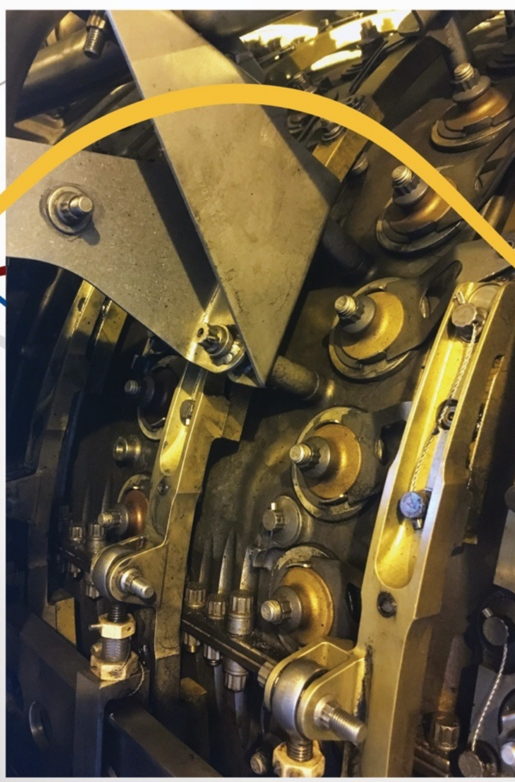
DYNAMIC CONTROLS
CANADA INC.

Training Manual Volume 1

Generator Basic

Theory



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VOLUME I: GENERATOR BASIC THEORY

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1 GENERATOR COMPONENTS

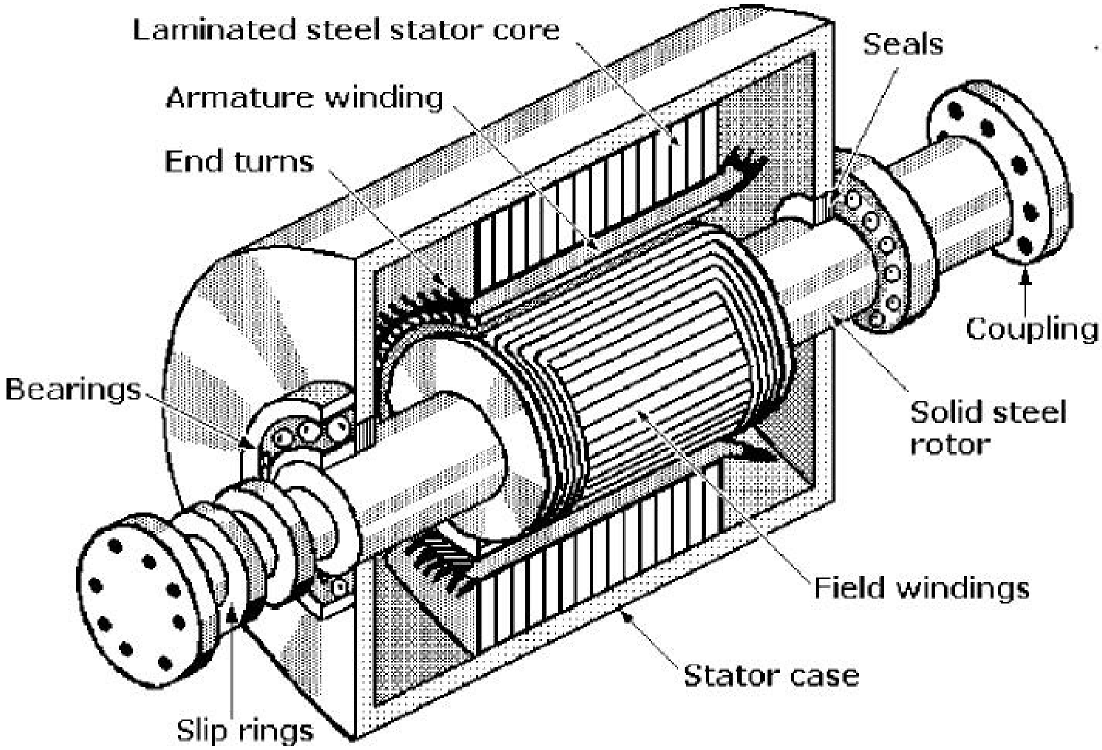

Figure 1-1: Cutaway view of synchronous AC generator with a solid cylindrical rotor capable of high-speed rotation

1.1 Rotor

Made of forged solid alloy steel. The windings are held in slots by wedges. The slots provide longitudinal cooling air passages. The windings consist of copper coils.

1.2 Stator

The steel core is built into a fabricated steel frame. It is divided into short sections by radial ventilating ducts. The stator windings are two-layer diamond type. Made in two halves which are pressed into the frame while hot to form their final sizes. The completed coils are protected against corona formation by conducting tape in all of the retaining slots.

2 ELECTRIC GENERATOR THEORY

A conductor is a material that allows the passage of electric current. Good conductors are generally metal and metal alloys. The following are the top ten metal conductors (in order): silver, copper, aluminum, zinc, brass, platinum, iron, nickel, tin and lead.

The flow or movement of electrons is called current. The symbol for current is I and the units are amperes or AMPS. One ampere equals 6 x 1018 electrons passing one point in one second.

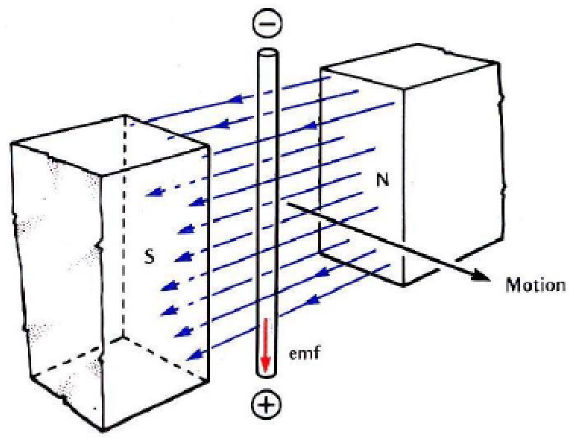

Figure 2-1: EMF generated on a conductor

Electrical current can be used to perform work and is the basis of all electrical power production. Voltage is the potential or ability to cause current to flow in a conductor.

Voltage will be induced on a conductor any time it is subjected to a variation or fluctuation in a magnetic field surrounding it.

2.1 Voltage

Is measured in Volts and its symbol is V. When there is no actual current flow, voltage is referred to as Potential and its symbol is E.

2.2 Resistance

Is the opposition to current flow and is measured in ohm. A resistor impedes the flow of current. The relationship between Voltage, Current and Resistance is referred to as OHM Law where:

I = E / R

I = Current (Amps)

E= Voltage (Volts)

R= Resistance (Ohms)

2.3 Faraday's Law Of Electromagnetic Induction

Illustrated as follows states that, if a conductor is moved in a magnetic field, then an electromotive force (EMF) - or simply, a voltage - is induced in that conductor.

