DISCUSSION ON GENERATOR CONTROL IN RELATION TO POWER GENERATION

Distribution at your own risk

OCTOBER 2014

Soft Copy: http://www.hailienene.com/personal-library.php

Foreword

The content of this document is meant only as a guide to understanding the electrical operation of a generator system. The repetition of some explanations re intended to clarify pints that may have seemed to have not been explained properly on previous sections. Before making comments, please read the disclaimer above.

Turbo Generator/Diesel Generators

A synchronous electrical machine (generator or motor) is intended to be operated at a constant speed. i.e. synchronous speed. When the generator rotor is rotated, the magnetic flux of the generator rotor induces a voltage in the generator stator windings, called the generator terminal voltage. This is the voltage you would measure on the outgoing terminals of a generator. Presuming a generator is rated at 5MW, 6.6kV. This terminal voltage is the 6.6kV the generator is rated at.

When the speed of the generator rotor is constant (or at rated) and the excitation is constant, the generator terminal voltage will be constant, or stable (there are always some tolerances in %age). The magnitude of the generator terminal voltage is a function of the strength of the magnetic field of the generator rotor, since the generator rotor is being rotated at a constant speed, which is the synchronous speed.

The exciter controls the strength of the rotor magnetic field, and the strength of the rotor magnetic field controls the magnitude of the generator terminal voltage, presuming the generator rotor is spinning at synchronous speed, which is also the rated speed for the generator.

For obvious reasons, the generator terminal voltage is usually held relatively constant during normal operation. In fact, most synchronous electrical generators are rated for a particular voltage, (for example, 400V, 6.6kV, 11kV, etc.), plus-or-minus 5%, meaning that the generator terminal voltage is only to be operated within +/-5% of 6.6kV, etc. The terminal voltage of a generator remains or is meant to remain constant or close to constant or stable.

To have a constant terminal voltage, the generator rotor magnetic field must be held constant. And the exciter controls the strength of the generator rotor magnetic field. So, that means the exciter will normally operate at a relatively constant, stable, output to maintain a relatively constant, stable generator terminal voltage.

When a synchronous generator and the prime mover (steam turbine for a TA) is synchronized to a grid in parallel with other generators and the prime movers driving those generators, current can flow in the generator's stator windings. To make more current flow "out" of the stator windings one needs to increase the torque produced by the prime mover. In a case of a turbo-alternator, that means increasing the steam flow-rate to the turbine. The steam floor rate is increased by opening the actuator, thus allowing more steam to flow into the turbine. The generator converts the torque to stator amperes.

The equation for electrical power for a three-phase machine is:

Power (Watts) = √3 * Volts * Amperes * Cos θ

To simplify this context, let's assume the Power Factor of the generator to be 1.0 and stable; constant; unchanging.

Defining an operating condition:

Terminal voltage of the generator is held constant by holding the generator rotor excitation constant, whilst presuming the power factor to be 1.0, and unchanging. The square root of three is a constant (it can't/doesn't change; it's always 1.7320).

So, to increase power, the only component of the power equation that can be changed is the generator stator amperes. And, since a generator is a device for converting torque into amperes, if we increase the torque being applied to the generator rotor, the amperes flowing in the generator stator will increase. And, when the generator stator amperes increase, then the power being produced by the synchronous generator will increase. This is done by increasing the steam flow by opening the actuator more.

So, in summary, steam flow generates torque, and torque equals/generates amperes, and varying amperes varies the power produced by the generator. So, in order to increase the TA generated load, increase the steam flow and to reduce the TA's generated power, reduce the steam flow. Note that the discussion is based on ideal situations. The TA generated power is not normally controlled by the operation on the TA but rather by the amount of load on the system. You do not force the TA to generate a certain amount of power; the load on the system determines how much power the TA must generate. Since power cannot be stored, you only generate what you require. In the event of exporting, the control explained above proves true, as the set points you put to get the your desired export amount controls the amount of power generated, taking into consideration the factory loading.

