A power based digital algorithm for the protection of embedded generators

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A POWER BASED DIGITAL ALGORITHM
FOR THE PROTECTION OF EMBEDDED GENERATORS

Submitted by Ö. USTA, BSc, MSc,

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of the University of BATH

1992

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SYNOPSIS

This thesis describes a power based digital protection algorithm to protect an embedded generation unit against loss of grid, which is the condition where a part of the utility network left connected to the embedded generation unit but disconnected from the utility grid supply. The algorithm monitors the power fluctuations at the embedded generators’ terminals to detect the loss of grid. When it detects this condition it initiates a trip signal for the inter-tie circuit breaker to disconnect the utility part of the island from the local generation unit.

The comparative performances of present loss of grid algorithms and the new algorithms are evaluated using computer simulation software. This software was developed to analyze a power system containing an embedded generation unit operating in parallel with and/or independently from the utility supply. The analysis includes Loss of Grid simulation studies, Load Switching Operation studies in both parallel and independent operation modes, and Out of Phase Reconnection of the two systems. The analysis also covers the performances of the new loss of grid protection algorithm under power system faulted conditions.

In the final stage, the new algorithm has been written in assembler to be implemented in a real-time system. After implementation of the algorithm into a general purpose microcomputer based relay which is available in the power system teaching laboratory at the university of Bath, the real-time performances of the new algorithm was examined.
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LIST OF SYMBOLS

a,b,c: Subscripts for Direct Phase Quantities.
d,q,o: Subscripts for d-,q-,o-axis Quantities.
F,D,Q: Subscripts for Generator's Field and Damper Winding.
g: Subscript for generator's parameters.
v,i: Instantaneous Voltage and Current.
V,I: Effective (Root Mean Square) Voltage and Current.
F: System Frequency.
p(t): Instantaneous Power.
P: Active (Average) Power.
Q: Reactive Power.
S: Apparent Power.
PF: Power Factor.
H: System Inertia Constant.
d/dt: Derivative Operation.
Φ: Flux Linkages.
L: Self Inductance.
M: Mutual Inductance.
r: Resistance.
ω: Angular Speed.
ω_s: Synchronous Speed.
ω_r: Rotor Speed.
δ: Generator Torque (Load) Angle.
T_m: Generator Mechanical Time Constant.
T: Torque.
\( T_m \): Mechanical Torque.
\( T_e \): Electrical Torque.
\( T_d \): Damping Torque.
\( D \): Damping Factor.
\( k \): \( \sqrt{3}/2 \)
\( [x] \): State Variables vector.
\( [u] \): Input Vector.
\( Y \): Phasor Admittance.
\( Z \): Phasor Impedance.
\( DP \): Change in Power.
\( a \): Acceleration of the Generator due to DP.
\( T_w \): The length of the Moving Window.
\( t_s \): Sampling Interval.
\( N \): The Number of the Samples in \( T_w \).
\( \pm C \): Upper and Lower Limits of Rate of Change of Power.
\( k_s \): Trip Setting.
\( R_s \): Integrator Output (Relaying signal).
ABBREVIATIONS

A/D: Analog to Digital Convertor.
ADC: Analog to Digital Conversion.
AVR: Automatic Voltage Regulator.
CPU: Central Process Unit.
DAS: Data Acquisition System.
EGU: Embedded Generation Unit.
EMTP: Electromagnetic Transient Program.
GW2: Generator Mains Monitor.
INOM: Independent Operation Mode.
I&AS: Isolation and Analog Scaling System.
I/O: Input/Output.
IO: Integrator Output.
LLF: Line to Line Fault.
LLG: Line to Line to Ground Fault.
LOM: Loss of the Main Power Supply.
LOG: Loss of Grid.
MLX: Multiplexer.
MPR: Microprocessor Relay.
NUG: Non-Utility Generation.
PGA: Programmable Gain Amplifier.
POM: Parallel Operation Mode.
PURPA: Public Utilities Regularity Policies.
REC: Reconnection with the Utility.
REED: Reactive Export Error Detector.
ROCOF: Rate of Change of Frequency.

ROCOP: Rate of Change of Power.

SCADA: Supervisory Control and Data Acquisition System.

S/H: Sample and Hold Circuit.

SS&H: Simultaneous Sample and Hold Circuit.

SP: Generator’s Speed Governor.

SLG: Single Line to Ground Fault.

SLOC: Single Line Open Circuit Fault.

3LG: Three Phase Line to Ground Fault.
CHAPTER 1

INTRODUCTION

1.1 THE BACKGROUND OF THE EMBEDDED GENERATION

Over the last decade, there has been a growing interest in the installation of small and medium size generation units which operate in parallel with the utility power supply. These units, defined as "Embedded Generation, Private Generation" or in the USA as "Dispersed Storage and Generation (DSG)" units, can be powered by waste energy or renewable energy sources such as water, wind, solar power, and biomass heat. Since the initial interest was dominated by the non-utility sector, these generation units are also known as Non Utility Generation (NUGs) or Customer Owned Generation Units (Co-Generation)[2,3]. More recently, utilities have also been investing in this type of generation systems in both USA and Europe. Traditionally, small and medium sized generations has been used to generate power for just local demand and have been prohibited to export power into the utility system. Government initiatives and regulations including the 1978 USA PURPA[2,3] (Public Utilities Regulatory Policies Act) and the 1983 and 1989 UK Electricity Acts[1,4], however have enabled these local systems to operate in parallel with and supply power to the utility networks.
Parallel operation of an embedded generation unit with the utility system creates several difficulties and complications for the reliable and safe network operations of both systems. Therefore, guidelines have been introduced defining their technical requirements which must be met before the utility will allow the embedded generation unit to operate in parallel with their network\[1,2,3,4,5,6\]. These are to ensure that the parallel operation of the two systems will not cause any reduction in the quality of the utility system services being provided to the other customers. These guidelines also define the general protection requirements to properly protect both systems and utility’s customers against all types of faults and abnormal conditions occurring on both systems. On the other hand, the owner of the embedded generation unit has been made responsible to provide the protection and control requirements\[6,7,8,9,...,21\] for his own embedded generation system. These requirements are given in the next chapter. One important requirement and the topic of this thesis is need to protect the embedded system against loss of grid, i.e Islanding, after which the generator is left connected to part of the utility load, but isolated from the utility’s main source of generation.

1.2 ISLANDING OPERATION

Islanding is term used to describe the condition where a
section of utility’s load remains connected to the embedded generation unit following the random opening of a circuit-breaker on the utility side isolating the two sources from each other. Islanding, i.e. the separation of the two systems could be caused by either a fault on the system or by a non-fault tripping. This separation produces an independent power island and depending upon the load and the capabilities of the embedded generator, it will continue to feed the power island as long as its frequency and the voltage are maintained within the required operational limits. The loss of grid protection scheme must immediately detect this random isolation of the two systems and disconnect the utility part of the power island from the embedded generation unit by tripping the inter-tie circuit breaker which connects the embedded generation’s busbar to the utility system, see Fig.1.1.

Loss of grid protection is also defined as "Islanding Protection" or "Loss of Mains Protection". There are some major conditions where loss of grid protection is vital for safe operations of both utility and embedded systems [11,13,15,16,17,25]. It is probably that the loss of grid protection is single most challenging aspect of designing the electrical installation involved in embedded generation[11].

Firstly, islanding operation in most cases is not desirable for the embedded generator, because loss of the grid supply
can cause dramatic changes in the electrical operating quantities in the power island. It is quite possible that the load connected to the island would be greater than the capacity of the embedded generator, with the result that the generator’s voltage and frequency would be dragged down and thus effecting the industrial process load[11,15]. This could lead to a complete outage. If loss of grid leaves the island with an excess of generation which would result in increasing in the system voltage and frequency, and an over excitation of transformers, etc. The possibility of presence of induction motors and capacitor banks in the island increases the probability of resonance conditions[11,18.22,23] in the power island.

For both legal and technical reasons islanding operation is also an undesirable condition for the utility system. After a loss of grid, especially when a portion of the utility network is energised by the local generator, it would be generally assumed that the loss of the grid supply would de-energised the whole system. This produces a safety hazard to the utility personnel and the public, and can also delay the restoration of normal supplies. In addition to this, the potential capability to feed the power island raises serious concerns for the quality of electric service on that power island during the period of isolated operation. This is not desirable for these utility’s customers left connected to the power island. Therefore, utilities do not usually permit an embedded generation unit
to serve other customers when not operating in parallel with the utility supply.

If a loss of grid remains undetected by the protective relays, there is a high possibility that the main source of supply could be reconnected to the power island with an out of phase reclosure\[11,13,15,16,17,18,19,20,21,22,23\]. This out of phase reclosing can produce very large magnitude of torques oscillations in both the generator electrical side and mechanical side, and result in winding and shaft damage. The large torque oscillations and resulting shaft fatigue may lead to premature shaft failure. There is also very high probability that this situation may cause damage to other equipments and devices on system.

Therefore, the owner of the embedded generation unit must recognised this problem due to the islanding. Some kind of local protection must be provided against islanding, first to detect the loss of the main power supply and open the inter-tie circuit breaker, and secondly to assure adequate generation to either continue production or to affect an orderly trip to the embedded generator.

1.3 PROTECTION AGAINST ISLANDING

If the load being connected to the power island exceeds the capacity of the embedded generation unit, then the
generator will be overloaded and both the system frequency and voltage will decline. Conversely, the system frequency and voltage will rise, if the islanded load is less than the capacity of the generation. This theoretical idea has led to the application of conventional relays, such as under/over frequency and under/over voltage relays as loss of mains detection for an embedded generation unit [2,3,11,13,15,17,19,21]. But there are cases when these conventional relays may not be effective for loss of grid detection.

i. The load remaining in the power island may be close to the capacity of the embedded generator.

ii. It may be relatively close to the generator capacity, but not exactly equal to it, it is also possible that generator controls would be able to respond quickly enough to establish a new equilibrium conditions, either increasing or decreasing the output of the generator to balance the load. In both situations, stable operation would continue after the loss of mains.

iii. There are also some cases where loss of mains phenomena can be detected, but "run on time" which is the time between happening of the loss of grid and opening the inter-tie breaker could be too long and reconnection of the two sources would occur with in this period. Also an increase in the run on time could result in the return
of the system voltage and frequency to near normal conditions, following AVR and governor action for those situations where the connected load is within the rating of the generator.

iv. Practical experience has also shown that under/over voltage and under/over frequency relays can not properly respond in the presence of the waveform distortion that is caused by over voltage due to islanding[11,19,22].

The number of embedded generations units connected to the utilities has increased over the last decade due to economic benefits. This has given a great impulse to providing effective islanding protection. Recently several sophisticated techniques have been devised[21,24,25,26] to provide an effective protection against loss of grid.

Loss of grid protection techniques can be divided into two main groups, these using active techniques and these using passive techniques. The first group include the reactive export power error detection relay and the system fault level monitor. Since these directly interact with the ongoing operation of the power system, hence are active techniques. The other group include the rate of change of frequency relay and the phase displacement relay, these passive techniques detect loss of grid by monitoring power system parameters and determining when the main source of generation is absent.
In addition to these techniques, a transfer tripping scheme based on the ability of a SCADA (Supervisory Control and Data Acquisition) system has also been used to open the inter-tie breaker after the loss of the grid supply [2,3,5,6].

All of these techniques have their own advantages and disadvantages which will be discussed in chapter 3, however, it is generally accepted that an ideal solution to the problem has not yet been found.

The introduction of digital technology and to move to integrated protection schemes, has enabled other protection techniques to be considered which are able to analyze more system data to make decision. One such a technique [52,97,114] based on fluctuations of the power output measured at the embedded generator terminal will be the subject of this thesis.

1.4 OBJECTIVES

The main objectives of the project hence of this thesis are:-

i. to create a model of an embedded generation unit operating in parallel with the utility network, and to develop a simulation software to analyze the behaviour of the local system under faulted and non-fault abnormal
conditions taking place on a power system containing an embedded generation unit.

ii. to develop new digital protection algorithm designed to protect a small and medium sized generation unit against loss of grid, and to examine the performance of the loss of grid protection techniques under faulted and non-faulted abnormal conditions.

iii. to develop the software for the new digital protection algorithm to be implemented on a microprocessor based relay which is available in the power system teaching laboratory, and the real time testing of the new algorithm using an in-house multi-generator test facilities.

1.5 SCOPE OF THE THESIS

Chapter 2

The general protection requirements for a medium sized cogeneration unit which is able to operate in parallel with and independently from the utility network are described. These protection requirements are for the protection of the embedded generation unit and for the interface section between the two systems, the main network and cogeneration unit.
Chapter 3

The operation of existing loss of grid algorithms with their merits and demerits are outlined in chapter 3. These algorithms are mainly devised into two groups. The algorithms belonging to first group are based on active techniques, and those in the second group of algorithms are based on passive techniques.

Chapter 4

A new digital algorithm for loss of grid protection based on rate of change of real power measured at the generator terminal is introduced in chapter 4. This includes the theoretical design of the new algorithm and the definition of the trip setting of the algorithm for an embedded generator. In addition to these, measurement of active power and its rate of change, and the moving average process are also discussed in this chapter.

Chapter 5

In chapter 5, the modelling of a power system containing an embedded generation unit with a site load is discussed. Also a simulation software program based on this model is developed to simulate an embedded generation unit under different power system disturbances. The simulation software is explained with the aid of a flow chart.
Chapter 6

The evaluation of the performances of loss of grid protection techniques discussed in chapter 3 and chapter 4 are examined in chapter 6 by driving the developed software. The responses of these algorithms to loss of grid, to load fluctuations during both parallel and independently operation modes, and to out of phase reconnection of the two systems, the local generation system and the utility system, will be analyzed. The related signals for these analysis; voltage, current, the system frequency, rate of change of frequency, power and rate of change of power, are derived at the local generator terminal.

Chapter 7

Similar simulation studies of chapter 6 are presented in chapter 7 to simulate the behaviour of an embedded generation unit under power system faulted condition. Four kind of fault conditions, three phase to ground, single phase to ground, double phase to ground and phase-to-phase faults are applied to the local generator terminal. The relay's behaviour is explained with the aid of related signal curves monitored at the generator's terminal.
Chapter 8

Chapter 8 consists of four sections; namely The Test system Hardware, Development of the Relay Software, Implementation of the Proposed Algorithm and Real-Time Simulation of the Proposed Relay Performances.

The test system hardware which is available at the Power System teaching lab is described. This test system has been used to do real-time test for the proposed rate of change of power algorithm. It consists of a microprocessor relay based on Intel 80286 microprocessor, necessary interface hardware, local load, and two synchronous generators able to operate in both parallel and independent operation modes.

The relay software written in assembler languages is described with the aid of a flow chart. Then the implementation of this algorithm on a microprocessor relay is explained. The real-time test results of the relay are discussed and given in the last part of this chapter.

Chapter 9

Chapter 9 includes the conclusion of the project and suggestions for the future work.
Figure 1.1. Network Configuration of a Power System Containing an Embedded Generation Unit.
CHAPTER 2

PROTECTION REQUIREMENTS FOR PARALLEL OPERATION
OF EMBEDDED GENERATION UNITS

2.1 INTRODUCTION

The installation of the embedded generation units able to operate in parallel with the electric utility system has resulted in a great interest in the problems of providing adequate protection for an embedded system and the interface between the utility and the embedded system, and adequate control for the embedded generation unit. Although, the control requirements[20] are mainly the same for all kind of embedded generation units such as: Automatic Voltage Regulator (AVR), Speed Governor Control (SGC), Power Factor Controller (PFC), Local Commander (LC) and automatic synchroniser, the protection requirements for an embedded generation unit depend on several factors as stated below:

-the embedded generation unit’s capacity
-type of the generation set
-system voltage level
-type of the system earthing
-the point where the two systems are connected each other
-type of operation modes (parallel or/and independent)
In this chapter, protection requirements for the parallel operation of an embedded generation unit will be summarized under four different titles:

- Electrical Design Considerations for an Embedded Generation Unit.
- System Earthing.
- Protection Requirements for an Embedded Generator.
- Protection Requirements for the Embedded Generation Unit/Utility system Interface (Inter-tie).

2.2 ELECTRICAL DESIGN CONSIDERATIONS FOR AN EMBEDDED GENERATION UNIT.

Since the interconnected power system gives maximum advantages and quality energy to the customers, i.e. infinite available ability of current at constant frequency and constant voltage, it is advantageous for the embedded generation units to operate in parallel with the utility power systems. However, when there is a failure of the utility supply, the embedded generation can operate independently from the utility to feed the critical local load, until a successful restoration of the utility supply. Operation of an embedded generation unit in parallel with a utility supply introduces the potential for hazards and problems in both systems which would not otherwise exist. Therefore, protective system for an embedded generation unit needs a special care during the electrical design of
the system.

In order to provide a perfect simultaneous and continues operation, to prevent damage to both systems, due to the faults and abnormal conditions occurring in both systems, the following consideration must be taken into account during the design stage of the protective relaying system [6,11,12,14,18,19,21].

-Since the embedded generation unit will be a part of the utility system due to the parallel operation, the designer of the embedded system must communicate with the engineers of the utility system during this designing stage to ensure that the two systems are compatible.
- The reliability and quality of the supply to the other customers not to fall below acceptable levels due to the presence of the local generation unit.
- The embedded generation system should include the necessary control functions for both parallel operation and independently operation modes.
- The owner of the embedded generation unit is responsible for synchronizing his system with the utility. Manual synchronizing should not be preferred.
- If the embedded generator is not connected to the local (process) bus over a site-transformer, a connecting reactor may be required between generator and process bus, to limit fault current which is originated in the embedded generator, and to protect the machine against
excessive over current due to fault conditions[5,7,8].
-The embedded generation unit should not be permitted to energised a dead utility circuit during the independent operation mode.
-The embedded generation unit must be isolated from the main system, whenever a fault or an abnormal condition occurs in both systems.
-The electrical design of embedded generation system must include a means of disconnecting the embedded generation unit from the utility, whenever the main source of supply is lost (i.e loss of grid)
-The protective scheme must provide a proper protection for embedded system including embedded generator and local load against all fault and abnormal conditions occurring in both systems.
-The protection system for the local generation unit must be compatible with the utility protection system.
-The local system may need a back up protection feature for the faults which occur in the utility system.
-For safety practices, the utility may require a lockable disconnect between utility and the embedded generation unit that is accessible to the utility personal.

2.3 SYSTEM EARTHING

System earthing is the heart of the ground fault protection system design for an embedded generation unit and is designed according to the system voltage level and the
utility earthing system. Embedded generators are usually star-connected and star point is grounded over a high value resistance to limit any earth fault current to a value to prevent the damage to the embedded generation unit \[2,9,31,32\]. For low voltage systems, this resistance is shunted, while the embedded generator is operating in the independent operation mode to feed the local load only.

Under these conditions, an over voltage relay which is located between the neutral point of the generator and ground can be utilized to detect an earth fault condition. A time delay is necessary to grade with other relays and prevent undesirable tripping. An overcurrent relay can be used to replace or back-up this over voltage relay.

On the other hand, for economic reasons, Engineering Recommendation G59[1] and Engineering Technical Report 113[4] recommend that, if the utility earthing system is available, there is no need to have a second earthing system for the embedded generation unit as long as it is running in parallel with the utility system. However, when the main source of supply is lost, the system will lose its earthing. For the independent operation mode, the embedded generator requires its own earthing system by which the generator neutral is connected to ground. For low voltage systems which contain single phase loads, the embedded generator neutral point is directly connected to ground. For medium and high voltage system it is connected to
ground using a high value resistance, or left isolated from the earth. For earth fault protection, overcurrent relays are suggested for low voltage system, whereas overvoltage relays are suggested for medium and high voltage system.

2.4 PROTECTION REQUIREMENTS FOR AN EMBEDDED GENERATOR

A protective system for an embedded generator includes several protective relays to provide a proper protection for the machine, as seen in Fig.2.1. A typical small generator needs a limited number of protective relays such as:

- Synchronization and Synchronizing Relay.
- Under/over Frequency Relay.
- Under/over Voltage Relay.
- Reverse Power Relay.
- Overcurrent Relay.
- Loss of Mains Relay.

Larger generators may need additional protective relays including:

- Differential Relay
- Stator earth Fault Relay
- Rotor earth Fault Relay
- Negative Sequence Relay
- Loss of excitation and pole-slipping Relay
It is preferred that all of these relays are included in a stand alone package for the embedded generator. Unlike the traditional electromechanical or solid state single function relays, major advances in microprocessor relay design make it possible to integrate several protection functions into a single microprocessor based relay. Digital relay technology provides an economically valuable alternative for the protection of embedded generation units. In addition, this technology has also introduced several other advantages which include: Improved performance, greater flexibility, reduced panel space and wiring, metering of various parameters, fault and non-fault abnormal condition recording, remote communication, continuous self checking and self-calibration. These advantages have encouraged the objective of providing a multifunction microprocessor relaying package for the embedded generator\[14,15\]. Such a multifunction relay has an important commercial advantage.

2.4.1 Stator Winding Protection

Generator stator winding faults are always considered to be serious, since they can cause severe and costly damage to insulation, windings and core. They can also produce severe mechanical torsional shock to shafts and couplings. Differential protection\[28,29,30,33,34,35,36\] is usually used to detect multi-phase faults and also phase to ground faults in the embedded generator.
During the presence of an external fault and abnormal conditions, no current will flow through the operating coil of the relay. But if there is a fault, within the protection zone, a current will flow through the operating coil and the relay will operate to trip the generator tie-breaker, field breaker and turbine throttle.

On the other hand, time delayed overcurrent relays can be utilized to protect stator winding of a small embedded generator. While the generator operates in the independent operation mode, overcurrent relays should be energised through Cts located at the neutral and of the generator to detect the winding fault conditions. During the parallel operation mode, they should be energised from Cts located at the line end of the generator. The relays can be either voltage controlled over current relays or voltage restrained overcurrent relays. Although, overcurrent protection method would be a primary protection scheme for a small generator’s windings, but it is usually utilized to protect the embedded generators as a back-up protection feature.

Earth fault protection scheme of the stator winding is established according to the system earthing as mentioned before. Since the neutral point of the embedded generators are usually grounded over a large value resistor or isolated from the earth, an over voltage relay is fed from a VT connected between the generator neutral point and
ground is used to detect earth fault occurring in the embedded generation unit. In the low voltage system, since the generator is directly connected to ground during the independent operation mode, an overcurrent relay, this time, is needed to detect earth faults.

2.4.2 Rotor Earth Fault Protection

A single rotor earth fault does not affect the operation of the embedded generator and will not give any damage to the rotor winding. However, second earth-fault will short circuits a part of the rotor winding, and will affect the generator. Therefore an earth fault should be detected and at least an alarm should be given. There are several techniques \[28,29,30\] including the potentiometer method, dc and ac current injection methods to detect an earth-fault.

2.4.3. Protection Against Unbalanced Conditions

Unbalanced loading of the generator phases, or an internal or an external asymmetrical fault results in production of negative phase sequence currents. These currents, which have a phase rotation in the opposite direction to the normal phase rotation in the stator winding, produce a magnetic field which induces currents in the rotor (in the field winding and rotor body) at twice the system frequency. The resulting eddy currents are very large and
cause severe heating of the rotor. Therefore, an unbalanced conditions due to the unbalanced loading or asymmetrical faults must be detected and a trip signal must be given to disconnect the generator before damage can result. This can be done by monitoring negative sequence currents in the stator winding or/and the second harmonic currents in the field windings[28,29,37,38,39,40].

A negative sequence current relay is normally utilised to protect the embedded generator against unbalanced loading. A digital approach[37,39,40] which is very convenient for multifunction microprocessor relaying and monitoring the second harmonic current in the field windings can be utilised to protect the generator against all types of asymmetrical faults. Discrimination between an external and an internal fault is achieved by monitoring the direction of negative sequence power flow at the generator terminal. During the internal asymmetrical faults, this negative sequence power flows from the generator to the system, inversely during an external fault it flows from the system into the generator.

2.4.4. Loss of Excitation and Pole Slipping Protection

When a synchronous generator losses its excitation source, it starts to operate as an induction generator by drawing reactive power from the main network as much as 2 to 4 times its rating current. It will cause voltage reduction
on the system and a power swing can also be seen. On the other hand, asynchronous operation of the generator produces alternating current of twice the slip frequency to flow in the rotor resulting in over heating. Therefore, the field protection scheme must isolate the generator from the system, whenever loss of excitation has occurred.

One of the loss of excitation protection methods[28] which utilizes an under current relay is suitable to protect small synchronous generator against loss of excitation. When the field current decreases to a predefined value, the under current relay will operate and isolate the generator from the system, or give an alarm only. But loss of field protection is generally based on impedance measurement at the stator terminal[14,19,28,29,41,42,43]. When the machine losses its excitation, the stator current will increase and terminal voltage will decrease. The impedance seen by the mho type impedance relay will decrease. The change in the impedance is followed by the impedance relay located at the machine terminal and looking through the stator winding. Whenever the impedance decreases to a value within the relay characteristic, the relay will trip. In order to prevent maloperation two mho type impedance relays are utilised.

Pole slipping results from failure of the generator excitation system or failure of AVR system, loaded without sufficient excitation and primary system faults, if the
protection system acting time is longer than the expected.

Pole slipping protection scheme[19,28,29,44] is also based on impedance measurement, and consists of two ohm type impedance relays and an offset mho distance relay. Since the possibility of pole slipping occurring in the embedded generation unit is very low, it is not usual to protect embedded generator against pole slipping. In general, the planning stage of a local generation unit should include the stability studies to determine, if pole slipping protection is required[29,44].

2.4.5. Prime Mover Protection (Anti-Motoring)

Generator motoring occurs when the supply to the turbine is shut off while the generator is connected to the utility. Under such circumstances, the generator will act as a synchronous motor and drive the turbine as a load. The protection is intended to prevent overheating of the turbine and damage to the blades.

Although, in the independent operation mode when the generator is operating alone there is no danger for the embedded generator due to the prime mover failure. It is necessary to protect every embedded generator against anti-motoring since it usually operates in parallel with the utility supply. A reverse power relay can be utilised to detect motoring conditions[9,19,28,29,45]. When the
motoring condition occurs the power at the generator terminal changes its direction and flows into the generator. A reverse power relay will detect this reverse power flow and will trip the generator.

2.4.6. Synchronisation and Synchronism-Check Relays

When interconnected power systems are designed one of the necessary decisions that must be made relates to the operating points at which the two systems can be synchronized together. For an embedded generation unit, there are two points at which systems can be synchronized. One of them is the generator tie-breaker connecting the embedded generator to the local load (process) bus. The other point is inter-tie breaker connecting the local bus to the utility systems as seen in Fig 2.1. Since the local generator should at least feed the critical part of the site load after the disconnection, the embedded generator is generally synchronized with the utility supply over the inter-tie circuit breaker.

Most utilities do not allow manual synchronization of embedded generators with their systems. The reason of this is that if the synchronization is not carefully done, synchronization conditions may not be provided at the instant that the breaker closes. The difference between the instantaneous angle of the incoming voltage and that of the local generator voltage will produces a momentary
power swing on the system. This situation is undesirable for both systems and the other utility’s customers.

Ideally the local generator would be equipped with automatic synchronizing[9,11,20]. When the operator closes the control switch for the inter-tie breaker or the generator tie-breaker, the automatic synchronizing equipment determines whether the two systems are sufficiently synchronized[9,20] to permit the breaker to close.

Synchronizing check relays compare the relative phase angle differences between the voltages on both sides of an open circuit breaker to determine if the two voltages are in synchronism. In an embedded generation the synchronism check relay supervises the closing of both the generator tie-breaker and the inter-tie-breaker as seen in Fig.2.1. If the utility system is de-energised, or the embedded system is not synchronized with the main supply, the relay will block closing.

2.4.7 Overload and Overcurrent Protection

Since the generator power is limited by its input power, the local generator is not in much danger of accidental overloading. However, if the machine is large, overload protection may be required. There are two main techniques to protect a generator against overloaded condition[28,29].
Although in most cases an overcurrent relay will provide an adequate overload protection having suitable time characteristic, in some cases it is necessary to monitor the temperatures of the stator and rotor windings.

2.4.8 Protection Against Abnormal Non-Fault Conditions

In the parallel operation mode, the system frequency and voltage are determined by the utility supply. Hence, any change in the field current due to the action of the automatic voltage regulator (AVR) will have a negligible affect on the magnitude of the system voltage, but will change the generator reactive power output to maintain the required power factor (normally that of the local load). Likewise, because of the high inertia of the utility system, any change in the input torque will have negligible effect of the system frequency, but will change the real power output of generator being supplied to the load.

On the other hand, any change in system load will be taken care of by the main utility power supply. The embedded generator will have a negligible effect. Because of these reasons, any abnormal conditions for the local generator’s voltage and frequency are unlikely to occurs as long as parallel operation maintains.

In the independent operation mode, the local bus voltage is under the control of the embedded generator’s automatic
voltage regulator (AVR), and any change in field current will directly change the system voltage. Any system voltage deviation will be sensed by the automatic voltage regulator (AVR) which will try to maintain the voltage within the operation limits. Again there is not a great risk of abnormal voltage changes. However because of an AVR failure or a sustained fault, the system may be subjected an sustained abnormal voltage condition. Under/over voltage relays monitoring the voltage will trip the generator tie-breaker, removing the generator from the system.

In the isolated operation mode, similarly any change in the input power will change the machine speed, hence the system frequency. Any change in the system frequency will be sensed by the speed governor controller which tries to maintain the frequency (speed) within the operation limits. However, an excessive load change or speed governor failure causes a sustained abnormal condition. The under/over frequency relays in the generator protection relaying package will trip the generator-tie breaker and separate the embedded generator from the local bus, or if necessary disconnect the embedded generator from all loads.

These relays are usually time delayed and back-up those relays included in the inter-tie protection system. It is expected that presence of an abnormal condition during the parallel operation mode, under/over frequency and
under/over voltage relays included in inter-tie section will separate the two systems, if the abnormal condition sustains, the local generator protection system will trip the generator.

2.5. EMBEDDED GENERATION UNIT/UTILITY INTER-TIE PROTECTION

The protection system described in section 2.4 is used to protect the embedded generator against all type of fault and non-fault abnormal conditions. However, some additional protection requirements are necessary to protect the embedded generation unit against faults and non-fault abnormal conditions occurring in the interface section, between the utility substation and the embedded generation unit. In the presence of a fault or an abnormal condition on the inter-tie, the protective relaying system will trip the inter-tie circuit-breaker and separate the two systems from each other. After restoration, the two systems will be resynchronized. During the restoration period, the local load might be supplied by the embedded generator.

The protection requirements for the Utility/Embedded Generation Unit interface will be reviewed here under two subtitle named:

- Protection Against Faulted Conditions
- Protection Against Abnormal Non-Fault Conditions.
2.5.1 Protection Against Faulted Conditions

When a fault occurs in the system, some part of the total fault current to this fault will come from the embedded generator. The response of the local protective relays to this situation depends on the location of the fault and determines whether primary or back-up clearing by the local protective system is required. If a fault is within the embedded generation unit side, primary faults clearing by the local protective system is required. However, when a fault occurs within the utility side, then any fault clearing that may be required by the local protective system will back-up the utility protective system.

(a) Protection Against Phase Faults

In cases where the primary fault clearing is required by the local protection system, overcurrent relays or distance measuring relays can be utilized according to the interface voltage level[6,9,11,12,18]. If the interconnection is at distribution voltage, or some cases at the subtransmission level, overcurrent relays which provide three phase protection can be utilized. These relays can be instantaneous or time overcurrent to relays. Depending on the complexity of the interface system, directional overcurrent relay may be required.

However, if the inter-tie is operating at transmission
voltages, distance measuring relays may be required. Two zone distance relays are the most suitable for phase protection at the embedded system/utility interface [2,3,11,18]. The first zone is required by the primary fault clearing purposes, and the second zone will provide back-up to the utility protection system. One three phase distance relay or three single phase distance relays can be utilized.

Engineering Recommendation G59[1], and Engineering Technical Reports 113[4] suggest the use of Reverse Active and Reactive Power relays as export limiters to protect the inter-tie section. These relays remain stable as long as the export power into the utility system is below the embedded generator’s capacity, however whenever the export power exceeds limits, the relays will trip the inter-tie breaker and leave the embedded generation unit with the local (site) load[1,4,20].