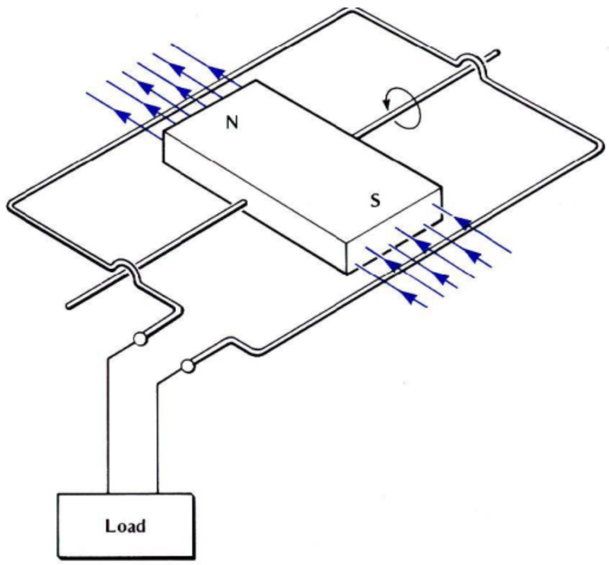

Figure 2-2: EMF from a rotating magnetic field

It follows that, if the ends of the conductor are connected to an external load, then an electric current, driven by that voltage, will flow from the conductor, through the load and back again. Faraday showed that if a wire moves in a magnetic field, an artificial charge, or voltage, will be created in that wire. Faraday also showed that the magnitude of the voltage induced in the moving conductor depends on the strength of the magnetic field and the speed of movement. These two laws form the basis of electrical power generation.

2.4 Frequency

If the rotor is spinning at 60 revolutions per second the oscillation in the voltage produced will be 60 cycles per second, commonly referred to as 60 Hertz. On some systems the rotor is built with four poles. This means that each revolution will produce two complete voltage cycles.

The relationship between generator speed and generated frequency is given by the expression

F = P/2*N/60

P = number of poles N = rpm F = Frequency (Hz)

2.5 Three Phase System

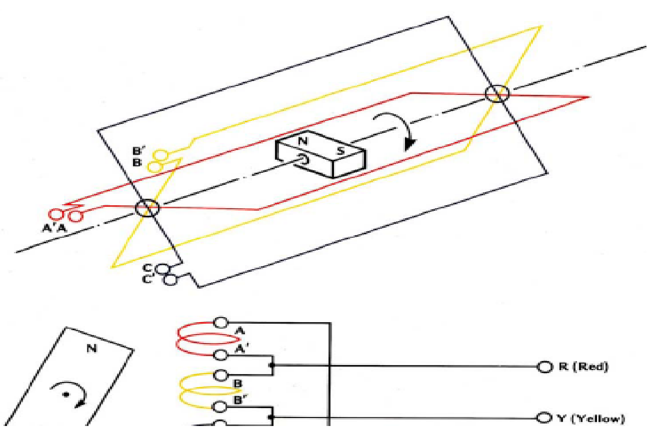

Figure 2-3: Three phase system

A power generation system is wound with three sets of conductors, physically spaced 120 degrees apart. The system is usually referred to as a three-phase system. Phases 1,2,3 referred to as Red, Yellow and Blue. In many cases the ends of each phase are connected together to form a star.

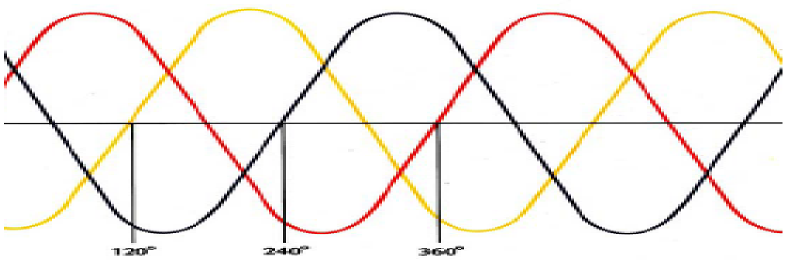

Figure 2-4: Voltage from a three phase system plotted against time

2.6 Grounding (neutral)

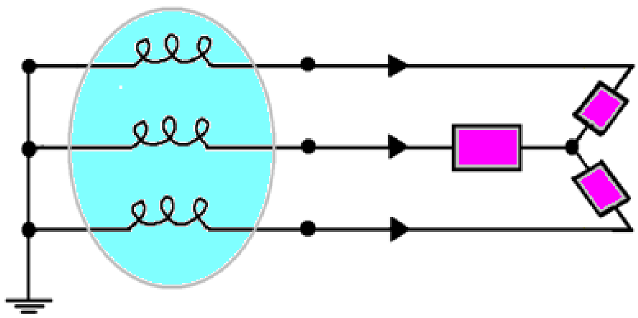

Figure 2-5: Grounded stator windings on a generator

On a balanced system the potential at the star point is zero and in many cases this point is connected to earth. Under normal operating conditions (a balanced load), the generator sees no neutral current.

Note: the current flow from the stator windings to the load. A ground fault on any load circuit will find its way back to the generator star point through this neutral connection. Monitoring of the neutral current then can give the operator information as to the state of the power network, in terms of possible fault conditions.

3 PRIME MOVER & GOVERNOR

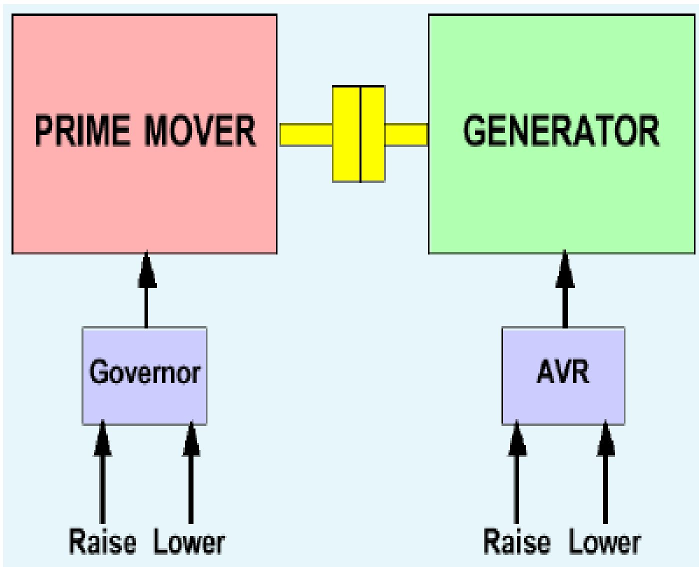

Figure 3-1: Relationship between governor and AVR

The prime mover is mechanically linked, or coupled, to the generator either directly or by a gearbox. Its function is to rotate the generator. As the generator is usually a synchronous machine, the rotational speed is required to be kept constant and this is the function of the governor.

Modern governors are normally electronic, providing a fast, closed loop control but the output may take many forms to suit the prime mover being controlled.

The governor output can be a fuel, water or gas valve; being opened to increase speed or closed to reduce it. Some form of speed signal is fed to the governor and compared with an adjustable reference. The difference, the error, is used to control the output. The raise/lower signals might come from a control switch, an automatic synchroniser or an automatic control system.