As the amperes flowing in the generator stator increase as the steam flow-rate to the turbine increases, one of the effects is that the magnetic field associated with the generator stator also increases. Remember; current flowing in a conductor produces a magnetic field. (Electricity generation fundamentals)

As the field associated with the generator stator increases, it "reacts" with the field of the generator rotor. Some context will describe the resultant interaction of the generator stator's increasing magnetic field strength as decreasing, or weakening, the generator rotor field strength. One tries to overpower the other. You can use vectors and maths to describe it in other ways, but, in essence what is happening is an interaction between two magnetic fields in the same space, and something has to "give" when one increases.

Now, when the generator field strength decreases that causes the generator terminal voltage to decrease. The intent, however, is always to maintain the generator terminal voltage relatively constant. In order to increase or maintain the generator terminal voltage, the excitation is increased, to increase the generator rotor field strength so to maintain the generator terminal voltage.

The exciter, when it's being operated in what's called "Automatic" or "AC" mode, is monitoring the generator terminal voltage, and it adjusts the excitation as required to try to maintain the generator terminal voltage setpoint set by the machine's operator or the controller (CGC, in the event of a Dawson Technology being used). If the terminal voltage goes down, the exciter will increase the excitation to try to maintain the generator terminal; the opposite happens if the generator terminal voltage increases.

So, as a synchronous generator is loaded (by increasing the steam flow-rate to a steam turbine being used as a prime mover to provide torque to the generator rotor) if no action is taken by the operator/controller or the exciter control system, then the generator terminal voltage will decrease below rated or desired. That is why it is required to increase the excitation as the generator is loaded to maintain something near rated generator terminal voltage. This is all done by the excitation system (e.g. DECS 200). This phenomenon can be observed on the system voltage when starting big loads. For a moment or so, the terminal voltage will drop which the excitation system is still trying to react to the sudden increase of the load.

Conversely, when a synchronous generator is being unloaded, if no action is taken to reduce the excitation, the generator terminal voltage will increase above rated or desired. This can also be observed when suddenly dropping off big load, the terminal voltage will temporarily jump up until the excitation system controls is back to normal.

All of that is basically true for a stable or unchanging power factor, and we assumed it was unity (1.0). Now, if we presume that the generator is operating at 50% of rated power output, stably, and that the power factor of your generator is 1.0 (which, coincidentally means that the excitation being provided to the generator rotor by the exciter is exactly equal to the amount required to make the generator terminal voltage equal to the grid voltage with which the generator is synchronized). If the operator then increases the excitation being applied to the generator rotor, the power factor will drop below 1.0 in the inductive/lagging direction and the reactive power (kVAr) will increase from 0.0 also in the lagging direction.

Please note that here, the load was not changed, we are assuming constant active power (kW)/load of the generator of which we now know is done by increasing the steam flow. We presumed that the operator only changed the generator excitation. In the event of a controller being used, this is under the presumption that the generator is NOT being operated with Pre-Selected Load Control enabled and active. The unit had been manually loaded to approximately 50% of rated load without placing the Controller in any kind of automatic load control. This is mostly possible under controlled tests/environments with constant load.

Essentially what the operator had done was to attempt to increase the grid voltage by increasing the generator terminal voltage (sometimes called "boosting"), and while the generator terminal voltage and the local grid voltage may have, in fact, increased slightly, what really happened is that reactive current began to flow in the generator stator windings.

From a generator's perspective, the reactive current is considered to be inductive and is called lagging reactive current, or lagging kVARs. If the operator continues to increase the excitation being applied to the generator rotor, the power factor will continue to decrease below 1.0, and the kVAr meter will continue to increase above 0.0 in the lagging direction.