(b) Ground Fault Protection

Since the two systems are usually earthed using high value resistors or the local generation unit may be operated with its neutral point isolated from the earth, the zero sequence current flowing from the inter-tie during an earth fault, the earth current may not be high enough to cause relay tripping. Therefore, the embedded generation unit/utility interface is usually protected by under/over
voltage relays against phase to ground unbalance faults [4,6,9,11,18].

The first approach to this protection uses a broken delta or zero sequence voltage relay. In this, three VTs are connected phase to neutral on their primary side, with their secondary windings connected in broken delta. An overvoltage relay is connected across the open corner of this delta. This arrangement measures the vector sum of the three phase to neutral voltage phasors. Under normal conditions it is zero, however, in the presence of a phase to ground fault, it will impose a measurable voltage across the relay resulting in tripping.

An alternative approach to this scheme which requires only one VT and relay, is to use an under/over voltage relay supplied from a VT connected phase to ground. Whenever an earth fault occurs on this phase, the voltage seen by the relay will be zero. However, if a phase to ground fault occurs on one of the other phases, the relay measures 1.73 time normal voltage.

2.5.2. Protection Against Abnormal Non-Fault Conditions

Whenever, an abnormal condition occurs in the system, the two system should be separated from each other by tripping the inter-tie circuit breaker. Since an abnormal condition results in an acceptable deviation in the system voltage
and/or frequency at the embedded generation unit/utility interface, under/over voltage and under/over frequency relays will detect the abnormal non-fault conditions occurring in the network[6,9,15,16,20].

2.6 SUMMARY

In this chapter, the general protection requirements for an embedded generation unit and its parallel operation with the utility power system have been reviewed. These requirements are to provide a proper protection against the fault or abnormal operating conditions which could be caused by the presence of the embedded system. After a brief summary of the general considerations taken into account during the design stage of embedded system, the protection requirements for an embedded generator were discussed. These requirements are to protect the local generator against all type of faults and abnormal non-fault conditions. In the presence of a fault or an abnormal non-fault condition, the generator should be isolated from the system by tripping the generator tie-breaker, so that the local load will continue to be fed by the utility supply.

In the last part of this chapter, the protection requirements for the embedded system/utility interface were also given. The aim of these relaying functions is to open the inter-tie circuit breaker connecting the local bus to the utility system to disconnect the link between the two
systems in the presence of a fault or a non-fault abnormal situation on the network during the parallel operation of the two systems. Since these protection requirements are ineffective during the isolated operation mode, they can also be defined as parallel operation requirements[20].

The relays such as under/over voltage, under/over frequency and reverse power which are included for the inter-tie protection can be effective to detect a loss mains as long as islanding produces enough changes in the related signal, otherwise they can not be effective for islanding protection. Therefore, the local protective relaying system must be included a proper relaying function for loss of mains protection[1,2,3,4].
Figure 2.1. Typical Protection Scheme For an Embedded Generation Unit Operating in Parallel With the Utility Network.
CHAPTER 3

PROTECTION TECHNIQUES FOR LOSS OF GRID

3.1 INTRODUCTION

The principal objective of "loss of Grid" protection is to detect the condition where the embedded generation unit is left connected to a portion of the utilities load network but disconnected from the main source of utility supply. There are many reasons why switching operations occur in the utility network, for example a sudden trip due to a fault in the embedded generation unit/utility interface or on the transmission line to the embedded generation unit, an error in the control wiring or relay settings, an operating error, a major disturbance on the utility network, etc.

Protection against loss of utility supply is required to disconnect the link between the embedded generation unit and the utility part of the power island to prevent an out of phase reconnection of the two supplies and a possible hazard to operating personnel.

The typical requirements for this protection, defined by Engineering Recommendation G59[1] and Engineering Technical Report 113[4] are that it should be operate within half
a second following the loss of mains phenomena. However, since the fastest reclosure which is 12 cycles, the two systems should be separated from each other within this time to prevent an unsupervised reconnection of the two systems. Fast detection of a loss of grid is also necessary so that the trip decision is made before the Automatic Voltage Regulator and the Speed Governor can respond and attempt to establish a new balance.

In small embedded generation installations, where the generators do not usually export power into the utility network, loss of grid results in power flow from the embedded generation unit into the utility’s load. Loss of grid can, therefore, be detected by using a reverse power relay monitoring the power flow in the inter-tie.

In the case of small generators which are operated such that they can export power to the utility network, loss of grid will result in severe overloading of the embedded generator. This will cause its output voltage and frequency to fall, and the under voltage and under frequency protection included inter-tie section to operate.

Normally generators, which have rated capacity more than 250 KVA are fitted with high speed automatic voltage regulators, there is a high possibility that the generation will be able to maintain the system voltage and frequency within specified limits following the loss of the main
supply[16,17,18,19,20]. Specialist relaying is therefore, required to detect the islanding, trip the inter-tie circuit breaker to disconnect the utility part of the power island from the embedded generation unit and leave the local generator supplying the site load in the independent operation mode.

Since the traditional conventional under/over voltage and under/over frequency relays can not provide an adequate level of protection for an embedded generator against loss of grid phenomena, several new algorithms mainly based on digital techniques have been developed [1,2,3,4,6,19,21,24,25,26]. These include; Reactive Export Error Detection[25], System Fault Monitoring[24], Generator Mains Monitoring[26], Rate Change of Frequency Relay[1,4,21,25] and the technique based on Rate of Change of Power[52,97,114] which is the subject of this thesis. As stated before, the first of two of these can be described as active techniques, since they directly interact with the on-going operation of the power system. Whereas, the other techniques can be considered as passive techniques, since they detect the loss of mains event by monitoring power system’s behaviour only. In addition to these, a communication system, known as Transfer Tripping Scheme[2,3,6,11] is also used to detect loss of mains. All of these techniques with their merits and demerits will be discussed in this chapter.
3.2. ACTIVE TECHNIQUES FOR LOSS OF GRID PROTECTION

3.2.1 Reactive Power Export Error Detection (REED)

The reactive power export error detector interfaces with the embedded generator’s Automatic Voltage Regulator to force it to generate a present level of reactive power flow into the inter-tie. The level of this exporting reactive power into the utility can only be maintained when the utility’s main source of generation is connected. The relay will trip when there is an error between the pre-set value and the actual reactive power been measured at the inter-tie. In order to avoid maloperation, a time delay prevents the relay from operation unless the trip condition is sustained for a period in excess of the time setting. Also, since import power to the site can only be occur when the main source of supply is connected, this condition is used to override the relay. The operating time of the relay varies from two to five seconds.

Although this relaying approach is slow, it is recognised as being effective. It can detect a loss of grid when there is no change in the generator’s loading due to the switching operation. Rather than primary protection, the relay is frequently used to provide a back-up protection to other faster loss of grid relays. It is usually utilised as a back-up of the Rate of Change of Frequency Relay. This is because in some situations islanding need not result in
a great enough change in the frequency to be detected by the rate of change of frequency relay. In these circumstances, however the reactive export error detector will produce a trip. It is usually preferred that the local generator reactive power output should maintain the required power factor which equals to that of the local load. The use of the Reactive Export Error Detector Protection relay for detecting loss of grid will over rule this.

The application of the Reactive Export Error Detecting Relay approach is limited when a power factor compensation capacitors remain connected to the island and hence, the reactive current can be maintained[9] following a loss of grid.

3.2.2 The System Fault Level Monitor

The system fault level monitor[24] provides the fastest operating protection for loss of grid. Its operation depends on measurements of the power system’s source impedance taken close the inter-tie. This is performed by the monitoring the short-circuit current and reduction in supply voltage repeatedly when a shunt inductor is connected across the supply using point-on-wave triggered thyristor switches. The firing of the thyristor’s just before a voltage zero causes a short pulse of current to flow in the inductor. If the firing angle of the thyristors
is always held constant the magnitude of the current pulse will be a function of the circuit impedance and hence the system fault level. In order to limit the pulse current to a low value, the firing angle is kept constant around 170°. The decision to trip depends on the comparison of the measured magnitude of pulse current (hence system fault level) with that corresponding to a network fed from the main utility generation.

Since there is a dramatic difference between the fault levels of the utility’s generation and that of the embedded generation unit, the system need not be particularly accurate. The operating times can also be very short, with a theoretical minimum of half a cycle. However, although similar techniques are already used to improve the performance of static voltage compensators, relays have not been produced using this type of loss of grid protection.

3.3. PASSIVE TECHNIQUES FOR LOSS OF GRID

In almost all circumstances, loss of grid results in changes in loading of the embedded generator and then produces changes in system voltage, current and frequency. These changes provide the basis for passive protection techniques for loss of grid protection.
3.3.1 Transfer Tripping

The most direct method for loss of mains protection [2,3,6,11,19] is to monitor auxiliary contacts on all of the circuit breakers on the utility network. When a random switching operation produces a loss of mains, a transfer trip scheme can be used to open the inter-tie circuit breaker connecting the two systems. Following the successful restoration of the utility supply, the embedded generation unit can be resynchronized with the utility system and then reconnected.

Although this scheme generally provides faster, effective and more reliable response to a loss of mains than other techniques, the difficulty is that every circuit breakers on the utility network could be a candidate for creating a loss of main; and a simultaneous monitoring system involving the contact position of every circuit breakers which could be involved would be unmanageable and not feasible for the most utilities to implement.

A similar transfer scheme, known as "Dead circuit Pick-up Supervision[19]" on the utility circuit breakers can also be utilized to block reclosing until the inter-tie circuit breaker between embedded generation unit and utility has been opened or voltage in the power island has collapsed. In this scheme, at the instant of reclosing if the embedded system side of the circuit breaker, which has created the
islanding is not de-energised, a trip will be initiated to open the inter-tie circuit breaker. The reclosing can then proceed without complications.

Unfortunately, this scheme also has the same disadvantages of the other transfer scheme, since every circuit breaker on the system needs a dead-line check voltage relay and a communication link with the inter-tie circuit breaker.

Both tripping scheme could become practical with the introduction of Supervisory Control and Data Acquisition (SCADA) system on the whole supply network, assuming that supervisory controls are available on the circuit breakers.

3.3.2 Rate of Change of Frequency Relay (ROCOF)

The effect of loss of grid is determined by the power flow across the loss of grid circuit breaker and its direction at the instant of the switching operation. If power is being imported, then the islanded load exceeds the embedded generation. When islanding occurs the excess load is placed on the embedded generator and forcing it to slow down. Whereas, if power is being exported into the utility system, then embedded generation exceeds the islanded load, after the disconnection of the two systems the excess generation will force the machine to speed up.

The change in the embedded generator speed (and hence, the
system frequency) following the loss of the utility supply is determined by the amount of excess power or generation in the power island and by the local generator inertia constant as seen in the following well known swing equation

\[
\frac{dF}{dt} = \frac{\Delta P F}{2H}
\]  

(3.1)

Where

\( \Delta P \) is the change in machine power output in per-unit
\( F \) is the system frequency just prior to the interruption
\( H \) is the embedded generator inertia constant (in seconds)
\( dF/dt \) is the rate of change of frequency.

Rate of change of frequency relays[26] monitor the voltage wave form at the generator terminal or at the inter-tie, and trip whenever the measured rate of change of frequency exceeds a preset level for longer than a set time period. The settings are chosen such that the relay will operate for fluctuations due to loss of the main supply and when the embedded generation unit is operating independently from the utility supply, but not trip for fluctuations governed by utilities time constants.

For small and medium sized embedded generation unit, a trip setting of 0.3 Hz/sec has been found to be optimum with an
operating time from 0.3 to 0.5 seconds[25]. Under extreme condition, causing dramatic changes in frequency, faster tripping is possible.

The technique of frequency measurement used in the Rate of Change of Frequency Relay is based on zero crossing, and uses a very high sampling rate and input signal filtering. A counter input frequency of 18 kHz represents one cycle per degree of phase at 50 Hz, and a frequency of 21 Khz is used for 60 Hz applications.

3.3.3 The Phase Displacement Monitor (GW2)

The phase displacement relay[26] which is also known as "Generator Mains Monitor" monitors the system voltage at the generator terminal or at the inter-tie, and will operate when there are sudden phase displacements in the voltage waveform. These phase displacements are a direct result of change in the generator load and its operating frequency.

The operation time is about 50 ms provided that the change in the generator output power exceeds 5% of the nominal power just prior to the disconnection. Since the sudden phase displacement are mainly determined by the change in the reactive power, the relay is less sensitive to the changes in real power due to the loss of grid.
Both relays, rate of change of frequency and phase displacement relays, require a single input signal only, the system voltage waveform, they use the minimum of input circuitry, thus offering an immediate advantage for stand alone relaying. However, an inherent advantage of both relays is that should the relays fail to operate for the loss of mains, any subsequent load changes could cause tripping.

3.3.4 Real-Time Frequency Measurement

Above frequency (hence rate of change of frequency) analysis is based on generator's swing equations, and the system frequency and its rate of change are derived from the generator's speed throughout this investigation presented in this thesis. However the real-time frequency and the phase angle measurement\[46,47,48,49,50,51\] are obtained from digital samples of the instantaneous voltage or current. Although this is beyond the scope of this thesis, in order to get some idea about the application of the present passive loss of mains protection technique such as rate of change of frequency and phase displacement algorithms, the main real-time frequency measurement methods will be briefly summarized here.

Girgis and Ham[46] introduced a technique which detects change in the system frequency, by relating it to a leakage coefficient in the Fast Fourier Transform (FFT). The
algorithm computes the deviation of the power system frequency from the fundamental component and the best estimate of its rate of change of frequency. The system required extra hardware to detect zero-crossing accurately. It is also required to evaluate the FFT at the every sampling step.

Another technique described by Fhadke et al [47] measures the frequency and phase angle from the rate of change of estimated voltage phasor. Although the algorithm does not need zero-crossing, the integration time required to provide a frequency estimate is inversely proportional to the frequency deviation. A 5 Hz change in the system frequency is measured 64 msec, whereas 0.1 Hz change takes at least 3.2 seconds to measure.

Malik et al [48] described method which is based on simple zero-crossing counts the time between two zero-crossing to estimate the power system frequency. A sophisticated input signal filtering is used together with a very high sampling frequency to provide measurement to a significant accuracy. The speed of response of measurement depends on the frequency measured. It is equal to 2/F, where F is the measured frequency.

More recently algorithms have been described by Sachdev and Giray[50], and Sachdev and Shen[51] which estimate the frequency from the voltage samples taken at pre-selected
intervals of the time. The method first calculates the phase angle of the phasor representing the voltage waveform and then estimates the frequency from the phase angle. A kalman filter then removes noise of the frequency measured. It needs theoretically at least three data windows for the correct measurement.

These techniques measure the system frequency accurately if the frequency deviation is around the power system frequency. They are limited for the power system conditions where large frequency deviation occur. Hence, none of them has been suggested for the purpose of power system protection.

3.4 SUMMARY

As discussed above, in order to provide a proper protection for an embedded generation unit against islanding, several sophisticated new algorithms which are based on active and passive techniques have recently been developed. Active protection systems are generally more effective at detecting loss of mains but have the disadvantage of requiring a direct influence on power system operation. Whereas passive protection techniques do not have this problem but can not detect islanding for all conditions. Although a communication system between the inter-tie circuit breaker and the other circuit breakers on the system which could creates a loss of mains phenomenon
is an effective solution, it would only be practical with the introduction of comprehensive transmission and distribution automation and supervision schemes.
4.1 INTRODUCTION

In this chapter, a new digital protection algorithm for loss of grid protection will be introduced. The aim of the proposed algorithm is to provide an effective protection for the embedded generation units against loss of the utility supply. The algorithm uses a passive technique and is based on monitoring changes in the real power measured at the embedded generator terminals. In addition, this chapter includes the basic definitions and mathematical theory behind the new algorithm.

4.2 BASIC CONSIDERATIONS FOR THE NEW ALGORITHM

The basic considerations taken into account during the designing stage of this algorithm can be outlined as follows.

i. It is assumed that loss of grid is a balanced condition, since a three phase switching operation is required to produce a loss of grid. Loss of only one or two phases of the utility grid supply, allows the embedded generator to
remain in synchronism with the utility and hence the two
system can be reconnected without major problems.
i. In the event of a loss of grid, the proposed algorithm
must detect loss of grid, and give a trip signal to open
the inter-tie circuit breaker leaving the embedded
generation unit alone to feed the local (site) load. An
orderly reconnection of the two systems can be executed
when the supply has been restored to that part of the
utility system connected to the inter-tie.

iii. The loss of grid relay should be inhibited, after the
opening of the inter-tie circuit breaker, and must be reset
following the reconnection of the utility supply.

iv. In the cases where loss of grid has not been detected,
the protection algorithm should give a trip signal to open
the inter-tie circuit breaker following load changes in the
power island while the main source of supply is
disconnected.

v. In the situations where the loss of grid has not been
detected before the utility supply is reconnected, the
algorithm must give a trip signal to the open inter-tie
circuit breaker immediately after an unsupervised
reconnection of the utility grid to the power island.

vi. The relay’s operation should be such that the effects
of noise are minimized and maloperation is avoided. The
tripping time should be short enough to avoid the AVR and
the speed governor correcting the imbalance. This tripping
must be before the earliest possible automatic reclosing of
the circuit breaker which created the loss of grid.
vii. In addition to the reliable detection of a loss of grid, the protection algorithm must be stable during the load fluctuations, while the main source of supply is connected.

viii. Finally, the proposed technique should be compatible with the other protection functions of an integrated protection scheme for an embedded generation unit.

4.3 BASIC DEFINITIONS FOR ELECTRICAL POWER

Since the new algorithm is related to the power, the basic definition of the power[57,58,59,60,61,62,63,64,65, 66] in an electrical power system will briefly be given here.

4.3.1 Power in the Single Phase Systems

**Instantaneous Power:** The instantaneous rate of energy flow or instantaneous power $p(t)$ is defined as the product of the instantaneous voltage $v$ and instantaneous current $i$

$$p(t) = v \times i \quad (4.1)$$

**Active Power:** The active power $P$ at a time $t_o$ is calculated by the equation of

$$P = \frac{1}{T} \int_{t_o-T}^{t_o+T} v i \, dt \quad (4.2)$$
Where $T$ is the measurement interval which is usually taken as being one or more periods of the voltage or current waveforms for ac input. The voltage and current waveforms are regularly sampled at a rate of $1/T_s$ (1/Sampling Period) and the integration equation (4.2) is evaluated numerically by summing the discrete sample products over the measurement interval. The discrete equation used to calculate the active power, more commonly called as average power[59,60,61,62,63,64] is then;

$$P = \frac{1}{N} \sum_{j=1}^{N} (v_j i_j)$$  \hspace{1cm} (4.3)

Where $N$ sample pairs are taken over an integer number of cycles of the voltage waveform. $v_j$ and $i_j$ represent the $j^{th}$ samples of the voltage and current waveforms, respectively. If both voltage and current are sinusoidal, the active power can be written as;

$$P = VI \cos \phi$$  \hspace{1cm} (4.4)

Where $\phi$ is the angular phase difference by which the voltage leads the current. $V$ and $I$ are the rms values of the voltage and current, and can be calculated by means of
These equations can also expressed in the discrete form [12,13] of

\[ V = \sqrt{\frac{1}{T_0} \sum_{j} v_j^2 dt} \]  

\[ I = \sqrt{\frac{1}{T_0} \sum_{j} i_j^2 dt} \]  

For non-sinusoidal waveforms, active power is defined as;

\[ P = \sum_{n} V_n I_n \cos \phi_n \]  

Where \( V_n, I_n \) and \( \phi_n \) are defined in the same way as in equation (4.4), but for the \( n^{th} \) harmonic component.

Reactive Power: For sinusoidal waveforms, the reactive power \( Q \) is defined as;

\[ Q = VI \sin \phi \]
For non-sinusoidal waveforms, reactive power is equal to the sum of the values of the reactive power for every harmonic component.

**Apparent Power:** The apparent power $U$ is equal to the product of the rms voltage and rms current.

$$U = V \times I \quad (4.9)$$

Because apparent power has the property magnitude only and its sign is ambiguous, it does not have a definite direction of flow. For convenience, it is usually treated as positive. In sinusoidal conditions, $U$ equivalent to the square root of the sum of the squares of the active and reactive powers, i.e;

$$U = S = \sqrt{P^2 + Q^2} \quad (4.10)$$

**Phasor Power:** For sinusoidal voltage and current, the phasor power is given by;

$$S = P + jQ \quad (4.11)$$

Where $P$ and $Q$ are the active and reactive power, respectively. As it is seen, its magnitude equals to the apparent power. For the non-sinusoidal conditions, the
phasor power will be equal to the phasor sum of the values of the phasor power for every harmonic.

**Power Factor (PF):** Finally, the power factor is defined as:

\[
PF = \frac{\text{Active Power}}{\text{Apparent Power}} = \frac{P}{U} \quad (4.12)
\]

For the sinusoidal conditions, power factor is identical to the cosine of the angle \( \phi \) by which the system voltage leads the current.

### 4.3.2 Powers in Polyphase Systems

In polyphase electrical power systems\[57,58,66,67,68\] the instantaneous, active and reactive powers represent the corresponding algebraic sums of the instantaneous, active and reactive powers for the individual terminal of the entry, when the voltages are all determined with respect to the same common reference point, i.e. the neutral point. Therefore, in a three phase system the instantaneous power will be:

\[
p_3(t) = v_a i_a + v_b i_b + v_c i_c \quad (4.13)
\]

and the active power will be defined as;
The active power in a three phase system can also manipulated in the discrete form as follow;

\[ P_3 = \frac{1}{T} \int_{t_o-T/2}^{t_o+T/2} (v_a i_a + v_b i_b + v_c i_c) \, dt \]  \hspace{1cm} (4.14)

For a three phase balanced system the equations (4.13), (4.14) and (4.15) will be equal to;

\[ P_3 = \frac{1}{N} \sum_{j=1}^{N} (v_{aj} i_{aj} + v_{bj} i_{bj} + v_{cj} i_{cj}) \]  \hspace{1cm} (4.15)

The reactive power in a three phase system will be the algebraic sum of the a,b,c phases reactive power. The apparent power in a three phase system is equal to arithmetic sum of the apparent power for three individual phases. Then, the power factor is defined[57,58,68] as the ratio the three phase active power to the three phase apparent power.

4.4 MATHEMATICAL THEORY FOR THE ALGORITHM

The mathematical theory on which the proposed algorithm based will be discussed in this section.
4.4.1 Moving Average Algorithm

Moving average is a widely used technique[69,70] to estimate average from raw data. Each smoothed value is computed as the average of a number of preceding raw data values, and process is repeated sample by sample through the data being sampled.

The moving average algorithm defined by;

\[ Y(n) = \frac{1}{N} \sum_{k=0}^{N-1} X(n-k) \]  

(4.17)

Where

- \( Y(n) \) and \( X(n) \) are the present output and input respectively.
- \( N \) is the length of the moving window (The number of samples in the moving window)
- \( k = 0 \ 1 \ 2 \ 3 \ \ldots \ \ldots \ N-1 \)

Equation (4.17) is non-recursive, because each output sample is computed solely from the input values. The equation defines the operation of a simple digital filter, which in this case produces a smoothing action on the input signal. This is not very efficient. The computation of each output values is almost exactly the same as the one before it, except that the most recent input sample is
included, and most distant one is taken out. By using this idea and the above equation, moving average at the instant of \((n+1)\) will be;

\[
Y(n+1) = Y(n) + \frac{1}{N} [X(n+1) - X(n+1-N)] \quad (4.18)
\]

Equation (4.18) shows that we can estimate each output sample by updating the previous output \(Y(n)\). The equation defines a recursive version of filter which much more efficient, requiring far fewer addition/substraction. If the sampling frequency is constant, there is no need to divide the equation by \(N\).

This technique has a low pass filter effect, because it removes the high frequency harmonics in the input signal. Application of the moving average process to the rate of change of power algorithm provides a simple and effective way to remove the double frequency component due to the unbalanced conditions and high harmonics due to the non-sinusoidal conditions.

4.4.2 Digital Estimation of the Derivative

The derivative of a signal can be estimated by using the related waveform[71]. Assume that the waveforms are sampled at an interval of \(\Delta t\), with actual sampling times being \(\ldots, t_i, t_{i+1}, \ldots\), and corresponding sampled value
values being ..., \( x_j \), \( x_{j+1} \), ... Take \( t_{j+1} \) as the reference point between \( t_j \) and \( t_{j+1} \). Then, the derivative of the signal of \( x(t) \) at this point will be,

\[
\frac{\Delta x_{j+1}}{\Delta t} = \frac{1}{\Delta t} (x_{j+1} - x_j)
\]  

(4.19)

In order to avoid excessive error due to the noise, a digital smoothing process[71] is normally utilized.

4.5 DEFINITION OF THE PROPOSED PROTECTION ALGORITHM

The technique being developed to detect loss of grid is based on monitoring the behaviour at the power system to disturbances and the differences in the system characteristics between those experienced when the main source of supply is connected to the embedded generation unit and when it is operating independently. The algorithm uses changes in the power output from the embedded generator to provide an insight into the transfer function of the generator to provide an insight into the transfer function of the generating plant feeding the power system. Under normal conditions where the utility supply is connected, the transfer function reflects the combination of the main network and embedded generation unit. Following the loss of mains, it reflects the characteristics of the embedded source only. The utility system capacity and its inertia constant are very large
compared with those of embedded generation unit alone. These differences will cause the embedded generation unit to response differently to a disturbance when it is in the isolated operation mode than that when operating in the parallel operation mode. The difference in the response to the same disturbances provides on immediate basis for determining whether or not the utility supply is disconnected.

This situation can be explained by analyzing the behaviours of the embedded generation unit in both parallel operation and isolated operation modes. Suppose that the power system consist of \( n \) machines if there is a load impact of \( \pm \Delta P_L \) on the system, every machine will start to accelerate/retardate according to its generation and inertia constant. But the main system reacts to bring the whole machines together and pull them towards the mean system retardation.

The \( i \)th machine will share the load impact according to \([52,53,54]\)

\[
\Delta P_i = \pm \Delta P_L \frac{H_i}{\sum H_j} \tag{4.20}
\]

Equation (4.20) implies that \( H_i \) constants for all machine are given to a common base. When they are given for each
machine on its own base, the power change of any machine after load impact of \( \pm \Delta P_L \) will be obtained\([53,54]\) by replacing \( H_i \) to \( H_i \left( S_i / S_a \right) \)

\[
\Delta P_i = \pm \Delta P_L \frac{S_i H_i}{\sum_{j=1}^{n} S_j H_j}
\]  (4.21)

Where

- \( S_a \) is the common base for the whole system in MVA
- \( S_i \) is the \( i^{th} \) machine rated capacity in MVA
- \( H_i \) is the \( i^{th} \) machine inertia constant and defined as the stored energy in the machine rotating parts per unit of VA or MVA, hence it has the units of in (MW sec/MVA) or seconds at unity power factor.

The inertia constant \( H \) for steam turbo-generators varies from 10 MW.sec/MVA for machines up to 30 MVA to values in the order of 4 MW.sec/MVA for large machines, the value decreasing as the capacity increases. For a salient-pole water wheel machines, \( H \) depends on the number of poles; for machines in the range of 200-400 rev/min the value varies from about 2 MW.sec/MVA at 10 MVA rating to 3.5 at 60 MVA, the value increasing as the machine capacity increases.

If it is supposed that the embedded generation unit operates in parallel with the utility supply as seen in Fig.1.1, and both the utility supply and the embedded
generator are modelled by idealized generators. When the embedded generator is operating in parallel with the utility supply, the system voltage and frequency are determined by the utility system and any change in the system load of \( \pm \Delta P_L \) produces a negligible change in the embedded generator's loading of \( \pm \Delta P_g \). From equation (4.21)

\[
\Delta P_g = \pm \Delta P_L \left( \frac{H_g S_g}{H_g S_g + H_m S_m} \right) \tag{4.22}
\]

Where;

- \( H_g \) and \( H_m \) are the inertia constants of the local generator and the utility system respectively.
- \( S_g \) and \( S_m \) are the local generator capacity and utility capacity respectively.

After loss of mains, any change in the system load will directly affects the embedded generator, since the equation (4.22) will reduce to equation (4.23);

\[
\Delta P_g = \pm \Delta P_L \tag{4.23}
\]

Then, the change in the load \( \pm \Delta P_L \), the embedded generation and the local system inertia constant will define the system behaviour after loss of grid. Some time after loss of grid, i.e after change in the generator load,
the control functions will respond to match the generator output power to that of the islanded load, and hence will attempt to maintain system frequency and voltage within the pre-set limits.

The new protection algorithm monitors the change in the power output over a defined sampling window. The rate of change of power is first amplitude limited and then it is integrated over a defined period. The tripping is occurred, when absolute value of the integrator output exceeds the trip setting. The algorithm mainly consists of four steps as seen from the flow chart in Fig.4.1.

Step I. Measurement of the Three Phase Power
Step II. Calculation of Rate of change of Power
Step III. Moving Average of Rate of Change of Power
Step IV. Trip Decision

4.5.1. Measurement of The Three Phase Power

The first step of the new digital algorithm is to measure the three phase instantaneous power at the embedded generator terminal. The generators three phase power output is derived by using

\[ P_g = v_a i_a + v_b i_b + v_c i_c \quad (4.24) \]
Where the values of $v_a, v_b, v_c, i_a, i_b$ and $i_c$ represent the sampled values of the instantaneous phase voltage and line current derived from the data acquisition system. If it is assumed that $i_a + i_b + i_c = 0$, above equation will be equal to:

$$P_g = v_{ab}i_a + v_{cb}i_b$$  \hspace{1cm} (4.25)

Where $v_{ab} = v_a - v_b$ and $v_{cb} = v_c - v_b$. Thus the two-wattmeter connection is a measure of the three individual phase power readings. For a balanced system the generator three phase power output will be equal to:

$$P_g = 3VI \cos \phi$$  \hspace{1cm} (4.26)

As seen in equation (4.26) $P_g$ is the active power output from the embedded generator and sinusoidal components, hence the power system frequency terms have disappeared from the power equation. However, since the power systems are not usually balanced and also the voltage and current signals generally contain harmonics, a pre-power filter or an averaging process as seen in equation (4.3) and (4.16) could be necessary for the power output to eliminate the sinusoidal component of the power due to the unbalanced conditions and to attenuate high frequency interference present on the power signal. A moving average process can also be utilised for this purposes, then the signals from
system (voltages and currents) do not need to be synchronized to the power system frequency, and sampling frequency is not critical as long as the three voltage and three current samples are taken at the same instant by using simultaneously triggered sample and hold circuit.

An integrated protection scheme for an embedded generation unit will also require these signals, three phase currents and three phase voltages, for multifunction relaying purposes, therefore, the new loss of main protection algorithm considered suitable for including into an integrated protection package for the embedded generation units without dramatically increased the hardware requirements.

4.5.2 Rate of Change of Power

In the second step, the rate of change of power (ROCOP) is calculated from the measured power output at the generator terminal. From equation (4.19) the rate of change of the power:

\[
\frac{\Delta P_g(j+1)}{\Delta t} = \frac{[P_g(j+1) - P_g(j)]}{\Delta t}
\]  (4.27)

Where
\[
\Delta P_g(j+1) \text{ is the change in the power at the instant of } (j+1) \text{ in (MW/sec)}
\]
\( P_g(j+1) \) is the estimated real power at the instant of \( (j+1) \)
\( P_g(j) \) is the estimated real power at the instant of \( i \)
\( \Delta t \) is the sampling interval:

As long as the sampling frequency is constant, it is not necessary to divide equation (4.27) by \( \Delta t \). Then, equation (4.27) will be:

\[
\Delta P_g(j+1) = P_g(j+1) - P_g(j) \quad (4.28)
\]

Using equation (4.28) for rate of change of power estimation will eliminate a division in every step during the manipulation and makes the algorithm faster. But it is necessary to take this into account for the calculation of the trip setting.

4.5.3 Moving Average of Rate of Change Power

In the third step, the amplitude of rate of change of power is limited to a value and then integrated over a defined moving window, so that the protection algorithm should remain stable during conditions of extreme load unbalance and load fluctuations. In addition, this signal clipping process before the integration will determine the earliest trip time, whereas the length of the moving window defines the maximum trip time for the algorithm.
A moving average process is utilised to smooth the relaying signals before applying the trip decision process. This moving average technique has a low pass filter effect, and makes the new protection algorithm stable during the power oscillations in the parallel operation mode. It linearises the relaying signal and provides more reliable signals for trip decision.