Notes

4 GENERATOR VOLTAGE CONTROL AND EXCITATION

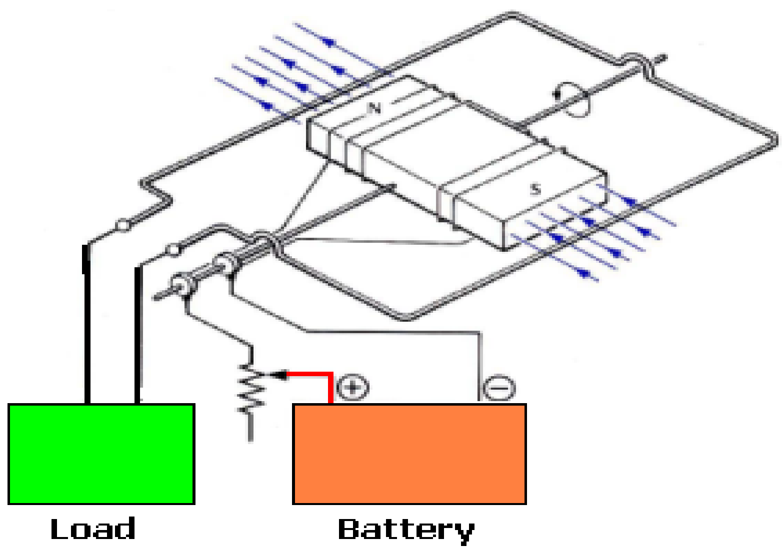

Figure 4-1: Simple excitation system

4.1 Simple Excitation System

In this simplified version (Figure 4-1) of excitation control, DC current is fed through slip rings from a power supply. In this case, the power source is a battery. The operator can change the level of excitation and ultimately the output voltage to the load by varying the position of the variable resistance shown.

In any standard system the excitation control is automatic and operates to control the voltage output of the generator. (AVR)

Excitation Types:

Generator excitation systems can be broken into two main categories:

- Static
- Brushless excitation

4.2 Static Excitation

Excitation is static when the DC field (figure 4-2) is fed directly on the generator rotor through a system of brushes. This means that the excitation current is large 100-8000 Amps depending on the size and the nature of the generator load. This large current needs to be controlled.

Static excitation systems are responsive and under normal circumstances can be operated in conjunction with other units stabilize the grid.

Note that the excitation current is fed directly the main field winding. This connection is made through a set of slip rings. (figure 4-3)

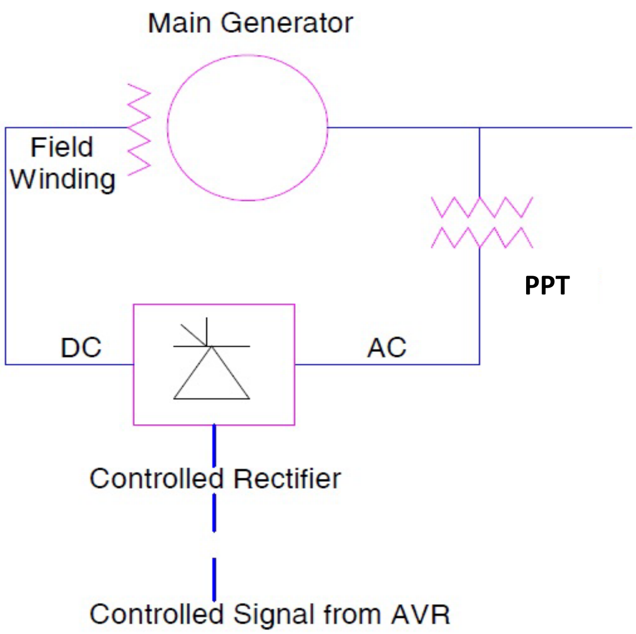

Figure 4-2: Static excitation system

Figure 4-3: Brushes to connect the AVR field voltage to the field rotor

4.3 Brushless Excitation

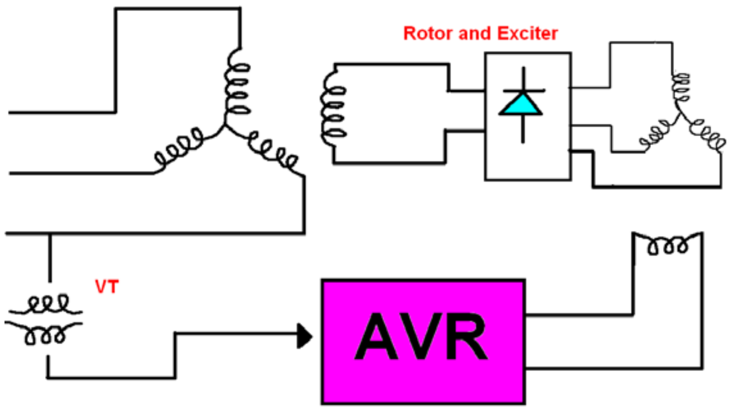

Figure 4-4: Brushless excitation

Excitation for the generator is controlled by the AVR (automatic voltage regulator)

In this case, the AVR is powered externally and the generator voltage is sensed by a PT/VT.

Note the brushless arrangement and the DC rectifier feeding the generator rotor.

A relatively small DC current is fed to the static side of the exciter where three phase AC is generated for rectification to the DC field.

Excitation system using a permanent magnet generator:

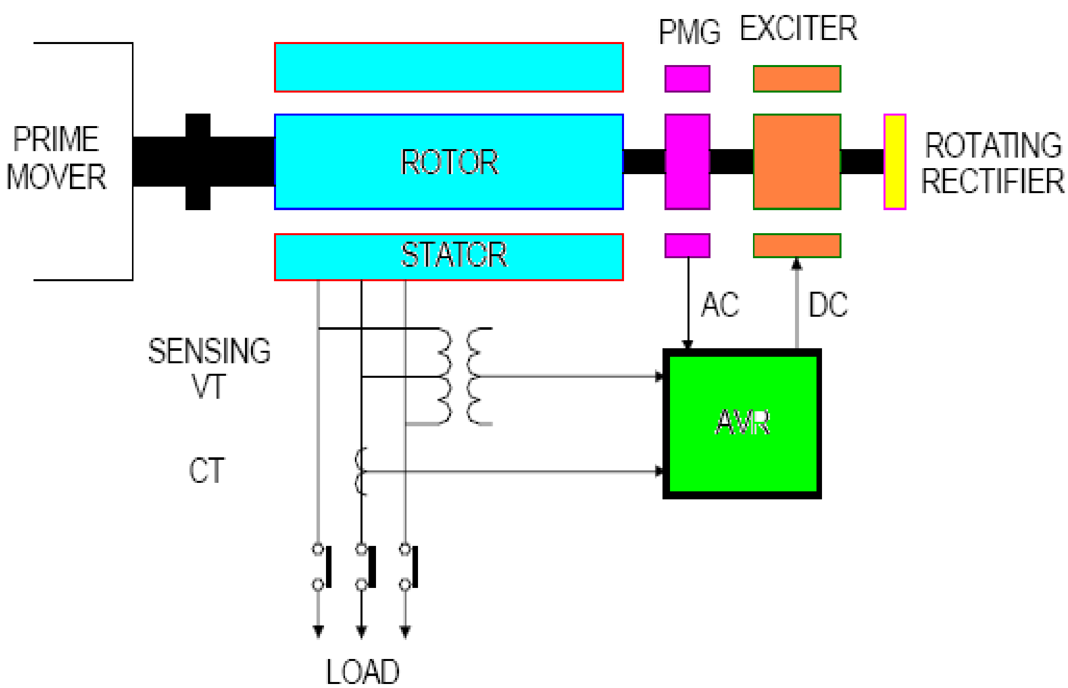

Figure 4-5: Brushless excitation using PMG

In this arrangement (figure 4-5) the AVR is supplied by a permanent magnet generator. The advantage here is that there will not be a power dip to the AVR in the event of a heavy load change or drop in network voltage.

The output from the PMG is constant, usually in the region of 220 Volts and delivers a constant voltage regardless of the state of the generator output. The frequency of the PMG is high (400Hz) because it is made up of a large number of magnets rotating in a stator.

Note that there is both voltage and current sensing on this system. Current sensing (CT) into the AVR is necessary to work out the reactive component.