What's happening when increasing the excitation being applied to the generator is that the total amount of energy that is being put to the generator is being split between real power (kW) and reactive "power" (kVAr), and that the percentage of real power being produced is decreasing. Power Factor is a measure of the amount of real power being produced versus the total amount of power being applied to the machine.

$$\mathbf{Cos\ \theta = P/S = kW / KVA}$$

So, the reactive current flowing in the generator stator windings is controlled by controlling the excitation being applied to the generator rotor. And the "real" power flowing in the generator stator windings is controlled by the amount of torque being applied to the generator rotor.

In summary: Excitation controls the reactive current flowing in the generator and Torque/steam/fuel flow controls the active current flowing in the generator. Reactive current implies the presence of reactive power and active current implies the presence of active power. Reactive power is 0 kVAr at unity power factor (1.0).

Now, lets' say the unit is operating at a stable power output and with a Power Factor of 1.0 (which means 0.0 VArs). After a while, the operator looks up to see the Power Factor has changed, It has decreased below 1.0 and, the kVAr has increased above 0.0., both in the leading direction.

This means that grid system voltage has increased above the level it was previously operating at, which means the excitation being provided to the generator is now not sufficient to keep the generator terminal voltage equal to the grid voltage. This means that reactive current is now flowing in the generator stator windings.

Say, the operator was told to maintain a power factor of 1.0, and a kVAr reading of 0.0 kVARs. In order to return to these values, the operator needs to increase the excitation.

Fuel is watts, or KW, or MW. Fuel is REAL power

Excitation is VArs. Excitation is REACTIVE power

A synchronous generator is supposed to be operated at a constant speed, called synchronous speed. For a two-pole generator operating on a 50 Hz system, that synchronous speed is 3000 RPM. For a four-pole generator at 50 Hz, that speed is 1500 RPM. The speed seen on SCADA may range from 5000RPM and beyond. This speed is normally that of the prime mover, (steam turbine, etc.). The alternator itself will be running at 1500 RPM if it is a 4pole and 3000 RPM if it is a 2 pole. That's because the speed of an AC machine is directly proportional to the frequency of the AC mains (the grid) with which it is connected. The formula is:

$$\mathbf{F = (P * N) / 120,}$$

Where: F = Frequency, Hz,

P = Number of poles of the generator rotor,

N = RPM

When synchronous generators are operated in parallel with each other, when they are SYNCHRONIZED with each other, they are all operating at the same frequency under normal conditions. And because, nominally, optimally, allegedly, the system frequency is constant (or relatively constant; meaning it changes relatively little and is relatively stable) all synchronous generators, and the prime movers directly connected to the synchronous generators, are all rotating at constant speeds that are directly proportional to the frequency of the grid with which they are connected. In the event of the TA's connected to the grid, the grid takes precedence on the frequency. This will be explained further on sections below.

In reality, grid frequency in never exactly 50.00 Hz and as grid frequency varies so do the speeds of the generators and the prime movers directly connected to those generators. But, for all intents and purposes, the frequency is relatively stable and even though the frequency varies by hundredths or tenths of a Hz, the machine speeds vary by an almost imperceptible amount that is directly proportional to the frequency variation and when the grid frequency disturbances are large, then generator and prime mover speed variations are large. That is why there is protection such as over frequency and under frequency, especially when operating in parallel with the grid, these are to protect the generators from tripping when the grid frequency varies excessively. The protection will take out the connector to the grid and run the generators on island mode.

That's because all of these machines are locked into synchronism with each other. And, allegedly, supposedly, somewhere there is a grid regulator that is monitoring the load on the grid and ensuring that the amount of generation on the grid exactly matches the amount of load, which is what's required to make the system frequency exactly equal to nominal (50.00Hz).

When the amount of load exceeds the amount of generation, then the frequency will begin to decrease. When the amount of generation exceeds the amount of load the frequency will begin to increase.

