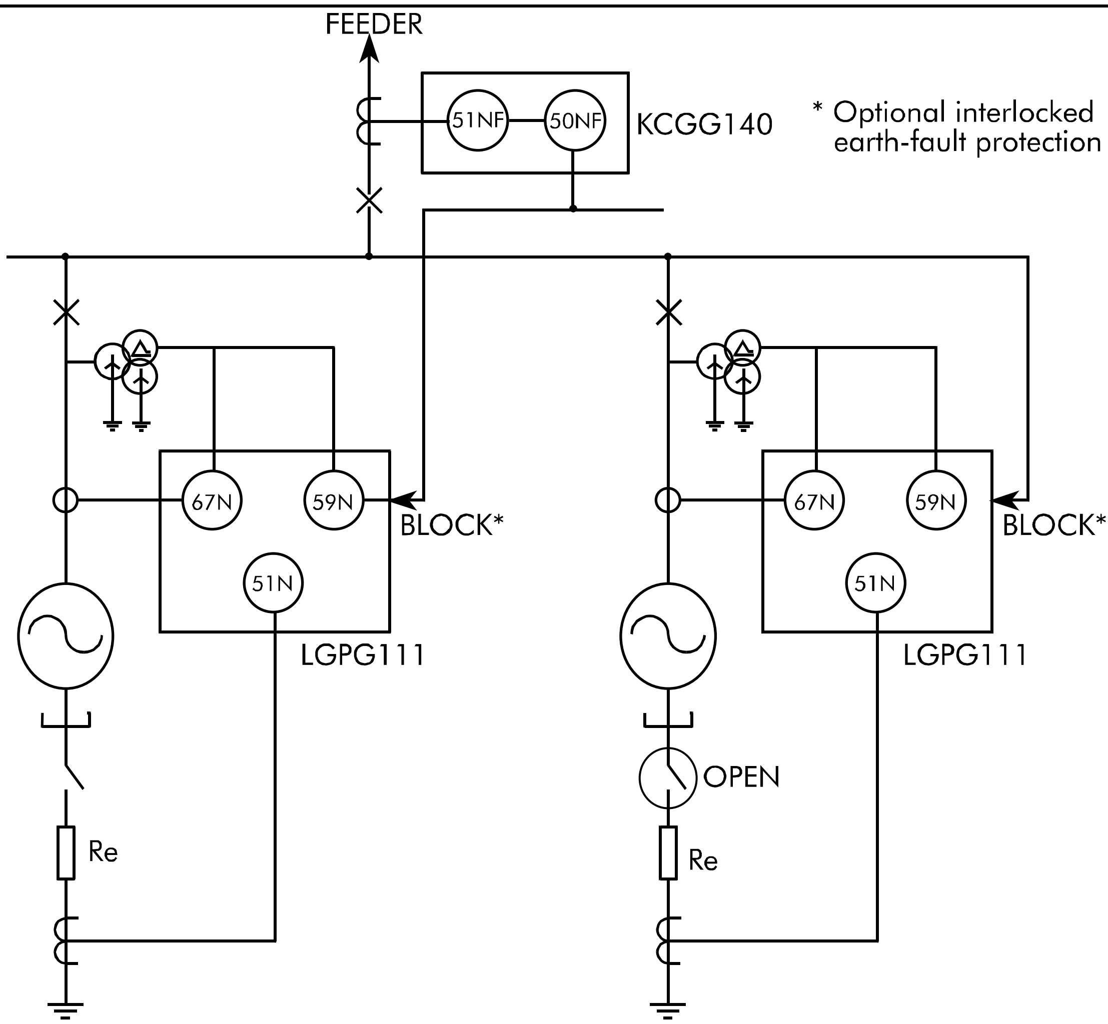
For indirectly connected applications, illustrated in Figure 5, the time-delayed earth fault protection function may be employed in one of two ways:

1. To measure earth fault current indirectly, via a CT in the secondary circuit of a distribution transformer earthing arrangement.

2. To measure earth fault directly, via a CT in the generator winding earth connection.

With the first mode of application, the current operated protection function (51N) may be used in conjunction with voltage operated protection function (59N), measuring the distribution transformer secondary voltage. This is a complementary arrangement, where the voltage operated protection function (59N) is able to operate in the event of an open-circuited loading resistor and the current operated protection function (51N) is able to operate in the event of a short-circuited resistor.

The second mode of application would be used for cases of direct resistive earthing. For distribution transformer earthing, this mode offers the advantage of being able to respond to an earth fault condition that leads to a flashover of the distribution transformer primary connections. Such a primary short circuit would render protection on the secondary side of the transformer inoperative and it would also result in a very high and damaging primary earth fault current. The high earth fault current should result in operation of the generator differential protection function, but use of the second stator earth fault protection element (Ie>>) as an instantaneous high-set element offers a second method of quickly clearing this fault condition, which may be seen as a prudent precaution.



Minimum earth fault level = $I_F = \frac{V_{ph-n}}{Re}$

Figure 9 system diagram - Stator earth fault protection function co-ordination example.

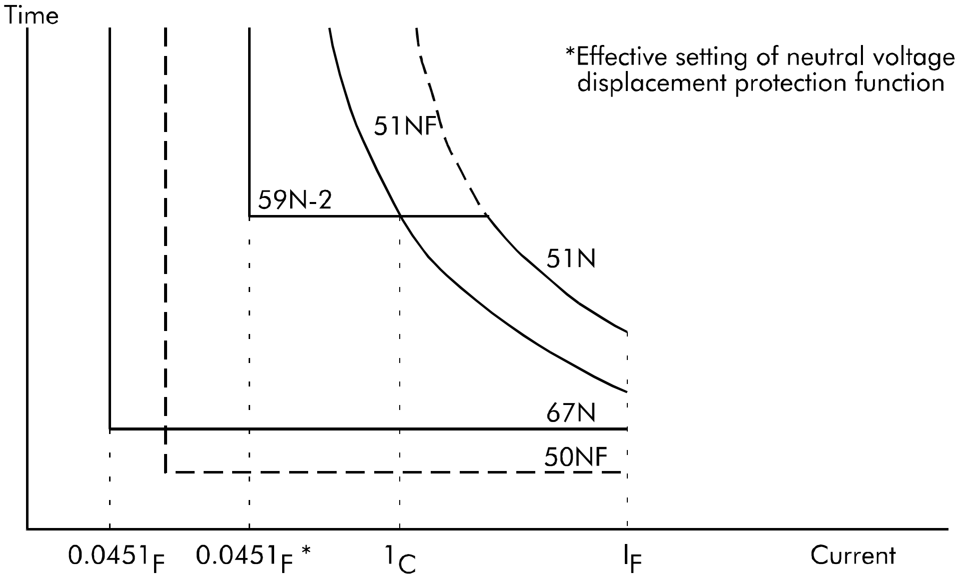


Figure 10 Stator earth fault protection function co-ordination example.

In such a situation, the main current operated protection element (Ie>) might be arranged to initiate a non-urgent shutdown, whereas operation of the additional protection element with a high setting and zero time delay (Ie>>), would be used to initiate an urgent shutdown.

In either mode of application, the main stator earth fault current operated protection element (Ie>) should be set to have a primary sensitivity of around 5% of the maximum earth fault current as limited by the earthing impedance. Such a setting would provide protection for up to 95% of the generator stator windings. The probability of an earth fault occurring in the lower 5% of the generator windings would be extremely low, due to the fact that the winding voltage with respect to earth is low in this region.

The time characteristic and setting of the main current operated protection element (Ie>) should be set to prevent false operation during HV system earth fault clearance, where a transient generator earth connection current may appear as a result of the inter-winding capacitance of the generator step-up transformer. The protection element should also co-ordinate with operation of generator VT primary fuses, for a VT primary earth fault, and with VT secondary fuses for a secondary earth fault on a VT that has its primary windings earthed. Depending on the VT fuse characteristics, and on HV system earth fault protection clearance times, a definite time delay anywhere between 0.5s and 3.0s would be appropriate.

The additional measuring element (Ie>>) would typically be set to operate with a primary current equal to 10% of the maximum limited earth fault current. The time delay for this element (t>>) would typically be set to zero. A higher current setting or time delay may be required in cases where VT fuse co-ordination would otherwise be infringed.

In machines with complex winding connection arrangements, e.g. some hydrogenerators, the probability of a fault occurring in the stator winding star-end region (first 5% of the winding) might be higher. For a highly rated, expensive machine, such increased probability may prompt operators to apply 100% stator earth fault protection. A suitable 100% stator earth fault protection scheme can be applied to supplement the LGPG111 in these cases. However, the relaying technique must be carefully selected so that it will be able to function correctly for the particular application, especially in the case of variable frequency operation. For most generator protection applications, the added complexity of providing a universally effective form of 100% stator earth fault protection is questionable.

Where stator winding inter-turn fault protection is required (see discussion in Section 2.2.), the current operated stator earth fault protection function might alternatively be used to provide this form of protection, using an additional single CT, as illustrated in Figure 11. In this case, the neutral voltage displacement protection (59N) would act as the main form of stator earth fault protection, even though the current operated protection function, as applied in Figure 11, could still respond to some stator earth fault conditions. This form of inter-turn fault protection, using the main current operated element (Ie>), offers the possibility of greater sensitivity compared to the technique discussed in Section 2.2. using the differential protection function. This is due to the fact that the required ratio of the single CT for this application is arbitrary. The current setting of the main current operated element (Ie>) should be set in accordance with the selected CT ratio to provide adequate primary sensitivity for the minimum possible inter-turn fault current. For similar reasons, the time delay applied should be similar to that recommended for application of the main current operated element of normal stator earth fault protection. The generator differential protection function would need to be connected as illustrated in Figure 7, to economise on CT's. A set of CT's for each group of windings must be connected in parallel to drive other LGPG111 protection functions.

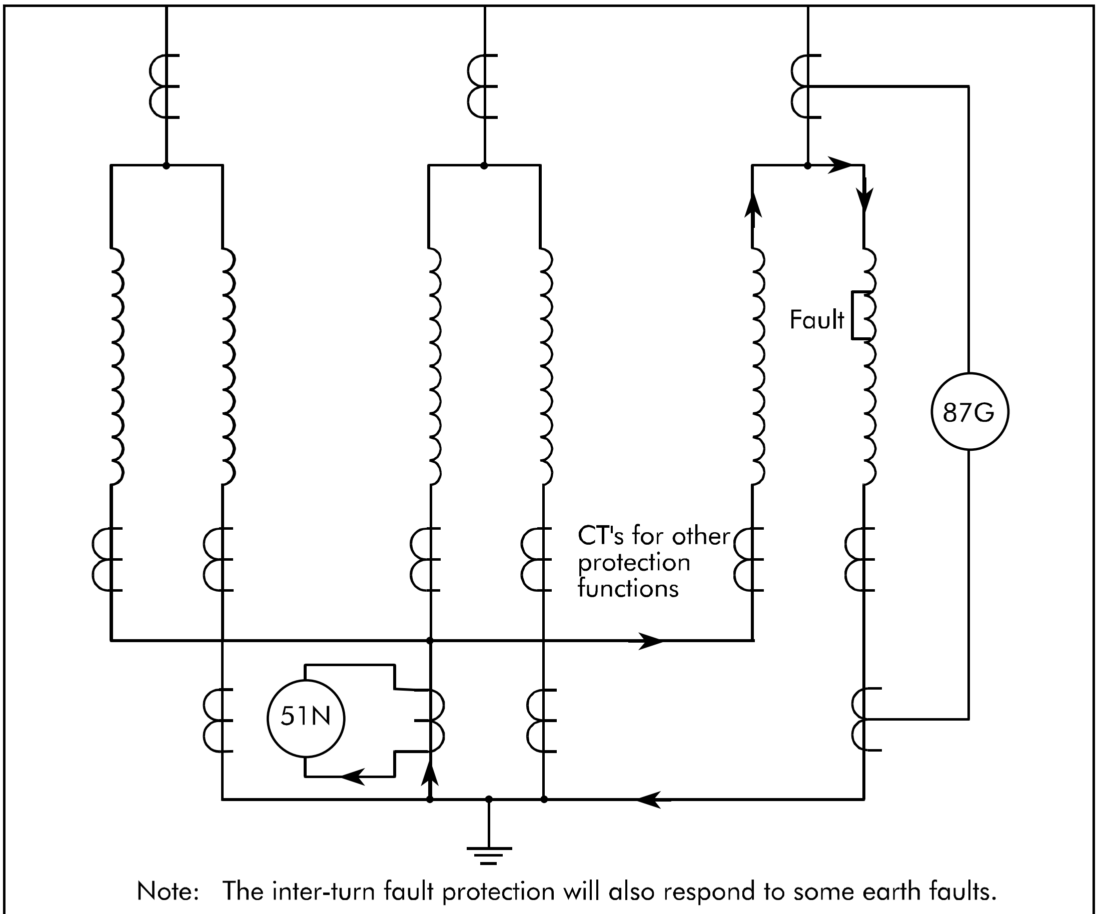


Figure 11 Inter-turn Fault Protection.

2.4. Neutral voltage displacement protection function (59N- I/59N-2)

Summary:

- Voltage operated.
- Single measuring element two time delay stages.
- Immune to third harmonics.
- **Applied to directly connected generators.**

  Supplied from a broken delta VT.

  The voltage setting should be greater than the effective setting of any down-stream earth fault protection.

  A time delay sufficient to allow downstream earth fault protection to operate first should be used.

  Fast earth fault protection can be enabled when the generator is not connected to the rest of the system.

- **Applied to in-directly connected generators.**

  Supplied from the secondary winding of a distribution earthing transformer or from a broken delta VT.

  A sensitive setting can be applied.

  A short time delay can be applied to stabilise the protection during voltage fluctuations due to VT failures or earth linkage during HV system faults.

The neutral voltage displacement protection function consists of a single measuring element with two independently adjustable time delays. This protection function 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. It would be the main means of providing stator earth fault protection for indirectly connected machines when the current operated protection function (51N) is used to provide stator winding inter-turn protection, as described in Section 2.3.2. A dedicated neutral voltage signal input is provided for this protection function. This input also provides a polarising voltage signal for the sensitive directional earth fault protection function (67N).

2.4.1. Application to a directly connected generator

For this mode of application, illustrated in Figure 3, the neutral voltage displacement protection function should be driven from a broken-delta-connected secondary winding of a generator terminal VT that has its primary winding star-point earthed. This VT should be made up of three single-phase units or should be a single-phase unit with a 5-limb core. If the VT is not provided with an independent set of secondary windings for broken delta connection, a set of three single-phase interposing VT's should be applied. The interposing VT's should have their primary windings connected in star to the main VT secondary winding terminals and star-point. Their secondary windings should be connected in broken-delta format, to drive the neutral voltage displacement protection function. Alternatively, this protection function could be driven from a single-phase VT connected between the generator winding star-point and earth.

The voltage setting of the neutral voltage displacement protection function should be set higher than the effective setting of current operated earth fault protection on any outgoing feeder from the generator bus. The setting should also be higher than the effective setting of the sensitive directional earth fault protection applied to any parallel generator. The effective voltage setting of any current operated earth fault protection may be established by multiplying the primary operating current of the protection by the generator grounding impedance and dividing by one-third of the VT winding ratio, in the case of a broken delta VT arrangement, or by the actual VT winding ratio in the case of a single-phase star-point VT.

The second time-delayed stage of protection (59N-2) should have a time delay that is set to co-ordinate with operation of feeder earth fault protection or parallel generator sensitive earth fault protection. The second protection stage will offer primary stator earth fault protection for the protected machine and back up protection for the rest of the power system when the protected machine is connected to the generator bus. In the case of inverse-time feeder earth fault protection, better back up protection could be afforded by using the inverse time current operated protection function (Ie>). Alternatively, where KCGG/KCEG relays are used to protect feeders, it may be possible to eliminate any co-ordination problem by interlocking the feeder relays and the LGPG111, as described in Section 3.4.

In the co-ordination example of Figure 10, a lack of co-ordination is apparent for feeder earth faults with currents less than I_c. It must be ascertained that I_c is less than the fault current for the maximum anticipated level of fault resistance and that remote earth faults resulting in a current of less than I_c will be cleared by remote protection in less than the time setting of the second stage of neutral voltage displacement protection (59N-2). Alternatively, an instantaneous low-set earth fault element (50NF) of a KCGG feeder relay could be used to block the 59N protection of the LGPG111 relays (see Section 3.4.).

The first protection stage (59N-1) should not be enabled in the group-1 LGPG111 settings unless it is being used in conjunction with the sensitive directional earth fault protection function (see Section 2.5.). Direct tripping of this stage could be enabled in the group-2 settings with a minimum time setting of 0s. The relay could be switched to adopt group-2 settings when the generator circuit breaker is open, via a normally closed breaker auxiliary contact acting on the group selection logic inputs (inputs 3 and 4). This arrangement would offer fast earth fault protection if an earth fault occurs on a generator when it is not connected to the generator bus and when there is no need to co-ordinate with the operation of any other earth fault protection. This protection will also clear an earth fault on an unsynchronised generator that does not have its own earth connection.

2.4.2. Application to an indirectly connected generator

For this type of application, illustrated in Figure 5, the voltage operated stator earth fault protection function should be driven from the secondary winding of a distribution earthing transformer. In the case of direct resistive earthing, or of no deliberate earth connection, the protection should be driven from a VT winding, as described in Section 2.4.1.

The voltage setting of the protection function should be set to 5% of the voltage that would be applied to the relay in the event of a solid fault occurring on one of the generator terminals. This would offer approximately 95% coverage of the generator winding. The voltage operated protection function might be used to complement the current operated protection function in the case of distribution transformer earthing, as described in Section 2.3.2.

The first-stage protection (59N-1) time delay should be set with the considerations that applied to setting the main current operated protection element (Ie>), as discussed in Section 2.3.2.

2.5. Sensitive directional earth fault protection function (67N)

Summary:

- Applied where two or more generators are connected directly to a common busbar.
- The operating current is obtained from the residual connection of the line side CTs.
- A sensitive operating current setting of 5% of the maximum earth fault level should be applied.
- Where the required sensitivity cannot be obtained from the residual connection of CTs a dedicated core balance CT can be used.
- Either current or voltage polarised.
- The stator earth fault input provides the current polarising signal.
- The neutral voltage displacement input provides the voltage polarising input.
- When voltage polarised the polarising threshold should be set to give an operating threshold equivalent to the current setting.
- When current polarised the polarising threshold should be just below the operating current setting.
- When combined with the neutral displacement protection, the inadvertent operation of earth fault protection, during transient CT saturation, can be achieved.

The instantaneous sensitive directional earth fault protection function is provided with a dedicated single-phase CT input for the operating current. This input could accept the residual current from three line CT's or current from a dedicated core-balance CT. An adjustable operating current threshold is provided (Iresidual>).

The polarising signal for the directional decision is either a voltage applied to the neutral voltage VT input or a current signal applied to the stator earth fault current input. Independent polarising voltage and polarising current threshold settings (Vep>, Iep>) are provided for this protection function. One of these polarising signal thresholds must be exceeded to allow operation of the sensitive directional earth fault protection function. Where the voltage threshold (Vep>) is exceeded, the current polarising signal is ignored.

A characteristic angle setting (RCA) is provided for the directional element. This determines the required angle between the polarising voltage and the operating current signals for optimum directional element response. The required angle between the polarising current and the operating current signals for optimum directional element response is zero degrees.

This protection function would only be applied in cases of parallel generators being directly connected to a busbar, see Figure 3, where the generator differential unit-type protection function does not have adequate sensitivity to detect earth faults over 95% of the stator windings. Sensitive directional earth fault protection function is a method of assuring proper earth fault protection discrimination.

In cases where a generator might be earthed, non-directional or non-unit earth fault protection may not be able to distinguish between a fault on a generator fed from another earthed source and a fault on a parallel generator or the power system, which may be fed by the protected generator.

Where earthing is provided by another power system source, or by a bus earthing transformer, a generator might never be earthed itself and so the generator might not be able to contribute zero sequence current to a system earth fault. With such an arrangement, there would still be a risk of incorrect non-directional protection operation in the event of transient CT spill current. This transient spill current might arise due to asymmetric CT saturation while passing offset current waveforms to an external phase fault or magnetising inrush current to a transformer being energised from the generator bus.

By setting the required residual polarising voltage threshold setting (Vep>) high enough when applying the sensitive directional earth fault protection function (67N), the problem of unwanted operation for external phase faults, or in the presence of transformer magnetising inrush current, can be eliminated. Where the generator is not earthed, there may still be a risk of maloperation of the instantaneous directional protection function with transient spill current generated by an external phase-phase-earth fault. Such a fault could result in transient spill current, with no dominating reverse zero sequence current and a significant residual polarising voltage, which may exceed the maximum threshold setting of 10V for the directional protection. In such a case, the protection function would either need to be driven from a dedicated core-balance CT (with insulated cable glanding, etc.) or tripping would need to be gated by operation of the spare first-stage of the neutral voltage displacement protection function (59N-1). The time delay of this first-stage of the neutral voltage protection function could be used as a method of providing transient spill current stability.

The operating current threshold of the directional earth fault protection function (Iresidual>) should be set to give a primary operating current down to 5% of the minimum earth fault current contribution to a generator terminal fault. Where it is not possible to achieve the required sensitivity with the minimum relay setting (0.005In) and the required line CT ratio, the use of a dedicated core-balance CT of lower ratio will be necessary to operate the directional earth fault protection function.

The polarising voltage signal threshold setting (Vep>) should be chosen to give a sensitivity equivalent to that of the operating current threshold. This current level can be translated into a neutral voltage as described for the neutral voltage protection function in Section 2.4.1.

Where the protected generator can be earthed, the current polarising signal threshold setting (Iep>) in primary amps should be less than 5% of the maximum current that could be delivered through the generator earthing impedance for a solid earth fault on a generator terminal. If the protected generator can never be earthed, the current polarising signal threshold setting should be set to maximum (0.02In).

The directional element characteristic angle setting (RCA) should be set to match as closely as possible the angle of zero sequence source impedance behind the relaying point. If this impedance is dominated by an earthing resistor, for example, the angle setting would be set to zero degrees.

In the case of a generator that will not be earthed, and where a dedicated core-balance CT is not available to drive the sensitive directional earth fault protection function, the LGPG111 scheme logic should be set up so that operation of both the first stage of the neutral voltage displacement protection function (59N-1) and the directional protection function (67N) is required before a trip command is given. The group-1 time setting for this protection should be chosen to give adequate trip stability in the event of transient CT spill current arising. The required time setting may need to be in excess of the minimum 0.5s setting and would have to be arrived at by judgement or by trial switching of transformers onto the generator busbar. A core-balance CT is a much more preferable option to avoid the transient spill problem with line CT's.

2.6. Voltage-dependent overcurrent protection function (51 V)

Summary:

- Provides back up protection for uncleared downstream faults.
- The protection operating mode can be configured to be: a simple overcurrent, a voltage controlled overcurrent or a voltage restrained overcurrent function.
- In any of the modes of operation, the associated time delay can be either definite time or standard inverse IDMT.
- The voltage dependent overcurrent protection must be time graded with down-stream overcurrent protection. Where overcurrent relays with start contacts are used on outgoing feeders, time grading can be achieved by blocking the operation of the voltage dependent overcurrent protection.
- The reset time of the protection can be set to be instantaneous or time delayed. A time delayed reset can be used to provide better time grading with downstream electro-mechanical protection and to detect intermittent faults.
- In the simple overcurrent mode the system voltage has no effect on the current setting of the protection.
- At normal system voltage the current setting should be 5% above full load current.
- When a fault close to the generator will result in a fault current decrement the system voltage should be monitored to distinguish between normal load current and a system fault. Here either the voltage controlled or the voltage restrained modes of operation should be selected.
- **Voltage controlled overcurrent protection.**

  A step change in the current setting is initiated if the system voltage falls below a selected level.

  Applied when the generator is directly connected to the system.

  At normal system voltage the current setting should be 5% above full load current.

  Under low voltage conditions, the current setting should be reduced to less than 50% of the minimum steady state fault current

  The reduction in the fault current setting is controlled by a multiplying factor, K.

  The voltage control threshold should be selected to ensure that a voltage reduction due to a single phase to earth fault will not result in a change of the current setting.

  When negative phase sequence protection is also applied, the calculation of the voltage threshold need only consider the effect of a remote three phase fault.

- **Voltage restrained overcurrent protection.**

  The current setting is incrementally decreased as the voltage falls below a selected level. A lower voltage level is also defined, below which the current setting will remain at a minimum value.

  The pick up current for a given voltage, below the set level, is evaluated by a simple calculation.

  Applied where the generator is indirectly connected to the system (via a step-up transformer).

  When negative phase sequence protection is also applied, the voltage reduction due to a remote three phase fault need only be considered.

  The voltage threshold should be selected to ensure that a voltage reduction due to a single phase to earth fault will not result in a change of the current setting.

  The lower voltage threshold should be set slightly above the voltage level resulting from a remote three phase fault.

  When set with a definite time characteristic, this protection can be set equivalent to under-impedance protection.

- A voltage transformation facility provides compensation for phase faults occurring on the HV side of a generator transformer.

The voltage-dependent overcurrent protection function is a three-phase protection function that is driven by the general protection CT inputs and which is intended to provide backup protection for an uncleared phase fault on the generator busbar or on a feeder from the busbar.

Operation of each overcurrent element can be made dependent on a phase-phase voltage signal. The A-phase current element for example, would be dependent on the A-B voltage signal from the generator main VT circuits. A facility has also been added to determine and use voltage signals that are equivalent to the HV phase-phase voltage signals where a Yd1 or Yd11 step-up transformer is used to indirectly connect the generator to a power system.

The voltage dependent overcurrent protection function can be set to operate in a ‘voltage-controlled’ mode or in a ‘voltage restrained’ mode. If voltage-dependency is not required, this function can be set to operate as plain overcurrent protection, with a fixed operating characteristic. The protection function can be set to operate with an adjustable standard inverse time characteristic or with a definite time delay.

In the case of a generator passing highly reactive current to a fault the level of fault current can fall below the maximum possible machine load current within 0.5s-1.0s unless a fast-acting automatic voltage regulator (AVR) is available. This is because the AVR is able to boost the level of field excitation during a fault. The problem of fault current decrement can be most acute when the excitation supply is derived from a transformer connected to the generator terminals. Where a fault current decrement is possible, voltage-dependent overcurrent protection provides time-delayed backup protection with adequate sensitivity for a multi-phase busbar or feeder fault, whilst remaining stable for the highest anticipated level of generator load current. The generator terminal voltage is monitored as a way of being able to distinguish between normal load and system fault conditions.

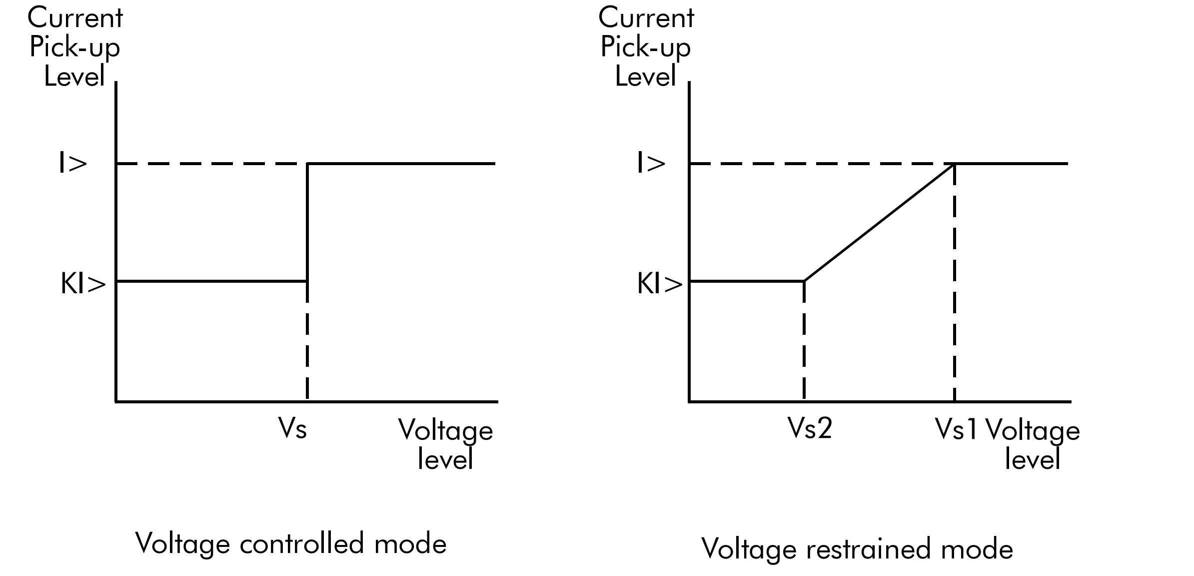


Figure 12 Voltage Dependent Overcurrent Functions.

In the voltage-controlled protection mode, see Figure 12, a step-change in current setting (I> to K.I>) is imposed when the monitored voltage signal drops below an adjustable threshold setting (Vs).

In the voltage-restrained protection mode, see Figure 12, a progressive change in current setting is made (I> to K.I>) for voltage variation between the upper threshold (Vs1) and the lower threshold (Vs2). This mode is analogous to under impedance backup protection, especially where a definite-time delay is applied. Under impedance protection is a more familiar method of providing backup protection for some operators.

The voltage-dependent overcurrent protection function (51V) is also provided with a characteristic timer-hold setting (tRESET). The percentage operation of the characteristic timer, following the current rising above the operating threshold of the protection for a period, is held for time tRESET if the current subsequently falls below the operating threshold before tripping has occurred. This feature will allow the protection to respond to the cyclic application of fault current in the event of ‘flashing’ or ‘pecking’ faults. It can also be used to ensure that the voltage dependent overcurrent protection function will respond to cyclic overcurrent conditions during pole slipping, as discussed in Section 3.5. 1.

The basis for the two modes of voltage-dependent protection function is really historical; originating from the two convenient ways of achieving voltage-dependency with electromechanical relay technology. However, for different applications, subtle advantages are often claimed for one form of protection over the other.

2.6.1. Application of the voltage controlled overcurrent protection function

In this mode, it is relatively easy to determine the behaviour of the overcurrent protection function during a fault, since it merely switches between a load characteristic and a single fault characteristic. This protection mode is ideally suited to applications where there is a significant phase-phase voltage collapse at the generator terminals for a busbar or feeder multi-phase fault. This would be the case where a generator is directly connected to the busbar.

The LGPG111 voltage-controlled current setting is related to the measured voltage as follows:

For V > Vs: Current setting (Is) = I>

For V < Vs: Current setting (Is) = K.I>

Where:

Is = Current setting at voltage V

V = Voltage applied to relay element

The operating time characteristic of the protection can be set as definite-time or inverse-time according to the following curve formula:

$$t = TMS \times \frac{0.14}{\left(\frac{I}{Is}\right)^{0.02} - 1}$$

The current setting at the normal level of voltage (I>) should be set to have a primary operating value in excess of the maximum required level of generator load current. The actual maximum load current should be divided by 0.95 to obtain a satisfactory margin for measurement accuracy.

The current setting multiplying factor (K) governs the protection function setting under low voltage conditions. The current setting multiplying factor should be set to give a primary operating current less than 50% of the minimum steady-state fault current for a multi-phase fault at the remote end of a feeder, fed from the generator bus, with the generator being the only source.

This ensures that protection failure or breaker failure for the faulted feeder will not result in the generator persistently feeding current to an uncleared feeder fault. The voltage-controlled protection function should co-ordinate with outgoing feeder protection for a feeder fault under minimum plant conditions. The most onerous case to consider is that of a close-up three-phase fault on a feeder, where there would be almost a full voltage collapse seen by the LGPG111. Where co-ordination is difficult to achieve and where KCGG/KCEG feeder overcurrent relays are employed, start contacts of the feeder overcurrent relays should be used to interlock operation of the LGPG111 voltage-dependent protection function, as described in Section 3.4.

Where there is more than one source for the generator bus, it may not be possible to ensure operation of the generator voltage-dependent protection function for a remote-end feeder fault until the additional source has been disconnected by its own protection. Where the additional source is another parallel generator, it may be that neither generator can respond to the remote fault with voltage-dependent protection. In such cases, the generators would have to be tripped by delayed under voltage protection for a remote persistent fault (see Section 2.10.). For phase-phase faults, tripping may occur earlier via the negative phase sequence thermal protection function of LGPG111, if it is set and enabled.

The minimum fault current for a remote-end multi-phase fault on a feeder can be determined as follows. This calculation is based on the no-load excitation being applied and on no field-forcing or AVR action during the fault.

$$\text{Three-phase fault: } I_f = \frac{E_n}{\sqrt{(nR_f)^2 + (X_s+nX_f)^2}}$$

$$\text{Phase-phase fault: } I_f = \frac{\sqrt{3}E_n}{\sqrt{(2nR_f)^2 + (X_s+X_2+2nX_f)^2}}$$

Where:

I_f = Minimum generator primary current seen for a multi-phase feeder-end fault

E_n= No-load phase-neutral internal e.m.f. of generator

X_s = Direct-axis synchronous reactance of the generator

X_2 = Negative phase sequence reactance of the generator

R_f = Feeder positive phase sequence resistance

X_f = Feeder positive phase sequence reactance

n = Number of parallel generators

The remote-fault operating consideration for the voltage-dependent protection function need only be a three phase fault where the negative phase sequence thermal protection function is applied. The required protection fault setting (K.I>) would need to be less than 0.25 p.u. if the longest feeder from the generator bus is very short and E_n = 1.0 p.u., with X_s = 2.0 p.u.

The under voltage switching threshold setting (Vs) should be selected so that switching does not take place with the minimum possible phase-phase voltage for single phase to earth fault conditions. For a single phase fault, the minimum possible phase-phase voltage would be for a close-up earth fault on a solidly earthed power system, where the voltage could fall to 57% of the nominal level. The voltage setting should also be set above the maximum phase-phase voltage for any element required to operate for a remote-end feeder fault. The steady-state voltage seen by the LGPG111 for such a fault and under the conditions mentioned earlier, can be deduced as follows:

$$\text{Three-phase fault: } V_{f\text{-}f} = \frac{E_n\sqrt{3\left((nR_f)^2 + (nX_f)^2\right)}}{\sqrt{(nR_f)^2 + (X_s+nX_f)^2}}$$

$$\text{Phase-phase fault:} V_{f\text{-}f} = \frac{2E_n\sqrt{3\left((nR_f)^2 + (nX_f)^2\right)}}{\sqrt{(2nR_f)^2 + (X_s+X_2+2nX_f)^2}}$$

As already mentioned, where the negative phase sequence thermal protection function is set and enabled, a remote three-phase fault need only be considered when determining the voltage threshold setting (Vs).

2.6.2. Application of voltage restrained overcurrent protection function

In this mode, it is more complex to determine the behaviour of the protection function during a fault. Thus it is more difficult to co-ordinate with the protection of feeders from the generator protection busbar. This protection mode is, however, better suited to applications where there is a less significant phase-phase voltage collapse at the generator terminals for a busbar fault. This would be the case where a generator is connected to a busbar via a delta/star step-up transformer. With indirect connection of the generator, a solid phase phase fault on the busbar will only result in a partial phase-phase voltage collapse at the generator terminals. For such a fault, the minimum phase-phase voltage seen by the LGPG111 would be 50% of the nominal voltage, when the generator transformer impedance is very small in relation to the generator synchronous reactance (as it would be) and the generator was initially at the no-load level of excitation.

To improve the sensitivity of the voltage-restrained overcurrent protection function, for HV phase-phase faults fed via a Yd1 or Yd11 step-up transformer, the appropriate voltage signal transformation facility should be switched in as part of the LGPG111 settings. Use of this feature will also de-sensitise the voltage-restrained protection function to an HV earth fault, which would yield a low phase-phase voltage on the generator side of the step-up transformer. Response to HV system earth faults is undesirable, since it should be the HV standby earth fault protection, see Figure 5, which deals with an uncleared HV earth fault fed by the generator. In the past, such correction of voltage signals has been addressed by adopting phase-neutral voltage measurement or the use of a star/delta interposing VT. Such an approach cannot be adopted with LGPG111 since the relay voltage inputs are common to other protection and measurement functions that would be undesirably affected by voltage signal correction.

The LGPG111voltage-restrained current setting is related to measured voltage as follows:

Current Setting (Is) =

$$I> \qquad \text{for } V > V_{s1}$$

$$K.I> + \frac{I> - K.I>}{V_{s1} - V_{s2}}(V - V_{s2}) \qquad \text{for } V_{s2} \le V \le V_{s1}$$

$$K.I> \qquad \text{for } V < V_{s2}$$

Where: I_s = Current setting at voltage V

V = Voltage applied to relay element

The protection operating time characteristic can be set as definite-time or inverse-time according to the following curve formula:

$$t = TMS \times \frac{0.14}{\left(\frac{I}{Is}\right)^{0.02} - 1}$$

The performance criteria on which the settings of the voltage-restrained overcurrent protection function should be based are similar to those discussed for the voltage controlled mode in Section 2.6.1. The current setting at the normal level of voltage (I>) should be set to give a primary operating current in excess of the maximum possible generator load current. This should include a margin to allow for measurement accuracy, as discussed in Section 2.6.1. The voltage-restrained protection function should also co-ordinate with outgoing feeder protection for a feeder fault under minimum plant conditions. The most onerous case to consider is that of a close-up three-phase fault on a feeder, where there would be almost a full voltage collapse seen by the LGPG111. Where co-ordination is difficult to achieve, and where KCGG/KCEG feeder overcurrent relays are employed, start contacts of the feeder overcurrent relays should be used to interlock operation of the LGPG111 voltage-dependent protection function, as described in Section 3.4.

The protection function should be able to respond to a remote-end fault on an outgoing feeder from the generator bus. It will be assumed that where a step-up transformer is being used, it will also be an application where the LGPG111 negative phase sequence thermal protection function would be set and enabled. For this reason, consideration will only be given to the detection of a remote-end three-phase feeder fault, with the protected machine as the only source. The relay primary operating current for a remote-end three-phase fault, with the generator acting as the only source, should be 50% of the relay current seen at the particular voltage level present for such a fault. With the recommended setting for the lower voltage threshold (Vs2), the relay current setting will be the base fault setting (K.I>). For the conditions mentioned in Section 2.6.1., the steady-state primary current and voltage magnitudes seen for a feeder remote-end three-phase fault are given as follows:

$$I_f = \frac{E_n}{\sqrt{(nR_f)^2 + (X_s + X_t + nX_f)^2}}$$

$$V_{f\text{-}f} = \frac{E_n\sqrt{3\left((nR_f)^2 + (X_t + nX_f)^2\right)}}{\sqrt{(nR_f)^2 + (X_s + X_t + nX_f)^2}}$$

Where:

I_f = Minimum generator primary current seen for a multi-phase feeder-end fault

E_n = No-load phase-neutral internal e.m.f. of generator

Xs = Direct-axis synchronous reactance of the generator

X_2 = Negative phase sequence reactance of the generator

X_t = Step-up transformer reactance

R_f = Feeder positive phase sequence resistance

X_f = Feeder positive phase sequence reactance

n = Number of parallel generators

All above quantities are to referred to the generator side of the transformer

The upper voltage threshold setting (Vs1) should be set below the minimum corrected phase-phase voltage level for a close-up HV earth fault. In the case of HV solid earthing, this voltage would be a minimum of 57% of the nominal operating voltage. The lower voltage threshold (Vs2) should be set above the minimum corrected phase-phase voltage level for the limiting remote-end feeder fault condition considered above. There would be no need for further reduction in current setting for closer faults, which would yield higher currents and lower voltages. Further reduction in current setting for closer faults may make co-ordination with local feeder overcurrent protection more difficult (if this is not already a problem).

2.7. Reverse power and low forward power protection functions (32R/32L)

Summary:

- **Reverse power protection**

  Detects active power flow into the generator.

  The level of power required to motor the generator will depend on the type of prime mover.

  A high sensitivity current input is used to monitor the system power. This may be connected to the main system protection CT's or, for applications which require a sensitive setting, the input can be driven from a high accuracy measurement CT.

  A compensation angle setting is provided to compensate for CT and VT phase errors.

  A time delay (typically 5s) should be used to prevent operation of the protection during some system fault conditions and power system swings.

  To detect fluctuating reverse power flow, which could result from failure of a reciprocating prime mover, a delay on drop off timer is available, in addition to the delay on pick up timer.

  Reverse power protection is blocked for currents exceeding 1.05In due to the sensitive nature of this protection function.

- **Low forward power protection.**

  Operates when the forward power falls below the set level.

  Operation can be instantaneous or time delayed.

  Usually interlocked with non-urgent protection to reduce over speeding of the generator following breaker operation for a non-urgent fault. The interlocking can be achieved using the internal scheme logic of the LGPG.

2.7.1. Reverse power protection function (32R)

The reverse power protection function offered by LGPG111 is driven from an A-phase sensitive current input CT and the A-B voltage signal and measures true Watts.

In the event of prime mover failure, a generator that is connected in parallel with a power system or other generators will begin to 'motor' and active power will be drawn from the power system to cover alternator and failed prime mover mechanical losses. To automatically detect this mechanical mode of failure in order to disconnect the afflicted machine from the power system, reverse power protection is often applied.

The consequences of generator motoring and the level of power drawn from the power system will be dependent on the type of prime mover. Where rapid prime mover damage could occur and/or where a high level of power is drawn from the power system, automatic generator disconnection should occur.

Typical levels of motoring power and possible motoring damage that could occur for various types of generating plant are given in table 1.

<table>
<tr><th>Prime Mover</th><th>Motoring Power
(Percentage rating)</th><th>Possible Damage</th></tr>
<tr><td>Diesel Engine</td><td>5% - 25%</td><td>Risk of fire or explosion from unburnt fuel</td></tr>
<tr><td colspan="3">Motoring level depends on compression ratio and cylinder bore stiffness. Rapid disconnection is required to limit power loss and risk of damage.</td></tr>
<tr><td>Gas Turbine</td><td>10% - 15%
(split-shaft)

>50%
(Single-shaft)</td><td>With some gear-driven sets, damage may arise due to reverse torque on gear teeth</td></tr>
<tr><td colspan="3">Compressor load on single shaft machines leads to a high motoring power compared to split-shaft machines. Rapid disconnection is required to limit power loss or damage.</td></tr>
<tr><td>Hydraulic Turbines</td><td>0.2 - >2%
(Blades out of water)

>2.0%
(Blades in water)</td><td>Blade and runner cavitation may occur with a long period of motoring</td></tr>
<tr><td colspan="3">Power is low when blades are above tail-race water level. Hydraulic flow detection devices are often the main means of detecting loss of drive. Automatic disconnection is recommended for unattended operation.</td></tr>
<tr><td>Steam Turbines</td><td>0.5% - 3%
(Condensing sets)

3% - 6%
(Non-condensing sets)</td><td>Thermal stress damage may be inflicted on low-pressure turbine blades when steam flow is not available to dissipate windage losses</td></tr>
<tr><td colspan="3">Damage may occur rapidly with non-condensing sets or when vacuum is lost with condensing sets. Reverse power protection may be used as a secondary method of detection and might only be used to raise an alarm.</td></tr>
</table>

Table 1 Motoring power and possible damage for various types of prime mover.

The need for automatic disconnection is arguably less for plant that is continuously supervised, but, in the event of prime mover failure, the attention of control staff could be diverted by other aspects of the mechanical failure. If motoring damage can occur rapidly, operator action may be too slow to prevent the onset of damage, so there may be a requirement for automatic generator disconnection or for an alarm to be raised. For unattended generation plant, e.g. small hydro schemes that are only periodically supervised, automatic generator disconnection should occur even if immediate prime mover damage would not be envisaged. If automatic disconnection did not occur in such cases, motoring may be possible for hours, with plant damage being gradually inflicted. Automatic disconnection would also prevent an unnecessary power system loss,

In many cases, prime mover failure can be detected by non-electrical means; e.g. by a steam turbine differential pressure switch or by a hydraulic flow device. If mechanical means of detecting prime mover failure are provided, an electrical measurement method would not be required or would only be used for backup detection.

Prime mover failure can be detected electrically by sensitive reverse power protection.

This protection can be offered on a single phase basis for detection of balanced reverse power flow. It can be seen from the above typical levels of reverse power flow, that a very sensitive power element setting (-P>) would be required to detect prime mover failure in some applications. The setting of the power element in secondary single phase Watts (-P>) should be less than 50% of the secondary motoring power as determined below:

$$P_m\ (\text{Sec}) = \frac{\%P_m\ (\text{Prim}) \times S_n \times CT \times VT}{3}$$

Where:

P_m(Sec)	= Secondary 1-phase motoring power (Watts)
$\%P_m$(Prim)	= Percentage motoring power of generator set.
S_n	= Generator rating (VA).
CT	= Protection CT ratio.
VT	= Protection VT ratio.

The operating boundary of the reverse power protection function should be where the A-phase current flowing from the generator into the power system, lies within $\pm\alpha°$ of the derived inverted A-phase voltage signal.

$$\alpha = 90° - \frac{(-P>) \times \sqrt{3} \times 180}{1.05 \times V_{ab} \times \pi}$$

The position of the positive α angle is indicated in Figure 13.

The operating criteria is according to the following formula, see Figure 13:

$$\frac{V_{ab}\angle{-30°} \times I_A \cos(180 - \Phi)}{\sqrt{3}} > (-P>)$$

Where.

V_{AB}	= Phase-phase voltage signal used.
I_A	= Current from sensitive input CT.
Φ	= Angle between I_A (in export direction) and V_A.
-P>	= LGPG111 reverse power threshold setting (1-phase secondary Watts).

In a practical relay design, the operative angle range must be slightly less than ±90°, to allow for small CT, VT and relay errors. These errors might otherwise result in false protection operation with low power factor forward current; e.g. when supplying excitation current to a step up transformer, prior to synchronisation. The angular operating range must not be reduced too much, since the reverse power protection may be required to respond to a small level of reverse active current (e.g. 0.5% I_n) while a much larger forward reactive current is maintained (e.g. 60% I_n), until AVR

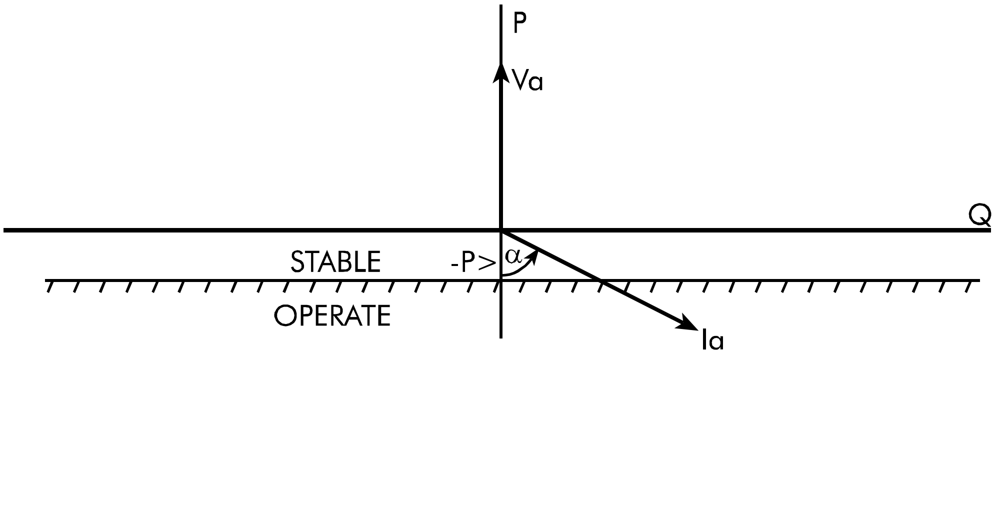


Figure 13 Reverse power protection function characteristic.

-P> Setting	0.3W	0.5W	1.0W	2.0W	4.0W	6.0W	8.0W
Theoretical Angle Boundary	±89.7°	±89.5°	±89.1°	±89.1°	±86.2°	±84.3	±82.4°

Table 2 Operating angle range of LGPG111 reverse power protection function

action takes place. The operating angle range of the reverse power protection may have to be in excess ±89°. The operative angle range of the LGPG111 reverse power protection function is given for various power threshold settings in Table 2.

To achieve the accuracy of current angle measurement required for sensitive reverse power protection, a dedicated, high-accuracy input CT is provided with the LGPG111 and the operative current range for the reverse power protection function is limited to rated current, see Figure 14. Where the sensitive reverse power protection function is required (less than 3%P_n), this dedicated current input should be driven by a high accuracy measurement CT and the burden imposed on this CT should be in line with the CT classification. To take into account inevitable phase errors that will exist between CT and VT signals on site, the reverse power protection function characteristic can be finely rotated in 0.1° steps to compensate for site errors. The method for setting this compensation angle (θcomp) is detailed in the commissioning instruction, but it will only be necessary to set this angle for sensitive reverse power protection. For general application, the compensation angle setting should be set to zero degrees.

The reverse power protection function needs to be time-delayed to prevent false tripping or an alarm given during power system swings, following power system disturbances or following synchronisation. During certain asymmetric power system faults, when balanced system operation does not exist, it must also be recognised that the reverse power protection function may see an operating condition during a fault. For example: a C-A fault with direct generator connection; or an HV B-N fault fed through a Yd11 step-up transformer. The time delay (t) must, therefore, be set longer than the clearance time of asymmetric system faults by back up protection, plus any delayed reset selling (tDO) that may have been applied. Such a time setting (typically

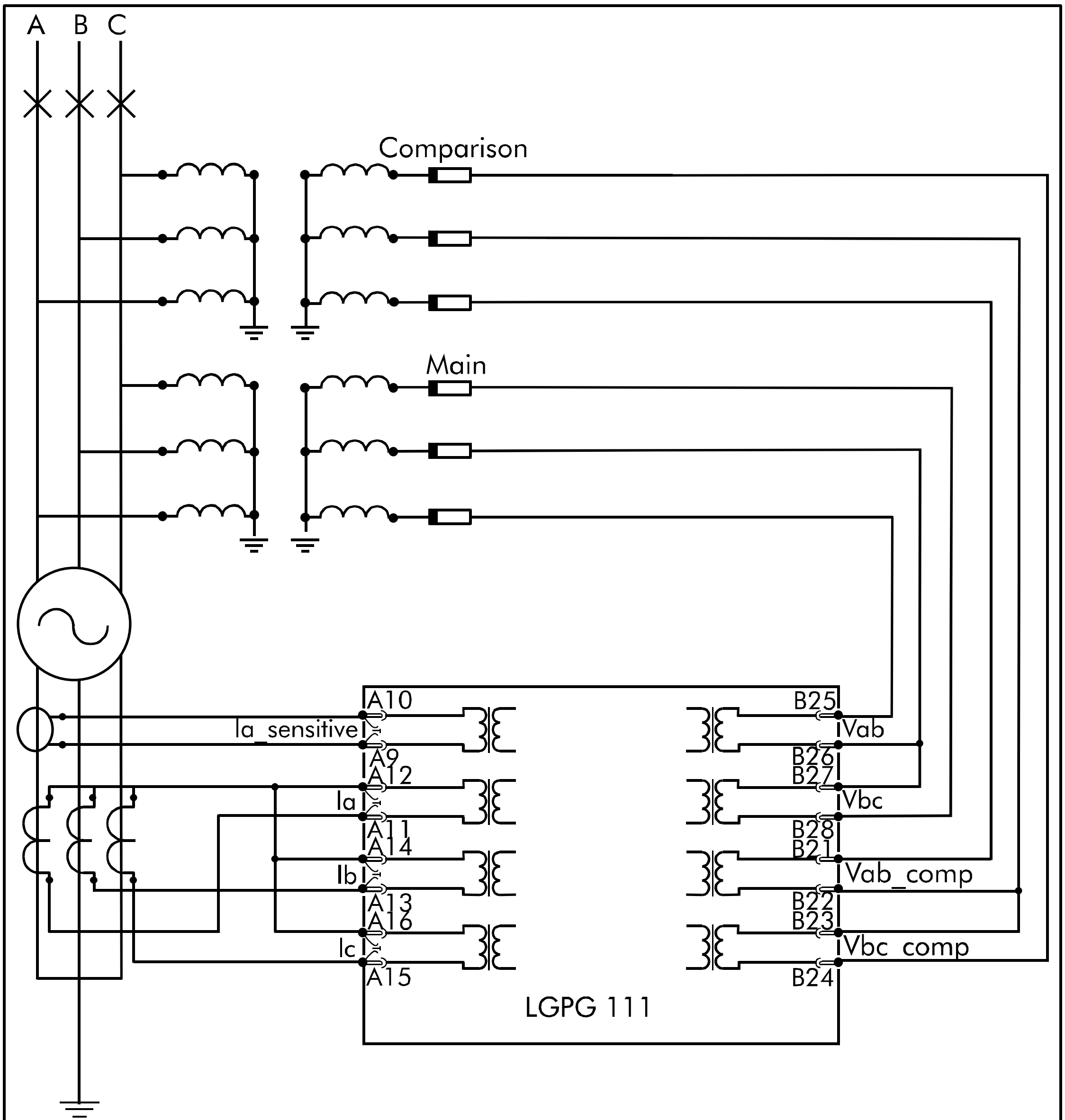


Figure 14 Connections for sensitive reverse power protection.

5s) should also give stability of the reverse power protection function during power swings.

In some applications, the level of reverse power in the case of prime mover failure may fluctuate. This may be the case for a failed diesel engine. To prevent cyclic initiation and reset of the main trip timer (t), and consequent failure to trip, an adjustable delay on measuring element reset (tDO) is provided. This delay would need to be set longer than the period for which the reverse power could fall below the power setting (-P>). This setting needs to be taken into account when setting the main trip time delay (t), as discussed above. It should also be noted that a delay on reset in excess of half the period of any system power swings could result in operation of the reverse power protection during swings. In general, the reset delay (tDO) should be set to zero.

In some applications, the reverse power protection function should be disabled during certain modes of protected machine operation. One example of such a situation is where, during dry seasons, a synchronous machine is de-coupled from its hydraulic prime mover and operated as a synchronous compensator for power system VAR control. One way of disabling the reverse power protection function would be to switch from the normal group of LGPG111 settings, where this protection function is enabled, to the second group of settings, where this protection function has not been enabled. Alternatively, a spare logic input could be assigned, through the relay scheme logic matrix, to act as a blocking input for the reverse power protection function.

It should be noted that the reverse power protection function is blocked if the current exceeds 1.051_n due to a sensitive current measurement limitation.

2.7.2. Low forward power protection function (32L)

This protection function is similar in nature to the reverse power protection function described above, with a single phase measuring element which operates from the sensitive A-phase measuring CT input, see Figure 15, according to the following formula:

$$\frac{V_{AB}\angle -30^\circ \times I_A \cos\phi}{\sqrt{3}} < (P<)$$

Where:

V_{AB} = Phase-phase voltage signal used

I_A = Current from sensitive input CT

ϕ = Angle between I_A (in export direction) and V_A

P< = LGPG111 low forward power threshold setting (1-phase secondary Watts)

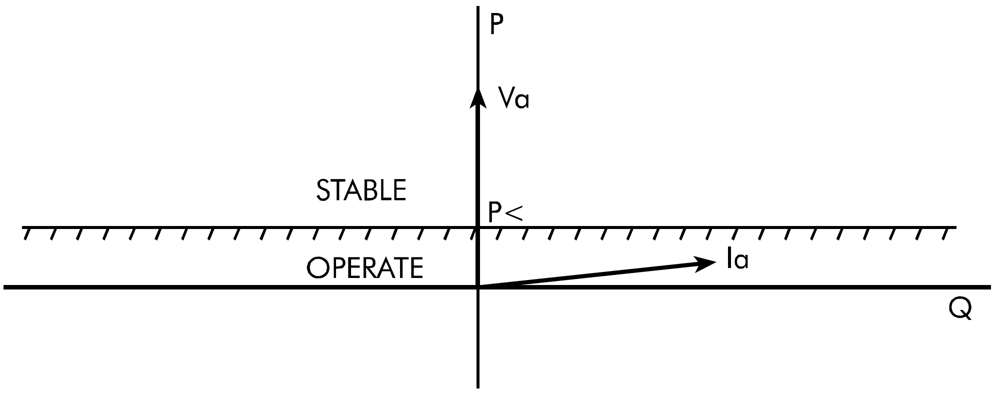


Figure 15 Low Foward Power Protection Function Characteristic.

The measuring element is followed by an adjustable time delay that can be set down to zero if desired.

This protection function is offered for those users who wish to interlock non-urgent protection function tripping and, possibly manual tripping of the generator breaker and excitation system. Interlocking with a low forward power measuring element confirms that the mechanical drive has been cut. Such an arrangement would ensure that there would be no possibility of generator set over speed when any restraining electrical load is cut by electrical tripping.

With any generator, tripping of the generator breaker and excitation system should be accompanied by throttle or valve closure. There is always a risk, however, that the throttle/valves may not close fully and that machine over speed will result when electrical loading is removed. With large high-speed steam turbo-alternator sets, an apparently small over speed could result in machine damage or wreckage, as well as a threat to human safety. Failure of a steam valve to fully close during a shut-down is an obvious risk This over speed risk could be addressed by using duplicate valves in series.

Even where valves, etc., do close fully, there will be some lag in dissipating all the

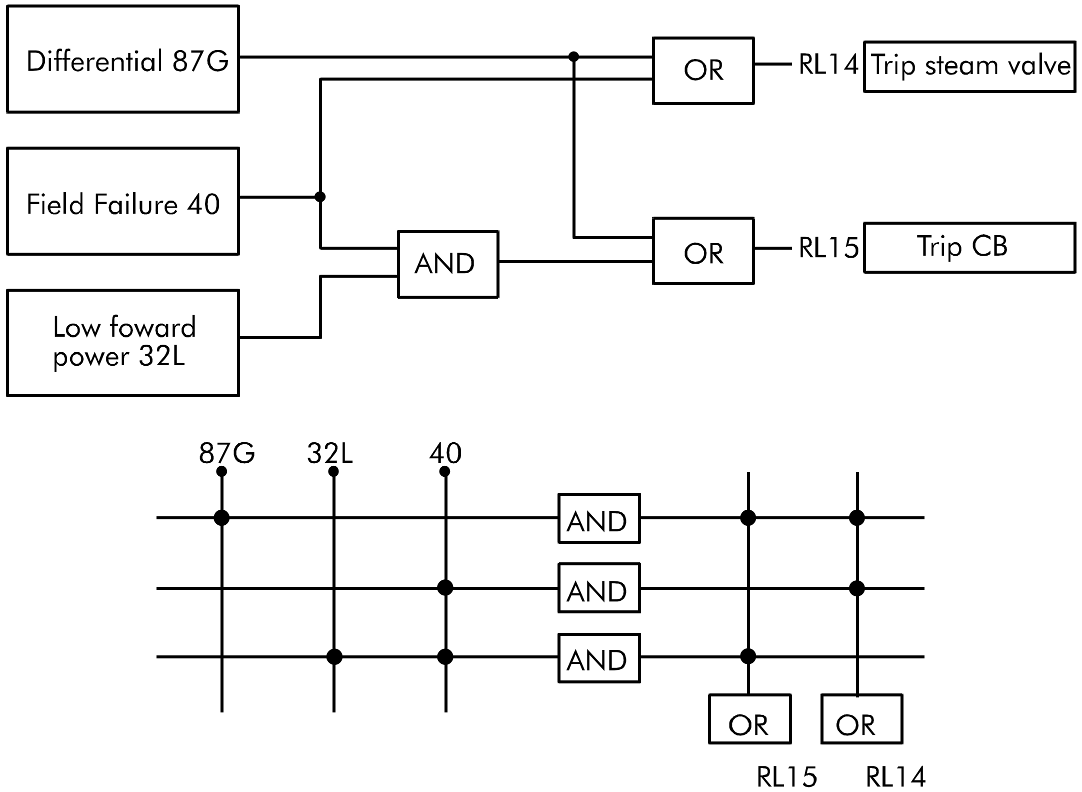


Figure 16 Low Forward Power Interlocking Of 'Non-urgent Tripping' Functions

energy within a prime mover, especially in the event of a shutdown from full-load. Some types of plant, are very prone to over speed following rejection of full-load, but have a good over speed tolerance, e.g. slow-speed hydro generators. Large turbo-alternators, with slender,low-inertia rotor designs, do not have a high over speed tolerance and trapped steam in the turbine, downstream of a valve that has just closed, can rapidly lead to over speed. To reduce the risk of over speed damage to such sets, it is sometimes chosen to interlock non-urgent tripping of the generator breaker and the excitation system with a low forward power check. The delay in electrical tripping, until prime mover energy has been completely absorbed by the power system, may be deemed acceptable for ‘non-urgent’ protection trips; e.g. stator earth fault protection for an indirectly connected generator. For ‘urgent’ trips by instantaneous electrical protection, e.g. stator winding current differential protection, any potentially delaying interlock should not be imposed. With the low probability of ‘urgent’ trips, the risk of over speed and possible consequences must be accepted.

When required, the setting of the LGPG111 low forward power protection function should be less than 50% of the power level that could result in a dangerous over speed transient without electrical loading. With a large generator, even a very small percentage of rated power could quickly accelerate an unloaded machine to a dangerous speed. A typical under power setting requirement would be 0.5% of rated power. The calculation to determine the required setting of the LGPG111 threshold (P<), in single phase secondary Watts, would be similar to that quoted in Section 2.7.1. for the reverse power protection function threshold (-P>).

The time delay associated with the low forward power protection function (t) could be set to zero. However, some delay is desirable so that permission for a non-urgent electrical trip is not given in the event of power fluctuations arising from sudden steam valve/throttle closure. A typical time delay for this reason is 2s. An adjustable delay on trip timer reset (tDO) is also provided; this would normally be set to zero.

The low forward power protection function can be arranged to interlock 'non-urgent' LGPG111 tripping using the relay logic matrix, see Figure 16. It can also be arranged to provide a contact for external interlocking of manual tripping, if desired.

2.8. Negative phase sequence thermal protection function (46)

Summary:

- Protects the rotor of a generator from damage resulting from the heating effects of negative phase sequence currents.
- Provides true negative phase sequence thermal protection and a definite time alarm.
- Accurate over a wide system frequency range.
- The trip threshold should be set slightly higher than the constant negative phase sequence current withstand of the generator.
- The protection must be time graded to allow downstream protection to clear an unbalance fault.
- To achieve easier grading with down stream protection, during clearance of a heavy asymmetric fault, a minimum operating time for the negative phase sequence protection can be set.
- For negative phase sequence currents slightly above setting, a maximum trip time can be set.
- Can provide back up protection for uncleared asymmetric faults.
- Models the cooling characteristic of the generator, following exposure to negative phase sequence currents.
- The alarm element is commonly set to 70% of the trip setting with a time delay well above the time taken to clear any system faults. The alarm element functions directly on the measured level of negative phase sequence current.

The negative phase sequence (NPS) protection provided by the LGPG111 is a true thermal replica with a definite-time alarm stage.

The NPS protection function is provided for applications where a generator (synchronous machine) is particularly susceptible to rotor thermal damage, in the event of the current supplied to the power system becoming unbalanced. The degree of susceptibility will depend on the generator rotor design (cylindrical or salient construction), methods of forced cooling employed and the presence of any ancillary metallic rotor components. The NPS protection function is driven from the general protection CT inputs of the LGPG111.

Unlike many traditional forms of negative phase sequence protection, the NPS protection in the LGPG111 is accurate over a wide frequency range. Traditional forms of protection derive an operating signal from a filter, which is designed to give zero output when a pure positive phase sequence input current is applied and a high output with pure negative phase sequence current. The filter will only behave in the required manner at nominal frequency. When operating away from nominal frequency, an unwanted output would be given even when there is no negative phase sequence input quantity. Such relays would need to be disabled when running a generator away from the nominal frequency, for example, in the case of a variable frequency supply being used to drive a synchronous machine as a motor or to start a gas turbine prime mover. The LPG111 continuously tracks the power system frequency and derives the negative phase sequence operating quantity algorithmically:

$$I_2 = \frac{I_a + I_b + aI_c}{3} \quad \text{where } a = 1.0\angle 120^\circ$$

Depending on the type of generation scheme, load unbalance can arise as a result of single phase loading, non-linear loads (involving power electronics or arc furnaces, etc.), uncleared or repetitive asymmetric faults, asymmetric fuse operation, single-pole tripping and reclosing on transmission systems, broken overhead line conductors and asymmetric failures of switching devices.

Lack of load current symmetry can be described in terms of a balanced, negative phase sequence (reverse phase rotation) component of current existing with the balanced positive phase sequence component. Any negative phase sequence component of stator current will set up a reverse-rotating component of stator flux that passes the rotor at twice synchronous speed. Such a flux component will induce double frequency eddy currents, which cause heating of the rotor body, main rotor windings, damper windings and various other metallic rotor components.

Synchronous machines will be able to withstand a certain level of negative phase sequence stator current continuously, where the rate of eddy current heating and the rate of heat dissipation is such that damaging temperatures are not reached within individual rotor components. All synchronous machines will be assigned a continuous maximum negative phase sequence current (1_{2cmr} per-unit) rating by the manufacturer. For various categories of generator, minimum negative phase sequence current withstand levels have been specified by international standards, such as 1EC60034-1 and ANSI C50.13-1977 [1]. The 1EC60034-1 Figures are given in Table 3.

Where a generator has a high continuous negative phase sequence current withstand level, as in the case of typical salient-pole machines, it may be decided that there would be no practical circumstances in which this level could be exceeded by any events on the power system that is to be supplied. In such cases, it would not be essential to set and enable the NPS protection function. The NPS protection function can, however, offer a better method of responding to an uncleared asymmetric fault at the remote end of a feeder from the generator bus. As already mentioned in Section 2.6., it may be difficult to set the voltage controlled overcurrent protection function to shutdown the generator for a remote fault and still be able to maintain co-ordination with feeder backup protection for a close-up 3-phase fault.

Generator type	Maximum I_2/I_n for continuous operation	Maximum $(I_2/I_n)^2t$ for operation under fault conditions
Salient pole:		
Indirectly cooled	0.08	20
Directly cooled (inner cooled) stator and/or field	0.05	15
Cylindrical rotor synchronous:		
Indirectly cooled rotor		
Air cooled	0.1	15
Hydrogen cooled	0.1	10
Directly cooled (inner cooled) rotor		
$\leq$ 350MVA	0.08	8
>350 $\leq$ 900MVA	*	**
>900 $\leq$ 1250MVA	*	5
>1250 $\leq$ 1600MVA	0.05	5

*For these generators, the value of I_2/I_n is calculated as follows:

$$\frac{I_2}{I_n} = 0.08 \quad \frac{S_n - 350}{3 \times 10^4}$$

*For these generators, the value of $(I_2/I_n)^2 t$ is calculated as follows:

$$\left(\frac{I_2}{I_n}\right)^2 t = 8 - 0.00545(S_n - 350)$$

Where S_n is the rated power in MVA

Table 3 IEC6034-1 Minimum negative sequence current withstand levels.

For high levels of negative phase sequence current, eddy current heating can be considerably in excess of the heat dissipation rate. Thus, virtually all the heat acquired during the period of unbalance will be retained within the rotor. With this assumption, the temperature attained within any critical rotor component will be dependent on the duration of the unbalance (t seconds) and the level of negative phase sequence current (I_2 per unit) and is proportional to I_2^2t. Synchronous generators are assigned a per-unit I_2^2t thermal capacity constant (K_g) to define their short-time negative phase sequence current withstand ability (see third column of Table 3). Various rotor components may have differing short-time thermal capacities and the most critical (lowest value of I_2^2t) should form the basis of the generator manufacturer's short-time per-unit I_2^2t withstand claim.

Many traditional forms of generator NPS thermal protection relays have been designed with an extremely inverse (I_2^2t) operating time characteristic. This characteristic would be set to match the claimed generator thermal capacity.

For intermediate levels of negative phase sequence current, the rate of heating is slower. As a result, heat dissipation should be considered. The basic expression of

$t=K/I_{2cmr}$ does not cater for the effects of heat dissipation or for low standing levels of negative phase sequence current. The latter resulting in an increase in rotor temperature which remains within the machines design limits. An existing, tolerable, level of negative phase sequence current ($I_2<I_{2cmr}$), has the effect of reducing the time to reach the critical temperature level, if the negative phase sequence current level should increase beyond I_{2cmr} The LGPG1 111 NPS thermal replica is designed to overcome these problems by modelling the effects of low standing levels of negative phase sequence currents.

The temperature rise in critical rotor components is related to the negative phase sequence current (I_2 per unit) and to time (t seconds) as follows. This assumes no preceding negative phase sequence current:

$$\theta\,°C \;\alpha\; I_2^{\,2}\left(1 - e^{-t/\tau}\right)$$

where:

τ is the thermal time constant; $\tau = \dfrac{K_g}{I_{2\,CMR}^{\,2}}$

K_g is the generator's per-unit current thermal capacity constant in seconds.

I_{2CMR} is the generator's per-unit continuous maximum I_2 rating.

The limiting continuous maximum temperature (θ_{CMR}) would be reached according to the following current-time relationship:

$$\theta°C = \theta_{CMR}\,°C \qquad \Rightarrow \qquad I_2^{\,2}\left(1 - e^{-t/\tau}\right) = I_{2CMR}^{\,2}$$

From the above, the time for which a level of negative phase sequence current in excess of I_{2CMR} can be maintained is expressed as follows:

$$t = -\frac{K_g}{I_{2CMR}^{\,2}}\,Log_e\left(1 - \left(\frac{I_{2\,CMR}}{I_2}\right)^2\right)$$

The LGPG 111 negative phase sequence protection function main element offers a true thermal characteristic according to the following similar formula:

$$t = -\frac{K}{I2{>>}^{2}}\,Log_e\left(1 - \left(\frac{I2{>>}}{I_2}\right)^2\right)$$

Note: All current terms are in per-unit, based on the relay rated current, In.

To obtain correct thermal protection, the relay thermal current setting(12>>) and thermal capacity setting (K) should be set as follows:

$$I2{>>} = I_{2cmr} \times \left(\frac{I_{flc}}{I_P}\right) \times In$$

$$K = K_g \times \left(\frac{I_{flc}}{I_P}\right)^2$$

Where:

I2>>	= Required relay I_2 maximum withstand (A).
K	= Required relay thermal capacity constant (s).
I_{2cmr}	= Generator per unit I_2 maximum withstand.
K_g	= Generator thermal capacity constant (s).
I_{flc}	= Generator primary full-load current (A).
I_p	= CT primary current rating (A).
In	= Relay rated current (A).

As with all inverse-time protection elements, it is necessary to limi t the minimum operating time of the negative phase sequence thermal protection function to allow sufficient time for downstream protection and fault clearing devices to clear heavy unbalanced faults on the power system fed by the protected machine. The LGPG111 negative phase sequence thermal protection function can be set to have a definite minimum operating time (tMIN). This time delay should be set to co-ordinate with close-up clearance of feeder phase to phase or phase to earth faults, by feeder backup protection under minimum plant conditions. For either fault condition, the negative phase sequence current seen by the LGPG111 and the thermal protection function operating time should be determined.

The definite minimum time setting (tMIN) should be set to provide an adequate margin between the operation of the negative phase sequence thermal protection function and external fault clearance protection. The co-ordination time margin used should be in accordance with the usual practice adopted by the customer for backup protection co-ordination.

For levels of negative phase sequence current that are only slightly in excess of the setting (I2>>), there will be a noticeable deviation between the LGPG111 true thermal protection current-time characteristic and that of the simple I_2^2t characteristic offered by many traditional static relays. For this reason, a maximum negative phase sequence protection function trip time setting is offered by the LGPG111 (tMAX). This maximum time setting also limits the tripping time of the negative phase sequence protection function for levels of unbalance where there may be uncertainty about the machine's thermal withstand.

When the protected generator sees a reduction in negative phase sequence current, metallic rotor components will decrease in temperature. Some rotor components, as a result of their varied location in relation to other components, materials and degrees of forced cooling, could have differing cooling time constants. Additionally these same components could well have differing short-time thermal capacities (I_2^2t values). In the case of cyclic application of negative phase sequence current, such as multiple-faults occurring on a power system during severe weather, it is theoretically possible for a component with a larger short-time thermal capacity to overheat, even though a component with a smaller short-time thermal capacity does not. For applications where such effects need to be considered, the LGPG111 is provided with a separate thermal capacity setting (Kreset) for use when the machine is cooling, due to a reduction in I_2. For general applications, the Kreset setting should be set equal to the main time constant setting, K.

A definite-time alarm stage has been traditionally provided with negative phase sequence protection relays since prolonged small levels of negative phase sequence current could result in thermal protection tripping and generator shutdown. This enables system operators to be made aware of a condition that may eventually lead to a shutdown if the offending power system condition is not dealt with. Some protective relays have also been provided with local and/or remote negative phase sequence current indication facilities. The LGPG111 is provided with a definite-time negative phase sequence overcurrent alarm stage. It is also possible to configure the LGPG111 to locally display the measured negative phase sequence current, as well as to provide remote indication via the relay’s serial communication ports.

The independent alarm current threshold setting (I2>) and the adjustable time setting (t>) should be set to avoid unwanted alarms during short periods of very light unbalanced operation. These, typically, might occur during delayed clearance of faults well within the power system being fed. A typical alarm current setting (I2>) would be 70% of the thermal trip setting (I2>>). The alarm time delay (t>) would have to be set well above system fault clearance times and any single-pole auto-reclose dead-times, whilst not unnecessarily reducing the time available to take corrective action to prevent thermal element tripping. The final time setting may have to be arrived at after commissioning (starting with a low value) in order to determine the minimum delay that will not result in unwanted alarms during normal operation.

2.9. Field failure protection function (40)

Summary:

- Monitors the generators terminal impedance in order to detect failures in the excitation system.
- Uses a circular, offset mho, impedance characteristic.
- The diameter of the impedance characteristic is based on the direct synchronous reactance of the generator.
- The offset of the impedance characteristic based on the direct axis transient reactance of the generator.
- An associated definite time delay prevents operation of the protection during stable power swings.
- Can be interlocked with the under voltage protection element (using the internal scheme logic of the LGPG) to prevent operation during power swings.
- A delay on drop off timer can be used to detect cyclic operation of the field failure protection. This could result during pole slipping (using the field failure element to detect pole slipping as discussed in Section 3.5).

This protection function measures the impedance at the terminals of a generator that is run in parallel with another source to detect failure of the generator excitation. The current used for single phase impedance measurement is obtained from the general protection CT inputs and the voltage is obtained from the main VT inputs. This protection function is provided with an adjustable, offset circular impedance characteristic, see Figure 17, an adjustable tripping delay timer (t) and an adjustable measuring element reset time delay (tDO).

Complete loss of excitation may arise as a result of accidental tripping of the excitation system, an open circuit or short circuit occurring in the excitation DC circuit, flashover of any slip rings or failure of the excitation power source. A pure open circuit in the excitation system is unlikely to be long-lasting in view of the high voltage that would be developed across the open circuit with the machine running and connected to a power system. Such a fault is likely to evolve quickly into a short circuit fault.

When the excitation of a synchronous generator fails, its internal e.m.f. will decay. This results in the active power output of the machine falling and in an increasing level of reactive power being drawn from the power system. As the active power output falls, the maintained mechanical drive will accelerate the machine so that it will gently pole-slip and run at a super synchronous speed. As the machine begins to run super synchronously, slip frequency currents will be induced in the rotor body, damper windings and in the field windings. The slip-induced, low-frequency rotor currents will result in a rotor flux being produced. The machine would then be excited from the power system and would be operating as an induction generator.

The mechanical input torque following loss of excitation might not exceed the peak of the machine's speed-torque characteristic when operating in the induction generator mode if the initial output of the generator was not a high percentage of its rated capability, or if the governor and prime mover have a very fast response. In such a case, stable operation as an induction generator might be achieved at low slip (0.1-0.2% above synchronous speed). The machine would be able to maintain an active power output (perhaps 20-30% of rating) whilst drawing reactive power from the power system (generating at a highly leading power factor). The ability to reach such a stabilised state will be dependent on the machine's effective speed-torque characteristic when operating as an induction generator and on the power system being able to supply the required reactive power without severe voltage depression.

Salient-pole generators can operate particularly well as induction generators up to a significant percentage of rated power output (20-30%P_n). This is due to the significant difference between the direct and quadrature axis synchronous reactance's. Cylindrical rotor machines have similar direct and quadrature synchronous reactance's and are less able to deliver a significant power output as an induction generator. They are more likely to be pushed over the peak torque level of their induction generator speed-torque characteristic when driven at only a small percentage of rated power output. If the peak induction generator torque level is exceeded, a machine will stabilise at a much higher level of slip (perhaps 5% above synchronous speed). When this happens, the machine will draw a very high reactive current from the power system and a stator winding current as high as 2.0 p.u. may be reached. In addition to stator winding thermal problems arising during super synchronous operation, the slip-frequency rotor currents could lead to rotor core or winding damage if the condition is sustained.

If, after an excitation failure, the generator continues to produce active power in an induction generation mode, with a small level of slip, there would be no great urgency to disconnect the machine. The condition could probably be sustained for many minutes without rotor damage being incurred. With the typical settings applied to the field-failure impedance protection such an operating condition might not be detected by the protection. It would be necessary for an operator to manually intervene to either re-establish the excitation or to shut down the generator. Such action could be taken if the remote instrumentation capability of the LGPG111 indicates that the generator is operating at an abnormally low leading power factor.

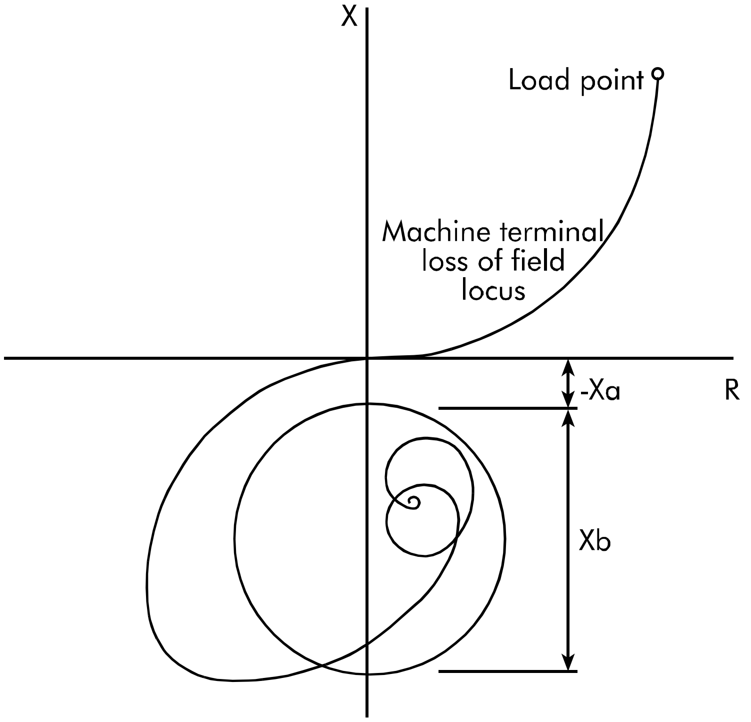


Figure 17 Field failure protection function characteristic with typical machine impedance locus.