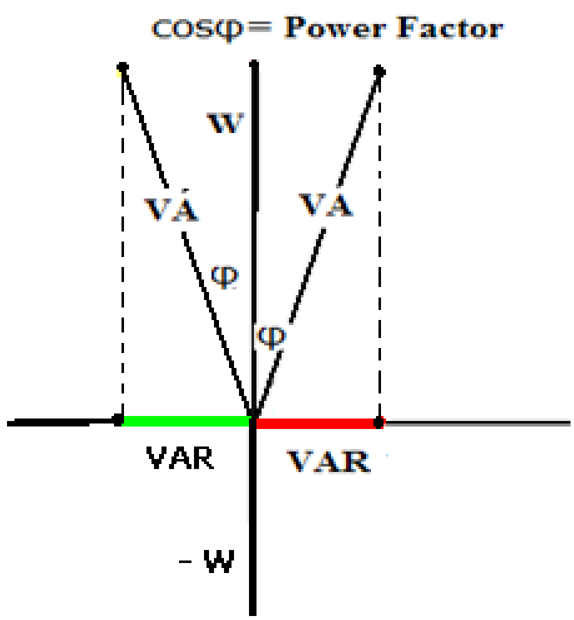

Figure 4-6: Power factor

This reactive component is affected by excitation when the generator is connected to the power network. Raising and lowering the excitation while connected to the grid will result in a shifting in reactive load. (Figure 4-6)

4.3.1 Open Circuit Voltage

While the circuit breaker is open voltage only is controlled and the value of the CT current is zero. In fact, an auxiliary switch on the generator main circuit breaker shorts out this CT.

4.3.2 Field Flash System

There is a possibility that insufficient residual magnetism in the field rotor might result in the generator terminal voltage failing to build up and provide enough voltage feed back into the power system.

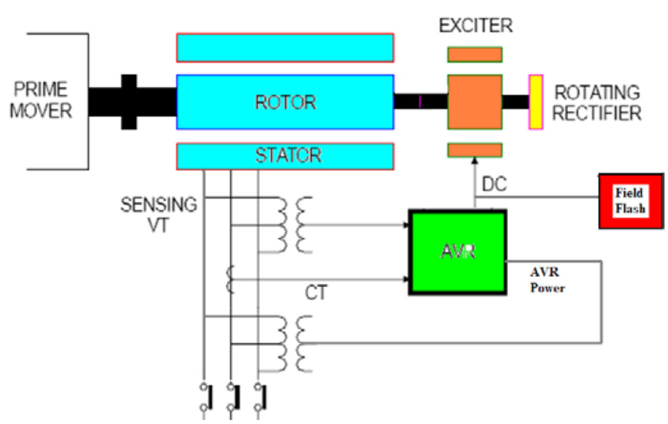

Figure 4-7 Field flash

To this end a field flash circuit is incorporated into the system design. Effectively a separate DC source is applied across the exciter field output as the generator runs up to sync speed. The application of this voltage is usually triggered at 60 to 90 percent speed.

Field flashing is configured into an excitation system when the power supply to the Voltage regulator (AVR) is taken from the generator bus. (see figure 4-7)

4.4 Volts/Hertz

It is important that the generator terminal voltage remains low below speeds of 60 percent to prevent excessive current flow into any connected loads (PT's) and other power devices. This excess current is due to the reduced reactance (Z) of any connected AC circuits at the lower frequencies. (Speeds below 60% equivalent to 36Hz @ 60Hz). For this reason, many excitation systems (field flashed or not) startup at between 60 and 90% speed.

4.5 Exception

There are some exceptions where the nature of the installation requires excitation at low speeds. (A requirement for engine cooling fans on a black start operation). In this case care must be taken to limit generator terminal voltage as a function of frequency. Many AVR systems have this additional limiting control which is represented as a V/Hz curve. Excitation voltage then is raised along this curve.

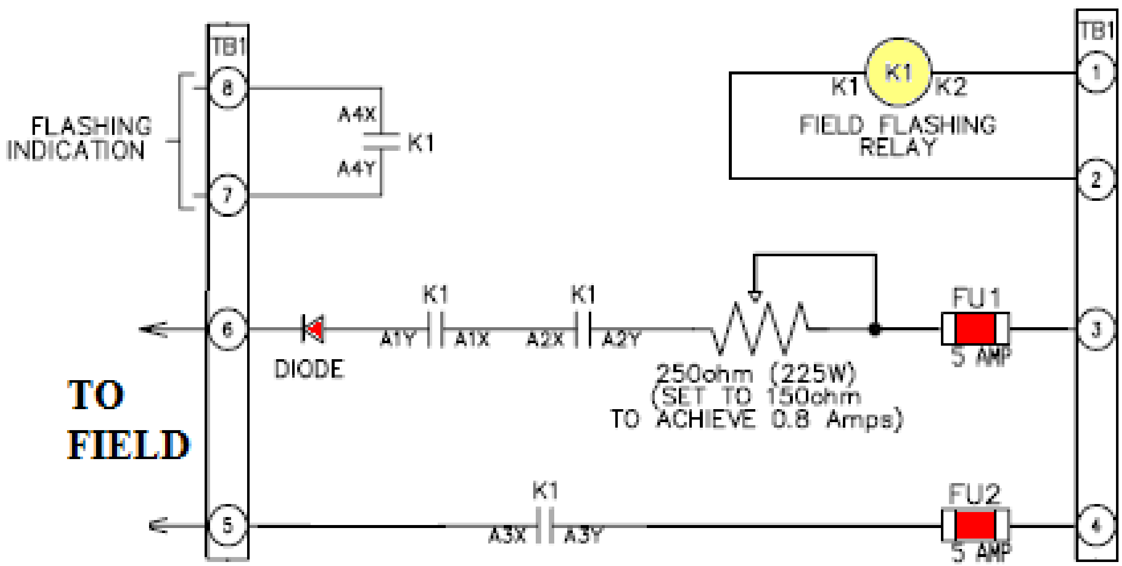

Figure 4-8: Field flash circuits

During initial start of the system a separate DC source at terminals TB4 (3, 4) supplies the exciter field through a 250 ohms variable resistor for a pre-determined time. The resistor is set to deliver a field current sufficient to excite the generator terminal voltage to approximately 60% (.8A).

4.5.1 BUR (Voltage buildup)

After the expiration of the time or where the terminal voltage has built up the Field Flash current is automatically removed. In this case K1 is deactivated.

Modern AVR systems use a level detector to deactivate the field flash circuit when the generator terminal voltage is sufficiently high for self-sustaining operation. The setting of this level detector is important in as far as it must operate only when the system can sustain itself without the assistance of the Field flash circuit. Experience has shown that this setting, particularly on new installations (re designed systems) can be sensitive and may need some incremental adjustments during commissioning.

4.5.2 PMG and Field Flash

PMG (Permanent Magnet Generator)

Without a PMG arrangement the AVR is powered by the buss itself and hence the need for field flash. On many new installations the exciter contains an additional part called a PMG.

Figure 4-9 shows a separate A/C generator comprised of rotating permanent magnets and a stator that supplies A/C power to the AVR directly. Voltages are usually in the region of 300V A/C and the frequency is in the order of 400Hz (depending on the number of magnets).