But, in any case, unless the prime mover is very large with respect to all of the other generators on the grid with which it is synchronized, increasing the fuel flowing to the steam turbine will not appreciably increase the speed of the turbine, and hence will not appreciably increase the speed of the generator rotor, and hence will not appreciably increase the frequency of the output of the generator. The speed of the generator rotor, and of the steam turbine which is directly coupled (connected) to the generator rotor, is controlled by the frequency of the grid with which it is SYNCHRONIZED.

It must be noted that there are very great magnetic forces at work in synchronous machines that keep the speed directly proportional to the frequency. Even though the fuel flow to the generator may be increased, when the generator is synchronized to the grid, the speed of the turbine, and the generator rotor, does NOT increase. The increased torque developed by the increased steam flow is converted by the generator into increased stator amps, which takes us back to the first formula seen earlier.

A generator is a device for converting torque into amps. Wires are used to transmit those amperes (torque) to devices located long distances from sources of torque (or the energy used to produce that torque). Motors and other devices that consume electricity (including lights, and even computers) convert amps back into torque.

So, the generator(s) at one location may be pumping tens of thousands of litres of water and lighting tens of home and allowing many people to send email and videos to others at many locations very distant from the turbine(s) at your site. Electricity is just a means of transmitting energy from one location to another location, or many locations, so that useful "work" can be done at those locations without having to have bazillions of generators at bazillions of locations around the world.

Alternating current grids transmit power at a nominal, desired frequency. Frequency control, and regulation, is a very important aspect of alternating current systems.

In a simple approach: when you buy a television or DVD player, or even a pump to pump water around your house or property, and it's rated for 50 Hz (or 60 Hz in some parts of the world). When you plug it into the outlet in the wall at your home or apartment, the expectation is that you will be receiving a nominal 50.0 Hz, with some very slight variations. Not 51.2, or 49.3, or 48.2, or 50.4, but a nominal 50 Hz. The generators connected to the grid supplying the power to that outlet in your home or apartment all have to be generating power at the same frequency. They can't be generating at wildly different frequencies, with some device at your home or at some substation that converts a bunch of different frequencies to 50.0 Hz. There is no such device in the electrical systems of just about any country or part of the world (unless there are high-voltage DC links, but that's a special case).

Producing electricity requires magnetism, and magnetic forces are also a result of current flowing in conductors. In AC motors and generators, the magnetic forces created when current flows in the stator windings seems to rotate around the stator, which is how motors rotate and generators create the waveform that creates the "rotating" magnetic field on the motor stators.

Excitation is what's used to create the magnetic field of the generator rotor. When current is flowing in the generator stator windings, there is another, a second, magnetic field created. Now, you know what happens when you try to put the North poles of two magnets together, they repel each other. And, you know what happens when the North pole of one magnet comes into proximity with the South pole of another magnet, there is a strong attraction. It’s a Romeo and Juliet phenomenon. Opposite attracts.

It's exactly the same in a generator (or a motor, for that matter). With two magnetic fields (one on the rotor and one on the stator), the North and South poles of each field attract each other, and that's what keeps the rotor spinning at a speed that is directly proportional to the frequency of the grid (that the generator stator is connected to).

When torque is being applied to the generator rotor, one of the things that happen is that the prime mover (steam turbine) is trying to twist the rotor and break that magnetic attraction. The more torque being applied, the more "twist" on the load coupling and generator rotor. You may have heard of "load angle"? Well, that's the "twist", basically. As more torque is applied, the load angle increases.

If the magnetic strength of the rotor isn't maintained sufficiently, then what can happen is that the rotor "slips a pole" and that means CATASTROPHIC damage to the machine. Load couplings break; generator rotors get "bent", and turbine rotors can be irreparably damaged when this happens. There are "loss of excitation" relays and other protective relays to sense and anticipate this condition BEFORE the damage occurs.

"Slipping a pole" means that the attraction between the North pole of one field and the South pole of another field is broken, and instantaneously the generator rotor increases speed. As the speed increases the North pole of one magnetic field passes the North pole of another magnetic field and very great repulsion occurs. This can cause the rotor to want to stop instantaneously and reverse direction (which it can't do!), or to move even faster past the revulsion until there is another North-South attraction, at which time the generator rotor will want to slow down, again, instantaneously. There are very great physical forces at work here, the torque from the prime mover, and magnetic forces, as well.