Where a generator stabilises at a high level of slip, following excitation failure, the reverse inductive impedance seen at the generator terminals will be highly reactive and will be less than the direct axis synchronous reactance of the machine (X_d). A typical minimum value for this impedance is twice the direct-axis transient reactance of the generator ($2X_{d'}$) for a level of slip below 1%. Figure 17 shows a typical machine terminal loss-of-field impedance locus, which illustrates the effect of rotor flux decay, leading to gentle pole-slipping and eventual stabilisation as an induction generator with a level of slip of around 1%.

To quickly detect a loss-of-field condition where machine damage may occur, the diameter of the LGPG111 field-failure impedance characteristic (Xb) should be set as large as possible without conflicting with the impedance that might be seen under normal stable conditions or during stable power swing conditions. To meet this objective, it is recommended that the diameter of the LGPG111 impedance characteristic (Xb) is set equal to the generator direct-axis synchronous reactance in secondary ohms. The characteristic offset (-Xa) should be set equal to half the direct-axis transient reactance ($O.5X_{d'}$) in secondary ohms.

Thus:

$$Xb = X_d \times \frac{\text{CT ratio}}{\text{VT ratio}}$$

$$-Xa = O.5X_d' \times \frac{\text{CT ratio}}{\text{VT ratio}}$$

Where:

Xb = Required impedance characteristic diameter in secondary ohms

-Xa = Required impedance characteristic offset in secondary ohms

X_d = Generator direct-axis synchronous reactance in primary ohms

$X_{d'}$ = Generator direct-axis transient reactance in primary ohms

The above guidelines are suitable for applications where a generator is operated with a rotor angle of less than 90° and never at a leading power factor. For generators that may be operated at slightly leading power factors and which may be operated with rotor angles up to 120°, by virtue of high-speed voltage regulation equipment, the settings would need to be different. The impedance characteristic diameter (Xb) should be set to 50% of the direct-axis synchronous reactance ($O.5X_d$) and the offset (-Xa) should be set to 75% of the direct axis transient reactance ($O.75X_{d'}$).

The field failure protection time delay (t) should be set to minimise the risk of operation of the protection function during stable power swings following system disturbances or synchronisation. However, it should be ensured that the time delay is not so long that stator winding or rotor thermal damage will occur. The stator winding should be able to withstand a current of 2.0 p.u. for the order of 15s. It is unlikely that rotor damage would be incurred in much less time than this. It must also be appreciated that it may take some seconds for the impedance seen at the generator terminals to enter the selected characteristic of the protection function. However, a time delay less than 10s would typically be applied. The minimum permissible delay, to avoid potential problems of false tripping due to stable power swings with the above impedance settings, would be of the order of 0.5s.

Some operators have traditionally interlocked operation of impedance-type field failure protection with operation of under voltage detection elements in order to allow a low field failure protection time delay without the risk of unwanted tripping for stable power swings. This arrangement may also have been used to prevent field failure protection operation for hydrogenerators that may be run as synchronous compensator's, with the turbine mechanically decoupled. Such interlocking would be possible with the LGPG111 under voltage protection function, by appropriate configuration of the scheme logic. A better approach would be to switch to the second group of relay settings when running as a compensator, where the field failure protection function could be disabled.

In some hydrogenerator applications, the operation of field failure protection may be blocked by operation of an over frequency detection element. This is to prevent maloperation of traditional forms of impedance protection elements during transient over frequency running that might result from power system separation. Hydrogenerators could experience speed/frequency excursions up to 200% of nominal, following rejection of full load. Such interlocking could be offered with the LGPG111 over frequency protection function elements and appropriate setting of the scheme logic.

The field failure protection function is offered with an adjustable delay on reset of the trip timer (tDO). This time delay can be set to ovoid delayed tripping that might arise as a result of cyclic operation of the impedance measuring element during the period of pole-slipping following loss of excitation. Some care would need to be exercised in setting this timer, since it could make the field failure protection function more likely to give an unwanted trip in the case of stable power swinging. The trip time delay should be increased by the setting of the reset time delay.

The delay on reset of the trip timer (tDO) might also be set to allow the field failure protection function to be used for detecting pole slipping of the generator when excitation is not fully lost; e.g. following time-delayed clearance of a nearby power system fault by delayed protection. This subject will be discussed in more detail in Section 3.5.

2.10. Under voltage protection function (27)

Summary:

- Operates when the three phase voltages fall below the common set point. An adjustable timer is available.
- Can be interlocked with the field failure protection to prevent its operation during stable power swings (see Section 2.9).
- Can be used to initiate dead machine protection (see Section 3.1).
- Can detect failure of the AVR or system faults which have failed to be cleared by other means.
- Prevents damage to any connected loads which could occur during operation at less than rated voltage.
- The pick up level should be set to less than the voltage seen for a three phase fault at the remote end of any connected feeder (see Section 2.6).
- The time delay should be set to allow the appropriate feeder protection to operate first to clear the fault, and also to prevent operation of the protection during transient voltage dips.
- A dedicated input is provided to block the operation of the under voltage and under frequency protection during run-up or run-down of the generator. This input can be driven from an auxiliary contact in the circuit breaker.

This protection function responds to the phase-phase voltage signals supplied to the relay via the main input VT's The protection function includes an adjustable time delay (t) which is initiated when all three under voltage elements detect a voltage below their common threshold setting (V<).

Under voltage protection is not a commonly specified requirement for generator protection schemes. However, under voltage elements are sometimes used as interlocking elements for other types of protection, such as field failure. In the case of LGPG111, such interlocking can be arranged by appropriate configuration of the relay scheme logic, as already indicated in Section 2.9. Where only interlocking is required, time-delayed under voltage tripping would not be enabled. The LGPG111's under voltage protection function elements can also be used to enable group-2 relay settings for dead-machine protection, as discussed in Section 3.1

Under voltage protection can be used to detect abnormal operating conditions or an uncleared power system fault that may not have been detected by other generator protection.

For an isolated generator, or for an isolated set of generators, especially in the case of standby generating plant, a prolonged under voltage condition could arise for a number of reasons. One reason would be some failure of automatic voltage regulation (AVR) equipment. If such a condition persists, automatic generator tripping should be initiated to prevent possible damage to system loads. Another reason could be that a fault exists somewhere on the power system that has not been cleared by other means.

In the case of generators feeding an industrial system, which is normally fed from a public power supply, system overcurrent protection settings would have to be above maximum levels of system load current with the normal supply available. If the public supply fails, the local generation would be left feeding the entire system. Where the local generation is unable to meet the entire system load, there would be a provision for the automatic shedding of non-essential loads. If a fault subsequently occurred on the system, the relatively low fault current contribution of the local generation and its decrement with time may result in the system overcurrent protection failing to respond. In this case it would be expected that the generator backup overcurrent should operate.

Operation of generator overcurrent protection in the above circumstances can be assisted by employing voltage-dependent protection, as discussed in Section 2.6. Where there is a parallel set of generators, and where the fault is relatively remote from the generators, even the generator voltage-dependent protection may fail to respond to the fault. If the fault is asymmetric, and if the negative phase sequence thermal protection function has been set and enabled, the unbalanced fault current may be sufficient to operate this form of generator protection. The worst situation would be for an uncleared three-phase fault. Although such a fault would be rare, it may be that the only form of protection that would reliably detect the fault would be generator under voltage protection.

Even in the case of generators feeding an interconnected power system, through a transmission or distribution connection, means of clearing a fault at the remote end of the longest feeder from the generator bus should be provided in the event of feeder protection failing to clear the remote fault. Where duplicated feeder protection and breaker-fail protection is provided, as with most primary transmission circuits, the probability of having to rely on generator backup protection to clear such a fault would be extremely low. In the case of an island power system, with generators connected to medium voltage feeders, it may be that generator under voltage protection would be the only form of protection that could reliably detect a feeder remote-end three-phase fault where the feeder protection or feeder circuit breaker fails.

In the case of large thermal power plant generators, a prolonged under voltage condition could adversely affect the performance of the auxiliary plant such as boiler-feed pumps and air-blowers. This would ultimately have an effect on the primary plant performance. If such a situation is envisaged, the application of time-delayed under voltage protection to trip the generator might be a consideration.

If the LGPG111 under voltage protection function is to be enabled, the under voltage threshold (V<) should be set below the steady-state phase-phase voltage seen by the LGPG111 for a three-phase fault at the remote end of any feeder connected to the generator bus or up to selected locations within an industrial power network. Allowances should be made for the fault current contribution of parallel generators, which will tend to keep the generator voltage up. Equations for determining the phase-phase voltage seen by the LGPG11 under such circumstances are given in Section 2.6.

The time setting of the under voltage protection function (t) should be set longer than the time required for backup feeder protection to clear remote-end feeder faults. The delay should preferably be longer than the time required for the generator back-up overcurrent protection function to respond to such a fault. Additionally, the delay should be long enough to prevent unwanted operation of the under voltage protection function for transient voltage dips during clearance of faults further into the power system or by starting of local machines. The required time delay would typically be in excess of 3s-5s.

To prevent tripping of the under voltage protection function following normal shutdown of a generator, a normally closed circuit breaker auxiliary contact should be used to energise the under voltage inhibit logic input. When this inhibit input is energised, under voltage protection function trip initiation and alarm initiation are blocked. However, the under voltage protection function elements will still be available for initiation of dead-machine protection, as discussed in Section 3.1.

2.11. Over voltage protection function (59)

Summary:

- Operates when the three phase voltages are above the common set point.
- Two tripping stages, each with an adjustable timer.
- Protects against damage to the generator insulation and that of any connected plant.
- Recommended for hydrogenerators which may suffer from load rejection.
- Time delayed protection should be set with a pick up voltage of 100-120% of the nominal voltage and a time delay sufficient to overcome operation during transient over voltages.
- Instantaneous protection with a setting of 130% - 150% of the nominal voltage can be implemented.

This protection function responds to the phase-phase voltage signals supplied to the relay via the main input VT's. The protection function includes an adjustable time delay (t>) which is initiated when all three over voltage elements detect a voltage above their common threshold setting (V>). A high-set over voltage protection element (V>>) is also provided which can be set for instantaneous or time-delayed operation (using t>>)

An unsynchronised generator terminal over voltage condition could arise when the generator is running, but not connected to a power system, or where a single generator is running and providing power to an isolated power system. Such an over voltage could arise in the event of a fault with automatic voltage regulating equipment or if the voltage regulator is set for manual control and an operator error is made. Over voltage protection should be set to prevent possible damage to generator insulation, prolonged over fluxing of the generating plant or damage to isolated power system loads,

When a generator is synchronised to a power system with other sources, a synchronised over voltage could only arise if the generator was lightly loaded and was required to supply a high level of power system capacitive charging current. An over voltage condition might also be possible following a system separation, where a generator might experience full-load rejection whilst still being connected to part of the original power system. The automatic voltage regulating equipment should quickly respond to correct the over voltage condition, but over voltage protection is advisable to cater for a possible failure of the voltage regulator to correct the situation or for the possibility of the regulator having been set to manual control.

The worst case of generating plant over voltage following a system separation, which results in full-load rejection, could be experienced by hydrogenerators. The response time of the speed governing equipment can be so slow that transient over speeding up to 200% of nominal speed could occur. Even with voltage regulator action, such over speeding can result in a transient over voltage as high as 150%. Such a high voltage could result in rapid insulation damage.

Generation electrical plant should be able to withstand a 5% over voltage condition continuously. The withstand times for higher over voltages should be declared by the generator manufacturer. The LGPG111 time-delayed over voltage protection function threshold (V>) should typically be set to 100%-120% of the nominal phase-phase voltage seen by LGPG111. The time delay (t>) should be set to prevent unwanted tripping of the delayed over voltage protection function due to transient over voltages that do not pose a risk to the generating plant; e.g. following load rejection with non-hydro sets. The typical delay to be applied would be 1s-3s, with a longer delay being applied for a low voltage threshold setting.

When selecting instantaneous operation of the LGPG111 high-set over voltage protection function, the typical threshold setting to be applied would be 130-150% of the nominal phase-phase voltage seen by LGPG111, depending on plant manufacturers' advice.

2.12. Under frequency protection function (81U)

Summary:

- Two under frequency stages each with an independent timer.
- First stage can be used to initiate load shedding for industrial systems. Time delayed to allow any down stream load shedding equipment to operate first.
- Second under frequency stage to trip more rapidly.
- A dedicated input is provided to block the operation of the under voltage and under frequency protection during run-up or run-down of the generator. This input can be driven from an auxiliary contact in the circuit breaker.

The under frequency protection function of LGPG111 utilises the AC voltage input signals as the frequency measurand. Two independent time-delayed stages of under frequency protection are offered by LGPG111. Each stage is provided with an under frequency threshold setting (F1<, F2<) and with a time delay setting (t1, t2). As well as being able to initiate generator tripping, the under frequency protection can also be arranged to initiate local load-shedding, where appropriate.

Under frequency operation of a generator will occur when the power system load exceeds the prime mover capability of an isolated generator or of a group of generators. Where the system load exceeds the alternator rating, but not the prime mover rating, the alternator could become overloaded without a frequency drop. It would therefore be important for the alternator manufacturer to provide stator winding temperature measurement devices, to give alarm or to automatically shut down the generator before winding thermal damage results.

Power system overloading can arise when a power system becomes split, with load left connected to a set of 'islanded' generators that is in excess of their capacity. Such events should be allowed for by system planners and automatic system load-shedding should be implemented so that the load would rapidly be brought back within the generation capacity. In this case, under frequency operation would be a transient condition; as during power swings. The degree of load shedding would have to take into account the fact that some generating plant, e.g. gas turbine plant, may have a reduced power capability when running below nominal frequency. In the event of under shedding of load, the generators should be provided with backup under frequency protection to shut down the generating plant before plant damage or unprotected system load damage could occur.

Under frequency running at nominal voltage will result in some over fluxing of a generator, and its associated electrical plant, which needs to be borne in mind. However, the more critical considerations would be in relation to blade stresses being incurred with high-speed turbine generators; especially steam-driven sets. When running away from nominal frequency, abnormal blade resonance’s can be set up which, if prolonged, could lead to turbine disc component fractures. Such effects can be accumulative and so operation at frequencies away from nominal should be limited as much as possible, to avoid the need for early plant inspections / overhaul. Under frequency running is most difficult to contend with, since there is little action that can be taken at the generating station in the event of load under shedding, other than to shut the generator down.

The LGPG111 under frequency protection function should be set to co-ordinate with automatic system load-shedding so that generator tripping will not occur in the event of successful shedding following a system overload. The protection function should also be set so that declared frequency-time limits for the generating set are not infringed. A 10% under frequency condition should be continuously sustainable. The two-stages of under frequency protection offered by the LGPG111 could be set-up as illustrated in Figure 18 to co-ordinate with multi-stage system load-shedding.

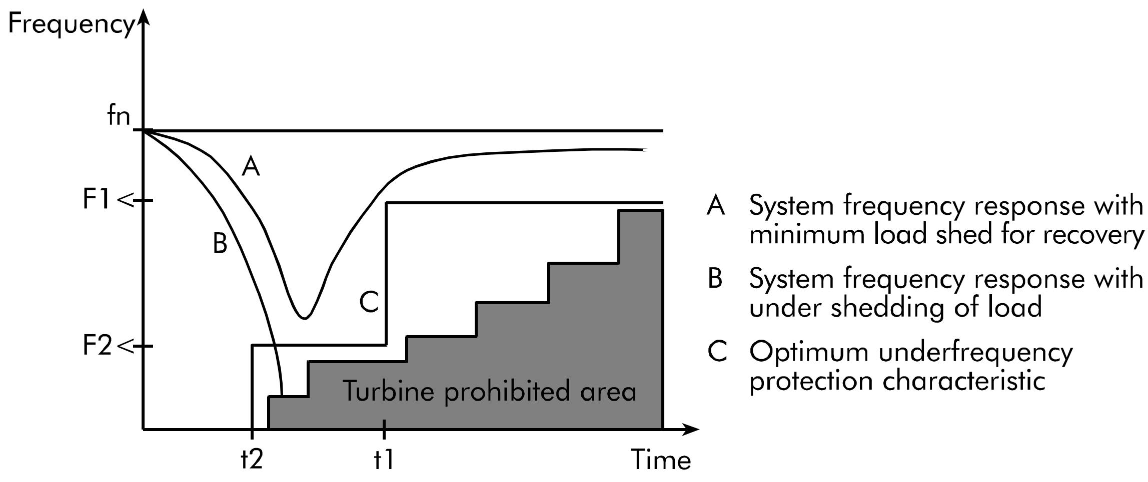


Figure 18 Co-ordination of under frequency protection function with system load shedding

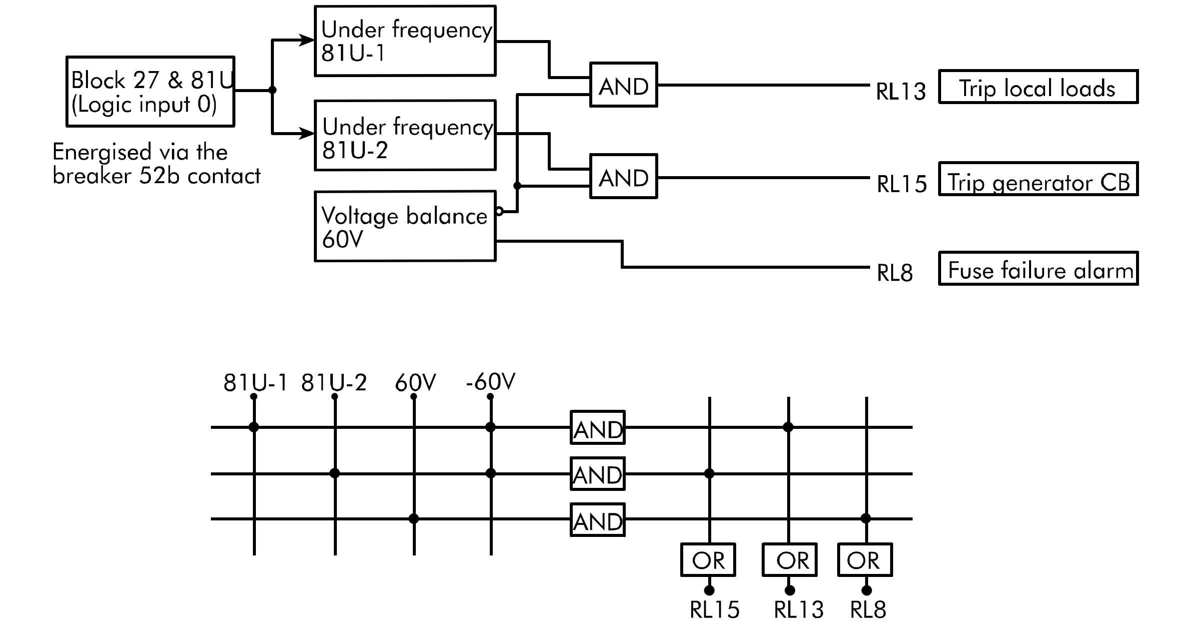


Figure 19 Initiating local system load shedding using the under frequency protection

For industrial generation schemes, where generation and loads may be under common control/ownership, one of the LGPG111 stages of the under frequency protection function could be used to directly initiate local system load-shedding. This could be arranged by suitably setting-up the LGPG111 flexible scheme logic matrix, as illustrated in Figure 19

To prevent under frequency protection tripping following normal shutdown of a generator, a normally closed circuit breaker auxiliary contact should be used to energise the under frequency protection function inhibit (logic input 0). When this input is energised, under frequency protection function trip initiation and alarm initiation will be blocked.

2.13. Over frequency protection function (81O)

Summary:

- Single over frequency stage with associated timer.
- Should be set above the sustainable over frequency level with a time delay sufficient to overcome transient over frequencies following load rejection.

The over frequency protection function of LGPG111 utilises the AC voltage input signals as the frequency measurand. A single time-delayed stage of over frequency protection is offered by LGPG111, with an over frequency threshold setting (F>) and a time delay setting (t).

Moderate over frequency operation of a generator is not as potentially threatening to the generator and other electrical plant as under frequency running and action can be taken at the generating plant to correct the situation without necessarily shutting down the generator.

As already described in Section 2.12., operation of a high-speed turbine generator away from nominal speed can lead to blade resonance that, if prolonged or accumulated, could lead to turbine damage. As discussed in Section 2.7.2., severe over frequency operation of a high-speed generating set could result in plant damage as a result of the high centrifugal forces that would be imposed on rotating components.

Over frequency running of a generating set arises only when the mechanical power input to the alternator is in excess of the electrical load and mechanical losses. The most common occurrence of over frequency is after substantial loss of electrical loading. When a rise in running speed occurs, the governor should quickly respond to reduce the mechanical input power so that normal running speed is quickly regained.

Over frequency protection may be required as a backup protection function to cater for governor or throttle control failure following loss of load or during unsynchronised running. The LGPG111 protection function settings should be selected to co-ordinate with normal transient over frequency excursions following full-load rejection. The generator manufacturer should declare the expected transient over frequency behaviour, which should comply with international governor response standards. A 10% over frequency should be continuously sustainable.

2.14. Voltage balance protection function (60)

Summary:

- Operates when a voltage difference above a selectable threshold is detected.
- Detects VT fuse failure.
- Supplied from the secondaries of two VTs or two separately fused secondary circuits of a single VT.
- Used to raise an alarm and block voltage sensitive protection if necessary.
- A voltage difference of 5v should be set unless the VTs are of dissimilar ratios or a voltage unbalance exists during normal operation.

This LGPG111 function is provided as a method of identifying blown VT fuses so that an alarm can be raised and so that unwanted generator shut down by the voltage sensitive protection functions can be prevented.

The voltage balance protection function operates from signals derived from the relay's two main VT inputs and signals derived from an additional pair of reference VT inputs. The level of voltage difference is determined between each of the two main and reference voltage inputs. When a voltage difference in excess of an adjustable threshold (Vs) is detected, an alarm is raised. The failed VT circuit is identified by comparing the voltage inputs to see which has the lower voltage level.

Where a generator is provided with two sets of terminal VT's, the set used for the generator protection functions should be connected to the main relay inputs and the other set should be connected to the reference inputs. With this arrangement, the voltage balance protection function will be able to respond to blown VT secondary fuses and possibly to blown VTprimary fuses. Where a three-phase, three-limb VT is used, the VT primary winding star-point should not be earthed if detection of blown primary fuses is a requirement. An alarm and failed VT indication will be raised if either set of VT signals fails. If the main VT signals fail, blocking of voltage-sensitive protection functions can be arranged via the LGPG111 flexible scheme logic matrix (see Figure 20).

Where only one generator terminal VT is provided, the VT secondary windings should be connected to two separately fused secondary circuits. One circuit should only be connected to the reference VT inputs of the LGPG111. The other set should be connected to the main VT inputs and to any other items of voltage-dependent generator protection (see Figures 3 & 4). With this arrangement, the LGPG111 voltage balance protection function will be able to detect blown VT secondary fuses, but not a blown VT primary fuse.

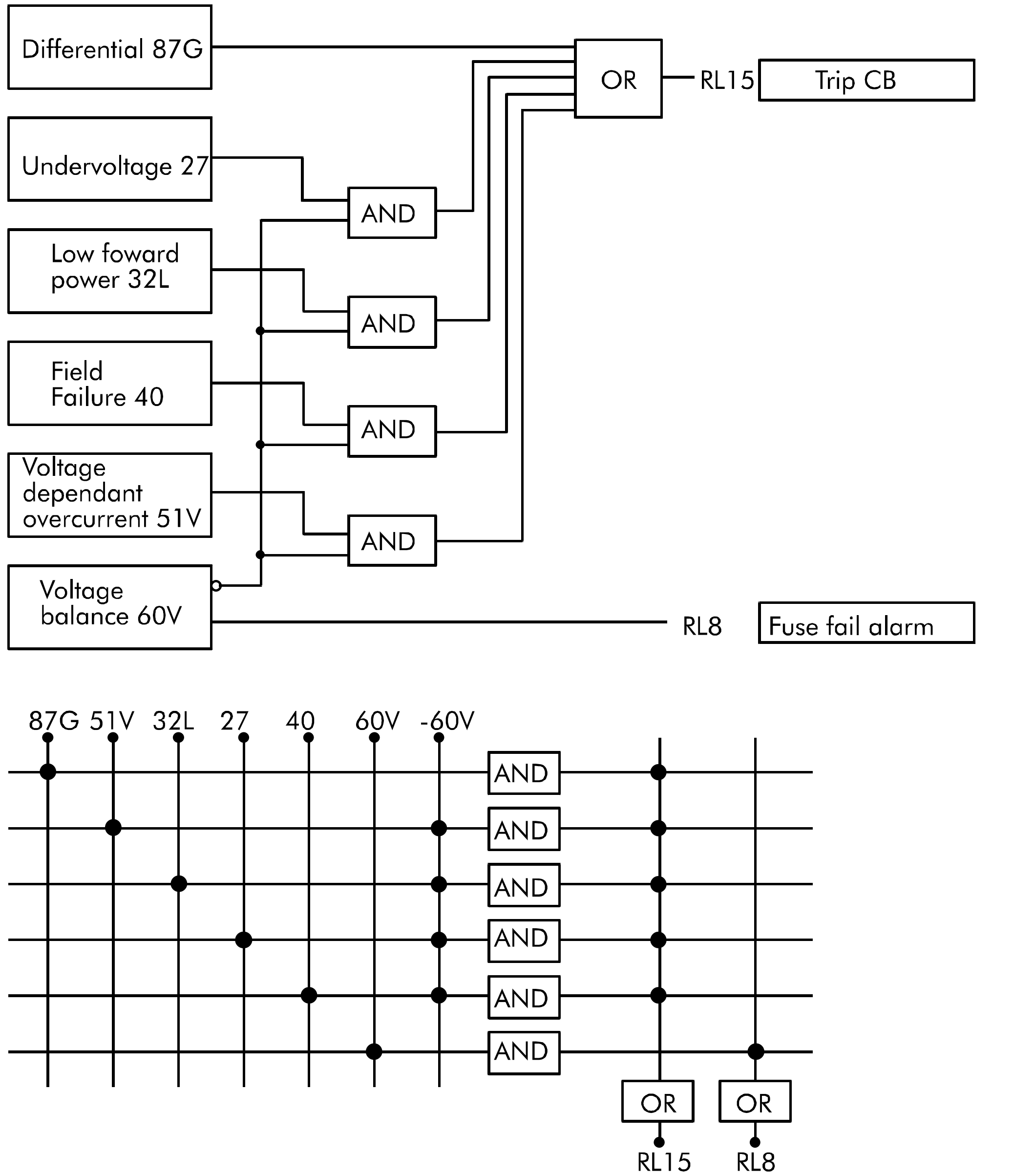


Figure 20 Fuse failure interlocking of 'voltage sensitive' protection functions.

The voltage balance threshold setting should be set to minimum (5V) unless two VT's of differing ratio are used or unless the standing unbalance, due to differing VT loading, causes false VT failure alarms during normal operation.

3. OTHER PROTECTION CONSIDERATIONS

3.1. Dead machine protection

For a multiple source power system, closure of a generator circuit breaker must be controlled either by automatic synchronising equipment, or by manual breaker closing carried out with the aid of synchronising instruments, and supervised by a synchronism check relay.

Whilst inadvertent closure of a generator circuit breaker should not be possible, a small risk does exist; especially when fault finding, carrying out maintenance tests or testing control systems. The possible damage caused by connecting a dead machine to a live power system, or energising a steam turbo-alternator when on turning gear, could be extremely costly if a method of quickly tripping the generator breaker is not provided.

If a dead machine is energised from a live power system, rotor currents will be induced and the machine will accelerate as an induction motor. The induced currents in the rotor body and windings would be very high with the machine initially at standstill and could rapidly result in thermal damage unless the machine is designed for direct-on-line run-up as an induction motor (possibly for starting a gas turbine prime mover). The unexpected shaft rotation could also result in rapid mechanical damage if lubrication systems are not running or if a steam turbo-alternator is on turning gear.

A number of the LGPG111's protection functions could respond to the inadvertent energisation of a dead machine. The effective machine impedance during such energisation would be similar to its sub-transient reactance and so the current drawn from the power system would be high. Both the field failure and overcurrent protection functions could respond to the condition. The reverse power protection function should also theoretically respond, but the very high reactive component of stator current may prevent the power measuring element from responding. All of these protection functions are normally arranged to initiate generator tripping via discrimination time delays such that tripping following energisation of a dead machine would be far too slow.

the LGPG111 can be used with two groups of protection function settings. In the normal setting group (Group-1), the protection functions would be set for normal operation. In Group-2, different protection settings can be selected to deal with special operating modes; e.g. running as a synchronous compensator or in pumping mode for pumped storage plant. The second group of settings (Group-2) could also be instated when a machine is not in service and the overcurrent and field failure protection functions could be set to initiate breaker tripping with a zero time delay if the machine is energised with the second group of settings instated. The overcurrent protection function could also be set with a reduced current threshold setting (I>) in the second setting group.

Automatic selection of the second group of protection function settings (Group 2) could be arranged as illustrated in Figure 21 The under voltage protection function threshold setting (V<) and time setting (t) should be set to meet any general protection requirements, as discussed in Section 2.10. These normal settings should also be used in the second setting group (group-2).

When the generator is shut down, a normally closed circuit breaker auxiliary contact can be used to prevent tripping and alarm initiation by the under voltage protection.

This arrangement will be different from that highlighted in Section 2.10., since the under voltage protection element must not be inhibited in this application. Here a logic input must be assigned to prevent the under voltage protection from operating output relays that will initiate plant tripping, but the under voltage protection will still be available for the dead machine protection logic. The under voltage protection will be free to operate a contact to act on the relay setting group selection logic inputs. This is achieved by taking them both to logic 1 to select setting group 2, after the under voltage protection function responds to the shutdown and as long as no other protection function is operated.

The over voltage protection function threshold settings (V> and V>>) should both be set to 99V in the group-2 setting schedule and the over voltage time delay (t>) should be set to 1s. The over voltage protection should not be arranged to initiate tripping or

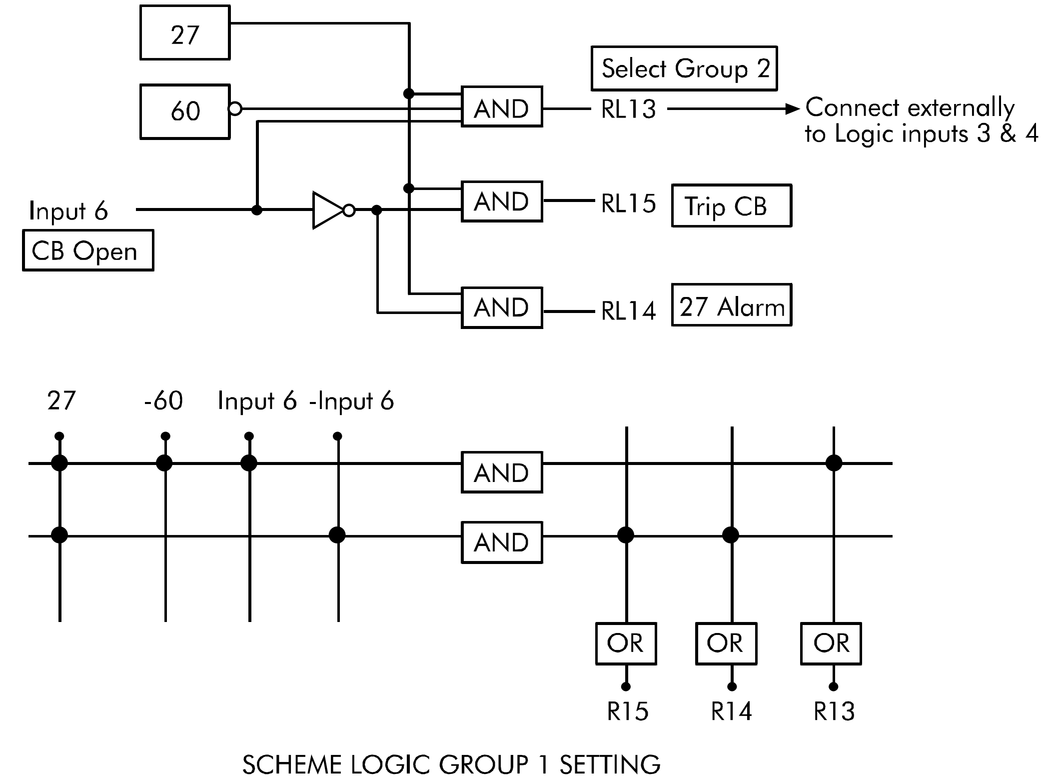


Figure 21 Dead machine protection scheme logic for group 1 setting

to give an alarm, but should output contact to make the relay setting group selection logic inputs (inputs 3 and 4) both logic 0, to select setting group 1, as illustrated in Figure 22. When the generator is run-up again, group-2 operation of the over voltage protection elements will result in group-1 settings being re-established prior to synchronisation, as long as no other protection element has operated.

If the protected generator is not in service, but is accidentally energised, fast tripping by undelayed overcurrent protection function (51V) or by undelayed field failure protection function should occur. Even if the LGPG111 sees a voltage above 99V when the protected machine is accidentally energised, the group-2 settings will be maintained for at least 1s and for as long as any subsequent protection function operation is maintained (e.g. 51V or 4O).

3.2. Breaker flashover protection

Prior to generator synchronisation, or just following generator tripping, where the protected generator could be slipping with respect to a power system, it is possible to establish at least twice rated phase-neutral voltage across the generator circuit breaker. An even higher voltage might briefly be established just after generator tripping for prime mover failure, where the pre-failure level of excitation might be maintained until AVR action takes place. Whilst generator circuit breakers must be designed to handle such situations, the probability of breaker interrupter breakdown or breakdown of contaminated open terminal switch gear insulators is increased and such failures have occurred.

This mode of breaker failure is most likely to occur on one phase initially and could be detected by a neutral current measuring element. If the generator is directly connected to the power system, the additional current-operated stator earth fault protection function element (Ie>>) could be applied as an instantaneous element, to quickly detect the flashover. This additional element could be enabled and arranged to operate an output contact when an assigned logic input is energised via a normally closed circuit breaker auxiliary contact, which indicates to the LGPG111 that the circuit breaker is supposed to be open. This arrangement could be set-up using the LGPG111's flexible scheme logic (see Figure 23).

When a generator is connected to the power system via a step-up transformer with only an HV synchronising breaker, it would be necessary to enable an instantaneous element of the HV standby earth fault protection. If this protection is being provided by a KCGG110 relay, for instance, one of the additional protection elements of this relay (Io< or Io>>) could be set to operate without delay. This protection element would be enabled when the circuit is open. the closing of a normally open generator breaker auxiliary contact can be used to block this specific relay element (see Fig24).

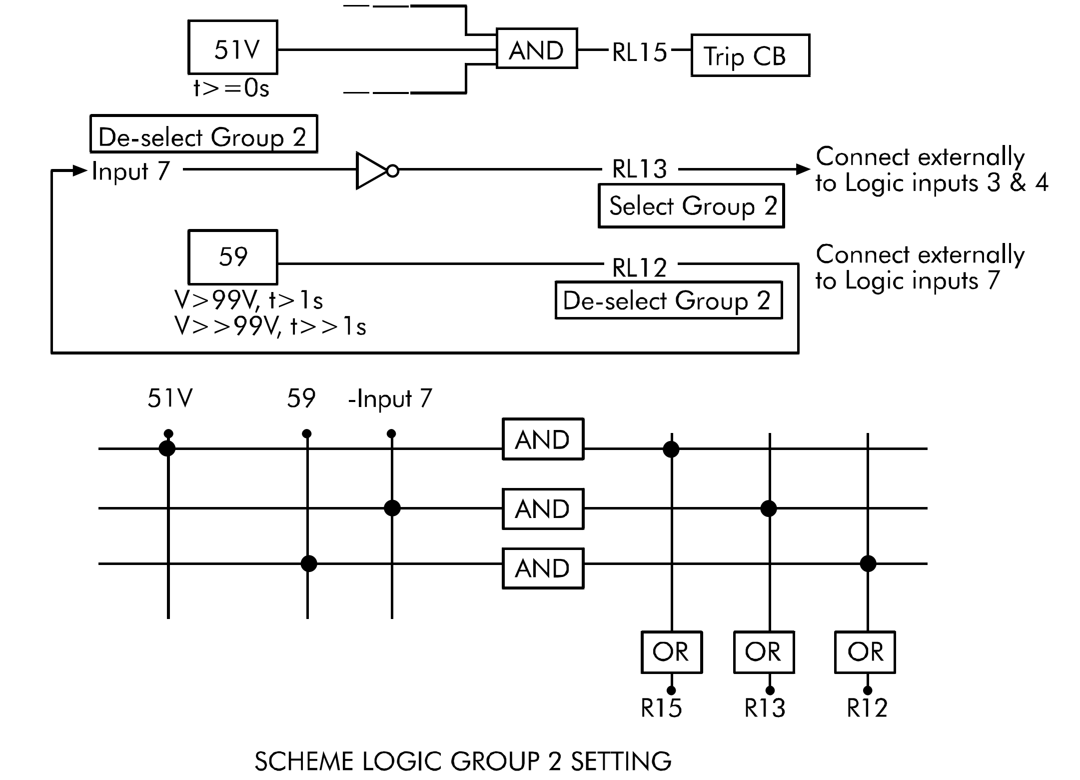


Figure 22 Dead machine protection scheme logic for group 1 setting.

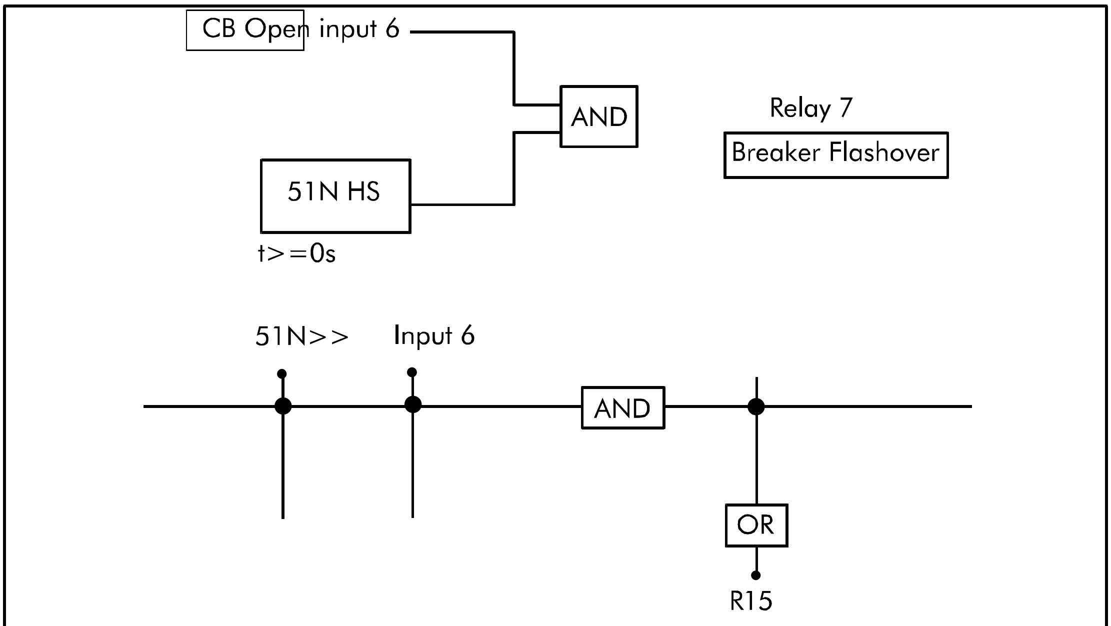


Figure 23 Breaker flashover protection

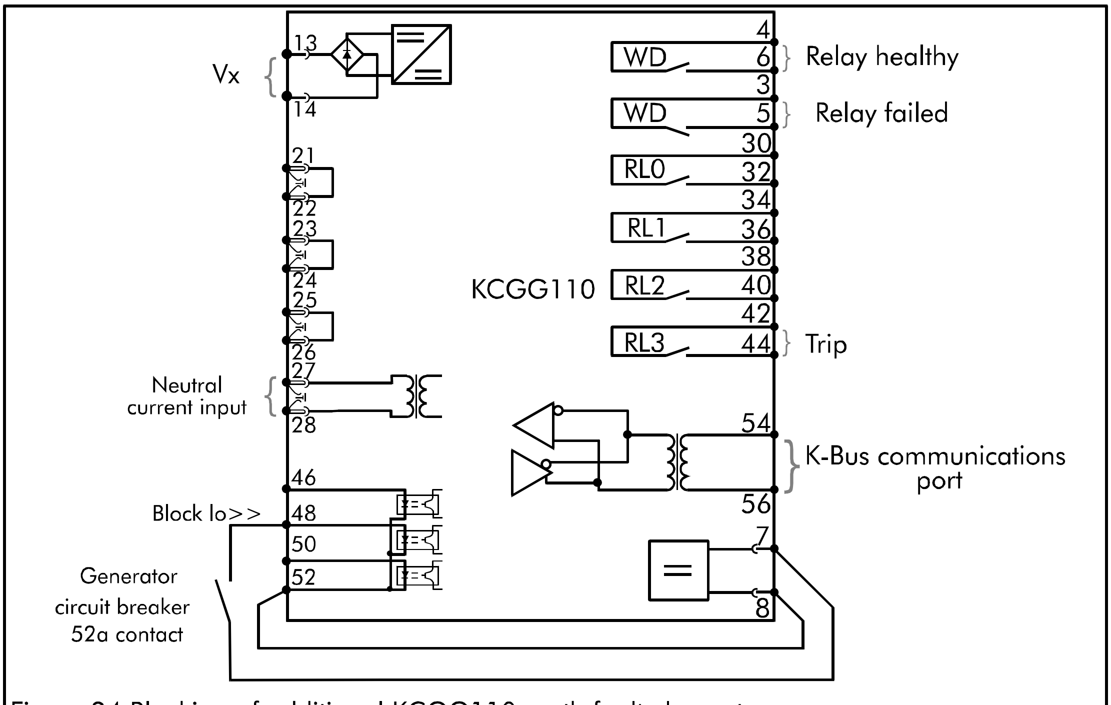


Figure 24 Blocking of additional KCGG110 earth fault element.

If instantaneous neutral current detector operation occurs when the generator circuit breaker is open, breaker-failure back tripping logic should be initiated, where breaker-fail protection is provided, or the trip rail of the busbar protection should be energised.

3.3. Over fluxing protection

When the ratio of per-unit generator terminal voltage magnitude to per-unit frequency exceeds 1.0, the generator and associated transformers (step-up, unit, excitation supply and voltage transformers) will become over fluxed. Since these items of plant will be operated close to their core saturation levels, to keep size and cost to a minimum, even moderate over fluxing in excess of 1.05 per-unit can lead to core saturation and an increase in flux levels through unlaminated plant components that are not designed to pass significant levels of flux; e.g. core bolts of traditional transformer designs. The resulting eddy currents in such components will lead to rapid localised heating, which may threaten the integrity of electrical insulation or increase the ageing of insulation, etc.

The common causes of plant over fluxing at generating stations are during under frequency operation of plant, prior to synchronising, and over voltage following sudden load rejection.

During slow run-up of a generator, the level of excitation must be controlled to limit the terminal voltage so that over fluxing does not occur. If excitation is commenced too early during run-up and the automatic voltage regulator is enabled to excite the machine to try and attain nominal voltage before nominal speed is reached, over fluxing of plant may occur. Severe over fluxing could result in operation of some designs of transformer differential protection, which would be beneficial for a sustained condition. However such tripping cannot be relied upon, since some protective relays are designed to try and prevent tripping due to transient over fluxing that would not pose a threat to a transformer.

Following significant load rejection, a generator terminal over voltage will transiently exist until the automatic voltage regulator is able to reduce excitation sufficiently. An over voltage condition will occur immediately following load rejection, before the machine accelerates to increase frequency and reduce over fluxing. The governor and prime mover response might also be faster than old-style regulator response times, so that the compensating effect of over frequency might be limited. The result may be that the generating plant is subjected to excessive flux for too long.

Over fluxing protection might generally be applied with generator sets that are connected to a power system via a step-up transformer. In such cases, transformer differential protection would be required. This is not a function provided by the LGPG111 relay. For such applications, the KBCH transformer differential protection relay should be applied, which includes inverse-time over fluxing protection.

3.4. Interlocked overcurrent protection

Where a single generator or small number of generators is the only source of infeed to the generating station main busbar, difficulty may be experienced in co-ordinating the voltage-dependent generator overcurrent protection (51V) with delayed overcurrent protection for circuits being fed from the generator bus. Difficulty arises with dependent-time protection, as a result of both sets of protection seeing similar levels of fault current for a feeder fault. This may result in the voltage-dependent protection being more sensitive to a close-up fault which results in a phase-phase voltage reduction.

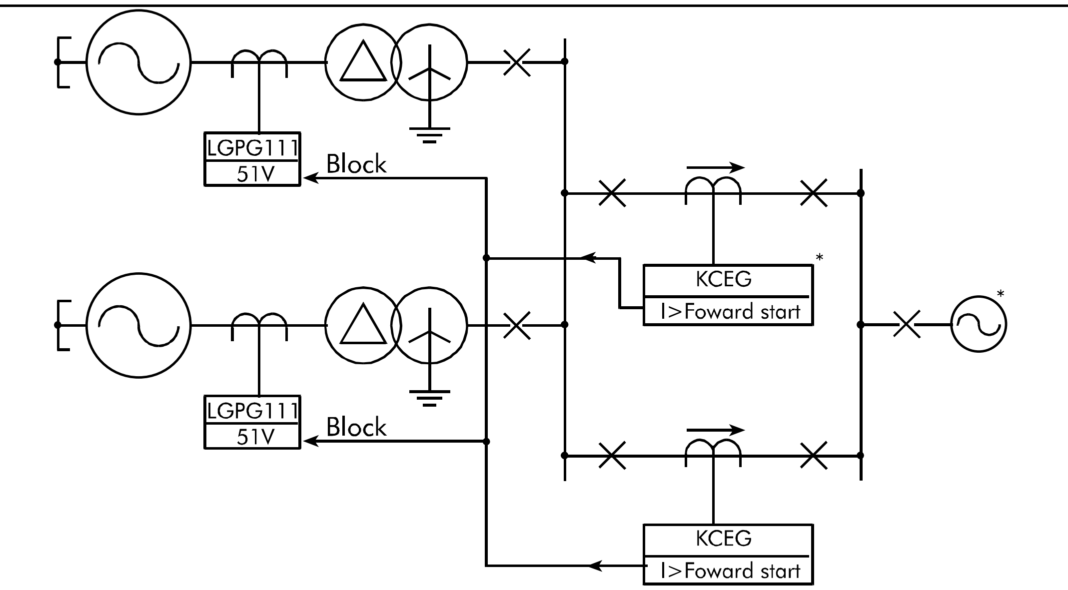
One method of dealing with the above type of problem would be to employ voltag-dependent overcurrent protection for the feeders from the generator busbar. Another solution offered with the LGPG111 generator protection and KCGG/KCEG feeder protection would be to block operation of the generator voltage-dependent overcurrent protection function (51V) if the feeder overcurrent protection picks up. This can be accomplished by allowing feeder protection 'start' contacts to act on the logic input for blocking the LGPG111 voltage-dependent overcurrent protection function (51V) as illustrated in Figure 25. An adequate co-ordination time margin must be allowed between the voltage-dependent protection function operating time for a close-up fault and the operating time of the feeder protection instantaneous ‘start’ contact.

Where time-delayed feeder overcurrent protection is insensitive to a feeder fault with a generator decaying infeed, the feeder protection ‘start’ contact would not operate and the voltage-dependent generator protection function would be free to provide the required backup protection.

In a similar manner to arranging for interlocked overcurrent protection, difficulties in co-ordinating the LGPG111 time-delayed stator earth fault protection function (51N) with feeder earth fault protection, in the case of a directly connected generator, can be overcome by creating an interlocked earth fault protection scheme as illustrated in Figure 26.

3.5. Pole-slipping protection

A generator might pole-slip, or fall out-of-step with other power system sources, in the event of failed or abnormally weak excitation or as a result of delayed system fault clearance; especially when there is a weak (high reactance) transmission link between the generator and the rest of the power system.



* KCEG directional relays are required where backfeed from another power system source is possible, otherwise non-directional KCGG relays could be used.

Figure 25 Interlocked voltage dependant overcurrent protection function.

The process of pole-slipping following excitation failure is discussed in Section 2.9. The LGPG111 impedance-type field failure protection function should respond to such situations to give a time delayed trip. The electrical/mechanical power/torque oscillations following excitation failure would be relatively gentle. If pole slipping occurs with maximum excitation (generator emf >2.0 p.u.), the power/torque oscillations and power system voltage fluctuations following loss of stability would be much more severe. There may be arequirement to confirm that protection is provided to trip the generator under such circumstances to prevent plant damage or remove the disturbance to the power system.

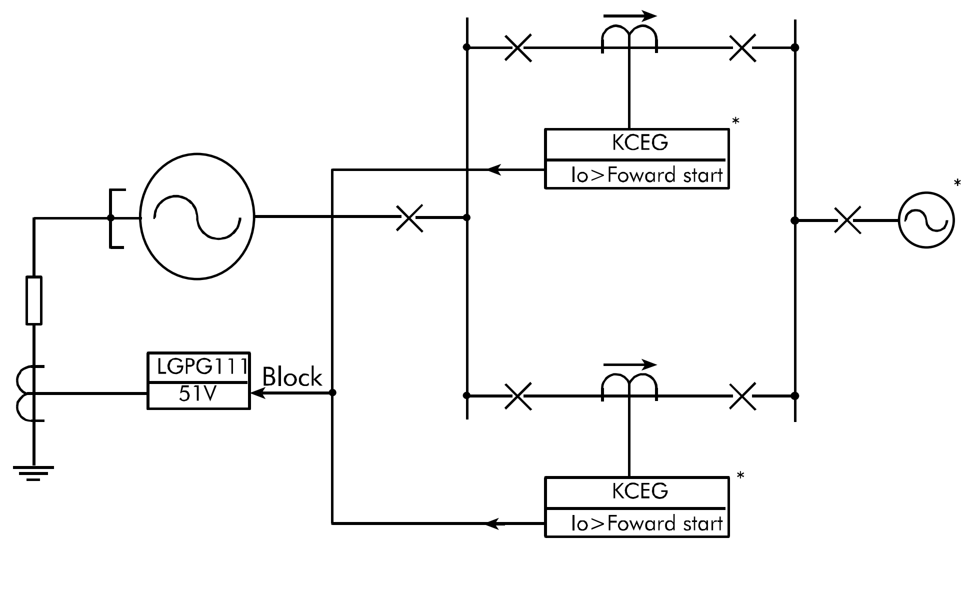
With large utility base-load generators, the requirement for pole-slipping protection will be dependent on the transmission system reactance. In the case of generators connected to a dense, interconnected system, pole-slipping protection may not be required. In the case of remote generation and a weak radial transmission link to the load centre, stability of generation may be an issue. Normally steps would be taken to minimise the risk of instability by keeping the transmission impedance to a minimum and by employing high-speed transmission protection with auto-reclosing, but the risk of pole-slipping and the need for pole-slipping protection may still exist.

Pole-slipping protection is frequently requested for relatively small generators running in parallel with strong public supplies. This might be where a co-generator runs in parallel with the distribution system of a public utility, which may be a relatively strong source, but where high-speed protection for distribution system faults is not provided. The delayed clearance of system faults may pose a stability threat for the co-generation plant.

With LGPG111 there is no specific pole-slipping protection function, but some of the protection functions provided will offer a method of ensuring delayed tripping, if appropriately applied.

3.5.1. Voltage-dependent overcurrent protection function (51V)

In a similar manner to the reverse power protection function, the voltage-dependent overcurrent protection function would operate cyclically with the periodic high levels of stator current that would arise during pole-slipping. These peaks of current may also be accompanied by coincident drops in generator terminal voltage, if the generator is near the electrical centre of swinging. As discussed in Section 2.6., the voltage-dependent overcurrent protection function (51V) is provided with a timer characteristic timer-hold setting (tRESET), which can be used to ensure that the protection function will respond to cyclic overcurrent during pole-slipping. In a similar



* KCEG directional relays are required where backfeed from another power system source is possible, otherwise non-directional KCGG relays could be used.

Figure 26 Interlocked Stator Earth Fault Protection Function.

manner, some operators of small, unmanned hydrogenerators have relied on the integrating action of induction disc overcurrent protection to ensure disconnection of a persistently slipping machine.

3.5.2. Field failure protection function (40)

Slightly faster pole-slipping protection might be assured in many applications by appropriately applying the field failure protection function and associated scheme logic timers.

Where the power system source impedance is relatively small in relation to the impedance of a generator during pole-slipping, the electrical centre of slipping is likely to lie within the generator. This would be 'behind' the LGPG111 relaying point, as defined by the location of the voltage transformer Such a situation is likely to exist

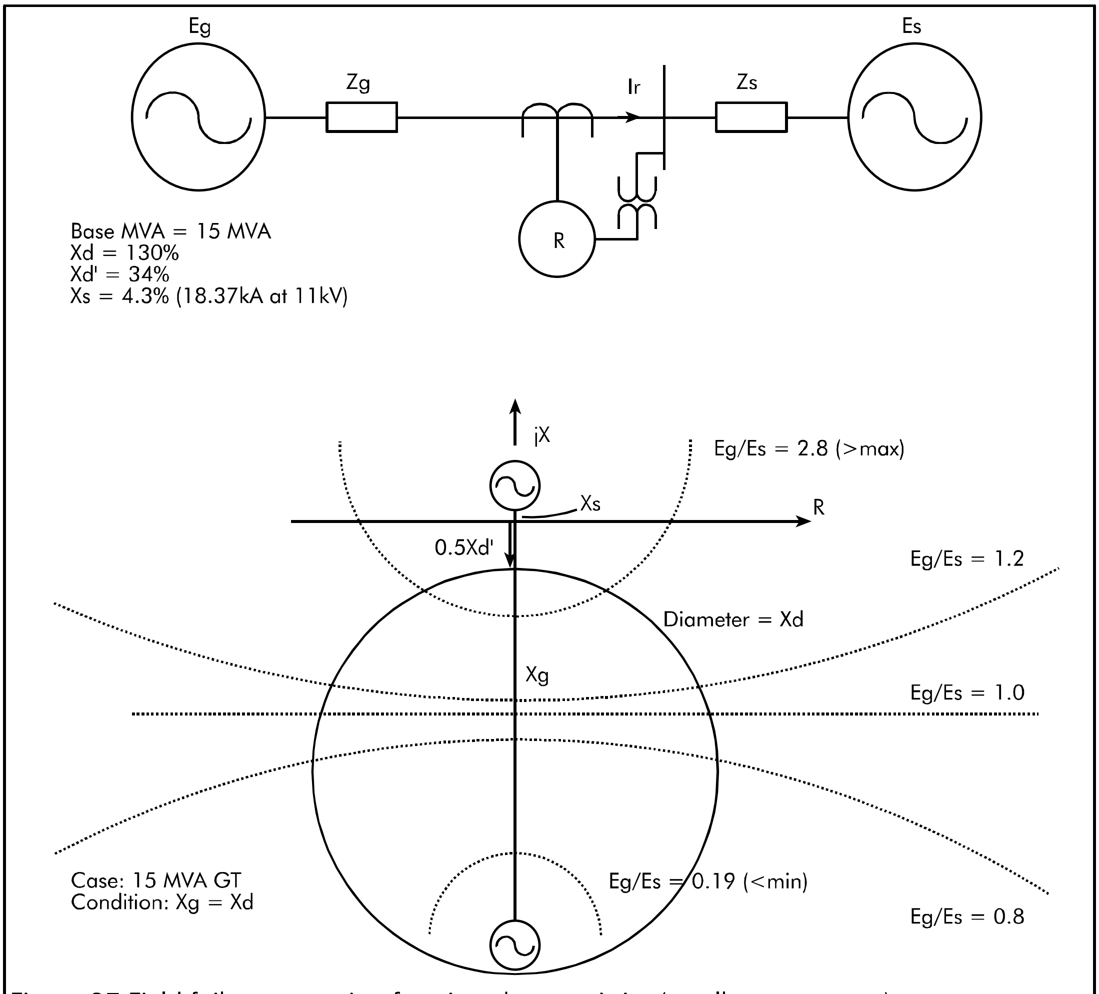


Figure 27 Field failure protection function characteristics (small co-generator).

for co-generation schemes and might also be the case for some fairly large utility generation schemes connected to a densely interconnected transmission system. The dynamic impedance of the generator during pole-slipping (X_g) should lie between the average value of the direct and quadrature axis transient reactance's (X_d' and X_q') and the average value of the direct/quadrature axis synchronous reactance's (X_d and X_q). However neither extreme would actually be reached. During low-slip periods of a pole-slip cycle, the synchronous reactance's would apply, whereas the transient impedance's would apply during periods of relatively high slip.

Figures 27 and 28 illustrate how the impedance seen at the generator protection relaying point may vary during pole-slipping for a relatively small co-generator directly connected to a relatively strong distribution power system. The two figures consider extremes of generator/system emf ratios and the two extreme values of generator impedance discussed above. Figures 29 and 30 are similar illustrations for a relatively large utility generator, connected to a strong, interconnected transmission system. It should be noted that the behaviour of a generator during pole slipping may be further complicated by intervention of an automatic voltage regulator and by the response of any speed-dependent excitation source (e.g. shaft-driven exciter).

It can be seen from the simple analysis of Figures 27 - 30 that the LGPG111 field failure protection function may respond to the variation in impedance seen during pole slipping for some applications. However the impedance characteristic offset might have to be reduced to guarantee response for the theoretical lower range of dynamic generator impedance (X_g). The lack of the normally recommended characteristic offset should not pose any problem of unwanted protection function response during the normal range of operation of a machine (with rotor angles kept below 90°), but a longer trip time delay might be required to prevent unwanted protection response during stable power swings caused by system disturbances. The

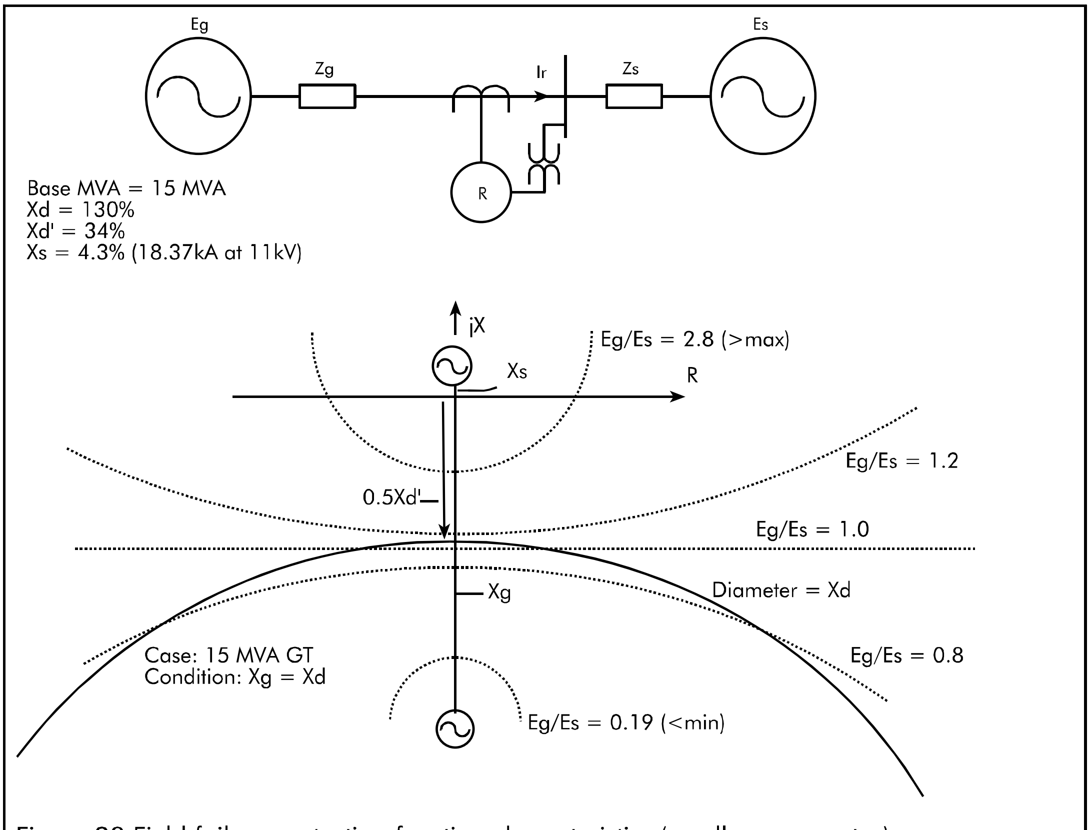


Figure 28 Field failure protection function characteristics (small co-generator).

most marginal condition to detect is where the generator is fully loaded, with maximum excitation applied. Even if the impedance characteristic offset is not reduced, impedance element pick up should still occur during part of a slip cycle, when the machine impedance is high and where the rotor angle is high. More careful consideration might have to be given to the reset time delay setting (tDC) required in such circumstances.

During pole-slipping, any operation of the LGPG111 field failure protection function will be cyclic and so it would be necessary to set the reset time delay (tDO) to be longer than the time for which the impedance seen will cyclically lie outside the field failure characteristic. A typical delay setting might be 0.6s, to cater adequately for cover slip frequencies in excess of 2Hz. When the timer tDO is set, the field failure trip time delay (t) must be increased by the setting of tDO.

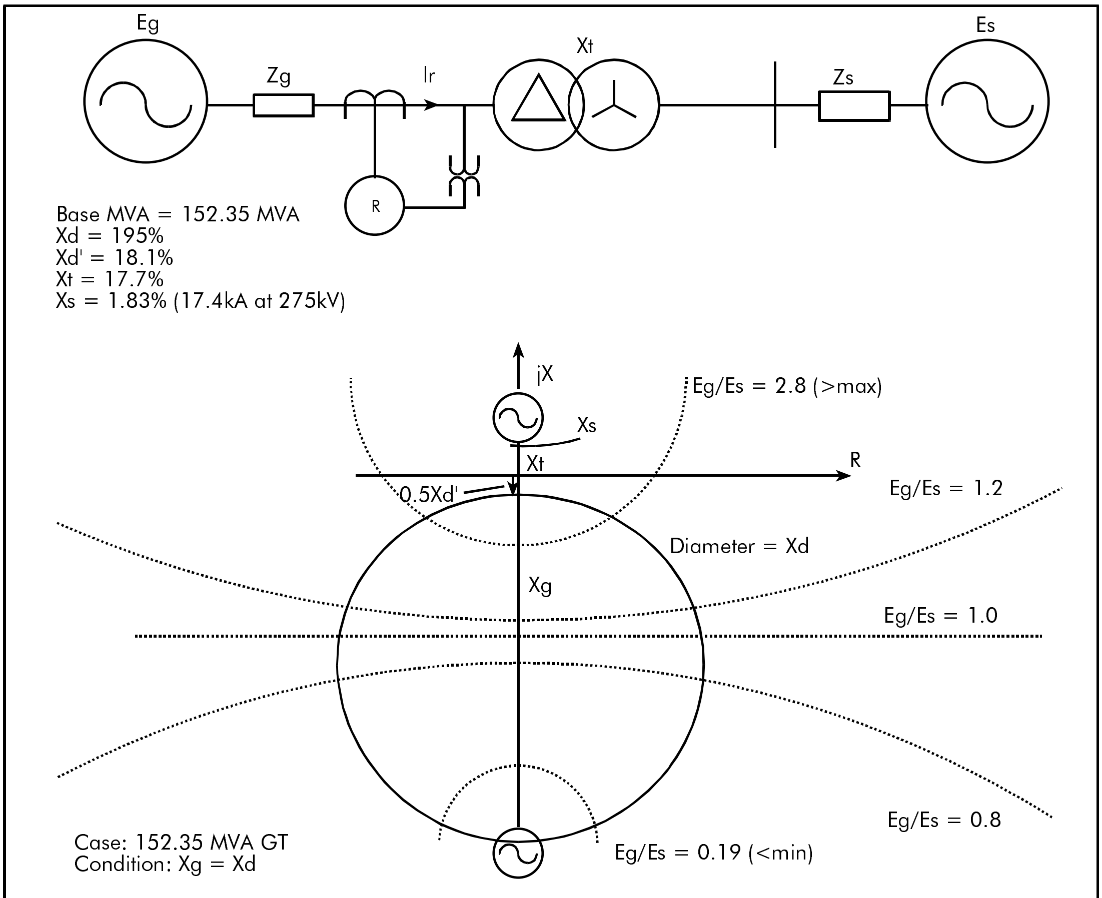


Figure 29 Field failure protection function characteristics (large generator).

Sometimes pole-slipping protection must be guaranteed, especially in the case of a larger utility generator connected to a relatively weak transmission system. Here the described means of providing pole-slipping protection might only be fully effective if the pole-slipping impedance measuring element uses voltage signals derived from the HV side of the step-up transformer. In such applications, and where fast tripping is required, or where the pole-slipping response of field failure protection function is otherwise uncertain, a stand-alone protection scheme, using HV current and voltage signals, should supplement LGPG111. The delayed detection and tripping offered by the LGPG111 field failure protection function should, however, be adequate for many applications.

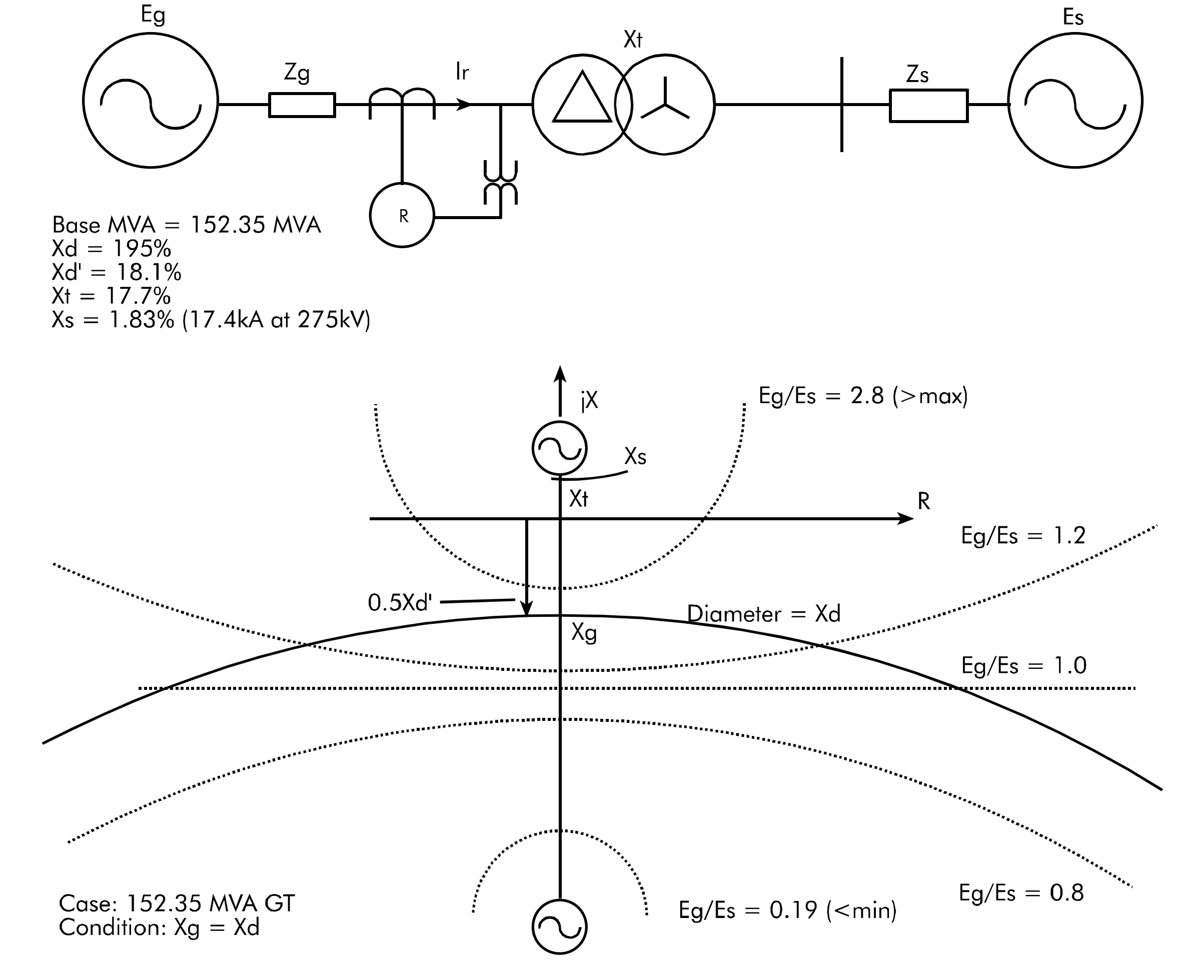


Figure 30 Field failure protection function characteristics (large generator).

4. STANDARD FACTORY SETTINGS

An overview of the LGPG111 factory scheme logic settings is given in Figure 31. Diagram 08 LGPG111 01 in chapter 11, details all the standard factory settings for the protection and scheme logic. (Note that the frequency tracking default is set to 50Hz in the System Data Section. This should be set to 60Hz for 60Hz countries, although no harm will result if it is not.)

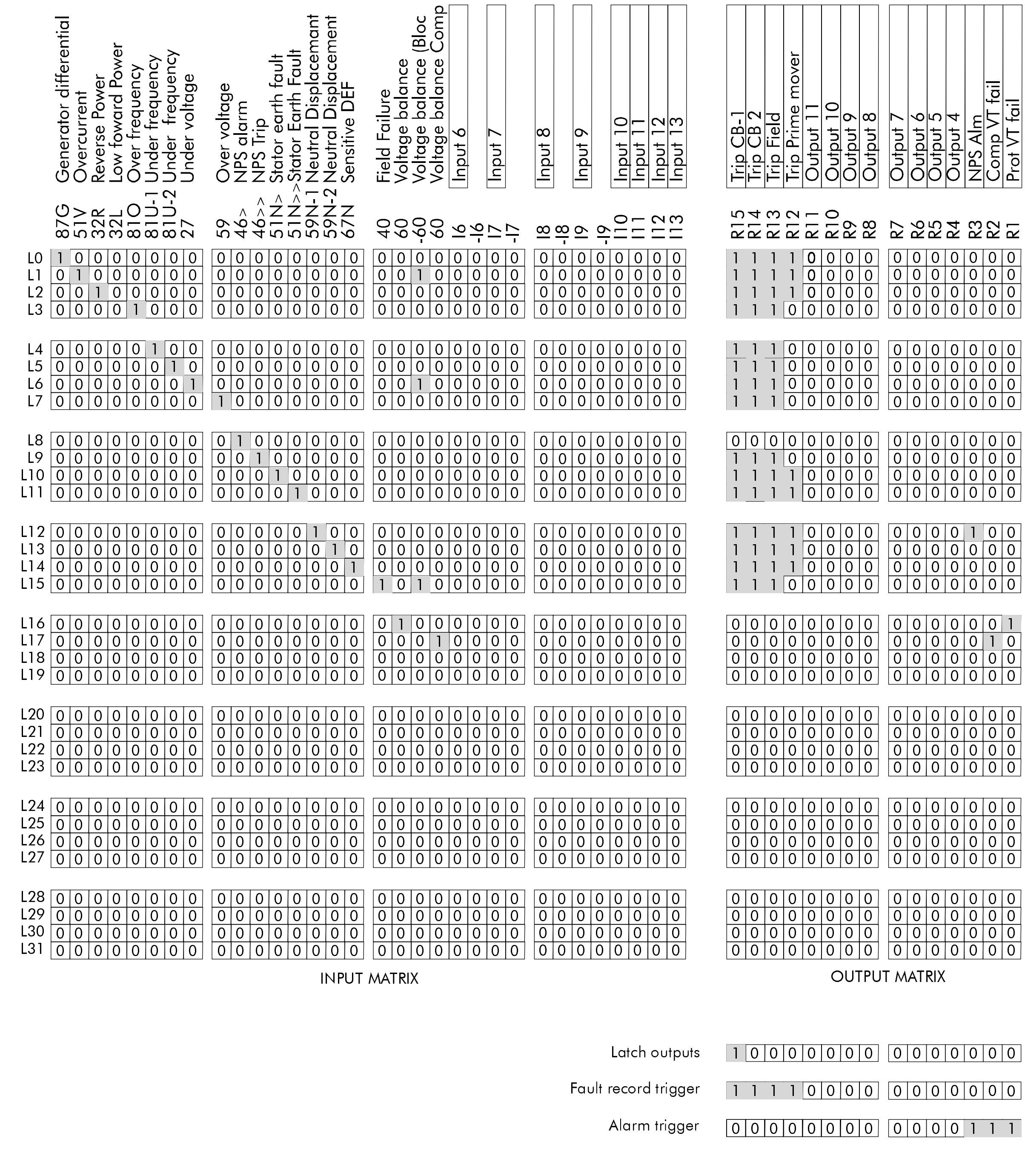


Figure 31 LGPG111 factory scheme logic settings.

The standard factory settings are designed to provide a basic protection scheme that should be suitable for most installations. By making minor modifications and additions to the standard factory scheme logic settings, the LGPG111 can be made to meet the individual application tripping requirements. To complete the application of the LGPG111, the protection function parameters should be set to values appropriate for the generator being protected.

The relay's standard scheme logic has been configured with all of the protection functions, except for the low forward power function, assigned to relay outputs. The low forward power function has not been included because, apart from applications with steam turbines, it is not normally used.

The protection functions that operate for generator faults or provide back-up for downstream protection, have relay outputs assigned for tripping the generator circuit breaker, field and prime mover.

The protection functions for detection of abnormal operating conditions have relay outputs assigned for tripping the generator CB and the excitation field. It is not necessary to trip the prime mover because abnormal conditions can usually be resolved quickly.

It should be noted that each active protection function has been assigned two relay outputs for circuit breaker tripping, a non-latched contact and a latched contact. Where it is not required for a particular protection function to initiate a circuit breaker trip via a latched contact, this allocation can be removed from the scheme logic.

5. CURRENT TRANSFORMER REQUIREMENTS

The current transformer requirements for each current input will depend on the protection function with which they are related and whether the line current transformers are being shared with other current inputs. Where current transformers are being shared by multiple current inputs, the kneepoint voltage requirements should be calculated for each input and the highest calculated value used.

Note should also be made of the effect on the current transformer requirements when using the LGPG111 at low frequencies. See Section 1.3.

5.1. Generator differential function

5.1.1. Biased differential protection

The kneepoint voltage requirements for the current transformers used for the current inputs of the generator differential function, with settings of Is1 = 0.05In, k1 = 0%, Is2 = 1.2In, k2=150%, and with a boundary condition of through fault current ≤ 10In and X/R ratio ≤ 12O, is:

$$V_k \geq 50\ I_n(R_{ct}+2R_L+R_r) \text{ with a minimum of 34V}$$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability.
I_n = Relay rated current.
R_{ct} = Resistance of current transformer secondary winding (Ω).
R_L = Resistance of a single lead from relay to current transformer (Ω).
R_r = Resistance of any other protective relays sharing the current transformer (Ω).

With a boundary condition of through fault current ≤ 10In and X/R ratio ≤ 60, the kneepoint voltage requirement is:

$$V_k \geq 30\ I_n\ (R_{ct} + 2R_L + R_r) \text{ with a minimum of 34V}$$

For class-X current transformers, the excitation current at the calculated kneepoint voltage requirement should be less than $2.5I_n$ For IEC standard protection class current transformers, it should be ensured that class 5P are used.

5.1.2. High impedance differential protection

If the generator differential protection function is to be used to implement high impedance differential protection, then the current transformer requirements will change. For this reason, please contact the Engineering Department of ALSTOM T&D Protection & Control Limited for advice on selecting suitable current transformers.

5.2. Voltage dependent overcurrent, field failure and negative phase sequence protection functions

When determining the current transformer requirements for an input that supplies several protection functions, it must be ensured that the most onerous condition is met. This has been taken into account in the formula given below. The formula is equally applicable for current transformers mounted at either the neutral-tail end or terminal end of the generator.

$$V_k \geq 20I_n(R_{ct}+2R_L+R_r)$$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability.
I_n = Relay rated current.
R_{ct} = Resistance of current transformer secondary winding (Ω).
R_L = Resistance of a single lead from relay to current transformer (Ω).
R_r = Resistance of any other protective relays sharing the current transformer (Ω).

For class-X current transformers, the excitation current at the calculated kneepoint voltage requirement should be less than $1.0I_n$. For IEC standard protection class current transformers, it should be ensured that class 5P are used.

5.3. Sensitive directional earth fault protection function residual current input

5.3.1. Line current transformers

With reference to section 2.5., the sensitive directional earth fault input current transformer could be driven by three residually connected line current transformers.

It has been assumed that the sensitive directional earth fault protection function will only be applied when the stator earth fault current is limited to the stator winding rated current or less. Also assumed is that the maximum X/R ratio for the impedance to a bus earth fault will be no greater than 5. The required minimum kneepoint voltage will therefore be:

$$V_k > 6I_n(R_{ct}+2R_L+R_r)$$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability.
I_n = Relay rated current.
R_{ct} = Resistance of current transformer secondary winding (Ω).
R_L = Resistance of a single lead from relay to current transformer (Ω).
R_r = Resistance of any other protective relays sharing the current transformer (Ω).

For class-X current transformers, the excitation current at the calculated kneepoint voltage requirement should be less than $0.3I_n$. For IEC standard protection class current transformers, it should be ensured that class 5P are used.

5.3.2. Core balanced current transformers

Unlike a line current transformer, the rated primary current for a core balanced current transformer may not be equal to the stator winding rated current. This has been taken into account in the formula:

$$V_k > 6NI_n(R_{ct}+2R_L+R_r)$$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability.

$$N = \frac{\text{Maximum earth fault current}}{\text{Core balanced current transformer rated primary current}}$$

I_n = Relay rated current.

R_{ct} = Resistance of current transformer secondary winding (Ω).

R_L = Resistance of a single lead from relay to current transformer (Ω).

R_r = Resistance of any other protective relays sharing the current transformer (Ω).

Note: N should not be greater than 2; since $2I_n$ is the maximum measurable secondary current. The core balance current transformer ratio should be selected accordingly.

5.4. Stator earth fault protection function and sensitive directional earth fault current polarising input

The earth path current input is used by the stator earth fault protection function and as the current polarising signal for the sensitive directional earth fault protection function.

The primary rating of the earth path current transformer may not be related to the stator winding rated current as discussed in Section 5.3.2. Therefore, the requirements for the earth path current transformer will be similar to that detailed in Section 5.3.2., as follows:

$$V_k > 6NI_n(R_{ct}+2R_L+R_r)$$

Where:

V_k = Minimum current transformer kneepoint voltage for through fault stability.

$$N = \frac{\text{Maximum earth fault current}}{\text{Earth path current transformer rated primary current}}$$

I_n = Relay rated current.

R_{ct} = Resistance of current transformer secondary winding (Ω).

R_L = Resistance of a single lead from relay to current transformer (Ω).

R_r = Resistance of any other protective relays sharing the current transformer (Ω).

Note: N should not be greater than 2; since $2I_n$ is the maximum measurable secondary current. The earth path current transformer ratio should be selected accordingly.

5.5. Reverse and low forward power protection functions

For both reverse and low forward power protection function settings greater than

$3\%P_n$, the phase angle errors of suitable protection class current transformers will not result in any risk of maloperation or failure to operate. However, for settings less than $3\%P_n$, it is recommended that the current input is driven by a correctly loaded metering class current transformer.