When the generator is subjected an unbalanced condition, its power output will oscillate at twice the power system frequency around the real power. The averaging process will remove the effects of these sinusoidal oscillations before the trip decision. Hence the algorithm will not respond to unbalanced operation conditions.

From the equation (4.17) or (4.18), the moving average of rate of change of power amplitude limited will become;

\[ N \cdot Y(n) = R_s = \sum_{n=0}^{N-1} (\Delta P_g)_n \]  

(4.29)

where

\( \Delta P_g \) sampled value of a amplitude limited rate of change of power

n is the sampling instant of \((\Delta P_g)_n\).

N is the length of the moving window period

Since the sampling frequency is constant, there is no need
to divide the equation (4.29) by $N$, as long as this situation is taken into account during the definition of the trip setting for the algorithm. Elimination of the division will make the algorithm easier to implement.

In the last step; the Protection trip criteria is defined by;

$$|R_a| > k_a$$  \hspace{1cm} (4.30)

When the absolute value of the integrator output signal $R_a$ exceeds the trip setting $k_a$ the algorithm will trip, otherwise it will be stable. Where, $k_a$ is the trip setting and will be defined section (4.5.4).

As seen equation (4.29) application of the moving average process to the relaying signal is also giving a new feature to the algorithm which provides fast tripping when rate of change of power is high and slower tripping when rate of change of power is low. This means that, when loss of grid causes a large amount of power change at the generator terminal, the new algorithm will trip quickly, conversely the tripping process will take longer time, if the change in generator power output due to loss of grid is smaller.
4.5.4. Definition of the Trip Setting

We shall consider a loss of grid which isolates the embedded generation unit from the utility system. This disconnection will change the electrical loading of the embedded generator and causes a load impact of \( \Delta P \) on it. The acceleration/retardation for the generator due to this load impact can be calculated by means of the machine swing equation. If the losses and the effect of the damper windings are ignored, the acceleration/retardation \([53,54,112]\) will be:

\[
a = \frac{d^2\delta}{dt^2} = \frac{\Delta P_g}{2 \cdot S \cdot H} \quad (1/\text{sec}) \quad (4.31)
\]

where \( a \) is the acceleration or retardation in (pu %/sec).

The power of inertia for the rotating masses of the machine liberated at any variation of the speed is proportional to the acceleration/retardation\([53,54,56]\). Thus, from equation (4.31), the rate of change of power following the disturbance will be:

\[
\Delta P_j = k \cdot \frac{\Delta P_g}{S \cdot H} \quad (\text{pu/sec}) \quad (4.32)
\]

Where \( k \) is a constant coefficient.
This equation shows that the rate of change of power is defined by the generator inertia constant and the load impact after the disturbance. These also affect the trip setting of the algorithm which is based on the rate of change of power. In addition to these, the moving window period and sampling frequency will also affect the trip setting. However, since the moving window and sampling frequency are constant for the algorithm, their effects will be the same for every generator. The trip setting will be different for generator which have different inertia constant and different capacity.

If the algorithm is desired to trip, at the presence of \( \Delta P(\%) \) per unit change in the generator’s real power, the trip value in per unit base will be:

\[
k_s = \pm k^* \frac{\Delta P}{H} \frac{T_w}{t_s} \quad (\text{pu \%} / \text{sec}) \quad (4.33)
\]

If the equation (4.33) is multiplied by \( P \), the trip setting in (MW/sec) will be defined as:

\[
k_s = (\pm) k^* P^* \frac{\Delta P}{H} \frac{T_w}{t_s} \quad (\text{MW/sec}) \quad (4.34)
\]

where

\( T_w \) is the moving window in (msec)
$t_*$ is the sampling interval in (msec)

$k_*$ will be the trip value in (pu/sec) or (MW/sec) at unity power factor for the generator having the inertia constant of $H$ and rated capacity of $S$. $S$ is equal to $P$ at unity power factor.

Since the number of samples in the moving window; $N = T_*/t_*$, equation (4.34) will be;

$$k_s = \pm k*P* \frac{\Delta P}{H}*N$$

(4.35)

The computer simulation results which will be given in chapter 6, and the real time test results which will be discussed in chapter 8 show that having the coefficient $k$ as one matches the above equations with the simulation results.

The minimum trip time $t_*$ can be defined by limiting the magnitude of the rate of change of power just before the integration. The limited magnitude of the signal can be calculated as follow.

$$C_s = \frac{k_s}{t_m}$$

(4.36)
Thus, the integration of the rate of change of power magnitude limited a never reaches the trip level before $t_1$ (msec).

As a result, as seen equations (4.34) and (4.35) the higher capacity of the generator, the high trip setting for the same percentage of change in power. Conversely, the higher inertia constant of the generator, the lower trip. When the relaying signal, i.e., the absolute value of the integrator output exceeds trip setting $k_s$, the relay will trip, otherwise it remains stable.

As seen from the equation of (4.22), a small part of the load fluctuations is seen by the embedded generator when the machine is running in parallel with the utility network. Furthermore, since the new algorithm integrates the rate of change of power over a defined period of time the relay remains stable during the load switching operations in the parallel operation mode.

4.6 SUMMARY

As explained above, the new digital protection algorithm for loss of mains protection monitors the active power output of the generator measured at the machine terminal, and integrates the rate of change of power over a defined sample period. Tripping occurs, when the integrated signal
exceeds the trip setting. The trip signal is given to open the inter-tie circuit breaker connecting the two systems to leave the embedded generation unit alone.

The features of the new digital protection algorithm can be summarised as follows.

i. The new algorithm is based on passive techniques which do not directly influence the operation of the power system.
ii. It monitors the major power system quantities, i.e. phase voltages line currents and quantities derived from them or their waveforms.
iii. It is independent of power system frequency, and does not need high sampling frequency and sophisticated filtering process.
iv. It also avoids the use of sophisticated digital signal processing.
v. It provides immunity to mal-operation under the conditions of spurious load fluctuations, extreme load unbalanced or when transducers fail to provide input for the relay.
GET INITIAL VALUES:
- MOVING AVERAGE WINDOW: $T_w$
- SAMPLING INTERVAL: $t_s$
- VALUES FOR LIMITING: $C$
- TRIP SETTING: $k_s$

$k = 0$

GET THREE PHASE VOLTAGES and CURRENTS

CALCULATE THE THREE PHASE INSTANTANEOUS POWER
$$P = V_a I_a + V_b I_b + V_c I_c$$

PRE-POWER FILTER

CALCULATE THE RATE OF CHANGE OF POWER: $DP$

? IS $DP$ GREATER THAN UPPER LIMIT $\implies DP = \text{UPPER LIMIT} = C_s$

? IS $DP$ LESS THAN LOWER LIMIT $\implies DP = \text{LOWER LIMIT} = -C_s$

CALCULATE THE MOVING AVERAGE OF RATE OF CHANGE
OF POWER OVER THE MOVING WINDOW: $T = R_s$

? IS MOVING AVERAGE GREATER THAN TRIP SETTING $\implies k = k + t_s$

TRIP

Figure 4.1. Flowchart of the Digital Power Based Algorithm for Loss of Grid Protection.
CHAPTER 5

MODELLING OF A POWER SYSTEM CONTAINING AN EMBEDDED
GENERATION UNIT

5.1 INTRODUCTION

As stated before, embedded generation units normally run in parallel with the utility and generate the power for the site (local) loads, but whenever the operation exceeds the local demand they will start to export power into the utility network. Conversely, if the local demand exceeds the generation, they will import power from the utility supply. It is also preferred that these generation unit feed the site loads alone whenever the utility supply is disconnected. Since most of embedded generation units consist of synchronous generators, throughout this study it will be assumed that the local generators are salient-pole synchronous generators.

In this chapter, modelling of a power system including an embedded generator with a site load will be discussed. It is not intended to provide an exhaustive treatment of the synchronous machine. The aim of this chapter is to select and discuss a convenient model of the synchronous machine to simulate the loss of grid event for an embedded generation unit connected to the utility network. A
simulation software based on the selected model has been written in Fortran programming language to analyze the behaviour of the local generation unit under following conditions:

- Parallel Operation with the Utility Network (POM).
- Islanding (Loss of the Utility supply-LOG).
- Operating Independently from the Utility Network (INOM).
- Unsupervised reconnection with the Utility supply (REC).

The state-space model of the synchronous machine which is also very useful for the control of the synchronous machine has been chosen and detailed for this purposes.

5.2 MODELLING OF AN EMBEDDED GENERATION UNIT.

5.2.1. The General Synchronous machine Model.

The most complex element of a power system is the synchronous generator. A set of mathematical equations representing synchronous machines is utilized to simulate the behaviour of the synchronous generator during the transient and/or steady state period. Some kinds of mathematical models ranging from simple classical model to highly complex models have been used for many years [72,73,74,....,92]. All of these models have been developed from fundamental machine equations[72,73,74,75]. The accuracy and computational cost are the two main factors affecting
the selection of a mathematical model of the generator for a particular study.

Although it is simple, the elementary classical synchronous machine mode\cite{74,76,91,92} is not always sufficient to represent the machine during the power system analysis. It can be utilized for load flow and short term transient analysis only. Despite its complexity, the general synchronous machine model has been widely used with some assumptions\cite{74,75,76,79,80,83} to analyze the machine. On the other hand, there have been significant improvements in the application of numerical and computational methods, hardware and software implementation, these led researchers to use the full model of the synchronous generator \cite{74,75,86,88,90} including a speed-governor model and automatic voltage regulator (AVR) model.

The general synchronous machine equations were derived by R H Park\cite{72}. The equations related to an ideal synchronous machine were defined by the same author\cite{73}. These general equations hold for any manner of variation of the speed of the machine, and any kind of transient change of currents and voltages. The ideal synchronous machine is defined as follow.

i. Saturation and harmonic effects are neglected. This is also common in theory of alternating-current machines.

ii. The magnetic circuit and all rotor windings are assumed
to be symmetrical both with respect to the direct axis in
line with the field poles and to the quadrature axis 90°
away from it.

iii. A current in any winding is assumed to set up an m.m.f
wave sinusoidally distributed in space round the air-gap.
Any m.m.f wave may be resolved into components along the
two axes.

iv. It is assumed that a component of m.m.f acting the
direct axis produces a sinusoidally distributed flux wave
which also acts along the direct axis. Similarly, a
quadrature-axis m.m.f produces a sinusoidal quadrature-axis
flux. The factors relating m.m.f and flux are, however,
different on the two axes in a salient-pole machine.

v. The stator slots cause no appreciable variation of any
of the rotor inductances with rotor.

vi. As seen in fig.5.1 the ideal machine has;

- Three stator windings on A, B and C axis placed at 120°
circumference. The voltages and currents in these
windings are applied to the system.
- One field winding along the d-axis. The voltage applied
to this winding comes as the output of the excitation
system.
- One damper winding on d-axis, another one on q-axis.
These are not actual windings with a well defined number
of turns, but they represent effects of currents in the
damper bars during the transient conditions
5.2.2. The State-space Model of the Synchronous Machine

The state-space model of the synchronous machine, by taking into account the ideal machine model, is in the form of

\[
\frac{dx}{dt} = f(x, u, t) \tag{5.1}
\]

where \(x\) is a vector of state variables consisting of generator flux linkages or currents, \(u\) is the system driving function consisting of generator voltages and mechanical torque, \(t\) is the time and \(f\) is a set of non-linear function. If the equations describing the machine is linear, then (5.1) will be well known form of

\[
\frac{dx}{dt} = Ax + Bu \tag{5.2}
\]

Choosing machine currents as state variables has an advantage of offering simple relations between voltage and state variables (through the power network connected to the machine terminal) and the model is called 'The Current State-Space Model'. If saturation of the inductance is taken into account, the flux linkages have to be chosen as state variables and this time the model is called 'The Flux State-Space Model'.

As seen in Fig 5.1, the machine is assumed to have three stator windings on the stator, one field finding and two
damper windings on the rotor. These six windings are magnetically coupled. The magnetic coupling between the windings is a function of the rotor position. The instantaneous voltage of any winding is in the form of

\[ v = \Sigma ri + \Sigma \phi \]  \hspace{1cm} (5.3)

Where, \( \phi \) is the flux linkages, \( r \) is the winding resistance and \( i \) is the current with positive direction of stator currents flowing out of the generator terminal. The generator terminal voltage equations can be written in the following form, from equation (5.3);

\[
\begin{bmatrix}
V_{abc} \\
V_{PQ}
\end{bmatrix} =
\begin{bmatrix}
R_{abc} & 0 \\
0 & R_{PQ}
\end{bmatrix}
\begin{bmatrix}
i_{abc} \\
i_{PQ}
\end{bmatrix} -
\begin{bmatrix}
\Phi_{abc} \\
\Phi_{PQ}
\end{bmatrix}
\frac{d}{dt}
+ \begin{bmatrix}
v_n \\
0
\end{bmatrix} \hspace{1cm} (5.4)
\]

Where \([v_{abc}]\) and \([i_{abc}]\) are respectively the stator voltages and stator currents vectors. \([v_{PQ}]\) and \([i_{PQ}]\) are rotor voltages and rotor currents vectors.
\[
\begin{bmatrix}
  v_{abc} \\
  i_{abc} \\
  v_{FDQ} \\
  i_{FDQ}
\end{bmatrix}^T =
\begin{bmatrix}
  v_a & v_b & v_c \\
  i_a & i_b & i_c \\
  v_F & 0 & 0 \\
  i_F & i_D & i_Q
\end{bmatrix}
\] (5.5)

Since the damper windings are short-circuited on the rotor, damper winding voltages \( v_D \) and \( v_Q \) are always zero. \([R_{abc}]\) and \([R_{FDQ}]\) are stator and rotor windings resistance matrices.

\[
[R_{abc}] = \begin{bmatrix}
  r_a & 0 & 0 \\
  0 & r_b & 0 \\
  0 & 0 & r_c
\end{bmatrix}
\] (5.6)

\[
[R_{FDQ}] = \begin{bmatrix}
  r_F & 0 & 0 \\
  0 & r_D & 0 \\
  0 & 0 & r_Q
\end{bmatrix}
\] (5.7)

\( v_n \) is the neutral voltage contribution and equals to

\[
v_n = -R_n \left[ i_{abc} \right] L_n \frac{d}{dt} \left[ i_{abc} \right]
\] (5.8)
When the system is balanced, it will be zero. Finally, $[\Phi_{abc}]$ and $[\Phi_{r_{dq}}]$ are respectively stator and rotor flux linkage vectors.

$$
[\Phi_{abc}]^T - [\Phi_a \Phi_b \Phi_c]
$$

$$
[\Phi_{FDQ}]^T - [\Phi_F \Phi_D \Phi_Q]
$$

These flux linkages and currents vectors are mutually dependent and the relationship between them can be expressed as follows.

$$
\begin{bmatrix}
[\Phi_{abc}] \\
[\Phi_{FDQ}]
\end{bmatrix} =
\begin{bmatrix}
L_{aa}(\theta) & L_{aR}(\theta) \\
L_{Ra}(\theta) & L_{RR}(\theta)
\end{bmatrix}
\begin{bmatrix}
i_{abc} \\
i_{FDQ}
\end{bmatrix}
$$

These equations are known as flux linkages equations;

Where

$L_{aa}$ : Stator-stator inductance matrix

$L_{ar}=L_{ra}$: Stator-rotor mutual inductance matrix

$L_{rr}$: Rotor-rotor inductance matrix

These matrices are defined in reference[54]. $\theta$ is the angle between reference phase A-axis and rotor direct axis as seen in Fig.5.1 and is expressed;
\[ \theta - \omega_r t + \delta + \pi/2 \]  
(5.11)

Where, \( \omega_r \) is the rotor speed and \( \delta \) is the rotor (torque) angle. If equation (5.10) is substituted into equation (5.4), the flux linkages state-space model or the current state-space model can be obtained in direct phase quantities[81]. The generator can be simulated by using one of these models. But, since the inductance matrix is time dependent, as seen in equations (5.10) and (5.11), it must be calculated in every step during the simulation in direct-phase quantities. In order to avoid time dependency, a certain transformation of variables, usually Park's transformation, is performed. Then the model can be obtained in dqo axes which is time independent.

5.2.2.1 The Park’s Transformation

The effect of Park’s transformation is simply to transform stator quantities (currents, fluxes and voltages) from phase A B C into new variables the frame of reference of which moves with the rotor. The new variables are obtained from the projection of the actual variables on three axes, one along the direct axis of the rotor field winding, called the direct axis, second along the neutral axis of the field winding, called quadrature axis and the third on a stationary axis. Then new variables will be d-axis and q-axis variables and zero sequence variables. By the
definition of

\[ [S_{odq}] = [P] [S_{abc}] \quad (5.12) \]

Where \([S_{abc}]\) represents stator quantities, in direct phase frame \([S_{odq}]\) represents transformed quantities in odq axis. \([P]\) is the improved Park's transformation matrix and defined as;

\[
[P] = \sqrt{2/3} \begin{bmatrix}
1/\sqrt{2} & 1/\sqrt{2} & 1/\sqrt{2} \\
\cos(\theta) & \cos(\theta-2\pi/3) & \cos(\theta+2\pi/3) \\
\sin(\theta) & \sin(\theta-2\pi/3) & \sin(\theta+2\pi/3)
\end{bmatrix} \quad (5.13)
\]

If the transformation (5.13) is singular, an inverse transformation also exists where:

\[ [S_{abc}] = [P]^{-1} [S_{odq}] \quad (5.14) \]

It is also noted \([P]^{-1} = [P^T]\), i.e. transformation is orthogonal. Since \([P]\) is orthogonal, the transformation is power invariant as shown below. Three phase power at the machine terminal;
\[ P_3 = [v_{abc}]^T [i_{abc}] = ([P^{-1}] [v_{odq}])^T ([P^{-1}] [i_{odq}]) \] (5.15)

then, three phase power in odq axes will be;

\[ P_3 = [v_{odq}]^T [i_{odq}] \] (5.16)

Other transformation found in the literature are not power invariant. Since the transformation (5.13) is power invariant, it produces a symmetric inductance matrix. This prevents unnecessary complications when the machine equations are normalized.

5.2.2.2 The current State-Space Model

If the transformation mentioned above is applied to (5.4) and flux linkages variables are eliminated by using (5.10), the transformed voltages equations of the generator can be obtained in dgo-axis in per unit quantities as follow.
This matrix equation can also be expressed as;

\[ u = [R(\omega) \cdot [i] - [LT] \cdot \frac{d}{dt}[i]] \]  

(5.18)
described in reference[54]. \( u \) is the input vector and \( i \) is the space variables vector. From equations (5.17) or (5.18) the current state-space model of the generator is obtained as follow:

\[
\frac{d}{dt} \begin{bmatrix} i_o \\ i_d \\ i_q \\ i_P \\ i_D \\ i_Q \end{bmatrix} = -\left([-([LT]T*R(\omega))\right]\begin{bmatrix} i_o \\ i_d \\ i_q \\ i_P \\ i_D \\ i_Q \end{bmatrix} + \left([-LT]T*[u]\right) \tag{5.19}
\]

This mathematical model of the synchronous generator is the desired form of equation (5.1) and the coefficient matrix is the function of the rotor speed. In some applications, constant speed is a good approximation for a short term transients analysis. The change in the speed directly affects the system frequency, therefore constant speed is not a good approximation for 'Loss of Grid' studies. In order to follow the generator speed during and after a disturbance, we need the generator speed equation and the relation between speed and torque angle. The well known swing equation from reference[54];

\[
T_J \frac{d\omega}{dt} = T_H - T_E - T_D - T_I - T_s \tag{5.20}
\]
Where $T_1$ is mechanical time constant and equals to twice the inertia constant, $T_m$ is the mechanical torque in per unit, $T_d$ and $T_l$ are respectively the damping torque and loss torque in per unit, $\omega$ is the generator angular speed in per unit, $t$ is the time in sec and finally, $T_e$ is the electromagnetic torque[4] in p.u and can be calculated as follow:

$$T_e = \frac{\partial W_{at}}{\partial t} = (i_d \Phi_d - i_d \Phi_q)$$  \hspace{1cm} (5.21)$$

Where, $W_{at}$ is the energy in the field.

Finally, the following relation between torque angle $\delta$ and $\omega$ can be derived in per unit from (5.11)

$$\frac{d\delta}{dt} = \omega - 1$$ \hspace{1cm} (5.22)$$

The relationship between $T_m$ and the generator output power is;

$$P_e = T_m * \omega$$ \hspace{1cm} (5.23)$$

If equations (5.21) and (5.22) are added to (5.19), the final current state-space model will be in the matrix
equations of (5.24).

\[
\begin{bmatrix}
i_o \\
i_d \\
i_q \\
i_F \\
i_p \\
i_Q \\
\end{bmatrix}
\begin{bmatrix}
\frac{d}{dt} \\
\omega \\
\delta \\
\end{bmatrix}
= \begin{bmatrix}
0 & -L_d i_q & L_d i_d & -\frac{kM_F i_q}{3T_j} & -\frac{kM_P i_q}{3T_j} & -\frac{kM_Q i_q}{3T_j} & -\frac{D}{3T_j} & 0 \\
\end{bmatrix} \tau \star R(\omega)

\begin{bmatrix}
i_o \\
i_d \\
i_q \\
i_F \\
i_p \\
i_Q \\
\end{bmatrix}
\begin{bmatrix}
\frac{d}{dt} \\
\omega \\
\delta \\
\end{bmatrix}
= -([LT] \tau \star [u])

\begin{bmatrix}
\frac{T_M}{3T_j} \\
-1 \\
\end{bmatrix}

(5.24)
This non-linear model is also in the desired state-space form as given by equation (5.1). The state variables, the number of which defines the system order, are stator currents, rotor speed and rotor angle. The input vector $u$ consists of voltages and mechanical torque. If this vector:

$$[u] = [v_o \ v_d \ v_q \ v_F \ 0 \ 0 \ T_m]$$  \hspace{1cm} (5.25)

is known, the state variable vector:

$$[x] = [i_o \ i_d \ i_q \ i_F \ i_D \ i_Q \ \omega]$$  \hspace{1cm} (5.26)

can be manipulated from the matrix equation of (5.24) by using one of numerical methods. $v_r$ and $T_m$ are the system driving functions and assumed to be constant during the simulation. This is a good approximation for short term analysis and for protective relaying purposes. If the analysis period is very long, AVR and speed-governor models would be necessary. This time $v_r$ and $T_m$ are computed by using the AVR and speed governor models. Since the damper windings are short-circuited on the rotor, two elements of the input vector, damper windings voltages, are zero. The other three elements, $v_o$, $v_d$ and $v_q$ are defined by the external circuit to which the generator is
connected. They can be computed by means of interface equations between the embedded generator and the external system.

5.2.3 Steady-State Equations of the Synchronous Generator

The mathematical model of the synchronous machine derived above are differential equations that describe the machine behaviour as a function of time. When the machine operates in a steady-state condition, differential equations are not necessary since all variables are either constant or sinusoidal variations with time. For this situation phasor equations are appropriate, and these will be derived. It is usually assumed that all machines are in the steady-state conditions prior the transient period. The phasor equations of the synchronous machine derived here will permit the calculation of the initial conditions prior to a disturbance.

At the steady-state conditions all currents are constant, in other words from the matrix equation of (5.17) mathematically,

\[
\frac{di_d}{dt} - \frac{di_q}{dt} - \frac{di_d}{dt} - \frac{di_q}{dt} - \frac{di_f}{dt} = 0 \quad (5.27)
\]

Then, from equations (5.17)
In this situation, the machine equations for the steady-state period will be:

\[
\begin{bmatrix}
V_o \\
V_d \\
V_q \\
V_p
\end{bmatrix} = \begin{bmatrix}
0 & 0 & 0 & 0 \\
r & 0 & \omega L_q & 0 \\
0 & -\omega L_q & r & -\omega kM_F \\
0 & 0 & 0 & r_f
\end{bmatrix}\begin{bmatrix}
i_o \\
i_d \\
i_q \\
i_p
\end{bmatrix}
\]

(5.29)

For the balanced conditions, the generator stator’s phasor equation can be defined as follows.

\[
\begin{align*}
V_d \& V_d/\sqrt{3} &= -ri_d - X_q i_q \\
V_q \& V_q/\sqrt{3} &= -ri_q + X_d i_d + E
\end{align*}
\]

(5.30)

Where \(E\) is the generator internal voltage corresponding to the excitation current \(i_r = v_r / r_r\) and equal to

\[
E = \frac{1}{\sqrt{2}} i_F \omega R M_P = \frac{1}{\sqrt{3}} i_F \omega R kM_F
\]

(5.31)

The stator phasor current and voltage will have two rectangular components \(I_d\) and \(I_q\) and be expressed as follow.
\[ I_a = I_q + jI_d \]
\[ V_a = V_q + jV_d \]  \hfill (5.32)

All of these equations are valid provided that the synchronous machine is in a steady-state condition and they are used to calculate the initial conditions of the machine prior to the transient simulations.

5.2.4. Modelling of The Site Loads

The loads connected to the power systems are usually combination of both static and dynamic loads, which depend on the system frequency and voltage. Voltage variations affects static loads more than dynamic load, whereas frequency variation affects dynamic loads more than static load. However, in modelling the power system, the frequency variation affects on both static and dynamic loads are usually ignored[95,96] and loads can therefore be modeled as static loads. With the preceding assumptions, the complex power of a load can be represented with equivalent impedance or admittance as a function of voltage. If certain load bus has voltage \( v_L \), power \( P_L \) and reactive power \( Q_L \), then the equivalent shunt admittance or impedance of the load will be:

\[ Y_L = \frac{(P_L - jQ_L)}{V_L^2} \]
\[ Z_L = \frac{V_L^2}{(P_L - jQ_L)} \]  \hfill (5.33)
5.3 MODELLING OF UTILITY POWER SYSTEM

For the analysis of the synchronous machine, it is generally assumed that the machine is operating in parallel with an infinite bus which provides infinite current at constant frequency and voltage. Although this is a reasonable approximation, for the studies presented in this thesis the utility can not provide infinite current at constant frequency and voltage in every conditions. Therefore, it is much more realistic to represent the utility supply as a large generator which has a reasonable inertia constant and a rated MVA. This generator can be represented by the classical synchronous machine model. The state variables for the generator represented by the classical model [54] will be the generator speed \( \omega_s \) and rotor angle \( \delta_s \) and the magnitude of the internal voltage is known.

Since the local generator is connected to the utility supply, its terminal voltages can be written in terms of the utility system in direct phase quantities as follow.

\[
\begin{bmatrix}
    v_a \\
v_b \\
v_c
\end{bmatrix} = \begin{bmatrix}
    \cos(\omega t + \delta_x) \\
    \cos(\omega t - 120^\circ + \delta_x) \\
    \cos(\omega t + 120^\circ + \delta_x)
\end{bmatrix} + i_s \begin{bmatrix}
    r_s u \\
x_s u \\
    \frac{d}{dt}
\end{bmatrix} + \begin{bmatrix}
    i_a \\
i_b \\
i_c
\end{bmatrix}
\]

(5.27)
Where, $E_*$ is the effective value of the internal voltage, of the utility generator, $\delta_*$ is the angle between arbitrary reference frame and machine rotor q-axis, if this machine is selected as a reference, it will be zero. $x_*$ is sum of the machine transient reactance and line reactance, $r_*$ is the line resistance, $u$ is a $(3x3)$ unit matrix. Finally the $[i_{abc}]$ currents vector, which is also equal to embedded generator current vector, if there is no load at the generator terminal. These are the interface equations between two generators. $[v_{odq}]$ vector is calculated by applying the defined transformation to (5.27). Thus, the last three elements of input vector for the system represented with matrix equation of (5.24) are obtained.

$$
{\begin{bmatrix}
  v_o \\
v_d \\
v_q
{\end{bmatrix}} = E_*\sqrt{3} {\begin{bmatrix}
  0 \\
-sin(\delta-\delta_*) \\
cos(\delta-\delta_*)
{\end{bmatrix}} + r_* u_{id} {\begin{bmatrix}
i_o \\
i_d \\
i_q
{\end{bmatrix}} + x_* u d\frac{dt}{dt} {\begin{bmatrix}
i_o \\
i_d \\
i_q
{\end{bmatrix}} - \omega x_* {\begin{bmatrix}
0 \\
-i_q \\
i_d
{\end{bmatrix}}}
$$

(5.28)

Thus, the last three elements of input vector for the system represented with equations of (5.24) have been obtained.
5.4 DEVELOPMENT OF A SIMULATION SOFTWARE BASED ON THE CURRENT STATE-SPACE MODEL OF THE SYNCHRONOUS GENERATOR

A simulation software based on the model derived above has been developed to simulate a simplified power system, as seen in Fig.1.1, containing an embedded generation unit, its site load together with the utility supply and its load. It has been designed according to the flow chart seen in fig 5.2 and written in fortran programming language. It can be considered that the developed software consists of two main steps:

i. Calculation of the initial conditions of the proposed system

ii. Simulation of the proposed system under applied power system disturbances

5.4.1. Calculation of Initial Conditions

Initial conditions of a power system, defined as steady-state conditions, must be known prior to the transient analysis. A load flow analysis[95] is usually carried out to determine initial conditions for the system being analyzed. For a load flow analysis, generators are represented by the classical model of a constant voltage behind the synchronous reactance and system loads are modeled with their equivalent admittance. Transmission lines are usually represented pi-model. It is also assumed
that the active power $P$ and the magnitude of the voltage $V$
are known at every generator terminal, but the active and
reactive power $P$ and $Q$ are known at every load buses. By
carrying out a load flow analysis for the proposed system
the voltage angle $\delta$ and reactive power $Q$ are found out for
the generators buses. Whereas $V$ and $\delta$ are found out for
the load buses. Thus, after load flow analysis $V, \delta, P, Q$ are
known for every bus. By using these values, every
electrical quantities can be calculated for the system. If
the system is containing a generator represented by the
idealised model of the synchronous machine, all variables
such as load angle, excitation current, electrical torque,
internal voltage and fluxes for this generator can be
calculated for the steady state conditions as explained in
section 5.2 with the aid of generator phasor diagram.
Thus, all initial conditions of the system are known just
before the transient period.

5.4.2. Simulation of the proposed system

The software developed can be utilised to examine the local
generator’s behaviour under the following power system
disturbances for both steady-state and transient periods.

i. Parallel Operation Mode (POM): In this mode, the local
generator can be run in parallel with the utility network
and the embedded generation unit can be also put in either
power exporting mode or power importing mode by changing
the site load or its input power. Thus, the response of the system to the load fluctuations taking place during the parallel operation will be able to be monitored.

ii. Loss of Grid (LOG): A power island can be created by disconnecting the two sources, embedded generator and utility generator. This is done by switching one of the circuit breakers on the utility side during the parallel operation mode and leaving a portion of the utility system being connected to the embedded system. The response to this event depends at which point disconnection has happened. In this mode, the isolation of the two systems, i.e a loss of grid event, can be produced in the following conditions:

-while the embedded system is importing power from the utility network, i.e loss of grid will result in an overload conditions for the local generator.
-while the embedded system is exporting power into the utility network, in this case loss of grid results in an over generation condition for the local system.
-while, the power flow is zero at the point where the two systems are disconnected, i.e the local generation will be equal to the island load.

In addition to these, the amount of power being exported or being imported prior to the loss of grid can be held to a specific amount by adjusting the local generator input power or the site load. The generator active power output
can also be adjusted by changing the generator's excitation current.

iii. Independent Operation Mode (INOM): If loss of grid does not cause sufficient amount of disturbances to be detected by the protective relay, the embedded generators continues to supply the load in the power island independent of utility supply. But since the utility system is disconnected, any change in the islanded load will result in a deviation in the electrical quantities on the system. The system response to the load fluctuation, while the main supply is not connected can be estimated in this mode.

iv. Unsupervised Reconnections (REC): This situation could happen if islanding is not detected quickly enough following the a loss of grid. There is a possibility that the two sources would be reconnected by the reclosing of the automatic reclosure which caused the disconnection. Since this could be an unsupervised reconnection, there is a high possibility that this will be an out of phase reconnection. This situation can be simulated by the developed software with different phase angles between two sources at the instant of reconnection.