Synchronizing involves making sure that the North pole of the generator rotor is in a position to be attracted to the South pole which will be created when current starts flowing in the generator stator windings. Otherwise, synchronizing check relays wouldn't be required to prevent synch'ing "out of phase" and causing extreme damage to machines.

For observation: Watch the speed of the turbine(s) when you are synchronized to the grid and loading and unloading. It doesn't change by more than a tenth of a per cent, or less. If you are observing the RPM, It doesn't change by more few RPMs, if that, during loading and unloading. And that's from zero load to full load, or from full load to zero load. Of from any load to any load, loading or unloading. When looking at the speeds, presuming the grid frequency is stable and not changing (as it should be). At the same time, watch the frequency of the generator output. The two are directly proportional, so you will the same "differences" during loading and unloading. If the frequency is changing, the speed will be changing proportionally.

Using a simple analogy:

An electrical grid with multiple synchronous generators is like a bicycle with multiple cranks (sets of pedals) and multiple riders to apply torque to each crankset. Those cranksets are usually all connected to each other and to the rear drive by chains, and the speed of each crankset cannot be different from any other crankset. In other words, one rider can't be pedalling at 23 revolutions per minute while some other one is pedalling at 37 revolutions per minute (unless the gears of the cranksets are different, in which case there is still a direct relationship between crankset rotation and bicycle speed for each crankset).

Further, if that bicycle is supposed to travel at a constant speed (which is directly relatable to a constant frequency) then all of the riders have to work together to ensure that the torque being applied by each of them is sufficient to maintain that speed. If every rider is pedalling as hard as they can then it's likely the speed will be excessive. If several riders decide to take a break and remove their feet from the pedals at the same time then it's likely the bicycle will slow down and if every other rider was already pedalling as hard as they could then it's likely the bicycle will not be able to maintain speed. There has to be some "coordination" between all the riders in order to be able to maintain a constant speed while going over hills (up them and down them) or carrying loads.

And, if there's one rider who is extremely strong in relation to the other riders and that rider starts pedalling as hard as he can then the speed of the bicycle will change, unless there is some coordination.

On that bicycle, there needs to be one person who is in charge and telling people to apply more torque (pedal harder) or less torque (pedal not a hard) to maintain speed. If every rider is trying to make that decision for themselves, then it will be a disaster. And the coordination of an electrical system is done by the grid regulators. It's their job to make sure the amount of generation on the grid matches the amount of load on the grid. They have to anticipate load swings (to the extent they can) and have "reserve" capacity available to meet demand.

Just as it's necessary to have some riders on the bicycle pedalling not quite as hard as others at all times so that changes in terrain or load can be handled while still maintaining a constant speed.

Grid regulators use various methods to tell various power plants to increase or decrease power output (Automatic Gain Controller, AGC, is the most common term for these methods) to balance generation and load.

Back to the bicycle analogy, think about what happens when a rider who had removed his feet from his pedals for some time decides to put his feet back on the pedals and begin pedalling while the bicycle is traveling at a constant speed. It takes some coordination because his crankset will be rotating and he has to time the placement of his feet back on the pedals (synchronizing) so as not to injure himself. And, if he suddenly begins pedalling hard then the bicycle speed will increase, and unless someone else reduces the torque they are applying to their pedals the bicycle speed will not return to normal.

It's a physical "law" that the speed of a synchronous generator rotor is directly proportional to the frequency of the grid with which it is connected. And, it's a physical "law" that says the frequency of an AC grid will be constant when the amount of generation exactly equals the load being supplied (the aggregate total of all the motors and lights and computers being powered by the grid). If the amount of generation isn't exactly equal to the amount of load, then the frequency won't be as desired. Just like on that bicycle, if the rider(s) isn’t (aren't) producing just the right amount of torque to maintain the desired speed, then the bicycle won't travel at the desired speed.