5.5.1. Protection class current transformers

For less sensitive power function settings ($>3\%P_n$), the $I_{a\ sensitive}$ current input of the LGPG111 should be driven by a correctly loaded class 5P protection current transformer.

To correctly load the current transformer, its VA rating should match the VA burden (at rated current) of the external secondary circuit through which it is required to drive current. Use of the LGPG111 phase-shift compensation feature will help in this situation.

5.5.2. Metering class current transformers

For low power settings ($\leq 3\%P_n$), the $I_{a\ sensitive}$ current input of the LGPG111 should be driven by a correctly loaded metering class current transformer. The current transformer accuracy class will be dependent on the reverse and low forward power sensitivity required. Table 4 indicates the metering class current transformer required for various power settings below $3\%P_{n.}$

To correctly load the current transformer, its VA rating should match the VA burden (at rated current) of the external secondary circuit through which it is required to drive current. Use of the LGPG111 phase-shift compensation feature will help in this situation.

Reverse and low forward Power Setting (-P> and P<) $\%P_n$	Metering CT Class
0.2 0.4 0.6	0.1
0.8 1.0 1.2 1.4 1.6 1.8	0.2
2.0 2.2 2.4 2.6	0.5
2.8 3.0	1.0

Table 4 Sensitive reverse power current transformer requirements

5.6. Converting an EEC 185 current transformer standard protection classification to a kneepoint voltage

The suitability of an IEC standard protection class current transformer can be checked against the kneepoint voltage requirements specified previously in Section 5.

If, for example, the available current transformers have a 15VA 5P 10 designation, then an estimated kneepoint voltage can be obtained as follows:

$$V_k \approx \frac{VA \times ALF}{I_n} + ALF \times I_n \times R_{ct}$$

Where:

V_k = Required kneepoint voltage
VA = Current transformer rated burden (VA)
ALF = Accuracy limit factor
I_n = Current transformer secondary rated (A)
R_{ct} = Resistance of current transformer secondary winding (Ω)

If R_{ct} is not available, then the second term in the above equation can be ignored.

Example: 400/5A, 15VA 5P 10, R_{ct}=0.2Ω

$$V_k \approx \frac{15 \times 10}{5} + 10 \times 5 \times 0.2$$
$$\approx 40V$$

CHAPTER 4 - Functional Description

Issue Control

engineering document number: 50005.1701.104

Issue	Date	Author	Changes
AP	February 1995	Tony Yip & Peggy Ling	Original
BP	June 1995	Dave Banham	Minor Corrections. NPS protection description updated to reflect change in LGPG111 functionality for software reference number 18LGPG002XXXE Issue A onwards. The NPS reset characteristic was an exponential decay, now the thermal replica is used. Kreset was the time constant of the exponential now it is the thermal capacity constant for cooling.
A	July 1995	Dave Banham / Publicity	Styles changed. Description of frequency tracking inputs improved. Bullet added to 'operational events' list to indicate, for software version 18LGPG002XXXEB onwards, that the state of the scheme output menu cell (in auxiliary functions) is now logged at reset and whenever it is changed. Description of event logging when real time clock set changed to reflect software version 18LGPG002XXXEB. (Previous versions of the software only logged the 'real time clock invalid' event.)
B	Feb 1996	Dave Banham / Publicity	Section 3.5.3. corrected formulae for the vector transformation. ANSI device numbers corrected in Figures 21 and 22.

Contents

1. INTRODUCTION

The design of the Integrated Generator Protection Relay LGPG111 is based entirely on numerical techniques. The analogue signals are converted into digital data, using an analogue-to-digital conversion circuit. The data is processed by a powerful 16-bit microprocessor, which performs digital signal processing and executes various protection algorithms.

The LGPG111 implements a user configurable scheme logic. The scheme logic monitors the states of the protection functions and logic inputs, and controls the relay outputs through logic functions. The scheme logic, because it is software based, is integrated into the relay at minimum extra cost and can be re-configured easily by changing relay settings.

Three types of recording facilities are available: event, fault and disturbance recording. An event record logs the operation of the protection functions, energisation of logic inputs or relay outputs, or any internal relay failure. A fault record is essentially an event record with additional measurement values recorded at the time of fault. The disturbance recorder captures data from 8 analogue channels, together with states of all the logic inputs and relay outputs, over a period.

The LGPG111 provides two user interfaces: one is situated on the relay's front panel and the other consists of a remote serial interface. Both interfaces access a common internal menu database. The database consists of the relay settings, measurements and recordings. Some of this information can also be printed out, through the parallel port, to a printer.

Testing facilities are available to aid commissioning and routine maintenance. These facilities include: testing of the front panel LED's, relay outputs and scheme logic settings, monitoring of the logic inputs, and checking the progress of protection function operation.

Self-checking and monitoring are also provided. The LGPG111 monitors the power supply, the analogue circuitry, memory and the software, and takes appropriate action once a failure is detected. Self-monitoring increases the availability of the relay, by notifying the user immediately of any failure.

A simplified functional block diagram of the relay is shown in Figure 1. A detailed description of these functions is provided in the following Sections.

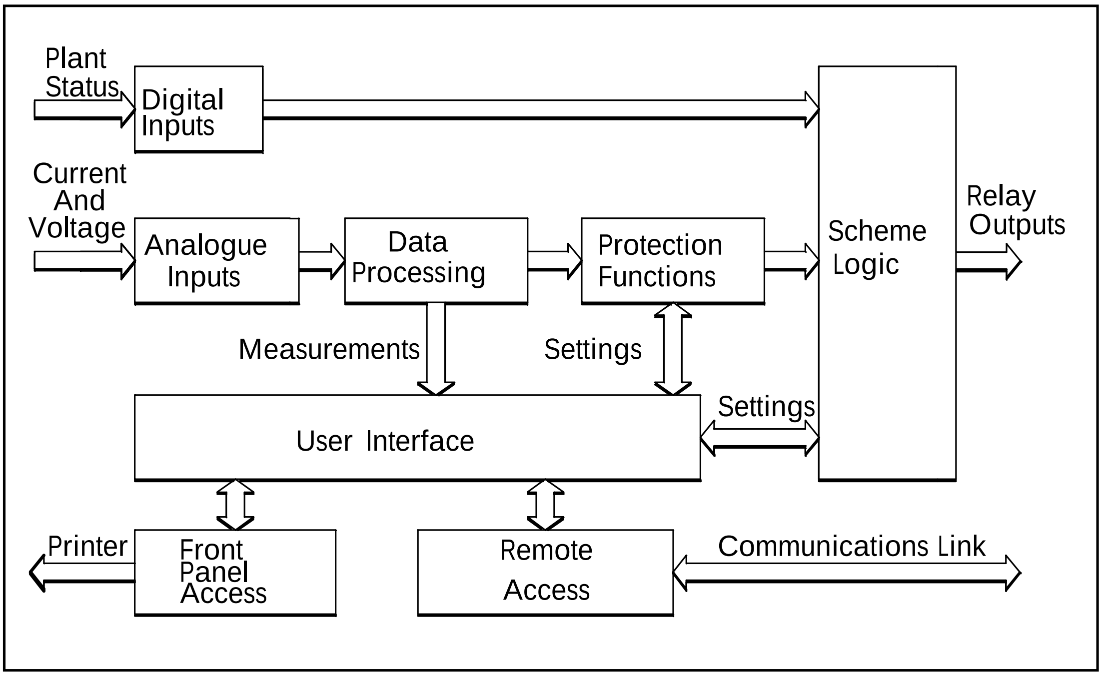


Figure 1 Simplified functional block diagram of the LGPG111 relay.

2. INPUT SIGNAL PROCESSING

2.1. Analogue inputs

The LGPG111 has 17 analogue inputs, consisting of 12 current inputs and 5 voltage inputs. Internal isolation transformers are used to scale the voltage and current signals from the generators' CT's and VT's to a level compatible with the electronic circuitry. These transformers also provide galvanic isolation between the relay and the generator plant.

The input signals are sampled sequentially, through multiplexers, using a sample and hold amplifier. The samples are converted into digital data with an analogue to digital converter (ADC). The LGPG111 uses a 12-bit ADC in bipolar mode, thus providing a bit resolution of 11 bits plus sign. The sample and hold amplifier has a gain-switching facility, with a x1 and x8 gain selection, which effectively increases the bit resolution from 11 to 14 bits.

There are two main sources of error associated with the analogue to digital conversion process. The first occurs when the input signal is larger than the full scale range of the ADC input. In this case the ADC will saturate and will produce a clipped waveform. Another type of error is digital quantization error. Since the signal after data conversion is represented by the nearest quantizing level, there can be a conversion error of up to ±½ lsb (least significant bit). This error is significant only when the input signal is small. When determining the dynamic range of an input, it is necessary to consider the minimum and the maximum signal levels which the relay is required to measure accurately.

The analogue inputs are separated into groups based on their measuring function. Different types of input transformers are used in each group to optimise the protection performance. The 12 current inputs are all designed to make full use of the gain switching facility to maximise the effective dynamic range. For the voltage inputs, there is no requirement for a comparatively wide dynamic range, therefore only one gain is selected. The following sub-sections discuss the design considerations for each group of inputs.

2.1.1. Generator differential CT inputs

Six current inputs are assigned specifically for the differential function, with two inputs per phase. A special type of input transformer, called a transactor,[1] is used internally to measure the current inputs. Transactors provide the differential function with improved stability when an offset waveform is applied.

For each phase, one input is used to measure the bias current, the other input is used to measure the differential current, as shown in Figure 2.

The differential function requires two bias current measurements, one from each end of the stator winding. The LGPG111 directly measures one of these and calculates the other from the differential and bias inputs, as explained in Section 3.1. This approach saves an extra input per phase, which allows the LGPG111 to achieve its compact size. The performance of the relay is not affected by whether the bias input is connected to the line end CT or the neutral end CT.

The differential function provided by the LGPG111 is a low impedance biased scheme. However, if there is a specific requirement for a high impedance scheme, then external stabilising resistors can be connected, as explained in the Application Notes, chapter 3.

The current input range is up to 20.48xIn, beyond which the ADC will saturate. ADC saturation effect causes the relay to measure a smaller current magnitude than the actual value, but this is unlikely to degrade the differential protection performance for internal faults, or cause discrimination problems for external faults.

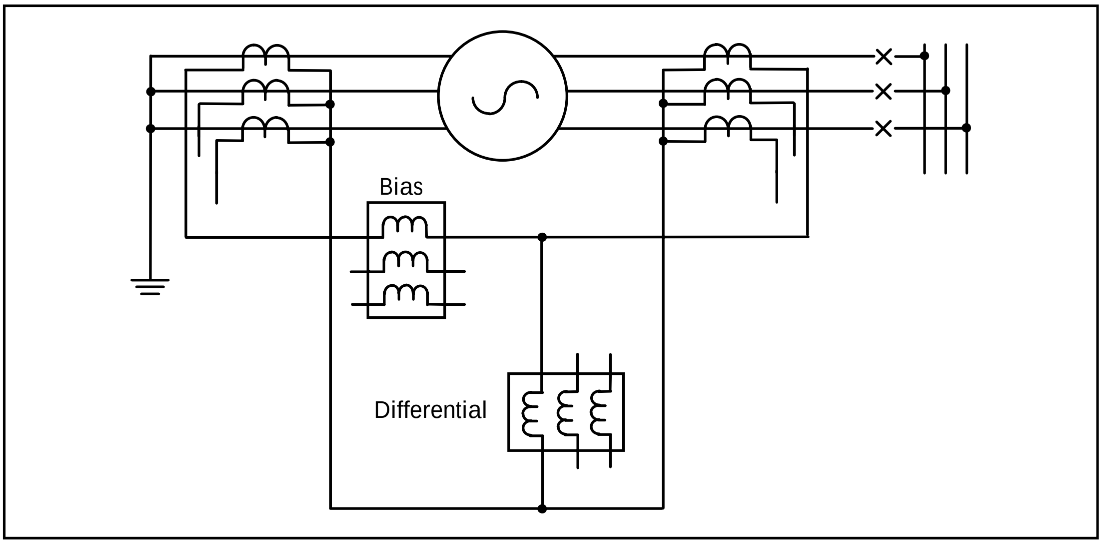


Figure 2 Generator differential: typical input connection (Phase A).

[1] A transactor is a transformer with an air gapped core. The air gap increases the inductance and saturation point which allows the transactor to cope with large through currents in a relatively small space. A transactor behaves as a transformer loaded with a reactive shunt and effectively produces a secondary e.m.f. proportional to its primary current. However, there is a quadrature relationship between the primary current and the secondary e.m.f. due to the effective secondary reactive shunt. In some respects the secondary e.m.f. can be seen to be proportional to the primary di/dt.

2.1.2. Earth CT inputs

Two CT's are used for the earth fault protection as shown in Figure 3.

The I_e input measures the neutral to earth current of the generator. The input is used for the stator earth fault protection function and as the polarising quantity for the sensitive directional earth fault function.

The $I_{residual}$ input measures the residual current at the line end of the generator. The input is used as the operating quantity for the sensitive directional earth fault function.

The input range for both CT's is up to 2.048xIn.

2.1.3. Neutral VT input

The neutral VT input V_e, shown in Figure 3, is used for the neutral displacement function and as a polarising signal for the sensitive directional earth fault function. Both functions require a sensitive measurement. The input range is therefore limited to 25.6V rms, to provide increased sensitivity for small signal levels.

2.1.4. Phase CT inputs

Three CT's are used to measure the phase currents, as shown in Figure 4. The measurements are used by the overcurrent and the negative phase sequence protection functions. The phase A current measurement is also used by the field failure protection function.

Additionally, if the three phase voltages collapse, the I_a input will be used by the frequency tracking algorithm.

The input range for the three phase CT's is up to 20.48xIn.

2.1.5. Sensitive A-phase CT input

A special A-phase current input, $I_{a\text{-}sensitive}$, is used by the reverse power and low forward power functions. The input is used, in conjunction with the V_{ab} input, to measure the A-phase active and reactive power. The input range is up to 1.024xIn. The smaller maximum input level allows the input to provide the required sensitivity to measure, accurately, small active power, even in the presence of a significant reactive power component.

2.1.6. Phase VT inputs

The LGPG111 provides four VT inputs for measuring the line voltages, as shown in Figure 4.

Two VT's are used for the measurement of the phase-to-phase voltages V_{ab} and V_{bc}. The measurements are used by the under and over voltage functions, the voltage dependent overcurrent function, and for frequency tracking. The V_{ab} voltage input is also used to derive the A phase-to-neutral voltage for the power and field failure protection functions.

Two other VT inputs are provided: $V_{ab\text{-}comparison}$ and $V_{bc\text{-}comparison}$. These inputs are used by the voltage balance function, for comparison with the protection VT inputs.

All four VT's are designed to have an input range of up to 204.8V rms.

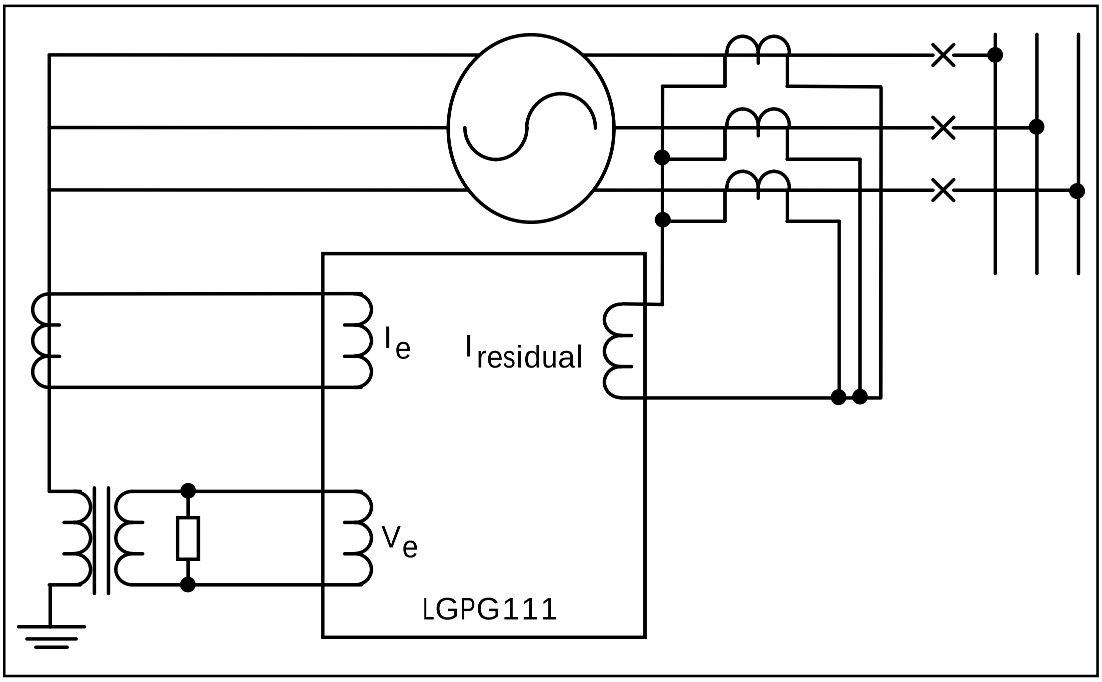


Figure 3 Earth fault protection - typical input connection.

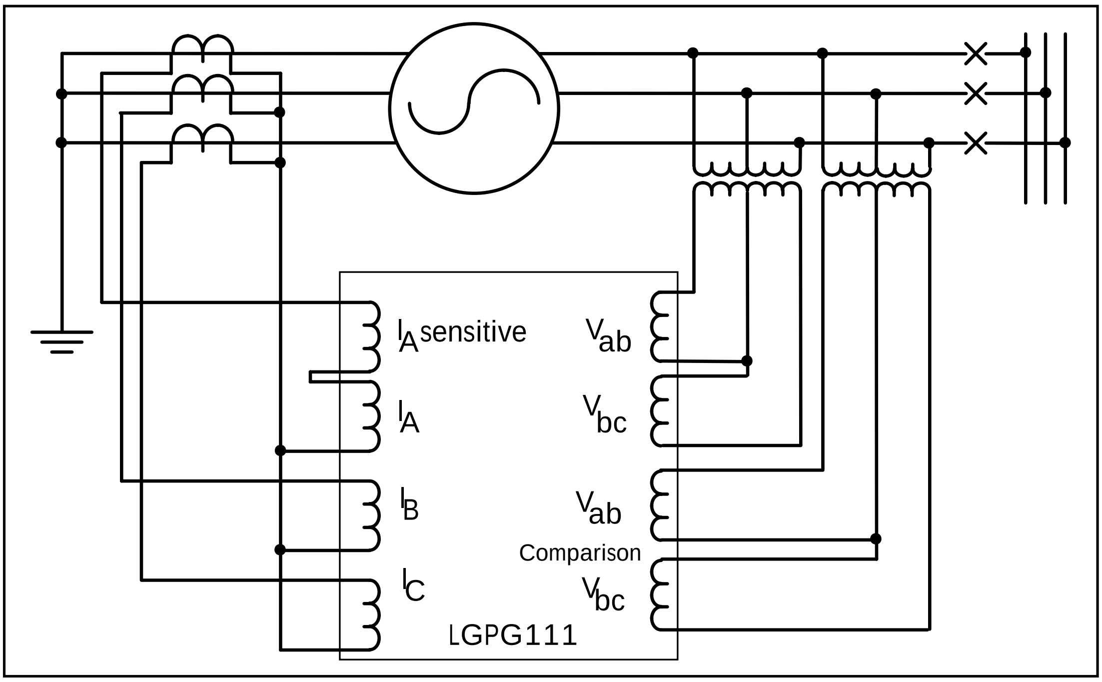


Figure 4 Phase currents and voltages - typical input connection.

2.2. Anti-aliasing filters

When an analogue signal is sampled at discrete time intervals, the original signal's content is preserved for up to half of the sampling frequency. Frequencies above this become aliased as lower frequencies because the frequency spectrum folds at half the sampling frequency. The effect of frequency aliasing or folding is for higher frequencies to impersonate lower ones and cause distortion. Prevention of aliasing is accomplished by band limiting the input signal, so that it has no significant frequency content above half the sampling frequency. Band limiting the frequency spectra of the input signal is achieved by using anti-aliasing filters.

With the exception of the transactor inputs, the relay's CT's and VT's have a constant frequency response, within the operating frequency range of 5Hz to 70Hz. The anti-aliasing filter used, for all these input signals, is a first-order passive low pass filter with a cut-off frequency at 132Hz.

The gain frequency response of a transactor is different from a CT, and increases with frequency. To compensate for this, the anti-aliasing filter is designed to attenuate increasingly the transactor's output, with respect to frequency. The combined effect produces a reasonably constant gain response, which allows the differential function to work accurately over the frequency range from 25Hz to 70Hz. The actual filter used is a 2-pole active low pass filter, with a cut-off frequency at 55 Hz.

2.3. Data sampling

All the input signals are sampled at a rate of 12 samples per cycle. This sampling rate provides a theoretical bandwidth of 6 times the fundamental. This is adequate for the extraction of the fundamental components, and provides a good bandwidth coverage for the disturbance waveform recording function.

The 17 input signals are sampled sequentially. Three multiplexers are used to multiplex the sampled signals to the signal conversion circuitry. Additionally, two reference DC levels, +5V and 0V, are available to each multiplexer. These act as voltage references for self-checking, which allows the microprocessor to test the analogue circuitry up to and including the multiplexers.

As mentioned earlier, all the current inputs are provided with gain switching to improve their resolution over a wide dynamic range. A simple technique is used to manage the gain switching. Each current input is sampled twice; at x1 and x8 gain, and stored in separate buffers. A peak detector is used to check the data with the x8 gain. If any of the last 12 samples exceeds 95% of the ADC saturation level, the data from the x1 gain is selected. This approach avoids the complexity of dynamically changing the gains during signal processing, and ensures consistent amplification for the one-cycle data window, used by the Fourier filter algorithm.

2.4. Fourier filtering

The input signals are processed using a 1-cycle Fourier filter. The purpose of the filter is to extract the fundamental frequency component of a signal in vector form.

The Fourier filter algorithm can be expressed as:

$$\mathrm{Is} = \frac{2}{N}\left[\sum_{n=1}^{N-1} \sin \omega n \Delta t \times i_n\right]$$

$$Ic = \frac{2}{N}\left[\frac{i_0}{2} + \frac{i_N}{2} + \sum_{n=1}^{N-1} \cos\omega n\Delta t \times i_n\right]$$

where N - Number of samples per cycle

ω - System angular frequency

i_n - Instantaneous value of signal i sampled at time $n\Delta t$

Is - Fourier sine integral of signal i

Ic - Fourier cosine integral of signal i

i_0 - Instantaneous value of signal i sampled at time 0

i_N - Instantaneous value of signal i sampled at time $N\Delta t$

If a signal at time t is expressed as $I\sin(\omega t + \phi)$, it can be shown that the Fourier sine and cosine components are a vector representation of the signal on the complex plane, i.e.,

$I \angle\phi = Is + jIc$

and

$Is = I\cos\phi$

$Ic = I\sin\phi$

For the LGPG111, the sampling rate is 12 samples per electrical cycle, i.e., N=12. Therefore, the corresponding Fourier equations are:

$$Is = \frac{1}{6}\left[\frac{1}{2}(i_1 + i_5 - i_7 - i_{11}) + \frac{\sqrt{3}}{2}(i_2 + i_4 - i_8 - i_{10}) + i_3 - i_9\right]$$

$$Ic = \frac{1}{6}\left[\frac{1}{2}(i_2 - i_4 - i_8 + i_{10}) + \frac{\sqrt{3}}{2}(i_1 - i_5 - i_7 + i_{11}) - i_6 + \frac{1}{2}(i_0 + i_{12})\right]$$

From the Fourier sine and cosine components, the magnitude and the phase quantities of a signal can be calculated. It is also possible to derive various power system quantities such as active and reactive power, and the sequence components. Some protection characteristics, such as the sensitive directional earth fault and field failure, can be implemented directly from the Fourier components of the relevant signals.

Figure 5 shows the frequency response characteristic of the 1-cycle Fourier filter. As shown in the Figure, the response of the Fourier filter to the 11th and the 13th harmonics is the same as the fundamental, due to the aliasing effect. The composite response of the Fourier filter together with the two types of anti-aliasing filters is shown in Figure 6. It can be seen that the effects of aliasing are very much reduced.

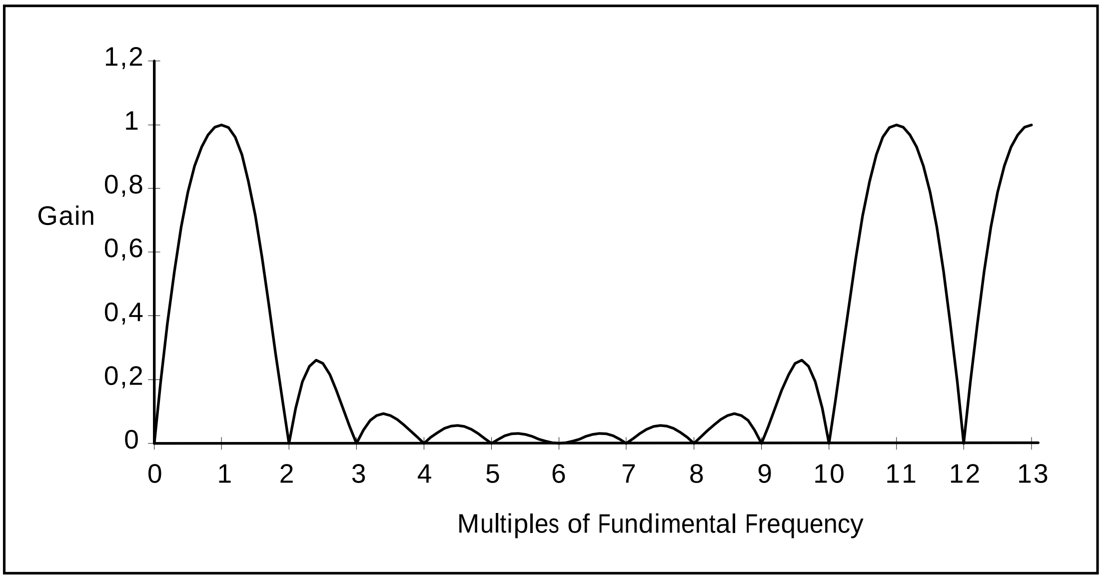
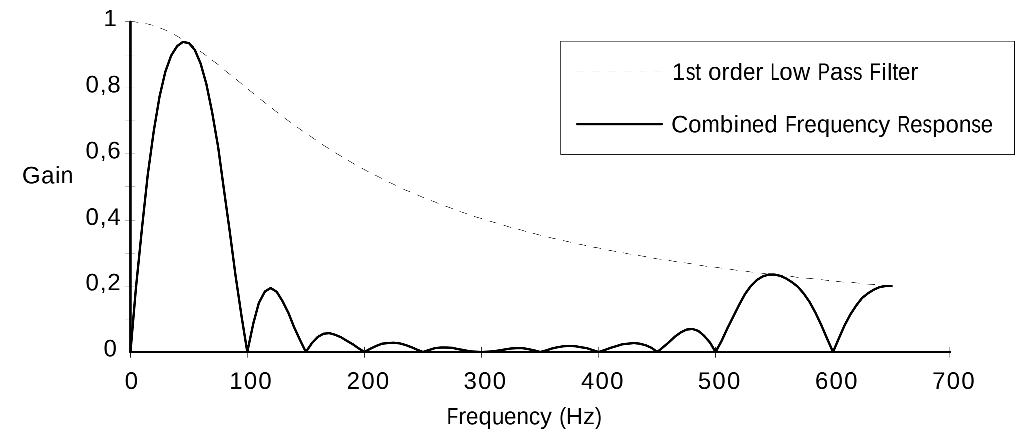
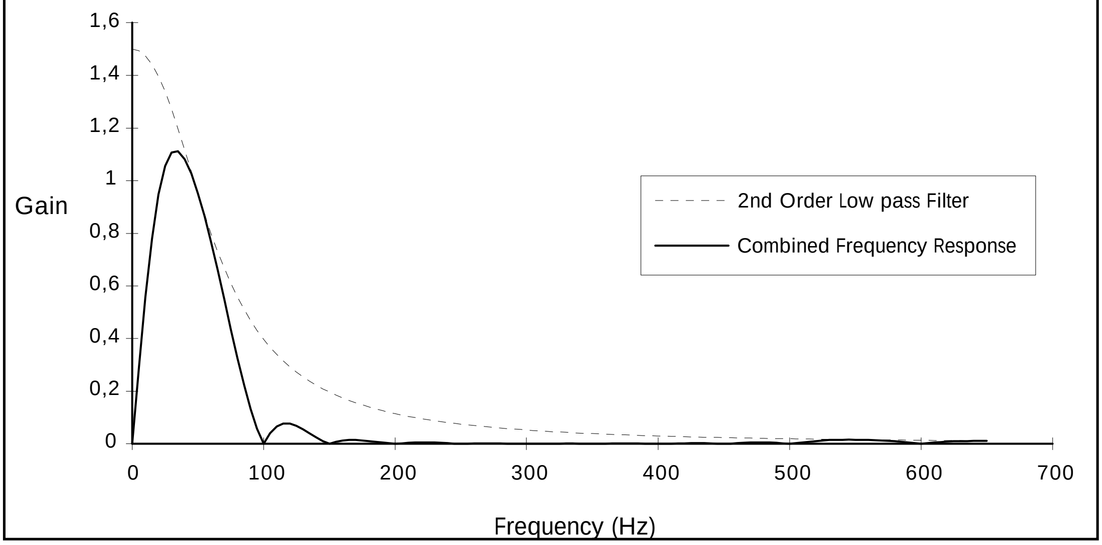


Figure 5 Characteristic of the 1-cycle Fourier Filter at 12 samples per cycle.



(a) Fourier filter and the 1st order low pass filter.



(b) Fourier Filter and the 2nd order low pass filter (for the transactor inputs only).

Figure 6 Composite frequency response of the Fourier filter and the anti-aliasing filters.

2.5. Magnitude approximation

The Fourier sine and cosine components of a signal can be converted into rms magnitude by evaluating a $\sqrt{\mathbf{I_s}^2 + \mathbf{I_c}^2}$ calculation. A direct implementation of this would be difficult to realise using an integer microprocessor, due to the squared root function. Therefore, a linear approximation technique is used, as follows:

Let:
u = max (Is, Ic)
v = min (Is, Ic)
then:

for	$u > 4v$	$\|I\| = 0.9950u+0.1225v$
for	$4v \geq u > 2v$	$\|I\| = 0.9398u+0.3476v$
for	$6v \geq 3u > 4v$	$\|I\| = 0.8518u+0.5264v$
for	$4v \geq 3u$	$\|I\| = 0.7559u+0.6560v$

This linear approximation technique introduces an error of -0.5% to +0.25% in the calculation.

2.6. Phase angle calculation

Using the Fourier components, it is possible to calculate the phase angle of the vector in the complex plane, by implementing the trigonometric $\tan^{-1}(Ic/Is)$ function. Again direct implementation is difficult. Instead, a look-up table technique is used to determine the angle. A table of conversion values from 0° to 45° is sufficient, and a total of 256 points is used to provide a resolution of 0.18°. The calculation needs to determine which of the eight 45° sectors the vector is positioned in, to produce the actual phase angle.

In the LGPG111, the phase angle calculation is not used directly by any of the protection functions. For those protection characteristics which are phase angle dependent, they are realised directly from the Fourier components. This avoids unnecessary processing of phase angles with the possible introduction of further errors.

The phase angles of V_{ab}, V_{bc} and I_a are calculated and used by the frequency tracking algorithm. Additionally, the relative phase difference between $I_{a\text{-sensitive}}$ and V_{ab} is calculated and provided as a measurement.

2.7. Frequency tracking

The LGPG111 is designed to work over a wide frequency range, from 5Hz to 70Hz. To achieve this, it is necessary to lock the sampling rate, at 12 samples per cycle, with the power system frequency. This ensures the frequency response of the Fourier filter, and hence the relay's performance, is constant over the specified frequency range. The frequency tracking also provides frequency measurement for the protection functions.

If the sampling frequency, f_{samp}, is exactly 12 times the power system frequency, f_{sys}, the vector of the tracking signal, derived using Fourier techniques, should rotate on the complex plane with an angular velocity of $2\pi f_{sys}$. If the phase angle of the vector is calculated once every cycle, i.e., $12/f_{samp}$, the result of the calculation should be the same from one cycle to the next. In other words, the rotating vector is expected to return to its original position after one cycle. Any angle deviation will indicate that there is a mismatch in the sampling frequency and the system frequency.

Let

$$\Delta\phi = \phi_{\mathbf{measured}} - \phi_{\mathbf{expected}}$$

Then, it can be shown that

$$\mathbf{f_{sys}} = \frac{\mathbf{f_{samp}}}{\mathbf{12}} + \frac{\Delta\phi}{\mathbf{2\pi t_s}}$$

Where t_s is time interval over which $\Delta\phi$ is measured. For angle calculations performed once every cycle, t_s equals $12/f_{samp}$.

There are two cases of mismatch in the two frequencies, on the complex plane, as shown in Figure 7. If $\Delta\phi$ is positive, it indicates that the system frequency has increased. If $\Delta\phi$ is negative, it indicates that the system frequency has decreased. The change in system frequency is proportional to the $\Delta\phi$ calculated. After the frequency measurement has been calculated, the sampling clock is then adjusted to minimise $\Delta\phi$.

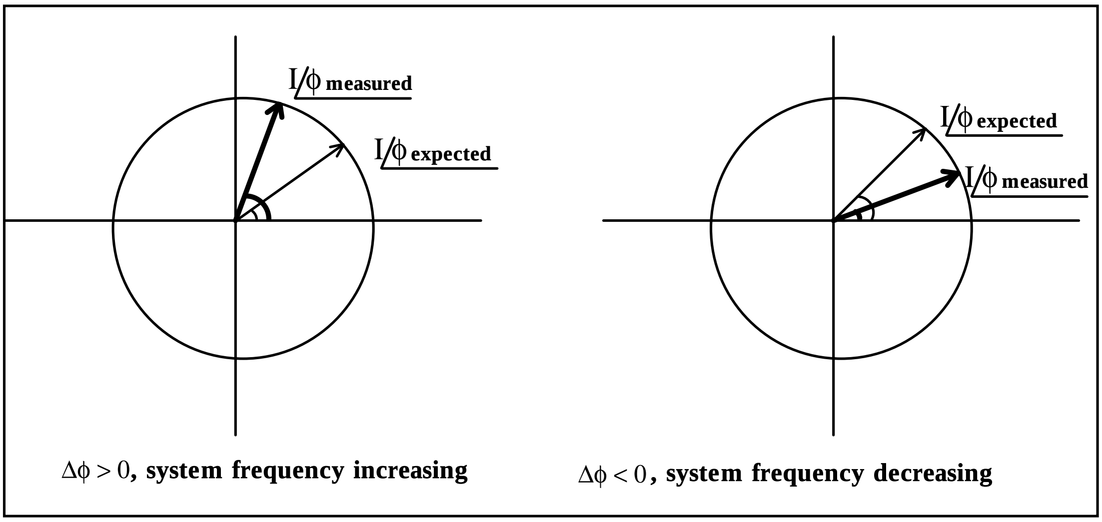


Figure 7 Angle deviation caused by frequency mismatch during frequency tracking

Using this method, the range of frequencies which the relay can track is limited from -½($f_{samp}/12$) to +½($f_{samp}/12$). For example, if the frequency setting of the relay is set at 50Hz, the theoretical tracking range is from 25Hz to 75Hz only. To track beyond this range, a zero-crossing technique is also implemented to complement the tracking algorithm. This is applied, when the relay is initially set up at nominal frequency, to track to a low frequency condition such as when the generator is running up.

The frequency tracking algorithm uses one of three possible inputs as the reference source. Initially the algorithm checks the V_{bc} input, followed by the V_{ab} and I_a inputs until a suitable signal to track is found. If the tracking signal fails, the algorithm will automatically switch to the next best input, with the voltage inputs taking preference over the current input. The minimum tracking threshold for the voltage signals is 7V, and 0.05×In for the current signal. When all three signals fail, the relay assumes a ‘no input’ situation and automatically disables the under voltage, under frequency and low forward power protection functions.

2.8. Error compensation

Apart from errors due to analogue to digital conversion, as mentioned earlier, there are other types of error conditions related to the signal conditioning for which software compensation techniques are used. These errors are:

1. Component tolerance errors in the analogue input circuitry. These consist of errors from the input transformers, the anti-aliasing filters, the sample and hold amplifier and the ADC internal voltage reference. An overall error of up to ±3% can be introduced.
2. Phase error due to sampling delay between channels. A sampling delay of 20µs is introduced between channels to allow time for data acquisition. This produces a phase error of 0.36° at 50Hz (0.43° at 60 Hz) between channels. Such an angular error, although small, can introduce significant errors in those functions where phase accuracy is important, such as negative phase sequence and power functions.
3. Frequency response of the analogue input circuitry. Since the LGPG111 has a wide frequency operating range, the frequency response of the input transducers and the low pass filters will affect the accuracy of the relay over the range.

The first two types of error are compensated using a software calibration procedure during production. In-phase voltage and current signals of specified magnitudes are applied to the relay inputs. With the relay in a special calibration mode, it samples the input signals and stores the data into disturbance records. The records are uploaded into a PC, which computes the magnitude and phase errors produced by the relay's measurement elements. These errors are transformed into compensation vectors which are stored in the non-volatile memory in the Analogue and Status Input Module. By multiplying the measured vector components of each signal with a corresponding compensation vector, the relay is able to compensate for both the component tolerance and the sampling delay.

Comparing with hardware calibration techniques, using trimpots for example, this software calibration procedure simplifies the production process and produces more reliable and accurate results. Errors caused by the sampling delay, which cannot be calibrated easily using hardware methods, can now be compensated.

The third type of error is compensated for by having a look-up table of magnitude correction factors versus frequency. For a given frequency, the relay will select the appropriate correction factor to compensate for the frequency response of the analogue input circuitry. This table is determined at the design stage.

The compensation vector, $\overline{F}$, can be expressed in complex form as:

$$\overline{F} = K(\cos(\delta\phi) + i\sin(\delta\phi))$$

Where K is the magnitude calibration factor, and $\delta\phi$ is the phase calibration angle.

The look-up table of magnitude correction factors versus frequency is represented by the function M(f).

An analogue input, , is calibrated by multiplying by and M(f) to produce the calibrated output, $\overline{I'}$:

$$\overline{I'} = \overline{I} \times \overline{F} \times M(f)$$

3. PROTECTION FUNCTIONS

3.1. Generator differential (87G)

3.1.1. General description

The generator differential function is a low impedance biased scheme with a dual slope bias characteristic. The lower slope provides sensitivity for internal faults, whereas the higher slope provides stability under through fault conditions, during which there may be transient differential currents due to saturation effects of the generator CT's.

To achieve fast fault clearance, the differential protection is executed at approximately every 5ms, which is four times more often than the other protection functions. Two consecutive calculations are required to confirm a differential condition. This, together with the fault inception time, produces an operating time of typically less than 30ms.

3.1.2. Bias current calculation

The function works on a per phase basis with one bias (I_{bias}) and one differential current input (I_{diff}) per phase, as discussed in Section 2.1.1, page 8. The second bias current is derived from these two measurements vectorially:

$$\overline{\mathbf{I_{bias'}}} = \overline{\mathbf{I_{bias}}} - \overline{\mathbf{I_{diff}}}$$

The mean bias current ($\mathbf{I_{mean-bias}}$) is the scalar mean of $\overline{\mathbf{I_{bias}}}$ and $\overline{\mathbf{I_{bias'}}}$.

$$\mathbf{I_{mean-bias}} = \frac{\left|\overline{\mathbf{I_{bias}}}\right| + \left|\overline{\mathbf{I_{bias'}}}\right|}{\mathbf{2}}$$

To provide further stability for external faults, the bias quantity used for each phase is the maximum mean bias current calculated from all three phases, i.e.,

$$I_{mean-bias-max} = Max\left(I_{a-mean-bias}, I_{b-mean-bias}, I_{c-mean-bias}\right)$$

3.1.3. Settings and protection characteristic

The settings provided by the function are as follows:

Is1- Differential current threshold.
Is2- Threshold for increasing the percentage bias.
K1- Percentage bias for Imean-bias-max ≤ Is2.
K2- Percentage bias for $I_{mean-bias-max}$ > Is2.

The tripping criteria are formulated as follows:

1. For $I_{mean-bias-max} \leq Is2$
   $I_{diff} > K1 x I_{mean-bias-max} + Is1$

2. For $I_{mean-bias-max} > Is2$
   $I_{diff} > K2 x I_{mean-bias-max} - Is2 x (K2 - K1) + Is1$

The characteristic is shown in Figure 8.

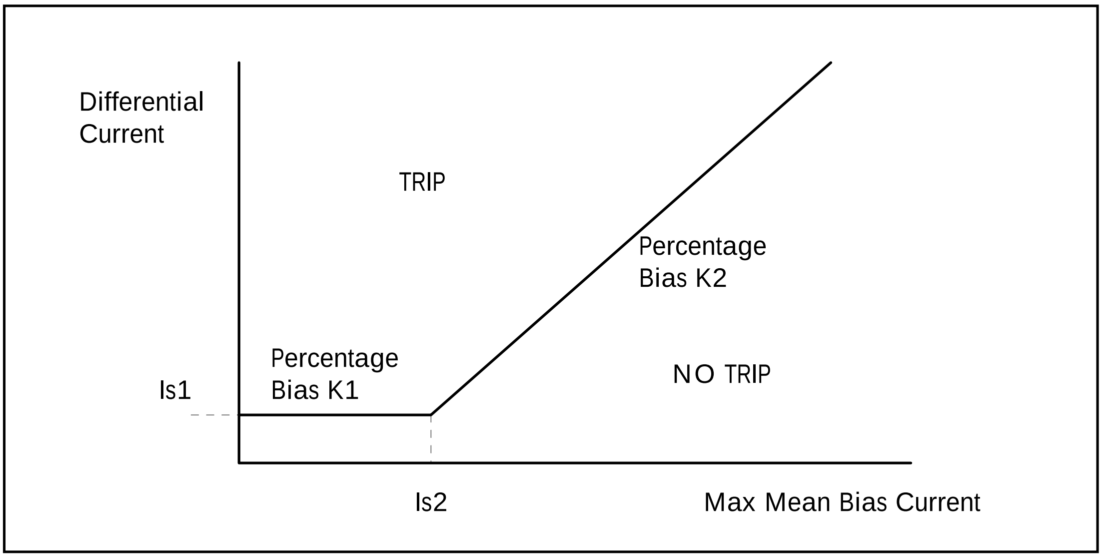


Figure 8 Generator differential biased characteristic.

The recommended settings, as explained in the Application Notes, are shown below.

Is1 = 0.05xIn
K1 = 0%
Is2 = 1.2xIn
K2 = 150%

3.2. Stator earth fault (51N)

3.2.1. General description

The stator earth fault protection function uses current from the I_e input as the operating quantity. The function consists of a low set element and a high set element. The low set element can be set to either a standard inverse or a definite time characteristic. The high set element has a definite time characteristic which can be set to instantaneous. Both elements are inherently immune to third harmonic currents, due to the response of the Fourier filter.

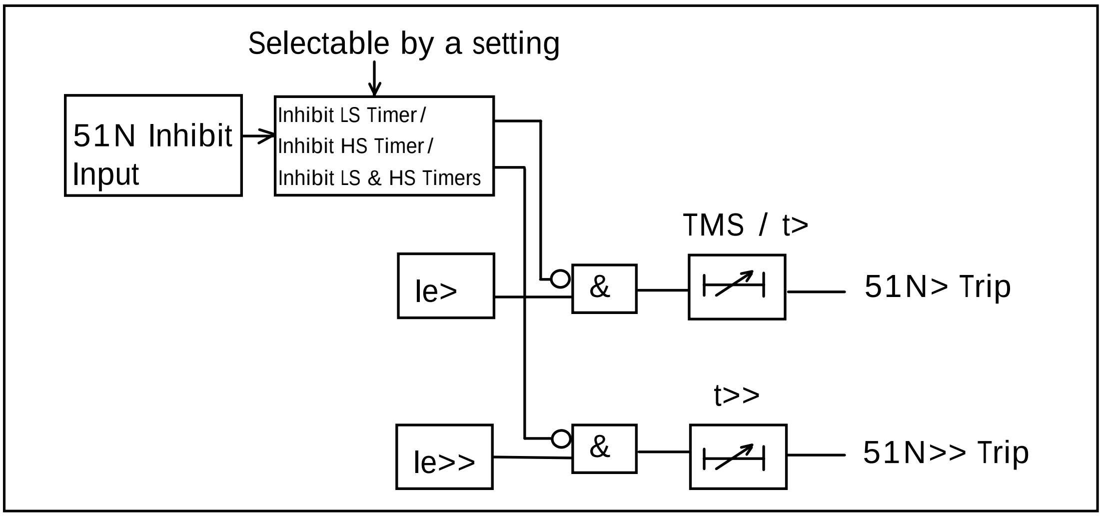


Figure 9 Logic of the 51N inhibit input.

A logic input, 51N Inhibit, is available to inhibit the low set timer, the high set timer, or both. A setting is provided to conFigure this. When the input is energised, it will force the selected timer(s) into reset mode. The logic is shown in Figure 9.

The low set element is also provided with an adjustable timer hold facility which is explained in Section 3.12.

3.2.2. Settings and protection characteristic

The settings provided by this function are as follows:

51N> Low set:

Characteristic	-	Selection for either standard inverse or definite time characteristic.
Ie>	-	Threshold setting for the low set element.
t>	-	Definite time delay, for use if definite time characteristic is selected.
TMS	-	Time multiplier setting, for use if the standard inverse is selected.
tRESET	-	Reset time for the timer hold.

51N>> High set:

Ie>>	-	Threshold setting for the high set element.
t>>	-	Definite time setting for the high set element.

The setting for configuring the function of the 51N inhibit input is located in the Auxiliary Functions Section of the menu:

Stator EF Timer Inhibit	-	Selection for inhibiting the low set element timer, the high set element timer, or both timers.

The standard inverse timing characteristic is defined as:

$$t = TMS \times \frac{0.14}{(I / Ie>)^{0.02} - 1} \text{ seconds}$$

The ADC saturates at 2.048xIn which results in the composite timing characteristic of Figure 10.

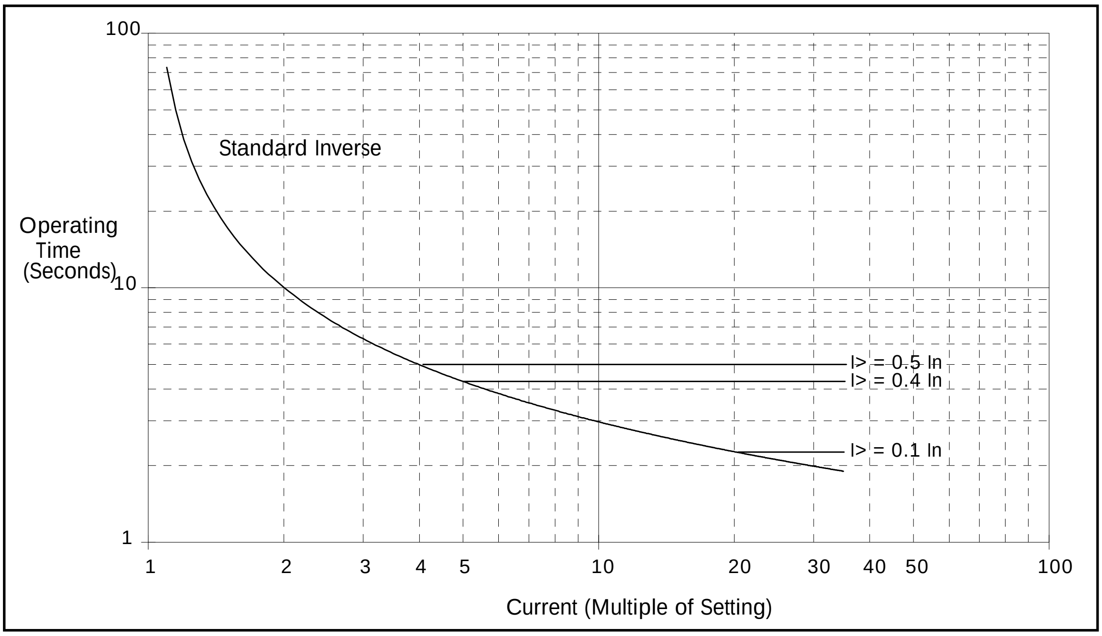


Figure 10 Stator earth fault low set element standard inverse timing characteristic.

3.3. Neutral displacement (59N)

3.3.1. General description

The neutral displacement protection function is voltage operated from the V_e input. Two definite time outputs are provided. The function is inherently immune to third harmonic components due to the Fourier filter.

An adjustable timer hold facility is available for the second timer output, as explained in Section 3.12.

3.3.2. Settings and protection characteristic

The settings provided are as follows:

Ve> - Neutral voltage threshold.

t1 - Timer 1 setting.

t2 - Timer 2 setting.

t2RESET - Reset time for the timer hold. Applied to timer 2 output only.

The characteristic is illustrated in Figure 11.

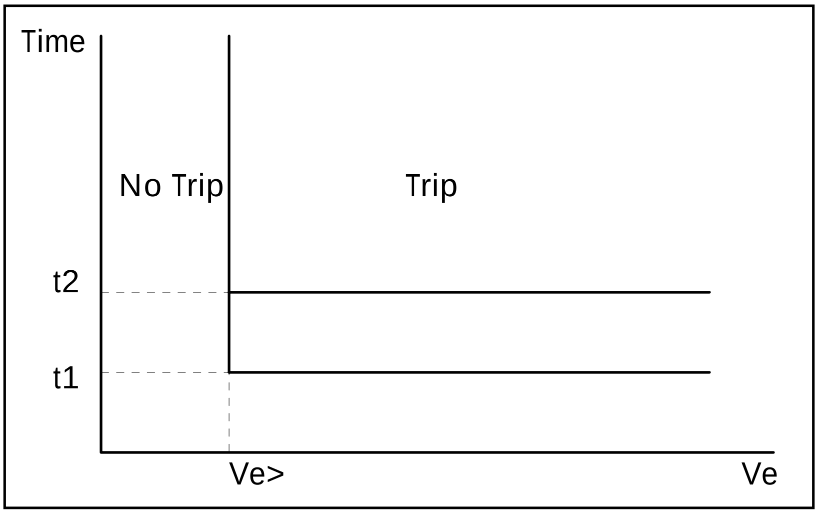


Figure 11 Neutral displacement characteristic.

3.4. Sensitive directional earth fault (67N)

3.4.1. General description

The sensitive directional earth fault protection is dual polarised. The operating quantity is the residual current signal, $I_{residual}$. The polarising quantity is either the voltage signal V_e, or a current signal I_e. If the polarising voltage is not available, then the polarising current is used. The function is inherently immune to third harmonic components, due to the Fourier filter. A relay characteristic angle (RCA) is provided which is only applied when V_e is used as the polarising signal.

The function is instantaneous in operation. The directional calculation is evaluated approximately every 20ms. Two consecutive calculations are required to confirm a relay operation. This produces an operating time of typically less than 65ms.

3.4.2. Settings and protection characteristic

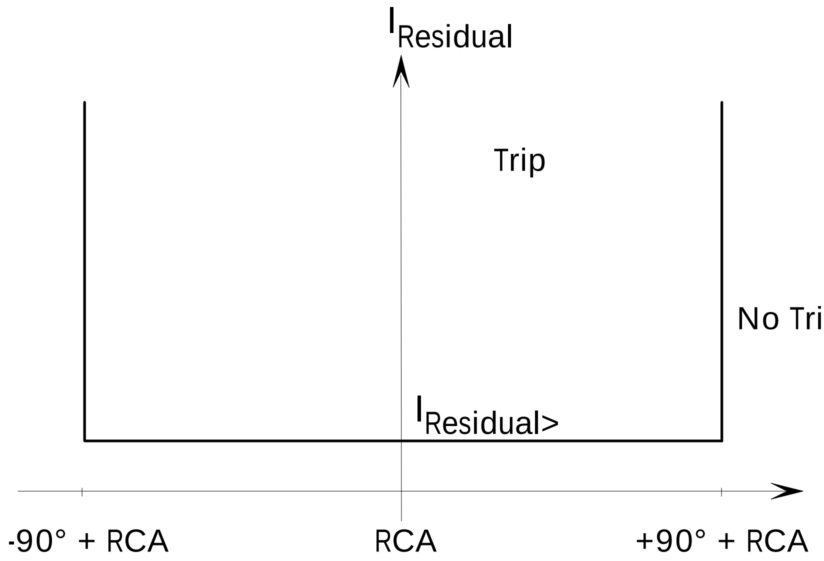
The settings provided by this function are as follows:

Iresidual>	-	Residual current threshold. Used as the operating quantity.
RCA	-	Relay characteristic angle. Applied only to the V_e polarising quantity.
Vep>	-	Threshold for the neutral voltage polarising quantity.
Iep>	-	Threshold for the neutral current polarising quantity.

The tripping criteria are as follows. All three criteria must be satisfied for the relay to operate.

1. V_e > (Ve>) or I_e > (Ie>)
2. $I_{residual}$ > (Iresidual>)
3. $|\phi I_{residual} - \phi V_e - RCA| < 90°$ (If voltage polarised)
   $|\phi I_{residual} - \phi I_e| < 90°$ (If current polarised)

The characteristic is shown in Figure 12.



Note: The horizontal axis represents the angle of the operating quantity with respect to the polarising quantity. The RCA setting applies to Ve polarising only. For Ie polarising the RCA is 0°.

Figure 12 Characteristic of the Sensitive Directional Earth Fault function.

3.5. Voltage dependent overcurrent (51V)

3.5.1. General description

The voltage dependent overcurrent is a three-phase function used for system back-up protection. The current signals are the three phase currents from the I_a, I_b and I_c inputs. The voltage signals are from the V_{ab} and V_{bc} inputs. V_{ca} is derived from V_{ab} and V_{bc} by the following formula:

$$\overline{V_{ca}} = -\left(\overline{V_{ab}} + \overline{V_{bc}}\right)$$

The voltage dependent characteristic can be either voltage controlled or voltage restrained. Voltage vector transformation is also provided for generators connected to the busbar by a delta-star step-up transformer, as explained later. Without voltage vector transformation, the voltage quantity V used for the voltage dependent characteristic of the individual element is as follows:

For I_a element, $V = V_{ab}$

For I_b element, $V = V_{bc}$

For I_c element, $V = V_{ca}$

For applications which do not require a voltage dependent characteristic, a simple overcurrent function can be selected.

The voltage controlled overcurrent function allows the timing characteristic to be changed from a load characteristic to a more sensitive fault characteristic when the voltage drops below a set level. The voltage restrained overcurrent function allows the current pick-up level to be proportionally lowered as the voltage falls below a set value. This results in an infinite number of timing characteristics.

The timing characteristic can either be standard inverse or definite time. An adjustable timer hold facility is available with this function, as explained in Section 3.12.

A logic input, 51V Inhibit, is provided, which will reset all the overcurrent timers when energised. The logic is shown in Figure 13.

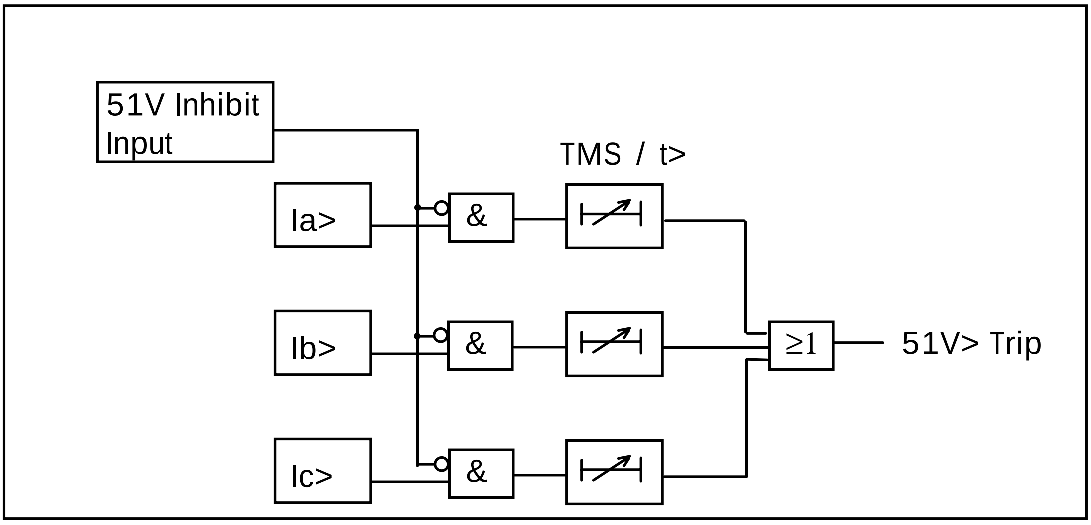


Figure 13 The ’51V Inhibit’ input to reset the overcurrent timers.

3.5.2. Settings and protection characteristic

The settings provided by this function are as follows:

Function	-	Selection for voltage restrained, voltage controlled, or simple overcurrent.
Voltage vector Rotate	-	Selection for either *None* (i.e., no vector rotation) or *Yd* (i.e., vector rotation for delta-star step-up transformer).
Vs1	-	First voltage threshold setting for voltage restrained overcurrent.
Vs2	-	Second voltage threshold setting for voltage restrained overcurrent.
Vs	-	Voltage threshold setting for voltage controlled overcurrent.

K	-	Constant for the voltage controlled or restrained overcurrent.
Characteristic	-	Selection for either standard inverse or definite time characteristic.
I>	-	Overcurrent threshold setting.
t	-	Definite time setting, if definite time characteristic is selected.
TMS	-	Timer multiplier setting, if standard inverse is selected.
tRESET	-	Reset timer setting for the timer hold facility.

The effect of the voltage level on the current pick-up level for both operating modes is as follows. The characteristics are illustrated in Figure 14.

The current pick-up level for the voltage controlled function is:

1. I> for $V > Vs$
2. K.I> for $V \le Vs$

The current pick-up level for the voltage restrained function is:

1. I> for $V > Vs1$
2. $K.I> + \dfrac{I> - K.I>}{Vs1 - Vs2}(V - Vs2)$ for $Vs2 \le V \le Vs1$
3. K.I> for $V < Vs2$

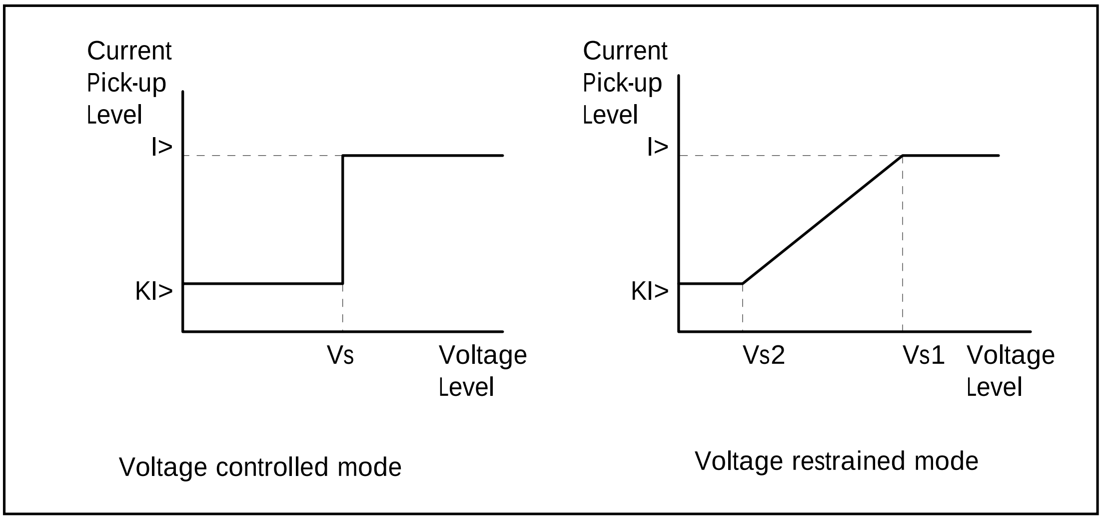


Figure 14 Voltage dependent overcurrent pick-up characteristic.

The standard inverse characteristic is:

$$t = TMS \times \frac{0.14}{(I/I>)^{0.02} - 1} \text{ seconds}$$

Since the ADC saturates for currents above 20.48xIn, the inverse timing characteristic is a composite, as illustrated in Figure 15.

3.5.3. Voltage vector transformation

If a generator is connected to a busbar through a delta-star step-up transformer, a solid phase-to-phase fault on the busbar will only result in partial phase-to-phase voltage collapse at the generator terminals. The voltage dependent overcurrent function (51V) may not be sensitive enough to detect such faults. On the other hand, a phase-to-earth fault on the HV side would yield a low phase-to-phase voltage on the delta side, and the 51V may respond inappropriately. Such faults should be dealt with by the HV standby earth fault protection.

In order for the voltage dependent overcurrent function to co-ordinate correctly with other relays on the system, where there is a delta-star step-up transformer, an internal voltage vector transformation feature is provided. This allows the 51V to make use of derived voltages with the same phase-phase relationship as the HV side voltages.

If the *Yd* option is selected for the *Voltage Vector Rotate* setting, the voltage dependencies for the three overcurrent elements are as follows. Note that these quantities apply to both Yd1 and Yd11 step-up transformers.

For I_a element, $\varsigma = \left|\left(\overline{V_{ab}} - \overline{V_{ca}}\right)\right| / \sqrt{3}$

For I_b element, $V = \left|\left(\overline{V_{bc}} - \overline{V_{ab}}\right)\right| / \sqrt{3}$

For I_c element, $V = \left|\left(\overline{V_{ca}} - \overline{V_{bc}}\right)\right| / \sqrt{3}$

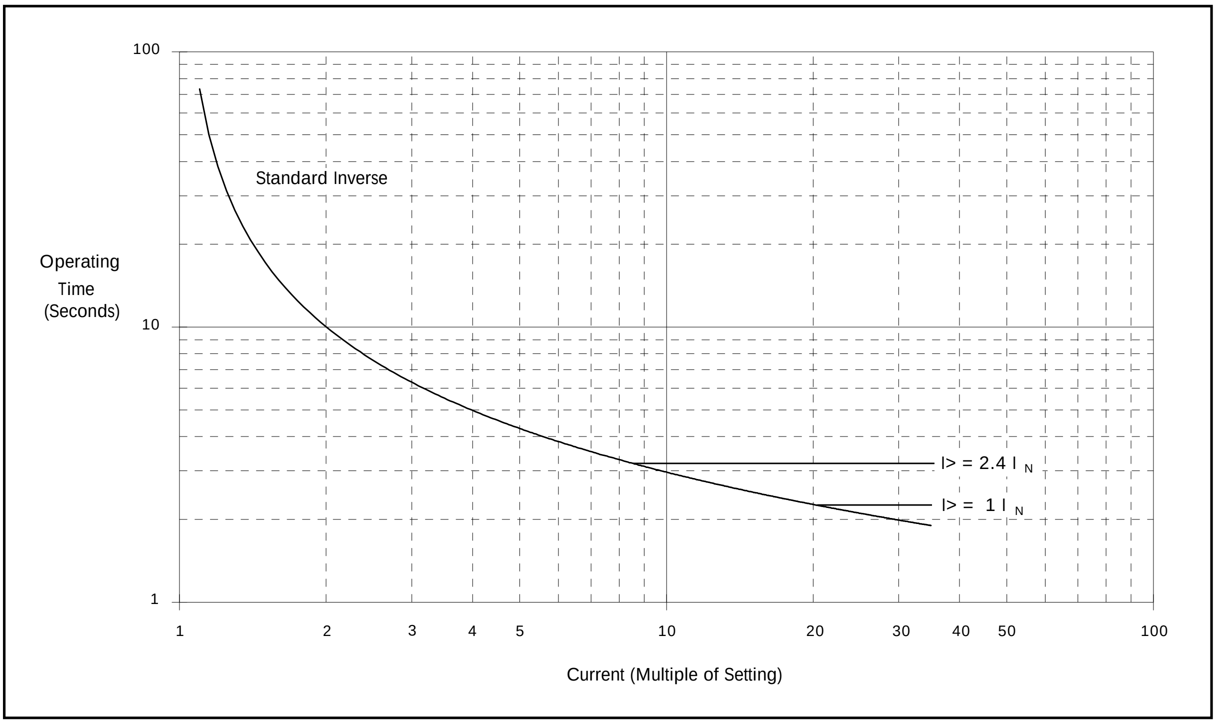


Figure 15 Voltage dependent overcurrent standard inverse timing characteristic.

3.6. Reverse power and low forward power (32R & 32L)

3.6.1. General description

Both power functions calculate the A phase active power $V_a x I_a x\cos\phi$, where ϕ is the angle of $\overline{\mathbf{I_a}}$ with respect to $\overline{\mathbf{V_a}}$. The quantity $\overline{\mathbf{V_a}}$ is derived from the $\overline{\mathbf{V_{ab}}}$ measurement, scaled by √3 and phase-shifted by -30°. The quantity $\overline{\mathbf{I_a}}$ is obtained from the $I_{a\text{-sensitive}}$ input. This dedicated current input is designed to provide the required sensitivity for the power protection functions.

A compensation angle, θcomp, can be used to compensate for the phase angle error of the generator's CT with respect to the VT. A -5° to +5° compensation is possible, in 0.1° steps. The setting shifts the voltage vector according to the following formula:

$$\overline{V_a} = \frac{\overline{V_{ab}}}{\sqrt{3}} \times 1\angle(-30°+\theta comp)$$

An integrating timing arrangement is available with both power functions, the logic of which is discussed in Section 3.13., page 34.

3.6.2. Settings and characteristic

The settings provided by both functions are as follows:

Compensation angle

(θcomp) - Compensation angle setting, applied to both reverse power and low forward power functions.

Reverse power 32R

-P> - Reverse power threshold.

t - Timer setting.

tDO - Delayed drop-off timer for integrated timing

Low forward power 32L

P< - Low forward power threshold.

t - Timer setting.

tDO - Delayed drop-off timer for integrated timing.

The criterion for operation of the reverse power is:

$$V_a \times I_{a-\text{sensitive}} \times \cos(180-\phi) > (-P>)$$

The criterion for operation of the low forward power is:

$$V_a \times I_{a-\text{sensitive}} \times \cos(\phi) < (P<)$$

The characteristics of both functions are shown in Figure 16.

If $I_{a\text{-sensitive}}$ is greater than 1.05xIn, then both functions will be blocked from operation. This is to prevent any internal saturation effects from affecting the stability of the functions due to their sensitive angular accuracy requirements.

This overcurrent blocking feature, together with the setting of the relay, will determine the angular boundary of the reverse power function, as shown in Figure 17. If this angular boundary is expressed as the angle α between $\overline{\mathbf{I_{a-sensitive}}}$ and $-\overline{\mathbf{V_a}}$, then α is given by the equation

$$\alpha = 90 - \sin^{-1}\left(\frac{(-P>)}{1.05 \times V_a}\right) \times \frac{180}{\pi}$$

For small angles from the horizontal axis, $\mathbf{sin^{-1}}\,\theta \approx \theta$. The equation then becomes

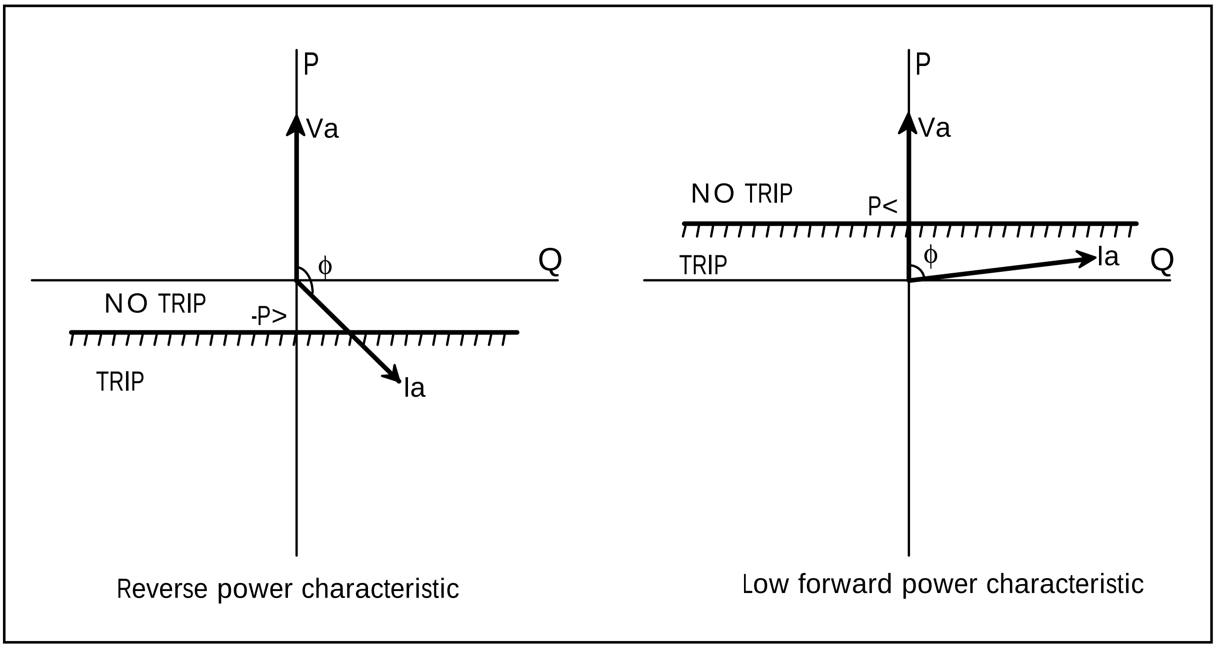


Figure 16 Reverse power and low forward power relay characteristics

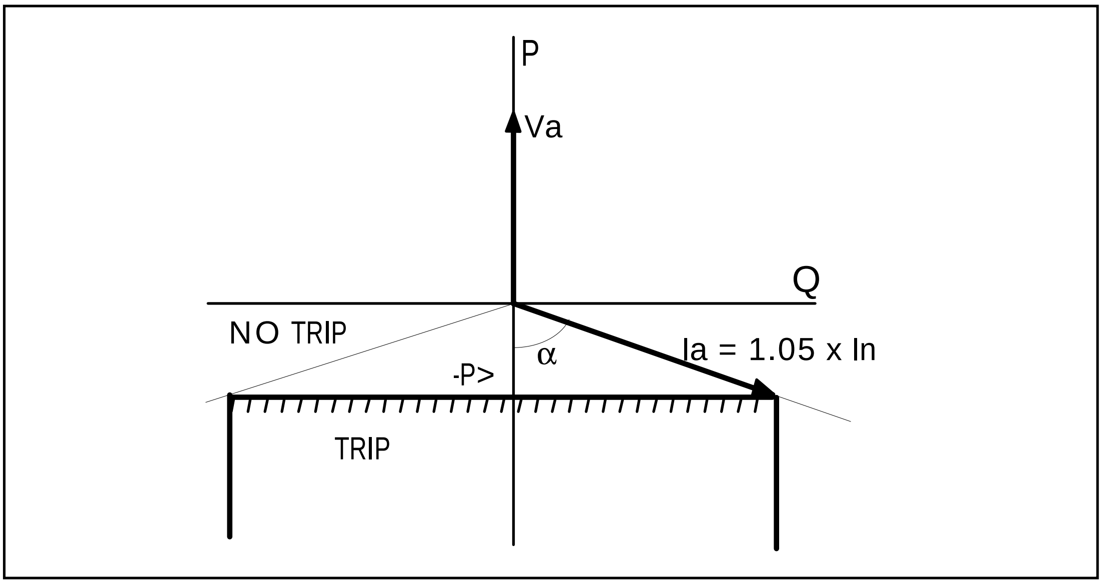


Figure 17 Angular boundary for the reverse power function.

$$\alpha = 90 - \frac{(-P>) \times \sqrt{3} \times 180}{1.05 \times V_{ab} \times \pi}$$

The angular boundary is therefore dependent on the setting -P> and on V_{ab}. If V_{ab} is maintained at the nominal voltage of, say, 100V, the angular boundary for -P> = 0.3W is ±89.7°, and when -P> = 1W, it is ±89.1°.

3.7. Negative phase sequence thermal protection (46)

3.7.1. General description

The negative phase sequence protection function provides a thermal replica characteristic which can be set to closely match the negative phase sequence withstand characteristic of the protected generator. The implementation of the thermal characteristic allows for pre-fault heating of the machine, due to standing negative phase sequence current, present under normal healthy running conditions, to be simulated.

A separate definite time negative phase sequence overcurrent alarm element is also provided, which can be set to be more sensitive than the thermal function. The alarm element can be used to provide a warning about unreasonable unbalanced load conditions.

The negative phase sequence component of the three phase currents is derived by the formula:

$$\mathbf{I_2} = \frac{\left|\overline{\mathbf{I_a}} + \mathbf{a^2} \times \overline{\mathbf{I_b}} + \mathbf{a} \times \overline{\mathbf{I_c}}\right|}{\mathbf{3}}$$

where a is $1\angle 120°$.

3.7.2. Settings and characteristic

The settings provided by this function are as follows:

Thermal trip element:

I2>> - The I_2 threshold for the thermal trip element. Normally set to the maximum negative phase sequence withstand of the generator.

K - Thermal capacity constant (heating), equivalent to the generator's short-time $I_2{}^2t$ withstand ability. Defines the rate of heating.

Kreset - Thermal capacity constant (cooling). Identical to K, but defines the rate of cooling for the thermal characteristic. Normally set equal to K.

TMAX - Maximum operating time.

tMIN - Minimum operating time.

Alarm element:

I2> - I_2 threshold for the alarm element.

t - Definite time setting.

The LGPG111 negative phase sequence tripping function is a true thermal replica characteristic which takes into account heat dissipation, and also the effects of standing low level negative phase sequence currents. The thermal characteristic also caters for cooling due to a reduction in I_2, with an independent cooling time constant.

The relay thermal replica model can be expressed as:

$$\frac{\theta_{new}}{\theta_s} = \frac{\theta_{old}}{\theta_s} + \left(\left(\frac{I_2}{I2>>}\right)^2 - \frac{\theta_{old}}{\theta_s}\right) \cdot \left(1 - e^{-\left(\frac{t \cdot I2>>^2}{K'}\right)}\right)$$

Where:

I2>>	is the maximum I_2 withstand of the machine in per unit quantity.
I_2	is the measured per unit negative phase sequence current.
θ_s	is the temperature (°C) attained when I_2=I2>>.
θ_{old}/θ_s	is the initial per unit temperature due to a previous negative phase sequence current.
θ_{new}/θ_s	is the new per unit temperature due to the applied I_2.
t	is the duration in seconds for the thermal replica to attain $\theta_{\mathbf{new}}$ from $\theta_{\mathbf{old}}$, due to the present I2 applied. The maximum temperature measurable by the relay is 10 p.u.
K'	is the thermal capacity constant in seconds. When the temperature is increasing the relay setting K is used, otherwise the relay setting Kreset is used. Normally both K and Kreset are set equal to the machine's negative phase sequence thermal capacity.

The relay trips when θ reaches $\theta_{\mathbf{s}}$. If there is no pre-fault heating, i.e., the initial per unit temperature $\frac{\theta_{old}}{\theta_s}$ is 0, and the above formula becomes

$$1 = \left(\frac{I_2}{I2>>}\right)^2 \cdot \left(1 - e^{-\left(\frac{t \cdot I2>>^2}{K'}\right)}\right)$$

The operating time can then be derived as

$$t = -\frac{K}{I2>>^2} \cdot \ln\left(1 - \left(\frac{I2>>}{I_2}\right)^2\right)$$

The operating time can be approximated to t = K/I_2^2, when I_2 is above four times the I2>> threshold.

When high values of K are selected and the negative phase sequence current measured is near to the threshold, the operating time may be too slow. In this case, a maximum time setting, tMAX, is available to provide a safe trip time.

Conversely, when I_2 is considerably above the I2>> threshold, the operating time may become too fast and cause incorrect discrimination with other overcurrent relays under fault conditions. To counter this, the inverse characteristic changes into a definite minimum time characteristic. The change-over point is defined by the minimum time setting tMIN.

The characteristic is as shown in Figure 18.

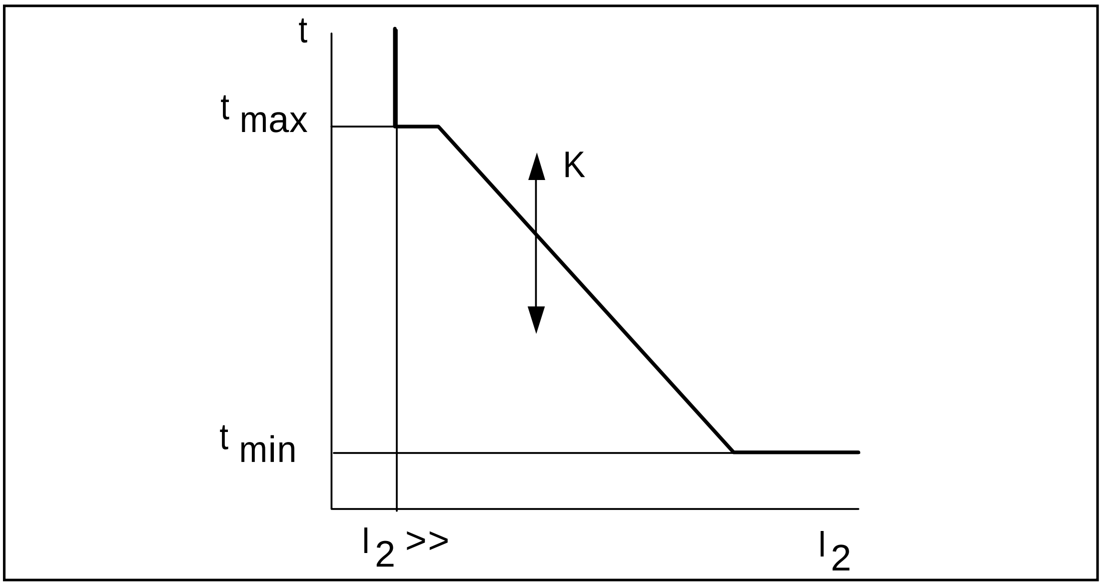


Figure 18 Negative Phase Sequence Thermal characteristic.

3.8. Field failure (40)

3.8.1. General description

The field failure protection function consists of an impedance measuring element with an offset mho characteristic. The centre of the mho circle lies on the negative reactive axis of the impedance plane. The measuring input quantities are I_a and V_a. The V_a quantity is derived from the V_{ab} input phase shifted by -30°, i.e.,

$$\overline{\mathbf{V_a}} = \frac{\overline{\mathbf{V_{ab}}}}{\sqrt{3}} \times \mathbf{1}\angle - \mathbf{30}^\circ$$

An integrating timing feature is provided for this function. The logic of the integrating timing is discussed in Section 3.13.

3.8.2. Settings And Characteristic

The settings provided by this function are as follows:

-Xa	-	Negative reactive offset of the circle from the origin of the impedance plane.
Xb	-	Diameter of the circle.
t	-	Timer setting.
tDO	-	Delayed drop-off timer for integrated timing.