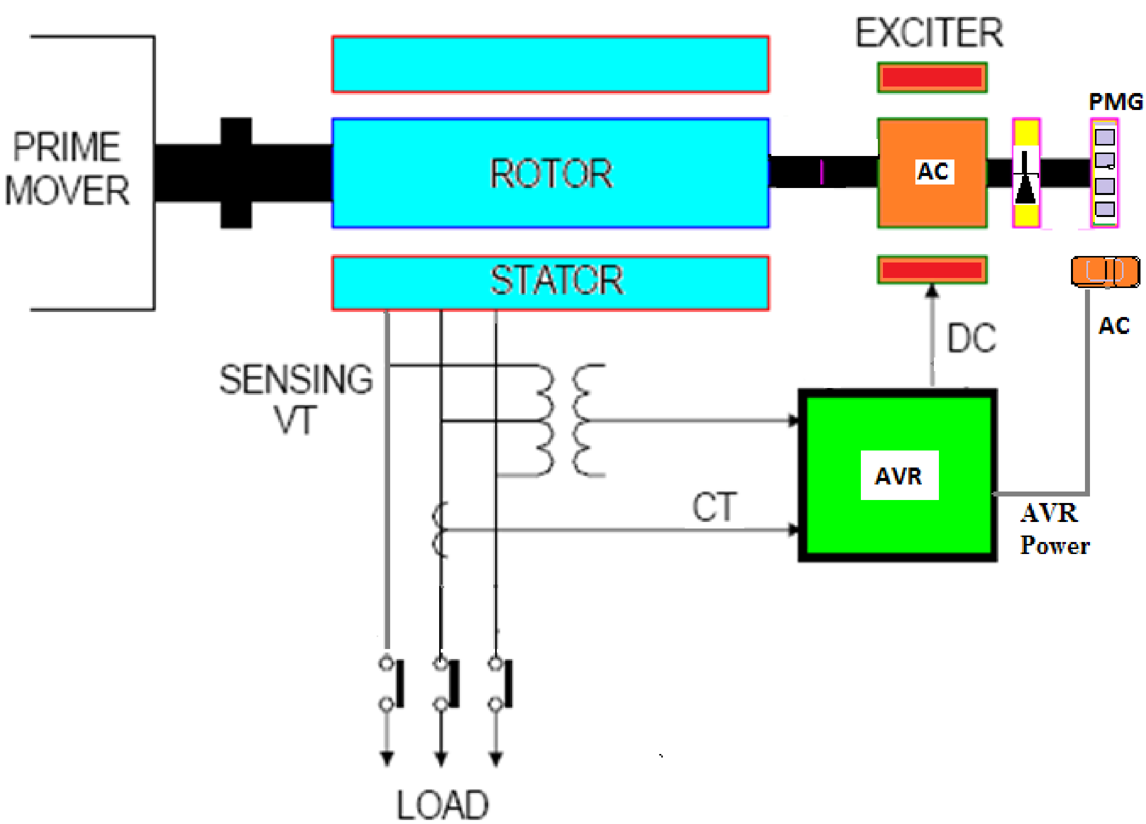

Figure 4-9: Brushless excitation with PMG

Apart from the fact that the field flash circuits can be eliminated from the overall design, the PMG system has another advantage. It maintains AVR power under all load conditions including, any voltage collapse under short circuit conditions.

4.5.3 Soft Start

The Soft Start facility is designed to avoid large overshoots in the automatic regulation loop during excitation start. The soft start limits the regulator structure output signal until this signal is higher than the soft-start limit as shown below.

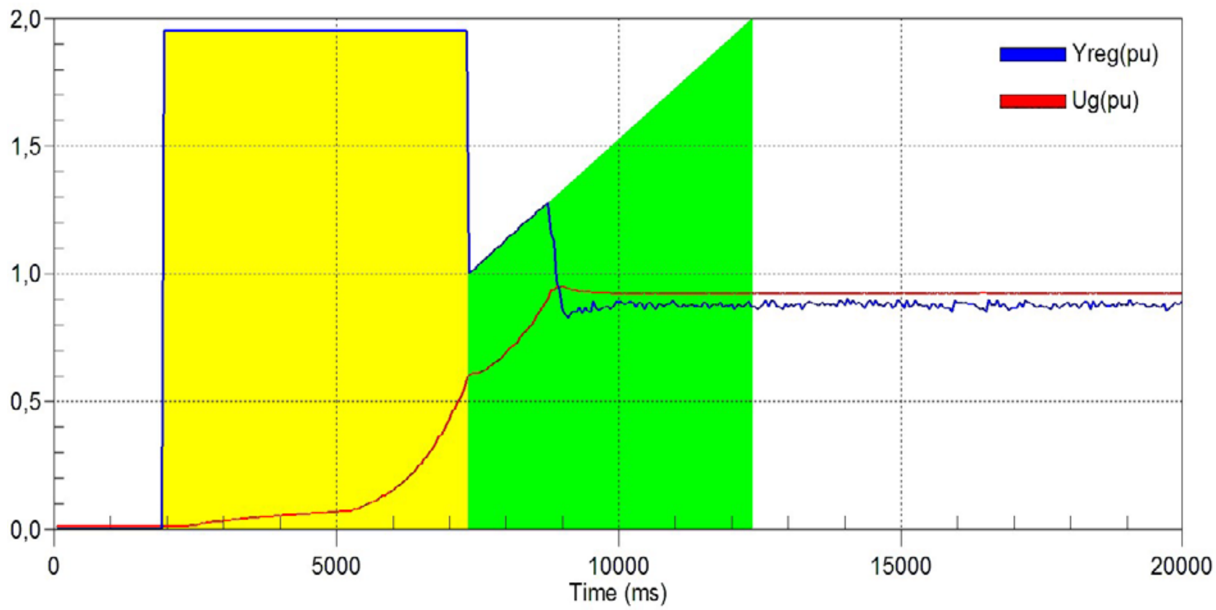

Figure 4-10: Soft start

Excitation soft start: 1st stage – yellow area, 2nd stage – green area

The Soft Start consists of two stages:

- 1st stage – field forcing
- 2nd stage – ramp

5 GENERATOR SPEED CONTROL

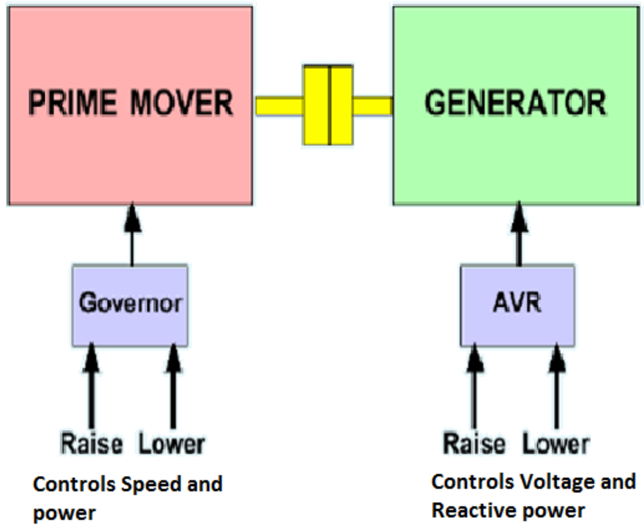

Figure 5-1: Load and Voltage control

Droop - the difference between Voltage Droop and Speed Droop**.**

5.1 Droop Control

Figure 5-1 illustrates the difference between load or torque control and voltage or excitation control. Droop control can refer to either and sometimes causes confusion because it refers to two entirely different processes.

In general, the generator load or torque is adjusted by controlling the fuel flow and the amount of energy produced by the generator and is proportional to the fuel consumed discounting by the machine itself.

On the other hand, the generator excitation (controlled by the AVR) has impact on the generator voltage open circuit and MVAR when connected to an electrical grid. The control modes of excitation (Field Current Adjustment) are also termed Droop and Isoch.