In all of these simulation modes, the simulation programs provides ability to monitor the instantaneous system voltage, currents, machine speed and rotor angle at the
generator terminal. The other electrical quantities such as; active and reactive power, power factor and system frequency can be estimated from the monitored signals. Although in practice, the system frequency is measured by monitoring the system voltage or current, the simulation software derive the frequency from the generators speed. This provides a fast estimation of the power system frequency. All of these signals give an opportunity to analyze the performances of loss of grid protection techniques given in chapter 3 and chapter 4.

5.5 SUMMARY

Since a three phase switching operation is required to produced a loss of grid condition, "The current State-Space Model" of the generator, which is the optimum model for balanced system analysis, has been chosen to analyze the local generation unit. A simulation software based on the selected model has been written in fortran to simulate the performances of the local generator unit under power system disturbances including islanding operation. This software has been used to examine the performances of loss of grid protection algorithms by monitoring the corresponded power system signals.
Figure 5.1. The Ideal Two-Pole Synchronous Machine Model.
Figure 5.2. Flowchart of the Simulation Software Developed for the Analysis of the Power System Containing An Embedded Generation Unit.
CHAPTER 6

EVALUATION OF THE PERFORMANCES OF LOSS OF GRID PROTECTION ALGORITHMS

6.1 INTRODUCTION

Extensive computer simulation studies will be undertaken in this chapter to examine both the effects of loss of grid and of other power system disturbances to an embedded generation unit able to operate in parallel with and independently from the utility power system. The potential performances of different loss of grid protection techniques which have been discussed in chapter 3 and chapter 4 to these disturbances will be simulated by monitoring the relevant signals at the embedded generators terminal with the aid of the computer simulation program developed. The results are obtained from the analysis of an 11 kV network containing a 3.75 MVA embedded generator with an inertia constant of 0.91 MW sec/MVA and 0.8 power factor, 3.75 MVA local load with 0.8 power factor, and a utility source of supply of 250 MVA with an inertia constant of 10 MW sec/MVA (Full data in dq0 axis frame for the embedded generator will be given in Appendix A). The results do not include the action of the embedded generator's control functions, i.e. the automatic voltage regulator (AVR) and the prime mover's speed governor (SG),
since these functions can not respond within the period of interest after the disturbances. The local generation is equal to the local generator's rated capacity prior to the disturbances.

The test period has been chosen to be one second, starting 100 msec before the disturbance. The trip levels used to represent the operation of the relays are taken from Engineering Recommendation G59[1] and Engineering Technical Report 113[4], and ± 6% of the nominal voltage for under/over voltage relays, ± 1% for under/over frequency relays, and ± 0.3 Hz/sec for rate of change of frequency relay. The trip setting for the new digital protection algorithm is chosen such that a one percent change resulting from loss of grid in the generator real output power based on generator's rated capacity would just produce the trip signal. The length of the moving window is chosen to give a maximum operating time of six cycles and the amplitude limiting of the rate of change of power is chosen to provide a minimum trip time of one cycle for the rate of change of power algorithm. The trip setting has been calculated to be 5 units for the generator being simulated.

The under/over voltage relays makes the trip decision according to the effective value of voltage calculated from digital samples of instantaneous phase voltage at the generator terminal. No time delay is applied, hence it
will produce a trip signal, whenever the change in the voltage exceeds the trip setting.

Power system frequency and rate of change of frequency is normally estimated from digital samples of instantaneous system voltage or current as discussed in chapter four. However, throughout these computer simulation studies the system frequency and its rate of change will be derived from the generator’s speed. Apart from rate of change of power algorithm, no attempt is made to emulate the operation of the particular protection algorithms used for under/over voltage, under/over frequency and rate of change of frequency protection. Practical protection algorithms would required additional time for the data acquisition and signal processing before tripping following a loss of grid.

The simulation studies which will be carried out in this chapter can be divided into four different sections.

- Simulation Studies For Loss of Grid.
- Simulation Studies For Independent Operation.
- Simulation studies For Non-Synchronizing Reconnection.
- Simulation Studies For Parallel Operation.

Every section will have some case studies which will be explained by using related curves. These curves will be representing the phase to ground voltage at the generator terminal, generator terminal current, system frequency,
rate of change of frequency, generator real power output, rate of change of power, and moving average of rate of change of power, i.e. the output of the integrator in the proposed loss of grid algorithm.

6.2 COMPUTER SIMULATION STUDIES FOR LOSS OF GRID

The purpose of these loss of grid simulation studies is to estimate the performances of loss of grid protection algorithms under different cases where the disconnection of the utility supply leaves different amount of utility's load left connected to the embedded generation unit.

The effect of loss of grid on an embedded generation unit depends wherein the power system utility supply has been lost. If the disconnection happens at a point where the power flows into the utility, loss of grid results in an excess generation in the power island, whereas if the direction of the power at the switching point is from utility into the local system, loss of grid results in an overload condition for the embedded generator. Switching operation would be at a point where disconnection of the two systems may not produce abnormal disturbances in the power island.

Excess in the reactive power in the power island increases the system voltage, whereas excess in the reactive demand decreases the system voltage following the loss of the
utility supply. The balance between them keeps the system voltage within the normal operation limits.

The change in the embedded generator's loading following a loss of grid condition can be expressed by using:

$$\Delta L = \frac{(L - G_0)}{G_0} \times 100 \quad (pu\%) \quad (6.1)$$

Where

- $G_o$ is the embedded generation before loss of grid
- $L$ is the load left connected power island
- $\Delta L$ will be the change in the embedded generator’s loading

As it is seen from the equation (6.1), if the islanded load is greater than the embedded generation, the generator will be overloaded, whereas there will be an excess in the generation, if the load left connected to the embedded generation unit is less than the embedded generation following the loss of grid.

The first example for the analysis of islanding will be used to explain the new algorithm for loss of grid protection discussed in chapter four and examine its performance, whereas the following examples are to compare the performances of loss of grid protection algorithms under different loss of grid conditions.
Case Study A:

In the first example, the islanded load left connected to the embedded generation unit is four times the generator rated capacity. In other words, islanding causes 300% increase in the system loading. The system response to this overload condition is seen in Fig 6.1. Since loss of grid causes a large step increase in the generator's loading, the generator terminal current and power output suddenly increase after the loss of grid to feed the islanded load and then start to decrease for the new steady state values. The increase in the generator's stator current decreases the system voltage and this causes the under/over voltage protection relays to respond just after the disturbances as seen in Fig.6.1a. Since the generator's prime mover's governor can not respond immediately after the disturbance, the generator's input power will stay constant, the increase in the power output will force to the machine to slow down. By decreasing its speed, the machine releases some of the inertia power reserved in its rotating parts to provide power for the load increase. Some time after disturbance, the generator's power output reaches the value before the loss of mains.

The new algorithm first estimates the three phase real power at the generator terminal, the estimated power is seen in Fig.6.1c, then calculates the derivative of the
estimated power as shown in Fig.6.1d. Before the integration, the rate of change of the power is limited to 0.25 MW/sec to provide the minimum trip time of 20 msec for 50 Hz systems. The rate of change of power amplitude limited is illustrated in Fig.6.1e. In the last stage the algorithm integrates this signal, rate of change of power amplitude limited, over a six cycle moving window to linearize the relaying signal and define the maximin trip time of 120 msec for the 50 Hz systems. As it is seen in Fig.6.1f, the integrator output reaches the trip level 26 msec after the loss of grid. In addition to the defining the minimum and maximum trips time, the limitation of the magnitude of rate of change of power and the averaging process also provide immunity for the algorithm against spurious trips.

Case Study B:

A similar situation is illustrated in Fig.6.2 as a second example for the analysis of loss of grid. In this example, the islanded load left connected to the embedded generator is twice the embedded generation capacity. Immediately after loss of grid, there is again a step increase in the generator armature current due to the load impact on the generator as seen in Fig.6.2a. The fall in the system voltage causes the under/over voltage relays to trip after 4 msec. The unbalance between the generator’s input and output power results in a decrease in the system frequency
after the disconnection, hence the under/over frequency protection trips after 28 msec and the rate of change of frequency algorithm responds this situation just after the loss of grid, and trips after 3 msec as seen in Fig.6.2c and Fig.6.2d respectively. Due to the violent change in the power the rate of change of power algorithm detects the loss of the utility supply after 26 msec as seen from the integrator output illustrated in Fig.6.2f.

Case Study C:

The condition shown in Fig.6.3 corresponds to the case where the islanded load is just 5% of the embedded generation after the disconnection of the two systems. As can be seen from the simulation results, the loss of grid happens while the embedded generation unit is exporting power into the utility network. Since there is a step decrease in the generator’s load at the instant of the loss of grid, the generator’s terminal current and output power suddenly drops, and the system voltage goes up, hence reaches the trip level after 6 msec. In this situation, the difference between input power and output power accelerates the machine, then the system frequency starts to increase and reaches the trip value after 21 msec. The rate of change of frequency shows a positive peak at the instant of the disturbance which causes to trip. The rate of change of power algorithm’s signal shows a positive increase and gives the trip signal after 26 msec.
Case Studies D and E:

The response to a loss of grid resulting in a fifty percent increase in the generator loading is shown in Fig. 6.4. Following the loss of grid the generator terminal voltage has a sudden drop and continue to fall to reach the new study-state value. The fall in voltage exceeds the trip value after 7 msec. The generator terminal current and power first have step increases and then starts to decrease for their new steady-state values. The rate of change of power algorithm responds this event after 27 msec. Following the isolation, the system frequency starts to fall again and goes beyond the operation limits after 28 msec. The rate of change of frequency has a negative peak around 11 Hz/sec and causes the rate of change of frequency protection to trip after 4 msec.

A similar condition to that shown in Fig.6.4 is shown in Fig.6.5, but this time the loss of grid results in 50% decrease in generator’s loading rather than 50% increase, i.e the local generation unit is exporting power into the utility network prior to the disturbance. The generator starts to accelerate due to the decrease in the power output and the generator speed increases. Hence the system frequency reaches the upper trip level after 267 msec. The rate of change of frequency has a positive peak at around 11.5 Hz/sec at the instant of loss of mains which is over the trip level. The system voltage increases after the
loss of mains event and under/over voltage protection reaches the trip level after 105 sec. The integrator output for the power based algorithm reaches trip level within 29 msec.

Case Studies F and G:

The condition shown in Fig.6.6 corresponding to the case where the islanded load is 20% over the pre-switching embedded generation, whereas the condition shown in Fig.6.7 related to the case where the loss of mains causes 20% decrease in the local generator’s loading. In both situations, although the under/over voltage protection respond to the islanding within the interested period, it is too slow and requires 645 msec for the case F seen in Fig.6.6a and 550 msec for the case G in Fig 6.7a. The under/over frequency protection trips for both situations within a reasonable period of 142 msec as it can be seen in Fig.6.6a and Fig.6.7a.

The most effective algorithms are rate of change of frequency and rate of change of power protection. Rate of change of frequency protection has a negative peak of 4.25 Hz/sec for the case F in Fig.6.6c and a positive peak of 4.25 Hz/sec for the case G in Fig.6.7c. Both peaks are at the instant of islanding and over the trip setting for the rate of change frequency protection. The integrator output for the power based algorithm reaches the trip level within
a period of 26 msec. The relaying signals of the rate of change of power algorithm are illustrated in Fig. 6.6f for the load increase and Fig. 6.7f for the load decrease due to islanding.

Case Studies H and I:

Fig. 6.8 and Fig. 6.9 show the system responses to a 5% change in the generator's load, respectively for a 5% increase and a 5% decrease at the instant of loss of mains. The changes in the system voltage for both situations do not produce trip for the under/over voltage protection. The under/over frequency protection trips for both cases taking 604 msec for 5% increase and 576 msec for 5% decrease in the generator's loading. The rate of change of frequency algorithm reaches the trip level just after the isolation for both conditions. The trip times are 29 and 28 msec for the rate of change of power protection respectively.

Case Studies J and K:

The marginal trip condition for the algorithm using rate of change of power is shown in Fig 6.10 and Fig 6.11, where loss of the main source of supply results in a 1% change in the generator's loading respectively. It produces trips after 121 msec for both situations. In both cases the limits for under/over voltage, under/over frequency and
rate of change of frequency do not exceed.

Case Studies L:

A very special case where the disconnection of the two systems does not result in any change in the generator's load. Although it is unlikely that this would happen in a real system, it is not unknown. When the disconnection occurs in a part of the system at which power flow is nearly zero at the instant of switching operation, there is no disturbance for the passive techniques to detect and hence they will not operate. Typical responses are shown in Fig.6.12, the system will continue its normal operation.

The above computer simulation results show that, under/over voltage relays and under/over frequency relays provide a limited protection for loss of grid. They are generally too slow for detection of an islanding. The rate of change of frequency algorithm is effective and seems to be fast. However, in these studies the power system frequency, as has been stated before, has been estimated from the generator swing equation. The trip time and accuracy of frequency measurement for under/over frequency relay and rate of change of frequency relays directly depends on frequency measurement method utilized in a practical system.
The rate of change of power algorithm is the most effective technique to detect a loss of utility supply. Its time characteristic against load changes due to the loss of grid is illustrated in Fig. 6.13. The minimum trip time is 26 msec at the case where islanding causes a doubling the generator load. The maximum trip time is 121 msec and it occurs when disconnection results in 1% change at the generator's real power output. The parameters used in this algorithm has been designed so that the minimum trip time is 20 msec and maximum trip time is 120 msec.

6.3 COMPUTER SIMULATION STUDIES FOR INDEPENDENT OPERATION

In this section, the response of loss of grid protection algorithms to the load fluctuations in the isolated operation mode has been examined. The behaviour of the loss of grid protection relays under load fluctuations will become important, when the isolation of the two systems has not been detected at the instant of the disconnection. Since the local generation station will continue to feed part of the utility's load, the local protection system should open the inter-tie breakers as quickly as possible to de-energise the utility part of the power island. As it is explained before, a local generation unit is not generally allowed to supply these utility's customers left connected to the power island without the utility's main source of supply.
Case Study A:

An example of load switching, while the embedded generator is feeding the power island independently of the utility supply is shown in Fig 6.14. A load in the power island which is equal to the generator’s rated capacity is switched on, causing 100% step increase in its loading. Since the local generator is overload after the switching operation, the system voltage decreases as shown in Fig.6.14a, hence under/over voltage relay trips after 8 msec. The system frequency also decreases, causes the under/over frequency relay to trip after 31 msec and the rate of change of frequency has a negative peak of 20 Hz/sec at the instant of load change which is over the trip setting. The change in the system frequency and its rate of change are illustrated in Fig.6.14c and Fig.6.14d. The integrator output of the power based algorithm reaches its trip setting of 5 within 29 msec.

Case Studies B and C:

The responses to the load changes in the isolated operation mode are seen in Fig.6.15 and Fig.6.16. Fig.6.15 shows the case where the switching increases the generator’s load 50%. All of the protection algorithms trip for this situation. Tripping time are 70, 59, 4 and 28 msec for under/over voltage relay, under/over frequency relay, rate
of change of frequency relay and rate of change of power algorithm respectively.

Fig.6.16 shows the case where there is 50 % step decrease in the generator power output due to the load switching. These curves are generally the inverse of those shown in Fig.6.15. The tripping times for under/over voltage, under/over frequency, rate of change of frequency and rate of change of power protection are respectively 52, 47, 4 and 25 msec following the load switching operation.

Case Studies D and E:

Two other examples of load switching operation, while the embedded generation unit is operating independently from the utility network, are shown in Fig.6.17 and Fig.6.18. Although load changes are limited to an increase of 5% and a decrease of 5% of the generator’s rating, apart from under/over voltage relay, all of the other protection techniques trip to disconnect the inter-tie between the embedded system and the utility part of the island. These tripping times are 735 msec for under/over frequency protection, 4 msec for rate of change of frequency protection and 28 msec for rate of change of power protection following a 5% step increase in the island load. The trip times are 685 msec, 4 msec and 29 msec for the under/over frequency relay, rate of change of frequency
relay and rate of change of power relays respectively for the case where load switching causes 5% step decrease in the system loading.

Case Studies F and G:

The marginal cases shown in Fig.6.19 and Fig.6.20. Load switching causes a 1% step change in the system load. For both cases, rate of change of power algorithm will detect the switching operation after 123 msec. The other algorithms fail to trip for this conditions.

For the above conditions, the loss of grid protection would trip the inter-tie breaker and isolate the embedded system from the utility network. However, if the inter-tie breaker has already been tripped, operation of the protection would be of no consequence. These computer simulation results show that the performances of relays to the load switching operation in the isolated operation mode are the similar to these under loss of grid conditions.

6.4 COMPUTER SIMULATION STUDIES FOR OUT OF PHASE RECLOSING

The operation of circuit beaker in the power system can result in power transient and current oscillations which can stress or damage generating units, synchronous and induction motors located electrically close that circuit
breaker[98,99,100,101,102,103,104,105]. The power and current transient will affect various components of the turbine-generators. These components include the unit shaft and all rotating parts in the exciter, generator and turbine, and generator stator elements.

A problem arises for an embedded generation unit, when an islanding has not been detected following the loss of the utility supply, if the remote circuit-breaker creating the loss of grid is reclosed without using synchronising system. This will almost certainly be disastrous for the embedded generator, thus the need for the local protection system must trip the inter-tie breaker as quickly as possible following the islanding. The possibility of an unsupervised reclosing with a phase difference between the two sources, becomes higher due to the presence of high speed automatic reclosures on the system. Most of the utilities use multiple shot reclosing for their distribution systems. The initial reclosure can be high speed (0.2-0.5 second) or delayed a few seconds. Then, one or two additional time delayed reclosures may be programmed [100].

The magnitude of the effect of an out of phase reclosing on a generator nearby depends on the phase difference between two sources and the utility system source impedance at the switching point. If the utility source reactance is
smaller than the generator negative-sequence reactance, a three phase out of phase reconnection will then produce more severe torques at the generator air-gap than other short-circuit conditions\[99,101,102\]. The highest faulty synchronising torque will occur, when the generator is connected approximately 120 electrical degree out of phase with the utility source\[99,100,101\]

In this section, out of phase reconnection of the embedded generator to the main source of supply has been analyzed. This is done by closing one of the remote circuit breakers on the utility side, while the embedded generation unit is operating independently from the utility supply with its rated capacity and feeding the same capacity of local load. At the instant of reclosing, the voltage and frequency will be equal to those of the utility supply, but there will be a phase difference between the two sources.

Case Study A:

An example of out of phase reconnection of the two supplies, the embedded supply and the utility supply, following a failure to detect the loss of mains is shown in Fig.6.21 where the phase difference between two sources is 180° at the instant of the reclosure. As shown in Fig.6.21b and Fig.6.21c, there are severe oscillations in the current and power measured at the generator terminal.
After these large oscillations the generator starts to operate as a synchronous motor drawing power from the utility supply. Fig.6.21a shows that following the reclosing, the system voltage measured at the generator terminal oscillates and goes beyond the operation limits for the under/over voltage protection for 525 msec and then settles within the operation limits. Because of the high inertia of utility system, the system frequency and its rate of change do not reach the trip levels.

The generator power output, its rate of change, the amplitude limited rate of change of power and the integrator output for the power algorithm are shown in Fig.6.21c, Fig.6.21d, Fig.6.21e and Fig.6.21f respectively. The filtering feature of the rate of change of power algorithm delays the operation of the new algorithm and tripping occurs after 218 msec. This delay is due to the sinusoidal oscillation in the generator power output.

Case Studies B and C:

Similar situations are seen in Fig.6.22 and Fig.6.23 where out of phase reclosing occurs when the phase differences between the two sources are ±120° respectively.

In the first situation, the embedded generator is 120° behind the utility supply prior to the reclosure. The
system response is shown in Fig. 6.22. Following the out of phase reclosing, the machine oscillates and starts motoring. The oscillations in the system voltage go beyond the operation limits for a period of 92 msec only, and then stays within the limits. Fig. 6.22c and Fig. 6.22d show that the system frequency and its rate of change do not exceed the trip levels within the interested period. The only secure trip for this non-synchronized reclosure is produced by the new loss of grid algorithm, which occurs after 168 msec.

Fig. 6.23 corresponds to the case where an out of phase reclosing occurs, while the embedded generator is 120° in front of the utility source of supply. Following the reclosing, the local generator tries to supply the synchronising power to synchronise with the utility supply, but shortly after reconnection, the pole slipping occurs. This pole slipping produces severe change in the system voltage and current monitored at the generator terminal as shown in Fig. 6.23a and 23b. The system voltage reaches the trip value just after 12 msec. Although the system frequency does not produce trip, the rate of change of frequency exceeds the trip level after 168 msec due to the pole slipping. Fig. 6.23e shows that there are severe oscillation in the power monitored at the local machine terminals, both taken from and fed to the generator during the pole slipping. The response of the new algorithm to
this reclosure produces a trip after 128 msec following the reconnection. This is before the pole slipping.

Case Studies D and E:

Fig.6.24 and Fig.6.25 show the cases where reclosing occurs, while the phase difference between the local system voltage and the incoming supply voltage are ±60°.

In the first situation, the out of phase of reconnection of the two systems occurs, while the embedded generator is running behind the utility supply with a phase difference of 60°. Immediately after the reconnection, the local generator starts to oscillate in a motoring range. Some time after reclosing, the generator output reach a new study state value and it continues to operate as a synchronous motor. The rate of change of power algorithm produce a trip after 245 msec.

The system response to an out of phase reconnection of the two systems while the local generator is 60° in front of the utility generator is shown in Fig.6.25. Immediately after the reclosing with the main supply, the embedded generator tries to provide the synchronising power, but following the oscillating it moves to the motoring condition as it is illustrated in Fig.6.25a. The tripping time of the new algorithm is 130 msec.
In both situations, the system frequency and the system voltage are maintained by the main supply. Hence, the limits on the system voltage, frequency and its rate of change are not exceeded.

Case Studies F and G:

Where the phase differences between the two sources are ±30° at the instant of reconnection of the embedded generation unit with the utility supply are also shown in Fig.6.26 and Fig.6.27. Following the reconnection, both the system voltage and the system frequency are maintained hence, the under/over voltage relay, the under/over frequency relay and rate of change of frequency relay do not response for both cases. The rate of change of power produces trips for both conditions, as shown in Fig.6.26f and Fig.6.27f, with times of 240 and 170 msec respectively. The power oscillations for these conditions are not much severe as in the previous.

Case Study H:

Finally, the extreme condition is shown in Fig.6.28, where the two systems are matched at the instant of reclosure. Since the systems are matched the voltage on both sides of the reclosing circuit breaker are equal in both magnitude and phase, and the frequency of the two sources are also
equal to each other just before the reclosing. Since these are the ideal synchronizing conditions, there is no disturbance at the electrical quantities to be detected by the relays.

Above simulation results have showed that, an out of phase reclosing with 180° phase difference forces to the local generator oscillates between motoring region and the generating region by taking power from and feeding power into the utility network and until the machine reaches a steady state condition. As it is expected, the maximum magnitude of oscillations at the generator output occurs, when generator is lagging the utility by 120°. This is followed by the cases where phase differences are 150° and 90° prior to the reclosing. Although the system voltage exceeds the trip level during the oscillation period following the disturbances for some cases, it does not produce secure trips. The new algorithm produces a trip output for every case, with the minimum trip time of 168 msec for 120° out of phase reclosing. The maximum trip time is 240 msec for 30° out of phase reclosing.

If a non-synchronized reclosure occurs, while the embedded generator is leading in front of the utility supply, the machine oscillates in the generating region and attempts to provide the synchronizing power. However, the pole slipping occurs for the case where the phase differences
are 150°, 120°, 90° and 60°. The change in the system voltage exceeds the trip value when the pole slipping happens. The rate of change of power algorithm trips for all cases of out of phase reclosing.

Since the embedded system capacity and its inertia constant are very small comparing with those of the utility supply, the system frequency is always maintained. Hence, the under/over frequency protection and rate of change of frequency algorithms do not generally respond these out of phase reclosing events. The rate of change of frequency protection can however trip due to the pole slipping.

6.5 COMPUTER SIMULATION STUDIES FOR PARALLEL OPERATION

The response of an embedded generation unit to the load fluctuations with utility supply connected are going to be examined in this section. The main purpose of doing this analysis is to ensure that the behaviour of loss of grid protection algorithms do not trip due to the load switching operation. Two different cases corresponding to the situations where local load is being switched on and off are simulated. The embedded generator is operating at its rated capacity with the local load equal to this just prior the switching operation.

The first example of load switching, while the embedded
generation unit is running in parallel with the main source of supply, is shown in Fig 6.29. The additional load being is half of the local generator capacity. The curves which are monitored at the local generator terminal represent the system voltage, generator armature current, generator power output, its rate of change, rate of change of power amplitude limited and the integrator output.

Fig.6.30 and Fig.6.31 show two examples where the load switching operation doubles and removes the local load during the parallel operation. The system voltage, generator armature current, system frequency and its rate of change, generator output power and the moving average of rate of change of power are monitored for both situations. The curves in Fig.6.30 are corresponded to the case where the switching operation causes 100% increase in the system loading are similar to the inverse of those of Fig.6.31 representing the case of 100% load decrease, i.e. to a no load condition.

In both situations, none of the protection limits are exceeded and the protections remain stable. Since the local system capacity and its inertia power are very small in comparison with those of the utility network, the disturbances are handled by the utility supply, with only a small part being handled by the local generator. Although there are some oscillations in the power at the
embedded generator terminal, the signal limiting and filtering feature of the moving average process in the power based loss of grid protection removes these and ensure that the new algorithm stable, as shown in Fig. 6.29.

6.6 SUMMARY

The comparative performances of loss of grid protection algorithms including under/over voltage, under/over frequency, rate of change of frequency and rate of change of power have been examined using computer simulation. In addition to the loss of grid, the analysis has also examined load switching operations in both parallel and independent operation modes, and non-synchronised reclosure.

The computer simulation has showed that:
- Under/over frequency and under/over voltage relays provide a limited protection against loss of grid. Although the rate of change of frequency relay shows better performance, it has some limitations for detecting loss of mains.

- The rate of change of power algorithm is the only effective method to detect the out of phase reclosing with the utility supply, although its filtering feature causes to delay for tripping. The under/over frequency relay fails
to detect the out of phase reconnection for all these cases. The rate of change of frequency protection can trip following the pole slipping.

- The relays' responses to the load changes in the independent operation mode are similar to the those of loss of grid producing the same amount of load changes in the generator.

- None of the loss of grid protection algorithms trips for the disturbances during the parallel operation mode.

Although the results are not included in this thesis, the performances of the rate of change of power algorithm has also been examined by using ATP version of the EMTP[109]. The results using the EMTP to simulate the system were the same as those using the simulator described in this thesis.
Figure 6.1. System Response to a Loss of Grid Resulting in Four Times Increase In the Generator's Loading.
Figure 6.2. System Response to a Loss of Grid Resulting in a 100% Increase in the Generator's Loading.
Figure 6.3. System Response to a Loss of Grid Reducing the Generator's Load to 5% of the Embedded Generation.
Figure 6.4. System Response to a Loss of Grid Resulting In a 50% Increase In the Generator's Loading
Figure 6.5. System Response to a Loss of Grid Resulting in a 50% Decrease in the Generator's Loading.
Figure 6.6. System Response to a Loss of Grid Resulting in a 20% Increase In the Generator's Loading.
Figure 6.7. System Response to a Loss of Grid Resulting in a 20% Decrease in the Generator's Loading.
Figure 6.8. System Response to a Loss of Grid Resulting in a 5% Increase in the Generator's Loading.
Figure 6.9. System Response to a Loss of Grid Resulting in a 5% Decrease in the Generator's Loading.
Figure 6.10. System Response to a Loss of Grid Resulting in a 1% Increase in the Generator's Loading.
Figure 6.11. System Response to a Loss of Grid Resulting in a 1% Decrease in the Generator’s Loading.
Figure 6.12. System Response to a Loss of Grid which does not Produce Enough Disturbance in the System to be Detected by the Relays.
Figure 6.13. (a) Integrator Output Versus Load Changes Due to the Loss of Grid.
(b) The Time Characteristic of The New Digital Protection Relay.
Figure 6.14. System Response to a 100% Step Increase in the System Load During the Independent Operation Mode.
Figure 6.15. System Response to a 50% Step Change in the System Load During the Independent Operation Mode.
Figure 6.16. System Response to a 50% Step Decrease in the System Load During the Independent Operation Mode.
Figure 6.17. System Response to a 5% Step Increase in the System Load During the Independent Operation Mode.
Figure 6.18. System Response to a 5% Step Decrease in the System Load During the Independent Operation Load.
Figure 6.19. System Response to a 1% Step Increase in the System Load During Independent Operation Mode.
Figure 6.20. System Response to a 1% Decrease in the System Load During the Independent Operation Mode.
Figure 6.21. System Response to an Out of Phase Reconnection With a Phase Displacement of 180 Degrees and No Load Change
Figure 6.22. System Response to an Out of Phase Reconnection With a Phase Displacement of -120 Degrees and No Load Change.
Figure 6.23. System to an Out of Phase Reconnection With a Phase Displacement of 120 Degrees and No Load Change.
Figure 6.24. System Response to an Out of Phase Reconnection With a Phase Displacement of -60 Degrees and No Load Change.
Figure 6.25. System Response to an Out of Phase Reconnection With a Phase Displacement of 60 Degrees and No Load Change.
Figure 6.26. System Response to an Out of Phase Reconnection With a Phase Displacement of -30 Degrees and No Load Change.
Figure 6.27. System Response to an Out of Phase Reconnection With a Phase Displacement of 30 Degrees and No Load Change.
Figure 6.28. System Response to a Perfect Synchronising.
Figure 6.29. System Response to a 50% Load Increase During the Parallel Operation with the Utility Network.
Figure 6.30 System Response to a 100% Load Increase During the Parallel Operation With the Utility Network
Figure 6.31. System Response to a 100% Load Decrease During the Parallel Operation With the Utility Network.
CHAPTER 7

THE PERFORMANCE OF THE NEW LOSS OF GRID PROTECTION ALGORITHM UNDER THE POWER SYSTEM FAULT CONDITIONS

7.1 INTRODUCTION

The new digital protection algorithm is developed to protect the embedded generation unit against islanding and not to protect the local generation unit against power system fault conditions. Other relaying functions are included in the protective relaying system for the embedded generation unit to provide fault detection and clearance. In this chapter a limited analysis of power system faulted conditions for an embedded generation unit will be carried out to define the responses of the proposed algorithm to the power system fault conditions. The analysis is included following fault conditions.

- Three Phase to Ground Fault (3LG).
- Line to Line Fault (LLF).
- Line to Line to Ground fault (LLG).
- Single Line to Ground fault (SLG).
- Single Line Open Circuit Fault (SLOC).
- Loss of Transducers Output (LOT)

Three different mathematical models of synchronous machines
have been utilised to estimate the transient performances of the synchronous machines under power system faulted conditions. These were derived from the general synchronous machine equations, equation 5.4 using appropriate assumptions[81,85,86,99,101,106,107,108,109,110,111,112]. These were defined as the dqo, αβ0 and direct phase models. Every model has its own advantages and disadvantages to represent the machine under transient and steady state conditions.

The dqo axes model yields differential equations with constant coefficients. As stated before, these equations are linear provided that the machine speed is assumed to be constant, but this rules out the logical, rigorous analysis for power swings. Although it is the optimum model for transient analysis of the synchronous machine, the resulting equations requires further transformations [106,107] for the analysis of unbalance systems. In such cases the αβ0 model has been found to be more convenient [81,107]. The αβ0 model uses differential equations with variable coefficients, and an approximate solution has been suggested[106,107] with the assumption of constant speed. A three phase model, which uses direct phase parameters[81,111] is more convenient for the analysis of power system for both balanced and unbalanced conditions. However, this needs higher sampling frequency and more computational time to give the same accuracy as provided by the dqo model with a very low sampling frequency.
Since, it is assumed that loss of grid phenomenon is a balanced condition, the state space model of synchronous machine in dqo axes has been found to be an optimum model for loss of grid analysis. This has been used to examine the embedded generator’s behaviour under balance and unbalance fault conditions. The combination of direct phase and dqo variables is utilized for this purpose. During the analysis, the equations representing the external system are solved in direct phase quantities and the results are then converted into dqo axes variables to solve the equations representing the synchronous generator in dqo axes\cite{85,86,106,109}.