The characteristic is illustrated in Figure 19.

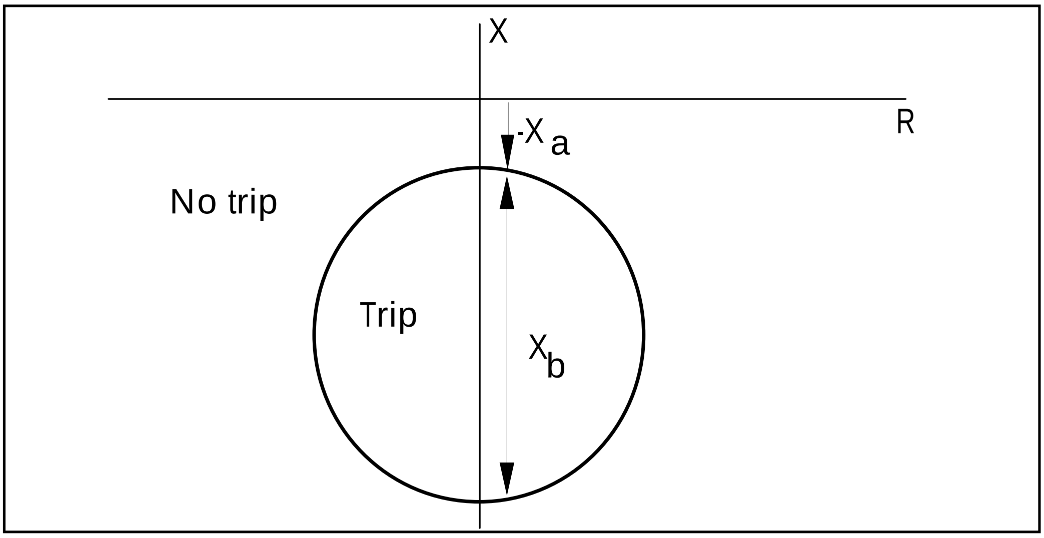


Figure 19 Field failure characteristic.

The technique to determine whether the impedance measured by the relay is inside the mho characteristic on the impedance plane is illustrated in Figure 20. If $\overline{\mathbf{Z_f}}$ is the impedance measured, it can be seen that, from Figure 20(a), $\overline{\mathbf{Z_f}}$ will be inside the mho circle if the phase angle between $\overline{\mathbf{Z_f}} - \overline{\mathbf{X_1}}$ and $\overline{\mathbf{Z_f}} - \overline{\mathbf{X_2}}$ is greater than 90°.

By multiplying the impedance with the current $\overline{\mathbf{I_a}}$, the mho characteristic can be represented as shown in Figure 20(b). The criterion for operation now becomes:

$$\angle\left(\overline{V_a} - \overline{I_a} \times \overline{X_1}\right) - \angle\left(\overline{V_a} - \overline{I_a} \times \overline{X_2}\right) > 90^\circ$$

This can be transformed into a cosine inequality, below, which can be expanded into terms of Fourier sine and cosine vector components and computed accordingly.

$$\cos\left[\angle\left(\overline{V_a} - \overline{I_a} \times \overline{X_1}\right) - \angle\left(\overline{V_a} - \overline{I_a} \times \overline{X_2}\right)\right] < 0$$

For the field failure function, X_1 = -jXa, and X_2 = -j(Xa+Xb).

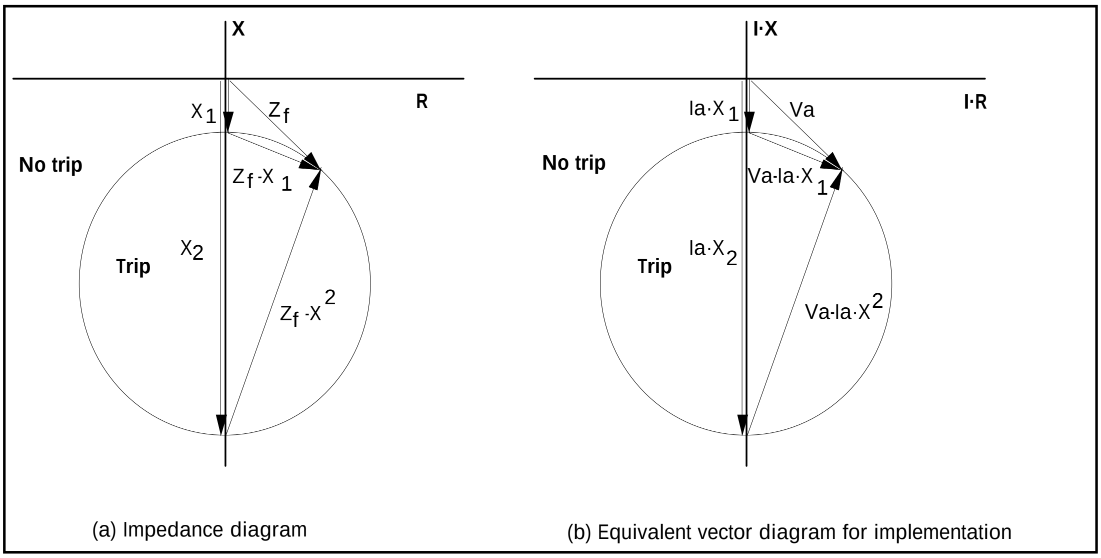


Figure 20 Implementation of the field failure mho characteristic.

3.9. Under and over voltage (27 & 59)

The LGPG111 provides an under voltage function and a two-stage over voltage function. The input quantities are V_{ab} and V_{bc}. The quantity V_{ca} is calculated from V_{ab} and V_{bc} vectorially:

$$\overline{V_{ca}} = -\left(\overline{V_{ab}} + \overline{V_{bc}}\right)$$

Both functions are three-phase devices. All individual phase elements must operate in order for the internal timer to start. The logic is shown in Figures 21 and 22.

A logic input, 27/81U Inhibit, is provided, which will inhibit the under voltage timer when energised. The logic is illustrated in Figure 22.

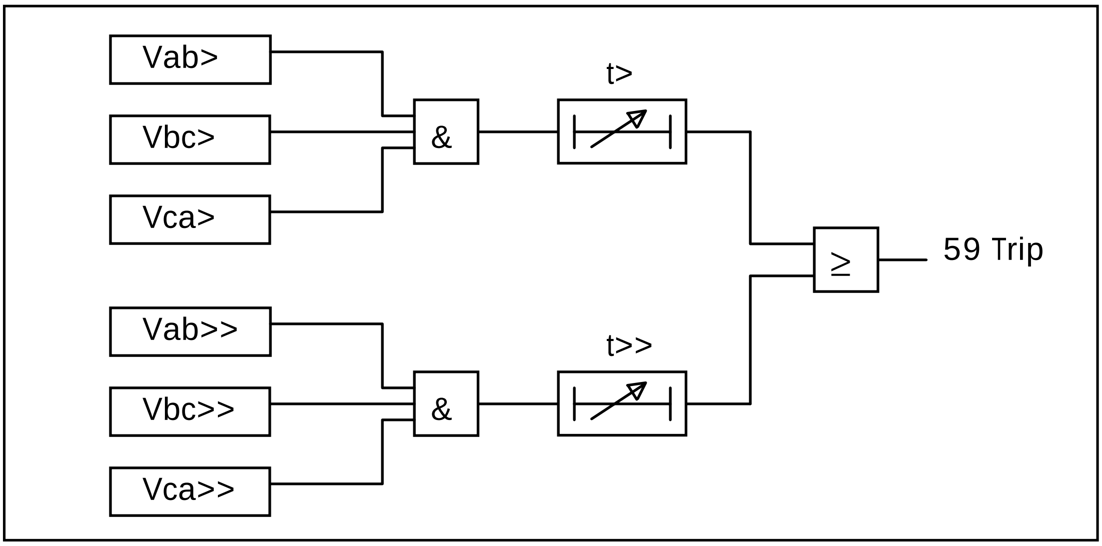


Figure 21 Over Voltage (59) operation logic.

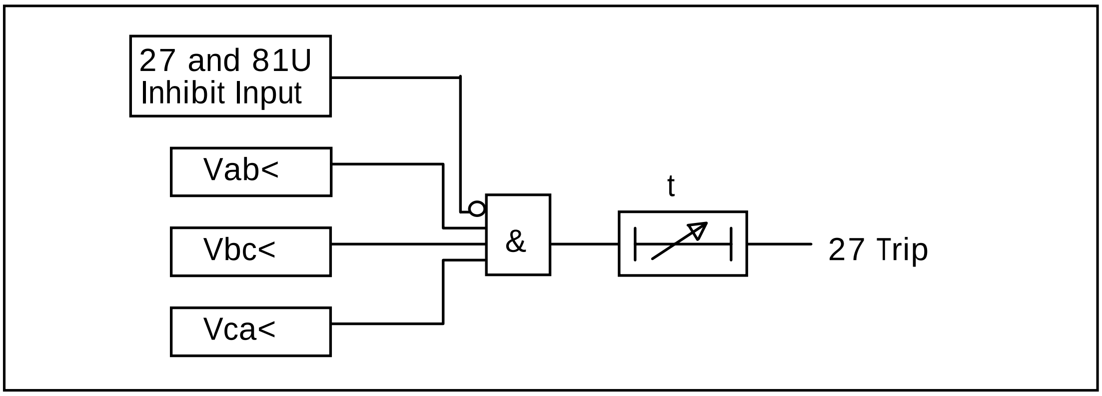


Figure 22 Under Voltage (27) operation logic.

3.9.1. Settings and characteristic

The settings provided by the under voltage and the over voltage functions are as follows:

Under voltage:

V< - Under voltage threshold.
T - Timer setting.

Over voltage:

V> - Over voltage low set threshold.
t> - Low set timer setting.
V>>- Over voltage high set threshold.
t>> - High set timer setting.

The characteristics are illustrated in Figure 23. Note that the over voltage element has a combined low set and high set characteristic with a single output.

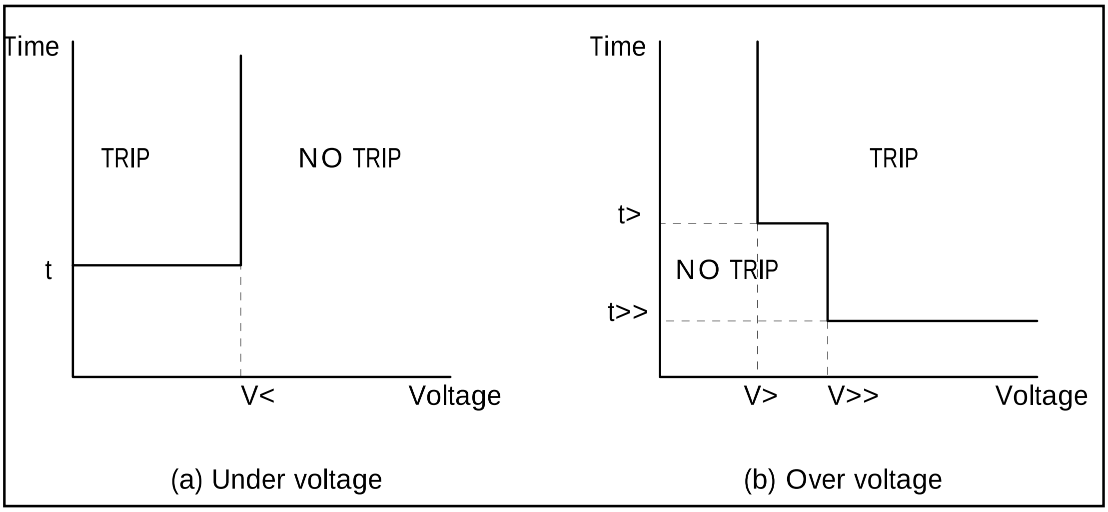


Figure 23 Under voltage (27) and over voltage (59) characteristics.

3.10. Under and over frequency (81U & 81O)

3.10.1. General description

Two independent under frequency elements and one over frequency element are provided. The frequency elements obtain their measurements from the frequency tracking algorithm, as discussed in Section 2.7

A logic input, 27/81U Inhibit, is provided, which will inhibit the under frequency timers when energised. The logic is illustrated in Figure 24.

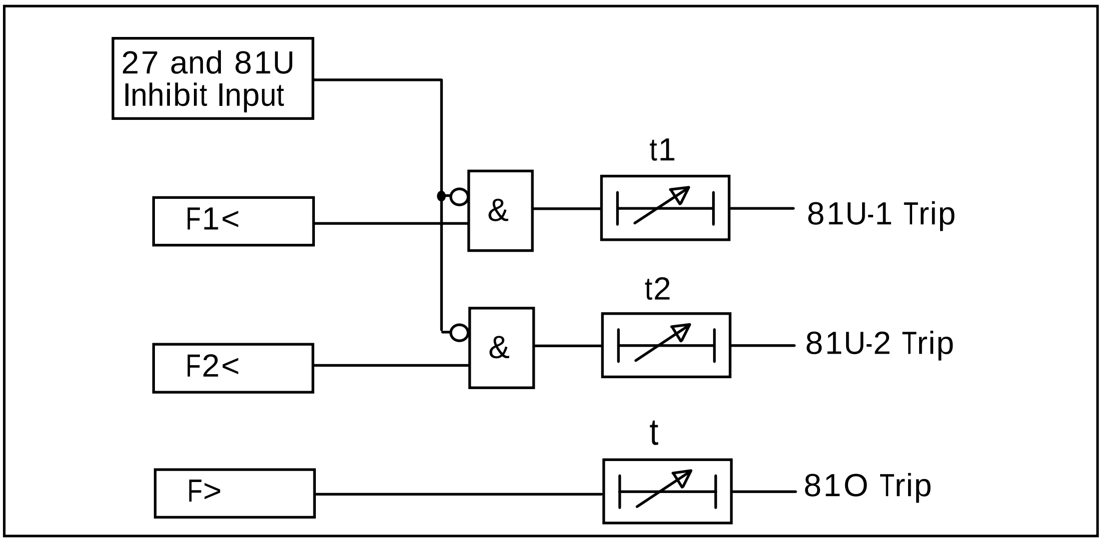


Figure 24 Logic diagram for the under and over frequency functions

3.10.2. Settings and characteristic

The settings provided by these functions are as follows:

Under frequency:

F1< - First threshold setting.
t1 - Timer 1 setting.
F2< - Second threshold setting.
t2 - Timer 2 setting.

Over frequency:

F> - Threshold setting.
t - Timer setting.

The characteristics are shown in Figure 25.

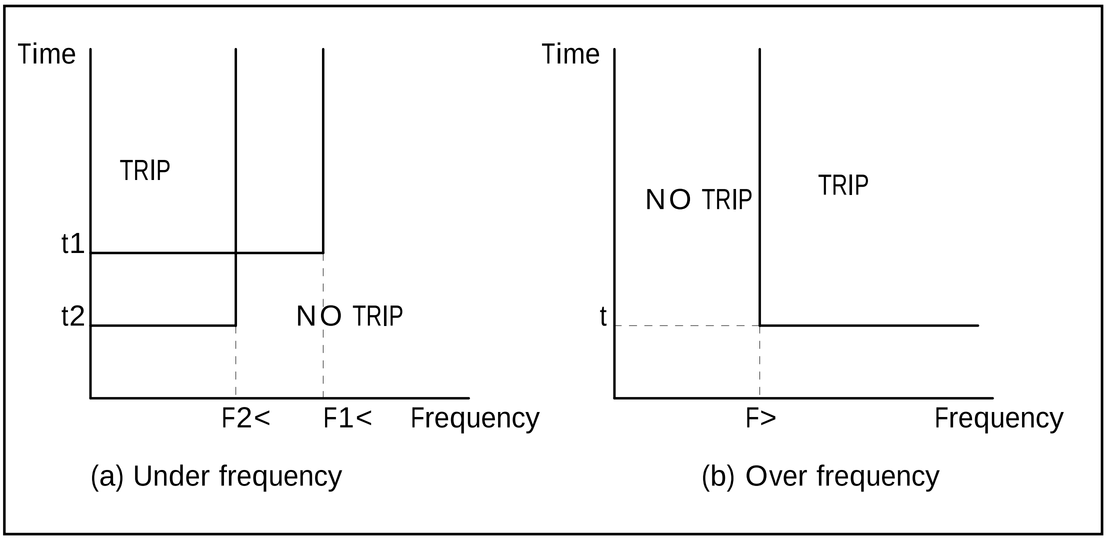


Figure 25 Characteristics for the under frequency and the over frequency elements

3.11. Voltage balance (60)

3.11.1. General description

A voltage balance function is designed to detect a VT fuse failure. The function works by comparing the secondary voltages from two sets of VT's, or from two separately fused circuits of the same VT.

The voltage balance function provides three outputs to the scheme logic: one output to indicate protection VT fuse failure, another output to indicate comparison VT fuse failure. The inverse of the protection VT fuse failure output can be used to block other voltage based functions, which might be affected by the apparent loss of voltage due to a VT failure.

The function is executed approximately every 20ms. Two consecutive calculations are required to confirm a relay operation. This produces an operating time of typically less than 60ms.

3.11.2. Settings and characteristic

The setting provided by this function is:

Vs - Voltage difference threshold.

The logic implemented by this function is:

- IF (V_{ab} - $V_{ab\text{-}comparison}$) > Vs OR IF (V_{bc} - $V_{bc\text{-}comparison}$) > Vs
  THEN comparison VT fuse failure.
- IF (V_{ab} - $V_{ab\text{-}comparison}$) < -Vs OR IF (V_{bc} - $V_{bc\text{-}comparison}$) < -Vs
  THEN protection VT fuse failure.

3.12. Timer hold facility

The overcurrent, stator earth fault and neutral displacement functions are all provided with a timer hold facility. This allows for faster clearance of intermittent faults. An example of which is a cable fault where the insulation breaks down, heals, breaks down again and heals again a number of times in rapid succession. If the timer resets instantaneously, the fault may remain undetected until it becomes permanent. The timer hold facility allows the timer to hold its value when the fault clears, provided the inter-fault period is less than the t_{RESET} timer setting. The t_{RESET} timer setting is selectable from 0 to 60s in 1s steps. The facility also enables closer co-ordination with electromechanical induction disc relays.

A further application of this facility is to provide pole slipping protection. During pole slipping, the systems current will pulsate widely. An appropriately set overcurrent function with a suitable reset time can be used to provide protection under such circumstances.

3.13. Integrating timer facility

An integrating timer facility is provided for the low forward power, reverse power and field failure functions. This facility is in the form of a delayed drop-off timer and a delayed pick-up timer, as illustrated in Figure 27. Time integration ensures that the relay will operate within its pre-determined operating time. This is true even if the measuring element is only intermittently picked up, provided the inter-fault time is within the setting of the delayed drop-off timer.

After the relay has operated, the timers, and hence the trip output, are reset instantaneously by the measuring element.

Time integration is required for the power functions under reciprocating load conditions when the measuring element picks up briefly and periodically. The same feature is also required by the field failure function during conditions such as pole-slipping.

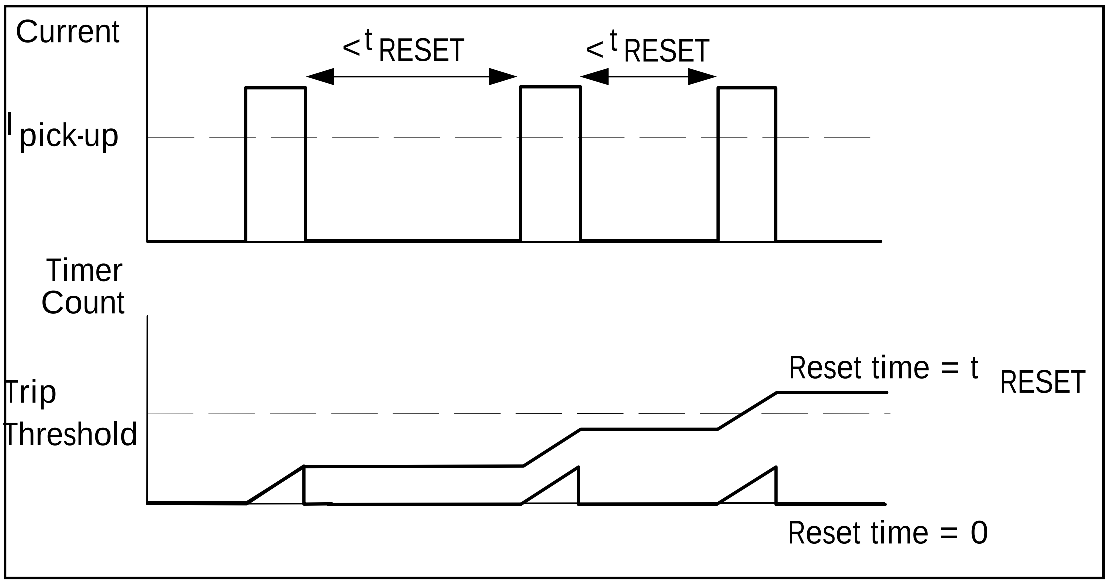


Figure 26 Timer hold facility.

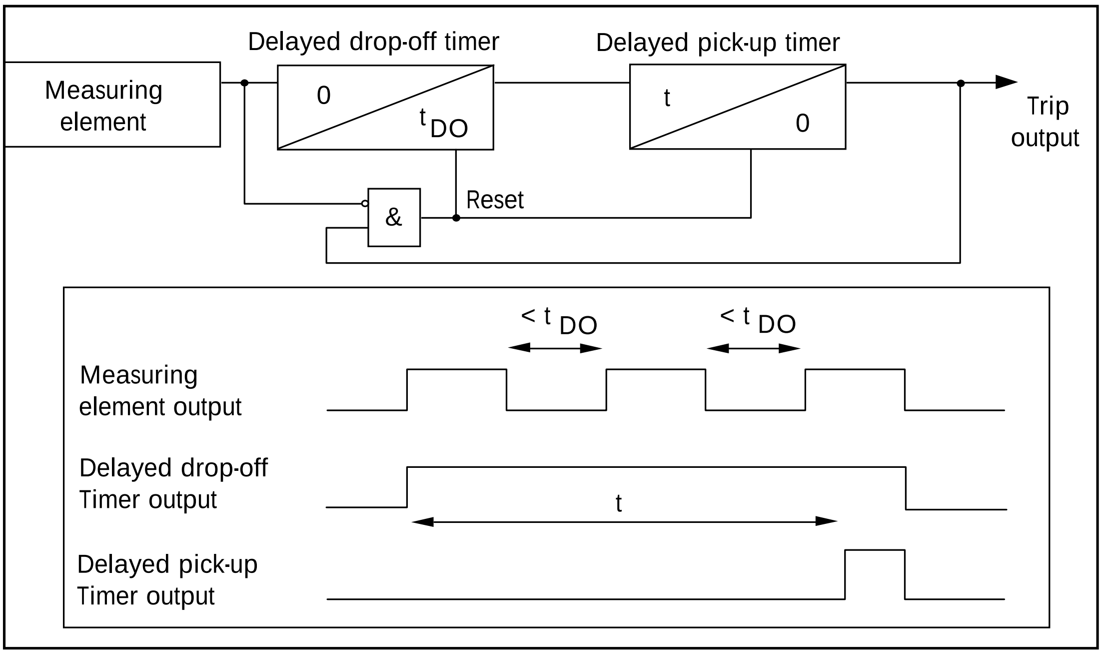


Figure 27 Integrating timing facility.

4. Scheme Logic

4.1. Basic principle

The protection scheme for a generator set normally involves a large number of protection functions combined to drive a few common trip outputs. Some blocking and interlocking logic may also be required. To accommodate different generator applications, the scheme logic design must be flexible and configurable.

The scheme logic provided by the LGPG111 is in the form of logic arrays with an architecture commonly found in programmable logic array devices. The logic arrays consist of an AND-OR structure shown in Figure 28.

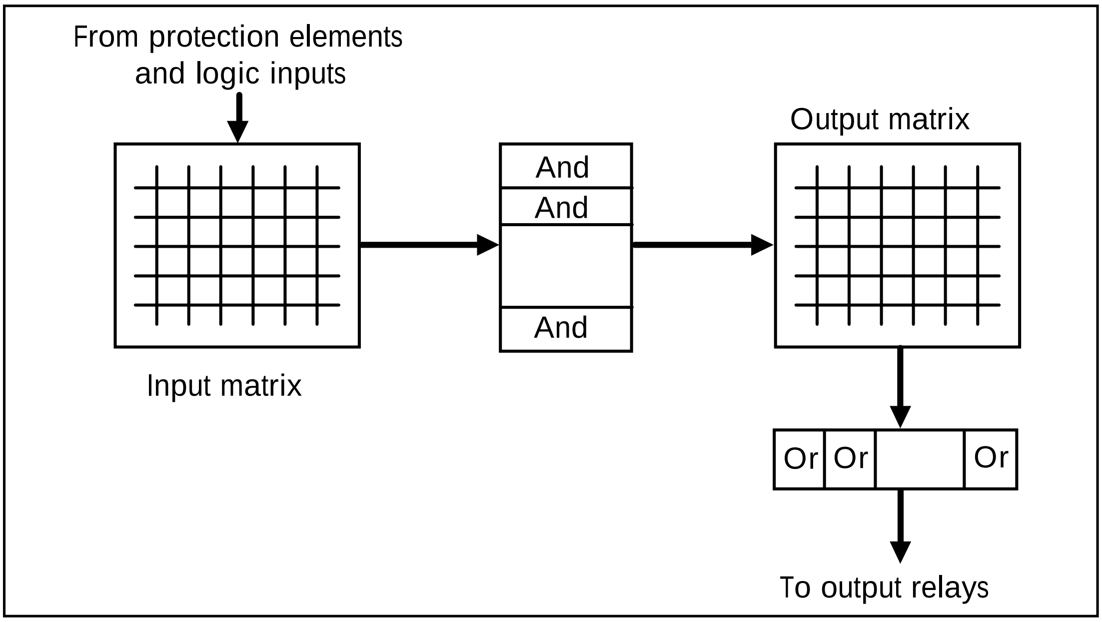


Figure 28 Scheme logic block diagram.

There are 32 inputs to the scheme logic: nineteen from the protection functions, eight from the logic inputs, and a selection of inverted inputs which allow blocking logic to be created. The AND function combines two or more inputs to provide blocking or interlocking logic, or simply acts as a through connection for one input. The OR function allows one or more of the AND function outputs to control each output relay. Up to thirty-two input combinations can be accommodated at any one time, and the scheme logic controls a total of fifteen output relays.

To implement the scheme logic settings, each logic line is represented by two binary words: one for the input AND matrix and one for the output OR matrix. Each interSection in the matrices is represented by a bit within each word. Thus the input matrix is made up of a series of 32-bit input words, and similarly the output matrix is made up of a series of 15-bit output words. A connection is made by changing a particular bit from ‘0’ to ‘1’.

Various facilities are built into the relay to make the setting up of the scheme logic easy and secure. In setting mode, when an interconnection *bit* is selected, a prompt identifies its function. This ensures the correct selection of an input or output bit where a connection is to be made. A scheme test facility is available; this allows the scheme’s response to input scenarios to be checked. The facility can be exercised at any time without affecting the protection functions. Also, the LGPG111 parallel printer connection can be used to print the scheme settings in a matrix format which allows easy comparison with the intended set-up.

The design of the scheme logic provides sufficient flexibility for different generator schemes. With the OR functions, the selection of protection functions to control different circuit breakers becomes an easy and inexpensive process. The inclusion of the AND function provides blocking and interlocking logic which further enhances the power of the scheme logic.

With this scheme logic design, the functions of the logic inputs and relay outputs can be used in any fashion required by the application. A facility is therefore provided for the user to enter a label to identify each of these inputs and outputs. The labels are used during the configuration of the scheme logic, by the input and output status displays and by the event, fault and disturbance recording systems.

4.2. Scheme logic examples

The flexibility of the LGPG111's scheme logic can be illustrated by way of the following examples.

4.2.1. Blocking with the voltage balance function

In this example, the differential protection is required to trip the circuit breaker directly. The voltage dependent overcurrent function is also used to trip the circuit breaker, but is to be blocked by the voltage balance function if there is a protection VT fuse failure. Additionally, an alarm indication is to be given when the voltage balance function operates.

Figure 29 illustrates the scheme logic arrangement. Relay 15 is assigned to trip the circuit breaker and Relay 8 is assigned to give VT fuse failure alarm indication. The differential function is connected directly to operate Relay 15. In this case, the AND gate simply serves as a through connection. The voltage dependent overcurrent function is also connected to operate Relay 15, but is gated with the inverted output from the voltage balance function. The AND gate therefore blocks the voltage dependent overcurrent whenever the voltage balance protection operates. The non-inverting output from the voltage balance function is connected separately to operate Relay 8 for an alarm.

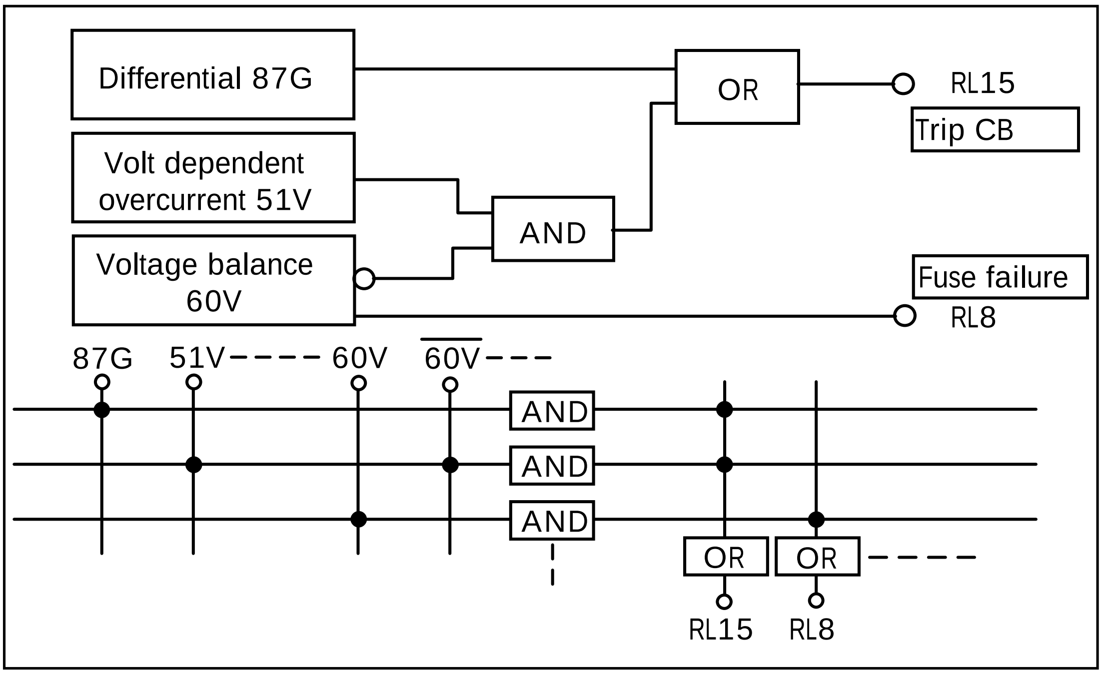


Figure 29 Example showing the blocking feature of the scheme logic.

4.2.2. Interlocking with the low forward power function

Figure 30 illustrates a low forward power interlocking scheme for the steam turbine sets, as explained in the chapter 3. In this example, the differential protection is regarded as an urgent trip condition, and is required to trip the steam valve and the circuit breaker simultaneously. The field failure function is required to trip the steam valve directly, but is to be interlocked with the low forward power function for tripping the circuit breaker.

In the scheme logic set up, Relay 14 is assigned to trip the steam valve, and Relay 15 is assigned to trip the circuit breaker. The differential function is connected to trip both Relays 14 and 15. The field failure function is connected independently to operate Relay 14. The connection of this function to Relay 15, however, is gated with the output from the low forward power function. Therefore, under field failure conditions, the circuit breaker will be tripped only when the power supplied by the generator has fallen below the setting of the low forward power.

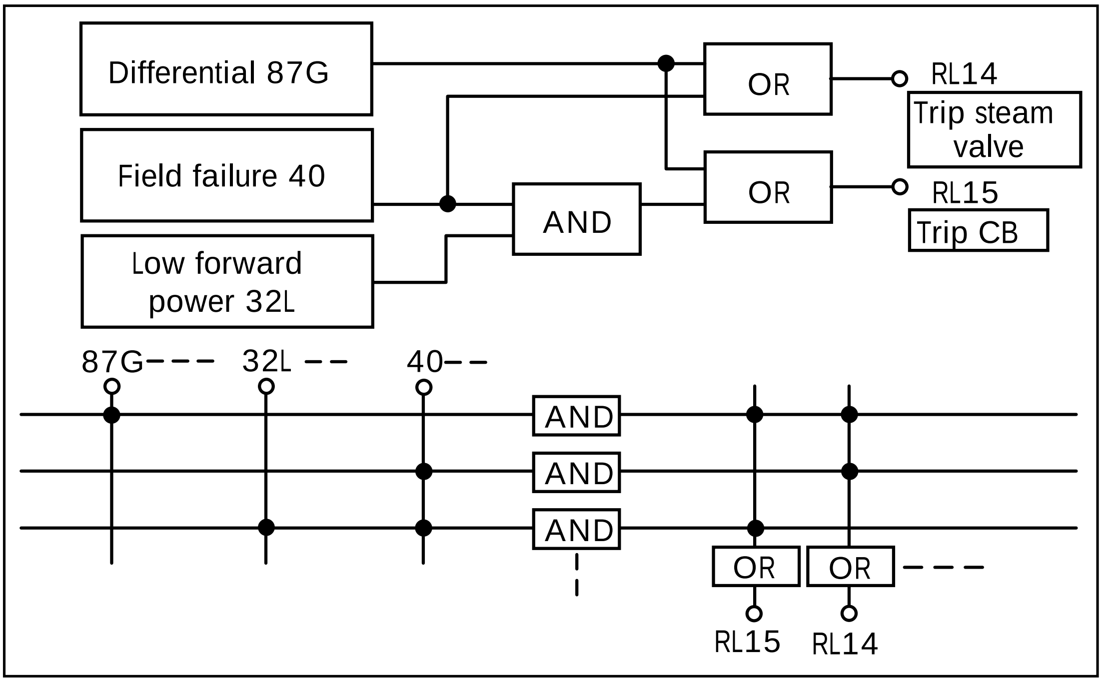


Figure 30 Example showing the interlocking feature of the scheme logic.

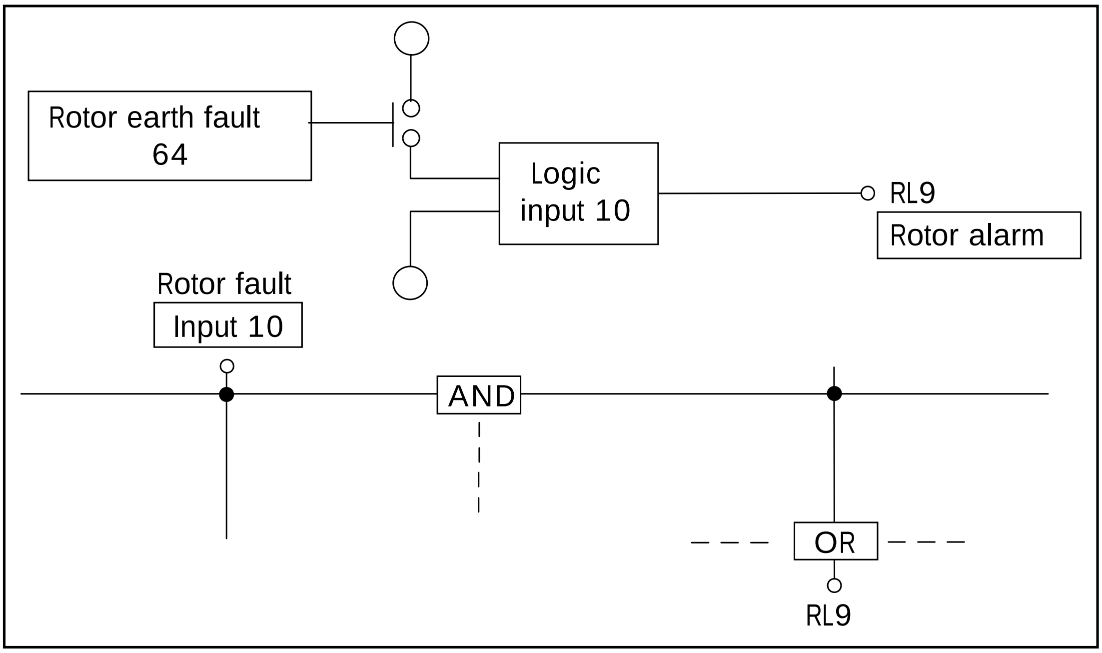


Figure 31 Example showing the connection of the scheme logic to external devices.

4.2.3. Interfacing external devices

The LGPG111 can be used in conjunction with external devices by way of any one of eight logic inputs. Rotor earth fault protection, for example (see Figure 31), is not provided by the LGPG111. However, by using one of the logic inputs, the operation of an external rotor earth fault relay can be monitored and included within the scheme logic of the relay. It is possible for external devices to block or interlock with the relay's own protection functions.

5. RELAY OUTPUT OPERATING TIME

The 15 relay outputs assigned to the scheme logic have different operating and reset times. Ten relays (Relays 3-7, 11-15) have a fast operating time of 2ms. The tripping outputs should be selected from these relays. The operating time of the other relays is 8ms, and can be used for alarms. All relays are capable of tripping circuit breaker coils.

All the relay outputs are provided with a minimum dwell time of 100ms. That is, once a relay has operated, the contact will remain closed for at least 100ms. This is to prevent a relay output breaking circuit breaker trip coil current if the controlling measuring element resets too quickly.

Relay	Pick Up Time	Drop Off Time
1	8ms	8ms
2	8ms	8ms
3	2ms	2ms
4	2ms	8ms
5	2ms	8ms
6	2ms	8ms
7	2ms	8ms
8	8ms	8ms
9	8ms	8ms
10	8ms	8ms
11	2ms	2ms
12	2ms	8ms
13	2ms	8ms
14	2ms	8ms
15	2ms	8ms

Table 1 Relay output operating times.

6. LATCHED OUTPUTS FACILITY

A facility is available whereby the user can select individual relay outputs to be latched once they have operated. The selection is done through the Latch Outputs setting in the Scheme Logic menu Section.

This facility is implemented in software. Therefore, when the relay loses its auxiliary power, the latched outputs will reset. However, the state of the latched outputs is stored in non-volatile EEPROM memory. When the auxiliary power is re-applied, the previously operated and latched contacts will be latched again.

The operation of a latched output will always cause a 'Relay operation' alarm to be generated. The output can be reset in two ways:

1. By the alarm scan process on the front panel - After all the alarm messages have been accepted, the Reset key will reset all the alarms and the latched outputs.
2. By the relay alarms cell in the menu - This cell allows alarms and the latched outputs to be reset.

7. LOGIC INPUT ASSIGNMENTS

The LGPG111 has fourteen optically isolated logic inputs. Inputs 0 to 5 are located in the Analogue and Status Input Module, and Inputs 6 to 13 are located in the Status Input Module.

Inputs 0 to 5 are assigned with specific functions as outlined in Table 2.

Logic Input	Description
0	Under frequency and under voltage inhibit.
1	Overcurrent timer inhibit.
2	Stator earth fault timer inhibit.
3 and 4	Alternative setting group selection.
5	Real-time clock synchronisation.

Table 2 Dedicated logic input assignment.

Inputs 6 to 13 are connected to the scheme logic. They can be used to operate relay outputs directly, or for blocking and interlocking with other protection functions. Inputs 6 to 9 are provided with inverted signals for blocking applications.

All the logic inputs are activated by applying the specified auxiliary voltage, Vx(2), across their input terminals. This produces a nominal 10mA current in the optical isolation circuitry. If a particular function is not required, the corresponding logic input may be left unconnected or shorted.

The logic inputs are sampled at 12 samples per electrical cycle, the same rate as the analogue inputs. A software filter ensures that the input states are consistent for 6 samples, before an internal state change occurs. This is to prevent inadvertent pickup caused by capacitive coupling from the power system signals. Therefore, for an input to be activated, it needs to be energised for a duration longer than half of the electrical cycle.

7.1. Under frequency & under voltage inhibit (27 & 81U inhibit)

This input is used to inhibit the under frequency and the under voltage protection, and can be energised during the start-up and run-down of the generator set. The input can be driven by a normally closed auxiliary output contact of the circuit breaker. When this input is energised, the timers of the two under frequency elements and the under voltage element are forced into reset.

Note that it is equally possible to block the operation of the under voltage and under frequency functions through the scheme logic, using one of the non-dedicated logic inputs. This is applicable to the dead machine protection scheme, as described in the Application Notes, chapter 3. When the generator is shut down, the under voltage function is required to initiate the alternative setting group, whilst its tripping and alarm initiation will be blocked by the normally closed circuit breaker auxiliary contact, via the scheme logic.

7.2. Overcurrent timer inhibit (51V timer inhibit)

This input is used to inhibit the timer of the overcurrent function. The input can be used in conjunction with the start element of K-Series overcurrent relays to provide a simple blocking scheme. With such schemes, the start contact of a K-Series relay, on an outgoing feeder, is used to block the overcurrent function from operating until the fault is cleared. This allows the LGPG111's overcurrent function to be set in a fast operating definite time mode, whilst still grading with overcurrent protection on the outgoing feeders; see Figure 31.

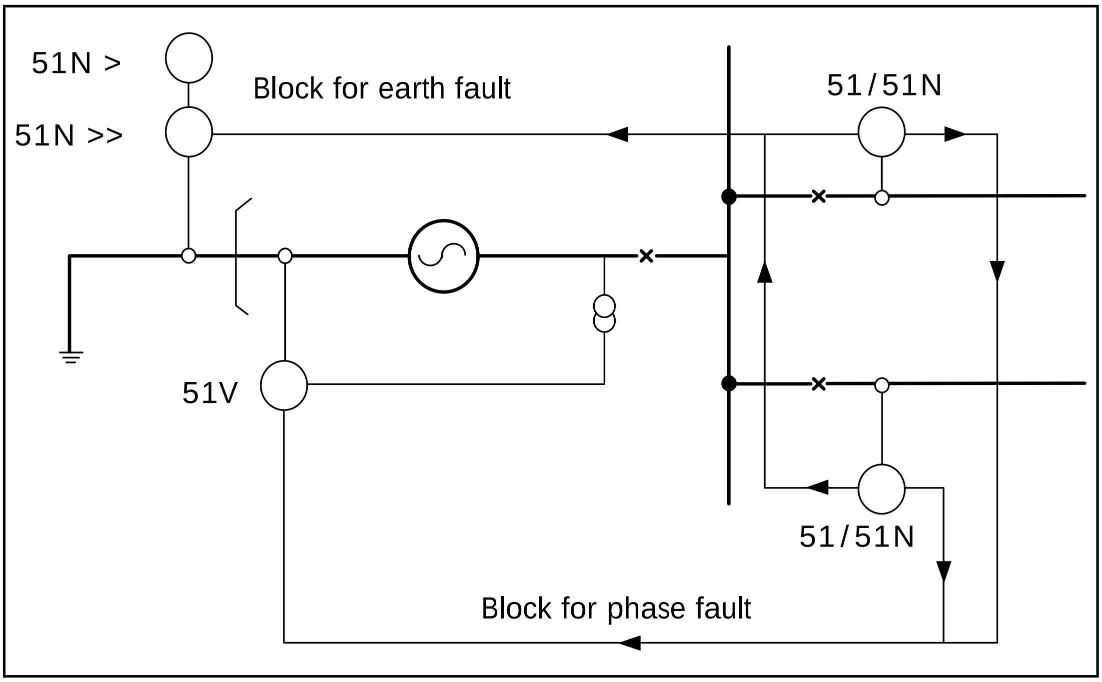


Figure 31 Application of LGPG111 51V and 51N timer inhibits for discrimination with feeder protection.

7.3. Stator earth fault timer inhibit (51N timer inhibit)

This input is used to inhibit the timer of the stator earth fault function. Either the low set or high set element, or both, can be inhibited. Its application is the same as that of the overcurrent timer inhibit input, as shown in Figure 31.

7.4. Alternative setting group selection (setting group select)

Inputs 3 and 4 are used to select the alternative setting group. Both inputs need to be energised for the selection to be effective. If only one input is energised, then the LGPG111 will assume that there is a failure and will raise an alarm. The group selection logic is shown in Table 3.

Logic Input 3	Logic Input 4	Group Selected
0	0	Group 1
1	1	Group 2
0	1	Indeterminate states, active setting group remains unchanged
1	0	

Table 3 Setting Group Select logic inputs.

7.5. Real time clock synchronisation (clock sync)

The Clock Sync input is used to feed a time-aligned pulse signal to the relay. This is used to synchronise the internal real time clock. The feature can be disabled, or it can be set to synchronise the clock every 30s, or every 1, 5, 10, 15, 30, or 60 minutes. If the Clock Sync setting is set to 30 minutes, for example, then activation of the Clock Sync input will pull the clock to the nearest hour or half-hour.

8. ALTERNATIVE SETTING GROUP

The LGPG111 provides two setting groups: a primary and an alternative - generally referred to as Group 1 and Group 2. These setting groups include all the protection and scheme logic settings. Settings can be changed from one group to another without significant interruption to the internal operation of the relay functions.

The alternative setting group is optional. If it is disabled, then the group 2 settings will not be available from the menu system.

The active setting group can be selected by one of the following methods:

1. By controlling two setting group select logic inputs, or
2. By a password protected command setting, or
3. By issuing a remote access command to the LGPG111.

The first method using logic inputs is mutually exclusive of the other two methods, collectively referred to as the menu methods. A setting, Select Setting Group, is used to select either the logic input or the men*u* method for controlling the setting group selection.

If the user has selected to use the menu method to change the setting group, then the relay will also be able to respond to a global setting group change command issued by the remote access system. This allows all the relays connected to the communication system to change to a specific setting group.

9. NON-PROTECTION FUNCTIONS

Because of the numerical nature of its design, the LGPG111 is able to provide the following non-protection functions to complement its functionality.

1. Measurements
2. Event and fault recording
3. Alarm indication
4. Disturbance recording
5. Real time clock
6. Test facilities
7. Print functions
8. Self-monitoring

The following Sections describe each function in detail.

9.1. Measurements

The rms magnitudes of all the seventeen analogue inputs are available as measurement values. They are: the three phase voltages and currents, the neutral voltage and current, the residual current, the differential currents and the bias currents.

Other derived quantities are also available. They are: the negative phase sequence current, the A-phase active and reactive power, the phase angle between $\overline{I_a}$ (from the $I_{a\text{-sensitive}}$ input) and $\overline{V_a}$, the mean bias currents, and the power system frequency.

All measurements can be displayed in either primary or secondary quantities. The selection is done through the Display Value setting in the Auxiliary Functions Section of the menu.

If primary quantity is selected as the display quantity, then all the measurement displays will be multiplied according to the system CT and VT ratio settings. These settings are located in the Transformer Ratios Section of the menu.

9.2. Event recording

The LGPG111 is capable of storing a maximum of 100 event records in its non-volatile memory area. Every record is stamped with the time and date of the event occurrence. When the record buffers are full, a new record will automatically overwrite the oldest one.

The types of events recorded by the relay can generally be divided into three groups: power system events, relay operational events and diagnostics events.

The power system events consist of the following:

- Protection function operation, including the faulted phase information if applicable.
- Energisation of any relay output.
- Energisation of any logic input, except the real-time clock synchronisation input.

These events are recorded once every 5ms. Note that the reset of any protection function operation, and the de-energisation of logic inputs and relay outputs, are not recorded.

The relay operational events consist of the following:

- Power-on reset or warm reset, see Section 9.11.
- Real-time clock invalid or set.
- Removal or restoration of password.
- Setting group change.
- State of the scheme output: Enabled or Inhibited.

Events recorded by the diagnostics/self-monitoring functions are as follows:

- Liquid crystal display (LCD) failure.
- Watchdog timer inoperative or incorrect.
- Analogue input module missing.
- Analogue input module uncalibrated.
- Analogue input module failure.
- Communication hardware failure.
- Non-volatile memory (EEPROM) write failure.
- Non-volatile memory (EEPROM) data corruption in:
  - i. analogue module,
  - ii. main processor module.
- Setting group select logic input failure.

9.3. Fault recording

The fault recording is designed to capture power system data when the relay trips. Since the LGPG111 has no pre-defined output contact for tripping, a Fault Record Trigger setting is available to select one or more of the fifteen output relays as the fault record trigger.

When the fault record trigger occurs, an alarm is raised, causing the yellow alarm LED to flash and the red trip LED to illuminate. The alarm messages will indicate which output relays have energised, together with the operation of the protection functions and possibly the status inputs.

The fault record consists of the following information:

1. Date and time of the recording.
2. Protection function operation, including the faulted phase information if applicable.
3. Status of the relay outputs.
4. Status of the logic inputs, excluding the real-time clock synchronisation input and the group selection inputs.
5. The Scheme Output setting to indicate whether the outputs were blocked when the trigger occurred.
6. The active setting group number.
7. A snapshot of the measurement values taken when the trigger occurred.

A fault record is essentially a special event record with additional measurement values. Out of the 100 event records, up to 50 fault records can be accommodated. The records are stored in non-volatile EEPROM memory and are preserved even in case of a power loss.

The fault recording is executed approximately every 5ms which is the same rate as the differential and bias currents are calculated by the differential protection. The other measurements are calculated approximately every 20ms. This may result in a misalignment between the two groups of measurements in the fault record. The maximum misalignment is 20ms.

9.4. Record retrieval mechanism

The event and fault records can be examined by using the following methods:

1) Through the user interface via the View Records Section of the menu.
2) Through the Print function in the Auxiliary Functions menu Section to produce a report on a printer.

Event and fault records can also be automatically extracted by the remote access system. They can then be displayed or stored in a file, as they occur. A record can only be automatically extracted once. However, they are retained in the non-volatile memory until overwritten, and can be examined on demand using the two methods listed above.

A Clear Event Record function is provided in the Auxiliary Functions Section of the menu to clear all the event and fault records from the relay's memory.

9.5. Alarm indication

Alarms are events which require immediate attention from the operator. These include failures detected by self-monitoring, relay tripping through the operation of the fault record trigger, and operation of any one of the latched output contacts selected by the Latch Outputs setting. Besides these initiations, it is possible to select other scheme logic outputs to generate an alarm message. An Alarm Record Trigger setting is provided, which is the selection of the fifteen relay output contacts.

When an alarm occurs, the alarm LED will flash to indicate that there is an outstanding alarm. The word 'ALARM' will also be flashing on the front panel's display, provided that the front panel user interface is at the default level. A user can then perform an alarm scan which scans through the alarm messages. The alarm messages are summaries of alarms that have occurred. At the end of the alarm scan the user is prompted to reset the alarms. This also resets the LED's and the latched output contacts, provided that the alarm conditions have already disappeared.

The alarm scan is not available remotely. However, an alarm flag is transmitted when an alarm occurs. The remote access system is able to indicate the presence of an alarm. Additionally, a Relay Alarms cell is available in the Auxiliary Functions Section of the menu, to provide another means of indicating the alarm status. This cell can also be used to clear the alarms and LED's, either locally or remotely and to reset the latched output contacts.

9.6. Disturbance recording

A maximum of two disturbance records can be stored in volatile memory (RAM). A record will remain in the buffer area until it is uploaded by a remote access system, after which the buffer is cleared for recording again. Note that the disturbance record cannot be examined through the front panel user interface. The records will also be lost if the relay loses its auxiliary power.

A record consists of one timer channel, two digital channels and up to eight analogue channels. The timer channel is used to time tag each sample. The two digital channels record the status of the fourteen logic inputs and the status of the sixteen[2] relay outputs respectively, in binary bit format. The eight analogue channels are selectable from the relay's seventeen analogue inputs.

[2]The sixteen outputs consist of the 15 scheme logic outputs (bits 1-15) and the relay inoperative output (bit 0).

The disturbance recorder can be set to capture either the raw data, or the magnitude and phase of the selected analogue inputs. The raw data is acquired every sample, whereas the magnitude and phase are captured at 20ms intervals. The features of these two types of recording are shown in Table 4.

Analogue Data	Data Type	Record Length	Record Duration
Raw data	Digitised data direct from ADC without calibration	768 samples	64 cycles at 12 samples per cycle
Magnitude & phase	Derived calibrated quantities after Fourier filter	384 samples	7.68 seconds at 20ms intervals[3]

Table 4 Comparison of disturbance recorder data capture modes.

When magnitude and phase data are selected for recording, the measurements from the differential protection function inputs can be up to 5ms out of step with the rest of the measurements. This is because the two groups of calculations are not time-aligned internally inside the relay.

The recorder can be set to trigger on the energisation of relay output contacts and logic inputs. Both triggers are user selectable. Trigger on de-energisation is not available.

A command is also available in the Disturbance Recorder menu Section to allow the user to trigger the recorder manually.

Records can be cleared with the Clear All Records command in the Disturbance Recorder Section of the menu.

9.7. Real time clock

The relay runs a real time clock in software. The clock provides the time and date for the recording functions, with a 1ms resolution. The clock has no battery backup. Therefore it must be set up every time the auxiliary power is switched on.

When the relay is powered up, it performs the following:

1. Defaults the date and time to 1 January 1994 00:00:00.000.
2. Generates a ‘real time clock invalid’ event record.
3. Displays a ‘DATE AND TIME NOT SETUP’ message on the front panel’s display.

The clock can be set through the menu or by a Set Time function provided by the remote access system. Once the clock is set, two event messages are logged and the message on the front panel is removed. The first event message logged is ‘real time clock set’ and is time stamped in the old time frame. The second event message is ‘real time clock valid’ and is time stamped in the new time frame at (more or less) the same instant. These two time stamps allow the conversion of time stamps, prior to the clock being set, into the new time frame. This is, of course, only possible for events as far back as the last relay reset (power on) which resulted in a ‘real time clock invalid’ event record.

[3]The magnitude and phase data may not be recorded at exactly 20ms intervals. The interval can be as much as $0.02+1/(f_{sys}\times12)$seconds. For a 50Hz system this equates to a sampling interval any where between 20 & 21.6ms. This implies the total recording duration may be longer than indicated.

The time base of the clock is derived from an internal free running crystal oscillator. The accuracy of this crystal is approximately 50ppm, which can result in an error of up to 3 seconds per day. For precise synchronisation with an external clock source the LGPG111 provides a logic input for a time synchronising signal. This allows the relay's clock to be synchronised at regular intervals.

9.8. Test facilities

Test facilities are provided to enable the LGPG111 to be thoroughly tested during commissioning, routine maintenance and fault finding operations.

The measurement functions allow the analogue inputs and their associated connections to be checked.

The status of the logic inputs is displayed in the System Data and the Auxiliary Functions Sections of the menu. This allows tests to be carried out on the individual inputs and associated plant.

The relay can display the operation of each protection function as a percentage of the final trip time in the Protection Operation Summary Section of the menu. The protection will trip when the target count reaches 100%. This allows the pick-up, progress and operation of any protection function to be checked.

A Scheme Output setting in the Auxiliary Functions menu Section is available to inhibit the scheme from operating the output contacts. When the setting is set to inhibited, the out of service LED on the front panel is illuminated, although all the other relay functions, including the protection and the recording, are carried out normally. It is then possible to carry out secondary injection tests without any risk of nuisance tripping. Whilst in this mode, it is also possible to test individual output contacts, as explained later.

Besides these facilities, the Test Functions Section of the menu provides further test options:

1. Lamp Test to test the four indicating LED's.
2. Relay Test to test the individual relay output contacts.
3. Scheme Setting check to check for half-programmed logic words in the scheme logic.
4. Scheme Logic Test to verify the logic of the scheme settings.

The Lamp Test function turns the four LED's to their opposite states for a duration of two seconds. The response of the relay healthy LED is slower than the rest, due to the design of the mono-stable circuit used to operate it.

The Relay Test function is a 16-bit binary flag setting with each bit representing a relay output contact. Before the test is carried out, the scheme output must be inhibited with the Scheme Output setting. Then, by setting the binary bits from zero to one will cause the corresponding relay outputs to operate. The relays are de-energised if the bits are reset to zero. When the Scheme Output setting is restored to enabled, all the bits will be forced to reset.

The Scheme Setting check looks for any half programmed logic word in the scheme logic settings. It warns that, for a particular logic line, the input word has been programmed but not the output word, or vice versa. The warning is displayed in the Scheme Setting cell in the form 'Error Line X', where X is the number of the erroneous logic line.

The Scheme Logic Test allows the user to check that the settings of the scheme logic are entered correctly. The user can enter an input bit pattern to the scheme and check its logic output. This test is run independently of the actual scheme itself, and will not affect the relay's normal operation.

9.9. Print functions

A Print function is provided in the Auxiliary Functions menu Section to allow information to be printed out, through the parallel port, to a printer. Information available for printing are:

1. System settings.
2. Protection settings.
3. Scheme logic settings.
4. Event and fault records.

Each print-out also contains the Plant Reference identification and a time and date stamp.

9.10. Self-monitoring

The LGPG111 includes a number of self-monitoring features designed to guard against hardware, or other fatal errors, from causing maloperation of the relay. Self-monitoring checks are performed during power up, run-time and background processing.

9.10.1. Power-on diagnostics

During power up, the relay runs its diagnostic program to check the main relay components: watchdog timer, microprocessor, interrupt controller, DMA controller, timers, LCD and memory components. Random access memory (RAM) is checked by read/write tests to each location. Erasable programmable read only memory (EPROM) is verified by checksum tests. In addition, the integrity of data stored in both EEPROM's of the main processor and analogue input modules are validated by CRC[4] checksum tests.

Any major error detected by the power-on diagnostics will cause the relay to lock-out. The exceptions are failures of the watch-dog and the LCD display, which will only cause an alarm to be raised.

9.10.2. Run-time and background self-monitoring

During run-time, the relay monitors the analogue input circuits, the communication hardware and the group select logic inputs.

During background processing, all the memory components in the main processor module, including data stored in the EEPROM, are checked continuously.

Depending upon the severity of a failure, the relay reacts in the following fashion:

1. Minor error
   A minor error is such that it does not cause maloperation of the relay. The protection will be allowed to continue and corrective action will be taken. See Table 5 for the errors that fall in this category.

[4]CRC is an acronym for cyclic redundancy code. In the relay, the CRC checksum is calculated based on the CRC-16 polynomial which is, $X^{16}+X^{15}+X^{2}+1$. The implementation of the polynomial is based on a word-wise, 'on the fly' method.

2. Fatal error
   An error is fatal when it could cause maloperation of the relay. Under such conditions, the protection will be disabled. Other functions, such as remote communications and front panel user interface, will be available if possible. See Table 6 for a list of the fatal errors.

3. Lock-out error
   The consequence of a lock-out error is such that the relay is unable to continue processing. Under such circumstances, the relay will not be able to record events and raise alarms. Most errors detected by the power-on diagnostics are categorised as lock-out errors. The cause of the error is displayed on the front panel's display when the relay locks out. The lock out causes the relay to be continually reset by the operation of the watchdog. The relay inoperative output relay will remain de-energised.

See chapter 6 for a summary of front panel user interface messages.

Minor Errors	Actions By Relay
Calibration Vector Error	Raise alarm. Set calibration data to default values. Protection is allowed to continue.
Communications Hardware Fail	Raise alarm. Attempt once to recover the failure by watchdog reset. Subsequent failures cause relay to disable the serial communications.
EEPROM Write Fail	Raise alarm.
Group Select Input Fail	Raise alarm. The current setting group remains unchanged.
LCD Fail	Raise alarm. Disable front panel user interface (local access).
Watchdog Inoperative	Raise alarm.
Watchdog Timer too fast	Raise alarm.
EEPROM Errors for settings other than scheme logic settings	Raise alarm. See chapter 6 for a description of non-volatile EEPROM memory errors..

Table 5 Summary of minor errors detected by the self-monitoring function.

Relay Fault	Actions By Relay
Uncalibrated Analogue Module	Disable protection, raise alarm, de-energise relay inoperative output.
Analogue Module Fail	Raise alarm, de-energise relay inoperative output. Attempt once to recover the failure by hardware reset. Subsequent failures cause relay to disable protection.
EEPROM error in scheme logic settings	Disable protection, raise alarm, de-energise relay inoperative output.

Table 6 Summary of fatal errors detected by the self-monitoring function.

9.11. Cold and warm resets

The LGPG111 makes a distinction between a cold reset (power-on reset) and warm reset (watchdog reset). A cold reset is caused by applying power to the relay. A warm reset is normally caused by watchdog operation. The watchdog provides a self-reset mechanism for the relay to attempt to recover from any runtime error.

The watchdog circuit consists of a mono-stable which must receive a *trigger* every 50ms, otherwise it will reset the relay's hardware. Under healthy conditions, the software will trigger the watchdog periodically, within its time-out period. If the microprocessor or the software fails, the trigger will not occur, forcing the watchdog to time out and reset the relay. Some self-monitoring functions can also force the watchdog to time out, to produce a warm reset.

When the relay resets, the power-on diagnostics will be executed. If the diagnostics test is successful, an event will be recorded, indicating whether this is a cold or a warm reset. A known pattern in the volatile RAM is used to distinguish between the two situations. Failure of any major diagnostics test will lockout the relay.

The failures detected by self-monitoring which will force a watchdog reset are as follows:

1. RAM failure
2. EPROM failure
3. Analogue input module failure
4. Communication hardware failure

Chapter 5 - Hardware Description

ISSUE CONTROL

ENGINEERING DOUCUMENT NUMBER: 50005.1701.105

Issue	Date	Author	Changes
AP	February 1995	Richard Price	Original
BP	June 1995	Dave Banham	Minor Updates.
A	July 1995	Dave Banham/ Publicity	Styles
B	Feb 1996	R Price	Hardware modifications for compliance to European Union EMC directive for model number issue letter D onwards.

Contents

1. INTRODUCTION

The LGPG111 is constructed using M4 multi-modular hardware. A number of identification systems are used to define a particular relay variant, the components within that variant and also its application. A brief description of these numbering systems is given within this Chapter. A description of the relay hardware is then given followed by functional details of each module, which includes information on the input and output connections. The position of movable links within the modules is listed at the end of the chapter.

2. RELAY IDENTIFICATION

2.1. Model numbering

The complete identification for the relay is described by a 16 character model number. The model number is broken down into a number of fields which are detailed below.

Issue:	See Model List	
Original		A
Software Change		B
EMC Phase 1 mods	21/11/95	C
EMC Phase 2 mods	module 5 & 6	D

VT & CT Ratings	
English	E
French	F
German	G
Spanish	S

VT& CT Ratings	
110V 1Amp	L
110V 5Amp	M

VX2 Auxiliary Supply Voltages	
24 - 27Vdc	1
30 - 34Vdc	2
48 - 54Vdc	3
110 - 125Vdc	4
220 - 250Vdc	5

VX1 Auxiliary Supply Voltages	
24 - 27Vdc	1
30 - 34Vdc	2
48 - 54Vdc	3
110 - 125Vdc	4
220 - 250Vdc	5

Case and Mounting		
Flush Panel	P (S1)	See note 1
Rack	R (S5)	

Setting File Reference	
	01

Main Variations	
Digital Integrated Multi-Function Generator Protection	111

LGPG											
1 to 4	5	6	7	8	9	10	11	12	13	14	15

note 1: The old model number format is shown in brackets.

Table 1 Model number field definitions.

2.2. Module numbering

Modules are identified by a 10 character code. This coding, which is known as a 2 alpha coding, is of the form:

GM mmmm nnn A

The identifier is marked on a strip fitted into the lower front extrusion of the module. The first two characters are always ‘GM’ for the M4 multi-modular hardware. Together with the next 4 digits they specify the type of the module. The next 3 characters represent a sequential number and vary according to minor variations such as the rating of the module. The last letter is a design suffix letter.

The position of a module in the equipment is designated by a number. Module 1 is in the left-most position of the top sub-rack, as viewed from the front. The rest of the modules are numbered sequentially from left to right. The module number is marked on a strip fitted into the top front extrusion of the module. The case also has numbered strips which indicate the position of each module.

2.3. Scheme numbering

Where an auxiliary sub-rack forms part of a more complex scheme, i.e. in conjunction with other ALSTOM T&D Protection & Control Limited equipment, a coding comprising 2 letters and 10 numbers is used. The related scheme or system diagrams are coded 12 L00 000 000 or 14 L00 000 000. The two digits 12 and 14 denote ‘tender’ or ‘contract’ diagram respectively. The 4th letter denotes the type of relay casing used. ‘L’ represents the M4 multi-modular case system. This and the digits following the coding are required for complete identification of the scheme.

2.4. Mechanical layout numbering

The case terminals and their functions are shown on the external connection diagram or application diagram. These are specified by a drawing number of the form 10 LGPG111 nn, Where 10 indicates external connection diagram and nn is the connection arrangement. The drawing numbers for the mounting details and for the arrangement diagrams are also given below. All the above diagrams can be found in chapter 11.

10 LGPG111 00		External connection diagram.
GM0008	sht 1	Outline and mounting details of 4U modular case - rack mounting.
	sht 2	Outline and mounting details of 4U modular case - panel mounting.
GM0054 025		LGPG111 arrangement diagram - rack mounting.
GM0055 023		LGPG111 arrangement diagram - panel mounting.

Table 2 Diagram reference numbers.

3. RELAY DESCRIPTION

The LGPG111 is housed in a single tier, 4U (178mm) high, rack or panel mounting case. The relay consists of 6 modules, a hinged front panel and a rear case mounted module:

Module Position	Function
1	Power Supply Unit
2	Output Module 1
3	Output Module 2
4	Microcomputer and Serial Communications
5	Status Input Module
6	Analogue and Status Input Module
Front panel	User Interface
Rear Case mounted	Communications Isolation Module

Table 3 Module numbering and description.

The arrangement diagrams show the relative positions of the modules within the case. External connections for CT, VT, output contacts and status inputs are made via standard 28-way MIDOS connectors mounted on the rear of the relay, CT shorting switches are fitted where required. There are also two connectors mounted on the communications isolation module. These are a 25-way D-type female connector, which is an isolated RS232 port using IEC870 protocol, and the other is a 3 terminal screw connector, which is an isolated RS485 port using K-Bus protocol. Both are designed for permanent remote connection.

There is no back plane wiring in the relay. All inter-module wiring is via a 64-way ribbon cable bus (the I/O bus) behind the hinged front panel. By this means all the electronic signals and internal power rails between modules are spaced as far as possible from the incoming wiring. The I/O bus runs along the front of modules and is terminated on the front panel. Connections are made to the modules by two-part insulation displacement connectors (IDC). Modules are locked in position by an aluminium screen mounted on the rear of the front plate. The microprocessor module controls all the modules on the I/O bus.

4. CASE DESCRIPTION

The single tier, 4U (178mm) high, rack or panel mounting case has been designed to provide adequate screening for high speed electronic circuitry. The whole case, including the front cover, is made in steel. The relay is of modular design and modules are located in grooves. Interposed between the plastic grooves and the outer case are two full size upper and lower aluminium plates which are insulated from the outer case. Each module has a complete aluminium side plate which provides both mechanical strength and electrical screening for the electronic circuitry. The side plates are electrically connected to the upper and lower plates by means of spring clips. This internal screen is connected to the case at a single earthing point. The arrangement gives a Faraday cage within the outer case. This cage diverts all electromagnetic noise and interference from inter-module coupling via a low impedance path, to a single earthing point.

5. MODULE DESCRIPTIONS

5.1. Power supply

Module Number: GM0026 24V, 30V & 50V
GM0097 110V & 220V

Five versions are available covering the following DC supply voltages:

Nominal	Operative Range
24/27V	19.2 - 32.4 V
30/34V	24 - 40.8 V
48/54V	38.4 - 64.8 V
110/125V	88 - 150 V
220/250V	176 - 300 V

Table 4 Power supply voltage ranges and withstands.

The function of the module is to supply four internal DC voltage rails from the single auxiliary DC input supply. The module is of a switched mode power supply design and the output rails are fully isolated from the input.

External connections are made via a 28-way MIDOS connector. The power supply output rails are distributed to the other modules in the equipment via the I/O bus. The four internal voltage rails are +6.5V, +19.5V, -l9.5V and +24V. The +6.5V rail is regulated to +5V locally in each of the modules to power logic circuitry. The ±19.5V rails are regulated on the analogue and status input board to ±15V for analogue circuitry, or to ±12V for RS232 factory test interface on the microcomputer board. The +24V rail is used, unregulated, to switch the output relays.

An under voltage monitoring circuit is employed within the power supply module. If the voltage on any rail is out of tolerance, a power supply fail signal is asserted on the I/O bus to disable the relay. An alarm output relay inside the power supply module is also de-energised. The alarm output relay has one normally open contact and one normally closed contact which are brought out to the MIDOS connector.

The terminal allocation of the power supply module is shown in Table 5. Also see the LGPG111 external connection diagram for specific connection details.

3 4		Power Supply Failure Alarm (normally open)
5 6		Power Supply Failure Alarm (normally closed)
13 14	+ –	Vx(1) auxiliary DC input

Table 5 Terminal allocation of the power supply module.

5.2. Relay output

Module Number: GM0032

Two relay output modules are fitted in the LGPG111.

Each module has eight PCB mounted miniature hinged armature relays. The rating of these relays is given in Table 6. Two change-over and eleven normally open contacts are wired to a 28-way MIDOS connector for external connection (see Table 7).

Make and Carry.	7500VA for 0.2s with maixima of 30A and 300V AC or DC.
Carry continuously:	5A AC or DC
Break:	AC 1250VA DC 50W resistive 25W L/R = 0.04s with maxima of 5A and 300V

Table 6 Output relay contact ratings.

Each module has an address which is set by the positions of jumper links JM1 and JM2 on the PCB. The states of the output relays are controlled by an 8-bit data latch. Data is written into the data latch when the address of the module is selected and the I/O bus strobe signal is asserted by software.

The module takes the +6.5V and +24V supplies from the I/O bus. The +6.5V is regulated to +5V for logic circuitry on the board. The +24V is used to drive the output relays.

All the output relays are held de-energised during power failure or hardware reset conditions. This prevents incorrect contact operations during power-up, power-down and reset conditions.

With the exception of the relay inoperative alarm relay all the other output contacts are user definable through the scheme logic settings, as described in chapter 4.

Relay Number	Terminal Number	Contact Type[1]	Pick-Up Speed	Drop-Off Speed
0	1 3 5	n.o. common n.c.	8ms	8ms
1	2 4 6	n.o. common n.c.	8ms	8ms
2	7 8	n.o.	8ms	8ms
3	9 11	n.o.	2ms	2ms
	10 12	n.o.	2ms	2ms
4	13 15	n.o.	2ms	8ms
	14 16	n.o.	2ms	8ms
5	17 19	n.o.	2ms	8ms
	18 20	n.o.	2ms	8ms
6	21 23	n.o.	2ms	8ms
	22 24	n.o.	2ms	8ms
7	25 27	n.o.	2ms	8ms
	26 28	n.o.	2ms	8ms

Table 7 Terminal allocation of the relay output module.

5.3. Microcomputer & serial communications

Module number: GM0099

5.3.1. Microcomputer board

The module consists of a powerful 16-bit microprocessor (Intel 80C186XL) featuring integrated on-chip peripherals. These peripherals include a timer unit with three programmable timers, a direct memory access (DMA) unit, a programmable interrupt controller unit (ICU), and an address decoder unit.

Eight 28-pin JEDEC memory sockets are provided. For the LGPG111, the memory sockets are populated with 64 kilobytes of RAM, 16 kilobytes EEPROM, and 128 kilobytes of EPROM giving a total of 208 kilobytes[2] of memory. The module

[1]In the table *n.o.* means *normally open* contact and *n.c.* means *normally closed* contact with respect to the common terminal or terminal pair.

incorporates a watchdog timer to ensure an orderly restart in the unlikely event of a system crash. An RS232 compatible serial interface controlled by a universal synchronous and asynchronous receiver transmitter (USART) allows serial communication with the microprocessor for factory test purposes.

The microcomputer module controls the I/O bus. All modules connected to the bus work as slave I/O modules to the microcomputer module. The module is powered from the +6.5V and ±19.5V bus rails.

5.3.2 Serial communications board

The serial communications board is designed to remove the time critical elements of the serial communication protocols. The board uses an Intel 87C196 microprocessor which is controlled by the main microprocessor module and which in turn, controls a dual channel serial communications controller. The board is linked to the microcomputer via the I/O bus and also directly connects to the isolation module mounted in the rear of the relay.

A choice of 3 ports is available through the LGPG111's user interface. One is on the front panel and the other two are at the rear of the relay. The front serial port is a non-isolated RS232 port using the IEC870 protocol for communications. Connection to this port is made via the I/O bus with only transmit and receive signals being available; the port is only suitable for temporary connection during commissioning and testing. The other two serial ports are an RS232 port using IEC870 protocol and an RS485 port using K-Bus protocol. Access to these to ports is via the isolation module which allows for permanent connection.

5.4. Isolation module

Module Number: GM0100

The module is made up of one PCB and is mounted into the back of the case.

The isolation module provides isolation for the two rear mounted serial communications ports and allows these ports to be permanently connected to serial communications networks or modems, etc.

5.4.1 K-Bus connection

K-Bus requires a twisted pair screened cable with resistive termination of the extreme ends.

5.4.1.1. Connection method

K-Bus is a multi-drop standard. This means that a K-Bus connection, shown in Figure 1, can be made point to point or can be daisy-chained together with a number of other products. A chain of connected units is known as a spur and no branches may be made from the spur.

5.4.1.2. Recommended cable

[2] It is standard convention to use the binary thousand of 1024 (2^{10}) to define kilo in the context of memory capacity. Thus the LGPG111 has 208x1024 = 212992 bytes of memory.

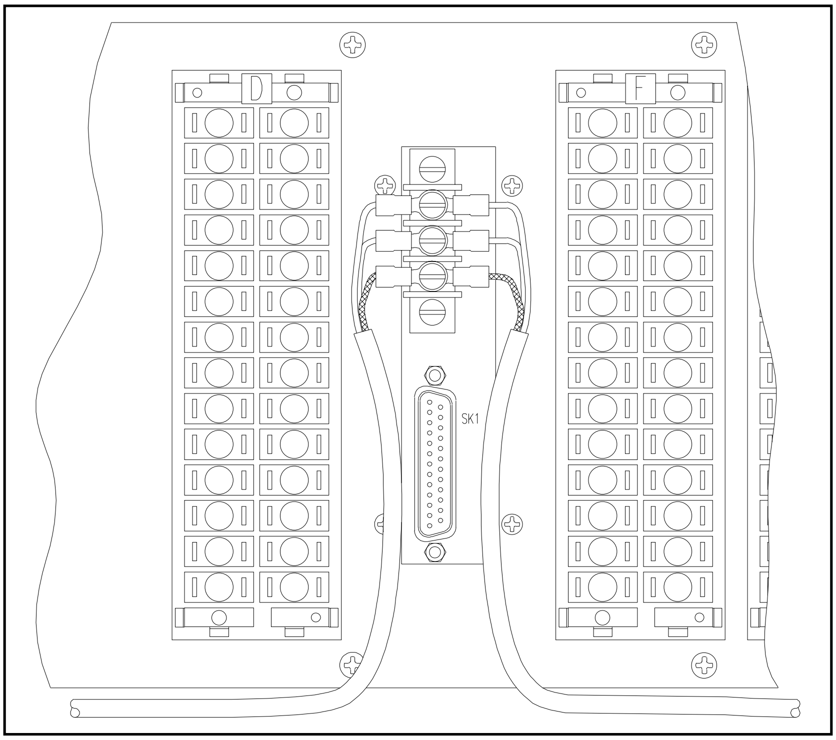


Figure 1 K-Bus connection arrangement on the LGPG111

Twisted pair with outer screen, to DEF STANDARD 16-2-2c 16 strand, 0.2mm diameter, 40mΩ per meter per core, 171pF per metre (core to core), 288pF per metre (core to screen).

5.4.1.3. Cable termination

A three terminal, 4mm, screw block is provided on the LGPG111. Two terminals are for the twisted pair communications wires and the third is for the screen. The screen connection is not internally connected to the LGPG111 in any way, since the screen should be earthed at one point of the cable only - normally at the master end. The transmission wires should be terminated using a 150Ω resistor at both extreme ends of the cable.

5.4.1.4. Cable polarity

Terminal No.	Connection
1	K-Bus 1
2	K-Bus 2
SCN	not connected

Table 8 K-Bus connections.

Polarisation is not necessary for the twisted pair.

5.4.1.5. Maximum cable length

The maximum cable length for a spur is 1000m.

5.4.1.6. Maximum devices per spur

The maximum number of devices per spur is 33. This ordinarily allows for one master connection and 32 slaves. The LGPG111 constitutes as a slave device.

5.4.1.7. RS232 (IEC870) connection

5.4.1.8. Connection method

The RS232 port is suitable for direct point to point connection between the LGPG111 and either a PC or modem. The pin out of the rear port on the relay is configured as a Data Terminal Equipment (DTE), the connections are listed in Table 9.

5.4.1.9. Earthing arrangements

The earthing arrangement of the RS232 connection is for the protective ground to be connected to 0V and also to the relay case. This arrangement provides maximum screening of the RS232 signals.

Pin Number[3]	Function	Direction
1	Protective ground	-
2	Transmitted data TxD	Out
3	Received data RxD	In
4	Request to send RTS	Out
5	Clear to send CTS	In
6	Data set ready DSR	In
7	Signal ground GND	-
8	Data Carrier Detect DCD	In
20	Data terminal ready DTR	Out

Table 9 Connection for the rear mounted RS232 serial connector.

The signal ground of RS232 connection is not connected to the 0V of the relay. This ensures that no earth loop currents can flow between the relay and other connected equipments. If it is required to connect the RS232 signal ground to the 0V of the relay then a 150Ω resistor can be fitted onto the PCB for R26. This modification will result in there being no isolation between the relay and the RS232 connection.

It is recommended that any modifications are carried out by ALSTOM T&D Protection & Control Limited

5.4.1.10. Recommended cable

A standard PC serial port interface cable should be used. It is essential that the cable screen be earthed at one end to ensure adequate screening. The connectors should be screw locked at each end. Reference should also be made to the PC or modem user manual for the exact connection requirements.

5.4.1.11. Cable length

The maximum recommended cable length between IEC870 communication ports is 15m or 2500pF total cable capacitance.

[3]Pins on the 25-way connector that are not listed are not connected.

5.4.1.12. Data rates

The maximum data rate available on the LGPG111 is 19600 bits per second.

5.5. Status input

Five versions are available covering the following DC supply voltages:

Eight optically-isolated logic status inputs are provided which are rated at the auxiliary DC supply voltage Vx(2). To reduce power dissipation caused by current flowing in the isolation circuitry, a strobing technique is adopted which only allows

Module number:	Model number issue letter:
GM0022	A to C
GM0111	D onwards

current to flow into the circuitry when the status inputs are being read.

Nominal	Operative Range	Maximum Withstand
24/27V	19.2 - 32.4 V	36.5 V
30/34V	24 - 40.8 V	45.9 V
48/54V	38.4 - 64.8 V	72.9 V
110/125V	88 - 150 V	168.8 V
220/250V	176 - 300 V	337.5 V

Table 10 Status input voltage ranges

Connections to external wiring is made via a 28-way MIDOS connector. Terminal allocation of the input module is given in Table 11. The input function assignment is user definable through the scheme logic settings, as described in chapter 4. The module is powered from the +6.5V rail of the I/O bus.