In this case we are looking at Droop Control in terms of the Turbine or Prime Mover.

As the Turbine/Generator rotates. the frequency of a sync is directly proportional to the speed of the rotating electrical field $F = P * N / 120$

Where:

F = frequency (in Hz).
P = number of poles of the rotating electrical field.
N = the speed of the rotating electrical field (in RPM).

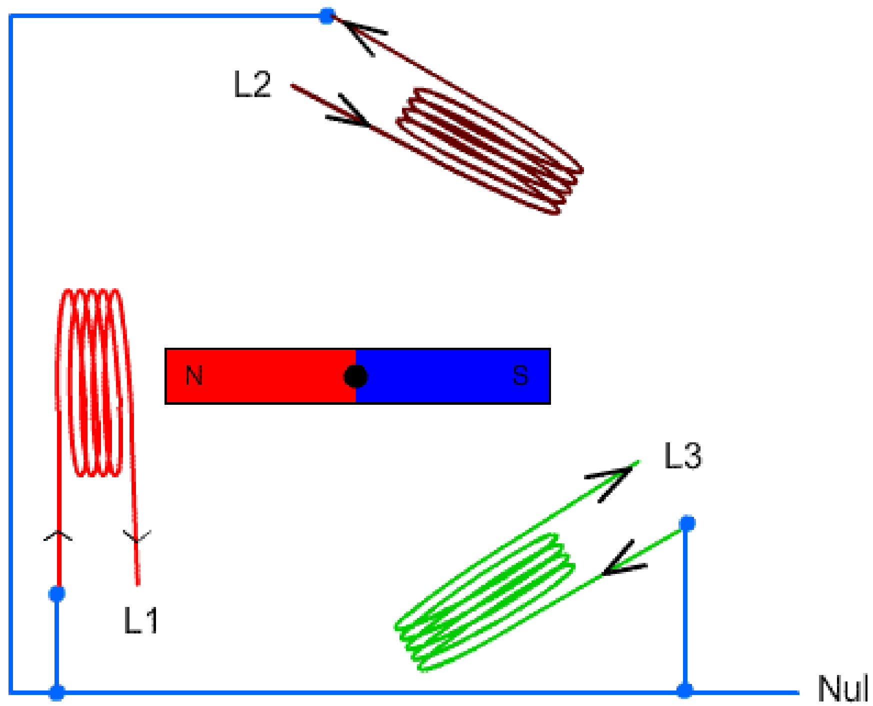

Figure 5-2: Three phase induction

In Droop Speed Control mode, the governor of the Turbine is not attempting to control the frequency of the generator, but rather the production of torque in terms of fuel supply when connected in parallel with other generators.

Droop Speed Control then refers to the fact that the fuel supply to the Turbine is being controlled in response to the difference between a speed (frequency) set-point and the actual speed (frequency) of the prime mover.

To increase the power output of the generator, the operator increases the speed set-point of the Turbine, but since the speed cannot change (it's fixed by the frequency of the grid to which the generator is connected) the error, or difference, is used to increase the energy being admitted to the prime mover. So, the actual speed is being "allowed" to "droop" below its set-point.

5.2 Isoch Speed Control mode

In Isoch Speed Control mode, the energy being admitted to the prime mover is regulated very tightly, in response to changes in load, which would tend to cause changes in frequency (speed). Any increase in load would tend to cause the frequency to decrease, but energy is quickly admitted to the prime mover to maintain the frequency at the setpoint. Any decrease in load would tend to cause the frequency to increase, but energy is quickly reduced to the prime mover to maintain the frequency at the setpoint.

On a small electrical grid, one machine is usually operated in Isochronous Speed Control mode, and any other (usually smaller) generators which are connected to the grid are operated in Droop Speed Control mode. If two prime movers operating in Isochronous Speed Control mode are connected to the same electrical grid, they will usually "fight" to control the frequency, and wild oscillations of the grid frequency usually result. Only one machine can have its governor operating in Isochronous Speed Control mode for stable grid frequency control when multiple units are being operated in parallel.

6 LOAD SHARING

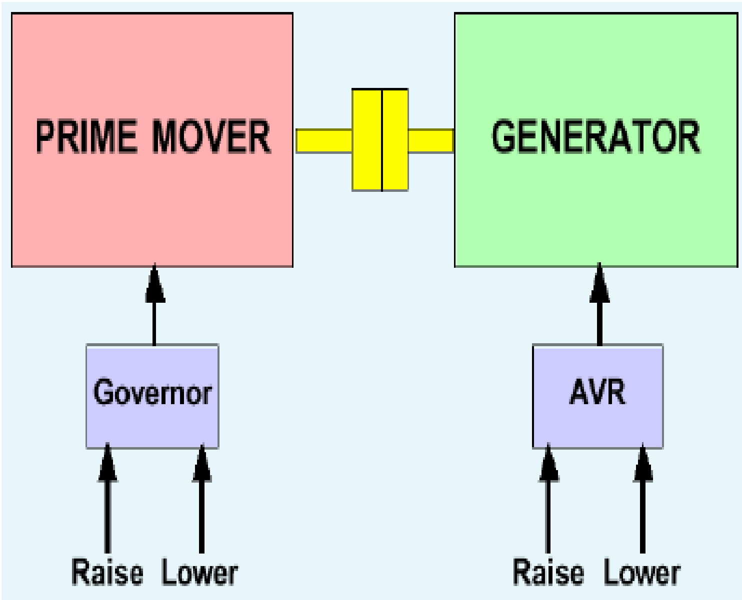

Figure 6-1: load and voltage control

6.1 Speed Droop

Speed droop is a decrease in generator speed proportional to the load it is carrying. Expressed as a percentage reduction in speed with load against the speed control set-point.

For example, with the engine fully loaded a speed set-point of 63Hz will mean an actual speed of 60Hz.

63-60/63 = 0.48... about 5% droop

Droop for most large generators is set between 3 and 5%.

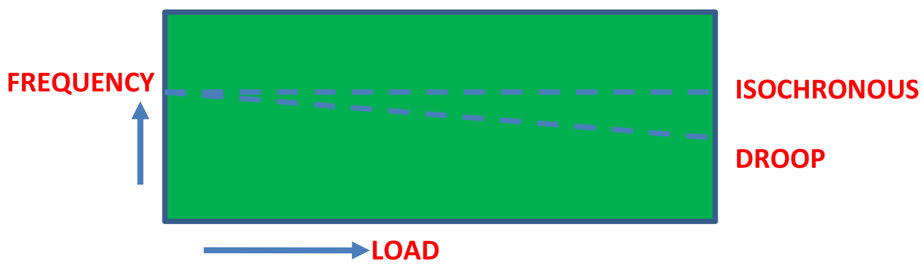

Figure 6-2: Load Droop

While connected to a grid and with constant grid frequency and a fixed droop setting output, power from the generator will remain constant. Any changes to the speed set-point will result in a new power setting.

6.2 Units using Droop Control in Isolation

If two generators are synchronized together but are isolated from the power grid, they will share load equally provided the droop settings and speed control set-point are equal.

6.3 Isochronous Operation

In isochronous operations the speed is automatically controlled to a fixed value of either 50 or 60 cycles depending on the network.

6.4 Island System

An island or stand-alone system has a single power generator and it provides a number of in-house loads. Typically, the island operation will be a single power plant providing power to a chemical plant, a refinery or even a very small town.