The power system model used in chapter 6 has been analyzed here to examine the performance of the proposed loss of grid protection algorithm during the fault conditions. Prior the faulted conditions the machine is in a steady-state condition and delivering the rated amount of the power into the system. The fault is applied to the local bus by making the related phase voltage 0.01 pu. The embedded generator is star-connected and the star point is isolated from the earth during the parallel operation with the utility supply. During the independent operation from the utility supply, it is solidly grounded. The utility generator is also star connected, but the star point is connected to ground using a resistance to limit the zero-sequence fault current to 2000 Amps. The test period is one second as with previous studies and the fault is
applied after 100 msec. During the test period, the generator terminal voltage, armature current, three phase power output are monitored. The integrator output which represents the response of the new algorithm to the fault conditions is also recorded.

7.2 BALANCED FAULT ANALYSIS

7.2.1 Three Phase to Ground Fault

Although the possibility of a three phase to ground fault occurring on a power system is very low comparing with the other type of faults, it is the worst fault condition for a synchronous generator. A three phase fault generally produces the highest magnitude of fault current than the other fault conditions. The boundary condition for a three phase to ground fault, at the instant of the fault are:

\[ v_a - v_b - v_c - v_f \] 

(7.1)

\( v_f \) is the voltage drop over the fault impedance. If this is zero, it indicates that the fault is a solid to ground fault.

An example of three phase short-circuit analysis is shown in Fig.7.1. The study considers a three phase to ground fault at the local process busbar, while the machine is running in parallel with the utility supply. As expected,
following the fault, the generator armature current suddenly increases, and then starts to decreases exponentially according to system subtransient and transient time constants, and finally reaches the steady-state fault current level as seen in Fig.7.1b. Immediately after the fault the generator terminal voltage collapses, hence the generator output power drops to a very low value after a short oscillation period. The generator output, its rate of change, integrator input and integrator output are also illustrated in Fig.7.1c, Fig.7.1d, Fig.7.1e and Fig.7.1f respectively. The integrator output shows that the filtering nature of the algorithm on oscillations causes the delay to trip, which occurs after 320 msec.

7.3. UNBALANCED FAULT ANALYSIS

It is known that an unbalanced fault can generate overvoltage on the unfaulted phases, and that these can be increased due to saliencies on the rotor and capacitor banks near the machine terminal. The generator’s earthing system also plays an important role during an unbalanced to ground fault and defines the amount of the zero-sequence current which flows through the generator. If a generator is isolated from earth, the zero sequence current which flows through the generator will be zero, whereas if it is directly grounded, the zero sequence current will be the maximum.
As discussed before, when the system is balanced, the generator’s instantaneous power output is equal to the generator real power output as seen from the simulation results in chapter 6. However, when the system is unbalanced, the real power is the dc component of the generator instantaneous power. In this case an averaging or a filtering process is needed to obtain the real power from the instantaneous power. An half cycle moving average filter with a cut off frequency of 100 Hz has ben utilized for this purpose for the following unbalanced system analysis.

Two different approaches of the rate of change of power algorithm will be simulated under the unbalanced fault conditions. In the first approach the algorithm is based on instantaneous power, whereas the second approach will be the same approach which was used for above example and for the analysis done in chapter six.

(a) Instantaneous Power Based Algorithm

In this approach, the rate of change of power is estimated from the instantaneous power measured at the machine terminal. Then, rate of change of instantaneous power is limited in amplitude before the integrating process to define the minimum trip time. In the last step, this signal is integrated over a six cycle moving window, and the trip decision is made according to the integrator output.
(b) Real Power Based Algorithm

This approach first estimates the real power from the measured instantaneous power at the generator terminal, and then uses the real power output of the generator to calculate the rate of change of power. In the third stage it limits the change in power to a definite value to provide a one cycle minimum trip time. In the last stage, this amplitude limited signal is integrated over a six cycle period, and the algorithm makes its trip decision by monitoring the integrator output.

The faulted phase voltage, the faulted phase current, instantaneous power and real power monitored at the local generator terminal are used to represent the system behaviour under faulted conditions. In addition to these, the integrator outputs based on both instantaneous power and real power are also included to follow the tripping. The two approaches have the same trip setting of 5 based on the embedded generator's rating and inertia constant.

7.3.1 Line to Line Fault

After a line to line fault, between phases a and b with zero fault impedance, the relationship between currents and voltages are;
\[ V_a - V_b \]
\[ i_a = -i_b \] (7.2)

An example of a line to line fault simulation is shown in Fig.7.2. After the fault inception, the faulted phases current show step increases and later starts to decrease to reach a post fault steady state value, whereas the unfaulted phase current decreases after the fault. The unfaulted phase voltage decreases slightly due to the fault, the faulted phase voltages suddenly drops to half value of the pre-fault value and then continue to decrease slowly. The instantaneous voltage and current for the faulted phase a are illustrated in Fig.7.2a and Fig.7.2b.

The unbalance condition can be seen from the generator output power. During the pre-fault period, since the system is perfectly balanced, the output power does not contain second harmonic components and defines the generator real power. Following the fault, due to the unbalanced situation the generator power output starts to oscillate at twice the power system frequency and this defines the generator instantaneous power output seen in Fig.7.2c. The real power calculated from this instantaneous power is seen in Fig.7.2d.

The instantaneous power based algorithm trips for this line to line fault condition after 255 msec as seen in Fig.7.e,
whereas the real power approach exceeds the trips after 207 msec. This can be seen from the integrator output shown in Fig.7.2f.

7.3.2 Line to Line to Ground Fault

The boundary condition for a double line to ground fault is

\[ V_a - V_b = V_f \] (7.3)

if the fault applied between phases a and b and ground. The faulted phases voltages are defined by the fault impedance and \( v_r = 0 \) indicates that fault impedance is zero.

The results shown in Fig.7.3 are related to the condition where a line to line to ground fault is applied at the local generator's terminals. The curves representing the system response to this fault condition are instantaneous voltage, instantaneous current, instantaneous power and the real power measured at the local generator terminal, and are illustrated in Fig.7.3a, Fig.7.3b, Fig.7.3c and Fig.7.3d respectively. The integrator output, seen in Fig.7.3e, shows the loss of grid algorithm response related with the instantaneous power output of the generator. The instantaneous power algorithm trips after 400 msec. Fig.7.2f shows that the second approach provides more secure and earlier trip. The tripping occurs after 325 msec following the fault inception.
7.3.3 Single Line to Ground Fault

Although a solid three phase fault is assumed to be most serious fault on the power system, when the generator is directly connected to ground, a single line to ground fault at the generator terminal produces the highest magnitude of fault current for the faulted phase and produces the most serious mechanical oscillation for the generator[99,101]. If the generator has an isolated earth, a single line to ground fault produces high voltage in the unfaulted phases.

The boundary condition for a phase a to ground fault will be;

\[ v_a - V_f \]  \hspace{1cm} (7.4)

If \( V_f \) is zero, this shows that the fault impedance is zero.

A single phase to ground fault is simulated, while the machine is running in parallel with the main supply. The fault is applied on phase a and Fig.7.4 represents the system response to this condition. Although following the fault inception phase a voltage collapse, since the local generator has an isolated earth, no zero sequence current flows through the generator. The generator continues to deliver power into the system but oscillates at twice the system frequency because of negative sequence current. The algorithm based on rate of change of instantaneous power
does not result in tripping as it can be seen in Fig.7.4e, because the integrating nature of the algorithm prevents tripping. However the algorithm based on rate of change of the real power output of the generator reaches the trip level after 300 msec as shown in Fig.7.4f.

7.3.4. Single Line Open Circuit Fault.

The response of the both algorithms to a single line open circuit fault has also examined and the results are shown in Fig.7.5. While the embedded generator is operating in parallel with the utility, one of the utility phases is lost. The system voltage and current for the related phase measured at the machine terminal are illustrated in Fig.7.5a and Fig.7.5b. The machine instantaneous power output oscillates at twice the power system frequency shown in Fig.7.5c. The trip limits on instantaneous power based algorithm are not exceed, hence it does not trip. The limits on the real power approach are exceeded after 268 msec for a period of 500 msec.

The final simulation has been done on loss of the relay's inputs which cause the algorithms to calculate the two or single phase instantaneous power. Fig.7.6a, Fig.7.6b and Fig.7.6c show the case where one voltage input or one current input of the algorithm has been lost. Hence, after loss of one input signal, the algorithms start to estimate two phase power. As seen in Fig.7.6b and Fig.7.6c, neither
the instantaneous nor real power approaches trip for this condition.

Fig. 7.6d, Fig. 7.6e and Fig. 7.6f show that the both algorithms do not respond to the situation where the failure of the transducers causes the algorithms to calculate single phase power.

7.5 SUMMARY

A limited fault analysis has been under taken in this chapter to examine the behaviour of the new digital algorithm for loss of mains protection. Two different approaches of the rate of change of power algorithm have been applied for the unbalanced fault analysis.

The algorithm based on rate of change of instantaneous power measured at the embedded generator terminal trips for the three phase fault conditions, since a three phase fault effectively isolated the two systems. However it does not produce secure trips for the fault conditions of line to line and line to line to ground fault, and fails to trip for single line to ground fault and the loss of phase fault.

The approach which is based on rate of change of real power output of the generator trips for all type of fault conditions and tripping time is slightly less than that of
the instantaneous power based algorithm.

The above simulation results show that if the loss of grid protection algorithm is based on the real power output of the embedded generator, it will lose some immunity against unbalanced fault conditions.
Figure 7.1. Response to a Three Phase to Ground Fault at the Generator Terminal
Figure 7.2. Response to a Line to Line Fault at the Generator Terminal
Figure 7.3. Response to a Line to Line to Ground Fault at the Generator Terminal
Figure 7.4. Response to a Single Line to Ground Fault at the Generator Terminal
Figure 7.5. Response to a Single Line Open Circuit Fault
Figure 7.6. Response to Loss of the Transducer Outputs
CHAPTER 8

REAL-TIME IMPLEMENTATION AND TESTING OF THE ALGORITHM

8.1 INTRODUCTION

This chapter deals with the real-time implementation and testing of the loss of grid protection algorithm which was simulated in chapter 6 and chapter 7 using the computer simulation program developed. The algorithm is first implemented on a microcomputer based relay which is available in the Power System Teaching Laboratory, then tested with the aid of a three phase model power system in the same laboratory. In this chapter, following the explanation of the test system, the microcomputer based relay hardware and relay software will be described. In the last section the real-time performance of the algorithm will be discussed by using the real-time test results. The real-time test of the algorithm has been carried out under the loss of grid, load changes, reclosing and fault conditions.

8.2 TEST SYSTEM

To complement computer studies of performance of the loss of mains protection algorithm, the initial practical trails have been conducted using a 200 V, three phase laboratory
model power system[113]. The model power system is based on a double bus generating station and includes two small synchronous generators. Both generators have 5 kVA rated capacity and are driven by dc machines. The model power system has also a variable resistive load which provides facilities to change the system load and to test the algorithm's behaviour under load fluctuations. The network configuration of the model power system is shown in Fig.8.1. One of these generators is protected by a mechanical relay, whereas the other generator has been fitted with a microprocessor based protection relay which is also supported by a personal computer. This computer is also equipped with necessary interface system to monitor an array of system voltages and currents, and provides a convenient platform for research into new digital algorithms for generator protection. These algorithms can be transferred to the relay hardware at a later stage. The microprocessor unit of this computer is an intel 80286 microprocessor which is supported by an intel 80287 co-processor. The block diagram for the microcomputer based relay system[113], which can also be considered as a general purpose relay to test different protection algorithm, is seen in Fig.8.2. Since the hardware design of the relay is beyond to this work, only a summary of the relay hardware will be given to help the understanding of the development of the relay software.
8.3 MICROPROCESSOR RELAYS

The use of microprocessor technology for power system relaying was first introduced in the early 1970s. Since the application of the microprocessor based equipment for the protective relaying has many advantages over conventional equivalent analog types, many microprocessor relays have become commercially available[115,116,117]. The advantages of these relays can be summarized in terms of higher speed, better performance, reliability, flexibility, compact size, low cost, in addition to easy of maintenance.

The functions of a microprocessor relay are software controlled, therefore it is possible to design a general purpose hardware that can be used to build microprocessor based relays for different functions[113,119,120]. The hardware requirements of a microprocessor relay can be divided into three sections[113,115,116,...,121].

- Isolation and Analog Scaling System (I&AS)
- Data Acquisition System (DAS)
- Microprocessor (µp) or microcomputer

8.3.1 Isolation and Analog Scaling

The isolation and analog scaling (I&AS) system is designed to accept the voltage and current signals from the power system transducers. It provides electrical isolation from
the power system and scales down the input signals from the system level to those suitable for the "Data Acquisition System" (DAS). Since Analog to Digital Converters (ADCs) accept only voltage signals, it is also converts current signals to equivalent voltage signals.

A voltage from a potential transformer is normally supplied to an auxiliary transformer in the I&AS system that reduces the voltage level and provides electrical isolation. The voltage is further reduced by a potentiometer to a level suitable for the data acquisition system. In some cases, a metal oxide varistor[119,120] (MOV) is used at the input of the auxiliary transformer that protects the data acquisition system against voltage transient in the signals.

A current from a current transformer is first reduced to a lower level by an auxiliary current transformer in the I&AS system. The secondary of the auxiliary current transformer is connected to a resistor that converts the current signal to an equivalent voltage signal. A metal oxide varistor is usually connected across the resistor to prevent high voltage transient in the signal from entering the data acquisition system.

Fig. 8.2 shows the schematic diagram of microcomputer based relay in which the isolation and analog scaling system consist of four identical modules for processing voltages
and four identical modules for processing currents. As seen in Fig.8.2, three voltage and three current modules are used for the testing of the new algorithm which monitors the generators output power. The other two modules are reserved for different applications possibly to monitor the zero-sequence current and voltage.

A voltage module of the isolation and analog scaling block includes an auxiliary voltage transformer and a potentiometer connected to the secondary of this transformer to reduce the system voltage the level to ±5 volts for the DAS. A current module has an auxiliary transformer to reduce the current level provided by the primary current transformer and a variable resistor connected to the secondary of the auxiliary transformer to convert the current signal to a voltage signal for DAS. Thus the generator terminal current is converted to ±5 V voltage signal. An analog switch is included in the current module to be used for changing the value of the resistor. This provides a greater dynamic range for the current signal and is used for testing of the algorithm under the power system fault conditions.

8.3.2 Data Acquisition System.

The data acquisition system of a microprocessor relay consist of four different parts. These are:
(a) Low Pass Filter  
(b) Sample and Hold Circuit  
(c) Multiplexer  
(d) Analog to Digital Converter

(a) Low Pass Filter (Anti-Aliasing Filter)

For digital protection, the design of the filters between the primary and the digital relay is very important. The choice of a specific filter depends upon the sampling rate, cut-off frequency, frequency response required in the pass band and the restrictions on inherent time delay introduced by the filtering process.

The data acquisition system of the general proposed relay has an analog low pass filter for every single analog channel. Since the sampling frequency of the proposed relay is 800 Hz for loss of grid protection algorithm, the low pass filter must reject all the frequency component beyond 400 Hz. To meet this requirement, six fourth order low-pass Bessel filter with a cut off frequency of 370 Hz have been utilized. This allows a margin of about 30 Hz between the edge of the filter pass band and the Nyquist frequency.
(b) Sample and Hold Circuit:

The filtered analog signals are sampled at the time instant determined by a sampling clock frequency for two reasons. First, when phase must be preserved, the sampling instants must be precisely controlled. Second the analog to digital conversion process requires that the analog signal presented to the A/D converter must be held steady during the conversion time.

The sampling process is done by means of a sample and hold circuit (S/H), which an analog device and consists of the operational amplifiers and an analog switch. Whenever the switch is closed (a positive pulse is used to turn the switch on), the device is in the TRACK mode and the input signal is seen in the output. When the switch is opened (the switched is turned off in the absence of the positive pulse), the S/H is in the HOLD mode and holds the analog signal at a constant value during its conversion to a digital form.

Although conventional Data Acquisition Systems (DAS) have a single sample and hold circuit, and sample the inputs sequentially. Most DASs employ a S/H circuit for each analog channel. This is known as Simultaneous Sample and Hold circuit (SS&H). This approach is adopted so as to minimize error in the sampled signal due to time stagger introduced between the sampling of the analog signals.
The data acquisition system of the general purpose relay has a SS&H circuit (one S/H circuit for every analog channel), as seen in Fig. 8.2. This can freeze values on all input simultaneously. The output signals from the isolation and analog scaling system, after being smoothed by the analog filters are sampled at the instants presented by an external clock at a rate of 800 Hz providing 1.25 msec sampling interval. Since the DT2821 DAS board[125,126] does not have a SS&H system, in addition to the analog filters block*, a SS&H circuit* was added to the input interface module.

(c) Analog Multiplexer:

Another important factor in a DAS is the ability to accept more than one analog signal into A/D converter. This is known as multiplexing. There are two ways to multiplex a microprocessor system for A/D conversion. One way of doing this is the digital multiplexing. Every channel has its own A/D converter to the microprocessor. But this approach has a major disadvantage of high cost.

An alternative to digital multiplexing is the analog multiplexing. In this approach, a device that acts as a rotary switch is connected to the input of A/D converter. Any one of several analog channels can be connected to the A/D converter through this switch. The input signals of

* Designed By J I Barrett Who is currently a postgraduate in School of Electrical Engineering.
the multiplexer are the analog signals and the output is routed the A/D converter pin. Only one of the input channels can be activated at a time and the channel selection is done by the microprocessor according to the data acquisition software.

Some of the DASs have a programmable gain amplifier (PGA) between the multiplexer and A/D converter, allows the processor to optimize the gain scaling of the analog channel before they are converted from analog to digital quantities. The PGA is controlled by the data acquisition software and has 1,2,4,8 gain setting.

The DAS is included in an DT2821 A/D Converter Board[115, 126] which has a 16-channel analog multiplexer, a programmable gain amplifier and a 12-bit analog to digital converter. The multiplexer does the channel selections for the A/D converter during the analog to digital conversion process. An external clock initializes the multiplexing for the first channel and the other channel are addressed via software (internal) trigger. After converting all channels, the external clock will start the next set of conversion.

(d) Analog to Digital Conversion:

The conversion of an analog signal into digital form is necessary at the interface to a microprocessor system, so that it can be read by the processor. This is done by an
A/D converter. Successive approximation A/D converters which incorporate Digital to Analog Converters (DAC) as a part of their design are the most popular and also best suited for digital protective relays[115,116,119,120]. The A/D converters use the Digital to Analog Converter (DAC) as controlled analog signal source which is compared to the input analog voltage signal. Their conversion speed change from 0.1 µsec 100 µ sec and the number of bits defining the resolution are 8,10,12,16.

The DAS, as shown in Fig.8.2, has a 12-bit successive approximation A/D converter with 10 micro seconds conversion time. The conversion time of the A/D converter can also be controlled by the data acquisition software which defines the pacer clock frequency for A/D conversion. The most significant bit (MSB) is used as a sign bit and remaining 11-bits provides the resolution for the conversion. This effectively means that when a ±10 volts A/D converter is used, one quantization level (Q) correspond to;

\[ Q = \frac{V_{inp}}{2^n} - \frac{10}{2^{11}} = 4.88\text{mv} \]  

(8.1)

Where, n is the number of the bits representing the digital output. \( V_{inp} \) is the A/D converter analog input.

The DT2821 board has eight 16-bit word-accessible
interface registers for control, data transfer and status functions. These registers are accessible in the I/O addressing area and used for programming the data acquisition unit.

These are:

A/D Control Status Register: This a Read/Write (R/W) that interfaces to and controls the A/D section of the DAS.

Channel-Gain List Control/Status Register: This is a (R/W) register that controls and monitors activities related with the RAM channel-gain list.

A/D Data Register: It is a read-only register that contains the digital data from the A/D conversion.

Supervisory Control/Status Register: This is a R/W register that interfaces and controls the supervisory section of the board, such as initialization bits and clock source control.

Pacer Clock Register: This R/W register is related with the frequency rate of the A/D and D/A converter.

Digital input output register (DIO): This R/W register is related with DIO unit included in the board and receives the digital data to be transferred to or from the DAS board.

The last two registers namely, D/A Control/Status register and D/A Data Register are associated with the D/A converter included in the DT2821 DAS board.
A microprocessor unit in a digital system plays the main role for whole system operation. A high speed microprocessor, along with efficient programming can substitute thousands of hardware analog or digital circuits required to perform the same function. The choice of one particular type from the variety of microprocessor available depends on a number of factors such as the type of application, the nature of the algorithm being implemented, the required speed, the accuracy requirements and its ability to perform the function of the algorithm in the real-time.

An intel 80286 microcomputer supported by an intel 80287 co-processor is used in the relay research test system. The 80287 co-processor is included for floating point arithmetic and the conversion between floating point numbers and integer numbers.

(a) 80286 Processor Architecture

The main processor, the 80286, belongs to the iAPX family of Advanced, high-performance microprocessor[15,16,19], which includes the 8086, the 8088, the 80186, the 80286, the 80386, the 80486 and has following feature.

- 12 MHz Clock frequency
- 16 MBs physical address space in the real address mode.
- 1 GBs of virtual address space in the protected mode.
- Two operation Modes
- One chip memory management unit
- Four Privilege levels
- Optional processor extension
- Programmable in assembly language, PLM, Pascal, C, Fortran

The 80286 central Process Unit (CPU) is made up of four independent units which work in parallel with each other. This parallel architecture commonly refereed to as pipelined architecture.

The four main components of the 80286 CPU are:

- Bus Unit (BU)
- Instruction Unit (IU)
- Execution Unit (EU)
- Address Unit (AU)

**Bus Unit:** The bus unit performs external memory and I/O access on behalf of the central process unit (CPU) by managing all required address, data, and control signals. It is also provides the interface to the processor extension and other bus master.

**Instruction Unit:** The instruction unit receives instructions from the pre-fetch in bus unit (BU). The
instructions are decoded and placed in a 3-deep decoded instruction queue for use by the execution unit.

**Execution Unit:** The execution unit fetches decoded instructions from the decoded instruction queue in Instruction Unit (IU). It uses the bus unit (BU) for all memory and I/O data transfers.

**Address Unit:** The address units provides memory management and protection services for the CPU, and translates virtual (logical) address to physical address for use by the bus unit (BU).

(b) 80286 Internal Register

The 80286 microprocessor contain fifteen 16-bit registers. These registers can be grouped into following categories: Eight general registers, four segment registers, and three control and status registers.

**General Registers:** These register are used to hold the operands used in arithmetic or logical operations. Four of them; AX, BX, CX, DX can be used either as a single 16-bit register or a two individual 8-bit registers. AX and DX can also be used a single 32-bit register for multiplication, division and I/O operations. CX is utilised for all loops, shift and repetitive string operations. The BX and BP are called the base registers, as they are often used to hold
the base address of a given data structure in memory. Similarly, SI and DI are called index registers, since they are often used to hold an index, which is automatically incremented in the course of processing a data structure. The last register in this group, SP, functions as a standard stack pointer.

**Segment Register:** Four segment registers which identify four currently addressable memory segments are CS, DS, SS and ES.

**Control Registers:** The control and status registers are IP, FW and MSW, named instruction pointer, flag register and machine status word respectively.

(c) 80287 Numeric Co-Processor

The system is also included a 80287 numeric co-processor [131,132] which is an extension to the Intel 80286 architecture. When combined with an 80286 microprocessor, it dramatically increases the processing speed of computer applications software which utilize floating point mathematical operations. The 80287 numeric processor consists of three different blocks, namely Bus Control Logic, Data Interface and Control Unit and Floating Point Unit.

**Bus Control Logic (BCL):** The BCL communicates solely with
the CPU using I/O Cycles. The CPU performs all memory access, transferring input operand from memory to the 80287 and transferring outputs from the 80287 to memory.

**Data Interface and Control Unit:** This unit synchronises 80287 activities with the main processor.

**Floating-Point Unit (FPU):** The FPU executes all instructions that involve the register stack, including arithmetic, logical transcendent, constant and data transferring instructions.

The 80287 Numeric co-processor adds to the Central Process Unit (CPU) additional data types, registers, instructions, and interrupts specially designed to facilitate high-speed numerics processing. All communication between the main processor and co-processor is transparent to the application software. The CPU automatically controls the 80287 whenever a numerics instructions is executed. Both the co-processor and the main processor operate together as a single unified system.

The co-processor contains eight 80-bit data registers[131], and three 16-bit and two 32-bit control registers. All data registers can be accessed either as a stack, with instructions operating on the top one or two stack elements, or individually addressable registers. These are included in the floating point unit of the co-processor.
illustrated.

The 80287 supports seven data types and presents the format for each data type. Internally, it holds all numbers in the extended-precision real format. Instructions that load operands from memory automatically convert operands represented in the memory as 16-, 32-, or 64-bit integers, 32- or 64-bit floating-point numbers, or 18-digit packed BCD numbers into extended-precision real format. Instructions that store operands in memory perform the inverse type conversion.

8.4 THE RELAY SOFTWARE DEVELOPMENT

The disadvantages of using a high level language for programming of a digital system is the relatively long times needed in the calling process of the various subroutines. The real-time requirement and the short sampling period of the signals usually rules out the possibility of using high level programming languages for the digital relaying. Therefore, the digital protection algorithm has been written in assembly language.

This sections describes in some detail how the software of the proposed loss of grid protection algorithm has been developed to perform the algorithm operation in a real-time system. The relay software consists of two main parts, namely: "Data Acquisition Software" and "Application
The data acquisition software controls the operation of the data acquisition system which samples and quantizes voltage and current signals, whereas the application software defines the character of the protection algorithm. Both of them were written in assembly language on an IBM compatible AT personal computer. The interface for I/O is provided by means of debugger commend and a software written in C.

8.4.1 Data Acquisition Software

The data acquisition software of the proposed relay which was written in intel 80286 assembler language controls the data acquisition system of the relay hardware including the simultaneous sample and hold circuit (SS&H), the multiplexer (MPX), the programable gain amplifier (PGA) and the digital to analog (A/D) converter. Figure 8.3. shows the flow-chart of both application and data acquisition software, and the interconnection of them.

The data acquisition software, which is designed as a subprocedure of the application software, performs following steps, whenever executed.

Step 1: Initialize ADC interface registers.
Step 2: Select the multiplexer channel (0,1,2,3,4,5).
   -If the channel is the first one (channel 0),
     initiate a signal to put all S/H in sampling mode.
Step 3: Check if Multiplexer has settled:
  -If not wait.
  -If yes move step 4.

Step 4: Check the channel number:
  -If the selected channel is 0, initiate the external trigger to put SS&H into 'hold' mode and start conversion for the first channel.
  -If it is not the first channel, initiate a software trigger for only ADC.

Step 5: Check if ADC has finished for the current channel:
  -If not, wait.
  -If yes, read the converted data from A/D converter interface register into a memory space and move the next step.

Step 6: Has the conversion finished?
  -If not, jump the step 1 for the next channel.
  -If yes, jump the Main Procedure.

The sampled values of the voltage and current signals will be read by the relay application software to estimate the three phase power for the current time interval.

8.4.2 Application software

The application software implements the rate of change of power algorithm which was discussed in chapter four. It uses quantized samples of voltages and currents acquired by the data acquisition software and performs following step.
Step 1: Initialize the system parameters and set the clock frequency for ADC.

Step 2: Estimate the three phase power by using quantized samples of voltage and current signals which were stored in a memory space by the DAS software.

Step 3: Smooth the power signal over a half cycle moving window.

Step 4: Calculate the rate of change of power.

Step 5: Keep the change in power within pre-defined limits.

Step 6: Integrate the signal obtained in step 5 over a six cycle moving period to obtain the relaying signal.

Step 7: Compare the integrator output with the trip setting.

   -If the magnitude is greater than the trip setting, issue a trip command,

Step 8: Go to subprocedure to start the next set of A/D conversion.

The relay application software was written in 80286 assembly language[127,128,129,130], and was required to perform 32-bit integer arithmetic. Although the intel 80286 microprocessor has 16-bit internal register, 32-bit arithmetic manipulation is carried out by using AX and DX registers as a single 32-bit register. This was done to provide greater resolution for the rate of change of power algorithm.

The application software was assembled and linked to the
library to obtain the object code and .exe code. The algorithm was tested using an off-line computer simulation software. The results from the off-line simulation software (three phase current and voltage signals), which represent the embedded generator behaviour under loss of grid condition and the other power system disturbances, were stored in the integer format to be read by the application software.

The .exe code of the application software was run via the debugger program which provides a way to monitor the internal registers and instructions, modify the register, and execute the .exe code of the application software step-by-step. The test software is arranged such that it produces output for power, rate of change of power and the moving average of the rate of change of power. The interface software then reads these results from the memory space and converts them to the ascii format to be analyzed. This provides a suitable way to develop the application software step by step and make it ready to be implemented into the real time system. The execution time of each cycle of the .exe code of the relay application software was about 40 micro seconds only well within the sampling period of 1000 micro seconds.

The same algorithm was also written in intel 80286/80287 assembly language[131,132] for a system included numeric co-processor. This allows the use floating-point
arithmetic for the manipulations. The integer input data which is read from the memory space is first converted into floating point number by using numeric instructions, then all manipulations are done with floating point arithmetic. The numerical instructions of the 80287 co-processor provides two ways in which the result can be written in a memory space either in integer format or in floating point format.

The execution time of the .exe code written in intel 80286/80287 assembly language was slightly more than that of the .exe code including only 80286 instructions. This due to the time required for the floating-point manipulation and data conversion.

8.5 IMPLEMENTATION AND TESTING OF THE ALGORITHM

8.5.1 Implementation of the Algorithm

The proposed algorithm written in intel 80286/80287 assembly language as tested via off-line simulation program has finally been implemented into available relay hardware in the teaching laboratory and tested. Voltage signals from the generator terminal were applied to the voltage processing model of the isolation and analog scaling system using a potential transformer. The output from the isolation and analog scaling system was applied to the corresponding channel of the data acquisition system in the
computer. Thus, the generator terminal voltage, which was normally 115.5 volts rms (phase to earth), was reduced to ±5 volts (10 volts peak to peak) for the data acquisition system.

A current inputs were injected into the current processing model of the isolation and analog scaling model using a current transformer. The output from the isolation and analog scaling system was then applied to the corresponding channel of the DAS. Thus, a current signal of 14.4 amps rms from the generator terminal converted to an equivalent voltage of ±5 volts (10 volts peak to peak) by means of isolation and analog scaling system (I&AS).

The data acquisition software was run to activate the data acquisition system to convert the analog signals to equivalent digital numbers and store them in a memory space. Thus, an analog signal of 10 volts from the I&AS system is stored in the memory space as an integer number of 2048 to be read by the application software of the algorithm.

The results were written in memory space and converted into ascii format by using interface software. Thus the result were controlled and analyzed. After getting right results from the data acquisition board, the two software were run together, as it is shown in Fig.8.3 to perform the algorithm.
In the first stage of the real-time test, the generator was run in the steady-state condition, the DAS controlled by the DAS software converts the six analog input signal into the digital form and the application software reads and uses this data to perform the algorithm block by block. The first block measure the three phase power, second block manipulated the rate of change of power, the third block calculates the relaying signal. Thus the whole relay software was tested and made ready for the further test.

8.5.2 Testing the Algorithm

The practical tests used 5 kVA test generator with a measured inertia constant of 0.35 sec kW.sec/kVA. The main supply was rated at 500 kVA with a nominal inertia constant of 10 kW.sec/kVA. In order to avoid spurious trip, the relays trip setting has set such that it would just trip following a loss of grid producing a 2.5% change in the generator output loading. Prior to the loss of grid conditions, the test generator is operating in a steady-state conditions and delivering 3.6 kW power into the system. The test period has been chosen to be one second, commencing 100 msec before the disturbances. A sampling rate of 16 samples per power system frequency was used by the algorithm. The relay trip setting, from the equation (4.35), has been calculated to be 25 unit. To directly compare the results with those shown earlier, the integrator output representing the relaying signal has been
divided by 5 and then plotted. Therefore, the trip value will be 5 unit for the figures related to the test results. The trip settling was also 5 for the generator simulated in chapter 6 and 7.