5.6. Analogue and status input

Module number:GM0105

Terminal No.		Description	Menu Ref
1 2	+ –	Input 6	User Definable
5 6	+ -	Input 7	User Definable
9 10	+ –	Input 8	User Definable
13 14	+ –	Input 9	User Definable
15 16	+ –	Input 10	User Definable
19 20	+ –	Input 11	User Definable
23 24	+ –	Input 12	User Definable
27 28	+ –	Input 13	User Definable

Table 11 Terminal allocation of the status input module.

Two AC input ratings are available: 1A, 110V
5A, 110V

Four DC voltage variations are available covering the following ranges:

5.6.1. Analogue inputs

The module contains three standard current transformers, three high sensitivity current

Nominal	Operative Range	Maximum Withstand
24/34V	19.2V- 40.8V	45.9 V
48/54V	38.4 - 64.8 V	72.9 V
110/125V	88 - 150 V	168.8 V
220/250V	176 - 300 V	337.5 V

Table 12 Status input voltage ranges for analogue and status input module.

transformers, six transactors and five voltage transformers. These interfacing transformers scale down the levels of the incoming signals and provide isolation. The different types of transformers are used to optimise the performance of the protection functions, whilst maintaining a compact design.

The output of each of the interfacing transformers is filtered by an anti-aliasing filter and multiplexed, by one of three analogue multiplexers, into a sample and hold filter. This has a x1 and x8 gain control to increase the dynamic range of the input signals. Data conversion is performed by a 12-bit analogue to digital converter. The 12-bit data is 2's complemented and sign extended to 16 bits before being transferred to the microcomputer module for processing.

In addition to multiplexing the analogue signals, the three multiplexers are also connected to two DC signals (+5V and 0V). These are used for checking the correct operation of the multiplexers, sample and hold and data conversion circuitry.

5.6.2. Status inputs

Six optically-isolated logic status inputs are provided which are rated at the auxiliary DC supply voltage Vx(2). To reduce power dissipation caused by current flowing in the isolation circuitry, a strobing technique is adopted which only allows current to flow into the circuitry when the status inputs are being read.

5.6.3. Calibration data storage

To increase the accuracy of the analogue inputs, software calibration is employed to correct the magnitude and phase errors which occur due to component tolerances on the input circuits. In order to make the modules fully interchangeable it is necessary to store this information within the analogue input module. To facilitate this, 128 bytes of non-volatile memory (EEPROM) is available which is directly mapped on to the I/O bus.

5.6.4. Connections

Connections to external wiring are made via two 28-way MIDOS connectors which provide a CT shorting facility for the CT inputs. Terminal allocation of the input module is given in Tables 13 & 14. See the LGPG111 external connection diagram for details of input function assignment.

The module is powered from the +6.5V and +19.5V rails of the I/O bus.

5.7. Front panel user interface

Module number: GM0025

The user interface is mounted in the hinged front panel. It consists of a 2 row by 16

Terminal Number		Description
5 6	Start End	Earth Path Current Ie
7 8	Start End	Residual current I-Residual
9 10	Start End	Reverse Power Ph A Ia-sensitive
11 12	Start End	Line Current Ph A Ia
13 14	Start End	Line Current Ph B Ib
15 16	Start End	Line Current Ph C Ic
17 18	Start End	Bias Current Ph A Ia-Bias
19 20	Start End	Bias Current Ph B Ib-Bias
21 22	Start End	Bias Current Ph C Ic-Bias
23 24	Start End	Differential Current Ph A Ia-Diff
25 26	Start End	Differential Current Ph B Ib-Diff
27 28	Start End	Differential Current Ph C Ic-Diff

Table 13 Terminal allocation of the analogue and status input module - block A.

Terminal Number		Description
1 2	+ –	27 & 81U Inhibit
3 4	+ –	51V Timer Inhibit
5 6	+ –	51N Timer Inhibit
7 8	+ –	Setting Group Select-1
9 10	+ –	Setting Group Select-2
11 12	+ –	Clock Sync
19 20	Start End	Earth Path Voltage Ve
21 22	Start End	Comparison Voltage Vab-Comp
23 24	Start End	Comparison Voltage Vbc-Comp
25 26	Start End	Measurement Voltage Vab

Table 14 Terminal allocation of the analogue and status input module - block B.

character alpha numeric liquid crystal display (LCD) and a 7-key keypad. With the glass cover in position, only two of the seven keys are accessible.

Also included on the front panel are four indication LED's and two 25-pin D-type sockets. One of the sockets marked 'SERIAL' is the front RS232 port for IEC870 serial communications. The connection for this serial port (see Table 15) is configured as a data communication equipment (DCE). No handshaking control signals are provided.

The other socket marked 'PARALLEL' is a parallel input and output port. The port is capable of driving a parallel printer as well as providing access to all the internal power rails. Table 16 gives the pin-out information for both the parallel printer and voltage rail connections.

Pin Number[4]	Function	Direction
1	Protective Ground[5]	
2	Received Data	In
3	Transmitted Data	Out
4 &	Connected	
5	Together	
7	Signal Ground	
6,	Connected	
8 &	Together	
20		

Table 15 Connection for the front panel RS232 serial connector.

Standard PC interface cables should be used for both ports. However the connections will need to be modified for the printer as shown in Table 16. It is essential that the cable screen is earthed at one end to ensure adequate screening. The connectors should be screw locked at each end. Reference should be made to the PC user manual for the exact serial connection requirements and to the printers manual for the parallel port connection.

There is no electrical isolation on either the serial port or the parallel port. An external isolation barrier with transient suppressers should be used if the earth potential of the connected equipment differs from that of the relay.

The front panel operator interface is powered by the +6.5V rail of the I/O bus.

6. REPLACEMENT MODULE HARDWARE CONFIGURATION

The modules used in the LGPG111 are selected from a standard hardware range.

[4]Pins on the 25-way connector, not detailed, are not connected.
[5]The protective ground is connected to the case, which is connected to 0V of the relay.

Pin Number	Parallel Printer Connection[6]	Test Port Connection	Level
1	Strobe	--Do Not Connect--	TTL
2	Data Bit 0		TTL
3	Data Bit 1		TTL
4	Data Bit 2		TTL
5	Data Bit 3		TTL
6	Data Bit 4		TTL
7	Data Bit 5		TTL
8	Data Bit 6		TTL
9	Data Bit 7		TTL
10	--Do Not Connect--	RESET Key	TTL
11	Busy	--Do Not Connect--	TTL
12	--Do Not Connect--	ACCEPT/READ Key	TTL
13	--Do Not Connect--	SET Key	TTL
14	--Do Not Connect--	← Key	TTL
15	--Do Not Connect--	↓ Key	TTL
16	--Do Not Connect--	→ Key	TTL
17	--Do Not Connect--	↑ Key	TTL
18	--Do Not Connect--	+6.5V	Via 10kΩ
19	--Do Not Connect--	+19.5V	Via 10kΩ
20	--Do Not Connect--	-19.5V	Via 10kΩ
21	--Do Not Connect--	+24V	Via 10kΩ
22	Ground	Ground	
23	Ground	Ground	
24	Ground	Ground	
25	Ground	Ground	

Table 16 Front panel parallel port pin connections for parallel printer and test port.

Many of the modules have a number of jumper links which must be set to allow them to be used in particular applications.

The following Section lists the link positions required by modules in the LGPG111. All links must be fitted as shown.

The following modules do not have any jumper links:

- Power supply module - GM0026/GM0097
- Isolation module - GM0100

[6]The parallel printer connection is a sub-set of the IBM PC printer port. An IBM printer cable can be used by disconnecting the --Do not connect-- lines.

6.1. Relay output module - GM0032

6.1.1. Address decode

Two links are required to select the correct address decode for this module: a coarse and fine address selection. See Figure 2, for the relay output module link positions.

Coarse

JM2	No link

Fine

JM1	Module at position No.2	Link	1-16
	Module at position No.3	Link	2-15

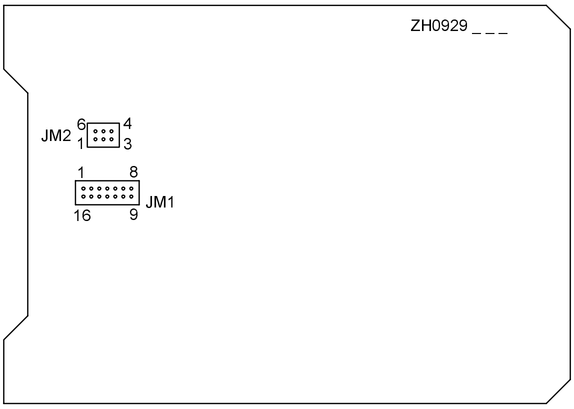


Figure 2 Relay output module link positions.

6.2. Microcomputer & serial communications module - GM0099

6.2.1. Microprocessor board

The microprocessor board has several options which must be selected with links. Four memory banks must be configured, the watchdog enabled, interrupt & DMA configured and the internal RS232 test port set-up. See Figure 3, for the microcomputer module link positions.

6.2.1.1. Memory selection

JM1	Link	1-2
		4-5
		7-9
JM2	Link	1-2
		4-6
		7-8
JM3	Link	1-2
		4-5
		7-9
JM4	Link	1-2
		4-6
		7-8

6.2.1.2. Watchdog Timer

JM5	Link	2-3

6.2.1.3. Interrupt & DMA Select

JM6	Link	3-4
		13- 14

6.2.1.4. RS232 Factory Test Interface Select

JM7	Rear connection	Link	1-2
	Front panel socket[7]	Link	3-4

JM8	Front panel socket	No link fitted

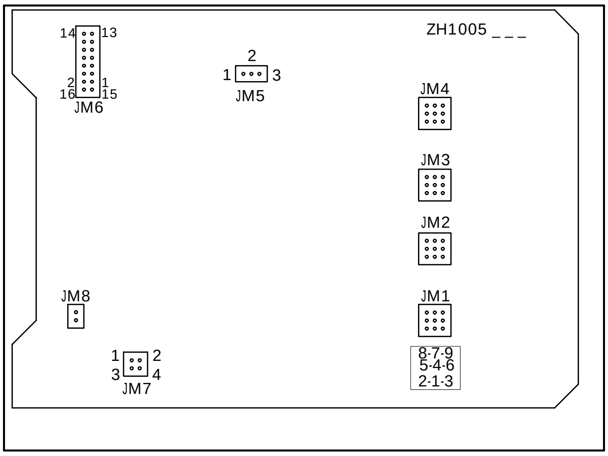


Figure 3 microprocessor & serial communications module link positions.

6.3. Status Input Module - GM0022/GM0111

Both modules use the same pcb which has two links that select the correct address decode for this module; a course and fine address selection. See Figure 4, for the Status Input Module link positions.

6.3.1. Address Decode

Coarse

JM2	Link	1-16

Fine

JM1	Link	3-6

[7]This connection is not available on the LGPG111 as the front panel socket is used by the remote communications.

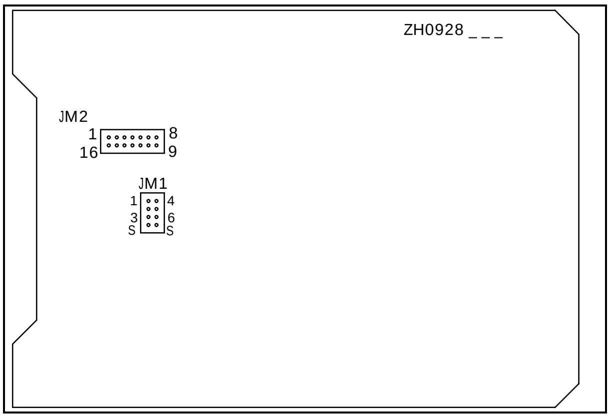


Figure 4 Status input module link positions.

6.4. Analogue and status input module

The analogue and status input module will have one to two pcbs fitted that both have three link sets. The pcb numbers are ZH1010 or ZH1017. The links are for address decoding, interrupt, DMA configuration and a calibration memory write protect. See Figures 5 and 6, for the analogue and status input module link positions.

6.4.1. Address Decode

JM2	Link	1-9
		2-10

6.4.2. Interrupt & DMA Select

JM1	Link	1-2

6.4.3. Calibration

JM3	Link	2-3	CALIBRATION OF RELAY ONLY
		1-2	Normal position

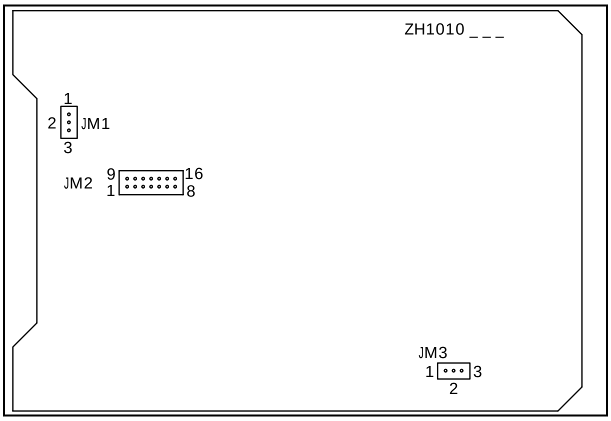


Figure 5 Analogue and status input module link positions. - -pcb no. ZH1010

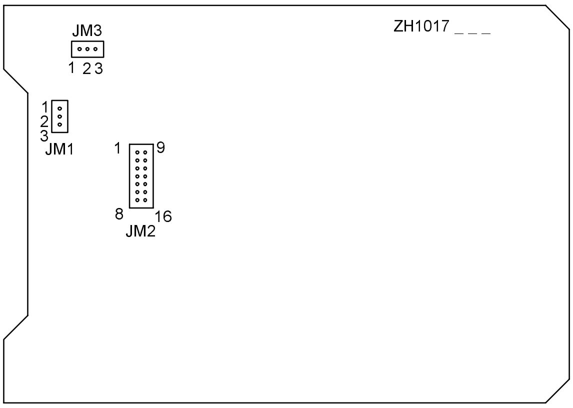


Figure 6 Analogue and status input module link positions. - -pcb no. ZH1017

6.5. Front panel operator interface

The front panel has one link which disables a push-button initiated reset of the LGPG111. See Figure 7, for the Front Panel Operator Interface link positions.

JM1	Link	1-2

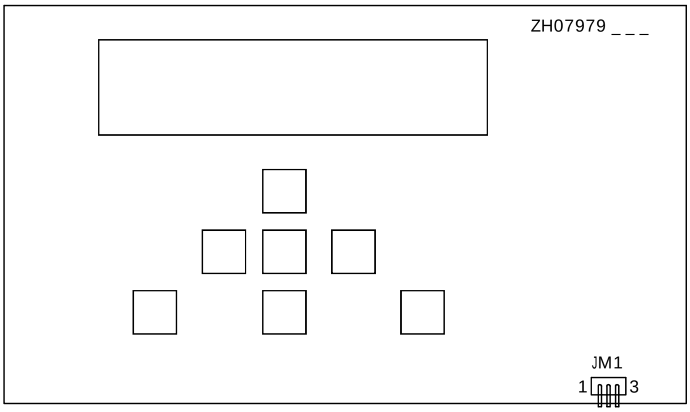


Figure 7 Front panel operator interface link positions.

Chapter 6 - User Interface

Issue Control

engineering document number: 50005.1701.106

Issue	Date	Author	Changes
AP	February 1995	Dave Banham	Original
BP	June 1995	Dave Banham	Minor corrections and layout improvements.
A	July 1995	Dave Banham/ Publicity	Styles changed. Features for software version 18LGPG002XXXEB onwards added: i) Paragraph added to ‘Scheme Output’ cell (in auxiliary functions) to indicate that the state of the cell is now logged at reset and whenever it is changed. Consequential event messages added to Table 19 along with new ‘real time clock set’ message. ii) Description cell in System Data is now settble. Old description default display renamed as ‘Title’ and a new description default display option added to display the Discription cell. The header of printed reports now includes the description as well as the plant reference entries.
B	Feb 1996	Dave Banham/ Publicity	Some minor corrections. Corrected Table 2: IEC870 character size specified incorrectly with 2 stop bits. Added note to K-Bus data that it is biphase FM0 encoded.

Contents

1. INTRODUCTION

The LGPG111 has been designed with two principal means of allowing a user to interact with it; there is a front panel interface and a remote communications access interface. Both these systems provide a broad range of standard facilities which allow a user to:

- Read or change relay settings
- Display measurement values
- Examine fault and event records
- Inhibit the relay outputs for testing
- Perform tests
- Print information through the parallel port

Additionally, the remote access interface provides further possibilities for using the data available in the LGPG111. SCADA type equipment can be interfaced and the measurement data provided by the LGPG111 used to annotate mimic diagrams. Measurement values can be collected for trend and performance analysis. Settings can be saved remotely and archived or transferred to further LGPG111's to speed up relay configuration.

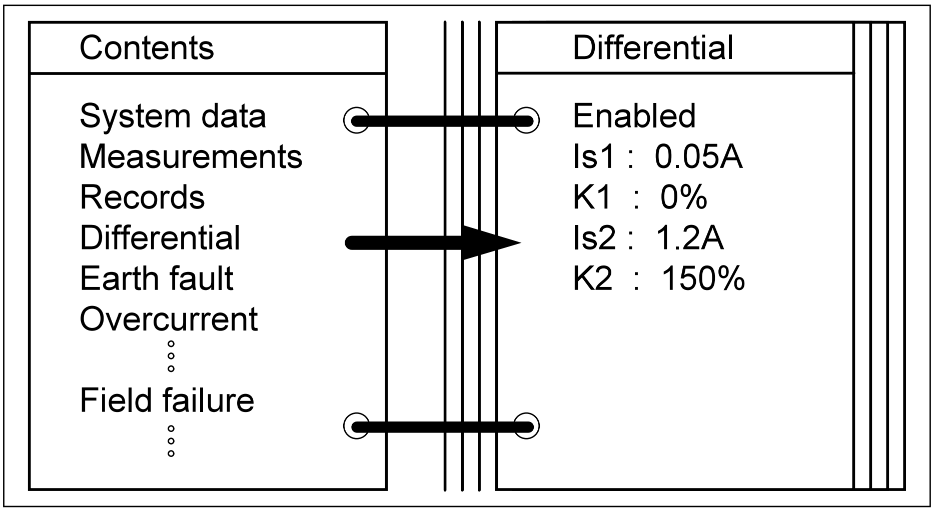
Throughout this Chapter the front panel user interface is generally referred to as the front panel[1] and the remote communications user interface as the remote access. Both user interfaces are collectively referred to as access methods.

The following sections describe the underlying philosophy and operation of each interface, security considerations and finally a detailed description of the menu system.

"A supplementary publication, R6138, is available which provides a detailed technical view of the remote user interface menu. The publication will only be required when remote terminal equipment such as RTUs and SCADAS are to be explicitly configured to exchange data with the LGPG111."

2. PHILOSOPHY

The underlying user interface for both systems is a database.



The database has been organised into a menu-like book with several sections. Each section has a title.

[1]Some times the front panel user interface is called the *local access*.

A user can browse over the section titles in a similar fashion to reading a book's contents page. Except, here, the contents of the desired section can be turned to directly by selection of the desired section heading.

The remote user interface accesses the information one section at a time. The front panel user interface navigates around the individual items of information (called cells) with 4 arrow keys.

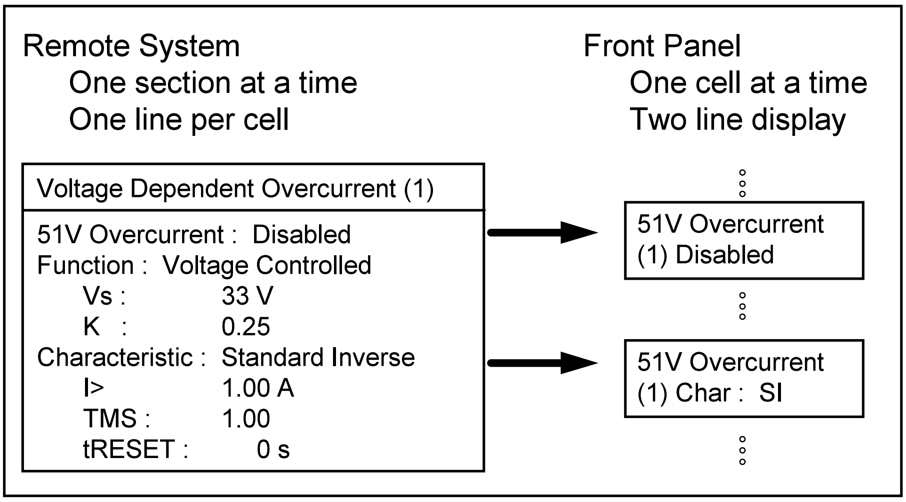


Figure 2 Illustration of the differences between the two access systems.

There are some minor differences in display formats between the two interfaces. The front panel's display is limited to 2 lines of 16 characters, whilst the remote interface is assumed to display one line of up to 50 characters. Thus, for the front panel, abbreviated text is used, where necessary, to cope with the line break and reduced line length. The format of cells on the remote system, however, takes full advantage of the increased line length to avoid the use of abbreviations, etc.

The functionality of both interfaces is the same except that the remote interface can extract disturbance and event records for further analysis.

Both the front panel and remote access user interfaces are always available. Although both share the same database, they operate independently from one another. However, only one interface is allowed to carry out a setting change at a time. Settings that are critical or relate to the operational scheme of the relay are password protected. While an interface is in the setting change mode or the password protection has been removed, a timer is started to detect any period of continuous inactivity at the interface. When the period of inactivity has expired, these modes are cancelled. Also, for the front panel, the display will revert to its default display. Each user interface (access) system has its own inactivity timer.

3. MULTIPLE SETTING GROUPS

The LGPG111 provides two complete groups of protection and scheme logic settings, either of which the protection can be switched to use. There is also the option to disable this facility, thus leaving the LGPG111 with just one setting group.

With the alternative setting group enabled, the two setting groups are shown as pairs of sections (see Figure 3); one for each group and one pair for every section of the protection and scheme logic. The group number is included in the section's title and, for the front panel interface, it is included in every cell within the section.

If the application for the LGPG111 does not require the use of an alternative setting group, it may be turned off. In this case, all references to multiple setting groups are removed from the menu and the alternative group hidden. If group 2 was selected when this happens, group 1 settings are re-selected.

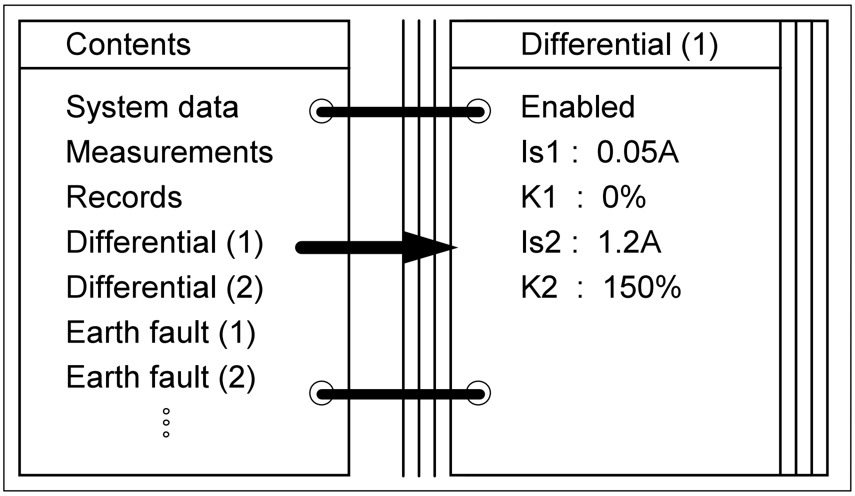


Figure 3 An illustration of the menu system with the alternative setting group enabled.

4. FRONT PANEL USER INTERFACE

4.1. Description

The front panel user interface consists of a liquid crystal display (LCD), seven push buttons and 4 light emitting diodes (LED's). There is also a non-isolated serial port for connection to a PC and a parallel port for connection to a 'Centronics' type parallel printer.[2]

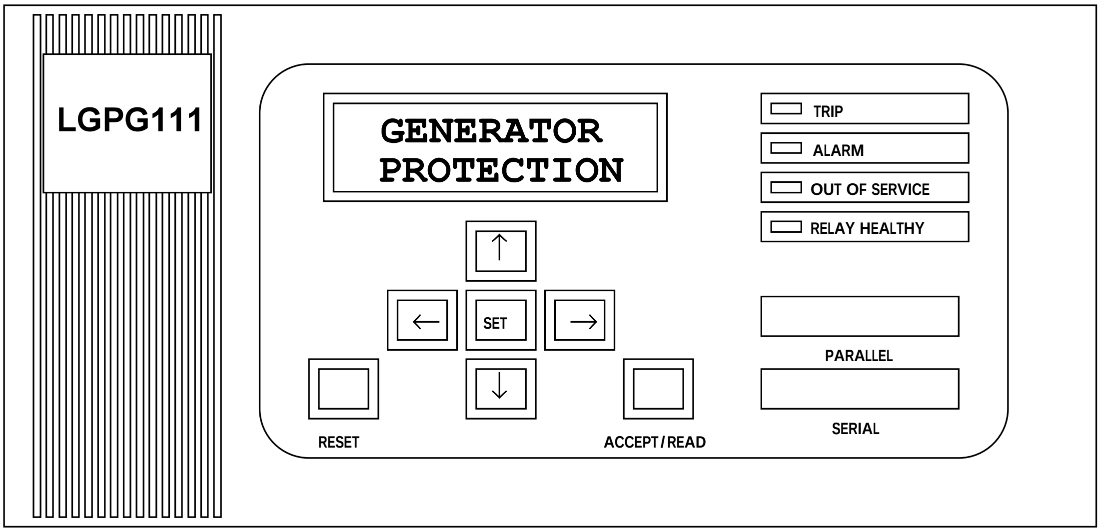


Figure 4 The LGPG111's front panel user interface.

[2]See chapter 5 for pin-out details of these ports.

4.1.1. Display

The display is a 2 row by 16 character alphanumeric liquid crystal device and is used to display one cell at a time from the relay's menu. The display is refreshed every 500ms or after every key press. The 500ms refresh allows the display of cells showing dynamically changing information, such as power system measurements, in real time.

4.1.2. LED status indicators

Four LED's provide status indication and are updated every 500ms.

The red trip LED is illuminated when any trip[3] output has operated.

The yellow alarm LED flashes when a trip or alarm[4] condition has occurred and remains flashing until all trip and alarm indications have been accepted. If any of these conditions are still active when the alarms are cleared, the LED stops flashing and remains on.

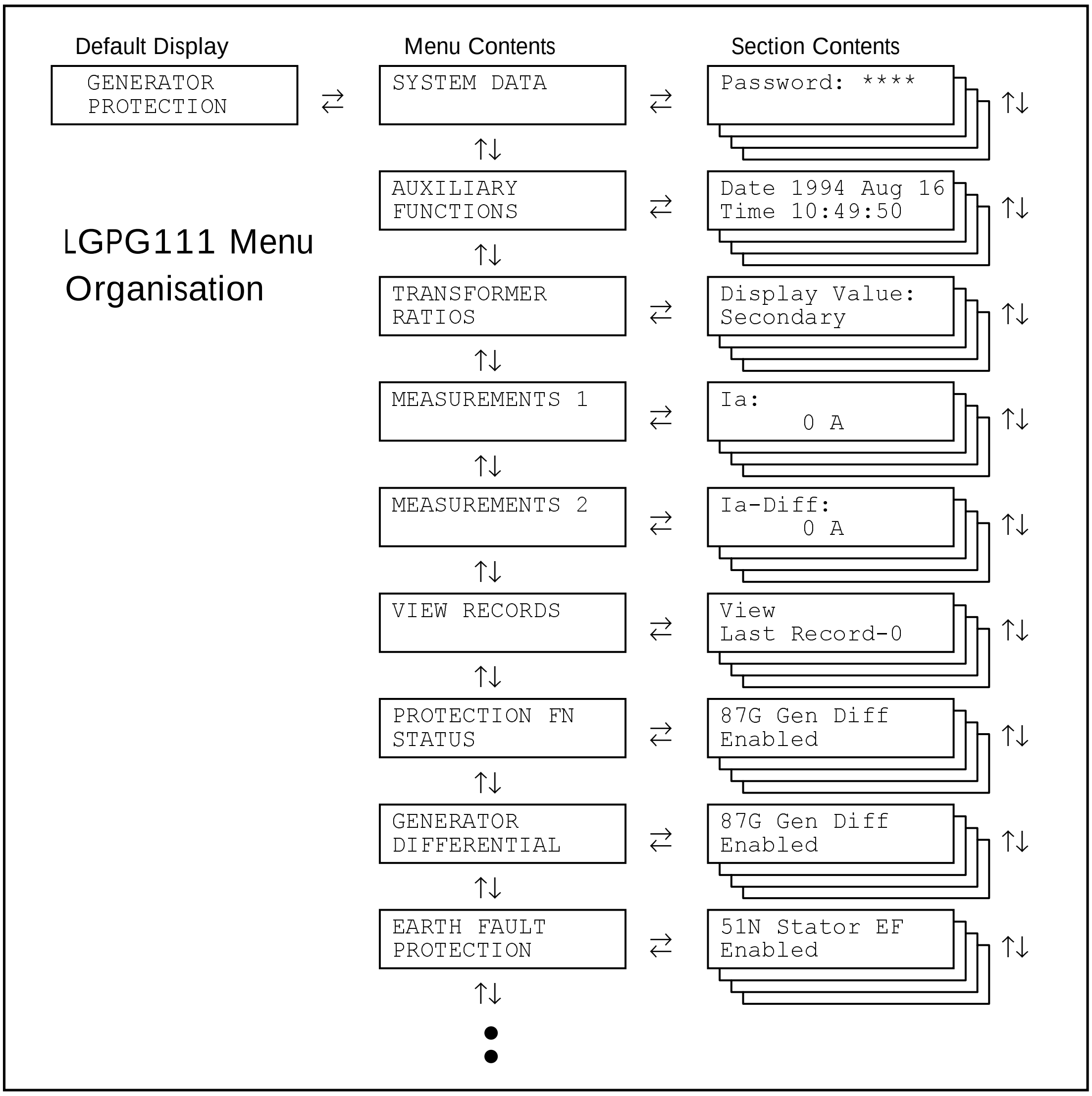


Figure 5 An illustration of the LGPG111's menu organisation. (Not complete.)

[3]A trip is defined by the fault record trigger from any of the 15 contact outputs.
[4]An alarm is defined by the alarm trigger, latched outputs and diagnostic exceptions.

The yellow out of service LED is illuminated when the output contacts are inhibited by the scheme output cell. Under this condition all the protection, alarm, recording and front panel indication functions are performed normally. All the relay outputs are, however, disabled. This allows injection testing without the risk of tripping circuit breakers, etc.

The green relay healthy LED is always on when the relay is functioning correctly, but is switched off if the relay becomes faulty. Under some failure conditions the relay will also illuminate the out of service LED.

4.1.3. Push buttons

The front panel has seven push buttons, consisting of 4 arrow keys (↑,↓,←,→), a SET key, an ACCEPT/READ key and a RESET key. The 4 arrow keys and the SET key are only accessible, to the user, when the transparent front cover is removed.

A key, if continuously pressed, will auto-repeat. The auto-repeat rate rapidly increases to facilitate rapid selection; this is particularly useful for large sections (such as the scheme logic) and for settings with a wide setting range (such as the transformer ratios). Since the display updates on each key press (including each auto-repeat press), the display always reflects the current selection and hence provides a visual feed-back as to the state of the auto-repeated selection.

The front panel's display is used to present the relay's internal menu and, in combination with the key buttons, facilitates user interaction with the relay. The menu is organised in a tree structure under the default display, as illustrated in Figure 5.

4.2. Default display

The default display represents the root of the LGPG111's menu system and it is from this display that one of the three modes of operation, described in the following section, can be entered. The default display consists of a selectble primary display and several over-ride displays. The over-ride displays replace the primary display when the LGPG111 has a warning to report.

The primary default displays are user selectble from the following:

• Title	GENERATOR PROTECTION	
• Description	Description: LGPG111 Relay	
• Model Number	Model Number: LGPG11101S533LEA	
• Plant Reference	Plant Reference: <Not Defined>	
• Phase Currents	0.68 A 0.69 A 0.67 A	I_A I_B I_C
• Line Voltages	110 V 110 V 110 V	V_{AB} V_{BC} V_{CA}
• Earth Quantities	Ie = 0.034 A Ve = 3.4 V	
• Negative Phase Sequence Current (I_2)	I2 = 158mA	

• A phase Active & Reactive Power	Pa = 43.02 W Qa = 3.763 VAr	
• Phase Angle Of I_a With Respect To V_a	θa = 5.0 deg	
• System Frequency	Frequency = 50.0 Hz	
• Date and Time	Sat 1994 Jan 01 10:31:22	
• Active Setting Group	Setting Group 1 Active	
• All (default display) Measurements	Cycles through the above 7 measurement displays at 5s intervals.	

The description, model number and plant reference displays correspond to their respective cells in the System Data Section of the menu.

There are three over-ride warning displays:

• Alarm Prompt	ALARM	Mimics operation of alarm LED.
• Real time calendar-clock uninitialised	DATE AND TIME NOT SET UP	
• Password protected settings unlocked	Local Settings Unlocked	Local refers to the front panel interface as opposed to the remote communications interface.

The priority for the selection of the default displays is shown in the Table below:

Priority	Default Display
1 (Highest)	Alarm prompt
2	Real time calendar-clock uninitialised
3	Local (front panel) settings unlocked
4 (Lowest)	Primary default display, as selected by user

Table 1 Default display priorities.

4.3. Modes of operation

The front panel interface provides three modes of operation:

- Alarm scan,
- Menu scan, and
- Menu browse.

4.3.1. Alarm scan

The alarm scan mode is available whenever the display is showing the alarm prompt message 'ALARM' and the alarm LED is on (either flashing or steady). In this situation the RESET and ACCEPT/READ keys can be used to scan through the alarm messages, which can then be accepted or reset. Since these two keys are accessible with the front cover fitted, they provide a convenient means for an operator to read these messages.

The ACCEPT/READ key enters this mode and allows the alarm messages to be stepped through, each press of the key selecting the next message. After the last alarm message has been displayed the user will be prompted to press 'RESET to clear alarms'. The RESET key can then be pressed to clear the messages. Alternatively, the ACCEPT/READ key can be pressed to accept the alarms without clearing them. In this case, if none of the alarms are still active, the display returns to showing a non-flashing 'ALARM' message combined with a continuously illuminated alarm LED. However, for both cases, if there are alarms which are still active, an 'ALARMS still active' message is displayed to indicate this condition and the ACCEPT/READ key must be pressed to return to the default display. The alarm message and alarm LED will remain on, but not flashing, although, if the clear alarms action had been selected, then only the active alarms will remain. An example of these alarm scan operations is provided in Figure 6.

With the relay's front cover removed, two further ancillary key actions are possible. The ← arrow key aborts the alarm scan and returns the menu to its default display. The alarms are neither accepted nor cleared, so the alarm display and LED will be as they were. This key action is included principally to allow the alarm scan to be aborted - as a quick way back to the default display - when the relay is being demonstrated. The ↓ arrow key causes the alarm scan to jump straight to the confirmation stage. This key action is included as an aid during repetitive testing.

Section 9.5., page 86, details the alarm messages.

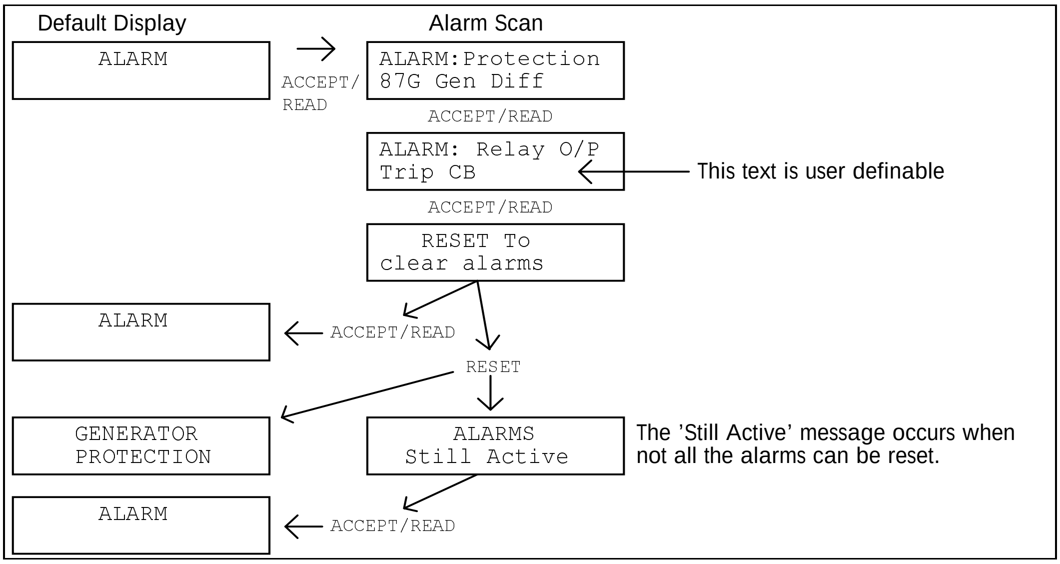


Figure 6 Example of the front panel alarm scan procedure.

4.3.2. Menu scan

The RESET and ACCEPT/READ keys are used to *scan* the menu. Since these two keys are accessible with the front cover fitted, they provide a convenient means of reading the relay's settings. It is not possible to change any settings in this mode of operation.

The RESETkey enters this mode and allows the section titles to be stepped through. The ACCEPT/READ key then selects the displayed section and allows the contents of the section to be stepped through. Pressing the RESET key, inside a section, returns the display to the next section title.

Both the title and content stepping wrap-around, with the title wrap-around including the default display.

With the relay’s front cover removed a further ancillary key action is possible. The ← arrow key aborts the menu scan and returns the menu to its default display. This key action is included principally as a quick way back to the default display, when the relay is being demonstrated.

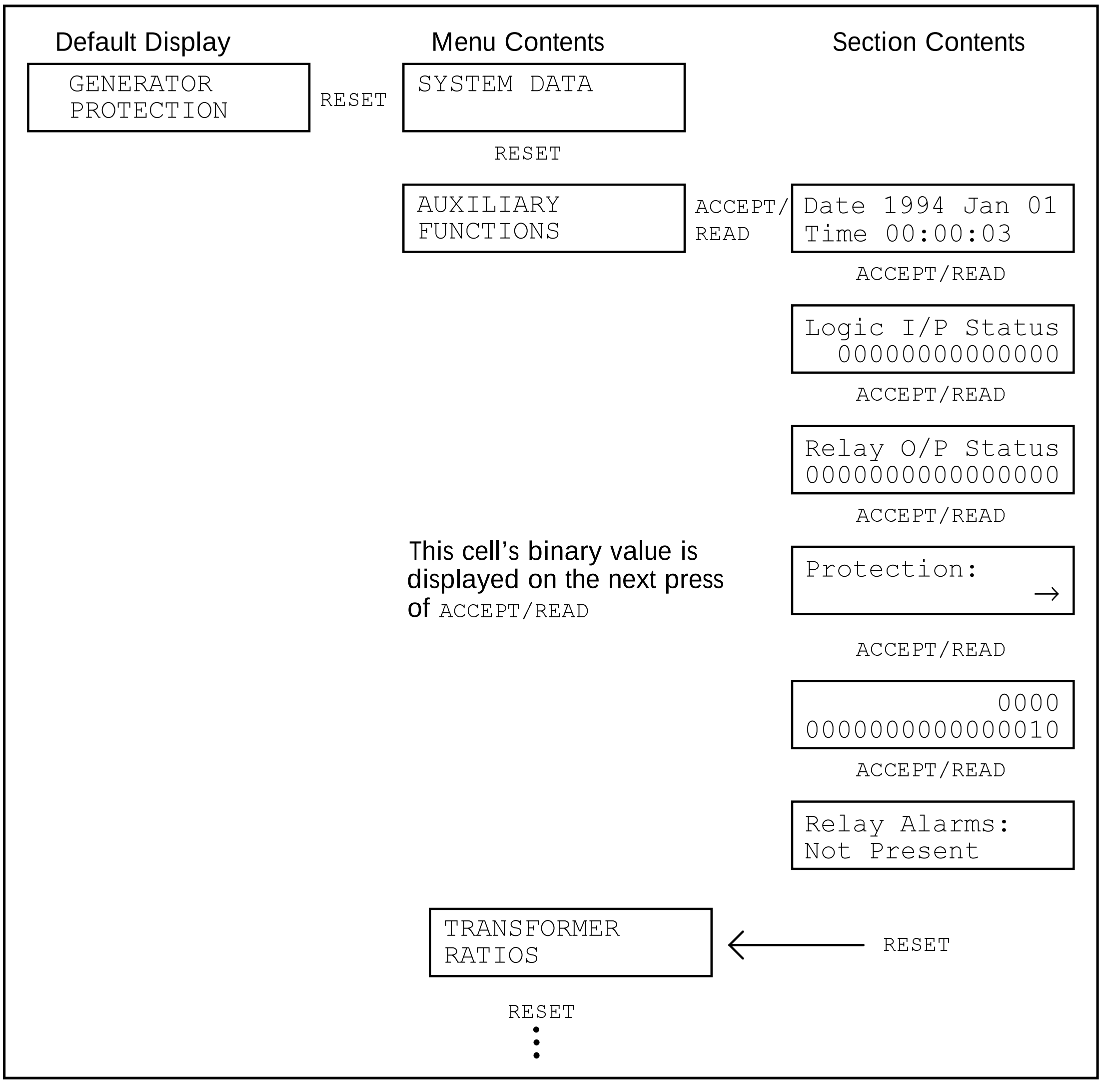


Figure 7 Example of the front panel menu scan procedure.

4.3.3. Menu browse

The four arrow keys, with the SET and RESET keys, are used to *browse* the relay's menu and to change settings.

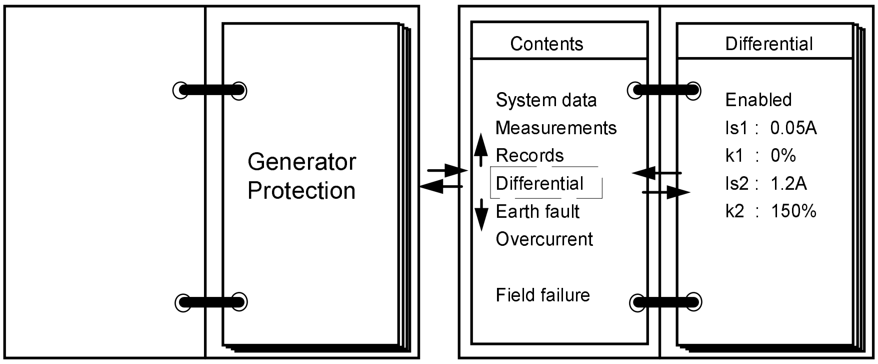


Figure 8 Illustration of the operation of the front panels arrow keys during menu browse.

In the menu browse mode, the keys of the key pad have the following principal functions:

The ↑ & ↓ arrow keys are used for selection. They allow the titles and section contents to be browsed by selecting the next or previous cell to be displayed. The selection process loops around from end to beginning and vice versa. The arrow keys are also used in selecting or changing cell values during setting mode.

The → arrow key is used as a selector. It enables section title browsing from the default display and allows the content of a section to be browsed by selecting its title. In this respect it may also be thought of as a turn to key. With a cell from a section displayed, pressing the → arrow key enters setting mode for it.

The ← arrow is used to back out of a section to the section title browse and from here to the default display. In this respect it may be thought of as a turn back key. It cannot be used to cancel (back out of) setting mode. However, in some sections, if settings have been altered, backing out of the section will cause a setting confirmation step to be introduced. This prompts the user to confirm the setting alterations to the section as a whole, by pressing the SET key. Alternatively, the RESET key can be pressed, causing the alterations to be undone or aborted.

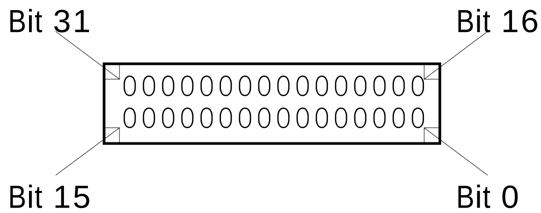
In setting mode the ← & → arrow keys may be used to select individual setting fields, when more than one exists. For example, to select individual characters of a string setting or to select each field of the calendar clock cell.

The SET key confirms a setting and cancels setting mode. In certain situations it is possible to enter a setting which the LGPG111 will reject, for example an incorrect password or too many analogue channels in the disturbance recorder set-up. In this case the message '`Sorry, Setting Is Invalid`' will appear and the ← arrow key must be pressed to return to setting mode.

The RESET key cancels setting mode without making any setting changes. Additionally, for a few cells there is a reset action associated when the cell is displayed normally, as part of the browse. For example; resetting the password cell re-enables the password protection.

If the → arrow key is pressed on a cell which is not a setting, the message '`Not A Setting`' is displayed. If the cell is currently password protected, the message '`Password Protected`' is displayed. In both cases pressing the ← arrow key will return to the display of the cell. For binary flag[5] type displays, these two messages have the additional qualifier `'View →'` appended, which indicates that the → arrow key may be pressed. This enters a mode very similar to the binary flag setting mode, except that the ↑ & ↓ arrow keys have no action - the flags cannot be changed. The view mode allows the display of the name of the selected bit flag and with every display update, the status of the flags is updated. Thus the state of a named flag can be monitored. The RESET key cancels this mode.

Some of the front panel's cell displays have a "→" at the bottom right hand side and no value. This is because the value consists of more than 16 binary bit flags which will not fit on the display. Although for consistency, in the scheme logic, the 15 binary output flags are treated in this fashion. Pressing the → arrow key causes the display to be replaced by up to 32 bit flags:



The ← arrow key can be pressed to return to the cell's normal display or the → arrow key to enter setting mode for the cell. This could result in the *password protected* or *not a setting* messages detailed above.

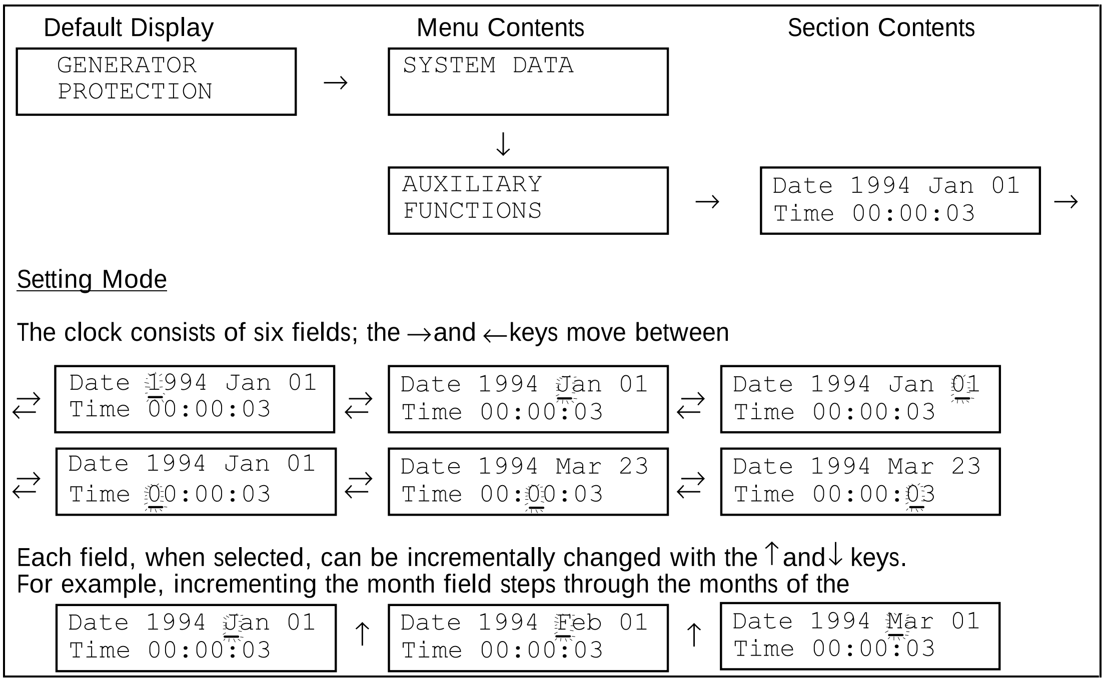


Figure 9 Example of the front panel menu browse procedure: Setting the clock.

[5] binary flag cell is one whose numeric value is displayed in base 2. However the cells numeric value is unimportant - it is the pattern of 1's and 0's which is of significance. Each digit, or bit, is used to represent some form of 2 state (binary) selection. In this sense each bit is treated as a flag, which when set to a 1 indicates the prescribed flag is set or on. The function of the flags is indicated through the user interface.

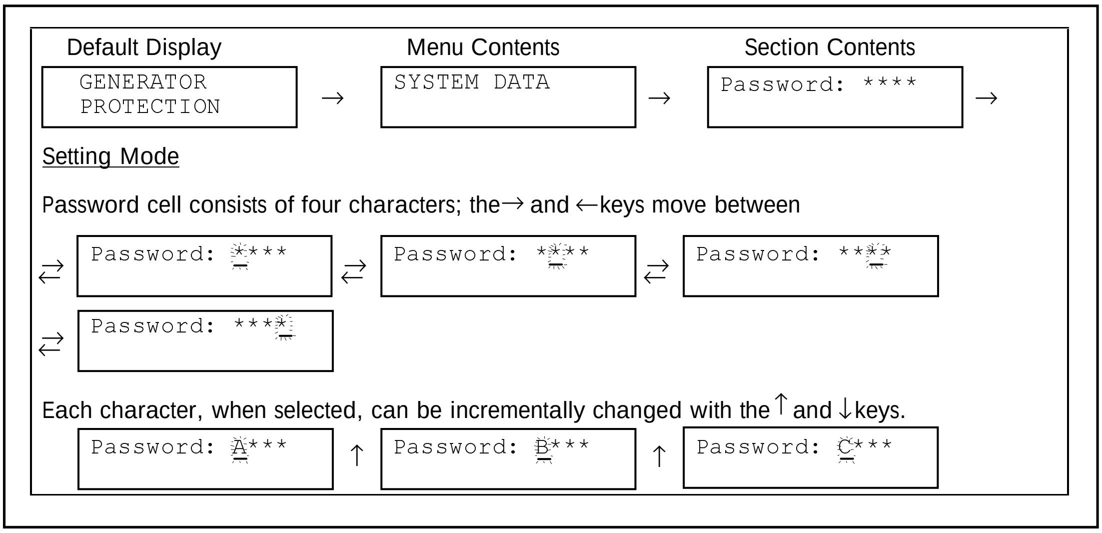


Figure 10 Example of the front panel menu browse procedure: Entering the password.

Default Display		Menu Contents		Section Contents	
GENERATOR PROTECTION	→	SYSTEM DATA			
		↓			
		AUXILIARY FUNCTIONS	→	Date 1994 Jan 01 Time 00:00:03	
				↓	
				Logic I/P Status 00000000000000	→

Example (i) Logic Input Status

Setting Mode

```
Not A Setting
        View→
```

→ This cell is not a setting, however the bits can be examined.

The → and ← arrow keys allow individual bits to be selected. The top line indicates the name of the selected bit. Bit 0 is always in the bottom right of the display and, in this example, bit 13 is left-most. Note that bits 6 to 13 of the Logic Inputs are scheme configurable with definable names.

```
⇄ | Input 13       | ⇄ | Input 12       | ⇄ | Input 11       | ⇄
  | 00000000000000 |   | 00000000000000 |   | 00000000000000 |
```

Press RESET to quit this mode.

The above procedure is slightly modified for binary flag cells with more than 16 bits. For example, the protection function status cell:

Default Display		Menu Contents		Section Contents	
GENERATOR PROTECTION	→	SYSTEM DATA			
		↓			
		AUXILIARY FUNCTIONS	→	Date 1994 Jan 01 Time 00:00:03	
				↓	
				Logic I/P Status 00000000000000	
				↓	
				Relay O/P Status 0000000000000000	
				↓	
				Protection: →	→

Example (ii) Protection Function Status

Here, because the 20 bit status information will not fit on the bottom line of the display, an extra display is introduced.
The first press of the → key, as prompted, brings up the value.
The next press of the → key brings the Not A Setting prompt up and the rest is as above, although the display has ←→ scroll indicators and only displays 14 of the bits at a time. The bits scroll left and right as required.

```
|             0000 | → | Not A Setting | →
| 0000000000000010 |   |         View→ |
```

```
⇄ | 87G Gen Diff      | ⇄ | 51V OC            | ⇄
  | ←00000000000000→  |   | ←00000000000000→  |
```

Figure 11 Example of the front panel menu browse procedure: Examining binary flag type cells.

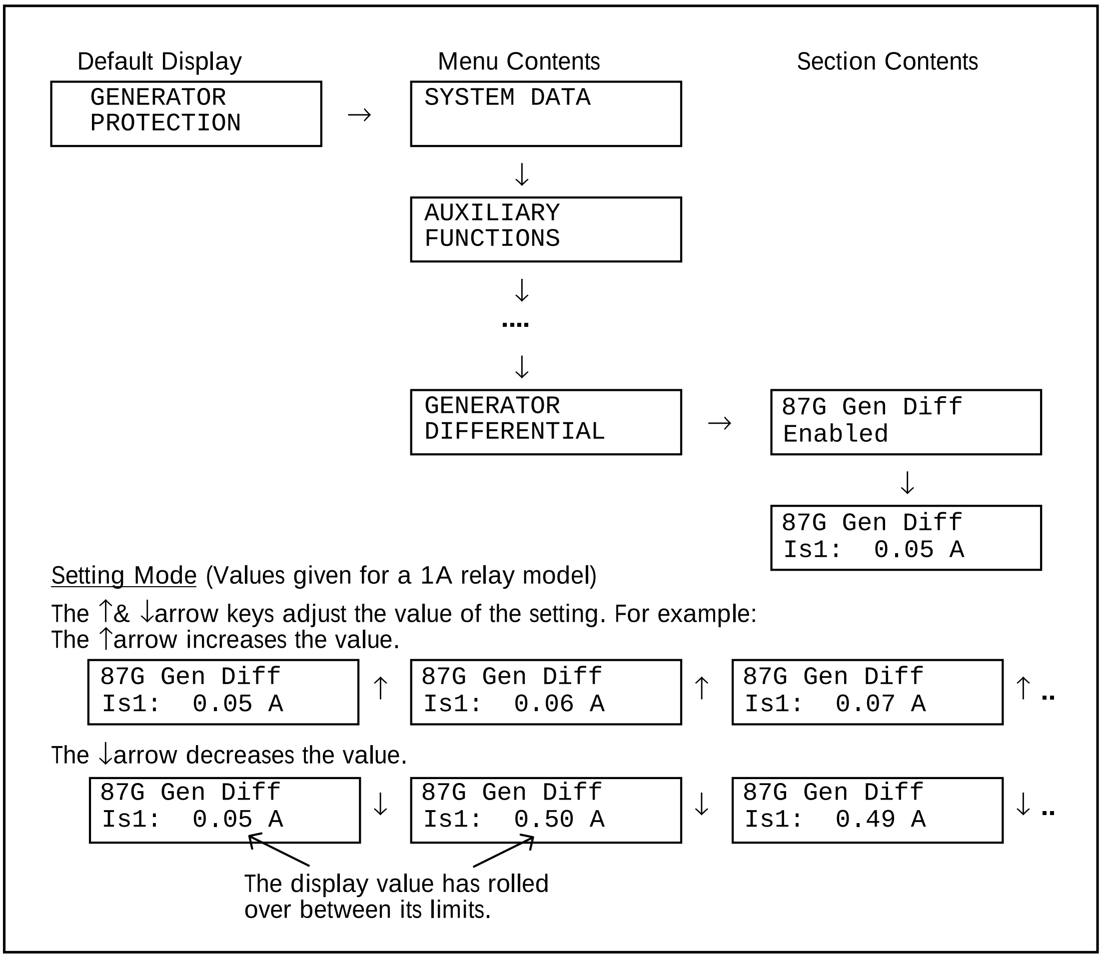


Figure 12 Example of the front panel menu browse procedure: Changing a value setting.

5. REMOTE ACCESS USER INTERFACE

For detailed information about how to use a particular remote access software package please refer to that package's user manual.

5.1. Typical features of remote access software

The remote access system is based on the ALSTOM T&D Protection & Control Limited Courier communications language.

The remote user interface is accessed by a PC, installed with suitable Courier based access software connected to one of the three serial ports. Courier based access software polls all relays connected to its system and allows a user to access information in each relay connected, by extracting the contents of the relay's database. ALSTOM Protection & Control Limited can supply suitable remote access software for use on a standard IBM compatible personal computer. Alternatively, a specifically programmed, third party, data acquisition device can be connected to collect data for data logging equipment, e.g. SCADA.

Typical features of a remote access system are:

- To provide the means to examine the relay's menu. The remote system can present a list of the available sections and then, by selecting a section, its contents can be displayed. In both cases, the remote system can usually display an entire page (or window) of the section titles or the section contents at once (or at least a scrollable page), which provides a major advantage over the small display on the front panel.
- Remote measurements. The measurement values which can be displayed on the front of the relay, can be polled regularly and stored to disk or graphically displayed on the screen of the PC.
- Automatic extraction of event and fault records. A sequential list of events can be captured automatically and displayed on the screen as they occur. They can also be stored on to disk and printed later.
- Disturbance recorder. Disturbance records can be extracted and stored for further analysis. It is also possible for the access software to detect the presence of disturbance records as they occur and extract them automatically.
- Remote change of settings. If the remote setting change facility is enabled (in the relay), then settings can be changed remotely.
- Transfer settings from or to the relay. The LGPG111 supports a setting transfer mode which allows a complete record of all the settings, regardless of current configuration, to be transferred. The transfer mode also eliminates certain settings which are either irrelevant (e.g. the printer control cell) or inappropriate to transfer (e.g. time & date setting cell). The individual descriptions of the menu cells indicate which cells are not included in the setting transfer.

	IEC870	K-Bus
Transmission Speed	600 to 19,200 Bits per second	64,000 Bits per second
Signal Levels	RS232	RS485
Maximum Cable Length[6]	15m	1000m
Connections	Singled ended	Multidrop (up to 33 connections)
Isolation (for 1 minute)	1kV rms (rear port only)	2kV rms
Protocol	IEC870 - 5 (FT1.2)	HDLC
Character Size	8 data bits, 1 even parity bit, 1 start bit & 1 stop bit	8 data bits packaged by HDLC protocol
Frame Check Sum	16 bit summation	CRC 16
Transmission Mode	Half duplex asynchronous start with synchronous frames	Half duplex synchronous HDLC - with biphase FM0 encoding
Message Format	Courier	Courier
Ports	Fully connected 25 pin D-Type female at the rear. Partially connected 25 pin D-Type female at the front.	Three terminal K-Bus port at the rear, using 4mm screws.
Modem Compatibility	Yes (rear port only)	No

Table 2 Comparison of the two communications protocols available in the LGPG111.

5.2. Connections

The LGPG111 provides three communications ports, only one of which can be used at any one time. Of the three, two are RS232 compatible using IEC870 protocol and one uses the ALSTOM T&D Protection & Control Limited K-Bus, which is based on the twisted pair RS485 specification. Table 2 summarises the two available communications protocols.

The front IEC870 port is designed for temporary connection in such circumstances as commissioning. It has no isolation to earth and no modem capability. However it is easily accessible with the front cover removed.

The rear IEC870 port is designed for permanent connection to either a locally sited system or to a modem. It offers a high isolation level and provides all the RS232 modem control signals.

The rear K-Bus port is also designed for permanent connection with a higher isolation level of 2kV. K-Bus can be directly connected to systems with a synchronous (HDLC) RS485 twisted pair port or to a protocol converter such as the KITZ101 which converts to IEC870. K-Bus is ideal for applications with a number of relays fitted with K-Bus ports, since they can all be daisy chain connected into a single cable length. Typical applications for this might be for sites with more than one LGPG111 installed, but it might also encompass other protective relay devices such as the ALSTOM T&D Protection & Control Limited
K-Series range for transformer and feeder protection.

[6]Maximum cable lengths are largely determined by capacitive effects; the figures quoted here are only typical and it may be possible to improve on them.

6. SECURITY

6.1. Password protection

Password protection is only provided for those settings which relate to the external configuration of the relay. In this respect they are set up during commissioning and the password protects against any accidental change which may seriously affect the ability of the relay to perform its intended functions. Settings under password protection are:

- Protection function status settings
- Protection function characteristic selection
- Scheme logic settings
- The system CT and VT ratios
- Logic input and scheme output labels
- Scheme Inhibit, remote setting capability and the alternative setting group selection commands

The password is four upper case alpha characters long. The default password is AAAA. A backup password is also available for each relay and can be used when the user password has been lost. Please contact ALSTOM T&D Protection & Control Limited quoting the model and serial numbers of the relay for which a backup password is required.

Password protection can be re-enabled if the particular access method is not in setting mode, by resetting the password cell. Disabling and re-enabling password protection is logged as an event.

Each user interface has its own password locks; entering the password in one system only unlocks that system and not both of them.

6.2. Remote Setting Change

In any system which can be controlled remotely, and particularly those accessed over the public telephone network, there are bound to be concerns about unauthorised access. In this respect there are two types of unauthorised access to be considered: benign and malicious.

Benign unauthorised access is only a problem when public communications are used. A hacker may stumble on the LGPG111's modem telephone number and try to communicate with it. However, it is unlikely that communications with the relay would be established without specific knowledge of the protocol and format of the communications employed, or a suitable access software tool - the communications system is not a simple ASCII based interface.

Malicious unauthorised access results when a hacker has the means to communicate successfully with the relay and is intent on altering settings. Here there are several solutions: Private communications links and modems with dial-back facilities could be used. Ultimately, though, the LGPG111 does provide the facility to disable remote setting capability. This means that all setting changes must be done through the relay's front panel. However, it does still allow the remote interface to be used to monitor the relay and associated generator set.

6.3. Inactivity timers

There are two inactivity timers, one for each access method. When a defined period of inactivity has elapsed, the particular access method is reset. For the local access method this involves restoring the default menu state, cancelling local setting mode and re-locking password protected cells. For the remote access method, this just involves the previous two items, except that remote setting mode is cancelled instead.

The two timers are fully independent but share one setting which can be set in the range 5 to 30 minutes in 5 minute increments.

Local access inactivity is defined as the time between successive key presses.

Remote access inactivity is defined as the time from entering setting mode to pre-loading a new value or aborting setting mode, and from pre-loading a new value to executing or aborting it. Additionally, the timer is started when the password protected cells are unlocked. The timer is also restarted whenever the menu is browsed with the read headings, section text & section values commands.

7. MENU SYSTEM

7.1. Menu contents

Item	Front Panel	Remote Access
1.0	SYSTEM DATA	System Data
2.0	AUXILIARY FUNCTIONS	Auxiliary Functions
3.0	TRANSFORMER RATIOS	Transformer Ratios
4.0	MEASUREMENTS - 1	Measurements - 1
5.0	MEASUREMENTS - 2	Measurements - 2
6.0	VIEW RECORDS	View Records
7.0	PROTECTION FN STATUS	Protection Function Status
8.0	GENERATOR DIFFERENTIAL	Generator Differential
9.0	EARTH FAULT PROTECTION	Earth Fault Protection
10.0	V DEPENDENT OVERCURRENT	Voltage Dependent Overcurrent
11.0	POWER PROTECTION	Power Protection
12.0	FREQUENCY PROTECTION	Frequency Protection
13.0	VOLTAGE PROTECTION	Voltage Protection
14.0	NEGATIVE PHASE SEQUENCE	Negative Phase Sequence
15.0	FIELD FAILURE	Field Failure
16.0	SCHEME LOGIC	Scheme Logic
17.0	INPUT / OUTPUT LABELS	Input / Output Labels
18.0	REMOTE COMMUNICATIONS	Remote Communications
19.0	DISTURBANCE RECORDER	Disturbance Recorder
20.0	TEST FUNCTIONS	Test Functions
21.0	PROTECTION OP SUMMARY	Protection Operation Summary

Table 3 The LGPG111's menu contents list (alternative setting group disabled).

The menu in the LGPG111 is divided into several sections. Each section represents some aspect of the relay and a brief summary of each is provided below.

Sections 7.0 to 16.0 relate to the protection. As shown, the second, alternative, setting group is disabled. When the second setting group is enabled, each of the sections, 7.0 to 16.0, is duplicated; one for each setting group which are ordered in pairs. The group identifier is appended to each section title and to each cell on the front panel. For example the section contents will appear as:

Item	Front Panel	Remote Access
...	...	...
8.0	GENERATOR DIFFERENTIAL(1)	Generator Differential (1)
8.0	GENERATOR DIFFERENTIAL(2)	Generator Differential (2)
9.0	EARTH FAULT PROTECTION(1)	Earth Fault Protection (1)
9.0	EARTH FAULT PROTECTION(2)	Earth Fault Protection (2)
...	...	...

Table 4 Illustration of the appearance of the menu contents list when the alternative setting group facility is enabled.

And the contents of, say, the Generator Differential group 1 section as:

Item	Front Panel	Remote Access
8.0	GENERATOR DIFFERENTIAL(1)	Generator Differential (1)
8.1	87G Gen Diff (1) Enabled	87G Generator Differential: Enabled
8.2	87G Gen Diff (1) Is1: 0.05 A	Is1: 0.05 A
8.3	87G Gen Diff (1) K1: 0%	K1: 0%
8.4	87G Gen Diff (1) Is2: 1.20 A	Is2: 1.20 A
8.5	87G Gen Diff (1) K2: 150%	K2: 150%

Table 5 Generator differential settings when the alternative setting group facility is enabled.

1.0 System data:

Contains basic information about the LGPG111 such as its model and serial numbers. The password cell is also in this section.

2.0 Auxiliary functions:

Contains a number of cells providing status information about the relay and a number of miscellaneous cells controlling some configuration aspects. The cell for printing various reports on the front panel's parallel port is also in this section.

3.0 Transformer ratios:

The LGPG111 provides the ability to display all its settings and measurements in terms of the system quantities. To do this the relay must know what the system CT & VT ratios are and these are detailed in this section. It should be noted that this feature only affects the displayed values; the protection operates on the measured quantities from the secondary of the system CT's & VT's.

4.0 Measurements 1:

Provides all the fundamental measurements which the LGPG111 has obtained or derived from its inputs.

5.0 Measurements 2:

This section complements the Measurements 1 section by providing all the other measurements the LGPG111 is making.

6.0 View records:

Allows event records to be examined.

7.0 Protection function status:

Provides a quick summary of which protection functions have been enabled and disabled.

8.0 Generator differential:

Settings for the differential protection function.

9.0 Earth fault protection:

Settings for stator earth fault, neutral displacement and sensitive directional earth fault protection functions.

10.0 Voltage dependent overcurrent:

Settings for the voltage dependent overcurrent protection function.

11.0 Power protection:

Settings for the reverse and low forward power protection functions. Also includes a setting to compensate for any phase error between the system CT & VT.

12.0 Frequency protection:

Settings for two under and one over frequency protection functions.

13.0 Voltage protection:

Settings for under and over voltage protection functions, plus a voltage balance or VT fuse failure function.

14.0 Negative phase sequence:

Settings for the negative phase sequence protection.

15.0 Field failure:

Settings for the field failure protection function.

16.0 Scheme logic:

Contains all the settings for the scheme logic plus settings for specifying which outputs are latched or self reset, which outputs trigger alarm events and which outputs trigger a trip event.

17.0 Input / output labels:

Allows all the application dependent inputs and outputs to be given appropriate identifier labels.

18.0 Remote communications:

Configuration settings for the remote access user interface.

19.0 Disturbance recorder:

Configuration settings for the disturbance waveform recorder.

20.0 Test functions:

Various test facilities.

21.0 Protection operation summary:

Provides protection operation status indications as a percentage time to trip.

Note that all setting values, measurements, etc., in the following sub-sections, are based on the 1A version of the LGPG111.

7.2. System data

Item	Front Panel	Remote Access
1.0	SYSTEM DATA	System Data
1.1	Password: ****	Password: ****
1.2	Description: LGPG111 Relay	Description: LGPG111 Relay
1.3	Plant Reference: <Not Defined>	Plant Reference: <Not Defined>
1.4	Model Number: LGPG11101S533LEA	Model Number: LGPG11101S533LEA
1.5	Serial Number: 000000O	Serial Number: 000000O
1.6	System Frequency 55 Hz	System Frequency: 55 Hz
1.7	Comms Level: 1	Communication Level: 1
1.8	Relay Address: 1	Relay Address: 1
1.9	Active Setting Group: 1	Active Setting Group: 1
1.10	Software Ref 1: 18LGPG002XXXEB	Software Reference 1: 18LGPG002XXXEB
1.11	Software Ref 2: 18SCM001002A	Software Reference 2: 18SCM001002A
1.12	Logic I/P Status 00000000000000	Logic Input Status: 00000000000000
1.13	Relay O/P Status 0000000000000000	Relay Output Status: 0000000000000000

Table 6 The LGPG111's System Data Section of its menu.

This section contains basic information about the LGPG111.

1.1 Password:

A four character, upper case, password can be entered in this cell. If the entered password matches with the one stored in the LGPG111, all the password protected cells in the relay are unlocked - these settings can now be altered. If the entered password does not match, the setting is rejected and password protected cells remained locked. Password protection can be re-applied by resetting this cell. Additionally, after a period of inactivity, the relay automatically re-applies password protection.

In the password unlocked state, the password can be changed by entering a new password. Care should be taken not to change the password inadvertently and equally a new password should be securely noted. If the password to the LGPG111 is lost, ALSTOM T&D Protection & Control Limited can be contacted for a backup password which will unlock the password protection and allow a new password to be entered.

There is a password lock for each user interface system; a password entered in one system unlocks only that system and not both. An event is logged for both the removal and re-application of password protection for each access system.

The LGPG111 is normally supplied with a default password of 'AAAA'.

1.2 Description:

A password protected 16 character string. Principal application is to identify the product and possibly its application, when viewed over the remote access system. The remote access setting transfer does not include this cell.

For software versions before 18LGPG002XXXEB, this cell was a non-settable cell containing a description of the protection, namely "Generator Protection".

1.3 Plant reference:

A password protected 16 character string. Principal application is to identify the location of the product when viewed over the remote access system. The remote access setting transfer does not include this cell.

1.4 Model number:

A password protected 16 character string. The cell identifies the particular model number of the LGPG111 over the remote access system. Use of replacement microprocessor modules makes it necessary to alter this cell. This is so that the model number in the menu matches the model number printed on the information label inside the relay's case. The remote access setting transfer does not include this cell.

1.5 Serial number:

A password protected 7 character string. Principal application is to identify the serial number of the LGPG111 over the remote access system. Use of replacement microprocessor modules makes it necessary to alter this cell. This is so that the serial number in the menu matches the serial number printed on the information label inside the relay's case. The remote access setting transfer does not include this cell.

1.6 System frequency:

Specifies the nominal system frequency which the LGPG111 is monitoring. Can be set to 50Hz, 55Hz or 60Hz. The setting determines the default tracking frequency when the relay has no input signals. The setting has no effect on the frequency tracking capability of the LGPG111.

1.7 Communications level:

A non-settable cell which indicates the capability of the remote communications interface to a remote system. The LGPG111 implements level 1 Courier communications.

1.8 Relay address:

The address of the LGPG111 on a remote communications network. Settable between 0 and 255. A value of 255 effectively removes the relay from direct addressing over the network and a value of 0 is used as a transition address by a remote system - a transition address is automatically changed by the remote system to a spare address on the network. The remote access setting transfer does not include this cell.

This cell is duplicated in the Remote Communications Section.

1.9 Active setting group:

A non-settable cell reflecting the currently active setting group. Used by the remote system to ascertain the LGPG111's current setting group selection.

This cell is duplicated in the Auxiliary Functions Section, where it may be changed.

1.10 Software reference 1:

The identity of the software in the main processor.

1.11 Software reference 2:

The identity of the software in the communications processor.

1.12 Logic input status:

A 14 bit binary flag representation of the optically isolated logic inputs to the relay. When an input is energised its flag bit will show as a '1' otherwise it will show as a '0'. This cell is duplicated in the Auxiliary Functions Section. The bits are summarised in Table 7.

Bit	Name
0	27/81U Inhibit
1	51V Inhibit
2	51N Inhibit
3	Group Select-1
4	Group Select-2
5	Clock Sync
6	Input 6
7	Input 7
8	Input 8
9	Input 9
10	Input 10
11	Input 11
12	Input 12
13	Input 13

Note: Bits 6 to 13 are scheme definable and their names can be changed in the Input / Output Labels Section.

1.13 Relay output status:

A 16 bit binary flag representation of the relay output status. The LGPG111 has 16 output relays. An energised relay is shown by a '1' and de-energised by a '0'. This cell is duplicated in the Auxiliary Functions Section. The bits are summarised in Table 8.

Bit	Name
0	Relay Inoperative
1	Relay 1
2	Relay 2
3	Relay 3
4	Relay 4
5	Relay 5
6	Relay 6
7	Relay 7
8	Relay 8
9	Relay 9
10	Relay 10
11	Relay 11
12	Relay 12
13	Relay 13
14	Relay 14
15	Relay 15

Table 8 Bit flag assignment (read right to left) of the relay outputs.

Note: Bits 1 to 15 are the fifteen scheme configurable outputs and their names can be changed in the input / output labels section. Bit 0, the relay inoperative alarms normally energised to indicate that the LGPG111 is functioning correctly. However, its bit indication is inverted so that it normally indicates as a 0; a 1 meaning that the relay is inoperative.

7.3. Auxiliary Functions

Item	Front Panel	Remote Access
2.0	AUXILIARY FUNCTIONS	Auxiliary Functions
2.1	Date 1994 Aug 16 Time 10:49:50	16 Aug 1994 10:49:50.769
2.2	Logic I/P Status 00000000000000	Logic Input Status: 00000000000000
2.3	Relay O/P Status 0000000000000000	Relay Output Status: 0000000000000000
2.4	Protection Status: →	Protection Status: 00000000000000000010
2.5	Relay Alarms: Not Present	Relay Alarms: Not Present
2.6	Scheme Output: Enabled	Scheme Output: Enabled
2.7	Clear Event Records	Clear Event Records: No
2.8	Print: Stopped	Print: Stopped
2.9	Second Setting Group: Disabled	Second Setting Group: Disabled
2.10	Select Setting Group: Menu	Select Setting Group: Menu
2.11	Active Setting Group: 1	Active Setting Group: 1
2.12	Remote Setting: Enabled	Remote Setting: Enabled
2.13	Inactivity Timer 30 min	Inactivity Timer: 30 min
2.14	SEF TimerInhibit Disabled	Stator EF Timer Inhibit: Disabled
2.15	Clock Sync: Disabled	Clock Synchronised: Disabled
2.16	Default Display: Title	Default Local Display: Title

Table 9 The LGPG111's Auxiliary Functions Section of its menu.

This section contains a number of cells providing status information about the LGPG111 and a number of miscellaneous cells controlling some configuration aspects of the relay.

2.1 Date & time:

The Current value of the LGPG111's real time clock. The cell is settable. Note that the format of the date & time on a remote access system is not governed by the relay. The remote access setting transfer does not include this cell.

2.2 Logic input status:

A 14 bit binary flag representation of the optically isolated logic inputs to the relay. When an input is energised its flag bit will show as a '1' otherwise it will show as a '0'. This cell is duplicated in the Auxiliary Functions Section. The bits are summarised in Table 7, page 28.

2.3 Relay output status:

A 16 bit binary flag representation of the relay output status. The LGPG111 has 16 output relays. An energised relay is shown by a '1' and de-energised by a '0'. This cell is duplicated in the Auxiliary Functions Section. The bits are summarised in Table 8, page 29.

2.4 Protection status:

A 20 bit binary flag representation of the protection function outputs. These outputs, combined with the logic inputs, are fed into the scheme logic.

The Front Panel display of the bit flag values is obtained by pressing the → arrow key. The bits are summarised in Table 10.

Bit	Front Panel Name	Remote Access Name
0	60 VB-Comp	60 Voltage Balance-Comp
1	-60 VB-Prot	-60 Voltage Balance-Prot
2	60 VB-Prot	60 Voltage Balance-Prot
3	40 FF	40 Field Failure
4	67N SDEF	67N Sensitive Directional EF
5	59N-2 ND	59N-2 Neutral Displacement
6	59N-1 ND	59N-1 Neutral Displacement
7	51N>> SEF	51N>> Stator Earth Fault
8	51N> SEF	51N> Stator Earth Fault
9	46>> NPS	46>> NPS Trip
10	46> NPS	46> NPS Alarm
11	59 OV	59 Over Voltage
12	27 UV	27 Under Voltage
13	81U-2 UF	81U-2 Under Frequency
14	81U-1 UF	81U-1 Under Frequency
15	81O OF	81O Over Frequency
16	32L LFP	32L Low Forward Power
17	32R RP	32R Reverse Power
18	51V OC	51V Overcurrent
19	87G Gen Diff	87G Generator Differential

Table 10 Bit flag assignment (read right to left) of the protection functions.

Note: Bits 1& 2 are complements of each other. For healthy voltage input, bit 1 will be set, since it is the complementary output from the voltage balance function. When there is a voltage balance fault, bit 2 will be set and bit 1 cleared.

2.5 Relay Alarms:

Provides an indication of the relay's alarm status, as indicated by the front panel alarm LED. The cell has three display states, see Table 11. Normally the 'Not Present' message is displayed. When there are alarms, this is replaced by 'Present'. The alarm indication can be reset by entering setting mode. This will also cause latched output contacts to be reset. The display then reverts to displaying 'Not Present'. The remote access setting transfer does not include this cell.

Front Panel	Remote Access
Relay Alarms: Not Present	Relay Alarms: Not Present
Relay Alarms: Present	Relay Alarms: Present
Press SET To Clr Alarms&Latch O/P	Relay Alarms: Clear Alarms & Latched Contacts

Table 11 States of the relay alarms cell.

2.6 Scheme output:

Controls whether the output from the scheme logic drives the output relays. The cell has two states: enabled and inhibited. The cell is password protected.

The enabled state means the scheme logic is controlling the output relays. This is the state for normal protection operation.

The inhibited state means the scheme logic is not controlling the output relays and the LGPG111's Out Of Service LED will be on. In this state the relay outputs can be operated manually with the Relay Test cell in the Test Functions Section. The relay output status cell will, however, reflect the current output state from the scheme logic. This allows testing of the relay without operating any outputs contacts.

The state of this cell is logged, as an event record, whenever the relay is reset and when the cell is changed.

2.7 Clear event records:

Allows the event records to be erased. This cell is password protected and is not included in the setting transfer.

Front Panel	Remote Access
`Clear Event Records`	`Clear Event Records: No`
`Press SET To Clear All Record`	`Clear Event Records: Yes`

Table 12 States of the Clear Event Records Cell.

The effect of clearing all the event records has no effect on the alarm status on the LGPG111's front panel, but it will stop any events from being extracted remotely. The cell allows the relay's event system to be purged after commissioning.