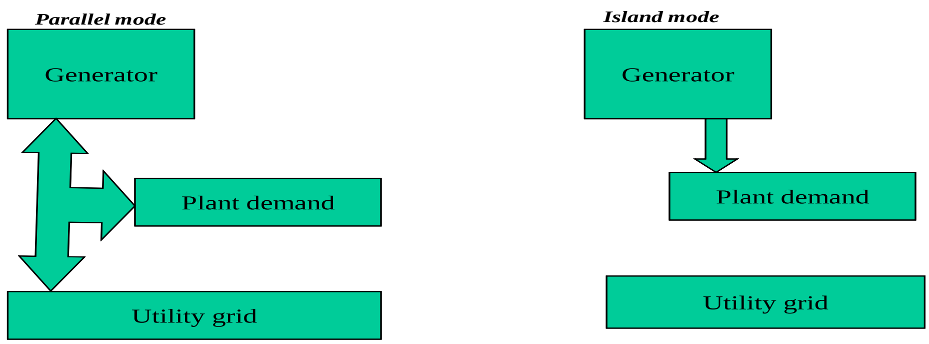

Figure 6-3: Modes Of operation

Island operations are simple; the system frequency is maintained by a speed-regulating governor. When power demand increases, the generator will tend to slow and the governor system will increase fuel to regain the proper speed.

Voltage and the Power Factor is usually maintained by automated systems, by an onsite operator or by a remote operator station. An island system can be operated in isochronous or droop modes.

6.5 Isolated System

An isolated system operates two or more units and they are NOT connected to a power grid. Each unit must be in synch with each other and have a system to ensure equal load sharing. If the units become unbalanced in their load share, one engine governor will take control and attempt to carry the entire load while other units may try to shed their load. The only way multiple units on an isolated system can operate with equal load sharing is if the governors on all the units react the same to changes in load. This is unlikely and generally the difference in droop between generators will cause a radical disproportional load sharing.

Typically, to resolve the issue of load sharing, one generator is designated as the SWING UNIT and it is operated as an isochronous unit while all other units are operated in droop. The droop units will run at the same frequency as the isochronous unit and the swing or isochronous unit will change to follow variations in the load demand.

When operating a swing unit, the minimum power output of the system cannot be allowed to drop below the combined output of the droop machines or the excess power from the droop machines will motorize the isochronous unit. As a good practice, the swing machine should be the largest generator with the greatest output capacity. In other applications, a differential load bias signal is injected into the two controlling governors. The value of the signal to both is a function of the load. This allows a system to operate in Isoch mode.

6.6 Base Power Operations

Most grid owners will require a power producer to operate a unit at a fixed or base power setting. The speed and droop are adjusted to provide a set amount of power. For example, frequency may be set at 63 Hertz for a 5% droop machine. In this mode of operation, the grid is the swing machine. In base mode, the unit frequency will be adjusted by the governor to match the grid and a lower or higher power output will occur as the governor adjusts to the grid. This is a normal reaction by the governor and should not be mistaken for governor problems.

7 REACTIVE LOAD SHARING

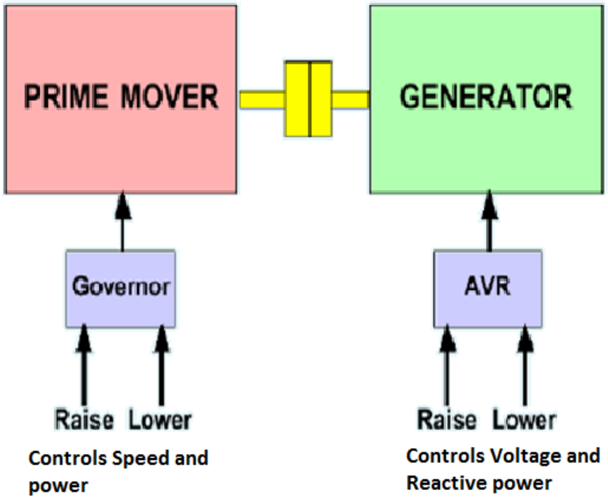

Figure 7-1: Load and voltage control

7.1 Voltage Droop

Reactive load between generators can become unbalanced due to the nature of the installation and drift into a situation where circulating currents flow between the generators. This will show as excessive positive or negative power leading to either over or under excitation condition.

To control this problem two methods of modifying excitation in response to power factor are used.

1. Reactive Droop Compensation
2. Cross Current Compensation

7.2 Reactive Droop Compensation

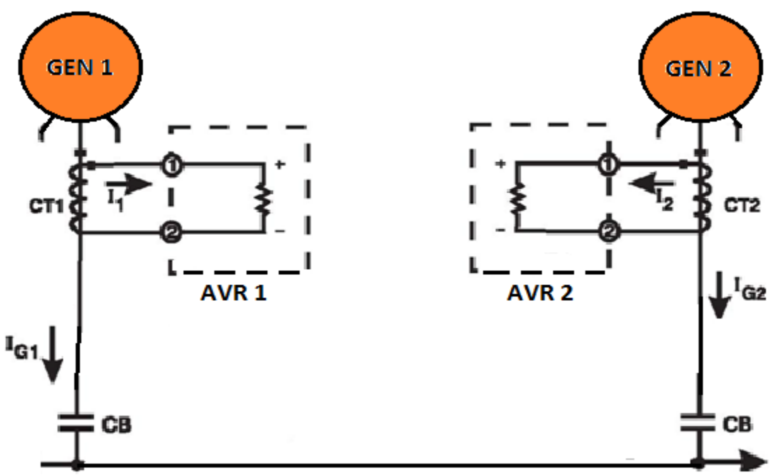

Figure 7-2 Reactive droopp compensation

The most often used type of paralleling compensation is the parallel droop compensation or using the IEEE designation, reactive droop compensation.

When reactive droop compensation is used to parallel two or more generators, each parallel droop circuit is independent of the other (Figure 7-2). A typical parallel droop circuit is made up of a current transformer and paralleling module connected to an aux switch on the generator circuit breaker (52AUX). When the generator breaker is closed the CT is open to the AVR and when the breaker is open the CT is shorted out.

The parallel compensation circuit will cause the voltage regulator to increase the field excitation on the generator with the lower field excitation and decrease the field excitation on the generator with the higher field excitation. By controlling the reactive load, the parallel compensation circuit can eliminate undesired circulating currents brought about by unbalanced excitation.

7.3 Cross Current Compensation

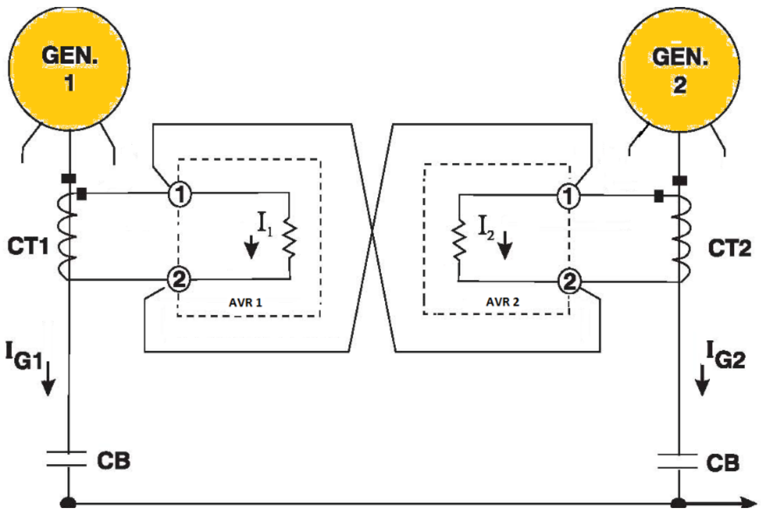

Figure 7-3: cross current compensation

Figure 7-3 shows two generators paralleled with reactive differential compensation. Inter connection of the current transformers can be seen.