The test system suffered from very high levels of waveform distortion and harmonic interference. This was very noticeable in the current waveform which was not fully filtered by the algorithm. The test results presented below demonstrate that the system was sinking noise and harmonics generated by the other users of the supply. The filtering capability of the algorithm was reinforced by using a half cycle digital filter applied to the measured power used by the algorithm.

The real-time tests have covered following power system disturbances:

- Loss of Grid
- Load Changes With Mains Disconnected
- Out of Phase Reclosures
- Load Changes With Mains Connected
- Power System Fault Conditions

As in chapter 6 and 7, every section has some case studies of the disturbances. Apart from the fault analysis, the first example of every disturbances discusses the effects of using a digital filter to remove the noise contained in
the measured power signal. Hence, the signals representing
the instantaneous power and filtered power, the amplitude
limited rate of change of instant and filtered power, and
the relaying signals based on these powers are included. In
the following examples, only the algorithm utilising a half
cycle digital filter has been taken into account.

(a) Real-Time Test for Loss of Grid

The new algorithm has been tested under loss of grid
conditions which are created by disconnecting the link
between the test generator and the utility grid supply,
while the generator operating in parallel with the grid
supply and feeding the site load. The power being imported
from and exported into the utility network prior to the
loss of grid has been adjusted by changing the site load
and the generator’s speed. This has provided the ability
to create different loss of grid conditions resulting
different amount of changes in the generator’s loading.

The first example of loss of grid producing 100% increase
in the test machine’s loading is shown in Fig.8.4. After
the loss of the main supply, the generator’s three phase
power output first shows a step increase and then starts to
decrease settling to a new steady-state value. As is shown
in Fig.8.4a, the power measured at the machine terminal
contains high level of harmonic interference and noise.
Therefore, a half cycle digital filter has been used to
smooth the power signal. The smoothed power signal representing the generator three phase average (real) power is shown in Fig. 8.4b.

In order to demonstrate the effect of the half cycle moving average power filter, the algorithm has been evaluated with and without smoothing the power measured. The magnitude limited rate of change of instantaneous power and the relaying signal based on the direct measurements are shown in Fig. 8.4c and Fig. 8.4e, whereas the magnitude limited rate of change of smoothed power and relaying signal calculated from it are illustrated in Fig. 8.4d and Fig. 8.4f respectively. From the comparison of Fig. 8.4e and Fig. 8.4f, it is clearly seen that the noise on the measured power desensitizes the algorithm and the measured power needs filtering process before applying any signal processing to it.

Although both approaches produce trip signal for this loss of grid conditions, the approach based on pre-filtered power provides much more reliable and secure trip for loss of mains conditions. Its tripping time is 42 msec as seen in Fig. 8.4f.

The responses to the loss of grid conditions resulting a 50% changes in the machine output power are shown in Fig. 8.5 and Fig. 8.6. Fig. 8.5 corresponds to the case where islanding produces a 50% increase in the test machine’s
loading. The generator's real power output and the response of the algorithm are shown in Fig.8.5.a and Fig.8.5b. The tripping occurs after 60 msec.

Fig.8.6 shows the condition where there is 50% decrease in the test generator output at the instant of loss of grid. The relaying signals illustrated in Fig.8.6b shows that the algorithm detects the islanding after 45 msec.

Fig.8.7 and Fig.8.8 are representing the relay's responses to the cases where loss of grid causes a 20% change in the test generator's loading, respectively for a 20% increase and a 20% decrease. The tripping times of the algorithm is 65 msec for the case seen in Fig.8.7 and 52 msec for the other loss of grid condition seen in Fig.8.8.

The response of the algorithm to a loss of grid condition producing a 5% increase in the machine's loading is illustrated in Fig.8.9. Although the islanded load is 5% over the pre-switching load, the algorithm detects this situation after 69 msec, as it is seen in Fig.8.9b.

A similar condition to that shown in Fig.8.9 is seen in Fig.8.10, but this time loss of grid results in a 5% decrease in the load connected to the generator. The tripping time of the algorithm is 93 msec.

The marginal trip conditions for the rate of change of
power algorithm are shown in Fig.8.11 and Fig.8.12. Fig.8.11 shows that there is just a 2.5% increase in the system loading due to the loss of grid. As expected the algorithm just produces a trip signal. The tripping occurs after 143 msec. The relaying signal also exceeds the trip setting after 120 msec for the islanding condition where there is only a 2.5% decrease in the generator load.

The above real-time test results have shown that the rate of change of power algorithm for loss of grid protection operates correctly in a real-time system. The tripping times of the relay are longer than those from the computer simulation results. This is due to the pre-power filter used to remove the noise from the measured power. The minimum trip time is 42 msec for the situations where loss of grid changes the system load a 100%. The maximum trip time is 143 msec following the loss of grid resulting a 2.5% change in the system loading.

(b) Real-Time Test For Load Switching Operations

With the Grid Supply Disconnected

The real-time performance of the new algorithm has been tested under the load switching operations, while the test machine was running independent of the utility supply and feeding the site load. The tests have been carried out by switching part of the variable site load and monitoring generator response to the event.
The first example of the load switching operation tests is shown in Fig.8.13 where the generator's load is increased by a 50%. The curves representing the instantaneous power, real power, amplitude limited rate of change of non-filtered power, amplitude limited rate of change of pre-filtered power, and the relaying signals based on instant and average power are shown in Fig.8.13. The algorithm produces a trip signal for this switching operation after 55 msec. The difference between the relaying signals in Fig.8.13e and Fig.8.13f shows the advantage of using a digital filter for the power signal.

The responses to the load changes in the independent operation mode, are seen in Fig.8.14 and Fig.8.15. Fig.8.14 shows the case where the switching operation increases the load by 10%, whereas Fig.8.15 relates to the situations where there is a 10% decrease in the generator's output. The trip times of the algorithms are 54 and 65 msec respectively.

The marginal conditions of the algorithm are illustrated in Fig.8.16 and in Fig.8.17. The switching operations cause a 2.5% change in the generator's output. The tripping occurs within 140 msec for both cases.

The algorithm has been shown to work correctly following a load switching operation, while the generator is operating in the isolated operation mode and supplying the power.
(c) Real-Time Test For Out of Step Reclosure

The real-time performances of the proposed relay to out of step reclosure have been examined by using the power system test facilities. The out of phase reconnection of the two supplies have been created by connecting the test generator to the grid supply, while the generator is operating in the isolated operation mode and feeding the site load. At the instant of out of step reconnection, the generator's terminal voltage is equal to that of the grid supply in both magnitude and frequency but there is a phase differences between them. This phase difference has been adjusted via synchronizing system.

The responses of the test machine and the algorithm to the out of phase reclosure conditions have been analyzed, when the phase differences between the two sources are 180°, ±120°, ±90°, ±30° prior to the reclosing.

The results of an out of phase reclosure are seen in Fig.8.18, where the phase difference between the two sources is 180° at the instant of reclosing. There is a large magnitude of change in the generator power output following the out of step reclosure. The outputs of the integrators representing the relaying signals for both instant power algorithm and average power algorithm are
seen in Fig.8.18e and Fig.8.18f. Both relating signal exceed the trip level after 80 msec following the reclosing.

Fig.8.19 and Fig.8.20 show the cases where the reclosure occurs, when the phase differences are $\pm 120^\circ$. In the first situation, the generator is running behind the utility grid supply with a phase difference of $120^\circ$ prior to the reclosure. The test generator response to this event is shown in Fig.8.19a. The power output of the machine shows a large change following the reclosure and pole slipping occurs. The integrator output shows that the algorithm produces a trip signal after 125 msec as shown in Fig.8.19b.

A similar situation is shown in Fig.8.20, where the generator operating $120^\circ$ in front of the utility supply at the instant of reconnection of the two supplies. The change in the power output of the generator and the integrator output are shown in Fig.8.20a and Fig.8.20b. Following the large changes in the power the again pole slipping occurs. The relaying signals exceeds the trip level after 80 msec and initiates a trip signal for this unsupervised reconnection.

The behaviours of the test generator following an out of step reclosure have been examined, when the phase differences are $\pm 90^\circ$ at the instant of the switching
operation. Fig.8.21 shows the responses of the generator and the algorithm to the reclosing conditions where the generator’s voltage is 90° behind that of the utility just before the reclosing. The output of the generator shows that pole slipping does not occur for this condition. The algorithm detects this out of step reclosing after 58 msec.

The tripping time of the algorithm is 80 msec for the out of phase reclosing condition which happens while the test machine is 90° in front of the utility source as shown in Fig.8.22. Since the test generator provides the synchronizing power for synchronization with the utility supply, some time after the out of phase reconnection, the machine pole slips.

As it is shown in Fig.8.23 and Fig.8.24, the algorithm also responds to the out of step reconnection of the two supplies, when the phase differences are ±30° before the reclosure. The tripping occurs within 87 msec for both cases. No pole slipping occurs after these out of step reclosures.

(d) Real-Time Test For Load Switching Operations With the Grid Supply Connected.

The real-time test has been extended to analyze the response of the algorithm to the load switching operation, while the test generator is operating in parallel with the
utility grid. The test carried out by switching part of the variable site load and recording the generator’s output power.

The response of a load switching operation which produces a loss of 50% of the load while the machine is running in parallel with the grid supply and delivering 3.6 kW power into system, is shown in Fig.8.25. As it is seen from the figure of 8.25e and 8.25f the trip setting are not exceeded.

Fig.8.26 and Fig.8.7 show the examples where the changes in the system load are ±100% based on the embedded generation prior to the disturbances. The responses of the embedded generator to these disturbances are shown in Fig.8.26a and Fig.8.27a. The relay repose are shown in Fig.8.26b and Fig.8.27b respectively.

As it is seen from the related figures, the relaying signals do not reach the trip level under above disturbances and the algorithm remains stable.

(e) Real-Time Test For Fault Studies

The responses of rate of change of power relay to the power system fault conditions have been analyzed by applying the fault to the test generator terminals. Unlike the fault analysis carried out in chapter 7, the faults have 1 ohm
resistance to prevent damage to the system. Prior to the fault, the generator is in a steady-state condition and delivering 3.6 kW power into the system. The test generator has an isolated earth, whereas the utility supply is grounded. As in chapter 7, the two approaches to rate of change of power algorithm, the instantaneous power based and the pre-filtered power based algorithm, were tested under following power system fault conditions:

- Three Phase to Ground Fault
- Line to Line Fault
- Line to Line to Ground Fault
- Single Line to Ground Fault

The faults have been cleared through the end of the test period, hence in addition to the fault inception, the curves representing the test generator responses to the fault conditions also contain information about fault clearance. The trip level representing the operation of the algorithms was set to 5 unit as in the above tests.

**Three Phase to Ground Fault:** The response to a three phase to ground fault condition is illustrated in Fig.8.28. The curves representing the generator instantaneous power and average power show that immediately after the fault, there is a tremendous change in the machine output. As it is seen in Fig.8.28a and Fig.8.28b, when the generator reaches the post-fault steady state condition, the fault is
Fig. 8.28e shows that the instantaneous power based algorithm just produces a trip signal following the fault, and its tripping time is 55 msec. The approach utilizing pre-power filter initiates a more secure trip signal after 115 msec, as seen in Fig. 8.28f.

**Line to Line Fault:** A line to line fault has been applied between phases a and b. The response of the test generator to this disturbance is shown in Fig. 8.29a and Fig. 8.29b. Since this is an unbalanced fault condition, immediately after the fault the machine instantaneous power starts to oscillate at twice the power system frequency due to the negative sequence component of the power. The digital filter removes out these oscillations as seen in Fig. 8.29b. Since the digital filter has a 100 Hz cut off frequency, the filtered power still contains sinusoidal components.

Due to these oscillations, none of the algorithms responds to the line to line fault, as seen in Fig. 8.29e and Fig. 8.29f.

**Line to Line to Ground Fault:** An example of a line to line fault, which is applied between phases a, b and to ground, is shown in Fig. 8.30. Since it is an unbalanced fault condition, the power measured at the machine terminal oscillates at 100 Hz throughout the fault period. The
instantaneous power algorithm do not detect the line to line to ground fault, whereas the integrator output of the average power algorithm exceeds the trip level after 220 msec.

**Single Line to Ground Fault:** The responses of the test generator and both algorithms to a single line to ground fault applied on phase a have also been examined and results are shown in Fig.8.31. Following the fault inception, the power output of the generators starts to oscillates due to the unbalanced condition. Because of this, the instantaneous power algorithm does not produce a trip signal as shown in Fig.8.31e. However the algorithm utilizing pre-power filter detects the single line to ground fault and trips after 100 msec as illustrated in Fig.8.31f.

The real-time performance of the loss of grid protection relay under power system faulted conditions have been analyzed above. Two approaches of the rate of change of power algorithm have been tested. The instant power algorithm does not sensitive to the fault conditions. This is due to the oscillations and noise contained in the power signal used. It just produces a spurious trip for a three phase to ground fault. The real power algorithm is very sensitive against fault conditions and trips for all type of faults. Its tripping times changes from 100 msec to 220 msec.
8.6 SUMMARY

In this chapter, the real-time implementation of the loss of grid protection algorithm has been discussed. In addition, the testing of the proposed algorithm in a real-time system has been explained. The results recorded from the real-time tests shows that the power based digital algorithm for loss of grid protection works correctly in a real-time system.

Since the measured power contains harmonics and noise, a pre-power filter was introduced to smooth the power signal. This filter increase the sensitivity of the algorithm for detecting the islanding and provides more secure trip for loss of grid conditions, load switching operations following an undetected loss of grid, and for out of phase reclosures. However it causes the algorithm to lose some immunity against tripping for unbalanced fault conditions.
Figure 8.1. Schematic Diagram of the Test System.
Figure 8.2. Block Diagram of the Microcomputer Based Relay Hardware
Figure 8.3. Flowchart of the Proposed Relay Software
Figure 8.4. Response to a Loss of Grid Resulting a 100% Increase in the Test Generator's Loading.
Figure 8.5. Response to a Loss of Grid Resulting in a 50% Increase in the Test Generator's Loading.

Figure 8.6. Response to a Loss of Grid Resulting in a 50% Decrease in the Test Generator's Loading.
Figure 8.7. Response to a Loss of Grid Resulting in a 20% Increase in the Test Generator’s Loading.

Figure 8.8. Response to a Loss of Grid Resulting in a 20% Decrease in the Test Generator’s Loading.
Figure 8.9. Response to a Loss of Grid Resulting in a 5% Increase in the Test Generator's Loading

Figure 8.10. Response to a Loss of Grid Resulting in a 5% Decrease in the Test Generator's Loading.
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Figure 8.12. Response to a Loss of Grid Resulting in a 2.5% Change in the Test Generator’s Loading.
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Figure 8.17. Response to a Switching Operation Producing a 2.5% Step Decrease in the System Load During the Independent Operation mode.
Figure 8.18. Response to an Out of Phase Reclosure With a Phase Displacement of 180 Degrees.
Figure 8.19. Response to an Out of Phase Reclosure With Phase Displacement of -120 Degrees.

Figure 8.20. Response to an Out of Phase Reclosure With a Phase Displacement of 120 Degrees.
Figure 8.21. Response to an Out of Phase Reclosure With a Phase Displacement of -90 Degrees.

Figure 8.22. Response to an Out of Phase Reclosure With a Phase Displacement of 90 Degrees.
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Figure 8.24. Response to an Out of Phase Reclosure With a Phase Displacement of 30 Degrees.
Figure 8.25. Response to a 50% Step Change in the System Load During the Parallel Operation With the Utility Network.
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Figure 8.27. Response to a 100% Step Decrease in the System Load During the Parallel Operation With the Utility Network.
Figure 8.28. Response to a Three Phase to Ground Fault at the Generator Terminal.
Figure 8.29. Response to a Line to Line Fault at the Generator Terminal.
Figure 8.30. Response to a Line to Line to Ground Fault at the Generator Terminal.
Figure 8.31. Response to a Single Line to Ground Fault at the Generator Terminal.
CHAPTER 9

CONCLUSIONS AND SUGGESTION FOR THE FUTURE WORK

9.1 CONCLUSIONS

"Providing protections against islanding is the single most challenging aspect of designing the electrical system involved in co-generation"[11]. In addition to the conventional protection relays used to protect embedded generator, several sophisticated protection algorithm have recently been developed to provide an effective protection against loss of grid, i.e. islanding. The algorithm based on passive techniques, such as The Transfer Tripping Scheme, Rate of Change of Frequency, and the Phase Displacement Relay, are more attractive than active techniques since they rely on monitoring the power system operational quantities to detect loss of grid condition. The transfer tripping method is the most direct one and offers the most active level of protection, but with most utility networks where SCADA systems do not cover all of the distribution network, they also present the greatest expense. In most cases it is not feasible to install a communication system to provide loss of grid protection.

The rate of change of frequency and phase displacement relays require a single input signal only, the voltage from
the embedded generators' terminals or the local busbars, hence offering an immediate advantage for stand alone relaying. However, they are ineffective to detect a loss of grid situation which does not produce a large enough changes in the related signal to be detected. In addition, their performances are also limited by the requirements of real-time frequency and phase displacement measurements.

The System Fault Level Monitor and Reactive Export Error Detector were designed such that they directly interact with the power system operating conditions to provide a proper protection against loss of grid. Although their effectiveness does not depend on the change in the system loading following a loss of grid, they are rarely preferred because of their interaction with the operation of the power system. The fault level monitor has not been used yet for loss of grid protection. The reactive export error detector has been widely used for back-up protection to faster loss of grid protection algorithms.

A power based digital protection algorithm for detecting loss of grid for the embedded generation units operating in parallel with the utility network has been developed. It has been shown to operate correctly for loss of grid conditions, during the independent operation mode, and after an out of phase reclosure with the utility supply. It has been also shown that the new algorithm remains stable during the severe load fluctuations while the
generation unit is operating in parallel with the utility source of supply.

The new algorithm requires six input signals from the embedded generators' terminals to monitor the three phase power output of the generators. These are the three phase voltages and currents. The power based algorithm has been designed so that the rate of change of power derived from the measured power is first limited in magnitude. It is then integrated over a six cycle moving window to obtain the relaying signal. The signal clipping process and the integrating period define the minimum and the maximum tripping time of the algorithm, and also provide immunity for the algorithm against false tripping due to the subtransient reaction to the switching. It produces the trip signal for the inter-tie circuit breaker to isolate the embedded generation unit from the utility network. The trip signal is produced, whenever magnitude of the integrator output of the algorithm, exceeds the pre-defined trip setting. This is determined by the inertia constant of the embedded system and its rated capacity.

An extensive series of computer simulations studies have been carried out to analyze the behaviour of an embedded generation unit. The simulation results representing the loss of grid conditions, load switching operations in both parallel and independent operation modes, and out of phase reclosures have been used to evaluate the comparative
performances of various loss of grid protection algorithms including under/over voltage relays, under/over frequency relays, rate of change of frequency relay and the algorithm based on rate of change of power.

I. Results From Loss of Grid Studies:

The under/over voltage and under/over frequency relays provide a limited ability for loss of grid protection. If load impact following a loss of grid condition is more than half of the embedded generation, these relays will detect islanding within a reasonable time period. Otherwise their tripping times would be long enough for the generator's control functions to respond and correct for the disturbances. They also are limited in detecting an unsupervised reconnection of the two supplies.

The rate of change of frequency protection has shown to provide a viable technique for loss of grid. It must be noted that, however the frequency and its rate of change of frequency were derived from the generator's speed throughout this work and not from voltage measurements. However, since a real time system the frequency and hence rate of change of frequency are measured from the sampled values of the system voltage or current, the performances of the frequency based loss of grid protection algorithms are directly affected by the difficulties of real-time frequency measurement.
The power based algorithm has shown the most effective performance for detecting the islanding conditions. The minimum trip time was 26 msec related with the loss of grid condition resulting in a 100% change in the generator’s loading. The minimum trip time was 121 msec corresponding to the case where islanding has produced just a 1% change in the generator’s loading. The parameters used for the algorithm were chosen so that the minimum trip time was 20 msec and the maximum trip time was 120 msec.

II. Results from Load Switching Operations

With the Grid Supply Disconnected:

The simulation results have shown that the loss of grid protection algorithms are very sensitive to the load fluctuations, while the embedded generation units only are feeding the power island, since under these conditions changes in the system loading directly affect the embedded generator. The protection is required to initiate a trip signal to open the inter-tie circuit breaker during the load fluctuations should the breaker be closed. Their responses to the load changes are similar to those of loss to a grid producing the same amount of change in the generator’s loading.
III. Results from the Load Switching Operations With The Grid Supply Connected:

The loss of grid protection algorithms must remain stable during the load switching operations, while the embedded generation unit is working in parallel with the utility system. In this mode, the change in the system load is mainly absorbed by the utility source of supply, with only a small part of the change being seen by the embedded supply. The algorithms have been shown to remain stable and load changes do not cause tripping. Furthermore, the signal clipping and the averaging process in the power based digital algorithm provide additional immunity against spurious tripping during disturbances taking place during parallel operation.

Simulation results have shown that none of the algorithms responded to the load switching operation which resulted in 100% step change in the system loading.

IV. Results from the Out of Phase Reclosure Studies:

Since the out of phase reconnection of the two systems, the utility system and the embedded system, will certainly be dangerous for the embedded generator, the loss of grid protection should detect the loss of the grid supply and disconnect the utility part of the power island from the local generation unit before reclosing can occur. If it
fails to do this, however ideally it must initiate a trip signal to open the inter-tie breaker to leave the embedded generation unit alone, when an out of phase reclosure occurs.

The analysis of out of phase reclosing has shown that the loss of grid protection relays based on the system voltage and power system frequency do not usually detect out of phase reclosing. The system voltage and system frequency are generally maintained by the utility supply and depending on the accuracy of the embedded generator’s controller, there may not be any change. The only algorithm which detects an out of phase reclosure is the rate of change of power algorithm. Although the averaging nature of the algorithm, which gives the immunity against spurious trips, delays tripping, it will detect the out of phase reconnection of the two supplies under all conditions examined and provides faster tripping than the other types of protections, such as for example overcurrent relay.

V. Results From Fault Analysis:

The computer simulation studies have also been extended to determine the response of the new algorithm to the power system fault conditions, and together with situations where one or more transducers fail.

Although protection against power system fault conditions
should be the responsibility of the other relays included in the protection package of the embedded generation unit, fault analysis was necessary to examine the response of the new algorithm to faults. Since the loss of grid protection will be running in parallel with the other protection algorithms included in the same protection package, it is important to determine its response to such conditions.

The conclusion obtained from the fault analysis is that if the algorithm is based on the instantaneous power, it would be immunity against severe unbalanced conditions. However, if a pre-power filter is included in the structure of the algorithm to remove the double power frequency oscillations from the measured power signal, it will lose some immunity to unbalanced fault conditions and can therefore trip.

The computer simulation studies has also examined the response of the power based algorithm when one or more transducers fail to supply input signals to the relay. It has been noticed that the failure of one or more input signals causes a step decrease in the measured power and creates the double frequency oscillations in the power calculated by the algorithm. The integrator output however remains zero, and the algorithm does not trip when one or more transducers fail.
VI. Results From the Real-Time Test:

Following the implementations of algorithm into a general purpose relay, the real-time performance of the new algorithm has been evaluated for the conditions of loss of grid, load switching operations and out of phase reclosure. The following conclusions have been obtained by analyzing the real-time test results:

Since the real power system could not be operated in a perfect balanced condition and because the voltage and current waveforms contain high frequency harmonics, the power measured at the test generator terminal benefitted from a pre-power filter before evaluating the protection algorithm. A half cycle moving average filter with a cut off frequency of 100 Hz was therefore introduced to smooth the power.

The use of 12-bit A/D convertor desensitized the algorithm and higher bit A/D converters are recommended.

The trip times of the relay from the real-time test were generally longer than those from the computer simulations. This was attributed to the pre-power filter.

The measured power signal contained a lower level of harmonics in the independent operation mode than when operating with the grid supply. This provided more smoothed
It was noticed that there were no sinusoidal oscillations in the power signal following an out of phase reclosure and this resulted in faster tripping for out of phase reclosing conditions comparing with the computer simulation results. This was attributed to the high level of damping of the test generator and the dc driver motor.

The algorithm remained stable under load switching operation while the generator was operating in parallel with the grid supply.

Although the test system was not convenient to test the algorithm under serious fault conditions, the results from the analysis of fault tests are similar to those obtained from the computer simulation studies. The algorithm loses its immunity against unbalanced fault conditions, if the pre-power filter is included.

9.2 SUGGESTION FOR THE FUTURE WORK

1. Embedded Generation Units Containing Multi-Generation Sets

In this study it was assumed that the embedded generation unit contains only one generation set. All of the computer simulation studies and real-time test have been carried out
using this assumption. However, embedded generation unit can use more than one generator operating in parallel. Although it is expected that the new algorithm will work correctly in such a situation, further simulation studies and real-time tests are required to demonstrate the response of the algorithm for multi-generator sets.

II. Power Measurement

The present algorithm requires six input signals, three phase voltage and current signals, from the embedded generator’s terminals to measure the power. If, however, the two wattmeter method, as mentioned in chapter 4, is used to measure the power, the rate of change of power relay needs only four input signals. This will reduce the cost of the relay hardware and could speed up the algorithm. In order to make a final decision about the situation, more work is required.

On the other hand, as it was noticed from the computer simulation and the real-time test results, when the system operating in unbalanced conditions the instantaneous three phase power oscillates around the real (active) power at twice the power system frequency due to the negative sequence component of the power. In this case, the instantaneous power needs further processing to obtain the average (real) power. In this study, this is done by using a low pass moving average filter. Unlike the method
suggested in reference[58], this averaging process does not need to be synchronized with the power system frequency. This filter also smooths the measured power signal in the real system to provide more linear and reliable relaying signal. However, having a pre-power filter in the algorithm reduces the immunity to unbalanced fault conditions.

In addition to the loss of grid, if the loss of grid relay is desired to response to the fault conditions, this filter will be the solution. However, detection of the fault conditions is normally left to the other relaying functions included in the same protection package. For this case, the filtering process becomes more complex. It needs to provide a filtering for the noise, but should not reduce the immunity of the algorithm against unbalanced fault conditions.

Another solution would be that the algorithm may be used to detect the unbalanced fault conditions, but it should distinguish between a loss of grid and a fault condition. Examinations of the fluctuations on the power response suggest that a pattern recognition technique could be successful.

III. Delay due to the Sinusoidal Oscillations

In order to avoid spurious trip under the power system
disturbances during the parallel operation mode, the algorithm has been designed so that it removes sinusoidal oscillations. This feature is included in the power based digital algorithm by clipping and averaging the rate of change of power over a preset period to obtain the relaying signal. Although this provides stability for the algorithm, it delays tripping, following an out of phase reclosure.

Further investigations into this matter may provide better performance for the algorithm to detect an out of phase reclosure.

IV. Relay Hardware and Real-time Test

Since the data acquisition board has a 12-bit A/D convertor, all the tests were done with an 11-bit resolutions. Recently 16-bit A/D convertor has been widely used for digital relaying. The use of a 16-bit A/D convertor provides $16 \left( \frac{2^{16}}{2^{11}} \right)$ times the resolution of a 12-bit convertor operating over the same range. This will automatically increase the sensitivity of the new algorithm.

V. Long Term Test

Finally, the simulation and real-time test results have shown that the algorithm does not produces spurious trip
and remains stable during the fluctuations in the parallel operation mode. In order to make a final decision, long term real-time held tests are required. This would be done by running the test generator for a long period of time and recording data and the relay output for the disturbances taken place in the power system, or installing the loss of grid algorithm in a host micro-computer relay and undertaking the extensive held tests.
REFERENCES


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[54] P M Anderson and A A Fouad, "Power System Control and Stability" The Iowa State Univ. Press Iowa 1977 USA.


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APPENDIX A

MACHINE PARAMETERS FOR THE GENERATOR SIMULATED

<table>
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<tr>
<th>Parameter</th>
<th>Value</th>
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<tr>
<td>Rated Power</td>
<td>3.75 (MVA)</td>
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<td>Rated Voltage Line to Line</td>
<td>11.0 (kV)</td>
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<tr>
<td>Excitation Voltage</td>
<td>64.0 (V)</td>
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<tr>
<td>Field Current</td>
<td>4.0 (Amps) On exciter field</td>
</tr>
<tr>
<td>Stator Current</td>
<td>207.4 (Amps)</td>
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<tr>
<td>Power factor</td>
<td>0.8</td>
</tr>
<tr>
<td>Rated Frequency</td>
<td>50 (Hz)</td>
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<tr>
<td>Mechanical Speed of Rotation</td>
<td>1000 (rpm)</td>
</tr>
<tr>
<td>Number of Poles</td>
<td>6 (3-pairs)</td>
</tr>
<tr>
<td>Rotor Type</td>
<td>Salient Pole</td>
</tr>
<tr>
<td>Stator Winding Connection</td>
<td>Star-Connected</td>
</tr>
<tr>
<td>Inertia Constant</td>
<td>0.91 (MWsec/MVA)</td>
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Base Values:

SBase: 1.750 (MVA)
VBase: 6.028 (kV)
IBase: 207.4 (Amps)

Data For Winding in Per-Unit:

Ld: d-axis synchronous reactance 1.241
LF: Field circuit reactance 1.315
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<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
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<td>LD: d-axis damper winding reactance</td>
<td>1.344</td>
</tr>
<tr>
<td>Lq: q-axis synchronous reactance</td>
<td>0.750</td>
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<tr>
<td>LQ: q-axis damper winding reactance</td>
<td>0.818</td>
</tr>
<tr>
<td>Lad: d-axis magnetizing reactance</td>
<td>1.181</td>
</tr>
<tr>
<td>Laq: q-axis magnetizing reactance</td>
<td>0.690</td>
</tr>
<tr>
<td>ld=1q: d- and q-axis leakage reactance</td>
<td>0.060</td>
</tr>
<tr>
<td>Ra: Stator winding resistance</td>
<td>0.0087</td>
</tr>
<tr>
<td>Rf: Field winding resistance</td>
<td>0.0015</td>
</tr>
<tr>
<td>RD: d-axis damper winding resistance</td>
<td>0.0184</td>
</tr>
<tr>
<td>RQ: q-axis damper winding resistance</td>
<td>0.0124</td>
</tr>
<tr>
<td>lD: d-axis damper winding leakage reactance</td>
<td>0.1623</td>
</tr>
<tr>
<td>lQ: q-axis damper winding leakage reactance</td>
<td>0.1280</td>
</tr>
<tr>
<td>IF: Field winding leakage reactance</td>
<td>0.1336</td>
</tr>
<tr>
<td>Rn: Neutral grounding resistance</td>
<td>100.00</td>
</tr>
<tr>
<td>Xn: Neutral grounding reactance</td>
<td>100.00</td>
</tr>
<tr>
<td>Xo: Zero sequence reactance</td>
<td>0.0800</td>
</tr>
<tr>
<td>Ro: Zero sequence resistance</td>
<td>0.0110</td>
</tr>
<tr>
<td>X2: Negative sequence reactance</td>
<td>0.1490</td>
</tr>
<tr>
<td>R2: Negative sequence resistance</td>
<td>0.0120</td>
</tr>
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</table>
APPENDIX B

PUBLISHED WORK


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LOSS OF MAINS PROTECTION FOR PRIVATE GENERATION OPERATING IN PARALLEL WITH THE UTILITY SUPPLY.

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INTRODUCTION.
The commitment to conservation and efficient use of natural resources for producing electricity has led to an expansion in the installation of private generation capable of operating in parallel with the local utility network. Further encouragement has been provided by government legislation in both the UK and the USA. This includes the 1978 USA PURDA legislation, the 1983 UK Energy Act and the 1989 UK Electricity Act.

Parallel operation of a private generator with the utility creates several difficulties for reliable and safe network operation. These arise from the private generator’s capacity to supply power to the network from a source not under the utility's direct control. Special precautions are required to prevent the private generator supplying low quality electricity to other customers and to ensure that it is isolated from the network whenever there are either faults on the system or switching mal-operations.

Power utilities have therefore generally resisted the introduction of private generation connected to their systems. Several large utilities have produced guidelines defining their requirements before agreeing to allow a private generator to operate in parallel with their network. The UK Electricity Board’s requirements are specified in the Electricity Council Engineering Recommendation G591. Generally, the utilities are required to ensure that the private generators will not detract from the quality of supply to other customers, and the individual private generators are responsible for providing and maintaining the required protection and control equipment.