2.8 Print:

Various reports can be printed on a parallel printer connected to the front panel parallel port. The cell also reports the status of the printer when a report is being printed. The remote access setting transfer does not include this cell.

Table 13 summarises the cell's various states. The first three are status indications and the remainder are requests for particular reports to be printed.

The printer busy status occurs when the busy signal into the parallel port is activated. This will occur when the printer is Off Line, out of paper or has a full input buffer. The busy message will return to printing when the busy signal is no longer asserted. When the LGPG111 has output the entire report to the printer, the print status will return to stopped. The cell can be reset at any time to cancel the selected print request.

Examples of print reports can be found in Section 8., page 75.

Event reports are printed in reverse chronological order; the most recent event is the last one in the report. This allows reporting on a real time system to a slow output device. For example, a request for 10 event records causes the report generator to start at the tenth record. When there are less than 10 event records, the report starts at the oldest record. The report finishes when the most recent event record has been printed; if events occur during printing, these will also be printed. Thus a request for 10 event records could result in the printed report containing more or less than 10 records. The same is true for the other event reports.

Front Panel	Remote Access
Print: Stopped	Print: Stopped
Print: Printing	Print: Printing
Print: Printer Busy	Print: Printer Busy
Press SET To Prn System Settings	Print: Print System Settings
Press SET To Prn Prot Settings	Print: Print Protection Settings
Press SET To Prn Scheme Logic	Print: Print Scheme Settings
Press SET To Prn 10 Event Records	Print: Print 10 Event Records
Press SET To Prn 25 Event Records	Print: Print 25 Event Records
Press SET To Prn All Event Record	Print: Print All Event Records

Table 13 States of the Print cell.

2.9 Second setting group:

Controls whether the LGPG111 has an alternative, second, setting group. The cell can be either ‘Disabled’ or ‘Enabled’.

In the disabled state the active setting group and select setting group cells are hidden. Additionally, the settings for the second setting group are hidden in the menu and the group 1 identifiers removed from the remaining visible settings. If group 2 settings are enabled when the disabled state is selected, group 1, primary, settings are selected and an event generated.

In the enabled state the active setting group and select setting group cells are visible. Additionally, the settings for the second setting group are visible in the menu. Cells belonging to the setting groups are identified by their group number. If the group selection is set to logic input and the inputs are energised to select group 2, group 2 is selected and an event generated.

This cell is password protected.

2.10 Select setting group:

Controls the selection method for the active setting group. The cell can be either ‘Logic Input’ or ‘Menu’.

The logic input setting allows the active group to be controlled by a pair of optically isolated logic inputs. In this mode the active setting group setting is disabled.

The menu setting disables logic input control of the active setting group and allows it to be controlled by the active setting group cell. Additionally, a remote access command for changing the active group is also enabled.

This cell is password protected.

2.11 Active setting group:

Indicates the active setting group. The cell is only visible if the second setting group has been enabled. The current group selection can also be changed if the group selection cell indicates menu. Valid settings are 1 and 2. The setting is password protected. An event record is generated for a change in the active setting group.

The cell is duplicated in the System Data Section, as an indication only cell.

2.12 Remote getting:

Allows remote access setting capability to be disabled. Can be either 'Disabled' or 'Enabled'.

When disabled, settings can only be changed through the front panel. This setting is password protected and is duplicated in the Remote Communications Section.

2.13 Inactivity timer:

Specifies the duration of inactivity on a user interface before the interface resets. The time may be specified between 5 and 30 minutes in 5 minute increments.

2.14 Stator EF timer inhibit:

Defines the operation of the stator EF timer inhibit optically isolated logic input. The cell can be: 'Disabled', 'High Set', 'Low Set' or 'Both'.

The setting determines which of the stator earth fault timers is inhibited when the '51N Inhibit' logic input is energised. Either the high set or the low set can be selected. Alternatively both timers can be inhibited or the function disabled entirely.

This setting is password protected.

2.15 Clock synchronised:

Specifies the period or time frame of the clock synchronism pulses to the 'Clock Sync' logic input. Time frames of 30 seconds, 1, 5, 10, 15, 30 and 60 minutes can be selected. Alternatively the function can be disabled.

For a given time frame setting, a pulse on the 'Clock Sync' logic input will cause the LGPG111's clock to be adjust to the nearest whole multiple of the time frame.

2.16 Default display:

Specifies the front panel default display.

The cell can have a value of any of: 'Title', 'Description', 'Model Number', 'Plant Reference', 'Phase Currents', 'Line Voltages', 'Earth Quantities', 'NPS (I2) Current', 'Power Aph', 'Phase Angle Aph', 'System Frequency', 'Date & Time', 'Active Group' or 'All Measurements'.

The content of each of the default displays is discussed in Section 4.2., page 9.

7.4. Transformer Ratios

Item	Front Panel	Remote Access
3.0	TRANSFORMER RATIOS	Transformer Ratios
3.1	Display Value: Secondary	Display Value: Secondary
3.2	Current Rating: 1 A	Current Rating: 1 A
3.3	Diff CT Ratio: 1.00:1	Differential CT Ratio: 1.00:1
3.4	Sensitive Ia CT Ratio: 1.00:1	Sensitive Ia CT Ratio: 1.00:1
3.5	Residual CT Ratio: 1.00:1	Residual CT Ratio: 1.00:1
3.6	Earth CT Ratio: 1.00:1	Earth CT Ratio: 1.00:1
3.7	Earth VT Ratio: 1.00:1	Earth VT Ratio: 1.00:1
3.8	Phase CT Ratio: 1.00:1	Phase CT Ratio: 1.00:1
3.9	Line VT Ratio: 1.00:1	Line VT Ratio: 1.00:1
3.10	Comp VT Ratio: 1.00:1	Comparison VT Ratio: 1.00:1

Table 14 The LGPG111's Transformer Ratios Section of its menu.

The LGPG111 can display all its settings and measurements in terms of the system quantities. To do this the relay must know what the system CT & VT ratios are and these are detailed in this section. It should be noted that this feature only affects the displayed values; the protection operates on the measured quantities from the secondary of the system CT's and VT's.

Transformer ratios are password protected and are settable in the range 1.00:1 through to 9999:1 in increments of the least significant digit.

3.1 Display value:

Indicates whether the settings in the Transformer Ratios Section are being used to scale values for display. A value of 'Secondary' means the LGPG111 is not scaling display values. Whereas a value of 'Primary' means the transformer ratios are being used to scale values.

3.2 Current rating:

Indicates the current rating of the LGPG111. The current rating is obtained from the analogue input module and is provided for information only. The relay can have a nominal current rating of either 1A or 5A.

3.3 Differential CT ratio:

Scales the differential settings and the measurements made by the differential and bias CT's.

3.4 Sensitive Ia CT ratio:

Scales the sensitive Ia input. This input is used by the power measurement function in the LGPG111; the scaling affects the power settings and measurements. The line VT ratio also affects these settings and measurements.

3.5 Residual CT ratio:

Scales the residual current measurement. This input is used by the sensitive directional earth fault function and scales the Iresidual> setting.

3.6 Earth CT ratio:

Scales the earth path current measurement. This input is used by the stator earth fault and sensitive directional earth fault functions. The Ie>, Ie>> and Iep> settings are scaled by this value.

3.7 Earth VT ratio:

Scales the neutral displacement voltage measurement used by the neutral displacement earth fault protection. The neutral displacement Ve> and directional earth fault Vep> settings are scaled by this value.

3.8 Phase CT ratio:

Scales the three phase current measurements and settings used by the overcurrent, negative phase sequence and field failure protection. The field failure impedance settings are also affected by the line VT ratios.

3.9 Line VT ratio:

Scales the line to line voltage measurements. This scaling affects the power settings and measurements, the under and over voltage protection and the field failure impedance settings. The field failure impedance settings are also affected by the value of the phase CT ratios. The power settings and measurements are also affected by the sensitive Ia CT ratio.

3.10 Comparison VT ratio:

Scales the comparison voltage measurement. The comparison voltage is used by the voltage balance protection function to ascertain the validity of the line voltage measurements. Since the voltage balance protection is only concerned with the differential voltage between the two sets of measurements, its setting is not affected by these scaling values.

7.5. MEASUREMENTS 1

Item	Front Panel	Remote Access
4.0	MEASUREMENTS - 1	Measurements - 1
4.1		16 Aug 1994 16:02:58.218
4.2	Ia: 0 A	Ia: 0 A
4.3	Ib: 0 A	Ib: 0 A
4.4	Ic: 0 A	Ic: 0 A
4.5	Vab: 0 V	Vab: 0 V
4.6	Vbc: 0 V	Vbc: 0 V
4.7	Vca: 0 V	Vca: 0 V
4.8	Ie: 0 A	Ie: 0 A
4.9	Ve: 0 V	Ve: 0 V
4.10	I-Residual: 0 A	I-Residual: 0 A
4.11	I2: 0 A	I2: 0 A
4.12	Active Power Aph: 0 W	Active Power Aph: 0 W
4.13	Reactive Power Aph: 0 VAr	Reactive Power Aph: 0 VAr
4.14	Phase Angle Aph: 0 deg	Phase Angle Aph: 0 deg
4.15	Frequency: 0 Hz	Frequency: 0 Hz

Table 15 The LGPG111's Measurement 1 Section of its menu.

Provides all the fundamental measurements which the LGPG111 has obtained or derived from its inputs. All magnitude values for the voltages and currents are rms values of the measured fundamental; all harmonic components have been removed by signal processing.

4.1 Date & time:

This cell only appears on the remote access menu. When the remote system reads this section it captures a snapshot of the measurement values - this cell provides a time stamp indicating when the data was captured. This is not a problem for the front panel since the display is updated approximately every 500ms.

4.2, 4.3 & 4.4 Three phase current:

The magnitudes of the three phase currents.

4.5, 4.6 & 4.7 Three phase voltage:

The magnitudes of the line to line voltages. V_{ab} and V_{bc} are measured directly and V_{ca} is derived from them.

4.8 Earth path current:

The magnitude of the earth path current.

4.9 Neutral displacement voltage:

The magnitude of the neutral displacement voltage.

4.10 Residual current:

The magnitude of the residual current.

4.11 Negative phase sequence current:

Calculated magnitude of the negative phase sequence component.

4.12, 4.13 & 4.14 Power & Phase angle:

Calculated active power, reactive power and phase angle in the A phase. The Power Section contains a setting to compensate for any phase errors and this is accounted for in these measurements.

4.15 Frequency:

The measured power system frequency.

7.6. MEASUREMENTS 2

Item	Front Panel	Remote Access
5.0	MEASUREMENTS - 2	Measurements - 2
5.1		16 Aug 1994 16:02:58.218
5.2	Ia-Diff: 0 A	Ia-Diff: 0 A
5.3	Ib-Diff: 0 A	Ib-Diff: 0 A
5.4	Ic-Diff: 0 A	Ic-Diff: 0 A
5.5	Ia-Bias: 0 A	Ia-Bias: 0 A
5.6	Ib-Bias: 0 A	Ib-Bias: 0 A
5.7	Ic-Bias: 0 A	Ic-Bias: 0 A
5.8	Ia-Mean Bias: 0 A	Ia-Mean Bias: 0 A
5.9	Ib-Mean Bias: 0 A	Ib-Mean Bias: 0 A
5.10	Ic-Mean Bias: 0 A	Ic-Mean Bias: 0 A
5.11	Ia-Sensitive: 0 A	Ia-Sensitive: 0 A
5.12	Vab-Comp: 0 V	Vab-Comp: 0 V
5.13	Vbc-Comp: 0 V	Vbc-Comp: 0 V
5.14	Tracking Input: No Signal	Tracking Input: No Signal

Table 16 The LGPG111's Measurements 2 Section of its menu.

This section complements the Measurements 1 section by providing all the other measurements the LGPG111 is making. All magnitude values for the voltages and currents are rms values of the measured fundamental; all harmonic components have been removed by signal processing.

5.1 Date & time:

This cell only appears on the remote access menu. When the remote system reads this section, it captures a snapshot of the measurement values - this cell provides a time stamp indicating when the data was captured. This is not a problem for the front panel since the display is updated approximately every 500ms.

5.2, 5.3 & 5.4 Differential current:

The magnitudes of the differential currents.

5.5, 5.6 & 5.7 Bias currents:

The magnitudes of the bias currents.

5.8, 5.9 & 5.10 Mean bias currents:

The derived magnitude of the mean bias current. Ordinarily a mean bias quantity is derived from two bias measurements. The LGPG111 has only one bias measurement per phase and derives the second from the differential and bias measurements.

$$\left|I_{MeanBias}\right| = \frac{\left|\overline{I_{Bias}}\right| + \left|\left(\overline{I_{Bias}} - \overline{I_{Diff}}\right)\right|}{2}$$

5.11 Sensitive A phase current:

The magnitude of the A phase high sensitivity current input. This measurement is used for the calculation of power and phase angle.

5.12 & 5.13 Comparison voltages:

The magnitudes of the comparison voltage inputs.

5.14 Frequency tracking input:

This cell indicates the input being used by the frequency tracking. The LGPG111 can frequency track from one of three inputs: V_{ab}, V_{bc} or I_a. When there are no signals on these inputs the frequency tracking assumes the default frequency and indicates no signal; the frequency measurement is set to zero Hertz.

7.7. View records

Item	Front Panel	Remote Access
6.0	VIEW RECORDS	View Records
6.1	View Last Record-0	View Last Record-0
6.2	Date 1994 Aug 17 Time 08:17:32	Aug 17 1994 08:17:32.349
6.3	Exceptions: 0000001	Exceptions: 0000001
6.4	Events: 0000000000001	Events: 0000000000001
6.5	Relay O/P Change 0000000000000001	Relay O/P Change: 0000000000000001
6.6	Logic I/P Change 00000000000100	Logic I/P Change: 00000000000100
6.7	Protection Status: →	Protection Status: 00000000000000000010
6.8	EEPROM Errors: →	EEPROM Errors: 0000000000000000010000000000
6.9	Diagnostic Error 000	Diagnostic Errors: 010
6.10	No Records Stored	No Records Stored
6.11		Fault Record:
6.12	Protection Status: →	Protection Status: 00000000000000000010
6.13	Relay O/P Status 0000000000000000	Relay Output Status: 0000000000000000
6.14	Logic I/P Status 00000000000000	Logic Input Status: 00000000000000
6.15	Scheme Output: Enabled	Scheme Output: Enabled
6.16	Active Setting Group: 1	Active Setting Group: 1
6.17	Ia: 998mA	Ia: 998mA
6.18	Ib: 1.0 A	Ib: 1.000 A
6.19	Ic: 999mA	Ic: 999mA

Continued ....

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Item	Front Panel	Remote Access
6.20	Ia-Diff: 998mA	Ia-Diff: 998mA
6.21	Ib-Diff: 989mA	Ib-Diff: 989mA
6.22	Ic-Diff: 946mA	Ic-Diff: 946mA
6.23	Ia-Mean Bias: 1.462 A	Ia-Mean Bias: 1.462 A
6.24	Ib-Mean Bias: 493mA	Ib-Mean Bias: 493mA
6.25	Ic-Mean Bias: 1.500 A	Ic-Mean Bias: 1.500 A
6.26	I2: 163mA	I2: 163mA
6.27	I-Residual: 980.1mA	I-Residual: 980.1mA
6.28	Ie: 982.0mA	Ie: 982.0mA
6.29	Vab: 109.6 V	Vab: 109.6 V
6.30	Vbc: 110.1 V	Vbc: 110.1 V
3.31	Vca: 108.9 V	Vca: 108.9 V
6.32	Ve: 1.23 V	Ve: 1.23 V
6.33	Active Power Aph: -54.10 W	Active Power Aph:-54.10 W
6.34	Reactive Power Aph: 32.04 VAr	Reactive Power Aph: 32.04 VAr
6.33	Phase Angle Aph: -149.9 deg	Phase Angle Aph:-149.9 deg
6.34	Frequency: 50.00 Hz	Frequency: 50.00 Hz
6.35	Fault Report Erased!	Fault Report Erased!

Table 17 The LGPG111’s View Records Section of its menu.

The View Records Section allows event records to be examined. The Event system categorises events into eight types:

1. Exceptions.
2. Relay output changes.
3. Logic input changes.
4. Protection operations.
5. Non-volatile EEPROM memory errors.
6. Diagnostic errors.
7. General events.
8. Fault records.

6.1 View last record-n:

Allows an event record to be selected. The last record is the record most recently stored; n is an index counting away from the last record up to the number of records stored. Thus Last Record-0 is always the most recent and Last Record-1 the next most recent and so on.

For a given record, the View Records Section adapts to present the information about the event. All records consist of a time stamp and one or more information cells.

If a new event record is generated whilst viewing a record, the section's content will change. A new record will cause existing records to increase their record numbers by one; the new record becomes record zero and the old record zero becomes record one and so on. The View Records Section always displays the selected record number, so the addition of a new record causes the section to display the next newest record. For example, if viewing Last Record-1 and an event occurs, the display will change to display the new Last Record-1 which was Last Record-0.

If there are no events stored then cell 6.10 is the only item visible and 'No Records Stored' is displayed.

6.3 Exceptions:

Various relay failures or exceptions.

Bit	Front Panel Name	Remote Access Name
0	Uncalib Analog	Uncalibrated Analogue Module
1	Analog Mod Fail	Analogue Module Fail
2	Calib Vector Err	Calibration Vector Error
3	Comms H/W Fail	Communications Hardware Fail
4	Grp Sel I/P Fail	Group Select Input Fail
5	EEPROM WriteFail	EEPROM Write Fail

Table 18 Bit flag names for the Exception cell.

6.4 Events:

General events.

Bit	Front Panel Name	Remote Access Name
0	RtClock Invalid	Real Time Clock Invalid
1	RtClock Valid	Real Time Clock Valid
2	RtClock Set	Real Time Clock Set
3	LPaswrd Removed	Local Password Removed
4	LPaswrd Restored	Local Password Restored
5	RPaswrd Removed	Remote Password Removed
6	RPaswrd Restored	Remote Password Restored
7	Group 1 Selected	Group 1 Selected
8	Group 2 Selected	Group 2 Selected
9	Relay Power On	Relay Power On
10	Relay Warm Reset	Relay Warm Reset
11	Scheme:Enabled	Scheme Output:Enabled
12	Scheme:Inhibited	Scheme Output:Inhibited

Table 19 Bit flag names for the Events cell.

6.5 Relay output change:

Indicates the operation of any relay output which is not associated with a fault record trigger. See Table 8, page 29, for the bit names.

6.6 Logic input change:

Indicates the energisation of any logic input which is not associated with a fault record. The ‘Group Select’ and ‘Clock Sync’ logic inputs are, however, excluded. A change in the selected setting group is logged in the events cell and clock synchronising pulses are expected to occur at regular time intervals. See Table 7, page 28, for the bit names.

6.7 Protection:

Indicates protection function operations which are not associated with a fault record. See Table 10, page 31, for the bit names.

6.8 EEPROM errors:

Indicates failures to information stored in the non-volatile memory (EEPROM) of the LGPG111.

Bit	Name	Bit	Name
0	System Data	15	Power Prot 1
1	Aux Functions	16	Power Prot 2
2	T'former Ratios	17	Frequency Prot 1
3	Disturbance Rec	18	Frequency Prot 2
4	Input Labels	19	Voltage Prot 1
5	Output Labels	20	Voltage Prot 2
6	Remote Comms	21	Neg Phase Seq 1
7	Alarm Record	22	Neg Phase Seq 2
8	Fault Record	23	Earth Fault 1
9	Event Record	24	Earth Fault 2
10	Current Rating	25	Field Failure 1
11	Generator Diff 1	26	Field Failure 2
12	Generator Diff 2	27	Scheme Logic 1
13	Overcurrent 1	28	Scheme Logic 2
14	Overcurrent 2		

Table 20 Bit flag names for the EEPROM Errors cell.

6.9 Diagnostic errors:

Indicates diagnostic messages from the LGPG111's self testing and monitoring systems.

Bit	Front Panel Name	Remote Access Name
0	LCD Fail	LCD Fail
1	Watchdog Inop	Watchdog Inoperative
2	Watchdog Fast	Watchdog Fast

Table 21 Bit flag names for the Diagnostic Errors cell.

6.10 No records:

This cell is the only one visible when there are no event records stored.

6.11 Fault record:

A sub-title cell for the remote access system only - the fault record is presented below.

6.12 to 6.34 Fault record:

These cells make-up the fault record. The first three cells provide status information about the LGPG111's inputs, outputs and protection functions. The scheme status cell is included so that fault records produced during commissioning can be identified with a scheme output inhibited. The active group cell indicates which setting group was in use when the fault trigger occurred.

Cells 6.17 to 6.34 form a record of the power system measurements when the fault record trigger occurred.

6.35 Fault Record Erased!

This cell is normally hidden and becomes visible when the selected fault record has no fault data; fault data cells 6.12 to 6.34 are then hidden.

It is possible to have fault records with no fault data, because only 50 of the 100 event records can have fault record data. When 50 fault records exist, a new fault record will take the data store from the oldest fault record, leaving just the time-stamp information in the event record memory.

7.8. Protection function status

Item	Front Panel	Remote Access
7.0	PROTECTION FN STATUS	Protection Function Status
7.1	87G Gen Diff Enabled	87G Generator Differential: Enabled
7.2	51N Stator EF Enabled	51N Stator Earth Fault: Enabled
7.3	59N Neutral Disp Disabled	59N Neutral Displacement: Disabled
7.4	67N SDEF Enabled	67N Sensitive Directional EF: Enabled
7.5	51V Overcurrent Enabled	51V Overcurrent: Enabled
7.6	32R Reverse Pwr Enabled	32R Reverse Power: Enabled
7.7	32L Low Fwd Pwr Enabled	32L Low Forward Power: Enabled
7.8	81U-1 Under Freq Enabled	81U-1 Under Frequency: Enabled
7.9	81U-2 Under Freq Enabled	81U-2 Under Frequency: Enabled
7.10	81O Over Freq Enabled	81O Over Frequency: Enabled
7.11	27 Under Voltage Enabled	27 Under Voltage: Enabled
7.12	59 Over Voltage Enabled	59 Over Voltage: Enabled
7.13	60 Volt Balance Enabled	60 Voltage Balance: Enabled
7.14	46 Neg Phase Seq Enabled	46 Negative Phase Sequence: Enabled
7.15	40 Field Failure Enabled	40 Field Failure: Enabled

Table 22 The LGPG111's Protection Function Status Section of the menu.

Provides a quick summary of which protection functions have been enabled and disabled. It is not possible to change a protection functions status here.

7.9. Generator differential

Item	Front Panel	Remote Access
8.0	GENERATOR DIFFERENTIAL	Generator Differential
8.1	87G Gen Diff Enabled	87G Generator Differential: Enabled
8.2	87G Gen Diff Is1: 0.05 A	Is1: 0.05 A
8.3	87G Gen Diff K1: 0%	K1: 0%
8.4	87G Gen Diff Is2: 1.20 A	Is2: 1.20 A
8.5	87G Gen Diff K2: 150%	K2: 150%

Table 23 The LGPG111's Generator differential Section of its menu.

Settings for the differential protection function.

8.1 Generator differential status:

The protection function can either be enabled or disabled. The setting is password protected.

8.2, 8.3, 8.4 & 8.5 Differential characteristic:

These cells specify the bias characteristic.

7.10. Earth fault protection

Item	Front Panel	Remote Access
9.0	EARTH FAULT PROTECTION	Earth Fault Protection
9.1	51N Stator EF Enabled	51N Stator Earth Fault: Enabled
9.2		51N> Low Set
9.3	51N> SEF-Low Set Char: SI	Characteristic: Standard Inverse
9.4	51N> SEF-Low Set Ie> 5mA	Ie> 5mA
9.5	51N> SEF-Low Set t> 0.1 s	t> 0.1 s
9.6	51N> SEF-Low Set TMS: 0.15	TMS: 0.15
9.7	51N> SEF-Low Set tRESET: 0 s	tRESET: 0 s
9.8	51N>>SEF-HighSet Enabled	51N>> High Set: Enabled
9.9	51N>>SEF-HighSet Ie>> 2.000 A	Ie>> 2.000 A
9.10	51N>>SEF-HighSet t>> 0 s	t>> 0 s
9.11	59N Neutral Disp Disabled	59N Neutral Displacement: Disabled
9.12	59N Neutral Disp Ve> 1 V	Ve> 1 V
9.13	59N Neutral Disp t1: 1.0 s	t1: 1.0 s
9.14	59N Neutral Disp t2: 1 s	t2: 1 s
9.15	59N Neutral Disp t2RESET: 0 s	t2RESET: 0 s
9.16	67N SDEF Enabled	67N Sensitive Directional EF: Enabled
9.17	67N SDEF Ires> 5mA	Iresidual> 5mA
9.18	67N SDEF RCA: +0 deg	RCA: 0 deg
9.19	67N SDEF Vep> 1 V	Vep> 1 V

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Item	Front Panel	Remote Access
9.20	67N SDEF Iep> 5mA	Iep> 5mA

Table 24 The LGPG111's Earth Fault Protection Section of its menu.

Settings for stator earth fault, neutral displacement and sensitive directional earth fault protection functions.

9.1 Stator earth fault status:

The protection function can either be enabled or disabled. Note that protection function implies both the low set and high set elements; it is not possible to disable just the low set element. The high set element may, however, be selectively enabled or disabled by cell 9.8.

The setting is password protected.

9.2 Low set:

A sub-title cell for the remote system only; all the stator earth fault low set settings are indented below this.

9.3, 9.4, 9.5, 9.6 & 9.7 Low set characteristic settings:

Cell 9.3 specifies the timing characteristic for the low set element. This setting is password protected.

Front Panel	Remote Access
51N> SEF-Low Set Char: SI	Characteristic: Standard Inverse
51N> SEF-Low Set Char: DT	Characteristic: Definite Time

Table 25 States of the stator earth fault low set timing characteristic cell.

Depending upon the value of the timer characteristic, cells 9.5 and 9.6 are alternatively visible; cell 9.5 is visible for the definite time characteristic and cell 9.6 is visible for the standard inverse characteristic.

9.8, 9.9 & 9.10 high Set Characteristic Settings:

Cell 9.8 Allows the high set element to be enabled or disabled; the high set is disabled, along with the low set, when the function's status is disabled. This setting is password protected.

9.11 Neutral displacement status:

The protection function can either be enabled or disabled. The setting is password protected.

9.12, 9.13, 9.14 & 9.15 Neutral displacement characteristic settings.

9.16 Sensitive directional earth fault status:

The protection function can either be enabled or disabled. The setting is password protected.

9.17, 9.18, 9.19 & 9.20 Sensitive directional earth fault characteristic settings.

7.11. Voltage dependent overcurrent

Item	Front Panel	Remote Access
10.0	V DEPENDENT OVERCURRENT	Voltage Dependent Overcurrent
10.1	51V Overcurrent Enabled	51V Overcurrent: Enabled
10.2	51V Overcurrent Fn: Restrain	Function: Voltage Restraint
10.3	51V Overcurrent Rotate: None	Voltage Vector Rotate: None
10.4	51V Overcurrent Vs: 33 V	Vs: 33 V
10.5	51V Overcurrent Vs1: 104 V	Vs1: 104 V
10.6	51V Overcurrent Vs2: 33 V	Vs2: 33 V
10.7	51V Overcurrent K: 0.25	K: 0.25
10.8	51V Overcurrent Char: SI	Characteristic: Standard Inverse
10.9	51V Overcurrent I> 1.00 A	I> 1.00 A
10.10	51V Overcurrent t: 0.1 s	t: 0.1 s
10.11	51V Overcurrent TMS: 1.00	TMS: 1.00
10.12	51V Overcurrent tRESET: 0 s	tRESET: 0 s

Table 26 The LGPG111's Voltage Dependent Overcurrent Section of its menu.

Settings for the voltage dependent overcurrent protection function.

10.1 Voltage dependent overcurrent status:

The protection function can either be enabled or disabled. The setting is password protected.

10.2 Voltage dependency function:

Determines the method of voltage dependency, if any.

Front Panel	Remote Access
51V Overcurrent Fn: Control	Function: Voltage Controlled
51V Overcurrent Fn: Restrain	Function: Voltage Restraint
51V Overcurrent Fn: Simple	Function: Simple Overcurrent

Table 27 States of the overcurrent function cell.

In the voltage controlled mode, cells 10.5 & 10.6 are invisible. Cell 10.4 is invisible in the voltage restraint mode and all three cells plus 10.3 & 10.7 are invisible in the simple overcurrent mode.

This setting is password protected.

10.3 Voltage vector rotation:

Determines whether the phase to phase voltage measurements are rotated, before being applied to the selected voltage dependent characteristic. This allows compensation for vector rotation incurred by a generator transformer and allows the overcurrent function to act correctly as backup protection for the high voltage side. This cell is password protected.

Front Panel	Remote Access
51V Overcurrent Rotate: None	Voltage Vector Rotate: None
51V Overcurrent Rotate: Yd	Voltage Vector Rotate: Yd

Table 28 States of the vector rotate cell.

The effects of the rotation settings are summarised in Table 29; for each phase current there is a voltage input to the voltage dependent characteristic.

Current Phase	None	Yd
Ia	$\left\|V_{ab}\right\|$	$\left\|\left(\overline{V_{ab}}-\overline{V_{ca}}\right)\right\|/\sqrt{3}$
Ib	$\left\|V_{bc}\right\|$	$\left\|\left(\overline{V_{bc}}-\overline{V_{ab}}\right)\right\|/\sqrt{3}$
Ic	$\left\|V_{ca}\right\|$	$\left\|\left(\overline{V_{ca}}-\overline{V_{bc}}\right)\right\|/\sqrt{3}$

Table 29 Voltage dependencies for each phase current verse vector compensation setting.

10.4, 10.5, 10.6 & 10.7 Voltage dependency characteristic settings.

10.8 Timing characteristic selector:

Specifies the timing characteristic; can either be a standard inverse definite minimum time or a definite time characteristic.

Front Panel	Remote Access
`51V Overcurrent` `Char: SI`	`Characteristic: Standard Inverse`
`51V Overcurrent` `Char: DT`	`Characteristic: Definite Time`

Table 30 States of the overcurrent timing characteristic cell.

This setting is password protected.

Depending upon the value of the timer characteristic, either cell 10.10 or 10.11 is visible: cell 10.10 is visible for the definite time characteristic and cell 10.11 is visible for the standard inverse characteristic.

10.9, 10.10, 10.11 & 10.12 Timer characteristic settings.

7.12. Power protection

Item	Front Panel	Remote Access
11.0	POWER PROTECTION	Power Protection
11.1	Power Prot θcomp: 0 deg	Compensation Angle: 0 deg
11.2	32R Reverse Pwr Enabled	32R Reverse Power: Enabled
11.3	32R Reverse Pwr -P> 5.00 W	-P> 5.00 W
11.4	32R Reverse Pwr t: 2.0 s	t (Pickup): 2.0 s
11.5	32R Reverse Pwr tDO: 0 s	tDO(Dropoff): 0 s
11.6	32L Low Fwd Pwr Enabled	32L Low Forward Power: Enabled
11.7	32L Low Fwd Pwr P< 1.75 W	P< 1.75 W
11.8	32L Low Fwd Pwr t: 2.0 s	t (Pickup): 2.0 s
11.9	32L Low Fwd Pwr tDO: 0 s	tDO(Dropoff): 0 S

Table 31 The LGPG111's Power Protection Section of its menu.

Settings for the reverse and low forward power protection functions. Also includes a setting to compensate for any phase error between the system CT & VT.

11.1 Compensation angle:

Allows the LGPG111 to correct any external phase error between its V_{ab} and sensitive I_a inputs, which are used to calculate the power and phase angle measurements. Can be set between ±5° in 0.1° increments. The setting is password protected and affects both the measurements and power protection functions.

11.2 Reverse power status:

The protection function can either be enabled or disabled. The setting is password protected.

11.3, 11.4, 11.5 Reverse power settings.

11.6 Low Forward power status:

The protection function can either be enabled or disabled. The setting is password protected.

11.7, 11.8 & 11.9 Low forward power settings.

7.13. Frequency protection

Item	Front Panel	Remote Access
12.0	FREQUENCY PROTECTION	Frequency Protection
12.1	81U-1 Under Freq Enabled	81U-1 Under Frequency: Enabled
12.2	81U-1 Under Freq F1< 48.00 Hz	F1< 48.00 Hz
12.3	81U-1 Under Freq t1: 8.0 s	t1: 8.0 s
12.4	81U-2 Under Freq Enabled	81U-2 Under Frequency: Enabled
12.5	81U-2 Under Freq F2< 46.00 Hz	F2< 46.00 Hz
12.6	81U-2 Under Freq t2: 0.2 Hz	t2: 0.2 Hz
12.7	81O Over Freq Enabled	81O Over Frequency: Enabled
12.8	81O Over Freq F> 55.00 Hz	F> 55.00 Hz
12.9	81O Over Freq t: 5.0 s	t: 5.0 s

Table 32 The LGPG111's Frequency Protection Section of its menu.

Settings for two under and one over frequency protection functions.

12.1 Under frequency 1 status:

The protection function can either be enabled or disabled. The setting is password protected.

12.2 & 12.3 Under frequency 1 settings.

12.4 Under frequency 2 status:

The protection function can either be enabled or disabled. The setting is password protected.

12.5 & 12.6 Under frequency 2 settings.

12.7 Over frequency status:

The protection function can either be enabled or disabled. The setting is password protected.

12.8 & 12.9 Over frequency settings.

7.14. Voltage protection

Item	Front Panel	Remote Access
13.0	VOLTAGE PROTECTION	Voltage Protection
13.1	27 Under Voltage Enabled	27 Under Voltage: Enabled
13.2	27 Under Voltage V< 60 V	V< 60 V
13.3	27 Under Voltage t: 1.0 s	t: 1.0 s
13.4	59 Over Voltage Enabled	59 Over Voltage: Enabled
13.5	59 Over Voltage V> 140 V	V> 140 V
13.6	59 Over Voltage t> 5.0 s	t> 5.0 s
13.7	59 Over Voltage V>> 160 V	V>> 160 V
13.8	59 Over Voltage t>> 0.2 s	t>> 0.2 s
13.9	60 Volt Balance Enabled	60 Voltage Balance: Enabled
13.10	60 Volt Balance Vs> 10 V	Vs> 10 V

Table 33 The LGPG111's Voltage protection Section of its menu.

Settings for under and over voltage protection functions, plus a voltage balance or VT fuse failure function.

13.1 Under voltage status:

The protection function can either be enabled or disabled. The setting is password protected.

13.2 & 13.3 Under voltage settings.

13.4 Over voltage status:

The protection function can either be enabled or disabled. The setting is password protected.

13.5, 13.6, 13.7 & 13.8 Over voltage settings:

The over voltage protection function consists of two elements; a low set, V>, and a high set, V>>.

13.9 Voltage balance status:

The protection function can either be enabled or disabled. The setting is password protected.

13.10 Voltage balance setting.

7.15. Negative phase sequence

Item	Front Panel	Remote Access
14.0	NEGATIVE PHASE SEQUENCE	Negative Phase Sequence
14.1	46 Neg Phase Seq Enabled	46 Negative Phase Sequence: Enabled
14.2		46>> NPS Thermal Trip
14.3	46>> NPS Trip I2>> 0.05 A	I2>> 0.05 A
14.4	46>> NPS Trip K: 2 s	K: 2 s
14.5	46>> NPS Trip tMAX: 500 s	tMAX: 500 s
14.6	46>> NPS Trip tMIN: 1.00 s	tMIN: 1.00 s
14.7	46>> NPS Trip Kreset: 2 s	Kreset: 2 s
14.8		46> NPS Alarm
14.9	46> NPS Alarm I2> 0.03 A	I2> 0.03 A
14.10	46> NPS Alarm t> 2 s	t> 2 s

Table 34 The LGPG111's Negative Phase Sequence Section of its menu.

Settings for the negative phase sequence protection.

14.1 Negative phase sequence status:

The protection function can either be enabled or disabled. The setting is password protected.

14.2 NPS thermal trip:

A sub-title cell for the remote system only; all the negative phase sequence thermal trip settings are indented below this.

14.3, 14.4, 14.5 14.6 & 14.7 NPS Thermal trip settings.

14.8 NPS Alarm:

A sub-title cell for the remote system only; all the negative phase sequence alarm settings are indented below this.

14.9 & 14.10 NPS Alarm settings.

7.16. Field failure

Item	Front Panel	Remote Access
15.0	FIELD FAILURE	Field Failure
15.1	40 Field Failure Enabled	40 Field Failure: Enabled
15.2	40 Field Failure -Xa: 2.500 Ohm	-Xa (Offset): 2.500 Ohm
15.3	40 Field Failure Xb: 250.0 Ohm	Xb(Diameter): 250.0 Ohm
15.4	40 Field Failure t: 3.0 s	t (Pickup): 3.0 s
15.5	40 Field Failure tDO: 0 s	tDO(Dropoff): 0 s

Table 35 The LGPG111's Field Failure Section of its menu.

Settings for the field failure protection function.

15.1 Field failure status:

The protection function can either be enabled or disabled. The setting is password protected.

15.2, 15.3, 15.4 & 15.5 Field failure settings.

7.17 Scheme logic

Item	Front Panel	Remote Access
16.0	SCHEME LOGIC	Scheme Logic
16.1	Latch O/P 000000000000000	Latch Output: 000000000000000
16.2	Flt Rec Trig 100000000000000	Fault Record Trigger: 100000000000000
16.3	Alm Rec Trig 111111111111111	Alarm Record Trigger: 111111111111111
16.4		Input AND Matrix:
16.5	Input Matrix Word 0 →	IN 0: 10000000000000000000000000000000
...	...	...
16.36	Input Matrix Word 31 →	IN31: 00000000000000000000000000000000
16.37		Output OR Matrix:
16.38	Output Matrix Word 0 →	OUT 0: 100000000000001
...	...	...
16.69	Output Matrix Word 31 →	OUT31: 000000000000000

Table 36 The LGPG111's Scheme Logic Section of its menu.

Contains all the settings for the scheme logic plus settings for specifying which outputs are latched or self reset, which outputs trigger alarm events and which outputs trigger a trip event.

16.1 Latched output specification:

Allows any of the fifteen outputs to be specified as latching with manual reset. A 1 in a bit position selects the output as latching, otherwise it will be self reset. This setting is password protected.

Note that in order for the latched outputs to be resettable, their operation triggers an alarm record; the alarm trigger is the logical OR of the latched output and alarm trigger settings.

The bits are summarised in Table 37.

Bit	Name
0	Relay 1
1	Relay 2
2	Relay 3
3	Relay 4
4	Relay 5
5	Relay 6
6	Relay 7
7	Relay 8
8	Relay 9
9	Relay 10
10	Relay 11
11	Relay 12
12	Relay 13
13	Relay 14
14	Relay 15

Table 37 Bit flag assignment (read right to left) of the fifteen scheme configurable outputs. The names can be changed in the Input / Output Labels Section.

16.2 Fault record Trigger:

Specifies which outputs are to generate a fault record. A 1 in a bit position causes the operation of that output to generate a fault record. Generation of a fault record also causes the LGPG111 to indicate a trip on the front panel and in the remote access status information. This setting is password protected.

The bits are summarised in Table 37.

16.3 Alarm record trigger:

Specifies which outputs generate an alarm record. A 1 in a bit position causes the operation of that output to generate an alarm record. Generation of an alarm record also causes the LGPG111 to indicate an alarm on the front panel and in the remote access status information. This setting is password protected.

The bits are summarised in Table 37.

16.4 Input AND matrix:

A sub-title cell for the remote system only; all the scheme logic input AND matrix settings are indented below this.

16.5 to 16.36 Input AND matrix settings:

Thirty two cells, one for each of the thirty two logic lines of the scheme logic input AND matrix. A bit set to 1 represents a connection in the matrix. All these settings are password protected.

The bits are summarised in Table 38.

Bit	Front Panel Name	Remote Access Name
0	Input 13	Input 13
1	Input 12	Input 12
2	Input 11	Input 11
3	Input 10	Input 10
4	-Input 9	-Input 9
5	Input 9	Input 9
6	-Input 8	-Input 8
7	Input 8	Input 8
8	-Input 7	-Input 7
9	Input 7	Input 7
10	-Input 6	-Input 6
11	Input 6	Input 6
12	60 VB-Comp	60 Voltage Balance-Comp
13	-60 VB-Prot	-60 Voltage Balance-Prot
14	60 VB-Prot	60 Voltage Balance-Prot
15	40 FF	40 Field Failure
16	67N SDEF	67N Sensitive Directional EF
17	59N-2 ND	59N-2 Neutral Displacement
18	59N-1 ND	59N-1 Neutral Displacement
19	51N>> SEF	51N>> Stator Earth Fault
20	51N> SEF	51N> Stator Earth Fault
21	46>> NPS	46>> NPS Trip
22	46> NPS	46> NPS Alarm
23	59 OV	59 Over Voltage
24	27 UV	27 Under Voltage
25	81U-2 UF	81U-2 Under Frequency
26	81U-1 UF	81U-1 Under Frequency
27	81O OF	81O Over Frequency
28	32L LFP	32L Low Forward Power
29	32R RP	32R Reverse Power
30	51V OC	51V Overcurrent
31	87G Gen Diff	87G Generator Differential

Table 38 Bit flag assignment (read right to left) of the scheme logic inputs.

Note: The names of the logic inputs bits, 0 to 11, can be changed in the input/output labels section. Negated logic inputs, bits 4, 6, 8 & 10 are indicated by a prefixed minus'-'. In a similar fashion the negated output from the voltage balance protection VT failure, bit 13, is prefixed by a minus.

16.37 Output OR matrix:

A sub-title cell for the remote system only; all the scheme logic output OR matrix settings are indented below this.

16.38 to 16.69 Output OR matrix settings:

Thirty two cells, one for each of the thirty two logic lines of the scheme logic output OR matrix. A bit set to 1 represents a connection in the matrix. All these settings are password protected.

The bits are summarised in Table 37.

7.18. Input / output labels

Item	Front Panel	Remote Access
17.0	INPUT / OUTPUT LABELS	Input / Output Labels
17.1		Digital Input Labels
17.2	Input 6: Input 6	Input 6: Input 6
...	...	...
17.9	Input 13: Input 13	Input 13: Input 13
17.10		Output Contact Labels
17.11	Output 1: Relay 1	Output 1: Relay 1
...	...	...
17.25	Output 15: Relay 15	Output 15: Relay 15

Table 39 The LGPG111's Input / output labels Section of its menu.

Allows all the application dependent inputs and outputs to be given appropriate identifier labels.

17.1 Input labels:

A sub-title cell for the remote system only; all the input label settings are indented below this.

17.2 to 17.9 Input label settings:

Eight, 15 character,[7] labels for the scheme definable optically isolated logic inputs. These settings are password protected.

17.10 Output labels:

A sub-title cell for the remote system only; all the output label settings are indented below this.

17.11 to 17.25 Output label settings:

Fifteen, 16 character, labels for the scheme logic definable output contacts. These settings are password protected.

[7]The 16th available character position is reserved for the minus, '-', prefix used to indicate negated inputs.

7.19. Remote communications

Item	Front Panel	Remote Access
18.0	REMOTE COMMUNICATIONS	Remote Communications
18.1	Relay Address: 1	Relay Address: 1
18.2	Remote Setting: Enabled	Remote Setting: Enabled
18.3	Comms Mode: Rear IEC870FT1.2	Communications Mode: Rear IEC870 FT1.2
18.4	Minimum Transmit Delay: 0 s	Minimum Transmit Delay: 0 s
18.5	Baud Rate: 19200	Serial Baud Rate: 19200

Table 40 The LGPG111's Remote Communications Section of its menu.

Configuration settings for the remote access user interface.

The remote system setting transfer does not include any of these settings.

18.1 Relay address:

The address of the LGPG111 on a remote communications network. Settable between 0 & 255. A value of 255 effectively removes the relay from direct addressing over the network and a value of 0 is used as a transition address by a remote system - a transition address is automatically changed by the remote system to a spare address on the network. This cell is duplicated in the System Data Section.

18.2 Remote setting:

Allows remote access setting capability to be 'Enabled' or 'Disabled'.

When disabled, settings can only be changed through the front panel. This setting is password protected and is duplicated in the Auxiliary Functions Section.

18.3 Communications mode:

Selects which port the communications system will use.

Front Panel	Remote Access
Comms Mode: Disabled	Communications Mode: Disabled
Comms Mode: K-Bus	Communications Mode: K-Bus
Comms Mode: FrontIEC870FT1.2	Communications Mode: Front IEC870 FT1.2
Comms Mode: Rear IEC870FT1.2	Communications Mode: Rear IEC870 FT1.2

Table 41 States of the communications mode cell.

If the communications hardware fails, the disabled mode is automatically entered.

18.4 Minimum transmit delay:

Determines the minimum response time of the LGPG111, in the range 0s to 60ms in 0.25ms increments. Normally this setting should be 0s, but it can be increased when using half duplex communications adapters[8] such as RS232 to twisted pair RS485 or RS232 to half duplex optical fibre. The delay allows the transceivers used in such devices to switch between transmitting and receiving.

This setting is not available when the remote communications are disabled.

18.5 Baud rate:

Defines the transmission and reception speed for the IEC870 communications modes in bits per second. Can be set to: 600, 1200, 2400, 3600, 4800, 7200, 9600, 14400 or 19200 Baud.

This setting is only available for the IEC870 communications modes.

[8]The term adapter is used here for a device which converts between physical communications mediums. This is distinct from a communications protocol converter, which may well change the communications medium as part of its protocol conversion. An adapter has no knowledge about what is being transmitted, whereas a protocol converter must have and therefore requires no transmit delay by the LGPG111.

7.20. Disturbance recorder

Item	Front Panel	Remote Access
19.0	DISTURBANCE RECORDER	Disturbance Recorder
19.1	Recorder Status: Running	Recorder Status: Running
19.2	Data Capture: Raw ADC Samples	Data Capture: Raw ADC Samples
19.3	Post Trigger Cycles: 32	Post Trigger Cycles: 32
19.4	Analogue Channel: →	Analogue Channel: 11100000011111000
19.5	Logic I/P Trig: 00000000000000	Logic Input Trig: 00000000000000
19.6	Relay O/P Trig: 111000000001000	Relay Output Trig: 111000000001000
19.7	Records Stored: 0	Records Stored: 0
19.8	Clear All Records	Clear All Records: No

Table 42 The LGPG111's Disturbance recorder Section of its menu.

Configuration settings for the disturbance waveform recorder.

19.1 Disturbance recorder status:

The status of the recorder. Can be: 'Stopped', 'Triggered' or 'Running'.

The disturbance recorder is normally in the running state and is ready to be triggered. When a trigger occurs, the recorder is in the triggered state for the duration of the post trigger data capture. After the first recording, the recorder automatically returns to the running state, ready for a second trigger, otherwise it enters the stopped state. The stopped state is automatically cleared, back to the running state, when the remote system extracts one of the two disturbance records. Alternatively, both records can be erased by activating the Clear All Records cell, 19.8, and the recorder will return to the running state.

The recorder can be manually triggered by manually changing this cell to the triggered state. It is not possible to enter the stopped or running states manually.

The relay will reject a manual trigger if it is currently processing a trigger.

The remote access setting transfer does not include this cell.

19.2 Data capture:

Determines the operating mode of the disturbance recorder.

Front Panel	Remote Access
`Data Capture:` `Raw ADC Samples`	`Data Capture: Raw ADC Samples`
`Data Capture:` `Mag & Phase`	`Data Capture: Magnitudes & Phases`

Table 43 States of the Data Capture cell.

The disturbance recorder can be set-up to record either the raw data from the analogue to digital converter hardware or the data from the output of the signal processing software.

Raw data is captured at twelve samples per electrical cycle and is frequency locked. Each of the two disturbance records can hold 768 such samples and hence provide a recording duration of 64 electrical cycles. Raw data is not magnitude and phase calibrated.

Magnitude and phase data is captured approximately every 20ms from the outputs of the software signal processing. The data is in the form of a magnitude and phase vector of the fundamental frequency component and is fully calibrated. Each of the two disturbance records can hold 384 such samples, which, at 20ms intervals, provides 7.68 seconds of data.

19.3 Post Trigger cycles:

Determines how long recording will continue after a trigger. For raw data, the trigger position can set anywhere between 0 & 64 post-trigger cycles. For magnitude and phase data, the trigger position can be set anywhere between 0 & 384 post-trigger cycles.

19.4 Analogue channels:

Specifies which analogue channels are to be recorded. The disturbance recorder can record any eight of the seventeen analogue inputs and all the digital status information about the logic inputs and relay contact outputs. This setting allows any combination, up to eight, of the seventeen analogue inputs to be selected, for data capture, by setting the appropriate bits to 1. If more than eight bits are set to 1, the setting will be rejected.

Bit	Name
0	Vbc-Comp
1	Vab-Comp
2	Vbc
3	Vab
4	Ia-Sensitive
5	Ia
6	Ib
7	Ic
8	Ia-Bias
9	Ia-Diff
10	Ib-Bias
11	Ib-Diff
12	Ic-Bias
13	Ic-Diff
14	Ie
15	I-Residual
16	Ve

Table 44 Bit flag assignment (read right to left) of the Analogue Channel select cell.

19.5 Logic input trigger:

Specifies which logic inputs can trigger the disturbance recorder. A bit set to 1 allows that logic input to trigger the recorder when it is energised. Any number of logic inputs can be selected between 0 and 14. The bits are summarised in Table 7, page 28.

It is not possible to trigger the recorder when an input is de-energised.

19.6 Relay output trigger:

Specifies which relay outputs can trigger the disturbance recorder. A bit set to 1 allows that output to trigger the recorder when it is operated. Any number of outputs can be selected between 0 and 15. The bits are summarised in Table 37, page 62.

It is not possible to trigger the recorder when an output is reset.

19.7 Number of records stored:

An indication of how many records are stored. Can be 0, 1 or 2. Note that for two records stored, the recorder is stopped.

19.8 Clear all records:

Allows currently stored records to be erased without the need to extract them.

Front Panel	Remote Access
`Clear All` `Records`	`Clear All Records: No`
`Press SET To` `Clear All Record`	`Clear All Records: Yes`

Table 45 States of the Clear All Records cell.

This cell is password protected and not included in the setting transfer.

7.21. Test functions

Item	Front Panel	Remote Access
20.0	TEST FUNCTIONS	Test Functions
20.1	Lamp Test	Lamp Test: Off
20.2	Relay Test: 0000000000000000	Relay Test: 0000000000000000
20.3		Scheme Logic Test
20.4		Group 1
20.5	(1)SchemeSetting OK	Scheme Setting: OK
20.6	(1)Set Events For Scheme Test→	In: 00000000000000000000000000000000
20.7	(1)Scheme O/P 000000000000000	Out: 000000000000000
20.8		Group 2
20.9	(2)SchemeSetting OK	Scheme Setting: OK
20.10	(2)Set Events For Scheme Test→	In: 00000000000000000000000000000000
20.11	(2)Scheme O/P 000000000000000	Out: 000000000000000

Table 46 The LGPG111's Test Functions Section of its menu.

Various test facilities. The section contents are shown as if the alternative setting group was enabled. When it is disabled the bracketed group identifier, (1) & (2), will disappear along with the group 2 cells. This is noted in the description of each cell below. None of these settings are included in the remote system setting transfer.

20.1 Lamp test:

Allows the operation of the front panels LED's to be checked.

Front Panel	Remote Access
Lamp Test	Lamp Test: Off
Press SET For Lamp Test	Lamp Test: On

Table 47 States of the Lamp Test cell.

when activated, the lamp test inverts the current states of the trip, alarm and out of service LED's for approximately 2s. the relay healthy led will remain on momentarily and then extinguish. after the completion of the test, in about 2s, the LED's return to their normal states and the cell returns to it's off state.

20.2 Relay test:

Allows the relay output contacts to be checked. This cell can only be changed when the scheme output has been inhibited, in the Auxiliary Functions Section.

With the scheme output inhibited, any desired combination of relay outputs can be operated simply by setting up the appropriate bit pattern. Resetting the cell provides a quick method of setting all the bits to zero and hence resetting all the outputs. All the bits are reset when the scheme output is re-enabled. The bits are summarised in Table 8, page 29.

Bit 0, the Relay Inoperative Alarm, is normally operated to indicate that the LGPG111 is functioning correctly. Setting bit 0 to a 1, will invert this output's state and cause it to reset.

The Relay Output Status cells in the System Data and Auxiliary Functions Sections will not reflect the bit pattern in this cell. Instead these cells reflect the output from the scheme logic.

20.3 Scheme logic test:

A sub-title cell for the remote system only. All the scheme logic tests are indented below.

20.4 Group 1 scheme logic test:

A sub-title cell for the remote system only. When the alternative setting group has been enabled, this cell is visible and the group 1 scheme tests are indented below.

20.5 Scheme setting check (Group 1):

Provides an indication of any incompletely programmed scheme logic lines. The check is limited to finding logic lines which have bits set in only the input AND matrix or the output OR matrix and not both. It cannot detect logic errors resulting from programming the bits. The check starts at logic line zero and progresses towards logic line 31. The first partially programmed logic line is indicated by '`Error in Line XX`', where 'XX' is the logic line number. If no errors are detected then '`OK`' is indicated.

When alternative settings are disabled, the group 1 identifier, (1), is removed.

20.6 Scheme logic (Group 1) test event input:

Allows scheme logic input scenarios to be set-up. The scheme logic processes this and the output is displayed in the next cell. The names of the input bits are identical to those used in the scheme logic input AND matrix, see Table 38, page 63.

This test can be performed with the LGPG111 protection fully functional and with no ill effect.

When alternative settings are disabled, the group 1 identifier, (1), is removed.

20.7 Scheme logic (Group 1) test output:

The scheme logic output bit pattern resulting from the input scenario of the above cell. The names of the output bits are identical to those used in the scheme logic output OR matrix, see Table 37, page 62.

When alternative settings are disabled, the group 1 identifier, (1), is removed.

20.8, 20.9, 20.10 & 20.11 Group 2 scheme logic tests:

Identical to cells 20.4 to 20.7, respectively, except that the tests are applied to the group 2 scheme logic settings.

When the alternative setting group is disabled, these cells are invisible.

7.22. Protection operation summary

Item	Front Panel	Remote Access
21.0	PROTECTION OP SUMMARY	Protection Operation Summary
21.1		16 Aug 1994 16:02:58.218
21.2		87G Generator Differential
21.3	87G Gen Diff A: 0%	Phase A: 0%
21.4	87G Gen Diff B: 0%	Phase B: 0%
21.5	87G Gen Diff C: 0%	Phase C: 0%
21.6	51N> Stator EF: 0%	51N> Stator Earth Fault: 0%
21.7	51N>> Stator EF: 0%	51N>> Stator Earth Fault: 0%
21.8	59N-1 Neutral D: 0%	59N-1 Neutral Displacement: 0%
21.9	59N-2 Neutral D: 0%	59N-2 Neutral Displacement: 0%
21.10	67N SDEF: 0%	67N Sensitive Directional EF: 0%
21.11		51V Overcurrent
21.12	51V OC A: 0%	Phase A: 0%
21.13	51V OC B: 0%	Phase B: 0%
21.14	51V OC C: 0%	Phase C: 0%
21.15	32R Reverse Pwr: 0%	32R Reverse Power: 0%
21.16	32L Low Fwd Pwr: 0%	32L Low Forward Power: 0%
21.17	81U-1 Under Freq 0%	81U-1 Under Frequency: 0%
21.18	81U-2 Under Freq 0%	81U-2 Under Frequency: 0%
21.19	81O Over Freq: 0%	81O Over Frequency: 0%

Continued ...

…Continued from previous page.

Item	Front Panel	Remote Access
21.20	27 Under Voltage 0%	27 Under Voltage-Low Set: 0%
21.21	59> Over Voltage 0%	59> Over Voltage-High Set: 0%
21.22	59>>Over Voltage 0%	59>>Over Voltage: 0%
21.23	46> NPS Alarm: 0%	46> NPS Alarm: 0%
21.24	46>> NPS Thermal 0%	46>> NPS Trip Thermal: 0%
21.25	46>> NPS tMIN: 0%	46>> NPS Trip tMIN: 0%
21.26	46>> NPS tMAX: 0%	46>> NPS Trip tMAX: 0%
21.27	40 Field Failure 0%	40 Field Failure: 0%
21.28	60 VB-Prot: 0%	60 Voltage Balance-Prot: 0%
21.29	60 VB-Comp: 0%	60 Voltage Balance-Comp: 0%

Table 48 The LGPG111's Protection Operation Summary Section of its menu.

Provides protection operation status indications as a percentage time to trip. Only cells with other usage are documented below, as the rest are self explanatory.

21.1 Date & time:

This cell only appears on the remote access menu. When the remote system reads this section it captures a snapshot of the protection operation summary - this cell provides a time stamp indicating when the data was captured. This is not a problem for the front panel since the display is updated approximately every 500ms.

21.2 & 21.11 Sub-title cells:

These two cells only appear on the remote access menu; the three phase information for the differential and overcurrent, respectively, appear indented below them.

21.24 NPS Trip thermal:

This cell does not indicate percentage time to trip, but percentage thermal withstand.

8. PRINT REPORT EXAMPLES

The following are examples of the various reports which the LGPG111 can print on a parallel printer connected to its parallel port. The reports are generated by the print cell in the Auxiliary Functions Section.

The examples of the protection and scheme logic reports where generated with only one setting group enabled; if both setting groups where enabled then settings for both groups would have been printed.

Each report begins with a header and ends with '`**End of Report**`'. The header consists of the Description and Plant Reference entries, from the System Data Section of the menu, followed by the relay's serial number and the date and time.

8.1. System settings

```
LGPG RELAY : <Not Defined>
Serial Number : 000000O
Printed on Tue 1994 Aug 23   16:33:53

System Data
Plant Reference: <Not Defined>
Model Number:  LGPG11101S533LEA
Serial Number: 000000O
System Frequency: 50 Hz

Auxiliary Functions
Scheme Output: Enabled
Second Setting Group: Disabled
Inactivity Timer:    30 min
Stator EF Timer Inhibit: Disabled
Clock Synchronised: Disabled
Default Local Display: Date & Time

Transformer Ratios
Display Value: Secondary
Current Rating: 1 A
Differential CT Ratio:    1.00:1
Sensitive Ia CT Ratio:    1.00:1
Residual CT Ratio:        1.00:1
Earth CT Ratio:           1.00:1
Earth VT Ratio:           1.00:1
Phase CT Ratio:           1.00:1
Line VT Ratio:            1.00:1
Comparison VT Ratio:      1.00:1
```

```
 Input / Output Labels
 Digital Input Labels
 Input  6: Input 6
 Input  7: Input 7
 Input  8: Input 8
 Input  9: Input 9
 Input 10: Input 10
 Input 11: Input 11
 Input 12: Input 12
 Input 13: Input 13
Output Contact Labels
 Output  1: Gen Diff Trip
 Output  2: Overcurrent Trip
 Output  3: Reverse Pwr Trip
 Output  4: Over Freq Trip
 Output  5: Under Freq Trip
 Output  6: O Voltage Trip
 Output  7: U Voltage Trip
 Output  8: NPS Trip
 Output  9: NPS Alarm
 Output 10: Volt Bal Operate
 Output 11: Relay 11
 Output 12: Relay 12
 Output 13: Field Fail Trip
 Output 14: Relay 14
 Output 15: Trip CB

Remote Communications
Relay Address: 1
Remote Setting: Enabled
Communications Mode: Rear IEC870 FT1.2
Transmit Delay:      0 s
Serial Baud Rate: 9600

Disturbance Recorder
Recorder Status: Running
Data Capture: Raw ADC Samples
Post Trigger Cycles: 0
Analogue Ch: 00011111100001000
Logic Input Trigger:   00000000000000
Relay Output Trigger: 000000000000000
Records Stored: 0

**End of Report**
```

8.2. Protection settings

```
LGPG RELAY : <Not Defined>
Serial Number : 000000O
Printed on Tue 1994 Aug 23   16:34:17
PROTECTION SETTINGS

Generator Differential
87G Generator Differential: Enabled
 Is1:  0.10 A
 K1:      0%
 Is2:  1.20 A
 K2:    150%

Earth Fault Protection
51N Stator Earth Fault: Enabled
 51N> Low Set
  Characteristic: Definite Time
  Ie>       385mA
  t>        0.1 s
  tRESET:     0 s
51N>> High Set: Enabled
  Ie>>   275mA
  t>>    0.1 s
59N Neutral Displacement: Disabled
 Ve>          1 V
 t1:        1.0 s
 t2:          0 s
 t2RESET:     0 s
67N Sensitive Directional EF: Disabled
 Iresidual>    20mA
 RCA:           0 deg
 Vep>           5 V
 Iep>          20mA

Voltage Dependent Overcurrent
51V Overcurrent: Enabled
 Function: Voltage Controlled
  Voltage Vector Rotate: None
  Vs:     34 V
  K:    0.25
 Characteristic: Definite Time
  I>       1.00 A
  t:        1.5 s
  tRESET:     0 s

Power Protection
Compensation Angle:     0 deg
32R Reverse Power: Enabled
 -P>             0.20 W
 t   (Pickup):   0.5 s
 tDO(Dropoff):     0 s
32L Low Forward Power: Enabled
 P<              0.20 W
 t   (Pickup):   0.5 s
 tDO(Dropoff):     0 s
```

```
Frequency Protection
81U-1 Under Frequency: Enabled
 F1< 45.00 Hz
 t1:   1.0 s
81U-2 Under Frequency: Enabled
 F2< 45.00 Hz
 t2:   1.0 s
81O Over Frequency: Enabled
 F>  55.00 Hz
 t:    0.1 s

Voltage Protection
27 Under Voltage: Enabled
 V<     30 V
 t:    4.0 s
59 Over Voltage: Enabled
 V>    105 V
 t>    0.5 s
 V>>   130 V
 t>>     0 s
60 Voltage Balance: Enabled
 Vs>    20 V

Negative Phase Sequence
46 Negative Phase Sequence: Enabled
46>> NPS Thermal Trip
 I2>>     0.50 A
 K:          2 s
 tMAX:    2000 s
 tMIN:    2.00 s
 Kreset:     2 s
46> NPS Alarm
 I2>  0.50 A
 t>     2 s

Field Failure
40 Field Failure: Enabled
 -Xa (Offset):   2.5 Ohm
 Xb(Diameter): 250.0 Ohm
 t   (Pickup):   1.0 s
 tDO(Dropoff):     0 s

**End of Report**
```

8.3. Scheme logic

```
LGPG RELAY : <Not Defined>
Serial Number : 000000O
Printed on Tue 1994 Aug 23   16:34:48

Scheme Logic
Latch Outputs:           000000000000000
Fault Record Trigger:    100000000000000
Alarm Record Trigger:    000000000000000


                     INPUT MATRIX                     OUTPUT MATRIX
Logic 00 10000000 00000000 00000000 00000000   10000000 0000001
Logic 01 01000000 00000000 00100000 00000000   10000000 0000010
Logic 02 00100000 00000000 00100000 00000000   10000000 0000100
Logic 03 00001000 00000000 00000000 00000000   10000000 0001000
Logic 04 00000100 00000000 00000000 00000000   10000000 0010000
Logic 05 00000010 00000000 00000000 00000000   10000000 0010000
Logic 06 00000001 00000000 00100000 00000000   10000000 0100000
Logic 07 00000000 10000000 00100000 00000000   10000000 0100000
Logic 08 00000000 01000000 00000000 00000000   10000000 1000000
Logic 09 00000000 00100000 00000000 00000000   10000010 0000000
Logic 10 00000000 00010000 00000000 00000000   10000011 0000000
Logic 11 00000000 00001001 00000000 00000000   10100000 0000000
Logic 12 00000000 00000100 00000000 00000000   00000100 0000000
Logic 13 00000000 00000000 00000000 00000000   00000000 0000000
Logic 14 00000000 00000000 00000000 00000000   00000000 0000000
Logic 15 00000000 00000000 00000000 00000000   00000000 0000000
Logic 16 00000000 00000000 00000000 00000000   00000000 0000000
Logic 17 00000000 00000000 00000000 00000000   00000000 0000000
Logic 18 00000000 00000000 00000000 00000000   00000000 0000000
Logic 19 00000000 00000000 00000000 00000000   00000000 0000000
Logic 20 00000000 00000000 00000000 00000000   00000000 0000000
Logic 21 00000000 00000000 00000000 00000000   00000000 0000000
Logic 22 00000000 00000000 00000000 00000000   00000000 0000000
Logic 23 00000000 00000000 00000000 00000000   00000000 0000000
Logic 24 00000000 00000000 00000000 00000000   00000000 0000000
Logic 25 00000000 00000000 00000000 00000000   00000000 0000000
Logic 26 00000000 00000000 00000000 00000000   00000000 0000000
Logic 27 00000000 00000000 00000000 00000000   00000000 0000000
Logic 28 00000000 00000000 00000000 00000000   00000000 0000000
Logic 29 00000000 00000000 00000000 00000000   00000000 0000000
Logic 30 00000000 00000000 00000000 00000000   00000000 0000000
Logic 31 00000000 00000000 00000000 00000000   00000000 0000000

**End of Report**
```

8.4. Event Records

Three options are available to specify the number of records to be printed. The options are: to print 10, 25, or All Records. When the number of records available is less than the number specified, the print function prints whatever records are available; at the end of printing, the string “`End of Report`” is printed.

```
     LGPG RELAY : <Not Defined>
     Serial Number : 000000O
     Printed on Tue 1994 Aug 23   16:35:19
     EVENT RECORDS

1    Sat 1994 Jan 01   00:00:00.014
     Events: Relay Power On

2    Sat 1994 Jan 01   00:00:00.014
     Events: Real Time Clock Invalid

3    Sat 1994 Jan 01   00:00:00.076
     Events: Group 1 Selected

4    Tue 1994 Aug 23   08:05:51.000
     Events: Real Time Clock Valid

5    Tue 1994 Aug 23   15:52:28.293
     Relay Output Change: Relay Inoperative Alarm

6    Tue 1994 Aug 23   16:05:33.188
     Exceptions: Analogue Module Fail

7    Tue 1994 Aug 23   16:06:28.981
     Events: Relay Warm Reset

8    Tue 1994 Aug 23   16:06:29.043
     Events: Group 1 Selected

9    Tue 1994 Aug 23   16:30:48.541
     Events: Local Password Removed

10   Wed 1992 Jan 01   05:39:05.956
     Events: Local Password Restored

11   Tue 1994 Aug 23   16:43:15.924
     Relay Output Change: O Voltage Trip

12   Tue 1994 Aug 23   16:43:15.924
     Protection: 59 Over Voltage
```

```
13  Tue 1994 Aug 23   16:45:14.599
    Fault Record:
    Protection: 87G Generator Differential ABC, 51V Overcurrent A,
    81U-1 Under Frequency, 81U-2 Under Frequency,
    27 Under Voltage, 59 Over Voltage >,
    51N> Stator Earth Fault, 51N>> Stator Earth Fault,
    40 Field Failure, 60 Voltage Balance-Comp
    Relay Output Status: Trip CB, NPS Alarm, NPS Trip,
    O Voltage Trip, Under Freq Trip, Overcurrent Trip, Gen Diff
Trip
    Logic Input Status:  No operation
    Scheme Output: Enabled
    Active Setting Group: 1
    Ia:                  1.000   A
    Ib:                  1.000   A
    Ic:                  1.000   A
    Ia-Diff:               998  mA
    Ib-Diff:             1.000   A
    Ic-Diff:               997  mA
    Ia-Mean Bias:          500  mA
    Ib-Mean Bias:          500  mA
    Ic-Mean Bias:          500  mA
    I2:                      0   A
    I-Residual:          1.003   A
    Ie:                  1.002   A
    Vab:                 110.1   V
    Vbc:                     0   V
    Vca:                 110.3   V
    Ve:                   0.43   V
    Active Power   Aph: 55.29   W
    Reactive Power Aph:-31.60   VAr
    Phase Angle    Aph:  29.9   deg
    Frequency:           44.49   Hz

**End of Report**
```

9. SUMMARY OF FRONT PANEL USER INTERFACE MESSAGES

9.1. Relay reset messages

The following messages are displayed when the relay is powered up (cold reset) or when it is reset by the watchdog (warm reset).

```
COLD RESET:
Self test.......
```

The relay has been powered up from cold and is carrying out the power-on diagnostic tests.

```
COLD RESET:
Memory test.....
```

The diagnostics is testing the RAM and EPROM memory devices.

```
WARM RESET:
Self test.......
```

The relay has been reset by the operation of the watchdog and is currently carrying out the *warm reset* diagnostic tests.

```
WARM RESET:
Memory test.....
```

The diagnostics is testing the RAM and EPROM memory devices.

```
RESET:RAM Fail
Self test.......
```

The relay has been reset due to a RAM error detected by the background self-monitoring. The power-on diagnostics is currently being executed. Note that this may result in a lock-out situation.

```
RESET:RAM Fail
Memory test.....
```

The diagnostics is testing the RAM and EPROM memory devices.

```
RESET:EPROM Fail
Self test.......
```

The relay has been reset due to an EPROM error detected by the background self-monitoring. The power on diagnostics is currently being executed. Note that this may result in a lock-out situation.

```
RESET:EPROM Fail
Memory test.....
```

The diagnostics is testing the RAM and EPROM memory devices.

```
RESET:A/Mod Fail
Self test.......
```

The relay has been reset due to a failure of the analogue input module during run-time. The power on diagnostics is currently being executed.

```
RESET:A/Mod Fail
Memory test.....
```

The diagnostics is testing the RAM and EPROM memory devices.

```
RESET:C/Hdw Fail
Self test.......
```

The relay has been reset due to a failure of the communication hardware during run-time. The power on diagnostics is currently being executed.

```
RESET:C/Hdw Fail
Memory test.....
```

The diagnostics is testing the RAM and EPROM memory devices.

9.2. Power on diagnostic error messages

The following are power on diagnostic error messages. The occurrence of any one of these errors will cause the relay to lockout. The microcomputer and serial communications module is faulty. Replace and return it to ALSTOM T&D Protection & Control Limited for repair.

Display	Cause of failure:
SELF TEST FAIL: Microprocessor	- Microprocessor fails self check.
SELF TEST FAIL: INT Mask Reg	- Interrupt mask register fails read / write test.
SELF TEST FAIL: INT Priority Reg	- Interrupt priority register fails read / write test.
SELF TEST FAIL: INT Status Reg	- Interrupt status register fails read / write test.
SELF TEST FAIL: INTTimer CtrlReg	- Interrupt timer control register fails read / write test.
SELF TEST FAIL: INT DMA0 CtrlReg	- Interrupt DMA 0 control register fails read / write test.
SELF TEST FAIL: INT DMA1 CtrlReg	- Interrupt DMA 1 control register fails read / write test.
SELF TEST FAIL: INT INT0 CtrlReg	- Interrupt INT 0 control register fails read / write test.
SELF TEST FAIL: INT INT1 CtrlReg	- Interrupt INT 1 control register fails read / write test.
SELF TEST FAIL: INT INT2 CtrlReg	- Interrupt INT 2 control register fails read / write test.
SELF TEST FAIL: INT INT3 CtrlReg	- Interrupt INT 3 control register fails read / write test.
SELF TEST FAIL: Unexpected INT	- An unexpected interrupt has occurred.
SELF TEST FAIL: Timer 2 INOP	- Timer 2 is inoperative.
SELF TEST FAIL: Timer 2 Fast	- Timer 2 is fast.
SELF TEST FAIL: Timer 2 Slow	- Timer 2 is slow.
SELF TEST FAIL: No DMA0 INT	- No DMA 0 interrupt occurred.
SELF TEST FAIL: DMA0 Transfer	- DMA 0 transfer error.
SELF TEST FAIL: RAM Memory	- RAM memory error.
SELF TEST FAIL: EPROM Memory	- EPROM memory error.

Table 49 Power on diagnostic lock-out errors.

9.3. Run-time default display messages

There are three default display messages. These override the normal default display which is detailed in Section 4.2., page 9.

```
ALARM
```

This message can be flashing or stable. When it is flashing there is a new alarm. When it is stable, either alarms have been accepted and not cleared or there is an alarm which is still active and cannot be cleared.

```
DATE AND TIME
NOT SET UP
```

Displayed at default level when there are no alarms and the date and time has not been set.

```
Local Settings
Unlocked
```

Displayed at default level when the password has been entered at the front panel user interface; all the password protected settings are now available for changing.

9.4. User interface operational messages

Various messages may occur on the front panel during the use of the menu system. These messages are listed here with their respective meanings and possible actions. Reference should also be made to the operational descriptions of the Alarm Scan and Menu Browse in Sections 4.3.1., page 10 and 4.3.3., page 12, respectively.

```
RESET To
Clear Alarms
```

Appears when the ACCEPT/READ key is pressed, during an Alarm Scan, to read the next alarm message when the last one is displayed. The RESET key can then be pressed to *clear* the messages. Alternatively, the ACCEPT/READ key can be pressed to *accept* the alarms without clearing them.

```
ALARMS
Still Active
```

Appears if there are alarms which are still active after an attempt to *accept* or *clear* them in the alarm scan. The ACCEPT/READ key must be pressed to return to the default display.

```
Password
Protected
```

Occurs when a password protected setting is blocked from enter setting mode as the password has not been entered to make the setting available for changing. Press the ← key to abort the action.

```
Password
Protected View→
```

Same as the '`Password Protected`' message but only occurs for binary flag type cells. A further press of the → key enables the labels of each binary bit flag to be viewed. The ← key aborts the action.

```
Sorry, Setting
Is Invalid
```

Occurs when an incorrect password has been entered or too many analogue channels have been selected in the disturbance recorder set-up. Press the ← key to abort the setting change and return to setting mode.

```
Not A Setting
```

Occurs when the → key has been pressed for a cell which is not a setting. Press ← key to abort this action.

```
Not A Setting
     View→
```

Occurs when the → key has been pressed for a binary flag value cell which is not a setting. A further press of the → enables the labels of each binary bit flag to be viewed. The ← key aborts the action.

```
Press SET To
Confirm Changes
```

Occurs when leaving some of the sections in the menu in which a setting(s) has been changed. Options are: → to re-enter the section, SET to update and RESET to ignore the setting change(s).

```
Remote Setting
In Progress
```

The remote access system is changing a setting and it is not possible to change a setting locally at the same time. The ← key will return to the cell's display.

```
Remote Setting
In ProgressView
```

The remote access system is changing a setting and it is not possible to change a setting locally at the same time. The → key enables the labels of each binary bit flag to be viewed. The← key will return to the cell's display.

9.5. Alarm messages

Alarm messages are categorised into five types and they are only available on the front panel during the alarm scan. The display format of an alarm message is shown in the following illustration.

```
ALARM: Exception
Analog Mod Fail
```

First line indicates the type of alarm.

Second line indicates the cause of the alarm.

Figure 13 Composition of the Alarm Scan message display.

9.5.1. Exceptional alarm messages

This type of error is generally caused by the failure of hardware.

```
ALARM: Exception
Uncalib Analog
```

- Out Of Service LED is on
- Relay Healthy LED is off

The analogue input module has not been calibrated or its vital calibration data has been corrupted and the protection is stopped.

The module must be (re-)calibrated. The analogue module should be returned to ALSTOM T&D Protection & Control Limited, or to a recognised service centre, for calibration.

```
ALARM: Exception
Analog Mod Fail
```

- Out Of Service LED is on
- Relay Healthy LED is off

The analogue input module has failed and the protection is stopped. Replace the faulty module. The analogue module should be returned to ALSTOM T&D Protection & Control Limited, or to a recognised service centre, for repair and calibration.

```
ALARM: Exception
Calib Vector Err
```

The compensation data in the analogue input module has been corrupted. The protection remains in service, but with reduced measurement accuracy.

The analogue module must be re-calibrated or replaced by a spare, at the earliest opportunity. The module should be returned to ALSTOM T&D Protection & Control Limited, or to a recognised service centre, for calibration.

```
ALARM: Exception
Comms H/W Fail
```

The interface between the main processor and the communication processor has failed. The remote communications has been disabled.

Reset the relay by power down and up again to see if the fault is persistent. If unsuccessful, replace the faulty microcomputer module. The module should be sent back to ALSTOM T&D Protection & Control Limited for repair.

```
ALARM: Exception
Grp Sel I/P Fail
```

The setting group select pair of logic inputs are in an inconsistent state. This could be due to an external wiring fault or a failed status input. The currently active setting group remains active. If after testing one of the status inputs is found to be faulty, the analogue and status input module should be sent back to ALSTOM T&D Protection & Control Limited for repair.

```
ALARM: Exception
EEPROM WriteFail
```

An attempt to write to the EEPROM memory in the microcomputer module has failed. Replace the faulty module with another. The module should be sent back to ALSTOM T&D Protection & Control Limited for repair.

9.5.2. Non-volatile EEPROM memory error alarm messages

Non-volatile EEPROM errors occur when there is corruption of information stored in the memory of the microcomputer module. Data is segmented into blocks in the EEPROM and each block has its own data integrity checksum. Thus each block can suffer a failure without affecting the integrity of the entire memory device. The segmentation of the data into blocks follows the organisation of the data in the menu system.

Most of the errors listed in Table 51 are not catastrophically detrimental as they affect only limited portions of the protection. The loss of the scheme logic settings is, however, catastrophic to the protection. The two failure modes are summarised in Table 50

	Non-Fatal Data Loss	Fatal Data Loss
Power on failure	Data is replaced by default values. For protection setting data this disables the protection. The LGPG111 runs normally.	Data is replaced by default values. The relay runs normally but all protection operations are suspended. • Out Of Service LED is on. • Relay Healthy LED is off.
Run time failure	No effect on the LGPG111's performance which continues normally. The error will continue to be asserted until new settings are entered or the relay is reset.	No effect on the LGPG111's performance which continues normally. The error will continue to be asserted until new settings are entered or the relay is reset.

Table 50 Failure modes for loss of non-volatile memory data.

Display	Data corrupted in:
ALARM:EEPROM Err System Data	- System Data setting area.
ALARM:EEPROM Err Aux Functions	- Auxiliary Functions setting area.
ALARM:EEPROM Err T'former Ratios	- Transformer Ratios setting area.
ALARM:EEPROM Err Disturbance Rec	- Disturbance Recorder setting area.
ALARM:EEPROM Err Input Labels	- Input Label setting area.
ALARM:EEPROM Err Output Labels	- Output Label setting area.
ALARM:EEPROM Err Remote Comms	- Remote Communications setting area.
ALARM:EEPROM Err Alarm Record	- Alarm Record data area.
ALARM:EEPROM Err Fault Record	- Fault Record data area.
ALARM:EEPROM Err Event Record	- Event Record data area.

continued...

continued from previous page…

Display	Data corrupted in:
ALARM:EEPROM Err Current Rating	- Current Rating copy area.
ALARM:EEPROM Err Generator Diff 1	- Generator Differential Group 1 setting area.
ALARM:EEPROM Err Generator Diff 2	- Generator Differential Group 2 setting area.
ALARM:EEPROM Err Overcurrent 1	- Voltage Dependent Overcurrent Group 1 setting area.
ALARM:EEPROM Err Overcurrent 2	- Voltage Dependent Overcurrent Group 2 setting area.
ALARM:EEPROM Err Power Prot 1	- Power Protection Group 1 setting area.
ALARM:EEPROM Err Power Prot 2	- Power Protection Group 2 setting area.
ALARM:EEPROM Err Frequency Prot 1	- Frequency Protection Group 1 setting area.
ALARM:EEPROM Err Frequency Prot 2	- Frequency Protection Group 2 setting area.
ALARM:EEPROM Err Voltage Prot 1	- Voltage Protection Group 1 setting area.
ALARM:EEPROM Err Voltage Prot 2	- Voltage Protection Group 2 setting area.
ALARM:EEPROM Err Neg Phase Seq 1	- Negative Phase Sequence Group 1 setting area.
ALARM:EEPROM Err Neg Phase Seq 2	- Negative Phase Sequence Group 2 setting area.
ALARM:EEPROM Err Earth Fault 1	- Earth Fault Group 1 setting area.
ALARM:EEPROM Err Earth Fault 2	- Earth Fault Group 2 setting area.
ALARM:EEPROM Err Field Failure 1	- Field Failure Group 1 setting area.
ALARM:EEPROM Err Field Failure 2	- Field Failure Group 2 setting area.
ALARM:EEPROM Err Scheme Logic 1	- Scheme Logic Group 1 setting area.
ALARM:EEPROM Err Scheme Logic 2	- Scheme Logic Group 2 setting area.