Figure 7-3 illustrates the connections used in differential current compensation. Under an imbalance in reactive load a differential voltage will be injected into both AVR one and two.

If one generator begins to assume more reactive load than the other, the line current will increase and the current from the secondary of the current transformer will also increase. The result will cause a greater voltage across the burden resistor of the paralleling circuit, which will in turn cause the voltage regulator to reduce the excitation in that particular generator, thus reducing line current. An increase in current through the crosscurrent connect loop caused by the imbalance of the first generator will develop a voltage across the second generator's paralleling burden resistor that is opposite in polarity to the normal voltage developed by the second generator's own current transformer.

Instead of causing a drop in line voltage, the opposite polarity will cause an increase in line voltage. The resulting increase in one generator and a decrease in the other generator will cause the parallel generating system to balance itself out.

For the reactive differential compensation to perform properly, all of the paralleling current transformers on all of the generators delivering power to the bus must be connected into the crosscurrent loop.

8 REACTIVE LOAD SHARING AND TROUBLESHOOTING

8.1 Reactive Droop Compensation

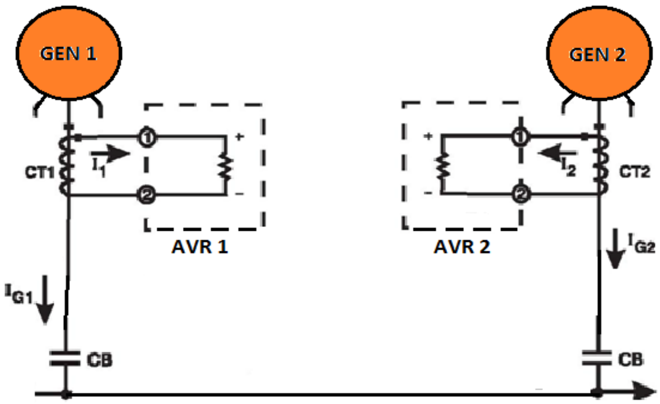

Figure 8-1 Reactive droop compensation

The most often used type of reactive power control is parallel droop compensation or using the IEEE designation, reactive droop compensation.

When reactive droop compensation is used to parallel two or more generators, each parallel droop circuit is independent of the other (Figure 8-1). A typical parallel droop circuit is made up of a current transformer and paralleling module connected to an aux switch on the generator circuit breaker (52AUX). When the generator breaker is closed the CT is open to the AVR and when the breaker is open the CT is shorted out.

The parallel compensation circuit senses changes in reactive load MVAR which will cause the voltage regulator to increase or decrease the field excitation on the generator, depending on the magnitude of the MVAR pickup and the droop setting. By controlling the reactive load, the parallel droop compensation circuit can eliminate undesired circulating currents brought about by unbalanced excitation.

8.2 Problems to Consider

Poor reactive load control can be as a result of the following conditions:

- Poor voltage regulation (excitation control)
- No excitation control
- Excitation control in manual (FCR) with an unstable system network voltage
- Malfunctioning reactive load control circuits or logic

During the commissioning process, the question of how well the parallel droop compensation circuit is doing comes to the fore when problems with wild reactive load and excessive generator current are experienced just after synchronization. More often, we see this on a newly commissioned package running for the first time with a grid or perhaps another unit in Island mode.

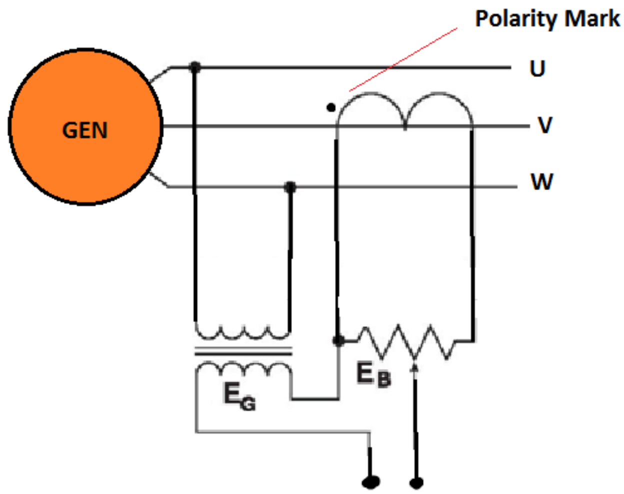

Figure 8-2: Reactive droop compensation CT

8.3 Reactive Droop Compensation CT

When a generator is synchronized for the first time the following can occur:

Abnormal indications

- Immediate increase in current
- Difficulty in adjusting voltage in an effort to balance reactive load
- Changing loads cause reactive unbalance

For immediate high current

- Check paralleling in droop only
- Verify that kW load is properly shared
- Check SENSING connections to AVR
- CT in correct phase (See procedure for polarity issues)
- Reverse CT secondary polarity
- Try to parallel again
- If all above is OK, try to close cross current loop
- Wrong phase

CT Polarity issues with other units in the system (isolated grid). There is a possibility that there is another unit on an isolated grid operating with an incorrectly polarized CT. This problem will only show up when two or more units are paralleled together.

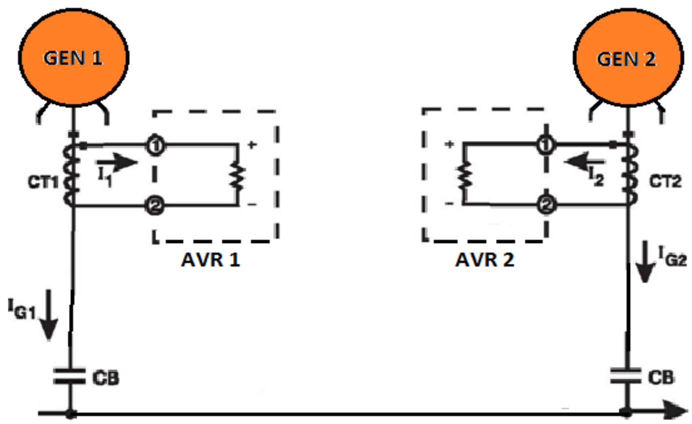

Figure 8-3: reactive droop compensation

For example, in figure 8-3 generator one and two will not share reactive load where one generator unit goes into excessive excitation, while the other heads down for under-excitation.

Carry out the following test to find out which CT is incorrect:

1. **Short CT1**
2. **Sync Gen 1**
3. **If current does not takeoff CT2 is OK**
4. **If current takes off Reverse CT2**
5. **Remove CT1 short**
6. **Short CT2**
7. **Sync Gen 2**
8. **If current takes off Reverse CT 1**

TIP

If the polarity of the compounding CT is unknown, and the risk of shutdown or network disruption is great, then it may be advisable to sync a newly commissioned unit with its compounding CT shorted and manually adjust the excitation. After this, the CT can be inserted for a time sufficient to take logs and evaluate. This gives the engineer a degree of control over the situation and allows for calm analysis of events as they unfold over that short period.

In most cases, those few seconds will be sufficient to detect a reversed CT but not long enough to disrupt the system. MVAR is not actual load and as such can be contained for a while during testing as long as the test does not drift into severe under excitation and the possibility of pole slip.