PROTECTION REQUIREMENTS FOR A PRIVATE GENERATOR.

Before agreeing to allow a private generator to operate in parallel with their system, most utilities require that the protection scheme will ensure that:

- the private generator cannot be connected to their system unless all phases of their supply are energised and operating within agreed limits.
- the private generator is disconnected from the utility when an abnormality occurs that results in an unacceptable deviation in the voltage or frequency at the point of supply.
- the private generator is disconnected from the utility when either system is short circuited.
- the private generator is disconnected from the network when the utility supply is lost.
- the private generator cannot be connected to the utility system, or if already connected, it is then disconnected, whenever there are failures in the protection systems or their supplies.

These features are in addition to the normal protection scheme required for the safe operation of a small generator.

For a private generator operating in parallel with a UK Electricity Board system, it is necessary for supplies to remain within statutory limits of ± 1% on frequency and ± 6% on voltage.

The protection scheme must therefore include:

- synchronisation control of the connection circuit breaker.
- under and over voltage protection.
- under and over frequency protection.
- overcurrent protection.
- loss of mains protection.

A typical protection scheme for a private generator operating in parallel with the utility system is shown in figure 1.

LOSS OF MAINS PROTECTION.

Loss of mains protection is required to protect against an accidental isolation of the two systems in which a portion of the utility’s load becomes isolated from the utility’s source of supply but is left connected to the private generator. In this condition the isolated system may continue to operate independently of the utility and form a power island.

Island operation is not a problem provided that the voltage and frequency remain within statutory limits. The main concern is the possibility of restoration of the utility’s supply out of synchronism with the private generator due to either a manual or automatic reclosure of a utility circuit breaker. Under these conditions the generator should be disconnected from the network in less than 200 ms.

In cases where the private generator is not intended to export power to the utility system, loss of mains can be detected using a reverse power relay on the inter-tie between the private network and the utility.

For small generators, typically less than 200 kVA, which are intended to export power to the utility, the loss of mains generally results in overloading the generator and both the output voltage and frequency will fall. This in turn will cause the under voltage and under frequency protection to operate.

Large generators fitted with high speed automatic voltage regulators may well be able to match the subsequent island load and therefore there is a possibility that the voltage and frequency will be maintained within preset limits. Under these conditions, loss of mains becomes more difficult to detect and a sophisticated protection is required.

Several protection schemes have been developed to detect loss of mains. These can be divided into two fundamental groups; the first using active techniques which directly interact with the operation of the power system and the second using passive techniques which monitor system behaviour. Active loss of mains protection techniques include the reactive export error detector and the fault level monitor. Passive techniques include under/over voltage, under/over frequency, rate of change of frequency and the phase displacement monitor.
An inherent advantage of rate of change of frequency

The relay setting is chosen such that it will operate when the disturbance and too high a setting could cause unnecessary tripping during system disturbances. The rate of change of frequency exceeds 0.3 Hz/sec after 4 msec when at the instant of loss of mains, the generator's output power changes by greater than 5% of its rating.

As with the rate of change of frequency relay, the phase displacement monitor will also operate for any subsequent load change which produces the required change in phase displacement, should the loss of mains fail to cause tripping.

POWER SYSTEM SIMULATION.

In order to examine the effects of loss of mains, the simplified network shown in figure 2 has been simulated. The private generator rating was 1 MVA at 11 kV, and the utility fault level was 250 MVA.

The potential performance of different types of passive loss of mains protection was examined using the generator terminal voltage, the system frequency, and the rate of change of frequency measurements derived from the simulation programme. The trip levels used to represent the operation of the protection relays are ± 6% of the nominal voltage for under/over voltage, ± 1% of the nominal system frequency for under/over frequency, and 0.3 Hz/sec for the rate of change of frequency.

In the first situation considered, the island load was twice the capacity of the private generator. Figures 3a, 3b, 3c and 3d show the voltage, current, frequency, and rate of change of frequency monitored at the island load terminals. The test period covers one second, starting 100 msec before loss of mains switching. Following loss of mains, the terminal voltage falls by 36.7% of the nominal value and then recovers. The generator output current rises slowly, and the system frequency falls rapidly, reaching 39.5 Hz after 900 msec. The rate of change of frequency curve has a negative peak of 18.3 Hz/sec after 4 msec. The generator output current rises slowly, and the system frequency falls rapidly, reaching 39.5 Hz after 900 msec. The rate of change of frequency exceeds 0.3 Hz/sec after 4 msec. The sinusoidal effects seen in the voltage and current waveforms are caused by the sampling techniques used and changes in the system frequency.

The conditions shown in figure 4 correspond to the case where the island load is half the private generator's capacity prior to the loss of mains. Immediately after loss of mains, the generator's terminal voltage rises by 7% over the nominal value and exceeds the 6% over voltage setting after 20 msec. The current falls slowly until a new steady state value is reached. The system frequency rises and exceeds the operate level of 1% after 85 msec. The rate of change of frequency peaks at 15.5 Hz/sec after 350 msec and exceeds the operate level after 1 sec.

Both the above situations produce significant changes in the island voltage, current and frequency following loss of mains. In figure 5 and 6 the changes between before and after loss of mains are minimal and the resultant changes in the operating conditions are equally small.

Figure 5 shows the operating conditions where the island load is 5% above the rated capacity of the private generator. Following loss of mains there is a 5% dip in the island voltage, after which the voltage recovers. The generator output current rises slowly to a significant value. The relay initially fails to operate, but will trip when a subsequent load change produces the required df/dt.

Reactive Export Error Detector.

The reactive export error detector directly controls the private generator's excitation current so that it maintains a level of reactive current in the utility to customer inter-tie which cannot be supported unless the utility source is connected. The relay trips when the estimated level of reactive current in the utility is such that the disconnection does not cause the generator to trip.

The time delay is typically set between 2 and 5 seconds and the relay is therefore inherently slow. The approach is also limited when power factor compensation capacitors remain connected to the island and hence the reactive currents can be maintained. The relay requires both voltage and current inputs, as well as connections to the voltage regulator.

This technique is one of the few techniques suitable for small power supply systems where other relays fail to differentiate between loss of mains and abnormal system fluctuations. It is also used to provide back-up protection to other faster schemes.

Fault Level Monitor.

The fault level monitor repeatedly measures the system fault level by monitoring the current flow through a shunt inductor controlled by a point on wave switch triggering an anti-parallel connected thyristor pair together with the resulting changes in the system voltage. Triggering the thyristors just before voltage zero, produces a short pulse of current which reduces system voltage. Measurements enable the source impedance and hence the system fault level to be calculated. The system does not need to be particularly accurate since there is a dramatic change in fault capacity between the private generator and the utility supply.

The advantage of this approach is that it responds quickly to loss of mains by measuring the fault level every half cycle. This method has been developed from equipment used to improve static voltage compensator performance, however a commercial unit has not yet been produced.

Rate of Change of Frequency.

This protection operates when the rate of change of frequency exceeds a preset limit. The frequency is monitored either at the generator terminals or on the utility to customer inter-tie using a voltage input. The relay setting is chosen such that it will operate for the private generator load changes associated with the loss of mains, but it will not operate for fluctuations governed by utility time constants. The setting is critical since too sensitive a setting could result in unnecessary tripping during system disturbances and too high a setting could cause failure to detect loss of mains.

Under loss of mains, any changes in the load connected to the private generator will result in a df/dt governed by the inertia constant and rated capacity of the private generator. For small and medium sized private generation, a trip setting of 0.3 Hz/sec has been found to be optimum. The relay algorithm is designed to ignore slow changes in frequency which could be caused by load changes on the utility network but to respond quickly to rapid changes in frequency when the private generation becomes isolated. The rate of change of frequency relay is able to operate in from 0.3 to 0.7 seconds, and trips in 80 msec with large load changes following dramatic disconnections.

An inherent advantage of rate of change of frequency relay, is that when loss of mains does not result in
its new steady state value. Island frequency falls slowly by 1.6% after 300 msec, and exceeds the 1% over frequency level after 510 msec. The rate of change of frequency falls to a negative peak of 1.6 Hz/sec after 350 msec and exceeds 0.3 Hz/sec after 30 msec.

Figure 6 shows the operating conditions where the island load is 1% above the rated capacity of the private generator. The voltage, current, frequency and rate of change of frequency diversions are similar to those in figure 5 but none are sufficient to cause the protection systems to operate.

These studies illustrate the capabilities of using different parameters for loss of mains protection and demonstrate their advantages and disadvantages. In general the changes in the rate of change of frequency following loss of mains are consistently faster than either those in the supply voltage or frequency. Changes in system frequency have been shown to be particularly slow.

CONCLUSIONS.

The increasing use of private generation operating in parallel with the utility supply is creating difficulties for the security and safe operation of the utility network. The protection of private generators against loss of mains is one the greatest challenges for relay research and development.

A variety of different techniques are available for loss of mains protection using both active and passive systems. Active systems are generally more effective at detecting loss of mains but have the disadvantage of requiring a direct influence on system operation. Passive techniques do not have this problem but cannot be guaranteed to operate under all conditions.

The results of simulation studies demonstrate the advantages of using rate of change of frequency for loss of mains protection. Under/over voltage also provides a viable technique, but the time required for frequency changes is excessive. It must be accepted that the potential operating times given in this paper are based on ideal measurements of system parameters and the response of practical relays will depend on the relay's data acquisition and signal processing.

The probability of failure to detect loss of mains, introduces the possibility of subsequent reclosure of the disconnecting circuit breaker when the two systems are out of synchronism. This could cause severe damage to the private generator.

ACKNOWLEDGEMENTS.

The authors are pleased to acknowledge the help and encouragement provided by the University of Bath, the Wuxi Institute of Light Industry, GEC Alsthom Measurements, and the SERC.

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FIGURE 3. SYSTEM RESPONSE TO LOSS OF MAINS WHERE THE ISLAND LOAD IS TWICE THE GENERATOR'S RATED CAPACITY.

FIGURE 4. SYSTEM RESPONSE TO LOSS OF MAINS WHERE THE ISLAND LOAD IS HALF THE GENERATOR'S RATED CAPACITY.

FIGURE 5. SYSTEM RESPONSE TO LOSS OF MAINS WHERE THE ISLAND LOAD IS 1.05 TIMES THE GENERATOR'S RATED CAPACITY.

FIGURE 6. SYSTEM RESPONSE TO LOSS OF MAINS WHERE THE ISLAND LOAD IS 1.01 TIMES THE GENERATOR'S RATED CAPACITY.
PAPER 2
A LABORATORY FACILITY FOR RESEARCH INTO DIGITAL PROTECTION ALGORITHMS USED FOR THE PROTECTION OF SMALL AND MEDIUM SIZED SYNCHRONOUS GENERATORS.

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INTRODUCTION.

The great potential for the installation of small and medium sized generation operating in parallel with the local utility supply network has led to considerable interest in new digital relaying schemes for protecting embedded generation.

Research into new digital relaying algorithms to be used for protecting embedded generation has led to the development of a laboratory facility for assessing new protection techniques. The facility has been built around a small synchronous machine which is connected to a model power system network containing another machine and inter-ties into the three phase system. The digital relaying environment is provided by either a programmable microprocessor based, general purpose protection relay system or a desk-top computer fitted with the required input and output units to execute real-time protection software.

This facility was initially designed as a teaching system to demonstrate the operation and limitations of differential protection when applied to a three phase generator. The inherent flexibility of the system has made it a powerful teaching aid and invaluable for research into new protection techniques suitable for the integrated generation protection.

The facility provides an intermediate step between the software simulation of new protection algorithms and field trials using relay hardware. It also complements other evaluation facilities available in the laboratory.

GENERATOR PROTECTION RESEARCH FACILITY.

Power System Model.

The facility uses a 5 kVA synchronous machine, coupled to a dc machine and connected to a model power system network containing a similar machine set and inter-ties into a 200 volt three phase system. Although these machines are intended for generation, they can be used as loads.

The schematic diagram for this model power system is shown in figure 1. The system contains a double bus system similar to that used in a medium range generating station and includes the power system switching systems associated with such an installation. A comprehensive array of current and voltage transformers are installed around the synchronous machine to provide inputs into the protection system. Other machines and plant can be connected to the system as required for special tests.

To facilitate protection system testing, the machines and breakers are generously rated and the stator windings of the synchronous machines are fitted with accessible taps. Faults can be applied without causing permanent damage.

Digital Generator Protection Relay Research System.

The digital relaying environment is provided by both the desk-top computer system and a programmable microprocessor research relay system. They monitor the behaviour of the synchronous machine using eight primary current transformers and four primary voltage transformers. The laboratory protection systems and their inter-connection to the power system instrument transformers are shown in figure 2.

The desk-top computer based research system uses a COMPaq 286 microcomputer, containing a third party interface board fitted with 16 analogue inputs and 32 channels of digital input and output, I/O.

The primary transducers are interfaced to the microcomputer using a purpose designed input system. This includes interposing transformers to provide an additional level of isolation for the microelectronic systems from the primary system. The input system also contains the anti-aliasing filters, the sample and hold circuits and the phase-locked loop control circuit to provide the sampling clock frequency generator. The standard generator protection algorithms use twelve samples per 50 Hz cycle, corresponding to 600 samples/sec.

To ensure that there were the least difficulties with the timing between the different input circuit functions, the sample and hold circuits were triggered using the falling edges of the square wave triggering waveform from the phase-locked loop and the analogue to digital converters were triggered using the rising edges. The phase-locked loop circuit locks onto the power system frequency and outputs a square wave exactly twelve times its frequency.

The trip output from the protection algorithm is provided via the digital I/O port, which with the aid of a driver circuit operates an auxiliary relay, which in turn trips the circuit breaker connecting the synchronous machine to the model power system. The trip circuit includes a ten second delay to enable current and voltage readings to be taken during the fault condition.

The block diagram of the desk-top computer based research system is shown in figure 3.

The programmable microprocessor research relay system uses the INTEL 80186 microprocessor together with the input circuits required to monitor current and voltage transducer secondary signals and output circuits containing the trip and alarm relays. The 80186 is of the same family as the 80286 used in the Compaq and with minor modifications programmes developed on this desk-top computer can be used in the programmable relay system.

The relay's input modules contain eight current transformers, four voltage transformers, the input filters, the sampling circuitry and the digital to analogue converters. A RS232 serial communications channel enables the microprocessor relay system to communicate directly to the desk-top computer enabling the operator to measure the currents and voltages monitored by the relay together with trip and flag status information. This communications link has enabled several teaching projects to be automated, dramatically reducing the student's effort in performing the experiments.

Software for the desk-top relaying environment and the microcomputer relay can be developed in either 'C' or Assembly. The close similarity between the two systems
enables research to start on the desk-top computer and then the protection algorithms to be moved to the microprocessor relay for in depth testing. The microprocessor relay is a stand alone system and can therefore be used for field trials or simulator testing.

**GENERATOR PROTECTION ALGORITHMS.**

**Generator Protection Scheme.**

The generator protection scheme is required to protect the machine from both internal and external faults. A typical protection scheme for a small or medium sized synchronous generator is shown in figure 4. The actual scheme used for a generator depends on the machine being protected and some features shown may be omitted while others may be included.

The IDMT relays, 51V and 51N, provide protection against high current faults on either the generator or the system to which it is connected. The negative sequence relay, 46N, provides protection against unbalanced loads damaging the machine or the loss of a phase connection. The reverse power relay, 32, prevents machine motoring should the prime mover fail.

The over and under voltage relays, 27 and 59, and the over and under frequency relays, 810 and 81U, ensure that the consumer’s supply is maintained within defined voltage and frequency limits. Should the supply move outside these for greater than the time period set, the embedded generator is disconnected from the load. The Loss of Mains relay, LOM, detects when the site becomes isolated from the utility’s source of generation for whatever cause and opens the inter-tie breaker to the utility resulting in stand alone operation of the site system.

The synchronisation checking relay, 2S, ensures that the generator is only connected to the site busbar when the voltages on both sides of the connecting breaker are within tolerable limits of each other and in phase. The operation of the synchronisation checking relay can be inhibited when the generator is being connected to a de-energised busbar.

The main protection for internal faults within the generator’s stator winding is provided by the differential protection, 87. Since this is a unit protection, it does not require time grading with other protection systems and can therefore be 'instantaneous'.

**Blasted Differential Protection.**

Arguably, the simplest method of protecting a generator’s stator against internal faults is to use current differential protection across the stator windings. Based on the Merz and Price circulating current principles, the scheme is enhanced using automatic through-current biasing.

The relay monitors the currents on both sides of the stator winding and determines the differential current which is used as the protection operate measurand. To avoid mal-operation due to current transformer mismatch and high through-currents, the currents measured are used to provide a bias measurand which restrains relay operation. The relay’s ideal characteristic curve is shown in figure 5.

For each phase of the generator, the biased differential protection algorithm uses the following trip criterion:

\[
(I_{\text{p}} - I_{\text{c}}) > K_1 I_N + K_2 (I_{\text{a}}^* + I_{\text{b}}^*)
\]

where, 

- \(I_{\text{p}}\) is the relay's nominal current, 
- \(I_{\text{c}}\) are the secondary currents measured at the generator's neutral and line ends.

The values of the constants \(K_1\) and \(K_2\) are the zero current trip setting and the bias setting for the characteristic respectively.

To reduce the effects of noise on the algorithm, a moving window equivalent to one cycle of samples is used to provide inherent filtering. Equation 1 has therefore been modified to provide a running total of the present sample value together with the previous n-1 sample values. The protection algorithm therefore causes trip when:

\[
\sum_{i=n}^{n-1} |I_{\text{p}}^i - I_{\text{c}}^i| > K_1 I_N + K_2 \sum_{i=n}^{n-1} (I_{\text{a}}^i + I_{\text{b}}^i)
\]

Differential Setting: Mean through current

Restraint Setting: 

\[
\text{Operate value} = (I_{\text{p}} - I_{\text{c}})
\]

\[
\text{Restraint value} = \frac{I_{\text{p}} + I_{\text{c}}}{2}
\]

The moving window functions of n samples are obtained by first subtracting the \((m-n)\)th samples from the appropriate running total and then adding the value of the \(m\)th samples. The \(m\)th samples are read into the array in place of the \((m-n)\)th samples, i.e. they overwrite the original values. The summation of the stored samples therefore gives a running total of the n samples which are available for use in the trip calculation.

When the protection algorithm is first energised, i.e. before any samples are taken, it is necessary to restrain the trip function for the first cycle period in order to prevent mal-operation. The values in the array elements are first zeroed and then during this restraint period operational data is collected. Once the program has collected n service samples after energisation, the array has been filled and the restraint is lifted.

To provide three phase protection, the program samples the six input channels corresponding to the six CT's connected on either side of the stator windings. Similar protection algorithms are used on each phase of the machine. The three trip-algorithms provide a common trip output such that whenever a fault is detected on any of the windings, the circuit breaker is tripped, thus disconnecting the machine from the system.

**DIFFERENTIAL RELAY PROTECTION PERFORMANCE.**

The relay's trip characteristic was determined by applying phase to phase faults between corresponding red and yellow phase taps on the machine. The resulting curve is shown in figure 5 which compares well with the ideal curve. Tripping times were typically 30 msecs, including the delays incurred by the output hinged armature relays.
Further investigations to examine the limitations of the differential protection scheme when an earthing resistor was connected to the machine's star point, produced the relationship shown in figure 6. This shows the percentage of the winding protected by the relay against the maximum fault current that could flow for an internal fault, as a percentage of the rated load current. These results demonstrate an inherent limitation of stator winding differential protection caused by the relay's inability to operate when the fault current is below its trip value.

RESEARCH INTO ENHANCED PROTECTION ALGORITHMS.

This facility provides an environment for further work into new and enhanced protection algorithms for small synchronous motors and generators. Current work is concentrating on both the refinement of new techniques for detecting loss of mains, and new differential protection algorithms to overcome the one cycle dead period following energisation and to extend the percentage of the stator winding protected without the use of injection systems. Several techniques exist for enhanced stator winding protection including monitoring the third harmonic content and monitoring the harmonic content in the machine's rotor. These and other work on generator protection highlight the need for further work in this area.

CONCLUSIONS.

This facility was initially designed as a teaching system to demonstrate the operation and limitations of biased differential protection when applied to a three phase generator.

The inherent flexibility of the system has led to its use for research into new protection techniques suitable for the integrated protection of embedded generation.

ACKNOWLEDGEMENTS.

The authors are pleased to acknowledge the help and encouragement provided by the School of Electronic and Electrical Engineering at the University of Bath, South Western Electricity plc, GEC Alsthom Measurements, the SERC and colleagues associated with the research.

REFERENCES.

**FIGURE 3. DESK-TOP COMPUTER PROTECTION RESEARCH SYSTEM.**

**FIGURE 4. TYPICAL PROTECTION SCHEME FOR A SMALL OR MEDIUM SIZED SYNCHRONOUS GENERATOR.**

**FIGURE 5. BIASSED DIFFERENTIAL PROTECTION RELAY CHARACTERISTIC.**

**FIGURE 6. PERFORMANCE OF A BIASSED DIFFERENTIAL PROTECTION.**
PROTECTION AGAINST LOSS OF UTILITY GRID SUPPLY FOR A DISPERSED STORAGE AND GENERATION UNIT.

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Abstract: - The installation of small or medium sized dispersed storage and generation units operating in parallel with the utility supply presents several technical complications for the protection and control of the system. Amongst these is the need to protect the system from islanding caused by the loss of the utility grid supply and the possible subsequent out-of-synchronism reconnection of that supply.

This paper examines the requirements of an islanding, or 'loss of grid', protection and outlines the principal methods used for this type of relaying. A new protection algorithm is introduced which is based on the rate of change of power as measured at the generator's terminals. The responses of the different measurands are examined for a selection of power system operating conditions to demonstrate the operation of this type of protection.

The new protection algorithm is shown to trip for loss of grid, for load fluctuations while the dispersed storage and generation unit is operating independently of the utility supply following a loss of grid, and for an out-of-synchronism reconnection of the utility supply to the dispersed storage and generation unit. It is also shown to remain stable for major load fluctuations while the utility supply remains connected to the dispersed generator system.

Keywords: - Power system protection, Dispersed storage and generation units, Islanding protection, Non-utility generation.

INTRODUCTION

Over the last decade there has been a growing interest in the installation of small and medium sized generation units which operate in parallel with the local electric utility's power supply. Defined as dispersed storage and generation facilities, the initial interest was dominated by the non-utility sector, but more recently, utilities have also been investing in this type of generation.

Before a dispersed storage and generation unit can be connected to the local utility network, several technical implications must be considered. Amongst these is the need to ensure that the whole system is properly protected, including the utility network, the dispersed storage and generation unit and any on-site load.

A particularly demanding protection requirement is the need to guard against the abnormal condition where a small section of the utility's load network remains connected to the dispersed storage and generation unit following system switching operations. This produces an independent power 'island'. Ideally, the protection system should automatically disconnect the dispersed storage and generation unit from the utility network; i.e. 'loss of grid' protection. Apart from the safety aspect of having a section of the network energised when it would generally be assumed that the loss of the main source of supply would de-energise the system, there is also the potentially disastrous scenario where the main source of supply could be reconnected to the power island out-of-synchronism with the dispersed storage and generation unit.

Traditionally utilities have resisted the installation of a dispersed storage and generation unit directly connected to the main network because of the technical complications involved. The use of private generation is however well established where generation has been installed to operate independently from the utility's supply, either as stand alone generation directly supporting the site load, or as stand-by generation for situations when the utility has been unable to maintain continuous supply.

In response to the growing interest in dispersed storage and generation, several guidelines have been introduced for the connection of small and medium sized generation to their networks. The utilities' objective has been to ensure that the presence of the dispersed storage and generation unit will not detract from the quality of supply to all customers connected to their system. The protection requirements for a dispersed generation and storage facility are further explained in reports associated with the guidelines. A common feature of these, either implicit or by inference, is the need to protect the system against 'loss of grid'.

REQUIREMENTS FOR LOSS OF GRID PROTECTION

The principal objective of 'loss of grid' protection is to detect the condition where the dispersed storage and generation unit is left connected to a portion of the utility's load network with no main source of utility power following a system switching operation. The main source of utility power could be obtained from either a main power station or a transmission supply point, commonly referred to as a grid connection, and hence the name 'loss of grid'.

There are several possible causes of loss of grid including; switching operations to clear a fault, load shedding, maintenance outages and equipment failure.

The loss of grid protection is required to disconnect the link between the dispersed storage and generation unit and the utility network enabling an uncomplicated restoration of the utility supply. The typical requirement for this protection is that it should operate within half a second following the isolation of the power island, but faster relaying is attractive.

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In itself, loss of grid is not a problem provided that the source of generation maintains the system's voltage and frequency within the specified limits. The main cause for concern[4,7,9,10] is the probability that the two systems will be reconnected when their generators are out of synchronism. In the last practice is to avoid reclosing. It is not reasonable to ask a utility to disable all reclosing close to the dispersed storage and generation unit. Should out of synchronism reclosure occur, there is a high probability that the dispersed storage and generation unit will be damaged.

Where the generator is used to supplement the utility supply to the local site and does not export power to the utility, loss of grid will result in power flowing from the dispersed storage and generation unit to the utility system. The dispersed generation unit can be resynchronised to the utility and then be used to open the inter—tie connecting the two systems. Although the best practice is to maintain the dispersed storage and generation unit will be damaged. If the dispersed storage and generation unit is out of synchronism, the generator is unable to synchronise to the utility system. Specialist relaying is therefore required to detect the loss of grid and trip the inter—tie breaker.

The loss of grid protection is required in addition to the other protection required for the generator, its site, and the utility system close to the generator. Specialist relaying is required for the dispersed storage and generation unit. The protection scheme used with a particular dispersed storage and generation unit depends on the machine and the system to which it is connected[4,7,9,11,12].

TECHNIQUES FOR LOSS OF GRID PROTECTION

The most direct method for loss of grid protection[4,7,10] is to monitor auxiliary contacts on all circuit breakers on the utility system between its main sources of generation and the dispersed storage and generation unit. When a switching operation produces a loss of grid, a transfer trip scheme can then be used to open the inter—tie connecting the two systems. Following successful restoration of the utility supply, the dispersed storage and generation unit can be resynchronised to the utility and then reconnected. Unfortunately, several circuit breakers are candidates for creating the loss of grid and a comprehensive monitoring system involving all circuit breakers which could be involved would be unmanageable for most utilities. The installation of an extensive SCADA and network automation can facilitate such a scheme.

Reclosure of the utility supply onto a dispersed storage and generation unit can be avoided by using dead circuit pick-up supervision[10] on utility circuit breakers. These would inhibit breaker closing until the load-side circuit was de-energised and initiate a transfer trip to open the inter—tie between the dispersed generator and the utility. Several techniques have been devised for detecting loss of grid using measurements taken on the dispersed storage and generation site. These include:- reactive power export error detection[10], system fault level monitoring[4], rate of change of frequency measurement[13], phase displacement monitoring[15,16], and the algorithms based on rate of change of generator power output which are presented in this paper. The first two of these can be described as active techniques, since they directly interact with the on-going operation of the power system, whereas the other techniques can be considered passive, since they detect loss of grid solely by monitoring the power system's behaviour.

Active Techniques.

The reactive power export error detection[13] relay interfaces with the dispersed generator's control system to force it to generate a level of reactive power flow in the intertie between the local site and the utility which can only be maintained when the utility's main source of generation is connected. Relay operation is triggered when there is an error between the setting and the actual reactive power being exported for greater than a preset time period. To avoid mal-operation, the time setting is chosen to be greater than the duration of possible supply fluctuations.

Although this relaying approach is slow, it is recognised as being very effective since it can detect loss of grid when there is no change in the generator's loading due to the switching operation. The relay is frequently used to provide a back-up protection to other 'faster' systems. Typical operating times vary from two to five seconds.

The system fault level monitor[14] provides a faster operating protection system and its tripping depends on measurements of the power system's source impedance as taken close to the intertie. This is performed by monitoring the short circuit current and reduction in supply voltage when a shunt inductor is connected across the supply using point-on-wave triggered, thyristor switches. The firing of the thyristors just before a current zero causes a short pulse of current to flow in the inductor and a voltage glitch. The decision to trip depends on the comparison of the measured system fault level with that corresponding to a network fed from the main utility generation.

Since there is a dramatic difference between the fault levels of the dispersed generation and the dispersed storage and generation unit, the system need not be particularly accurate. The operating times can also be very short, with a theoretical minimum of half a cycle. However, although similar techniques are also used to improve the performance of static voltage compensators, relays have not been produced.

Passive Techniques.

In almost all circumstances, loss of grid results in changes to the loading of the dispersed storage and generation unit and hence produces changes in system voltage, currents and frequency. The behaviour of the system is monitored by the relay and these changes provide the basis for passive protection.

The most direct protection techniques are based on under/over voltage, and under/over frequency relaying. In many small generator applications these provide an acceptable level of protection, but they can only operate if the loss of grid produces a change of load greater than that which can be compensated for by the generator's control system.

Several of the more sophisticated passive techniques depend on the generator swing equation[17] which defines the rate of change of frequency:-

### TECHNIQUES FOR LOSS OF GRID PROTECTION

- **Reactive Power出口 Error Detection**
- **System Fault Level Monitoring**
- **Active Techniques**
- **Passive Techniques**
DF is the change in power output
F is the power system frequency
H is the inertia constant of the generator/system
G is the rated capacity of the generator/system.

Rate of change of frequency\(^13\) relays monitor the voltage waveform and trip when the measured rate of change of frequency exceeds a preset level for longer than a set time period. The settings are chosen such that the relay will operate for fluctuations associated with loss of grid and when the dispersed generator is operating independently from the utility’s source of supply, but not for those fluctuations governed by utility time constants.

For small and medium sized dispersed storage and generation unit, a trip setting of 0.3 Hz/sec has been found to be optimum with an operating time from 0.3 to 0.7 seconds. Under extreme conditions, accompanied by dramatic changes in frequency, tripping in four or five cycles is possible.

The phase displacement monitor\(^15,16\) is generically related to the rate of change of frequency relay and operates when there are phase displacements in the voltage waveform. These are a direct result of changes in the dispersed generator’s loading and can cause the relay to operate in 50 ms following a loss of grid which results in a load change of greater than 5\% of its rating.

An inherent advantage of both rate of change of frequency relaying and the phase displacement monitor is that, should the relay fail to operate for the loss of grid, any subsequent load changes could cause tripping. Since these relays require a single input signal, the system voltage waveform, they use the minimum of input circuitry, thus offering an immediate advantage for stand alone relaying.

The introduction of digital technology and the move to integrated protection schemes, has enabled other techniques to be considered which require more input data for the decision making. One such technique uses an algorithm based on the rate of change of power output measured at the dispersed generator’s terminals.

Considering the simplified representation of a dispersed generator, its site load and the utility network as shown in Figure 1, both the dispersed generator and the utility supply can be modelled by idealised generators of capacity \(G_g\) and \(G_m\), and with inertia constants \(H_g\) and \(H_m\) respectively. A change in system load of \(\Delta P_L\) produces a change in the generator’s loading of \(\Delta P_g\) defined by:

\[
\Delta P_g = \Delta P_L \frac{H_g}{H_g + H_m} G_g + \frac{H_m}{H_g + H_m} G_m
\]

However, if the dispersed storage and generation unit operates independently from the utility supply, any change of load will directly affect the dispersed generator since the equation above reduces to:

\[
\Delta P_g = \Delta P_L G_g
\]

Since loss of grid generally produces a load change, monitoring changes in the power output of the generator provides a direct method of detecting the phenomena.

The instantaneous three phase power output from the generator is derived from:

\[
F_g = v_{a1} + v_{b1} + v_{c1} + v_{a2} + v_{b2} + v_{c2}
\]

where \(v_{a1}, v_{b1}, v_{c1}, v_{a2}, v_{b2}, v_{c2}\) represent the sampled values of the line currents and phase voltages measured at the generator’s terminals. All of these signals are required by a comprehensive integrated protection scheme for a dispersed generator.

The protection algorithm monitors the changes in power output and integrates these changes over a defined sample period. Tripping occurs when the integrated signal exceeds the trip setting, \(k_s\). In the digital sampling relay the algorithm’s trip criteria are represented by:

\[
\sum_{n = 0}^{\infty} (\Delta P_g)_n > k_s
\]

where; \(n\) is the sampling instant of \(\Delta P_g\) and, \(tx\) is the length of the sampling window.