Table 51 Non-volatile EEPROM memory errors.

9.5.3. Protection operation alarm messages

This type of alarm is caused by the operation of the fault record trigger, alarm record trigger, or the operation of latched outputs.

Display	Protection Operation:
ALARM:Protection 60 VB-Comp	- Voltage Balance due to failure of the comparison VT's.
ALARM:Protection 60 VB-Prot	- Voltage Balance due to failure of the protection VT's.
ALARM:Protection 40 FF	- Field Failure.
ALARM:Protection 67N SDEF	- Sensitive Directional Earth Fault.
ALARM:Protection 59N-2 ND	- Timer 2 element of Neutral Displacement.
ALARM:Protection 59N-1 ND	- Timer 1 element of Neutral Displacement.
ALARM:Protection 51N>> SEF	- High set element of Stator Earth Fault.
ALARM:Protection 51N> SEF	- Low set element of Stator Earth Fault.
ALARM:Protection 46>> NPS	- Trip element of Negative Phase Sequence.
ALARM:Protection 46> NPS	- Alarm element of Negative Phase Sequence.
ALARM:Protection 59 OV >	- Over Voltage. The field '>' is the element information with '>' mean ing low set and '>>' high set.
ALARM:Protection 27 UV	- Under Voltage.
ALARM:Protection 81U-2 UF	- Under Frequency 2.
ALARM:Protection 81U-1 UF	- Under Frequency 1.
ALARM:Protection 32L LFP	- Low Forward Power.
ALARM:Protection 32R RP	- Reverse Power.
ALARM:Protection 51V OC A	- Voltage Dependent Overcurrent. The field 'A' is the phase information.
ALARM:Protection 87G Gen Diff A	- Generator Differential. The field 'A' is the phase information.

Table 52 Protection operation Alarm messages.

9.5.4. Logic input operation alarm messages

This type of alarm is caused by the energisation of the optically isolated logic inputs. However, the ‘Clock Sync’ and ‘Group Select’ logic inputs are excluded. The ‘Clock Sync’ input is expected to occur on a regular time base and the two ‘Group Select’ logic inputs are recorded by group selection events or by a group select input failure event.

Display	Logic Input Energisation:
ALARM: Logic I/P 27/81U Inhibit	- Under Voltage and Under Frequency inhibit.
ALARM: Logic I/P 51V Inhibit	- Voltage Dependent Overcurrent inhibit.
ALARM: Logic I/P 51N Inhibit	- Stator Earth Fault timer inhibit.
ALARM: Logic I/P Input 6	- A logic input with the definable label of ’Input 6’. There are eight scheme configurable logic inputs.

Table 53 Logic input energisation Alarm messages.

9.5.5. Relay output operation alarm messages

This type of alarm is caused by the operation of relay outputs.

Display	Relay Output Operation:
ALARM: Relay O/P Rly Inoperative	- Relay inoperative contact. A fatal error occurred. Check with other alarm messages to find out the cause of the error.
ALARM: Relay O/P Output 1	- A relay output with the definable label of ’Output 1’. There are fifteen scheme configurable relay outputs.

Table 54 Relay output Alarm messages.

9.5.6. Diagnostic error alarm messages

The following three diagnostic errors are considered to be minor. Hence alarms are raised instead of locking out the relay.

Display	Diagnostic alarms:
ALARM:DiagnosErr LCD Fail	- The check on operation of LCD has failed. The front panel user interface is disabled.
ALARM:DiagnosErr Watchdog Inop	- The watchdog is found to be inoperative.
ALARM:DiagnosErr Watchdog Fast	- The watchdog timer is found to be fast.

Table 55 Diagnostic error alarm messages.

Chapter 7 - Fault Finding

ISSUE CONTROL

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AP	February 1995	Dave Banham	Original
BP	June 1995	Dave Banham	Minor corrections.
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C	April	H JBurke/ Publicity	Section 2.2, inclusion of new tolerance data in table

Contents

1. INTRODUCTION

This chapter covers two distinct areas of fault finding: Isolating faulty hardware modules within the LGPG111 and providing solutions to common operational problems.

1.1. Problem analysis

The LGPG111 consists of seven removable modules. In the unlikely event of component failure, the following fault finding information should allow the identification of the failed module. There are no serviceable parts within any module.

The procedure for repair is to identify the faulty module and replace it. The faulty module should be returned for repair and calibration with as much information regarding the fault as possible.

This documentation assumes you are conversant with the operating instructions and hardware arrangement of the relay.

Warning

1. **The relay must be de-energised before the hinged front panel is opened and any bus connections removed. Failure to comply with this instruction may result in damage to the electronic circuits of the modules or corruption of non-volatile memory.**
2. **Modules must be removed from the case with a proper module extraction tool. It is especially important that the analogue and status input module is handled with care; the front PCB should not be forcibly handled during extraction or insertion. Note that this module is heavy.**
3. **With the hinged front panel open, electrostatic discharge precautions must be observed.**

1.2. Fault finding procedure

Problems which arise in the LGPG111 as a result of a faulty module will usually result in one of the following occurring:

1. The relay will fail to power-up or initialise correctly.
2. The self-monitoring will lockout the relay if a failure is fatal or disable the protection by placing the relay *out of service*.
3. The relay will not function correctly.

The following hardware fault finding instructions are therefore divided into two main sections:

1. Power-on failures,
2. General operational failures.

Important

1. **Before beginning any fault finding procedures, visually check all connections and link positions on all modules. Chapter 5 provides this information.**
2. **Ensure each module is in its correct position in the relay case; the module identification numbers should correspond with the module numbers on the relay case and with the module identification list fixed to the reverse side of the front panel.**
3. **When replacing modules, ensure the replacement has the same module number as that which it replaces.**
4. **Ensure no modules show signs of obvious damage due to improper handling.**
5. **Check the ribbon cable bus is connected correctly to each module and that no socket pins are bent or otherwise damaged.**

1.3. Initialisation sequence

The following sequence of events should occur when the DC auxiliary supply is ap plied to the relay's DC supply terminals.

1. The relay's display shows '`COLD RESET`' on the top line with the current power-on diagnostic test being performed on the bottom line.
2. The power-on diagnostic tests proceed through several tests.
3. The display changes to the default display of the relay's menu system. This will either be '`DATE AND TIME NOT SET UP`' or an alarm message.

2. POWER-ON FAILURES

Failure of the relay to power up usually indicates a power supply, microprocessor or front panel module problem. A broken ribbon cable bus may also result in a seemingly dead relay.

2.1 Power supply checks

1. Begin by checking all external DC auxiliary supply connections. Check the DC supply on the relay terminals is within the power supply specification. Check the polarity of the supply is correct.

2. Check the normally open power supply alarm contacts, terminals H3 & H4, are closed. If they are open, remove the DC supply, disconnect the power supply module from the ribbon cable bus and re-apply the DC supply. Check the normally open contact again. If it is still open the module will have to be replaced.

3. If the normally open contact is closed, with the module connected to the ribbon cable bus, but the relay refuses to power-up normally, there is a fault in either the front panel or microprocessor modules.

4. If the normally open contact is open with the ribbon cable bus connected and the relay powered, there is a short circuit fault which could be in any of the

remaining modules. In turn: disconnect the DC supply, remove a module and re-apply the supply until the contact closes; the last module removed is potentially faulty. Re-connect all the other modules and check the contact is still closed; if it is now open, repeat the test to isolate another potentially suspect module. Re-connect the suspect module and check the contact is now open. This module should be replaced.

2.2. Front panel checks

1. If the front panel's display is blank continue by checking the voltage rails on the parallel printer port, as detailed in Table 1. If any one of the voltage rails is out of tolerance, check the ribbon cable bus for shorts or breaks and replace the power supply module.

2. It is possible to determine whether the display is powered and functional by observing very faint black squares on the top line for each character position. The squares disappear when the DC supply is removed. Observing at an oblique angle with a direct but not glaring light source can help.
A powered but blank display would suggest a problem with either the ribbon cable bus or the microprocessor module.

Pin	Voltage Rail	Tolerance
25	0V	
21	+24V	±10%
19	+19.5V	±20%, -10%
18	+6.5V	±20%, -10%
20	-19.5V	±20%, -10%

Table 1 Front panel parallel port voltages, 110/125V & 220/250V versions only

Pin	Voltage Rail	Tolerance
25	0V	
21	+24V	±10%
19	+19.5V	±10%
18	+6.5V	±10%
20	-19.5V	±10%

Table 2 Front panel parallel port voltages, all other voltage versions

2.3. Main microprocessor checks

1. When the DC auxiliary supply is applied to the relay, check the normally open relay inoperative alarm contacts close (terminals G1 & G3). If they close then the main microprocessor is functional.

2. Try establishing communications with the relay, preferably by one of the rear communications ports. If communications can be established then both the main microprocessor and slave communications microprocessor are functional.

3. OPERATIONAL FAILURES

Should the relay be suspected of being faulty, each module can be tested to verify that it is working correctly. Faulty modules can therefore be identified and replaced.

3.1. Power supply checks

Testing the power supply is discussed in section 2.1. Check the voltage rails brought out on the parallel port, as discussed in section 2.2., and that the power supply fail contacts operate correctly when the supply is switched on and off. A faulty power supply can also be the cause of spurious resets.

3.2. Main microprocessor checks

The microprocessor is extensively tested during the power on diagnostics. To verify that it is working correctly, switch off the DC supply to the relay. Then switch it back on, after a few seconds, and observe the cold start diagnostic test messages on the front panel display. A lockout error, as shown in Chapter 6 Section 9.2. indicates a faulty microcomputer and serial communications module.

The non-volatile EEPROM memory in the microprocessor module is constantly checked for integrity. If an error is found, an EEPROM error alarm message is logged in the event recording system. Errors detected during relay operation have no direct effect because the relay is using volatile RAM copies of the data. Errors detected during power on will cause the faulty area to be reset with default data and hence will require that lost settings are reinstated.

3.3. Front panel checks

A faulty front panel can be identified by visual inspection and use of the key pad. Failure of the display driver may result in an inoperative front panel user interface. The remote user interface should be still functional, though.

Operation of the LED indicators can be tested with the lamp test option in the Test Functions section of the relay’s menu; see chapter 6.

Care should be taken to ensure the two relay output modules are inserted into their correct module positions: the LGPG111 will apparently function correctly with the modules swapped, except the wrong contacts will be operated.

3.4. Relay output module checks

Contacts on each relay output module can be energised manually with the relay output test option in the Test Functions section of the relay’s menu; see chapter 6. Isolate all tripping and alarm circuits before performing this test.

3.5. Logic input status checks

The 14 optically isolated logic or status inputs to the relay are divided between the status input module and the analogue and status input module. The latter module contains the first six dedicated inputs and the former module contains the remaining eight scheme definable inputs.

Using the logic input status cell in the Auxiliary Functions section of the menu, the status of all 14 inputs can be ascertained. Manually energising each input should cause the corresponding bit flag in the status cell to change from 0 to 1 and vice versa. Care should be taken to avoid inadvertent operation of external plant - isolate plant connections to the logic inputs.

3.6. Analogue input checks

The analogue input circuitry includes a self check which allows the operation of the multiplexers, sample and hold, analogue to digital converter to be constantly monitored. Failures in this circuitry will automatically be reported and the relay will attempt to recover from this fault by forcing a watchdog reset once only. If the attempt fails, the protection will be disabled and the relay is out of service.

Failures in the internal transformers and anti-aliasing filters can be determined by comparison of the measurements in the menu with known injected quantities. Care should be taken to ensure that apparent failures are due to the analogue module and not due to external wiring and transducer failures.

The analogue input module also contains a non-volatile EEPROM which stores the module's calibration data. This data is read, during a reset sequence, into the main microprocessor module. During this procedure the integrity of the data is checked. Any errors are reported and depending upon the level of data corruption, the relay may attempt to run the protection with no calibration, or to stop the protection and take itself out of service.

3.7. Communications checks

The remote access user interface is provided by the main processor and a slave communications microprocessor controlling a serial communications interface. A simple go no-go test is easily performed by trying to establish communications in the normal fashion, preferably on one of the two rear ports. The front port can be used if there are no suspected faults in the ribbon cable bus or in the front panel.

For the RS232 (IEC60870) based communications the configuration of the serial channel, baud rate, etc., should match at both ends. RS232 test boxes with indicator LED's can be useful in establishing whether the fault lies with the master end or the slave (relay) end.

Care should also be taken with the wiring of RS232 connection leads, since there is no standardisation on the orientation of the transmit and receive pins. Standard connection leads can normally be obtained in either a straight or crossed arrangement. A straight or through lead connects the pins of the connector at one end through to the same pins of the connector at the other end. A crossed lead interchanges the receive and transmit connections. In all cases it is advisable to compare the pin assignments of the serial ports on the LGPG111 with those of the equipment to be connected. The receive and transmit pins are interchanged between the front port and rear port pin assignments.

If the LGPG111 detects any problems with the communications hardware, it will raise an alarm, log the event and attempt to restore communications by forcing a watchdog reset once only. If the failure is still evident, the communications will be disabled and an alarm raised. Other aspects of the LGPG111 are not affected by this failure.

4. PROBLEM SOLVING

4.1. Password lost or not accepted

If the LGPG111 will not accept its password, it is a probably because the password has been inadvertently changed in the relay.

The password lock in the LGPG111 can be unlocked with a backup password obtainable from ALSTOM T&D Protection & Control Limited or our nearest authorised representative. Please supply the relay's full model number and serial number. These must be the numbers reported in the *System Data* section of the menu.

4.2. Relay tripping

Relay does not operate when protection has operated:

1. Scheme logic and / or protection settings incorrect - possibly due to a non-volatile EEPROM error and default settings have been restored.
2. Relay is out of service; OUT OF SERVICE LED is illuminated.
3. Relay output module is faulty.

4.3. LED's

4.3.1. No alarm or trip indications

The alarm and fault triggers have not been set up in the Scheme Logic section of the menu.

4.3.2. Out of service LED is on

1. The relay has been manually placed out of service by setting the scheme output status cell, in the Auxiliary Functions section of the menu to 'Inhibited'.
2. The relay is in calibration mode. Reset the relay or exit from the remote access calibration software.

4.3.3. Out of service LED is on and relay healthy LED is off

This happens when a fatal error has been detected by the self-monitoring. The protection has been disabled. See the Self-Monitoring section of chapter 4.

4.4. Second setting group not displayed

The second setting group has not been enabled. Set the second setting group cell to 'Enabled' in the Auxiliary Functions section of the menu.

4.5. Alarms

4.5.1. Too few or too many alarms

Check the setting of the alarm trigger cell in the Scheme Logic section of the menu. Also note that outputs defined as latched or those specified to generate a fault record will also generate alarms.

4.5.2. Cannot reset the latched outputs

The condition which operated a latched output is still present.

4.6. Event records

Event and fault records have been lost - The LGPG111 has a continuous event recorder, but with only finite memory in which to store event and fault records. When this memory is full, new records will overwrite the oldest records.

4.7. Disturbance recorder

4.7.1. New settings have been rejected

1. The analogue channel selection cell will not be accepted if more than 8 channels are selected. The disturbance recorder can record between 0 and 8 analogue channels selected from the 17 analogue inputs. Check the setting and try again.
2. It is not possible to change the configuration of the disturbance recorder when it is in the process of making a recording. Try changing the settings again after a few seconds.

4.7.2. Cannot access disturbance records at the front panel user interface

It is not possible to examine disturbance records on the LGPG111's front panel user interface. Disturbance records can only be extracted from the relay through the remote user interface.

4.7.3. No disturbance record generated or records lost

1. Check the disturbance recorder triggers are set up correctly.
2. The relay has lost its DC auxiliary supply after the recording was made. Unlike event records, the disturbance records are stored in volatile RAM memory and will be lost when power is removed from the relay.

4.7.4 The length of the disturbance record is shorter than expected

When the time interval between two consecutive triggers is less than the duration of a disturbance record, the second record will have a shorter length. This is due to the pre-fault time, of the second record, being reduced by the proximity of the second trigger to the end of the first record. The two records are continuous and there is no loss of information.

4.8. Inaccurate measurements

May also manifest as inaccurate pickup levels during injection testing.

1. For the LGPG111 to make accurate measurements it must be frequency tracking. The relay can only frequency track on one of three channels, namely V_{ab}, V_{bc} and I_a, which it automatically selects depending upon the presence of sufficient signals. Therefore, injecting on any other channel will not provide the relay with a frequency source to track and the relay will assume its default tracking frequency. It is recommended that all checks on measurement and protection accuracy are made with the frequency track engaged. This can be accomplished by series connecting I_a with current inputs under test and parallel connecting V_{ab} or V_{bc} with voltage inputs under test. The last cell of the Measurements 2 section of the menu indicates which input is driving the frequency

tracking. Since the frequency tracking is based on a single phase measurement, it is assumed that all other inputs are of the same frequency.

2. The relay has lost its calibration data. This will be indicated by none resettable alarm message on the front panel. The analogue and status input module will need to be replaced or re-calibrated.

4.9. Problems with printing

1. Printer does not respond - relay indicates printer is busy or prints and stops. The most probable cause for this is the connection lead. The LGPG111 does not have a standard IBM PC printer port so standard printer connection leads must be modified. Either make up a dongle style adapter or remove the inappropriate connections from the lead; see the front panel description in chapter 5.

   Another typical cause of this problem is a faulty paper-out detector in the printer. This will cause the relay to report the printer is busy. Check the printer is working with a self test or better still with another device such as a computer. Assuming the printer works, then the fault is either with the connection lead or with the parallel port on the relay. Check the connection lead carefully. If an IBM PC style computer is available, try the connection lead, including the adapter dongle, using the printer and computer to print something. If this works OK then the front panel port is probably at fault.

2. Printer accepts data from the relay, but prints random characters or nothing. Two probable causes: i) Connection lead, including adapter dongle, has open circuit, short circuit or crossed data bit wires. ii) Printer is not a plain text ASCII printer. For example, most PostScript printers will not print plain text data.

3. Printed output is double spaced. The LGPG111 terminates each line with a carriage return and line feed. Some printers will automatically generate a line feed on processing a carriage return character and some will automatically carriage return on receipt of a line feed character. Printers which do this can normally be configured not to; consult the instructions for your printer.

4. Printed titles are not underlined, but have a line of underscores printed to the right. The LGPG111 relies on a carriage return character to bring the print head to the start of the current line before it underscores titles. The technique works on most printers.

4.10. Relay contact test

1. The relay contact test can only be performed when the out of service LED is on. The LGPG111 must be brought out of service, by inhibiting the scheme output in the Auxiliary Functions section of the menu, before the output contacts can be manually tested.

2. The displayed state of the relay outputs does not correspond to the bit-setting of the relay test. The relay output status reflects the status of the scheme logic output. This allows the scheme logic outputs to be monitored during injection testing of the protection without operating any of the output contacts.

3. When there is a genuine fault with the LGPG111, the Relay Inoperative Alarm contact will de-energise and the out of service LED will be illuminated. Because the relay is now out of service, the relay contact test can be performed, except that it is not possible to operate the relay inoperative alarm contact.

4. An internal relay can be heard to operate when a contact test is performed, yet the operation of the contact can not be detected. Firstly, check that the correct relay has been operated by the test and the corresponding terminals are identified correctly. Secondly, ensure the two relay output modules have been inserted into their correct module positions and not swapped over.

4.11. Communications

4.11.1. Cannot establish communications

Check the following:

1. The communications port selected on the relay matches the physical connection.

2. For RS232 (IEC60870) based communications, the correct RS232 lead - crossed or uncrossed - is being used. If a modem is connected, check the correct control signals are present.

3. The correct IEC60870 baud rate is selected.

4. The correct relay address is selected. The relay will not communicate when its address is set to 255.

5. Check the frame length: 10 or 11 bit. Most simple modems will only accept 10 bit frame lengths, whereas the LGPG111 only provides 11 bit framing (to conform to the IEC60870 standard).

6. Check the modem’s set-up. If the modem will not connect, check that the line is not engaged. Also check the correct telephone number is being used, complete with dialling codes. When dialling from a PBX (private branch exchange) ensure local dialling prefix codes are dialled, e.g. for external line access. On some exchanges it is necessary to pause between requesting an external line and dialling the external number.

7. A common problem with PBX’s is phase noise. This is not noticeable in speech, but will cause problems with frequency and phase encoded digital transmission. Phase noise can be the source of intermittent communications errors, but it can also be severe enough to stop any form of successful communications. In this case, the solution is to install a direct dial line or even a dedicated private line. There are also sophisticated modems available which have phase noise cancellation features that may be able to overcome these difficulties.

8. Check the configuration of the remote access software being used - see relevant documentation. Most of the previous points will also relate to the remote access system.

4.11.2. Communications fails

Check the following:

1. The integrity of the communications link.

2. The LGPG111 is powered-up.

3. The communications hardware is still functioning - check for a communications hardware failure alarm. Consider fault finding the communications isolation card and communications hardware.

3. The communications settings have not been changed in the relay or the remote access system, rendering them incompatible.

4. Check modems, interface boxes, etc. are powered-up and that settings have not been changed.

5. Check for modem communication problems: noisy telephone line, line disconnected, etc.

4.11.3. General

1. The set time command has no effect when the K-Bus serial link is used in conjunction with a KITZ101. Early models of the KITZ101 were designed to use the set time command for the sole purpose of setting its internal real time clock and as a result did not pass the command onwards. Contact ALSTOM T&D Protection & Control Limited to arrange for an upgrade.

2. Cannot change settings in the remote user interface. The remote setting cell in the Remote Communications section of the menu should be set to ‘Enabled’ to allow remote change of settings.

3. The relay’s remote access menu appears different after a setting transfer. This will be the case if the setting transfer did not finish successfully. To restore the menu to its proper arrangement access the, now visible, communication system column section of the menu. Set the transfer mode cell to ‘No’ and exit from this section. The relay’s menu is now restored to its normal arrangement.

Chapter 8 - Commissioning Instructions

Issue control
Engineering document number: 50005.1701.108

Issue	Date	Author	Changes
AP	February 1995	Dave Banham	Original
BP	February 1995	Dave Banham	Maximum continuous current rating was incorrectly quoted as '4' instead of '4xIn' in Sections 5.3.2 and 5.11.4.
CP	June 1995	Dave Banham	Minor Corrections. NPS protection test instructions updated to reflect change in LGPG111 functionality for version 18LGPG002XXXEA onwards. The NPS reset characteristic was an exponential decay, now the thermal replica is used. Kreset was the time constant of the exponential now it is the thermal capacity constant for cooling. The commissioning test results report Section has been removed and placed in a separate document (50005.1701.111) as Error! AutoText entry not defined.. This is to facilitate extra copies being ordered.
A	July 1995	Dave Banham/ Publicity	Styles
B	Feb 1996	Dave Banham/ Publicity	Section 5.11.5 corrected timing formula; added timing formula for commissioning software versions prior to 18LGPG002XXXEA
C	June 1997	Andy Forshaw/ Publicity	Addition of new section, for commissioning as one unit (section 6). Major re-write of the old sections. All tolerances corrected.

Contents

Important

The LGPG111 is a sophisticated generator protection relay and includes many protective functions and operating features. You are strongly recommended to read these instructions and to allow sufficient time to familiarize yourself with the relay, its user interface and the rest of this service manual, before commencing with the commissioning tests.

1. GENERAL NOTES

Before commissioning an LGPG111, you should understand the following aspects:

- The relay's scheme logic; see chapter 4.
- The user interface; see chapter 6.

Although the settings can be entered manually there can be considerable time savings if a portable PC is available with suitable Courier based access software installed. This is easier to use and greatly facilitates entering settings, which can then be saved for future reference. Instructions are provided with the Courier based access software. See chapter 6 for a basic overview. In these commissioning instructions, specific operations regarding the user interface are given for the relay's front panel only.

Testing the remote access feature of the LGPG111 is not covered by these commissioning instructions.

Before commencing the commissioning of the relay the notes in section 5.1. should be read.

The recommended commissioning procedure is as follows:-

Section 3	Commissioning preliminaries
Section 4	Auxiliary power supply tests
Section 5	Secondary injection tests preliminaries

The commissioning engineer, along with the customer, should decide whether to follow Section 6 or Section 7

Section 8	Logic input status checks
Section 9	Contact checks
Section 10	Scheme logic tests

Error! AutoText entry not defined. is for recording the commissioning test results. Two test forms are provided, the appropriate form should be completed depending on which type of test is followed (section 6 or section 7).

2. TEST EQUIPMENT REQUIRED

- 2 off variable current sources
- 1 off variable voltage sources
- 1 off variable three phase supply which can be phase shifted
- 1 off variable frequency supply
- 1 off phase angle meter (if applicable)
- 2 off multimeters
- 1 off timer
- 1 off stop watch (if applicable)

Electronic test sets combine many of the above features into the one unit. These type of test sets, if available, can reduce the time taken to commission the relay.

3. COMMISSIONING PRELIMINARIES

Warning

Do not open the secondary circuit of a live CT since the high voltage produced may be lethal to personnel and could damage insulation.

3.1. Handling of electronic equipment

Reference should be made to chapter 2 which describes a simple precautions to be taken before handling electronic circuits which may be sensitive to electrostatic discharge. With in the front panel closed, the relay is completely safe from electrostatic discharge.

Prior to commissioning the relay, it is necessary to open the front panel and inspect the relay modules. Before this inspection, you should touch the earthed panel as a precaution against electrostatic voltages.

If modules are removed from the case an anti static wrist strap should be worn, and the modules should be handled by the front plate, frame or edge of the printed circuit boards to avoid contact with electrical components or connections. Always store and transport modules in electrically conductive anti-static bags.

3.2. Inspection

With no DC auxiliary voltage connected, carefully examine the relay to ensure that no damage has occurred during transit. Check the front nameplate label for the correct model number and rating information.

- Vx(1) - Rated voltage of auxiliary supply to the power supply module.

- Vx(2) - Rated voltage of auxiliary supply to the optically isolated logic inputs.
- In - Rated current of the CT's.

Remove the relay's cover and open the front panel by undoing the large screw on the right hand side of the front plate. The equipment label on the back of the front panel lists the model number, serial number, firmware reference and details about the front panel and the modules fitted in the relay. Check that the module references are correct and that the modules are fitted in the correct positions. Record the relay's rating and serial number in the commissioning test results(chapter 9).

With the analogue input module removed from the case, check that the shorting switches between the terminals listed below are closed. This can be done either with a continuity check, or by injecting rated current, In, through the shorting contacts. Both methods will require the external CT's to be isolated from the relay.

3.2.1. Earthing

A5 and A6,	A7 and A8,	A9 and A10,	A11 and A12,
A13 and A14,	A15 and A16,	A17 and A18,	A19 and A20,
A21 and A22,	A23 and A24,	A25 and A26,	A27 and A28.

Table 1 Terminals fitted with internal shorting switches.

Ensure the case earthing terminal above relay terminal block H is used to connect the relay to the local earth bar.

3.3. Main current transformers

Do not open the secondary circuit of a live CT since the high voltage produced may be lethal to personnel and could damage insulation.

3.3.1. Insulation

Insulation tests can be done if required but are not necessary for the LGPG111's commissioning.

The insulation of the relay and its associated wiring may be tested between

1. All electrically isolated circuits, and
2. All circuits to earth.

An electronic or brushless tester having a voltage not exceeding 1000V DC should be used. Accessible terminals of the same circuit should first be connected together. Deliberate circuit earthing links removed for the tests, must be subsequently replaced. The outgoing terminal allocation for the relay is shown in the drawing 10 LGPG111 00 in chapter 11.

3.3.2. Wiring checks

Check that the external wiring is correct to the wiring schedule or scheme diagram. If MMLG test blocks are provided, the connections should be checked to the scheme diagram; particularly that the supply connections are to the live side of the test block, coloured orange with odd terminal numbers.

4. AUXILIARY POWER SUPPLY TEST

CAUTION

The relay can withstand some AC ripple on its DC auxiliary supplies, however the peak value of the auxiliary supply should not exceed the maximum withstand value. Do not energize the relay from a supply with the batteries disconnected and the system run from the charger alone.

The LGPG111 is fitted with transient suppression circuits, which are designed to protect it from potential damage by intermittent spikes of short duration.

4.1. Relay auxiliary voltage (Vx1)

Before applying the auxiliary supply to the LGPG111, check the polarity of the power supply wiring corresponds to the relay's connections; terminal H13 is positive (+ve) and H14 negative (–ve).

Remove the auxiliary supply's fuse and isolation link and check the polarity and measured value of the auxiliary supply. The supply must be within the operating range specified for Vx(1) in the following table. Replace the isolation and fuse links.

Nominal (Vx1)	24/27V	30/34V	48/54V	110/125V	220/250V
Operative Range	19.2 - 32.4 V	24 - 40.8 V	38.4 - 64.8 V	88 - 150 V	176 - 300 V
Maximum Withstand	36.5 V	45.9 V	72.9 V	168.8 V	337.5 V

Table 1 Auxiliary Vx1 operating ranges.

4.2 Optically isolated logic input supply (Vx2)

Check the polarity of the optically isolated logic input supply wiring corresponds to the relay's connections.

Remove the auxiliary supply fuse and isolation link and check the polarity and measured value of the auxiliary supply. The supply must be within the operating range specified for Vx(2) in the following table. Replace the isolation and fuse links.

Nominal (Vx2)	24/27V	30/34V	48/54V	110/125V	220/250V
Operative Range	19.2 - 32.4 V	24 - 40.8 V	38.4 - 64.8 V	88 - 150 V	176 - 300 V
Maximum Withstand	36.5 V	45.9 V	72.9 V	168.8 V	337.5 V

Table 3 Auxiliary Vx2 operating ranges.

4.3. Energizing the LGPG111

Connect the auxiliary supply to the LGPG111. The relay should power up; the display should read 'DATE AND TIME NOT SETUP' and the green Relay Healthy LED should be illuminated. If the relay has been energized before and a trip or alarm condition was present when the relay was de-energized, upon energization this trip or alarm indication will be given and it will be necessary to reset this indication. Other power on conditions should be checked off against the fault diagnosis Chapter, especially if the relay healthy LED is not illuminated, see chapter 7.

4.4. Testing the power supply failure alarm

De-energize the relay and check that the contact across relay terminals H3-H4 opens and the contact across H5-H6 closes. Check the remote power supply failure alarm, if connected, is on.

Re-energize the relay. Set the correct date and time on the relay as follows:

With the default display indicating 'DATE AND TIME NOT SETUP', press → ↓ → keys. The relay should now be displaying the date and time in the Auxiliary Functions Section of the menu. Press → key: the year should flash; press the ↑ or ↓ keys to set the correct year. Press the ← ↓ → keys to move the cursor to the month and then set the correct month by following a similar procedure for setting the year. Set the date and time. After the time is set, press the SET key to confirm the setting.

4.5. Testing the LED's

Press the arrow keys to display 'Lamp Test' in the Test Functions Section. Press the → key to display 'Press SET for Lamp Test'. Press the SET key. Check the red LED and the two yellow LED's on relay front panel light up momentarily and the green LED extinguishes momentarily.

5. SECONDARY INJECTION TESTS PRELIMINARIES

5.1. Choice of commissioning tests

Traditionally, generator protection has been provided by using several discrete relays to achieve overall protection, the LGPG111 integrates these functions within one unit. With discrete relays it was necessary to test each relay individually as there were no common elements, however with the LGPG111 the separate protection functions share common hardware and software functions, and as such it is only necessary to test the LGPG111 as one unit.

Detail of these test are given in Section 6. However, if the customer requires, each individual element can be tested and details of these tests are given in section 7. It should be noted that there is significant reducation in commissioning and outage times if the instructions in section 6 are followed. For maintenance test it is recommended that the tests in section 6 are used. The commissioning engineer should read both section 6 and section 7, in consultation with the end customer, decide which instructions to use.

If the in service settings are not available at the time of commissioning then the instruction in section 7 should not be followed, as are designed to test the relay as it would be used in service.

Section 6 This section gives details of the tests the manufacturer recommends for the site testing of the relay, these tests are designed to prove the correct operation of both the hardware and software functions. This section should also be used as the basis of any maintenance tests. It should be noted that there is a significant reduction in commissioning and outage times if these instructions are followed.

Section 7 If it is required that each individual function of the relay is tested as a discrete relay, the instruction contained in this section should be followed. If the in service settings are not available at the time of commissioning then the instructions in section 7 should not be followed, as they are designed to test the relay as it would be used in service.

5.2. Notes for secondary injection tests

Only the protection functions which are enabled in the application's protection scheme need to be secondary injection tested.

The LGPG111 has 15 programmable output relays. However, in checking their operation it is only necessary to test those which are connected in the external scheme. Operation of the output relays can be checked with a continuity tester on the relay's terminal blocks. Drawing 10 LGPG111 00 in chapter 11 shows the output relays and their corresponding terminal numbers.

The LGPG111 is a multi-function relay. If the relay is being tested as discrete units then only one protection function is enabled at a time. Therefore, only one protection function is tested at a time. The protection function test method is similar to testing individual protective relays.

To enable a protection function, set the functions Enabled/Disabled setting to Enabled. To disable a protection function, set it to Disabled. The original Enabled/Disabled setting must be restored after the secondary injection tests have been completed.

Since only one protection function is enabled at a time, protection interlocking logic, in the scheme logic, must be removed to allow each individual protection function to operate its output contact. Interlocking logic exists when there is more than one '1' flag in a particular input AND matrix word of the scheme logic.

However, 1's associated with negated inputs can be discounted as these are used for blocking. Negated inputs have names beginning with a minus, '–'. To disable interlocking, change the ‘1’ to ‘0’ for the interlocking element.

Figure 1 illustrates the various types of logical arrangements which the LGPG111’s scheme logic is capable of providing.

Word L0: Operation of the 87G Differential will operate output relays R15 and R1.This is an independent operation and can be tested without modification

Word L1: Operation of the 51V Voltage Dependent Overcurrent will operate output relays R15 and R2 if the -60 Voltage Balance, for fuse failure, does not operate. This is a blocking operation as indicated by the prefixed ‘–’. With the voltage balance function disabled, the voltage dependent overcurrent can be tested without modification to the scheme.

Word L2: Operations of the 51N>> Stator Earth Fault high set element and the 67N Sensitive Directional Earth fault will operate relays R15 and R3. This is an interlocking operation. To test the stator earth fault high set, the interlock with the directional earth fault must be removed. Similarly, to test the directional earth fault, the interlock with the stator earth fault must be removed.

During the secondary injection testing, the output relays of the LGPG111 will operate. Therefore, isolate the tripping circuits to the circuit breaker, AVR and turbine. Isolate alarms or indications as necessary. Ensure VT’s are isolated before injection, and that the primary CT’s are shorted.

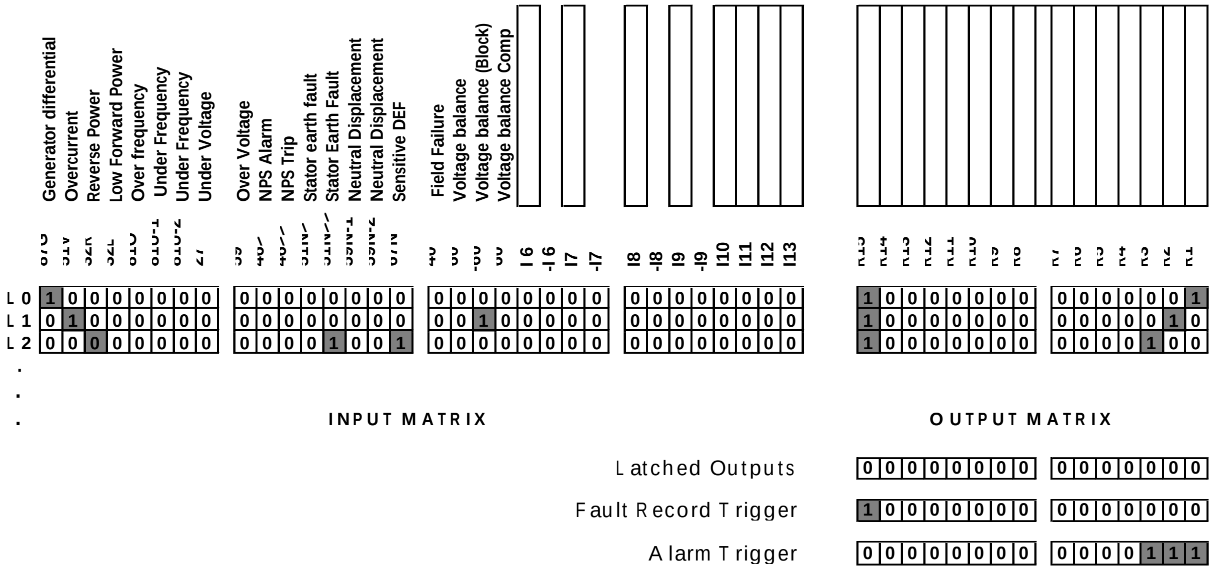


Figure 1 Illustration of plain tripping logic (L0), blocking logic (L1) and interlocking logic (L2) in the scheme logic.

Protection function operation time can be measured from an MMLG test block, if one is installed, or from the panel terminal block, or directly from the relay terminals.

During secondary injection testing, the amount of current or voltage injected depends upon the relay’s settings. The test instructions specify the amount of current or voltage to be injected in terms of a multiple of a setting; 1.5xI> means the current injected should be 1.5 times the value of the I> setting. It is recommended you copy settings from the setting schedule to the test record, calculate the amount of current or voltage to inject and then do the test. This allows the service settings to be applied and the protection operation checked off against them.

Different tolerances for checking the relay's pick-up and drop-off values, operating time and measurements are specified in the test instructions. Allowance for the accuracy of the injection equipment, instrumentation and supply stability are not included in these tolerances, therefore a reasonable additional tolerance can be added at the discretion of the commissioning engineer.

Pick-up and drop-off points can be checked, without external indication, by monitoring a percentage time-to-trip value in the Protection Operation Summary Section of the relay's menu. A reading of 0% indicates the element is not picked up or has dropped-off. A value other than 0% indicates the measuring element has picked-up. When the value reaches 100%, the element's output operates.

The red Trip LED, on the relay, can be operated by one or more of the output relays. The Fault Record Trigger setting in the Scheme Logic Section specifies which outputs are to considered as trips and hence also to produce a fault record. For example, in Figure 1, when output relay R15 operates the red trip LED will operate and a fault record is generated. Operation of the other output relays will not cause the red Trip LED to turn on.

The yellow Alarm LED, on the relay, can be operated by one or more of the output relays. The Alarm Record Trigger setting in the Scheme Logic Section specifies which outputs are to considered as Alarms. For example, the alarm record trigger, in Figure 1, generates an alarm whenever output relay R1, R2 and R3 operate. Operation of the other output relays will not cause the yellow Alarm LED to turn on. The Alarm LED will also illuminate whenever there is a trip causing the red Trip LED to illuminate or when an output operates which has been specified as latching. For example, if the alarm record trigger is removed from relay R1, in Figure 1, an alarm will still be generated since R1 is specified as a latched output.

New alarms are signified by a flashing yellow Alarm LED and a flashing '`ALARM`' message on the relay's display.

There are two types of alarms: one is a protection alarm and indicates which protection function operated. The other is a relay output alarm and indicates which output relay operated. For example:

'`ALARM: Protection 87G Gen Diff A`' is a protection alarm which indicates the operation of the phase A element of the generator differential function.

'`ALARM: Relay O/P Output 7`' is an output relay alarm which indicates the operation of the output relay contact labeled '`Output 7`'. Note the names of the outputs (and the logic inputs) can be set by the user.

To scan and reset alarms, repeatedly press the ← key until the relay displays '`ALARM`'. Press the Accept/Read key to successively scan through the alarm messages until the display shows '`Press RESET To Clear Alarms`'. Press the RESET key to clear all the alarms, thus also resets any latched outputs.

The Under Voltage, Low Forward Power and Under Frequency protection functions are suspended if there is no voltage or current input into the relay, on its frequency tracking inputs of V_{ab}, V_{bc} or I_a.

The default display on the relay is '`Generator Protection`' or '`Local Settings Unlocked`', if the relay's password has been entered through the front panel user interface. Note the default display can be set by the user.

5.3. Setting the relay

In order to enter the settings from the setting schedule you should understand the description of the user interface in chapter 6, particularly the front panel interface methodology, if this is to be used. If a PC running a suitable program is to be used, then the program's instruction book should be consulted - especially if the settings have been supplied as a setting file on a diskette.

Some of the relay's settings are password protected. To remove or unlock these cells, the relay's password must be entered into the password cell in the System Data Section. The relay's default password is 'AAAA'. Password protection can be restored by resetting this cell; for the front panel interface this means pressing the RESET key when the password cell is displayed. The LGPG111 implements separate password locks for each user interface; entering the password in one interface will not unlock the other one. If the password has been lost or forgotten, an emergency password can be provided by ALSTOM.

Each user interface has an inactivity timer. The duration of the timer can be set between 5 and 30 minutes, in the Auxiliary Functions Section. When the timer expires, cells which have not had a setting change confirmed will return to their previous value and the password lock will be enforced. The front panel will also return to displaying its default display.

Enter the relay settings from the setting schedule and check. If you have a parallel printer and suitable data connection lead, the settings can be printed for comparison and as a permanent record. See chapter 6 for more details about the parallel printer. After entering the scheme logic, check the Scheme Setting cell in the Test Functions Section indicates '`OK`'.

Check the model and serial numbers displayed in the System Data Section of the menu correspond with the numbers printed on the identification label attached to the back of the front panel (found by opening the front panel). If they are different, enter the relay's password then change these two settings to correspond with the numbers on the label. Check also that the system frequency setting, in the System Data Section, is set appropriately.

The LGPG111 can display its settings and measurements in terms of the systems primary or secondary voltages and currents. These commissioning instructions require injection levels to be calculated from the protection settings. The settings are assumed to be in secondary terms for this purpose. Check the 'Display Value' cell in the Transformer Ratios Section is set to 'Secondary' for the duration of these commissioning tests.

If both setting groups are used, set the Active Setting Group cell in the Auxiliary Functions Section to 1 and perform the injection tests. If necessary the injection tests can then be repeated for the group two settings by setting this cell to 2. Note that it is only possible to change the Active Setting Group cell in the menu when the Select Setting Group cell is set to '`Menu`'. If it is set to '`Logic Input`' then either set it temporarily to '`Menu`' and proceed as before or use the group select logic inputs to control which setting group is active.

6. SECONDARY INJECTION FOR TESTING THE LGPG111 AS ONE UNIT

When testing the relay as one unit it is necessary to ensure that each of the three "Sections" of the relay are functioning correctly, and within the acceptable tolerances. The three "Sections" can be described as:-

The current and voltage inputs, with their associated analogue to digital conversion hardware, and the digital inputs.

The central processing unit, comprising of the micro-computer, I/O bus, power supplies, measurements, timers, user interface, internal diagnostic systems, and the remote communications.

The output contacts and their relation to the scheme logic.

The tests that follow are designed to test the first two of these "Sections", the tests for the output contacts are given in section 9 of this chapter.

At the completion of the following tests, the instructions given in section 8 (Logic inputs), section 9 (Contact tests), and section 10 (Scheme logic tests) should be carried out.

Note, the tolerances quoted throughout this section are the acceptable limits of the relay's operation, and as such do not include any allowance for instrumentation errors. The commissioning engineer should make suitable adjustments to the tolerances based on the accuracy of the measuring test equipment used.

6.1. Current based protection

The following instructions are for the testing the functions that are current based. The functions that are exclusively current based are 87G Current differential, 51N Stator earth fault, and 46 Negative phase sequence.

6.1.1. Measurement checks

Inject 0.1 x rated current into the following current inputs. Record and compare the current injected with the value measured by the relay. Allowing a tolerance of ±5%.

Input	Terminals
$I_{residual}$	A7-A8
$I_{a\text{-}sensitive}$	A9-A10
I_e	A5-A6

Inject 1.0 x rated current into the following current inputs. Record and compare the current injected with the value measured by the relay. Allowing a tolerance of ±5%.

Input	Terminals
$I_{a\text{-}diff}$	A23-A24
$I_{b\text{-}diff}$	A25-A26
$I_{c\text{-}diff}$	A27-A28
$I_{a\text{-}bias}$	A17-A18
$I_{b\text{-}bias}$	A19-A20
$I_{c\text{-}bias}$	A21-A22
I_a	A11-A12
I_b	A13-A14
I_c	A15-A16

6.1.2. Check of pick-up value

If necessary change the scheme logic, so that only the 51V voltage dependent overcurrent is enabled. Set this function to be used in the “Simple” mode, and set the I> setting value to equal rated current.

Inject 0.9 x rated current into the I_a input (terminals A11-A12), and slowly increase the current until the relay picks up . As there is a time delay associated with this function the Protection Operation Summary Section of the relay’s menu can be used to determine the point at which this function starts to operate. The Protection Operation Summary should indicate 0%, when the current injected is increased to the pick-up point the displayed percentage will start to increase, this is the pick-up point, the displayed value will rise from 0% and displays 100% when the time delay has expired.

I_a pick up value = I> setting with a tolerance of ±5%

I_a drop off value = I> setting x 0.95 with a tolerance of ±5%

6.1.3. Measurement of time delay characteristics

With the conditions and connections as above, set the time delay characteristic to “DT” definite time, with the setting t set to 2.0 seconds and the TMS set to 1.0.

Inject 2.0 x rated current into the I_a input (terminals A11-A12), measure and record the operating time.

Operating time = 2.0 seconds with a ±5% tolerance + (-10 to 40mS)

Change the settings so that the time delay characteristic is set to “SI” standard inverse. Inject 2.0 x rated current into the I_a input (terminals A11-A12), measure and record the operating time.

Operating time = 10.03 seconds with a ±5% tolerance + (-10 to 40mS)

Repeat the test but this time inject 10.0 x rated current into the I_a input (terminals A11-A12), measure and record the operating time.

Operating time = 2.97 seconds with a ±5% tolerance + (-10 to 40mS)

6.1.4. Fault record checks

Use the front panel keys to navigate to the menu section View Records, and ensure that the records match the injected faults carried out above.

6.1.5. Thermal curve characteristic

Change the scheme logic so that only the 46>> NPS thermal trip will cause the output relays to operate. Ensure that the setting I2>> is set to 0.2, and that the setting K is set to 10.

For measuring relay operating time, allow at least 4xKreset seconds between timings to allow the thermal element to reset (allow to cool until the relay displays a thermal value off 0%). Note, the thermal value will be reset to 0% if the auxiliary supply to the relay is switched off.

Inject 1.386 x rated current into the I_a and I_b inputs so that phases A and B are in anti-phase (terminals A11-A13, with A12 and A14 linked), to obtain the relay operating time.

Operating time = 16.125 seconds with a ±10% tolerance + (-10 to 40ms)

Repeat the injection and check that the I2 measurement in the relay indicates 0.8 x rated current.

6.2. Voltage based protection

The following instructions are for the testing the functions that are voltage based. The functions that are exclusively voltage based are 81U Under frequency, 81O Over frequency, 27 Under voltage, 59 Over voltage, and 60 Voltage balance.

6.2.1. Measurements

Inject 20v into the V_e input and rated volts into the remaining voltage inputs. Record and compare the voltage injected with the value measured by the relay. Allowing a tolerance of ±5%.

Input	Terminals
V_e	B19-B20
V_{ab}	B25-B26
V_{bc}	B27-B28
$V_{ab\text{-}comp}$	B21-B22
$V_{bc\text{-}comp}$	B23-B24

6.2.2 Check of pick up value

Enable the 59 over voltage protection function only, if necessary change the scheme logic so that only the 59 function will cause the output relays to operate. Set the V> setting to equal rated volts, and the time delay setting t> to 2.0 seconds. Note, the protection function will operate only when the voltage at the V_{ab} and V_{bc} inputs are both above the setting V>.

Inject 0.9 x V> Volts into the V_{ab} and V_{bc} inputs (terminals B25-B26 and terminals B27-B28). Slowly increase the voltage until the relay picks up. Record the smallest reading from either of the voltage inputs; this is the pick-up value. With the relay operated, slowly decrease the voltage injected until the relay resets. Record the smallest reading from either of the voltage inputs; this is the drop-off value.

Pick-up voltage = V> with a ±5% tolerance.

Drop-off voltage 0.95xV> with a ±5% tolerance.

6.2.3. Measurement of time delay characteristic

With the same connections and conditions as above, switch from a voltage below the setting to a voltage above the setting at the same time as starting a timer to obtain the operating time. Record the operating time obtained.

Operating time = 2.0 seconds with a ±5% tolerance + (-10 to 40mS)

6.2.4. Measurement of frequency

Inject rated voltage with rated frequency into the V_{bc} input (terminals B27-B28). Record and check the frequency injected and the value measured by the relay, allowing ±0.5 Hz tolerance.

6.2.5. Fault record checks

Use the front panel keys to navigate to the menu section View Records, and ensure that the records match the injected faults carried out above.

6.3. Power based protection

The following instructions are for the testing the functions that are based on power measurement. The functions that use power measurement are 32R Reverse power, and 32L Low forward power.

6.3.1. Measurement of phase angle

The 32L Low Forward Power uses $I_{a\text{-}sensitive}$ and V_{an} to calculate the active power in the A phase. As there is no input for $V_{an,}$ the relay calculates it from the V_{ab} input, by dividing by √3 and rotating by 30°.

Inject rated volts into the V_{ab} input (terminals B25 - B26) at a 0° phase angle, and rated current into the $I_{a\text{-}sensitive}$ input (terminals A9 - A10) at a 0° phase angle. The phase angle measured by the relay should read 30°.

The measured active power should be :

I x V x cos30° / √3 Watts allowing a ±5% tolerance

where V and I are injected voltage and current respectively, and cos30° = 0.866

6.3.2. Measurement of Directional Boundary

Enable the 67N Sensitive Directional Earth Fault protection only. If necessary, change the scheme logic input matrix so that only the 67N will cause the output relays to operate. Set a value for the characteristic angle RCA.

Inject 20V into the V_e input (terminals B19-B20) and rated current into the $I_{residua}$l input (terminals A7-A8). Rotate the phase difference lagging to measure the phase angle when the relay picks-up and drops-off. Rotate the phase difference leading to measure the pick-up and drop-off phase angles. Record the phase angles measured.

Pick-up phase angles = RCA±90°	with a ±5° tolerance.
Drop-off phase angles = RCA±95°	with a ±5° tolerance.
Operating region = RCA-90° to RCA+90°	with a ±5° tolerance.

6.4 Final checks

The instructions given in Section 8 (Logic inputs), Section 9 (Contact tests), and Section 10 (Scheme logic tests) should now be carried out.

7. Secondary injection for testing each function as a discrete unit

Note, the tolerances quoted throughout this section are the acceptable limits of the relay's operation, and as such do not include any allowance for instrumentation errors. The commissioning engineer should make suitable adjustments to the tolerances based on the accuracy of the measuring test equipment used.

7.1. 87G Generator differential

The generator differential function is used for the protection of the stator winding for single phase or poly-phase faults. Such conditions can produce high fault currents, therefore fast fault clearance is required. The function is a low impedance bias scheme, and has a dual slope bias characteristic. The lower slope provides sensitivity for internal faults, whereas the higher slope provides stability for through fault conditions, especially if the generators CT's saturate.

Enable the 87G Generator Differential protection function only. If necessary, change the scheme logic input matrix so that only the 87G will cause the output relays to operate, see Section 6.1

7.1.1. Sensitivity, operating time, and output relay tests.

Inject current into the $I_{a\text{-}diff}$ input (terminals A23 - A24). Slowly increase the current until the relay operates. Record the minimum operating current. Accept and reset all alarms on the relay.

The Trip level = Is1 with a ±5% tolerance

Inject 4xIs1 Amps into the $I_{a\text{-}diff}$ input (terminals A23 - A24), and record the relay operating time.

Operating time = <33ms

Check the operation of the output relays against the scheme logic settings. Check that the red Trip LED turns on and the yellow Alarm LED flashes when relay operates, if selected to do so by the scheme logic matrix. Check '`ALARM: Protection 87G Gen Diff A`' appears on the display; ignore the other alarms. Reset all alarms.

Repeat the above tests for the $I_{b\text{-}diff}$ input (terminals A25 - A26) and for the $I_{c\text{-}diff}$ input (terminals A27 - A28)

7.1.2. Measurement Checks

Inject rated current through both the $I_{a\text{-}diff}$ input and the $I_{a\text{-}bias}$ input (A17 - A24, with A18 and A23 linked), ignore relay tripping. Record the current injected, and the differential and bias current measured by the relay, allowing a ±3% tolerance. Accept and reset all alarms on the relay.

Note: Injected current = I_{diff} = I_{bias} = $0.5xI_{mean\text{-}bias}$

Repeat the test for phase B (A19 - A26, with A20 and A25 linked)

Repeat the test for phase C (A21 - A28, with A22 and A27 linked)

7.1.3. Bias characteristic

The 87G Generator Differential has three elements, one for each phase. The 87G uses the highest mean bias current measured out of the three phases as the bias for all three elements. The detailed bias characteristic is described in Error! AutoText entry not defined.. For the following tests always keep the current injected into the bias coil greater than the current injected into differential coil.

Record the differential protection's settings; Is1, K1, Is2 and K2. Reference to these values is made in the following text.

For A-N faults, Diff coil = terminals A23 - A24, Bias coil = terminals A19 - A20

For B-N faults, Diff coil = terminals A25 - A26, Bias coil = terminals A21 - A22

For C-N faults, Diff coil = terminals A27 - A28, Bias coil = terminals A17 - A18

<u>Lower slope</u>

The expected trip level (I_{diff}) can be calculated from the following equation:-

I_{diff} = Trip level = Is1 + (K1 x $I_{mean\ bias}$) with a ±5% tolerance

Inject 0.5 x Is2 Amps into the Bias coil, and inject 0.5 x Is1 Amps into the Diff coil. Slowly increase the current injected into the Diff coil until the relay operates. The measured mean Bias and Differential currents are:

$I_{mean\text{-}bias}$ = Value of current injected into the Bias coil.

I_{diff} = Trip level = Value of current injected into the Diff coil.

Record the $I_{mean\text{-}bias}$ and I_{diff} above. Accept all the alarms and reset them.

Repeat for all three phases.

Upper slope

The expected trip level (I_{diff}) can be calculated from the following equation:-

I_{diff} = Trip level = Is1 + (K1 x Is2) + [K2 x ($I_{mean\ bias}$ - Is2)] with a ±5% tolerance

Inject 1.5 x Is2 Amps into the Bias coil, and then inject 0.5 x Is1 Amps into the Diff coil. Slowly increase the current injected into the Diff coil until the relay operates. If 1.5 x Is2 is greater than the relay's maximum continuous rating of 4xIn the current should only be injected for a short duration to avoid damaging the relay. The measured mean bias and differential currents for A phase element are:

$I_{mean\text{-}bias}$ = Value of current injected into the Bias coil.

I_{diff} = Trip level = Value of current injected into the Diff coil.

Record the $I_{mean\text{-}bias}$ and I_{diff} above. Accept all the alarms and reset them.

Repeat for all three phases.

7.1.4. Fault record checks

Use the front panel keys to navigate to the menu section View Records, and ensure that the records match the injected faults carried out above.

7.2. 32R Reverse power

Reverse power protection is used to guard against the loss of the prime mover, and hence prevent motoring of the generator. Reverse power is a balanced condition, and therefore single phase measurement of the condition is sufficient. The relay calculates VIcosϕ from the A phase inputs. In order to provide the required sensitivity a separate current input is used. A compensation angle setting is provided to allow for phasing errors of the generators CT's and VT's.

Enable the 32R Reverse Power protection only. If necessary, change the scheme logic input matrix so that only the 32R function will cause the output relays to operate. There is no need to change the input matrix for blocking by the Voltage Balance element.

7.2.1 Measurements

The 32R Reverse Power uses $I_{a\text{-sensitive}}$ and V_{an} to calculate the active power in the A phase. As there is no input for $V_{an,}$ the relay calculates V_{an} from the V_{ab} input, by dividing by √3 and rotating by 30°.

Inject rated voltage into the V_{ab} input (terminals B25-B26) and rated current into the $I_{a\text{-sensitive}}$ input (terminals A9-A10). Adjust the phase difference between the volts and the current so that $I_{a\text{-sensitive}}$ is leading V_{ab} by 150°, the relay should display the phase angle in the measurements section as -180°. Record and check the current, voltage, phase angle and active power measured by the relay; allowing ±3% tolerance for measured current and voltage.

The measured active power should be :

-I x V / √3 Watts allowing ±5% tolerance

where V and I are injected voltage and current respectively.

The phase angle between $I_{a\text{-sensitive}}$ and V_{an} measured on the relay should be ±180 degrees with a tolerance of ±5°. Stop the current injection. Reset all alarms.

Alternatively, if the available test equipment cannot provide a phase shift, inject rated volts into B25 - B26 and rated current in anti phase to the voltage into A9 - A10. The phase angle now measured by the relay should read 150°.

The measured active power should be :

-I x V x cos30° / √3 Watts allowing ±5% tolerance

where V and I are injected voltage and current respectively, and cos30° = 0.866

7.2.2 Characteristic and operating time

Record the reverse power protection settings; -P, t and tDO.

With the current leading the voltage by 150°, apply rated voltage (terminals B25-B26), inject zero Amps into the relay (A9-A10) and slowly increase the current to check the 32R Reverse Power pick-up and drop-off values. Record the current injected.

Pick-up Power = -(Measured pick-up current)x(Rated voltage) /√3

Check that the measured value is within ±5% of the set value -P.

The Drop-off value should be within 95% of the pick-up value.

With the connections and conditions as above, inject a current of twice the pick-up value to obtain the operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay trips. Check 'ALARM: Protection 32R RP' appears on the display. Ignore other alarms. Reset all alarms. Record the operating time.

Operation time = the setting, t allowing ±5% tolerance + (0 to 120mS)

7.2.3. Operation of output relays

Repeat the previous injection test to operate the 32R relays. Check the operation of the LGPG111's output relays against the scheme logic settings. Record the output relays operated.

Restore the original Scheme Logic settings, if changed.

7.3. 32L Low forward power

Low forward power is sometimes applied to steam turbines where sequential shutdown is preferable under less urgent operations to avoid over speeding. Low forward power is a balanced condition, and therefore single phase measurement of the condition is sufficient. The relay calculates VIcosφ from the A phase inputs. In order to provide the required sensitivity a separate current input is used. A compensation angle setting is provided to allow for phasing errors of the generators CT's and VT's.

Enable the 32L Low Forward Power protection only. If necessary, change the scheme logic input matrix so that only the 32L will cause the output relays to operate. There is no need to change the input matrix for blocking by the Voltage Balance element.

7.3.1. Measurements

The 32L Low Forward Power uses $I_{a\text{-sensitive}}$ and V_{an} to calculate the active power in the A phase. As there is no input for $V_{an,}$ the relay calculates it from the V_{ab} input, by dividing by √3 and rotating by 30°.

Inject rated voltage into the V_{ab} input (terminals B25-B26) and rated current into the $I_{a\text{-sensitive}}$ input (terminals A9-A10). Adjust the phase difference between the applied volts and current so that $I_{a\text{-}sensitive}$ is lagging V_{ab} by 30° (a unity power factor for A phase). Record and check the current, voltage, phase angle and active power measured by the relay; allowing ±3% tolerance for measured current and voltage.

The measured active power should be :

$-I \times V / \sqrt{3}$ Watts allowing ±5% tolerance

where V and I are injected voltage and current respectively.

The phase angle between $I_{a\text{-}sensitive}$ and V_{an} measured on the relay should be ±0 degrees with a tolerance of ±5°. Stop the current injection. Reset all alarms.

Alternatively, if the available test equipment cannot provide a phase shift, inject rated volts into B25 - B26 at a 0° phase angle, and rated current into A9 - A10 at a 0° phase angle. The phase angle now measured by the relay should read 30°.

The measured active power should be :

$-I \times V \times \cos 30° / \sqrt{3}$ Watts allowing ±5% tolerance

where V and I are injected voltage and current respectively, and cos30° = 0.866

7.3.2. Characteristic and operating time

Record the reverse power protection settings; P, t and tDO.

Set the phase difference between the applied volts and current so that $I_{a\text{-}sensitive}$ is lagging V_{ab} by 30°, inject 1.1 x the expected pick-up current into the $I_{a\text{-}sensitive}$ input (terminals A9-A10) and rated volts into the V_{ab} input (terminals B25-B26). Slowly reduce the current to check the 32R Reverse Power pick-up and drop-off values. Record the current injected.

Pick-up Power = (Measured pick-up current)x(Rated voltage) $/\sqrt{3}$

Check that the measured value is within ±5% of the set value P.

The Drop-off value should be within 95% of the pick-up value.

With the connections and conditions as above, inject a current of twice the pick-up value, then reduce the current to zero at the same time as starting the timer in order to obtain the operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay trips. Check ‘`ALARM: Protection 32R RP`’ appears on the display. Ignore other alarms. Reset all alarms. Record the operating time.

Operation time = the setting, t allowing ±5% tolerance + (0 to 120mS)

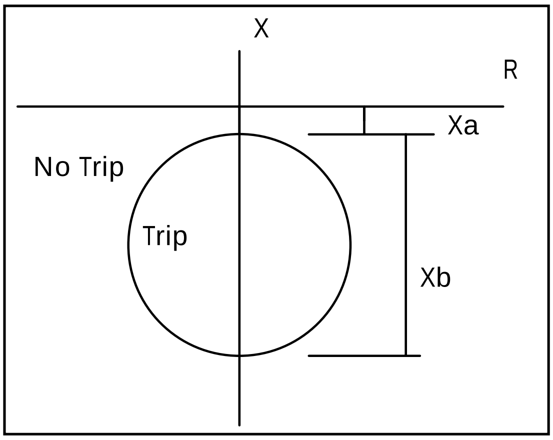
7.3.3. Operation of output relays

Repeat the previous injection to operate the 32L. Check the operation of the LGPG111's output relays against the scheme logic settings. Record the output relays operated.

Restore the original Scheme Logic settings, if changed.

7.4. Field failure

Severe loss of excitation caused by field failure can cause a high value of reactive current to be drawn from the power system, which can endanger the generator. The field failure protection provided by the relay is a single phase measuring element, with an offset mho characteristic.



Enable the 40 Field Failure protection only. If necessary, change the scheme logic input matrix so that only the 40 Field Failure will cause the output relays to operate. There is no need to change the input matrix for blocking by the Voltage Balance element.

7.4.1. Measurement checks

The Field Failure element uses I_a and V_{an} to calculate impedance. V_{an} is derived from the V_{ab} input by rotating by 30° and dividing by $\sqrt{3}$.

Inject rated voltage into terminals B25-B26, and rated current into terminals A9 and A12 with A10 and A11 linked (the input A9-A10, $I_{a\text{-}sensitive}$, is used in order to obtain a phase angle measurement). Adjust the phase difference between the voltage and the current until the phase angle meter reads I_a leading V_{ab} by 60°. Record the current and voltage measured by the relay, allowing ±3% tolerance. Check the 'Phase Angle Aph' measured by the relay. The phase angle between I_a and V_{an} measured by the relay should be +90°; allowing ±5° tolerance. Reset all alarms.

7.4.2. Characteristic and operating time

Record the field failure protection settings; -Xa, Xb, t and tDO.

The set values for Xa and Xb are given in terms of resistance. To avoid damage to the relay ensure that the current injected is not increased above 3 x rated current. The allowable tolerance for Xa and Xb is ±5%.

Measurement of Xa + Xb

The expected value of pick-up for Xa + Xb is given by the equation:-

Xa + Xb = V / (Ix√3)where V and I are the injected volts and current.

Calculate the required values of volts and current to inject. With the phase angle meter reading 60° leading, inject the calculated value of current, and inject 1.1 x calculated voltage. Reduce the voltage slowly until the relay operates.

Record the voltage and current injected for operation.

Measurement of Xa

The expected value of Xa is given by the equation:-

Xa = V / (Ix√3)   where V and I are the injected volts and current.

Calculate the required values of volts and current to inject. With the phase angle meter reading 60° leading, inject the calculated value of current, and inject 0.9 x calculated voltage. Increase the voltage slowly until the relay operates.

Record the voltage and current injected for operation.

Operating Time.

Calculate the volts and current required to simulate a fault corresponding to a resistance of (Xa + Xb)/2. Apply the injection to obtain the operating time. The tolerances for the operating time is ±5% + (-10 to 60mS). Check the red Trip LED turns on steadily and the yellow Alarm LED flashes when the relay operates. Check the '`ALARM: Protection 40 FF`' appears on the relay, ignore other alarms. Reset all alarms.

7.4.3. Operation of output relays

Repeat the previous injection test to operate the 40 Field Failure element. Check the operation of the LGPG111's output relays against the scheme logic settings. Record the output relays operated.

7.5. 67N Sensitive directional earth fault

When two or more generators are connected in parallel directly to the busbar, the sensitive directional earth fault function is used in conjunction with either the stator earth fault, or the neutral displacement to discriminate between internal or external faults. The operating quantity is the residual current measured at the line end of the generator. The polarizing quantity is derived either from the voltage input of the neutral displacement function, or the current input of the stator earth fault function, depending on which is available.

Enable the 67N Sensitive Directional Earth Fault protection only. If necessary, change the scheme logic input matrix so that only the 67N will cause the output relays to operate.

If I_e is used as the polarizing current, go to Section 7.5.2. unless the 67N is dual polarized, in which case both V_e and I_e polarizing tests should be carried out.

7.5.1 Measurements and characteristic for polarizing voltage V_e

Record the directional earth fault settings; Iresidual>, RCA and Vep>.

Inject 20V into the V_e input (terminals B19-B20), and rated current into the $I_{residual}$ input (terminals A7-A8).

Adjust the phase difference between the volts and the current so that the phase angle meter reads $I_{residual}$ leading V_e by RCA degrees, (where RCA is the setting applied to the relay). Record and check the current and voltage measured by the relay, allowing ±3% tolerance. Accept and reset all alarms.

Measurement of $I_{residual}$

With the connections and phase angle set as above, inject 2xVep> Volts into the relay. Inject zero Amps into the relay and slowly increase the current to measure the pick-up and drop-off values for $I_{residual}$.

$I_{residual}$ pick-up value = Iresidual> with a ±5% tolerance.

$I_{residual}$ drop-off value = 0.95 x Iresidual> with a ±5% tolerance.

Measurement of Vep>

With the connections and phase angle set as above, inject rated current into the relay. Inject zero Volts and slowly increase the voltage to measure the pick-up and drop-off values for V_e. Stop injection and reset all alarms.

V_e pick-up value = Vep> setting	with a ±5% tolerance.
V_e drop-off value = 0.95xVep> setting	with a ±5% tolerance.

Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check '`ALARM: Protection 67N SDEF`' appears on the display, ignore other alarms. Reset all alarms.

Measurement of RCA

With the connections and phase angle set as above, inject 2xVep> Volts and rated current into the relay. Rotate the phase difference lagging to measure the phase angle when the relay picks-up and drops-off. Rotate the phase difference leading to measure the pick-up and drop-off phase angles. Record the phase angles measured.

Pick-up phase angles = RCA±90°	with a ±5° tolerance.
Drop-off phase angles = RCA±95°	with a ±5° tolerance.
Operating region = RCA-90° to RCA+90°	with a ±5° tolerance.

Go to Section 7.5.3, unless the 67N is dual polarized.

7.5.2 Measurements and characteristic for polarizing current I_e

Record the directional earth fault settings; Iresidual>, RCA and Iep>.

Inject 0.2A into the I_e input (terminals A5-A6), and rated current into the $I_{residual}$ input (terminals A7-A8). Adjust the phase difference between the two current inputs so that the phase angle meter reads $I_{residual}$ leading I_e by RCA degrees (where RCA is the setting applied to the relay). Record and check the currents measured by the relay, allowing a ±3% tolerance. Accept and reset all alarms.

Measurement of Iresidual>

With the connections and phase angle set as above, inject 0.2A into the I_e input, and inject zero Amps into the $I_{residual}$ input. Slowly increase $I_{residual}$ current to measure its pick-up and drop-off values. Accept and reset all alarms.

$I_{residual}$ pick-up value = Iresidual> setting with a ±5% tolerance.

$I_{residual}$ drop-off value = 0.95xIresidual> setting with a ±5% tolerance.

Measurement of Iep>.

With the connections and phase angle set as above, inject rated current into the $I_{residual}$ input, and inject zero Amps into the I_e input. Slowly increase the I_e current to measure its pick-up and drop-off values.

I_e pick-up value = Iep> setting with a ±5% tolerance.

I_e drop-off value = 0.95xIep> setting with a ±5% tolerance.

Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check '`ALARM: Protection 67N SDEF`' appears on the display, ignore other alarms. Reset all alarms.

Measurement of RCA

Inject 0.2A into I_e and rated current into $I_{residual}$. Rotate the phase difference lagging to measure the phase angle when the relay picks-up and drops-off. Also measure the relay operating angle region. Rotate the phase difference leading to measure the pick-up and drop-off phase angles and the relay operating angle region again. Record the phase angles measured.

Pick-up phase angles = RCA±90° with a ±5° tolerance.

Drop-off phase angles = RCA±95° with a ±5° tolerance.

Operating region = RCA-90° to RCA+90° with a ±5° tolerance.

7.5.3 Operation of output relays

Repeat the previous injection test, as appropriate, to operate the 67N SDEF. Check the operation of the LGPG111's output relays against the scheme logic settings. Record the output relays operated.

7.6. 51N Stator earth fault

This protection function is current operated and can be set to cover up to 95% of the stator windings. It is normally applied to generators which are resistively earthed, and is connected to the earth path CT to measure the neutral earth current. Low set and high set elements are provided. The low set element can either be set to a standard inverse curve, or to a definite time characteristic. The high set element consists of a definite time characteristic, which can be set to instantaneous.

Enable the 51N Stator Earth Fault protection only. Disable the 51N>> High Set element. If necessary, change the scheme logic input matrix so that only the 51N> will cause the output relays to operate.

Note, the I_e input is designed to measure small amounts of current, to achieve this sensitivity the range is limited and the input will “swamp” at approximately 2.5 x rated current, i.e. any current greater than 2.5 x rated current at this input will be measured and displayed as 2.5 x rated current.

7.6.1. Measurement checks

Inject rated current into the I_e input (terminals A5-A6). Record and check the current injected and measured by the relay, allowing ±3% tolerance.

7.6.2. Characteristic and operating time for 51N>

Record the stator earth fault protection settings; Ie>, t> or TMS, tRESET and the timer characteristic.

Measurement of Ie>

Inject 0.8 x Ie> Amps into the I_e input (terminals A5-A6), and slowly increase the current to check the 51N> pick-up value. Decrease the I_e current to check the drop-off value. As there is a time delay associated with this function the Protection Operation Summary Section of the relay’s menu can be used to determine the point at which this function starts to operate. The Protection Operation Summary should indicate 0%, when the current injected is increased to the pick-up point the displayed percentage will start to increase, this is the pick-up point, the displayed value will rise from 0% and displays 100% when the time delay has expired. Accept and reset all alarms on the relay.

I_e pick-up value = Ie> setting	with a ±5% tolerance.
I_e drop-off value = 95% of Ie> setting	with a ±5% tolerance.

Measurement of time delay characteristic.

Inject 2 x Ie> Amps into the I_e input (terminals A5-A6), to obtain the operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check the ‘`ALARM: Protection 51N> SEF`’ appears on the display, ignore other alarms. Reset all alarms on relay.

For the DT characteristic:

Operating time = t seconds with a ±5% tolerance + (-10 to 40mS)

where t is the applied setting

For the SI characteristic:

Operating time = 10.03 x TMS seconds with a ±5% tolerance + (-10 to 40mS)

where TMS is the applied setting

7.6.3. Operation of output relays for 51N>

Repeat the previous injection test to operate the 51N>. Check the operation of the LGPG111’s output relays against the scheme logic settings. Record the output relays operated.

7.6.4. Characteristic checks for 51N>>

Enable the 51N>> High Set. The 51N status should be left as ‘`Enabled`’, since disabling it will disable both the low set and high set elements. If necessary, change the scheme logic input matrix so that only the 51N>> will cause the output relays to operate.

Record the stator earth fault protection settings, Ie>> and t>>.

Measurement of Ie>>.

Inject 0.8 x Ie>> Amps into the I_e input (terminals A5-A6), and increase the current to check the 51N>> pick-up value. Decrease I_e current to check the drop-off value. The Protection Operation Summary Section of the relay’s menu can be used to determine these points, without the need to wait for timer operation. Accept and reset all alarms on the relay.

I_e pick-up value = Ie>> setting with a ±5% tolerance.

I_e drop-off value = 95% of Ie>> setting with a ±5% tolerance.

Measurement of time delay characteristic.

Inject 2 x Ie>> Amps into the I_e input (terminals A5-A6), to obtain the operating time. Check '`ALARM: Protection 51N>> SEF`' appears on the display; ignore other alarms. Reset all alarms on relay. Compare the measured operating time with the setting, allowing ±5% + (-10 to 40mS) tolerance.

7.6.5. Operation of output relays for 51N>>

Repeat the previous injection test, as appropriate, to operate the 51N>>. Check the operation of the LGPG111's output relays against the scheme logic settings. Record the output relays operated.

7.7. 59N Neutral Displacement

This function is applicable to a generator which is earthed via a distribution transformer, loaded with a resistor, to limit the earth fault current. Operation is by measuring the voltage developed across the distribution transformers loading resistor.

Enable the 59N Neutral Displacement protection only. If necessary, change the scheme logic input matrix so that only the 59N-1 will cause the output relays to operate.

7.7.1. Measurement checks

Ensure that the neutral transformer is isolated from the panel terminal block before beginning these tests.

Inject 20V from the panel terminal block into the V_e input (terminals B19-B20). Record and check the voltage injected and the voltage measured by the relay, allowing ±3% tolerance.

7.7.2. Characteristic and operating time for 59N-1

Record the neutral displacement protection settings; Ve> and t1.

Measurement of Ve>.

Inject 0.8 x Ve> Volts into the V_e input (terminals B19-B20), and slowly increase the voltage to measure the 59N-1> pick-up value. Decrease V_e to check the drop-off value. As there is a time delay associated with this function the Protection Operation Summary Section of the relay's menu can be used to determine the point at which this function starts to operate. The Protection Operation Summary should indicate 0%, when the voltage injected is increased to the pick-up point the displayed percentage will start to increase, this is the pick-up point, the displayed value will rise from 0% and displays 100% when the time delay has expired.

V_e pick-up value = Ve> setting with a ±5% tolerance.

V_e drop-off value = 95% of Ve> setting with a ±5% tolerance.

Measurement of time delay characteristic.

Ensure the output contact, connected to the timer on the test set, is operated by the 59N-1 and not by the 59N-2. Inject 2 x Ve> Volts to obtain the operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check '`ALARM: Protection 59N–1 ND`' appears on the display, ignore other alarms. Reset all alarms

Operating time = the setting, t1 with a ±5% tolerance + (-10 to 40mS)

7.7.3. Operation of output relays for 59N-1

Inject 2xVe> Volts into the V_e input (terminals B19-B20), to operate the 59N-1. Check the operation of the output relays against the scheme logic settings. Record the output relays operated.

7.7.4. Operating time for 59N-2

If the 59N-2 is not used in the scheme logic there is no requirement for the following 59N-2 tests.

If necessary, change the scheme logic input matrix so that only the 59N-2 will cause the output relays to operate.

Record the neutral displacement protection settings; t2 and t2RESET.

Ensure the output relay, connected to the timer on the test set, is operated by the 59N-2 and not by the 59N-1. Inject 2xVe> Volts to obtain the relay's operating time. Check '`ALARM: Protection 59N–2 ND`' appears on the display, ignore other alarms. Reset all alarms.

7.7.5. Operation of output relays for 59N-2

Inject 2xVe> Volts into the V_e input (terminals B19-B20), to operate the 59N-2. Check the operation of the output relays against the scheme logic settings. Record the output relays operated.

7.8. 51V Voltage dependent overcurrent

The purpose of the voltage dependent overcurrent function is to disconnect the generator from the system if a system fault has not been cleared by the main protection, after a pre-determined time delay.

The voltage dependent characteristic can either be voltage controlled or voltage restrained, and the timing characteristic can either be standard inverse or definite time. When the generator is directly connected to the busbars the voltage controlled overcurrent function is used, whereas if the generator is connected to the busbars via a step-up transformer the voltage restrained overcurrent is preferred. For applications that do not require a voltage dependent characteristic, a simple overcurrent function can be used.

With voltage controlled overcurrent, the operating time characteristic is changed from a load characteristic to a fault characteristic when the voltage drops below the set level. With voltage restrained overcurrent, when the voltage falls below a set value, the current pick-up level is proportionally lowered, producing an infinite number of curves.

For generators that are connected to the system via a Delta/Star transformer, a Yd voltage correction is selectable within the relay.

Enable the 51V Overcurrent protection only. If necessary, change the scheme logic input matrix so that only the 51V will cause the output relays to operate. There is no need to change the input matrix for blocking by the Voltage Balance element.

7.8.1. Measurement checks

Inject rated volts into the V_{ab} input (terminals B25-B26). Record and check the voltage injected and the value measured by the relay, allowing ±3% tolerance. Repeat the test by injecting rated volts into the V_{bc} input (terminals B27-B28).

Inject rated current into the I_a input (terminals A11-A12). Record and check the current injected and the value measured by the relay, allowing ±3% tolerance. Repeat the test for the I_b input (terminals A13-A14) and the I_c input (terminals A15-A16).

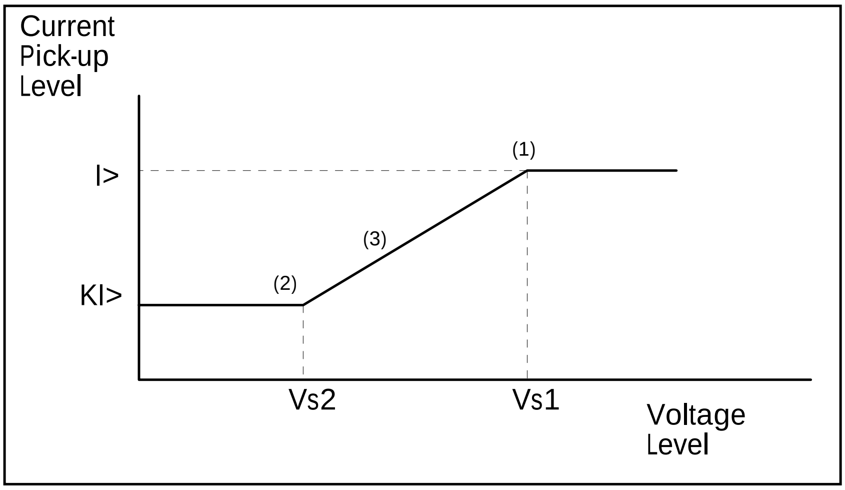
The 51V has three operating functions, of which only one will be used. Use the appropriate section for the relevant test instructions.