FIGURE 1. NETWORK CONFIGURATION CONTAINING A DISPERSED STORAGE AND GENERATION UNIT.

The integrating feature provides immunity to mal-operation during conditions of extreme load unbalance or loss of phase operation. An unbalance in the input waveforms would introduce sinusoidal terms of twice the power system frequency and these can be filtered out by the integrating process. The length of the sampling window was chosen to give a maximum operating time of six cycles, and \((\Delta P_g)_n\) was amplitude limited to give a minimum tripping time of one cycle. The relay’s setting was chosen such that the relay would trip whenever the disturbance produced a load change of 1% of the dispersed storage and generation unit’s rating.
In addition to providing an effective technique for detecting loss of grid, this system will also operate for grid fault cases. The technique should enable a grid fail to produce the disturbance required to trip. It will also trip if the systems are reconnected while the systems are out-of-synchronism.

**POWER SYSTEM STUDIES**

Power system studies were undertaken using the network shown in Figure 1. The results presented were obtained from the analysis of an 11 kV network containing a 3.75 MVA dispersed storage and generation unit with an inertia constant of 0.91 MW-sec/MVA, a 3 MW local load, and a utility supply of 250 MVA and inertia constant of 10 MW-sec/MVA.

The test period was chosen to be one second, commencing 100 ms before the disturbance. The model did not include the action of the automatic voltage regulator or the prime mover's governor, since the period of interest was short in comparison to their time constants.

The variations in the dispersed generator's terminal line voltage and frequency were derived from measurements of the machine algorithms and the network model. Apart from the operation of the algorithms based on the rate of change of power, no attempt was made to emulate the operation of particular protection algorithms used for under/over voltage, under/over frequency or rate of change of frequency protection.

The performance of protection systems using under/over voltage, under/over frequency or rate of change of frequency would be determined by the changes in power system operation, the signal processing techniques used, and any enhancement features included. Several techniques exist for these types of relaying and all have their own complications and response times. The measurements of frequency and rate of change of frequency from a monitored input waveform are far from straight forward and are time consuming. The simpler techniques rely on zero crossings of the monitored waveform, whereas the more robust techniques use complex signal processing.

The trip settings for the protection algorithms based on the rate of change of power were chosen such that a one percent change in load resulting from the loss of grid would cause a trip. This corresponded to a change of 5.0 (MW) on the scale used in the response curves shown. The limits of MV are derived from (MW/sec) integrated over time.

The trip settings for the under/over voltage protection were set to six percent of voltage nominal, the under/over frequency protection settings were one percent of the nominal frequency, and the rate of change of frequency was set to 0.3 Hz/sec.

**Loss of Grid Studies.**

The response to a loss of grid resulting in a fifty percent increase in loading is shown in Figure 2. Immediately following the disturbance, the voltage and frequency are depressed causing the under/over voltage protection to fall below the trip setting after 36 ms, and the under/over frequency protection to fall below its trip setting after 48 ms. The system's rate of change of frequency falls almost immediately, and exceeds the trip setting after 4 ms. The rate of change of power suffers violent changes immediately following the switching, then settles to an almost steady value. The algorithms trips after 24 ms.

The response to a loss of grid resulting in a five percent increase in loading is shown in Figure 3. The generator's terminal line voltage is again depressed less than in the case above, and in the test period considered, the voltage limits were not exceeded. The fall in measured frequency only exceeded the lower limit after 540 ms. Again there was an immediate change in the rate of change of frequency and its limit was exceeded after 4 ms. The algorithm based on rate of change of power tripped after 26 ms.

The marginal trip condition for the algorithm using rate of change of power is shown in Figure 4, and produces a trip after 123 ms. In this case, the limits for under/over voltage, under/over frequency, and rate of change of frequency were not exceeded.

**Parallel Operation Studies.**

Figures 5 and 6 show the responses to a doubling of the local load and a loss of the local load while the generator is operating in parallel with the utility supply. In both cases none of the protection limits are exceeded and the protections remain stable. All the curves contain oscillations after the switching operation as the system re-establishes equilibrium.

**Independent Operation Studies.**

An example of load switching while the generator is operating independently of the utility supply is shown in Figure 7. Although the load change is limited to an increase of five percent of the generators rating, the rate of change of power algorithm trips after 26 ms, the frequency falls below its limit after 564 ms, and the rate of change of frequency after 4 ms. Under these conditions, the loss of grid protection would trip the inter-tie breaker and isolate the generator from the utility system. If however the inter-tie breaker was already tripped, the protection would be inhibited.

**Non-synchronised Reclosure.**

The responses to non-synchronised reclosure resulting in no load changes, but with phase displacements of 180 and 5 degrees are shown in Figures 8 and 9 respectively. In both cases there are severe oscillations in the power taken from and fed to the generator, but little change in either the system voltage or frequency. The rate of change of power algorithm trips after 275 and 272 ms respectively, whereas the limits on voltage, frequency, and rate of change of frequency are not exceeded.

**CONCLUSION**

"Providing protection against islanding probably is the single most challenging aspect of designing the electrical system involved in cogeneration."8 Loss of grid protection is arguably the greatest challenge in the protection package.

Several different techniques are available for protecting a dispersed storage and generation unit against loss of grid. These include network supervision, active techniques, which directly interact with the operation of the power system, and passive techniques, which rely on monitoring the power system's behaviour.

Network supervision methods are the most direct and offer the greatest level of protection. However, with most utility networks where SCADA systems do not cover all of the distribution network, they present the largest expense. Active techniques are generally very effective in detecting the loss of grid, but have the
FIGURE 2. LOSS OF GRID RESULTING IN A 50% INCREASE IN GENERATOR LOADING.

FIGURE 3. LOSS OF GRID RESULTING IN A 5% INCREASE IN GENERATOR LOADING.

FIGURE 4. LOSS OF GRID RESULTING IN A 1% INCREASE IN GENERATOR LOADING.

FIGURE 5. 100% LOAD INCREASE DURING PARALLEL OPERATION WITH THE UTILITY GRID.
(a) Terminal Voltage (Ph/Ph).
(b) System Frequency.
(c) Rate of Change of Frequency.
(d) Rate of Change of Power (Amplitude Limited).
(e) Rate of Change of Power Protection Algorithm (Summation Output).

FIGURE 6. LOSS OF LOCAL LOAD DURING PARALLEL OPERATION WITH THE UTILITY GRID.

(a) Terminal Voltage (Ph/Ph).
(b) System Frequency.
(c) Rate of Change of Frequency.
(d) Rate of Change of Power (Amplitude Limited).
(e) Rate of Change of Power Protection Algorithm (Summation Output).

FIGURE 7. A 5% INCREASE IN GENERATOR LOADING WHILE THE DISPERSED GENERATOR IS OPERATING ALONE.

(a) Terminal Voltage (Ph/Ph).
(b) System Frequency.
(c) Rate of Change of Frequency.
(d) Rate of Change of Power (Amplitude Limited).
(e) Rate of Change of Power Protection Algorithm (Summation Output).

FIGURE 8. AN OUT-OF-SYNCHRONISATION RECONNECTION WITH A PHASE DISPLACEMENT OF 180 DEGREES AND NO LOAD CHANGE.

(a) Terminal Voltage (Ph/Ph).
(b) System Frequency.
(c) Rate of Change of Frequency.
(d) Rate of Change of Power (Amplitude Limited).
(e) Rate of Change of Power Protection Algorithm (Summation Output).

FIGURE 9. AN OUT-OF-SYNCHRONISATION RECONNECTION WITH A PHASE DISPLACEMENT OF 5 DEGREES AND NO LOAD CHANGE.
significant disadvantage of requiring a direct influence on the power system. Passive techniques avoid this problem and are generally the least expensive to install, but they cannot be guaranteed to operate under all loss of grid conditions.

The results of the power system studies demonstrated the fundamental capabilities and limitations of using supply voltage, frequency and rate of change of frequency for loss of grid protection. The performance of the new algorithm using the rate of change of power is shown to operate as required.

A significant advantage of this new approach is its ability to quickly detect out-of-synchronism reconnection of the utility supply to a power island containing the dispersed storage and generation unit. This is considered to be a particularly onerous requirement since it represents the greatest danger to the dispersed storage and generation unit.

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Miles A Redfern (M'79) received his BSc degree from Nottingham University and PhD degree from Cambridge University in 1970 and 1976 respectively. In 1970, he joined British Railways Research, and in 1975, moved to GEC Measurements where he held various posts including Head of Research and Long Term Development and Overseas Sales Manager. In 1986, he joined Bath University with interests in Power Systems Protection and Management. He is currently a member of IEE Professional Group Pi1, Power System Measurement, Protection and Control, and is a corresponding member of the IEEE Line Protection Sub-Committee and working group Di3, Six Phase Power Systems.

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INTRODUCTION.

The operation of small or medium sized generation running in parallel with the local utility supply, creates several difficulties for the reliable and safe operation of the power supply system. These difficulties arise from the generator's capacity to supply power to the network and because it operates independently of the network control system.

The protection scheme required by the embedded generator must include functions which provide protection for faults directly affecting the site's generator, protection for the utility from faults on the generator's site, and protection for the generator's site from faults or disturbances on the utility network. An important element in the latter requirement is the need to protect against the accidental isolation of the generator's site from the main source of utility power. In such a situation, the generator's site could be left connected to part of the utility load and operate as an independent power island.

This situation is illustrated in figure 1. Following the opening of the 'loss of grid' circuit breaker, the generator's site is left connected to part of the network load. Ideally the loss of grid protection would trip the inter-tie breaker disconnecting the generator's site from the utility and thereby facilitate the orderly restoration of the utility supply to the network. Unfortunately for the operation of the network, the 'loss of grid' circuit breaker need not be a specific circuit breaker but may potentially be any breaker, switch, or isolator connecting the utility's main source of supply to the generator's site.

Protection designed to detect loss of grid supply is a relatively new area for relaying and is commonly referred to as either loss of grid protection or loss of mains protection. Occasionally it is referred to as islanding protection.

Before a utility will agree to the connection of an embedded generator to its network, they will need to be satisfied that the presence of the embedded generator will not detract from the quality of supply provided to its customers. In the UK, the technical requirements for connecting an embedded generator to a Regional Distribution Company's system are defined in the Electricity Council Engineering Recommendation G59. The protection requirements include the need to provide loss of grid protection as part of the generator's site protection scheme.

LOSS OF GRID PROTECTION.

Several techniques have already been developed for detecting loss of grid and the difficulties with this type of relaying have led to considerable interest in exploring new concepts for this function. Quoting from a recent IEEE paper, "Providing protection against islanding probably is the single most challenging aspect of designing the electrical system involving cogeneration." These difficulties arise because loss of grid is not a clearly defined fault condition but is an undesirable and unsafe operating state. For most systems, scenarios exist where the different protection techniques may fail to detect the loss of grid.

The techniques being examined to detect loss of grid are based on monitoring the behaviour of the power system to disturbances and the differences in system characteristics between those experienced when the main utility supply is connected to the embedded generator and those when the embedded generator is operating in isolation. The algorithm uses changes in the power output from the embedded generator to provide an insight into the transfer function of the generating plant feeding the power system. Under normal conditions with the utility supply connected, the transfer function reflects the combination of the main source and the embedded generation. Following loss of grid, or while the embedded generator is operating in isolation, it reflects the characteristics of the embedded generator alone.

Returning to the simplified representation of a power system shown in figure 1, the embedded generator and the main utility supply can be represented by idealised generators of capacity G and G* with inertia constants H and Hm respectively. While the utility's source of supply is connected to the network, a change in the system load of DP, produces a change in the distributed generator's loading of DP defined by:

\[ DP = \frac{H_m G}{H_m G + H G_m} \]

However if the distributed generator operates independently from the utility supply, for example following loss of grid, any change of system load will result in the distributed generator's loading of DP defined by:

\[ DP = \frac{DP}{DP + H_m G_m} \]

Accepting that the utility has a greater capacity than the embedded generator and that its inertia constant will also be greater, the differences in response to a disturbance provides an immediate basis for determining whether or not the utility supply is connected to the portion of the network containing the embedded generation.

An additional advantage of using the power as the relaying measurement is that it is readily obtained from instantaneous measurements of the generator's terminal voltages and output currents. Providing that the samples are taken at the same instant, they also do not have to be synchronised to the power system frequency. The generator's three phase power output is derived from:

\[ P = v_1i_1 + v_2i_2 + v_3i_3 \]

where:

\[ v_1, v_2, v_3 \] are the sampled values of the generator's terminal voltages.
In a typical protection scheme associated with an embedded generator, these measurements are also required for other relaying functions required to protect the machine. The loss of grid protection is therefore suitable for including into an integrated protection package for a small or medium sized embedded generator without dramatically increasing the hardware requirements.

In addition to reliably detecting the occurrence of a loss of grid, the protection algorithm must remain stable during conditions of extreme load unbalance, loss of phase and during load flicker. These conditions have been accommodated by amplitude limiting measurements of changes in power output from the embedded generator and integrating samples over a moving window period. The protection's trip criteria is defined by:

\[
\begin{align*}
  n &= 0 \\
  \sum_{n = t_o - n}^{n} (DP_g)_n &> k_o \\
  n &= n - t_o
\end{align*}
\]

where;

- \( n \) is the sampling instant of \((DP_g)_n\),
- \( k_o \) is the trip setting,
- and, \( t_o \) is the length of the sampling window.

**POWER SYSTEM STUDIES.**

Extensive simulation studies have been undertaken to study both the effects of loss of grid and of other disturbances to a power system containing an embedded generator. These studies were conducted using both the alternative transients version of the EMTP programme, ATP \( ^o \), and programmes developed in-house. Unfortunately, limitations were found in the generation model used in the ATP and hence detailed new models had to be developed.

To illustrate the capabilities of the protection algorithm, an 11 kV network containing a 3.75 MVA embedded generator was modelled. The embedded generator had an inertia constant of 0.91 MWsec/MVA and the site load was 3 MW. The utility supply was set at 250 MVA with an inertia constant of 10 MWsec/MVA. The test period considered used a one second window commencing 100 ms before the disturbance.

The length of the sampling window used in the protection algorithm was chosen to give a maximum operating time of six cycles and the amplitude limiting was chosen to provide a minimum tripping time of one cycle. The trip setting was selected such that a one percent load change following loss of grid produced tripping.

The response to a loss of grid producing a 5% increase in generator load is shown in figure 2. For this disturbance, the protection algorithm trips after 26 ms. The traces for the a-phase voltage shows that it dips after the disturbance whereas the a-phase current increases.

The response to a 5% increase in generator load while the generator is operating independently of the utility supply is shown in figure 3. These curves are virtually identical to those of figure 2 and tripping also occurs 26 ms after the disturbance. In a practical situation the loss of grid trip would open the inter-tie breaker if it were closed ensuring that the utility supply could be safely restored to the utility without disturbing the embedded generator. Satisfactory restoration of supply to the adjacent network bus could be followed by a controlled reclosure of the inter-tie breaker. Naturally operation of the loss of grid protection while the inter-tie breaker was open would have no effect.

The restraint of the algorithm to violent load changes while the distributed generator is operating in parallel with the utility supply is shown in figure 4. This shows the response to a 100% change in the local load and the non-operation of the protection algorithm. The auto-scaling feature of the plotting package masks the lack of disturbance to the embedded generator.

Arguably the worst case scenario following a failure to detect loss of grid is an out-of-synchronism reclosure of the loss of grid breaker. An example of this is shown in figure 5 where the phase angle between the two systems is thirty degrees before reclosure. Tripping results 234 ms after the reclosure, disconnecting the embedded generator from the utility before serious damage can result. Although in an ideal world such a reclosure would be unthinkable, in the real world where an embedded generator is connected to an established power network, the distribution switchgear will rarely be equipped with check synchronisers or live line/dead bus, dead line/live bus supervision.

In addition to the algorithm's response to switching disturbances, its response to fault conditions is also of interest. A solid three phase fault on the local busbar would produce a condition similar to that for a loss of grid. The fault effectively splits the system into two and would in effect be fed independently by the generation on either side. This type of fault would therefore cause the algorithm to trip the inter-tie breaker. The response to a three phase fault is shown in figure 6, and tripping occurs 340 ms after the fault. The initial violent changes in power output from the distributed generation unit are attenuated by the signal limiting action of the algorithm and hence operation is delayed. Naturally this fault would be seen by other protection functions which would also isolate it from the system. The operating times of the loss of grid protection are suitable to allow proper grading.

A single phase fault on the same busbar, however, need not result in three phase tripping of the inter-tie breaker and hence should be left to the remaining protection relays to clear. The algorithm does not result in tripping for a single phase to ground fault as shown in figure 7. Since in this case, only one phase is effectively lost, the power output oscillates at twice the power system frequency and the integrating nature of the algorithm prevents tripping.

**CONCLUSIONS.**

The loss of grid protection described in this paper provides an effective technique for detecting this condition and enabling the utility supply to be reconnected in a controlled manner. The algorithm has been shown to remain stable under extreme load fluctuations while the utility supply remains connected to the generator's site, but to operate quickly for small fluctuations when the generator's site is disconnected from the main utility supply.

The algorithm also trips for an out-of-synchronism reclosure of the utility supply onto the generator's site protecting the embedded generator from possible damage. Extreme fault conditions effectively splitting the power system result in tripping, but if the interconnection remains intact, it remains stable.
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FIGURE 1. NETWORK CONFIGURATION CONTAINING A DISTRIBUTED GENERATION UNIT.

FIGURE 2. RESPONSE TO A LOSS OF GRID PRODUCING A 5% INCREASE IN THE GENERATOR LOADING.

FIGURE 3. RESPONSE TO A DISTURBANCE PRODUCING A 5% INCREASE IN THE GENERATOR LOADING WHILE IT IS OPERATING INDEPENDENTLY OF THE UTILITY SUPPLY.
FIGURE 4. RESPONSE TO A DISTURBANCE PRODUCING A 100% INCREASE IN THE LOCAL LOAD WHILE OPERATING IN PARALLEL WITH THE UTILITY SUPPLY.

FIGURE 5. RESPONSE TO AN OUT-OF-SYNCHRONISM RECLOSURE BETWEEN THE POWER ISLAND AND THE UTILITY GRID SUPPLY WITH PRE-CLOSURE PHASE SEPARATION OF 30 DEGREES.

FIGURE 6. RESPONSE TO A THREE PHASE FAULT ON THE LOCAL BUSBAR.

FIGURE 7. RESPONSE TO A SINGLE PHASE FAULT ON THE LOCAL BUSBAR.
INTRODUCTION.

"Providing protection against islanding probably is the single most challenging aspect of designing the electrical system involved in cogeneration.1.2 For small or medium sized cogenerators, also referred to as embedded generators, operating in parallel with a utility power supply, islanding generally occurs following utility switching operations which leave the generator connected to part of the utility's load but disconnected from the utility's main source of power. The condition is also referred to as loss of mains or more recently as loss of grid.

Considering the simplified system shown in figure 1, the power island is produced by opening the loss of grid breaker. Unfortunately the circuit breaker causing loss of grid could be any of several breakers providing the link between the utility's main source of power and the embedded generator. In itself loss of grid should not damage the power system. However since it produces two separate power networks, it complicates the orderly reconnection of the power supply network. For those utility customers left connected to the embedded generator, it could result in their power supply deviating from required standards. There is also a potential safety hazard to personnel, since following loss of grid part of the utility system remains energised which would normally be expected to be de-energised.

In the UK, Electricity Council Recommendations GC2 and Engineering Technical Report ET 113 describes the requirements of the protection systems which need to be satisfied before the connection of an embedded generator to the utility system can be authorised. These requirements include the need to provide loss of grid protection. Most major utilities in other countries who allow non utility generation to be connected to their system have similar guide-lines.3,4

The requirements of the loss of grid protection as defined by GC2 are that it should automatically disconnect the generator from the Electricity Board's system in the event of loss of the Board's supply to that installation. The tripping time should be such that the two systems have been successfully separated before automatic reclosing equipment could attempt to reconnect the two systems. On a distribution system the time setting of the recloser could be one second. The protection system is also required to ensure that the embedded generator is properly earthed following loss of grid.

TECHNIQUES FOR DETECTING LOSS OF GRID.

The most direct method for detecting loss of grid is to take advantage of a SCADA system and monitor auxiliary contacts on all circuit breakers on the utility system between the embedded generator and the utility supply. Detection of a loss of grid would be followed by a transfer trip instruction to open the inter-tie breaker connecting the embedded generator to the utility. Although this is the most effective technique available, most distribution systems and the circuit breakers they employ have not been fitted with a suitable supervisory system and the expense involved with a retro-fit is difficult to justify.

Several techniques have been developed for detecting loss of grid using local power system measurements made on the embedded generator's site. These can be divided into active techniques, which have a direct influence on the operation of the power system, and passive techniques, which rely on passive measurements of system parameters. Active techniques include the Reactive Power Export Error Detector and the System Fault Level Monitor. The passive techniques include Under/Over frequency, Under/Over Voltage, Reverse Power, Rate of Change of Frequency and Phase Displacement Monitoring. All of these techniques have limitations and there is considerable interest in investigating new possibilities.

THE NEW LOSS OF GRID PROTECTION ALGORITHM.

The commercial attraction of a loss of grid protection which can be included in an integrated digital protection scheme for an embedded generator led to the formulation of this new algorithm. Unlike previous techniques the algorithm is based on monitoring fluctuations in the generator's power output. The operation of the algorithm depends on the characteristics of these disturbances and the different responses which result when the embedded generator is operating while connected to the utility supply and while it is operating independently.

Considering the simplified system shown in figure 1, both the embedded generator and the utility supply can be modelled by idealised generators of capacity G_g and G_u with inertia constants H_g and H_u respectively. While the utility source of generation remains connected to the utility source of supply, a change in the network loading, Δ_P_n, will produce a change in the generator's power output, Δ_P_g, defined by:-

\[
\Delta P_g - \Delta P_n = \frac{H_u G_u}{H_g G_u + H_u G_g} \]

Since the capacity and inertia constant of the utility source is greater than that of the embedded generator, the changes to the generator's power output will be small when compared to the change in the load. However, when the embedded generator is operating independently from the main source of utility supply, a change in the network loading, Δ_P_n, will have a direct effect on the generator's power output, Δ_P_g, such that:-

\[
\Delta P_g = \Delta P_n
\]

The measurement of the generator's power output is based on the instantaneous power, P_g, measured in a three phase system:-

\[
P_g = v_1 i_1 + v_2 i_2 + v_3 i_3
\]

where v_i, v_j, v_k, i_1, i_2, and i_3 represent the sampled values of phase voltages and currents measured at the
INTRODUCTION.

"Providing protection against islanding probably is the single most challenging aspect of designing the electrical system involved in cogeneration.

For small or medium sized cogenerators, also referred to as embedded generators, operating in parallel with a utility power supply, islanding generally occurs following utility switching operations which leave the generator connected to part of the utility's load but disconnected from the utility's main source of power. The condition is also referred to as loss of mains or more recently as loss of grid.

Considering the simplified system shown in figure 1, the power island is produced by opening the loss of grid breaker. Unfortunately the circuit breaker causing loss of grid could be any of several breakers providing the link between the utility's main source of power and the embedded generator. In itself loss of grid should not damage the power system. However, since it produces two separate power networks, it complicates the orderly reconnection of the power system involved in cogeneration.

In the UK, Electricity Council Recommendations G592 and Engineering Technical Report ET 1139 describe the requirements of the protection systems which need to be satisfied before the connection of an embedded generator to the utility system can be authorised. These requirements include the need to provide loss of grid protection. Most major utilities in other countries who allow non utility generation to be connected to their system have similar guide-lines.

Several techniques have been developed for detecting loss of grid using local power system measurements made on the embedded generator's site. These can be divided into active techniques, which have a direct influence on the operation of the power system, and passive techniques, which rely on passive measurements of system parameters. Active techniques include the Reactive Power Export Error Detector and the System Fault Level Monitor. The passive techniques include Under/Over frequency, Under/Over Voltage, Reverse Power, Rate of Change of Frequency and Phase Displacement Monitoring. All of these techniques have limitations and there is considerable interest in investigating new possibilities.

THE NEW LOSS OF GRID PROTECTION ALGORITHM.

The commercial attraction of a loss of grid protection which can be included in an integrated digital protection scheme for an embedded generator led to the formulation of this new algorithm. Unlike previous techniques the algorithm is based on monitoring fluctuations in the generator's power output. The operation of the algorithm depends on the characteristics of these disturbances and the different responses which result when the embedded generator is operating while connected to the utility supply and while it is operating independently.

Considering the simplified system shown in figure 1, both the embedded generator and the utility supply can be modelled by idealised generators of capacity Gg and Gs with inertia constants Hg and Hs respectively. While the utility source of generation remains connected to the utility source of supply, a change in the network loading, ΔPs, will produce a change in the generator's power output, ΔPg, defined by:

\[ ΔPg = ΔPs \frac{HgGg}{HsGg + HgGs} \]

Since the capacity and inertia constant of the utility source is greater than that of the embedded generator, the changes to the generator's power output will be small when compared to the changes in the load. However, when the embedded generator is operating independently from the main source of utility supply, a change in the network loading, ΔPs, will have a direct effect on the generator's power output, ΔPg, such that:

\[ ΔPg = ΔPs \]

The measurement of the generator's power output is based on the instantaneous power, \( P_n \), measured in a three phase system:

\[ P_n = v_i^a i_a + v_i^b i_b + v_i^c i_c \]

where \( v_i^a, v_i^b, v_i^c, i_a, i_b, i_c \) represent the sampled values of phase voltages and currents measured at the
generator's terminals at sampling instant $n$. If the three phase system is balanced, this measurement is divorced from the point-on-wave of the input samples and the system need not be locked onto the power system frequency. A low sampling rate can also be used.

The protection algorithm monitors fluctuations in the power output over a defined sampling window. Fluctuations in the generator's power output are amplitude limited by the function $f_n$. This signal is integrated, the trip setting is initiated when the absolute value of the integrated signal exceeds the trip setting, $k_t$. The algorithm is defined by:

$$\sum_{n=0}^{n-t_x} f_n(dP_n) > k_t$$

where:

- $n$ is the sampling instant of $\Delta P$
- $n - t_x$ is the length of the sampling window.

Both the use of the sampling window and the amplitude limiting function provide inherent filtering capability for noise and unbalance. The length of the sampling window is chosen to give a maximum nominal operating time of six cycles of the power system frequency, and provides inherent immunity to mal-operation due to extreme conditions of load unbalance or when an input transducer is lost. This could for example be caused by the loss of one of the voltage transformers. The nominal minimum operating time is defined by the level used for the amplitude limiting function. For the tests illustrated below this has been chosen to be equivalent to one cycle of the power system frequency. The trip setting is chosen such that the relay would just trip whenever a loss of grid or a load disturbance during independent operation produced a pre-defined percentage change in the generator's power output. The choice of setting depends on the application and local conditions. For the algorithm the setting is defined by the sampling interval, the length of the sampling window, the generator's inertia constant and its rated capacity.

**MICROPROCESSOR BASED RELAY IMPLEMENTATION.**

To complement computer studies of the performance of the loss of grid protection algorithm, initial practical trials have been conducted using a laboratory 200 V, three phase, model power system. The model is based on a double bus generating station and includes two small synchronous generators driven by dc machines. One of these generators has been fitted with a microprocessor protection relay which is supported by a personal computer. This computer is also equipped with input transducers to monitor an array of system voltages and currents, and provides a convenient platform for research into new digital algorithms for generator protection which can be transferred to the relay hardware at a later stage.

The loss of grid protection algorithm was programmed into the personal computer to run in real time alongside other protection functions. Advantage was taken of existing data acquisition and data recording systems. The system used 12 bit A/D converters with a 200kHz dynamic range for the voltage inputs and a switched range of dynamic ranges for the current inputs. For the following tests a 200% dynamic range was used for the current inputs and the system was run at 16 samples per power cycle.

The personal computer used a 12 MHz 80286 processor together with a 80287 co-processor. The algorithm was coded in assembler using approximately fifty instructions.

**PROTECTION PERFORMANCE STUDIES.**

The computer studies modelled an 11 kV system similar to that shown in figure 1. The embedded generator was rated at 3.75 MVA with an inertia constant of 0.91 MW-sec/MVA and the utility supply was rated at 250 MW with an inertia constant of 10 MW-sec/MVA. A one second test period was used commencing 100 msec before the switching disturbance. The algorithm's trip setting was set such that it would trip following a loss of grid producing a one percent change in the generator's output loading. A sampling rate of 20 samples per power system frequency cycle was used by the algorithm.

The practical tests used the 5 kVA test machine with a measured inertia constant of 0.35 kW-sec/kVA. The mains supply was rated at 500 kVA with a nominal inertia constant of 10 kW-sec/kVA. To avoid spurious tripping, the relay's trip setting was set such that it would just trip following a loss of grid producing a two and a half percentage change in the generator's output loading. The test system suffered from very high levels of waveform distortion and harmonic interference, particularly in the current waveform which was not fully filtered by the algorithm. The tests and results presented below also demonstrate that the system was sinking noise and harmonics generated by other users of the supply. The filtering capabilities of the algorithm were reinforced by a half cycle digital filter applied to the measured power $f_n$ used by the algorithm.

The responses to a loss of grid producing a 50 percent change in the generator's loading are shown in figure 2. The responses from the computer model, figure 2(a), and test machine, figure 2(b), are very similar apart from the noise and the lower inertia constant seen in the response of the laboratory system. The computer simulation model tripped 28 msec after loss of grid and the microcomputer relay tripped after 50 msec. Part of the difference in these results is the additional filtering used by the laboratory algorithm.

The responses to a loss of grid producing a 5 percent change in the generator's output loading are shown in figure 3. Again the responses from the different tests are similar apart from the noise and lower inertia constant of the laboratory machine. In this case the computer simulation model trips after 30 msec and the microcomputer relay trips after 67.5 msec. This difference is a direct result of the different trip settings used by the two algorithms.

The responses to a 5 percent load change while the generator is operating independently from the utility system are shown in figure 4. The microprocessor relay responses are again similar to those obtained from the computer simulation, with tripping occurring after 87.5 msec and 28 msec respectively. There are many similarities between these responses and those shown in figure 3. The curves from the microcomputer relay reveal a higher level of waveform distortion present while the generator is running in parallel with the mains than when it is operating alone.

The response to a 100 percent load change while the generator is operating in parallel with the utility supply is shown in figure 5. In both cases the algorithms remain stable and do not trip. Although there is a small oscillatory disturbance with the computer simulation this is not apparent with the laboratory test. The laboratory test again demonstrated the effects of waveform distortion and harmonics. The fluctuations in the output of the algorithm's integration however do not cause tripping with the setting chosen.

The response to an out-of-step reclosure is shown in figure 6. For both tests, the phase difference between the two power systems prior to reclosure was 45 degrees. From the computer simulation, the
oscillatory nature of the machine's response and the inherent filtering included in the algorithm slow the protection. Tripping occurred 222 msec after reclosure. The low inertia of the laboratory machine and the capacity of the mains supply produce a more direct response without the subsequent oscillations and tripping occurs after 47.5 msec.

CONCLUSIONS.

A new digital protection algorithm for detecting loss of grid for a small or medium sized embedded generator operating in parallel with a utility supply has been shown to operate correctly for loss of grid conditions, during independent operation, and after an out-of-synchronism reclosure with the utility. It also remains stable during severe load fluctuations while operating in parallel with the utility.

The algorithm has been formulated to be suitable for an integrated digital protection for an embedded generator. The test platform used to demonstrate the practical algorithm's operation was similar to that used by commercially available protection relays.

Laboratory tests have supported results from computer simulation. These tests also demonstrated the successful operation of the algorithm in the presence of high levels of current and voltage waveform distortion and harmonic interference.

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Figure 3. Response of Loss of Grid Algorithm to a 5% Increase in the Embedded Generator's Load Following Loss of Grid.

Figure 4. Response of Loss of Grid Algorithm to a 5% Increase in the Embedded Generator's Load While Operating Independently from the Utility.

Figure 5. Response of Loss of Grid Algorithm to a 100% Increase in the Embedded Generator's Load While Operating in Parallel with the Utility.

Figure 6. Response of Loss of Grid Algorithm to a Out-of-Synchronisation Reclosure With a Phase Displacement of 45 Degrees.