Function:	Section:
Restraint	6.10.2
Controlled	6.10.3
Simple	6.10.4

7.8.2. Characteristic and operating time for restraint function

Record the voltage restrained overcurrent settings; Voltage rotation, Vs1, Vs2, K, I>, t/TMS, tRESET and the Definite Time (DT) or Standard Inverse (SI) characteristic applied.

The following tests should be applied to each phase element, complete the tests for each element in turn. Begin by testing phase A. For this function it is necessary to test three points on the “curve”, for each phase.



The following connections will be required during these tests:

Signal designator	LGPG111 Connections
I_a	A11-A12
I_b	A13-A14
I_c	A15-A16
V_{ab}	B25-B26
V_{bc}	B27-B28
V_{ca}	B25-B28, Link B26-B27
V_{ab}*	B25-B26, Link B25-B28 & B26-B27

Measurement of I> (point 1)

For the different voltage vector rotation setting’s, inject the voltage as follows for each phase:

Voltage Rotation Setting	Phase A Inject:		Phase B Inject:		Phase C Inject:	
None	I> into I_a	1.2xVs1 into V_{ab}	I> into I_b	1.2xVs1 into V_{bc}	I> into I_c	1.2xVs1 into V_{ca}
Yd	I> into I_a	1.2xVs1 into V_{ab}	I> into I_b	1.2xVs1 into V_{ab}*	I> into I_c	1.2xVs1 into V_{bc}

Inject the specified current and voltage to check the pick-up and drop-off values. As there is a time delay associated with this function the Protection Operation Summary Section of the relay's menu can be used to determine the point at which this function starts to operate. The Protection Operation Summary should indicate 0%, when the current injected is increased to the pick-up point the displayed percentage will start to increase, this is the pick-up point, the displayed value will rise from 0% and displays 100% when the time delay has expired. Accept and reset all alarms.

I_a pick-up value = I> setting with a ±5% tolerance.

I_a drop-off value = 0.95xI> setting with a ±5% tolerance.

Repeat the tests for phases B and C.

Measurement of K.I> (point 2)

For the different voltage vector rotation setting, inject the voltage as follows for each phase:

Voltage Rotation Setting	Phase A Inject:		Phase B Inject:		Phase C Inject:	
None	K.I> into I_a	0.5xVs2 into V_{ab}	K.I> into I_b	0.5xVs2 into V_{bc}	K.I> into I_c	0.5xVs2 into V_{ca}
Yd	K.I> into I_a	0.5xVs2 into V_{ab}	K.I> into I_b	0.5xVs2 into V_{ab}*	K.I> into I_c	0.5xVs2 into V_{bc}

Inject the specified current and voltage to check the pick-up and drop-off values. The Protection Operation Summary Section of the relay's menu can be used to determine this, without the need to wait for timer operation. Accept and reset all alarms.

I_a pick-up value = K.I> setting with a ±5% tolerance.

I_a drop-off value = 0.95xK.I> setting with a ±5% tolerance.

Repeat the tests for phases B and C.

Measurement at 50% of curve (point 3)

For the different voltage vector rotation setting, inject the voltage as follows for each phase:

Voltage Rotation Setting	Phase A Inject:		Phase B Inject:		Phase C Inject:	
None	0.5x(K+1)I> into I_a	0.5x(Vs1+Vs2) into V_{ab}	0.5x(K+1)I> into I_b	0.5x(Vs1+Vs2) into V_{bc}	0.5x(K+1)I> into I_c	0.5x(Vs1+Vs2) into V_{ca}
Yd	0.5x(K+1)I> into I_a	0.433x(Vs1+Vs2) into V_{ab}	0.5x(K+1)I> into I_b	0.433x(Vs1+Vs2) into V_{ab}*	0.5x(K+1)I> into I_c	0.433x(Vs1+Vs2) into V_{bc}

Note: For Yd rotation the "0.433" value in the in above procedure is derived from the following:-

Phase A $|(V_{ab}-V_{ca})| / \sqrt{3}$ where $V_{ca} = -(V_{ab}+V_{bc})$

Phase B $|(V_{bc}-V_{ab})| / \sqrt{3}$

Phase C $|(V_{ca}-V_{bc})| / \sqrt{3}$ where $V_{ca} = -(V_{ab}+V_{bc})$

Inject the specified current and voltage to check the pick-up and drop-off values. The Protection Operation Summary Section of the relay's menu can be used to determine this, without the need to wait for timer operation. Stop the current injection only. Accept and reset all alarms.

I_a pick-up value = 0.5x(K+1)I> setting with a ±5% tolerance.

I_a drop-off value = 0.95x(0.5x(K+1)I>) setting with a ±5% tolerance.

Repeat the tests for phases B and C.

Measurement of operating time characteristic

Inject a voltage of 1.2 x Vs1 and inject a current of 2 x I> Amps to obtain the relay's operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check '`ALARM: Protection 51V OC A`' appears on the display, where '`A`' is the phase designator for the phase under test. Ignore other alarms. Reset all alarms. Record the operating time.

For the DT characteristic

Operating time = t seconds, with a ±5% tolerance + (-10mS to 40mS)

where t is the applied setting

For the SI characteristic

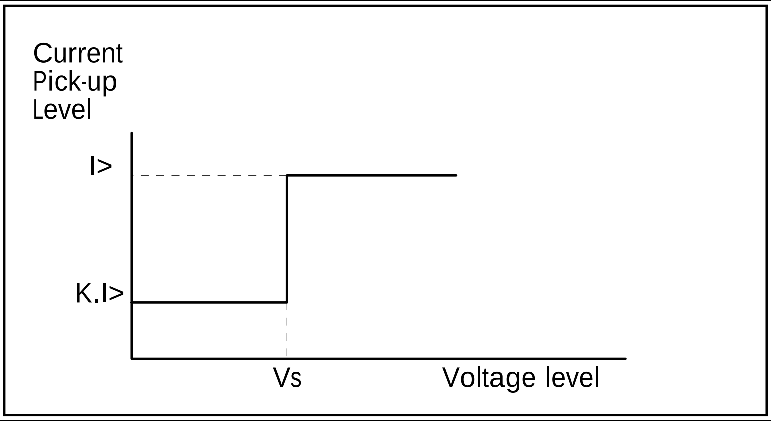
Operating time = 10.03 x TMS seconds, with a ±5% tolerance + (-10mS to 40mS)

where TMS is the applied setting

7.8.3. Characteristic and operating time for controlled function

Record the voltage controlled overcurrent settings; Voltage rotation, Vs, K, I>, t/TMS, tRESET and the Definite Time (DT) or Standard Inverse (SI) characteristic applied.

The following tests should be applied to each phase element; complete the tests for each element in turn. Begin by testing phase A.



The following connections will be required during these tests:

Measurement of I>.

Signal designator	LGPG111 Connections
I_a	A11-A12
I_b	A13-A14
I_c	A15-A16
V_{ab}	B25-B26
V_{bc}	B27-B28
V_{ca}	B25-B28, Link B26-B27
V_{ab}*	B25-B26, Link B25-B28 & B26-B27

For the different voltage vector rotation setting, inject the voltage as follows for each phase:

Voltage Rotation Setting	Phase A Inject:		Phase B Inject:		Phase C Inject:	
None	I> into I_a	1.2xVs into V_{ab}	I> into I_b	1.2xVs into V_{bc}	I> into I_c	1.2xVs into V_{ca}
Yd	I> into I_a	1.2xVs into V_{ab}	I> into I_b	1.2xVs into V_{ab}*	I> into I_c	1.2xVs into V_{bc}

Inject the specified current and voltage to check the pick-up and drop-off values. As there is a time delay associated with this function the Protection Operation Summary Section of the relay’s menu can be used to determine the point at which this function starts to operate. The Protection Operation Summary should indicate 0%, when the current injected is increased to the pick-up point the displayed percentage will start to increase, this is the pick-up point, the displayed value will rise from 0% and displays 100% when the time delay has expired. Accept and reset all alarms.

I_a pick-up value = I> setting with a ±5% tolerance.

I_a drop-off value = 0.95xI> setting with a ±5% tolerance.

Repeat the tests for phases B and C.

Measurement of K.I>.

For the different voltage vector rotation setting, inject the voltage as follows for each phase:

Voltage Rotation Setting	Phase A Inject:		Phase B Inject:		Phase C Inject:	
None	K.I> into I_a	0.5xVs into V_{ab}	K.I> into I_b	0.5xVs into V_{bc}	K.I> into I_c	0.5xVs into V_{ca}
Yd	K.I> into I_a	0.5xVs into V_{ab}	K.I> into I_b	0.5xVs into V_{ab}*	K.I> into I_c	0.5xVs into V_{bc}

Inject the specified current and voltage to check the pick-up and drop-off values. The Protection Operation Summary Section of the relay’s menu can be used to determine this, without the need to wait for timer operation. Accept and reset all alarms.

I_a pick-up value = K.I> setting with a ±5% tolerance.

I_a drop-off value = 0.95xK.I> setting with a ±5% tolerance.

Repeat the tests for phases B and C.

Measurement of time delay characteristic.

With the voltage conditions as above, inject 2xK.I> Amps to obtain the operating time. Record the operating time.

For the DT characteristic:

Operating time = t seconds, with a ±5% tolerance + (-10mS to 40mS)

where t is the applied setting

For the SI characteristic:

Operating time = 10xTMS seconds, with a ±5% tolerance + (-10mS to 40mS)

where TMS is the applied setting

Repeat the tests for phases B and C.

7.8.4. Characteristic and operating time for simple function

Record the overcurrent settings; I>, t/TMS, tRESET and the Definite Time (DT) or Standard Inverse (SI) characteristic applied.

The following tests should be applied to each phase element; complete the tests for each element in turn. Begin by testing phase A.

The following connections will be required during these tests:

Signal designator	LGPG111 Connections
I_a	A11-A12
I_b	A13-A14
I_c	A15-A16

Measurement of I>.

Inject 0.8 x I> Amps and slowly increase to measure the pick-up value. Decrease the current to check the drop-off value. As there is a time delay associated with this function the Protection Operation Summary Section of the relay's menu can be used to determine the point at which this function starts to operate. The Protection Operation Summary should indicate 0%, when the current injected is increased to the pick-up point the displayed percentage will start to increase, this is the pick-up point, the displayed value will rise from 0% and displays 100% when the time delay has expired. Accept and reset all alarms.

I_a pick-up value = I> setting with a ±5% tolerance.

I_a drop-off value = 0.95xI> setting with a ±5% tolerance

Repeat the tests for phases B and C.

Measurement of time delay characteristic.

Inject 2 x I> Amps to obtain the operating time. Check the red LED turns on and the yellow Alarm LED flashes when the relay operates. Check the '`ALARM: Protection 51V OC A`' appears on the display, where '`A`' is the phase designator for the phase under test. Ignore other alarms. Reset all alarms. Record the operating time.

For the DT characteristic:

Operating time = t seconds, with a ±5% tolerance + (-10mS to 40mS)

where t is the applied setting

For the SI characteristic:

Operating time = 10xTMS seconds, with a ±5% tolerance + (-10mS to 40mS)

where TMS is the applied setting

Repeat the tests for phases B and C.

7.8.5. Fault record checks

Use the front panel keys to navigate to the menu section View Records, and ensure that the records match the injected faults carried out above.

7.8.6. Operation of output relays

Inject sufficient current into the relay to operate the 51V. Check the operation of the LGPG111's output relays against the scheme logic settings. Record the output relays operated.

7.9. 46 Negative phase sequence

The negative phase sequence function is for the detection of unbalanced load conditions. Under such conditions second harmonic frequency eddy currents are induced into the rotor, which can cause rapid overheating. The function has a thermal replica characteristic which can be set to closely match the negative phase sequence withstand characteristic of the machine. In order to take into account the heating effect of the standing negative phase sequence current under normal healthy working conditions, pre-heating of the machine is simulated.

The operating time t>> of the trip element follows a time/current characteristic equation, as given by the expression:-

$$t>> = -\frac{K}{I_2>>^2}\log_e\left[1-\left(\frac{I_2>>}{I_2}\right)^2\right]$$

Where $I_2>>$ = negative phase current threshold

K = constant proportion to the thermal capacity of the generator rotor

I_2 = negative phase sequence current present

The characteristic approximates to the $t = K/I_2^2$ characteristic when the I_2 value is well above the threshold.

When high values of K are selected, and the negative phase sequence currents measured are near to the threshold, the operating time as determined by the characteristic may be too slow. In this case a maximum time setting t_{Max} is available to provide a safe trip time.

When I_2 is above the nominal current, the operating time may become too fast, and may cause incorrect discrimination against other overcurrent relays under fault conditions. The inverse characteristic should then change to a definite time characteristic, which is defined by the minimum time setting t_{MIN}.

To provide integration of successive I_2 when the duration of each I_2 input is insufficient to cause tripping, an exponential reset characteristic is provided.

Enable the 46 Negative Phase Sequence protection only. If necessary, change the scheme logic input matrix so that only the 46 will cause the output relays to operate.

7.9.1. Measurement checks

Inject rated current into the I_a and I_b inputs so that phases A and B are in anti-phase (terminals A11-A13, with A12 and A14 linked). Record the current injected and the negative phase sequence current, I2, measured by the relay. The measured I2 should be 0.577 times the injected current, allowing ±5% tolerance.

Repeat the above test, but inject into the I_b and I_c inputs, (terminals A13-A15, linking A14 to A16).

7.9.2. Characteristic and operating time for 46> NPS alarm

If the 46> NPS Alarm is not used in the scheme logic there is no requirement for the following 46> NPS Alarm tests. If necessary, change the scheme logic input matrix so that only the 46> NPS Alarm will cause the output relays to operate.

Record the 46> NPS Alarm settings; I2> and t>.

Measurement of I2>.

Inject 3 x I2> Amps into the I_a input (terminals A11-A12). Slowly increase the current until the 46> NPS Alarm picks up. Record the pick-up current. With the relay operated, slowly decrease the current injected until it resets. Record the drop-off current. As there is a time delay associated with this function the Protection Operation Summary Section of the relay's menu can be used to determine the point at which this function starts to operate. The Protection Operation Summary should indicate 0%, when the current injected is increased to the pick-up point the displayed percentage will start to increase, this is the pick-up point, the displayed value will rise from 0% and displays 100% when the time delay has expired. Accept and reset all alarms.

Pick-up current = 3 x I2> setting	with a ±7.5% tolerance.
Drop-off current = 2.85 x I2> setting	with a ±7.5% tolerance.

Repeat the tests for the I_b input (terminals A13-A14), and the I_c input (terminals A15-A16).

Measurement of operating time.

Inject 6xI2> Amps current into the I_a input terminals A11-A12, to obtain the operating time. Check the yellow Alarm LED is flashing and '`ALARM: Protection 46> NPS`' appears on the display, ignore other alarms. Reset all alarms.

Operating time = t> setting	with a ±5% tolerance + (-10 to 40mS)

Repeat the tests for the I_b input (terminals A13-A14), and the I_c input (terminals A15-A16).

7.9.3. Operation of output relays for 46> NPS alarm

Repeat the injection described previously to operate the 46> NPS Alarm. Check the operation of the output relays against the scheme logic settings. Record the output relays operated.

7.9.4. Characteristic and operating time for 46>> NPS thermal trip

If necessary, change the input matrix in the scheme logic so that only 46>> Thermal Trip will cause the output relays to operate.

Record the negative phase sequence settings; I2>>, K, tMAX, tMIN and Kreset.

Measurement of I2>>.

Inject 3 x I2>> Amps into the I_a input (terminals A11-A12). Slowly increase the current until the 46>> NPS Thermal Trip picks up. The Protection Operation Summary Section of the relay's menu can be used to determine this, without the need to wait for timer operation. Note that the displayed value must be 100%, as this is an indication of thermal capacity. As it may take some time to reach 100%, more current may be injected to "warm" up the relay. Inject several times I2>> current until the display reaches 95%, stop injection then inject the required 3 x I2>> and slowly increase until the display reaches 100%. Record the current injected.

Pick-up current = 3xI2>> with a ±7.5% tolerance.

Repeat the tests for the I_b input (terminals A13-A14), and the I_c input (terminals A15-A16).

Measurement of operating time characteristic.

For measuring relay operating time, allow at least 4xKreset seconds between timings to allow the thermal element to reset (allow to cool until the relay displays a thermal value off 0%). Note, the thermal value will be reset to 0% if the auxiliary supply to the relay is switched off.

Inject 6.93 x I2>> Amps into the I_a and I_b inputs so that phases A and B are in anti-phase (terminals A11-A13, with A12 and A14 linked), to obtain the relay operating time. The I2 measurement displayed in the relay should indicate 4xI2>> for this condition; for two currents in opposite polarity $I_2=I/\sqrt{3}$, therefore 4 x I_2=6.93 x I.

The following equation is derived from the equation stated in section 7.9. If it is desired to inject any other value of current other than 4 x I2>> then the equation given in section 7.9 should be used to calculate the expected tripping time.

$$\text{expected operating time} = \frac{0.0645 \times K}{\left(I2>>\!/_{In}\right)^2}$$

where: I2>> & K are the relay settings, In is the relay's current rating: 1A or 5A.

Allow ±10% tolerance + (-10mS to 50mS)

Check the red Trip LED turns on and the yellow Alarm LED flashes when relay operates. Check '`ALARM: Protection 46>> NPS`' appears on the relay, ignore other alarms. Reset all alarms.

Measurement of t_{MIN} operating time.

To check t_{MIN} inject $2.5 \times \sqrt{K/t_{MIN}} \times In$ into the I_a and I_b inputs so that phases A and B are in anti-phase (terminals A11-A13, with A12 and A14 linked), to obtain a fast operating time. K and t_{MIN} are the relay settings. Make sure the current injected does not exceed the CT's continuous thermal rating of 4xIn. Record the operating time obtained and compare with the t_{MIN} setting.

Operating time = t_{MIN} with a ±5% tolerance + (-10 to 40mS)

Measurement of t_{MAX} operating time.

Firstly, calculate the expected tripping time for an injected current of 1.2 x I2>> using the following equation:-

$$Time = \frac{1186 \times K}{\left(12 \times I2 >> / In\right)^2}$$

where: I2>>and K are the relay settings.

If the calculated time is less than the t_{MAX} setting it is not possible to measure the t_{MAX} operating time.

If the calculated time is greater than the t_{MAX} setting then inject 3.6 x I2>> Amps into the I_a input (terminals A11-A12), and at the same time start a stop watch to measure the relay's operating time. Record the operating time obtained and compare with the setting.

Operating time = t_{MAX} with a ±5% tolerance.

7.9.5. Checks for 46>> NPS thermal trip reset time

To perform this test the relay is "heated" to 100% (the trip value), then the relay is allowed to "cool" for a known period of time, then the fault is re-applied until the relay operates. By this method it is possible to show that the Kreset function is working correctly.

The equation to calculate the time taken to fall to a thermal value θ, assuming that the thermal value is at 100% initially, (where θ is the % value indicated in the protection Op summary), is as follows:-

$$t = -\left[\left(\frac{Kreset}{(I2 >>)^2}\right)\log_e\left(\frac{\theta}{100\%}\right)\right]$$

The equation to calculate the thermal value θ to which the generator will cool after a time t has expired, assuming that the thermal value is at 100% initially, (where θ is the % value indicated in the protection Op summary), is as follows:-

$$\theta = e^{-\left[t(I2>>)^2 / Kreset \right]} x100\%$$

The equation to calculate the time taken to rise from an initial thermal value θ to 100%, is as follows:-

$$t = \frac{Kreset}{(I2>>)^2} \log_e \left[\left(\frac{1 - \theta/100\%}{\left(I2/I2>> \right)^2} \right) - 1 \right]$$

For the following tests it is assumed that the generator is allowed to cool from 100% to 88.7%, the point at which the 46>> output will reset.

Inject 6.93 x I2>> Amps into the I_a and I_b inputs so that phases A and B are in anti-phase (terminals A11-A13, with A12 and A14 linked). The I2 measurement in the relay will indicate 4 x I2>> for this condition. Stop injection when the relay operates (a thermal value of 100%). At the same time start a stop watch, and wait for a duration of $\frac{0.12 \times Kreset}{\left(I2>>/In \right)^2}$ seconds, (which is the time taken for the thermal value to fall from 100% to 88.7%).

When the thermal value has fallen to 88.7% immediately re-apply the injection, for a second time, and measure the relay's operating time.

operating time $= \frac{K}{133.65 \times \left(I2>>/In \right)^2}$ seconds with a ±20% tolerance.

Where Kreset and I2>> are the relay settings.

For software versions before 18LGPG002XXXEA, the Kreset setting is used differently. The test may be performed by following the stated injection procedure, but wait for a duration of Kreset seconds before applying the second injection.

second operating time $= \dfrac{0.0645 \times K}{\left(I2>>/In\right)^2} \times 63$ % seconds with a ±20% tolerance.

7.9.6. Operation of output relays for 46>> NPS thermal trip

Inject 3.5xI2>> Amps into phase A-N, relay terminals A11-A12 to operate the 46>> Thermal Trip. Check the operation of the output relays against the scheme logic settings. Record the output relays operated.

Restore the original Scheme Logic settings, if changed.

7.10. 81U Under frequency

There are two under-frequency elements, which are used to detect overloading of the generator caused by various system disturbances or operating conditions.

7.10.1. Measurements

Inject rated voltage with rated frequency into the V_{bc} input (terminals B27-B28). Record and check the frequency injected and the value measured by the relay, allowing ±0.5 Hz tolerance.

7.10.2. Characteristic and operating time

The LGPG111's under frequency protection consists of two independent elements, 81U-1 & 81U-2. If both are used in the scheme logic then the following tests should be repeated for both elements.

Record the under frequency settings for the 81U-1; F1< and t1.

Enable the 81U-1 under frequency protection only. If necessary, change the scheme logic input matrix so that only the 81U-1 will cause the output relays to operate.

Measurement of F1<, with a variable frequency supply.

If a variable frequency voltage source is available, carry out the tests as follows:

Inject rated voltage, with frequency above the F1< setting, into the V_{bc} input (terminals B27-B28). Vary the frequency to check the relay's pick-up and drop-off values. Stop injecting and reset all alarms.

Pick-up frequency = F1< with a ±0.5Hz tolerance.

Drop-off frequency = F1< + 0.2 Hz with a ±0.5Hz tolerance.

Measurement of operating time, with a variable frequency supply.

Arrange the variable frequency supply to step change the frequency from above F1< to less than 0.8 x F1<, to obtain the relay's operating time. Alternatively this can be accomplished by changing the voltage connection to the relay from a system supply to the variable frequency supply set at 0.8xF1<. The single pole quad throw switch can be used for this purpose.

Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check the '`ALARM: Protection 81U-1 UF`' appears on the display, ignore other alarms. Reset all alarms. Record the operating time.

Operating time = t1 with a ±5% tolerance + (-10 to 60mS)

If a variable frequency voltage source is not available, carry out the tests as follows:-

Measurement of F1<, without a variable frequency supply.

Inject rated voltage with rated frequency into the V_{bc} input (terminals B27-B28). Increase the setting F1<, in steps of 0.1 Hz, until the relay operates and then record the setting. Stop injecting and reset all alarms.

F1< setting = injected frequency with a ±0.5 Hz tolerance.

With the relay operated, decrease the setting F1< to check when the output contacts reset. Record the setting which causes the relay to reset.

F1< setting = injected frequency - 0.2Hz with a ±0.5 Hz tolerance.

Measurement of operating time, without a variable frequency supply.

With the F1< setting set to a value higher than the rated frequency, energize the 27 and 81U Inhibit logic input with a voltage equal to relay's Vx(2) rating. Inject rated voltage with rated frequency into the V_{bc} input (terminals B27-B28). Arrange to de-energize the 27 and 81U Inhibit logic input and start a timer, at the same time, to obtain the relay's operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check '`ALARM: Protection 81U-1UF`' appears on the display, ignore other alarms. Accept all alarms. Record the operating time obtained.

Operating time = t1 with a ±5% tolerance + (-10 to 60mS)

Restore the original setting for F1<.

Repeat the tests for the 81U-2, if required, with settings F2< and t2.

7.10.3. Operation of output relays

Inject rated voltage with rated frequency into relay terminals B27-B28 to operate the 81U-1, change setting F1< if necessary. Check the operation of the output relays against the scheme logic settings. Record the output relays operated.

Restore the original Scheme Logic settings, if changed.

Restore the original setting F1< if changed.

Repeat for the 81U-2, if required.

7.11. 81O Over frequency

There is one over-frequency element which is used to back-up the speed control governor when overspeeding occurs in the event of a severe loss of generator load.

Enable the 81O Over Frequency protection only. If necessary, change the scheme logic input matrix so that only the 81O will cause the output relays to operate.

7.11.1. Characteristic and operating time

Record the over frequency settings; F> and t.

Measurement of F>, with a variable frequency supply.

Inject rated voltage, with frequency below the F> setting, into the V_{bc} input (terminals B27-B28). Vary the frequency to check the relay's pick-up and drop-off values.

Pick-up frequency = F>	with a ±0.5Hz tolerance.
Drop-off frequency = F> - 0.2 Hz	with a ±0.5Hz tolerance.

Measurement of operating time, with a variable frequency supply.

Arrange the variable frequency supply to step change the frequency from less than F> to above 1.1xF>. Alternatively this can be accomplished by changing the voltage connection to the relay from a system supply to the variable frequency supply set at 1.1xF>. A single pole quad throw switch can be used for this purpose. Record the operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check that '`ALARM: Protection 81O OF`' appears on the display, ignore other alarms. Reset all alarms. Record the operating time.

Operating time = t1 with a ±5% tolerance + (-10 to 40mS)

Measurement of F>, without a variable frequency supply.

Inject rated voltage with rated frequency into relay terminals B27-B28. Decrease the setting F> 0.1 Hz at a time until the relay operates and then record the setting.

F> setting = injected frequency with a ±0.5 Hz tolerance.

With the relay operated, increase the setting F> to check when the output contacts reset. Record the setting which causes the relay to reset.

F> setting = injected frequency + 0.2Hz with a ±0.5 Hz tolerance.

Measurement of operating time, without a variable frequency supply.

With no voltage injected, re-apply the injection at the same time as starting a timer in to obtain the operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check '`ALARM: Protection 81O OF`' appears on the display, ignore other alarms. Accept all alarms. Record the operating time obtained. This test method will incur a timing penalty of between 100 and 200ms whilst the relay establishes a frequency measurement.

Operating time = t1 with a ±5% tolerance + (-10 to 40mS)

Restore the original setting for F>.

7.11.2. Operation of output relays

Inject rated voltage with rated frequency into relay terminals B27-B28 to operate the

81O, change setting F> if necessary. Check the operation of the LGPG111's output relays against the scheme logic settings. Record the output relays operated.

Restore the original Scheme Logic settings, if changed.

Restore the original setting F> if changed.

7.12. Under voltage

A single element, three phase undervoltage detection function is provided. It primarily used for the back-up of the speed control governor and the automatic voltage regulator.

Enable the 27 Under Voltage protection only. If necessary, change the scheme logic input matrix so that only the 27 will cause the output relays to operate. There is no need to change the input matrix for blocking by the Voltage Balance element.

7.12.1. Measurements

Inject rated voltage from into the V_{ab} input (terminals B25-B26). Record and check the voltage injected and the voltage measured by the relay. Repeat for the V_{bc} input (terminals B27-B28). Allowing ±3% tolerance.

7.12.2. Characteristic and operating time

Record the under voltage settings; V< and t.

The under voltage protection is a 3-phase function which operates when V_{ab}, V_{bc} and V_{ca} are below the setting.

Measurement of V<.

Inject V< Volts into the V_{ab} input (terminals B25-B26) to check the pick-up and drop-off values. (note V_{bc} = 0, and V_{ca} = V_{ab})

Pick-up voltage = V< setting with a ±5% tolerance.

Drop-off value is 1.05xV< with a ±5% tolerance.

Repeat the injection into the V_{bc} input (terminals B27-B28) to check the pick-up and drop-off values. Reset all alarms.

Measurement of time delay characteristic t.

Inject rated current into the I_a input (terminals A11-A12) as this will stop the under voltage protection being inhibited when the volts are removed. Inject rated voltage into the V_{ab} input (terminals B25-B26). Reset all alarms. Stop the voltage injection at the same time as starting a timer to obtain the operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check '`ALARM: Protection 27UV`' appears on the display, ignore other alarms. Stop current injection and reset all alarms on the relay. Record the operating time obtained.

Operating time = t setting with a ±5% tolerance + (-10 to 40mS)

7.12.3. Operation of output relays

Repeat the previous injection to operate the 27 Under Voltage. Check the operation of the output relays against the scheme logic settings. Record the output relays operated.

Restore the original Scheme Logic settings, if changed.

7.13. Over voltage

A two stage element, three phase over voltage detection function is provided. It primarily used for the back-up of the speed control governor and the automatic voltage regulator. When severe over voltage occurs, the high set element can be set to provide fast operation.

Enable the 59 Over Voltage protection only. If necessary, change the scheme logic input matrix so that only the 59 will cause the output relays to operate. Note, the protection function will operate only when the voltage at the V_{ab} and V_{bc} inputs are both above the setting V>.

7.13.1. Measurements

Inject rated voltage from into the V_{ab} input (terminals B25-B26). Record and check the voltage injected and the voltage measured by the relay. Repeat for the V_{bc} input (terminals B27-B28). Allowing ±3% tolerance.

7.13.2. Characteristic and operating time

Record the over voltage settings; V>, t>, V>> and t>>.

Measurement of V>.

Inject 0.9 x V> Volts into the V_{ab} and V_{bc} inputs (terminals B25-B26 and terminals B27-

B28). Slowly increase the voltage until the relay picks up. Record the smallest reading from either of the voltage inputs; this is the pick-up value. With the relay operated, slowly decrease the voltage injected until the relay resets. Record the smallest reading from either of the voltage inputs; this is the drop-off value.

Pick-up voltage = V>	with a ±5% tolerance.
Drop-off voltage 0.95xV>	with a ±5% tolerance.

Repeat the test to measure the pick-up and drop off values of the high set element V>>

Pick-up voltage = V>>	with a ±5% tolerance.
Drop-off voltage 0.95xV>>	with a ±5% tolerance.

Measurement of time delay characteristic t>.

With the same connections and conditions as above, switch from a voltage below the setting to a voltage above the setting at the same time as starting a timer to obtain the operating time. Check the red Trip LED turns on and the yellow Alarm LED flashes when the relay operates. Check the '`ALARM: Protection 59OV >`' appears on the display, ignore other alarms. Reset all alarms. Record the operating time obtained.

Operating time = t> setting	with a ±5% tolerance + (-10 to 40mS)

Repeat the timing tests for the high set element V>>, to measure the time delay t>>.

Operating time = t>> setting	with a ±5% tolerance + (-10 to 40mS)

7.13.3. Operation of output relays

Repeat the previous injection to operate the 59 Over Voltage element. Check the operation of the output relays against the scheme logic settings. Record the output relays operated.

Restore the original Scheme Logic settings, if changed.

7.14. 60 Voltage balance

The 60 Voltage Balance element can detect the failure of a fuse in either the protection VT's or the comparison VT's. The voltage balance compares measurements of V_{ab} and V_{bc} from the protection VT's with the corresponding measurements from the comparison VT's. If a difference of greater than the setting is detected, the voltage balance element will operate. This function can be set to block possible incorrect operation of those protection functions whose performance may be affected by the apparent loss of voltage, such as when a VT fuse blows.

Enable the 60 Voltage Balance protection only.

Record the voltage balance setting; Vs.

7.14.1. Measurement checks

Inject rated voltage into the protection VT's; the V_{ab} input (terminals B25-B26) and the V_{bc} input (terminals B27-B28). Record and check the voltage injected and the values measured by the relay, allowing ±3% tolerance. Repeat for the comparison VT's; the V_{ab} input (terminals B21-B22), and the V_{ab} input (terminals B23-B24).

7.14.2. Characteristic checks for 60 VB-Prot

If necessary, change the scheme logic input matrix so that only the 60 VB-Prot will cause the output relays to operate.

Inject 0.8xVs> Volts into the V_{ab} comparison input (terminals B21-B22). Slowly increase the voltage until the relay operates. Record the pick-up value. Check the yellow Alarm LED flashes and the '`ALARM: Protection 60 VB-Prot`' appears on the display, ignore other alarms. With the relay operated, slowly decrease the voltage injected until the relay resets. Record the drop-off value.

Repeat the test for the V_{bc} comparison input (terminals B23-B24).

Pick-up voltage = Vs with a ±5% tolerance.

Drop-off voltage = 0.95xVs with a ±5% tolerance.

7.14.3. Characteristic checks for 60 VB-Comp

Enable the 60 Voltage Balance protection only. If necessary, change the scheme logic input matrix so that only the 60 VB-Comp will cause the output relays to operate.

Inject 0.8xVs> Volts into the V_{ab} protection input (terminals B25-B26). Slowly increase the voltage until the relay operates. Record the pick-up value. Check the yellow Alarm LED flashes and the '`ALARM: Protection 60 VB-Comp`' appears on the display, ignore other alarms. With the relay operated, slowly decrease the voltage injected until the relay resets. Record the drop-off value.

Repeat the test for the V_{bc} protection input (terminals B27-B28).

Pick-up voltage = Vs	with a ±5% tolerance.
Drop-off voltage = 0.95xVs	with a ±5% tolerance.

7.14.4. Operation of output relays for voltage balance prot.

Repeat the previous tests to operate the voltage balance protection VT fail element. Check the operation of the output relays against the scheme logic settings. Record the output relays operated. Repeat for the comparison VT fail element.

Restore the original Scheme Logic settings, if changed.

8. LOGIC INPUT STATUS CHECKS

Only those logic input terminals which are wired in the protection scheme need to be checked.

Energize each logic input, one by one. Check the binary pattern in the 'Logic Input Status' cell, in the Auxiliary Functions Section, is as follows.

Relay Terminals Energized		Logic Input Status
+	–	
B1	B2	00 0000 0000 0001
B3	B4	00 0000 0000 0010
B5	B6	00 0000 0000 0100
B7	B8	00 0000 0000 1000
B9	B10	00 0000 0001 0000
B11	B12	00 0000 0010 0000
D1	D2	00 0000 0100 0000
D5	D6	00 0000 1000 0000
D9	D10	00 0001 0000 0000
D13	D14	00 0010 0000 0000
D15	D16	00 0100 0000 0000
D19	D20	00 1000 0000 0000
D23	D24	01 0000 0000 0000
D27	D28	10 0000 0000 0000

Table 3 Logic Input Status patterns for single input energization.

9. CONTACT TEST

These tests are to operate the output relays, in turn. Only the output relays which are wired in the protection scheme need to be tested. All external relay contact connections from the panel should be isolated. This will remove auxiliary voltages from the contacts and ensure that external plant is not operated inadvertently.

Set the ‘Scheme Output’ cell to ‘Inhibited’ in the Auxiliary Functions Section. The relay is now out of service and the yellow Out Of Service LED will be lit.

Enter a bit pattern in the ‘Relay Test’ cell in the Test Functions Section and press the SET key to operate and latch the output relays, (Note, the outputs will latch in the closed position until the reset procedure is followed). To reset the output relays, replace the 1’s by 0’s and press the SET key. Alternatively, the cell can be reset to all 0’s by pressing the RESET key. The following table illustrates the bit patterns required to operate an individual output relay. Check normally open contacts close and normally closed contacts open with a continuity tester or multimeter.

Output Relay to be Operated	Bit Pattern Entered for “Relay Test”
Relay 1	0000 0000 0000 0010
Relay 2	0000 0000 0000 0100
Relay 3	0000 0000 0000 1000
Relay 4	0000 0000 0001 0000
Relay 5	0000 0000 0010 0000
Relay 6	0000 0000 0100 0000
Relay 7	0000 0000 1000 0000
Relay 8	0000 0001 0000 0000
Relay 9	0000 0010 0000 0000
Relay 10	0000 0100 0000 0000
Relay 11	0000 1000 0000 0000
Relay 12	0001 0000 0000 0000
Relay 13	0010 0000 0000 0000
Relay 14	0100 0000 0000 0000
Relay 15	1000 0000 0000 0000

Table 4 Output contact test patterns for single output operation.

9.1. Relay inoperative alarm

Enter a bit pattern of ‘0000000000000001’ into the ‘Relay Test’ cell in the Test Functions Section and press the SET key. Check the contact across terminals G1-G3 opens and the contact across terminals G1-G5 closes. Check the relay inoperative alarm is on, if the contact is wired in the protection scheme. Record the test result.

At the completion of the tests set the ‘Scheme Output’ cell to ‘Enabled’ in the Auxiliary Functions Section. The yellow Out Of Service LED should turn off.

10. SCHEME LOGIC TESTS

A number of tactics can be employed to check and prove the scheme logic settings:

Visual comparison of the settings against the setting schedule.

Use of the remote communications via a PC, or have the relay print the scheme settings out to facilitate a comparison of the settings with the setting schedule.

Test the operation of the scheme logic.

The latter option is discussed here.

The LGPG111 allows the operation of the scheme logic to be tested without the need to trip protective elements. Instead, input events or scenarios to the scheme logic can be set-up and the scheme's output response observed. The tests can be carried out whilst the relay is in service and without operating any of the output contacts.

In order to carry out the scheme logic tests, a thorough understanding of the scheme logic in the LGPG111 is required. Error! AutoText entry not defined. provides a suitable description of the scheme logic. Then, from the setting schedule, scheme logic input scenarios can be devised along with their expected scheme outputs. The test proceeds by setting each input scenario and checking the output corresponds with the expected result.

10.1. Example scheme logic tests

Figure 2 illustrates the various types of logical arrangements which the LGPG111's scheme logic is capable of providing.

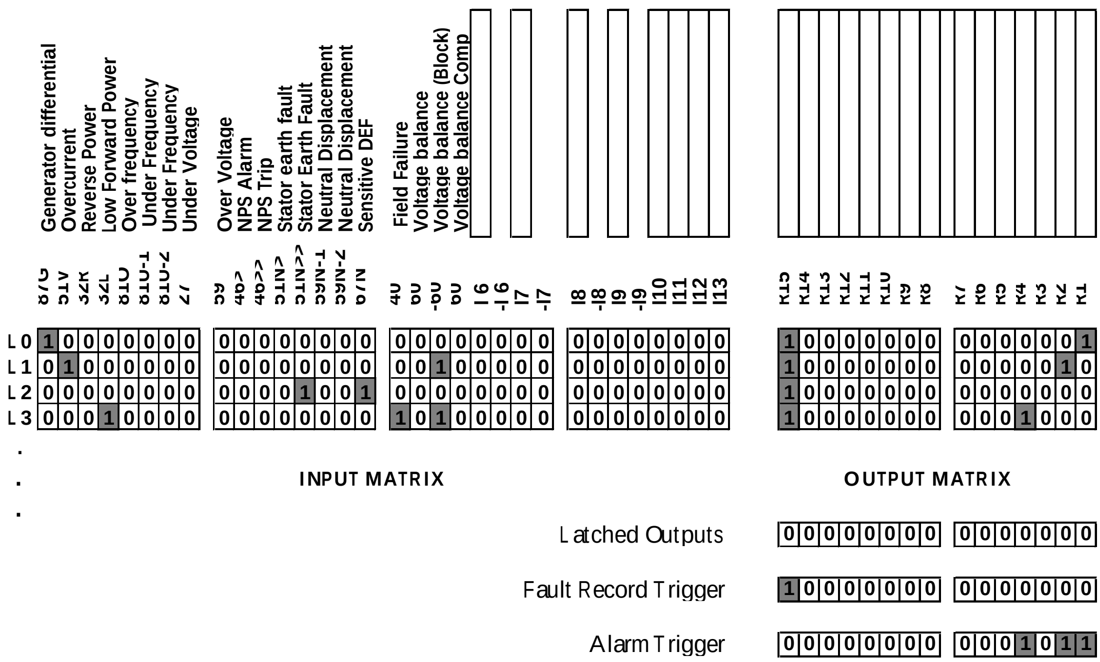


Figure 2 illustrates the various types of logical arrangements which the LGPG111's scheme logic is capable of providing.

Figure 2 Illustration of plain tripping logic (L0), blocking logic (L1), interlocking logic (L2) and a combination of interlocking and blocking logic (L3) in the scheme logic.

Word L0: Operation of the 87G Differential will operate output relays R15 and R1. This is an independent operation.

Word L1: Operation of the 51V Voltage Dependent Overcurrent will operate output relays R15 and R2 if the -60 Voltage Balance, for fuse failure, does not operate. This is a blocking operation as indicated by the prefixed '-'.
(R15 and R2 operation = op of 51V + NO op of 60)

Word L2: Operations of the 51N>> Stator Earth Fault high set element and the 67N Sensitive Directional Earth fault will operate relay R15. This is an interlocking operation, since both must operate.
(R15 operation = op of 51N>> + op of 67N)

Word L3: Operation of the 40 Field Failure and the 32L Low Forward Power at the same time will operate output relays R15 and R4, but only if the -60 Voltage Balance has not operated. This is a combined interlocking and blocking operation.
(R15 and R4 operation = op of 40 + op of 32L + NO op of 60)

Interlocking logic exists when there is more than one '1' flag in a particular input AND matrix word of the scheme logic. However, 1's associated with negated inputs are used for blocking. Negated inputs have names beginning with a minus, '–'. Figure 3 illustrates the scheme logic of Figure 2 in a more classical form of relay ladder logic.

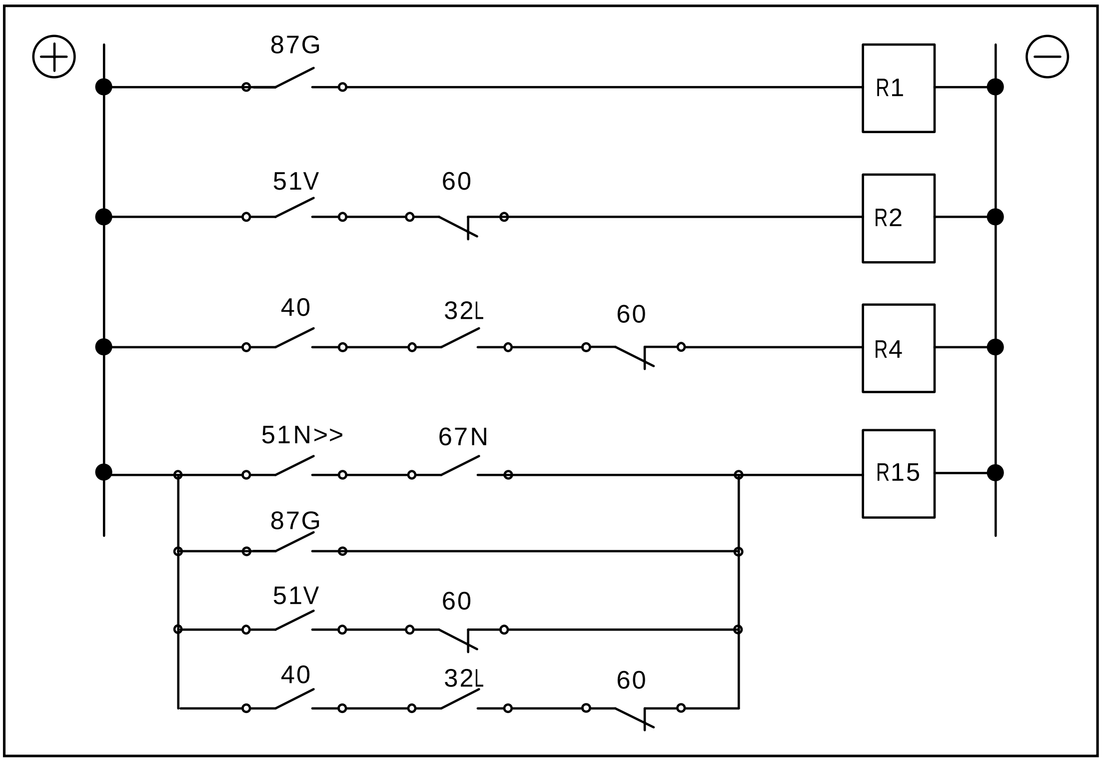


Figure 3 The scheme logic of Figure 2 presented as relay ladder logic.

Testing the scheme logic of Figure 2, with the scheme test facility in the Test Functions Section, proceeds as follows.

For logic word L0:

Logic word L0 has only one '1' bit in its input AND word and hence is an independent operation. In the example of Figure 2, the '1' is in the 87G Generator Differential position, so by setting up a scenario for 87G operation, outputs R15 and R1 should operate.

For logic word L1:

Logic word L1 has more than one '1' bit set in its AND word and hence some form of interlocking or blocking logic is being formed. Closer examination reveals that the negated 60 Voltage Balance is selected which implies blocking logic with the selected 51V Voltage Dependent Overcurrent. Thus outputs R15 and R2 should operate when only the 51V operates. By adding the -60 operation to the scheme test scenario the 51V should be blocked and the outputs R15 and R2 drop off.

For logic word L2:

Logic word L2 represents interlocking logic between the 51N>> and the 67N. Thus an input scenario with both operated should cause output R15 to operate. Removing either one should cause R15 to drop off.

For logic word L3:

This represents the 40 Field Failure interlocked with the 32L Low Forward Power. However, the loss of a protection VT fuse is catered for with a blocking action from the -60 Voltage Balance. Thus, outputs R15 and R4 can operate when the 32L and 40 operate. Adding the -60 to the scheme input scenario should cause the outputs to drop off. Alternatively, by removing either of the 40 or 32L protection functions should cause the outputs to drop off as well.

10.2. Procedure for testing the scheme logic

Record the scheme logic Input and Output Matrix settings in the test results in Error! AutoText entry not defined.. from the setting schedule provided. Check the settings applied on the relay against the setting recorded.

Check the 'Scheme Setting' is 'OK' in Test Functions Section; fix any logic lines which are reported as being in error.

Based on the Input Matrix settings recorded, design the various test patterns or scenarios for the scheme test and record them in Error! AutoText entry not defined.. Based on the input scenarios and the scheme Output Matrix settings, record the expected scheme output for each test.

For each test pattern, enter the input scenario into the '`Set Events for Scheme Test`' cell and then press the SET key. Press the ↓ key to display '`Scheme O/P`'. Record the '`Scheme O/P`' bit pattern observed on the relay and check it against the expected output pattern.

For example, using the settings given in Section 10.1 Figure 2, if the following bit pattern was entered into the "`Set Events for Scheme Test`" cell

0001000000000000 1010000000000000

text was given, but was not understood

Then the "`Scheme O/P`" cell should display

(1) Scheme O/P 100000000001000

As operation of "`32lLow Forward Power`" AND "`40 Field Failure`" AND "`–60 Voltage Balance (Block`)" will cause the operation of output contacts R4 and R15. This test will not cause operation of the output contacts as it is designed to prove the scheme logic without the need to secondary inject and operate contacts.

When two setting groups are used, both groups' scheme logic will need to be tested. The Test Functions Section provides two sets of scheme test cells, one for each group.

11. WIRING CHECKS

For many of the functions of the relay the polarity and phase rotation of the current and voltage inputs is critical for their correct operation. It is essential that tests are carried out to ensure that the primary CT's and VT's are of the correct polarity, and that the polarity and phase rotation is correct throughout the wiring from the CT's and VT's to the connections on the rear of the relay.

As each installation, and the type of test equipment available, is different from site to site it is difficult to provide any meaningful instructions. However, it is strongly recommended that primary injections are carried out. If a test set capable of providing three phase volts and current is available that secondary injections are carried from a point close to the CT and VT connections.

Particular care must be exercised when proving the polarity of the I_e and/or V_e polarizing CT and VT circuits, as under normal operating conditions it is not possible to detect whether the polarizing input is of the correct polarity. If the polarizing input is incorrectly connected the system may mal-trip or not trip for internal or external faults.

12. STABILITY CHECKS FOR 87G GENERATOR DIFFERENTIAL

Carry out these tests as required.

It is recommended that CT and VT tests are carried out before these tests.

Ensure that the primary circuit is dead and isolated. Connect a temporary short to the primary circuit as shown in Figure 4.

Disable the '`Scheme Output`' cell in the Auxiliary Functions Section to prevent the relay tripping.

Run the generator up to normal speed with no excitation. Slowly increase the excitation until the primary current is approximately full load.

Record all the current measurements on the relay and check that they are correct. Check that the differential currents Ia-Diff, Ib-Diff and Ic-Diff measured by the relay are less than 10% of the mean-bias current measured by the relay.

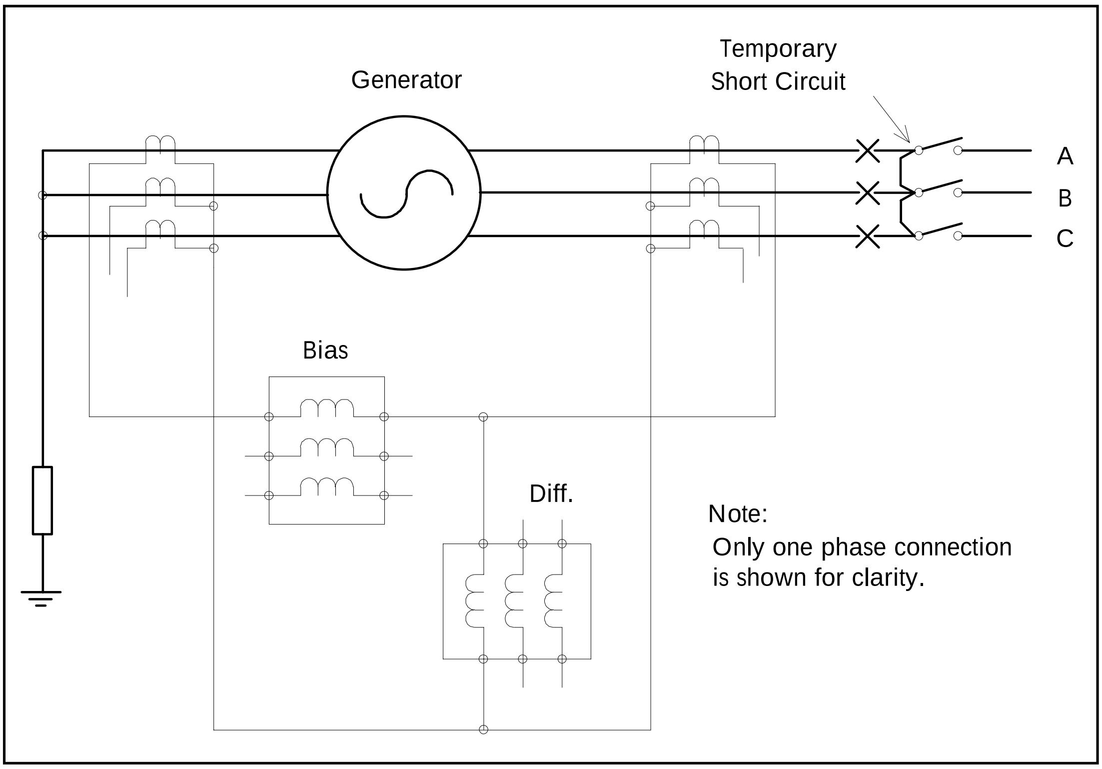


Figure 4 Arrangement for checking the stability of the 87G Generator Differential.

12.1. Stability of sensitive directional earth fault

There is no practical site procedure for checking the stability of Sensitive Directional Earth Fault element. The polarity of CT's and VT's must be independently vindicated.

13. ON LOAD CHECKS

Carry out these checks, for which the generator should be on at least 10% full load, as required.

Check the VT phase sequence by using a phase sequence indicator and measure the VT voltage on the relay panel terminal block. Record the results.

Record the measurements on the relay in the Measurements-1 and Measurements-2 Sections and check they are correct.

Check that Ia-Diff, Ib-Diff and Ic-Diff measured on the relay are less than 10% of the mean-bias current measured by the relay. Check that I2, the negative phase sequence current measured by the relay, is not greater than expected for the particular installation.

Check that the active power and reactive power measured by the relay are correct.

13.1. Phase angle compensation for the power measurement

The LGPG111 provides a setting for phase angle compensation in the Power Protection Section. The default setting for the Compensation Angle is 0°. Altering this compensation angle setting is not recommended, unless an accurate phase angle meter is available.

With an accurate measurement of the generator's phase angle, note the difference between it and the relay's phase angle measurement, as displayed in the Measurements-1 Section. Enter this value into the compensation setting and check that the relay's phase angle measurement corresponds with the metering.

14. FINAL SETTING CHECKS

Check the date and time on the relay is correct in the Auxiliary Functions Section. If it is not, set the correct date and time.

Check each protection function is Enabled or Disabled as specified in the setting schedule provided for service.

Check the settings applied to the relay are correct against the setting schedule provided for service.

Check the ‘`Scheme Setting`’ cell in the Test Functions Section is ‘OK’.

Record the settings applied to the relay in the commissioning test results (Error! AutoText entry not defined.). The LGPG111’s printer facility is useful for this, subject to a parallel printer being available.

Replace the relay’s cover.

Chapter 9 - Commissioning Test Results

Issue control

engineering document number: 50005.1701.111

Issue	Date	Author	Changes
AP	June 1995	Dave Banham	Original. (Was included in the commissioning instructions, 50005.1701.108.)
A	July 1995	Dave Banham/ Publicity	Styles
B	June 1997	Andy Forshaw/ Publicity	Change of style. Addition of new form.

Contents

COMMISSIONING TEST RECORD FOR THE LGPG

TESTED AS ONE UNIT

Date --
Tested by:- --
Company --
Site --

Generator / Circuit --

Model number ------------------------ Serial number --

Vx(1) ------------------------ Vx(2) --

In ------------------------

Commissioning Preliminaries:

Relay model number, rating and module reference correct?	YES / NO
CT shorting switches in case checked?	YES / NO
Earth connection to case checked?	YES / NO
Insulation checked?	YES / NO
External wiring checked to drawing?	YES / NO

Auxiliary Power Supply Test:

Polarity of Vx(1) and Vx(2) checked?	YES / NO
Measured Vx(1) = ________ V, Vx(2) = __________ V, Correct?	YES / NO
Relay power supply failure alarm checked?	YES / NO
LED's tested?	YES / NO

Secondary Injection Tests:

Service settings applied?	YES / NO
Model and serial number correct in menu?	YES / NO
System frequency correct in menu?	YES / NO
CT and VT ratios correctly entered?	YES / NO
Primary / secondary display value selected correctly?	YES / NO
Alternative setting group enabled?	YES / NO
Secondary injection tests applied to group 1 or 2?	1 / 2

Current based protection

Measurement checks

Input	Injected current	Measured value
$I_{residual}$		
$I_{a\text{-}sensiitive}$		
I_e		
$I_{a\text{-}diff}$		
$I_{b\text{-}diff}$		
$I_{c\text{-}diff}$		
$I_{a\text{-}bias}$		
$I_{b\text{-}bias}$		
$I_{c\text{-}bias}$		
I_a		
I_b		
I_c		

Check of pick-up value

I> setting --

Expected pick-up	Measured pick-up	Expected drop-off	Measured drop-off

Measurement of time delay characteristics

	Expected time	Measured time
DT		
SI 2x I>		
SI 10x I>		

Fault record checks

Fault records match injected faults ☐

Thermal curve characteristic

Injected current	
Expected trip time	
Measured trip time	
Expected I2 current	
Measured I2 current	

Voltage based protection

Measurements

Input	Expected voltage	Measured voltage
V_e		
V_{ab}		
V_{bc}		
$V_{ab\text{-}comp}$		
$V_{bc\text{-}comp}$		

Check of pick-up value

I> setting --

Expected pick-up	Measured pick-up	Expected drop-off	Measured drop-off

Measurement of time delay characteristic

Expected time	Measured time

Measurement of frequency

Expected	Measured

Fault record checks

Fault records match injected faults	

Power based protection

Measurement of phase angle

Expected phase angle	
Measured phase angle	
Expected power reading	
Measured power reading	

Measurement of RCA

Expected Pick-up Values	
Measured Pick-up Value (lead)	
Measured Pick-up Value (lag)	
Measured Drop-off Value (lead)	
Measured Drop-off Value (lag)	

Input Status Checks

Relay Terminal Energized	Input Status Displayed	Results as expected

Relay output tests

Contact Name Or Number	Relay Test Pattern Entered	Results As Expected

Relay inoperative alarm

Alarm tested

Scheme logic tests

Scheme logic setting group tested

Bit pattern entered in "Set Events for Scheme Test" cell	Results displayed in "Scheme O/P" cell

INPUT MATRIX

	87G Generator differential	51V Overcurrent	32R Reverse Power	32L Low Forward Power	81O Over frequency	81U-1 Under Frequency	81U-2 Under Frequency	27 Under Voltage	59 Over Voltage	46> NPS Alarm	46>> NPS Trip	51N> Stator earth fault	51N>> Stator Earth Fault	59N-1 Neutral Displacement	59N-2 Neutral Displacement	67N Sensitive DEF	40 Field Failure	60 Voltage balance	-60 Voltage balance (Block)	60 Voltage balance Comp	I 6	-I 6	I7	-I7	I8	-I8	I9	-I9	I10	I11	I12	I13
L 0																																
L 1																																
L 2																																
L 3																																
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L 31																																

OUTPUT MATRIX

	R15	R14	R13	R12	R11	R10	R9	R8	R7	R6	R5	R4	R3	R2	R1
L 0															
L 1															
L 2															
L 3															
L 4															
L 5															
L 6															
L 7															
L 8															
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L 29															
L 30															
L 31															
Latch outputs															
Fault record trigger															
Alarm trigger															

-- --

Commissoning Engineer Customer Witness

-- --

Date Date

Commissioning Test Record For The LGPG111

TESTED AS DISCRETE RELAYS

Date	________________
Tested by:-	________________
Company	________________
Site	________________
Generator / Circuit	________________

Model number	________	Serial number	________
Vx(1)	________	Vx(2)	________
In	________		

Commissioning Preliminaries:

Relay model number, rating and module reference correct?	YES / NO
CT shorting switches in case checked?	YES / NO
Earth connection to case checked?	YES / NO
Insulation checked?	YES / NO
External wiring checked to drawing?	YES / NO

Auxiliary Power Supply Test:

Polarity of Vx(1) and Vx(2) checked?	YES / NO
Measured Vx(1) = ________ V, Vx(2) = __________ V, Correct?	YES / NO
Relay power supply failure alarm checked?	YES / NO
LED's tested?	YES / NO

Secondary Injection Tests:

Service settings applied?	YES / NO
Model and serial number correct in menu?	YES / NO
System frequency correct in menu?	YES / NO
CT and VT ratios correctly entered?	YES / NO
Primary / secondary display value selected correctly?	YES / NO
Alternative setting group enabled?	YES / NO

Secondary injection tests applied to group 1 or 2?	1 / 2

87G Generator Differential Tests

Sensitivity and Operating Time:

Element	Expected Operating Current	Measured Operating Current	Operating Time
$I_{a\text{-}diff}$			
$I_{b\text{-}diff}$			
$I_{c\text{-}diff}$			

Correct Operation Of Output relays

Measurements:

Injected Current	$I_{a\text{-}diff}$	$I_{b\text{-}diff}$	$I_{c\text{-}diff}$	$I_{a\text{-}bias}$	$I_{b\text{-}bias}$	$I_{c\text{-}bias}$

Bias Characteristic:

Is1 = _________ K1 = _________ Is2 = _________ K2 = _________

Lower Slope:-

Phase	Injected Bias Current	Expected Trip Current	Measured Trip Current
A			
B			
C			

Upper Slope:-

Phase	Injected Bias Current	Expected Trip Current	Measured Trip Current
A			
B			
C			

Fault Record Checks:

Fault records match injected faults

Notes:

32R Reverse Power

Measurements:

Injected Values				Measured Values			
$I_{a\text{-sensitive}}$	V_{ab}	Phase Angle	Power (Watts)	$I_{a\text{-sensitive}}$	V_{an}	Phase Angle	Power (Watts)

Characteristic Checks:

-P = _________ t = _________ tDO = _________

Expected Pick-up Power	
Measured Pick-up Power	
Measured Drop-off Power	
Measured Operating Time	

Operation of Output Relays:

Correct Operation Of Output relays	

32L Low Forward Power

Measurements:

Injected Values				Measured Values			
$I_{a\text{-}sensitive}$	V_{ab}	Phase Angle	Power (Watts)	$I_{a\text{-}sensitive}$	V_{an}	Phase Angle	Power (Watts)

Characteristic Checks:

P = __________ t = __________ tDO = __________

Expected Pick-up Power	
Measured Pick-up Power	
Measured Drop-off Power	
Measured Operating Time	

Operation of Output Relays:

Correct Operation Of Output relays	

Notes:

40 Field Failure:

Measurements:

Injected Values			**Measured Values**		
Current	**Voltage**	**Phase Angle**	I_a	V_{an}	**Phase Angle**

Characteristic and Operating Time:

-Xa = ________ **Xb =** ________ **t =** ________ **tDO =** ________

Measurement of Xa + Xb

Expected Pick-up Value (ohms)	Injected Current	Injected Voltage	Measured Pick-up Value (ohms)

Measurement of Xa

Expected Pick-up Value (ohms)	Injected Current	Injected Voltage	Measured Pick-up Value (ohms)

Measurement of Operating Time

Measured Operating Time

Operation of Output Relays:

Correct Operation Of Output relays

Notes:

67N Sensitive Directional Earth fault:

Polarizing = Voltage / Current / Dual

Measurements and Characteristic For V_e:

$I_{residual}$ = __________ RCA = __________ V_{ep}> = __________

Measurement of $I_{residual}$

Expected Pick-up Value	
Measured Pick-up Value	
Measured Drop-off Value	

Measurement of V_{ep}>

Expected Pick-up Value	
Measured Pick-up Value	
Measured Drop-off Value	

Measurement of RCA

Expected Pick-up Values	
Measured Pick-up Value (lead)	
Measured Pick-up Value (lag)	
Measured Drop-off Value (lead)	
Measured Drop-off Value (lag)	

Measurements and Characteristic For I_e:

$I_{residual}$ = __________ RCA = __________ V_{ep}> = __________

Measurement of $I_{residual}$

Expected Pick-up Value	
Measured Pick-up Value	
Measured Drop-off Value	

Measurement of V_{ep}>

Expected Pick-up Value	

Expected Pick-up Value	
Measured Pick-up Value	
Measured Drop-off Value	

Measurement of RCA

Expected Pick-up Value	
Measured Pick-up Value (lead)	
Measured Pick-up Value (lag)	
Measured Drop-off Value (lead)	
Measured Drop-off Value (lag)	

Operation of Output Relays:

Correct Operation Of Output relays	

Notes:

51N Stator Earth Fault

Measurement Checks:

Injected Current	
Measured Current	

Characteristic and Operating Time for 51N>:

Ie> = __________ t> = __________ treset = __________ SI / DT = __________

Measurement of Ie>:

Expected Pick-up Value	
Measured Pick-up Value	
Measured Drop-off Value	

Measurement of Time Delay Characteristic:

Expected Time Delay	
Measured Time Delay	

Operation Of Output Relays for 51N>:

Correct Operation Of Output relays	

Characteristic And Operating Time For 51N>>:

Ie>> = __________ t>> = __________

Measurement of Ie>>:

Expected Pick-up Value	
Measured Pick-up Value	
Measured Drop-off Value	

Measurement of Time Delay Characteristic:

Expected Time Delay	
Measured Time Delay	

Operation Of Output Relays For 51N>>:

Correct Operation Of Output relays	

Notes:

59N Neutral Displacement

Measurement Checks:

Injected Voltage	
Measured Voltage	

Characteristic And Operating Time for 59N-1:

Ve> = __________ t1 = __________

Measurement of Ve>

Expected Pick-up Value	
Measured Pick-up Value	
Measured Drop-off Value	

Measurement of Time Delay Characteristic

Expected Operating Time	
Measured Operating Time	

Operation Of Output Relays For 59N-1:

Correct Operation Of Output relays	

Operating Time For 59N-2:

t2 = __________ t2 reset __________

Expected Operating Time	
Measured Operating Time	

Operation Of Output Relays For 59N-2:

Correct Operation Of Output relays

Notes:

51V Voltage Dependent Overcurrent

Measurement Checks:

Injected Voltage	Measured Vab	Measured Vbc

Injected Current	Measured Ia	Measured Ib	Measured Ic

Characteristic and Operating Time for Restraint Function (if applicable)

Rotation ________ Vs1 = ________ Vs2 = ________ K = ________

I> = ________ t/TMS = ________ treset = ________ SI or DT ________

Measurement of I> (point 1)

Phase	Injected Voltage	Expected Pick-up	Measured Pick-up	Measured Drop-off
A				
B				
C				

Measurement of K.I> (point 2)

Phase	Injected Voltage	Expected Pick-up	Measured Pick-up	Measured Drop-off
A				
B				
C				

Measurement at 50% of curve (point 3)

Phase	Injected Voltage	Expected Pick-up	Measured Pick-up	Measured Drop-off
A				
B				
C				

Measurement of Operating Time Characteristic

Expected Operating Time	
Measured Operating Time	

Characteristic and Operating Time for Controlled Function (if applicable)

Rotation ________ Vs1 = ________ Vs2 = ________ K = ________

I> = ________ t/TMS = ________ treset = ________ SI or DT ________

Measurement of I>

Phase	Injected Voltage	Expected Pick-up	Measured Pick-up	Measured Drop-off
A				
B				
C				

Measurement of K.I>

Phase	Injected Voltage	Expected Pick-up	Measured Pick-up	Measured Drop-off
A				
B				
C				

Measurement of Operating Time Characteristic

Expected Operating Time	
Measured Operating Time	

Characteristic and Operating Time for Simple Function (if applicable)

I> = ________ t/TMS = ________ treset = ________ SI or DT ________

Measurement of I>

Phase	Expected Pick-up	Measured Pick-up	Measured Drop-off
A			
B			
C			

Measurement of Operating Time Characteristic

Expected Operating Time	
Measured Operating Time	

Fault Record Checks:

Fault records match injected faults	

Operation Of Output Relays:

Correct Operation Of Output relays	

Notes:

46 Negative Phase Sequence

Measurements:

Phases	Injected Current	Measured Current
Ia-Ib		
Ib-Ic		

Characteristic And Operating Time For 46> NPS Alarm:

I2> = _________ t> = _________

Measurement of I2>

Phase	Expected Pick-up Current	Measured Pick-up Current
Ia		
Ib		
Ic		

Measurement of Operating Time

Phase	Expected Operating Time	Measured Operating Time
Ia		
Ib		
Ic		

Operation Of Output Relays For 46> NPS Alarm:

Correct Operation Of Output relays [ ]

Characteristic And Operating Time For 46>> NPS Thermal Trip:

I2>> = _________ K = _________ tMAX = _________ tMIN = _________

Kreset _________

Measurement of I2>>

Phase	Expected Pick-up Current	Measured Pick-up Current
Ia		
Ib		
Ic		

Measurement of Operating Time Characteristic

Injected Current	Expected Operating Time	Measured Operating Time

Measurement of t_{MIN} Operating Time

Injected Current	Expected Operating Time	Measured Operating Time

Measurement of t_{MAX} Operating Time

Injected Current	Expected Operating Time	Measured Operating Time

46>> NPS Thermal Trip Reset Time:

Injected Current	Time Allowed for Cooling (seconds)	Expected Time for Second Operation	Measured Time for Second Operation

Operation Of Output Relays for 46>> NPS Thermal Trip

Correct Operation Of Output relays [ ]

Notes:

81U-1 Under Frequency

Tests carried out with:- Variable Frequency / Fixed Frequency Supply

Measurements

Injected Frequency	Measured Frequency

Measurement of F1<

F1< = __________ t1 = __________

Expected Pick-up Frequency	Measured Pick-up Frequency	Measured Drop-off Frequency

Measurement of Operating Time

Expected Operating Time	Measured Operating Time

Operation Of Output Relays:

Correct Operation Of Output relays [ ]

81U-2 Under Frequency

Tests carried out with:- Variable Frequency / Fixed Frequency Supply

Measurements

Injected Frequency	Measured Frequency

Measurement of F2<

F2< = _________ t2 = _________

Expected Pick-up Frequency	Measured Pick-up Frequency	Measured Drop-off Frequency

Measurement of Operating Time

Expected Operating Time	Measured Operating Time

Operation Of Output Relays:

Correct Operation Of Output relays [ ]

81O Over Frequency

Tests carried out with:- Variable Frequency / Fixed Frequency Supply

Measurements

Injected Frequency	Measured Frequency

Measurement of F>

F> = _________ t = _________

Expected Pick-up Frequency	Measured Pick-up Frequency	Measured Drop-off Frequency

Measurement of Operating Time

Expected Operating Time	Measured Operating Time

Operation Of Output Relays:

Correct Operation Of Output relays

Notes:

27 Under Voltage

Measurements

Injected Voltage	Measured Voltage Vab	Measured Voltage Vbc

Characteristic and Operating Time

V< = __________ t = __________

Measurement of V<

Input	Expected Pick-up Voltage	Measured Pick-up Voltage	Measured Drop-off Voltage
Vab			
Vbc			

Measurement of Time Delay Characteristic

Expected Operating Time	Measured Operating Time

Operation Of Output Relays:

Correct Operation Of Output relays [ ]

59 Over Voltage

Measurements

Injected Voltage	Measured Voltage Vab	Measured Voltage Vbc

Characteristic and Operating Time

V> = __________ t> = __________ V>> = __________ t>> = __________

Measurement of V>

Expected Pick-up Voltage	Measured Pick-up Voltage	Measured Drop-off Voltage

Measurement of V>>

Expected Pick-up Voltage	Measured Pick-up Voltage	Measured Drop-off Voltage

Measurement of Operating Time t>

Expected Operating Time	Measured Operating Time

Measurement of t>>

Expected Operating Time	Measured Operating Time

Operation Of Output Relays:

Correct Operation Of Output relays

Notes:

60 Voltage Balance

Vs = _________

Measurement Checks

Input	Injected Voltage	Measured Voltage
Vab Prot		
Vbc Prot		
Vab Comp		
Vbc Comp		

Characteristic Checks for 60 VB-Prot

Input	Expected Pick-up Voltage	Measured Pick-up Voltage	Measured Drop-off Voltage
Vab			
Vbc			

Characteristic Checks for 60 VB-Comp

Input	Expected Pick-up Voltage	Measured Pick-up Voltage	Measured Drop-off Voltage
Vab			
Vbc			

Operation of Output Relays

Correct Operation Of Output relays | |

Notes:

Input Status Checks

Relay Terminal Energized	Input Status Displayed	Results as expected

Relay output tests

Contact Name Or Number	Relay Test Pattern Entered	Results As Expected

Relay inoperative alarm

Alarm tested

Scheme logic tests

Scheme logic setting group tested

Bit pattern entered in “Set Events for Scheme Test” cell	Results displayed in “Scheme O/P” cell

INPUT MATRIX

	87G Generator differential	51V Overcurrent	32R Reverse Power	32L Low Forward Power	81O Over frequency	81U-1 Under Frequency	81U-2 Under Frequency	27 Under Voltage	59 Over Voltage	46> NPS Alarm	46>> NPS Trip	51N> Stator earth fault	51N>> Stator Earth Fault	59N-1 Neutral Displacement	59N-2 Neutral Displacement	67N Sensitive DEF	40 Field Failure	60 Voltage balance	-60 Voltage balance (Block)	60 Voltage balance Comp	I 6	-I 6	I7	-I7	I8	-I8	I9	-I9	I10	I11	I12	I13
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OUTPUT MATRIX

	R15	R14	R13	R12	R11	R10	R9	R8	R7	R6	R5	R4	R3	R2	R1
L 0															
L 1															
L 2															
L 3															
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L 31															
Latch outputs															
Fault record trigger															
Alarm trigger															

Stability Checks For 87G Generator Differential

Measurements:

Primary Values

Ia =		Ib =		Ic =	

Current Measurements

Ia		Ib		Ic	
Ie		$I_{residual}$		I2	
$I_{a\text{-}diff}$		$I_{b\text{-}diff}$		$I_{c\text{-}diff}$	
$I_{a\text{-}bias}$		$I_{b\text{-}bias}$		$I_{c\text{-}bias}$	
$I_{a\text{-}mean\ bias}$		$I_{b\text{-}mean\ bias}$		$I_{c\text{-}mean\ bias}$	
$I_{a\text{-}sensitive}$					

Measured Current as Expected	
Measured Diff Currents Less than 10% of Mean-Bias Currents	

On Load Checks

VT Phase Sequence Check:

VT Phase Sequence Correct	

Measurements:

Primary Values

Va =		Vb =		Vc =	
Ia =		Ib =		Ic =	

Relay Measurements

Ia		Ib		Ic	
Ie		$I_{residual}$		I2	
$I_{a\text{-}diff}$		$I_{b\text{-}diff}$		$I_{c\text{-}diff}$	
$I_{a\text{-}bias}$		$I_{b\text{-}bias}$		$I_{c\text{-}bias}$	
$I_{a\text{-}mean\ bias}$		$I_{b\text{-}mean\ bias}$		$I_{c\text{-}mean\ bias}$	

____

$I_{a\text{-}sensitive}$ ______________

Vab	______________	Vbc	______________	Vca	______________
Ve	______________	$V_{ab\text{-}comp}$	______________	$V_{bc\text{-}comp}$	______________
Frequency	______________				______________

Active Power Aph	
Reactive Power Aph	
Phase Angle Aph	

Measured Current and Voltage as Expected	
Measured Diff Currents Less than 10% of Mean-Bias Currents	
Measured I2 as Expected	
Active and Reactive Power Measurements Correct	

Final Setting Checks

Date and Time on Relay Correct	
Settings Applied to Relay	
Scheme Setting OK	

System Parameters

Diff CT Ratio	______________	Sensitive Ia Ratio	______________
Residual CT Ratio	______________	Comp VT Ratio	______________
Earth VT Ratio	______________	Earth CT Ratio	______________
Phase CT Ratio	______________	Line Vt Ratio	______________

Final Settings Applied To The Relay:

System Data

Password	______________	Plant Reference	______________
System Frequency	______________		

Auxiliary Functions

Scheme Output	____________	Display Value	____________
Second Setting Group	____________	Select Setting Group	____________
Active Setting Group	____________	Stator E/F Timer Inhibit	____________
Inactivity Timer	____________	Remote Setting	____________
Clock Synchronized	____________	Default Display	____________

	Group 1 Settings	Group 2 Settings

Generator Differential:

87G Generator Diff	Enabled / Disabled	Enabled / Disabled
Is1		
K1		
Is2		
K2		

Earth Fault Protection:

51N Stator Earth Fault	Enabled / Disabled	Enabled / Disabled
51N> Low set Charact	SI / DT	SI / DT
Ie>		
t>		
tRESET		

51N>> High set	Enabled / Disabled	Enabled / Disabled
Ie>>		
t>>		

59N Neutral Disp	Enabled / Disabled	Enabled / Disabled
Ve>		
t1		
t2		
t2RESET		

67N Sensitive DEF	Enabled / Disabled	Enabled / Disabled
Iresidual>		
RCA		
Vep>		
Iep>		

Voltage Dependent Overcurrent:

51V Overcurrent Function	Enabled / Disabled	Enabled / Disabled
Vs1		
Vs2		
Vs		

K		
Characteristic	SI / DT	SI / DT
I>		
t>		
tRESET		

Power Protection:

Compensation Angle		
32R Reverse Power	Enabled / Disabled	Enabled / Disabled
-P<		
t		
tDO		
32L Low Forward	Enabled / Disabled	Enabled / Disabled
P<		
t		
tDO		

Frequency Protection:

81U-1 Under Freq	Enabled / Disabled	Enabled / Disabled
F1<		
t1		
81U-2 Under Freq	Enabled / Disabled	Enabled / Disabled
F2<		
t2		
81O Over Freq	Enabled / Disabled	Enabled / Disabled
F>		
t		

Voltage Protection:

27 Under Voltage	Enabled / Disabled	Enabled / Disabled
V<		
t		

59 Over Voltage	Enabled / Disabled	Enabled / Disabled
V>		
t>		
V>>		
t>>		

60 Voltage Balance	Enabled / Disabled	Enabled / Disabled
Vs>		

Negative Phase Sequence:

46 Neg Phase Seq	Enabled / Disabled	Enabled / Disabled
46>> Thermal trip		
I2>>		
K		
tMAX		
tMIN		
Kreset		
46> NPS Alarm		
I2>		
t>		

Field Failure:

40 Field Failure	Enabled / Disabled	Enabled / Disabled
-Xa		
Xb		
t		
tDO		

Scheme Logic:
In the following tables, fill-in the squares to represent 1's to record the Scheme Logic settings in the LGPG111.

Group 1 Settings:

INPUT MATRIX

	87G Generator differential	51V Overcurrent	32R Reverse Power	32L Low Forward Power	81O Over frequency	81U-1 Under Frequency	81U-2 Under Frequency	27 Under Voltage	59 Over Voltage	46> NPS Alarm	46>> NPS Trip	51N> Stator earth fault	51N>> Stator Earth Fault	59N-1 Neutral Displacement	59N-2 Neutral Displacement	67N Sensitive DEF	40 Field Failure	60 Voltage balance	-60 Voltage balance (Block)	60 Voltage balance Comp	I 6	-I 6	I7	-I7	I8	-I8	I9	-I9	I10	I11	I12	I13
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OUTPUT MATRIX

	R15	R14	R13	R12	R11	R10	R9	R8	R7	R6	R5	R4	R3	R2	R1
L 0															
L 1															
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	R15	R14	R13	R12	R11	R10	R9	R8	R7	R6	R5	R4	R3	R2	R1
Latch outputs															
Fault record trigger															
Alarm trigger															

Group 2 Settings:

INPUT MATRIX

	87G Generator differential	51V Overcurrent	32R Reverse Power	32L Low Forward Power	81O Over frequency	81U-1 Under Frequency	81U-2 Under Frequency	27 Under Voltage	59 Over Voltage	46> NPS Alarm	46>> NPS Trip	51N> Stator earth fault	51N>> Stator Earth Fault	59N-1 Neutral Displacement	59N-2 Neutral Displacement	67N Sensitive DEF	40 Field Failure	60 Voltage balance	-60 Voltage balance (Block)	60 Voltage balance Comp	I 6	-I 6	I7	-I7	I8	-I8	I9	-I9	I10	I11	I12	I13
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OUTPUT MATRIX

	R15	R14	R13	R12	R11	R10	R9	R8	R7	R6	R5	R4	R3	R2	R1
L 0															
L 1															
L 2															
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	R15	R14	R13	R12	R11	R10	R9	R8	R7	R6	R5	R4	R3	R2	R1
Latch outputs															
Fault record trigger															
Alarm trigger															

Signatures

Commissioning Engineer	Customer Witness
Date	Date