An AC (Alternating Current) grid depends on frequency control to properly provide power to loads. So, since speed and frequency are directly related, the speed of generator rotors has to be constant so that frequency remains constant. It's just like the bicycle analogy, the speed of the bicycle won't be constant if the torque being applied to the pedals isn't varied as necessary.

When the Speedtronic (or any other controller/governor) is controlling turbine speed when the generator breaker is NOT closed, increasing fuel will increase speed, and decreasing fuel will decrease speed. But, if the turbine is rated for 5MW (example) and it's connected to a grid with 800 MWs of generation (many generators all synchronized together), then the 5MW turbine is not going to substantially change the grid frequency as it's loaded and unloaded. There are just too many other generators out there and as long as the grid regulators are doing a good job, then any one prime mover can't have an effect on grid frequency.

There are basically two modes of governing action: Droop Speed Control, and Isochronous Speed Control.

Droop Speed Control basically means the governor (the prime mover control system) isn't trying to control its speed; it's only producing power in a stable fashion while operating in parallel with (synchronized to) other generators to provide a load that is larger than any single generator and its prime mover is capable of providing.

Isochronous Speed Control means that the prime mover governor is going to adjust its power output very quickly in response to any changes in speed caused by changes in load in order to maintain a nominal frequency. And just like in the bicycle analogy, if there are too many people trying to adjust their output to maintain speed without any coordination then the speed will not be very constant, and worse, for generator prime movers, the load of those prime movers will be swinging wildly from one machine to another and back. In theory, without some special kind of load-sharing schemes, no more than one prime mover governor can be operated in Isochronous Speed Control mode at a time on a grid. There needs to be a controller of some sort that will maintain a certain sharing scheme to ensure the load is shared in a controlled manner. E.g. equal percentage based on rated.

On most "grids" of any size with multiple synchronous generators, all of the prime movers (again, without some special load-sharing scheme) must be in Droop Speed Control mode in order to share in the powering of a large load with other generators. And, someone, or something, must be monitoring the frequency and adjusting the total generation to match the total load in order to maintain the frequency. It's a balancing act. The development of new generator control systems are meant to perfect this balancing act.

However, if a 100 MW machine is connected to a small grid with many smaller prime movers, say 5-15 MW each, it's very possible that if the load of all the generators isn't very well coordinated as the large machine is loaded and unloaded then the grid frequency can deviate. It's just like the example of a very strong bicycle rider; no different.

As far as loading and excitation, If, as the current in the stator windings increases (as a result of applying more torque ("twist") to the generator rotor), the magnetic field strength of the stator windings can "overcome" or "weaken" the strength of the rotor field and if something isn't done to increase the rotor field strength then the net effect is that leading kVARs will flow in the generator stator windings. And if severe enough, then a loss of magnetism and a resultant slipping of a pole will occur. So, it's necessary to increase excitation as load is increased to maintain the desired power factor, or kVAr value, or bad things will happen to the unit. The excitation system will automatically do some of that increasing, but operators will also need to do some (unless there is some kind of automatic Power Factor or kVAr Control scheme to do that, e.g. DECS 125 or 200, etc.).

For all intents and purposes, on a properly regulated grid, or even a mildly-well regulated grid, the frequency-related speeds of the generator rotors and prime movers are all the same.

And, the control systems of those prime movers driving those generators are NOT trying to control the speed of those prime movers and the generator rotors. "Droop" Speed Control control system is allowing the speed of the prime mover to be less than the speed reference. It's straight proportional control.

Torque is produced by the prime mover. The steam, passing through the turbine nozzles impinge on the turbine buckets which are a fixed distance from the centre of the shaft. However, increasing the steam flow-rate increases the steam passing through the turbine nozzles and turbine buckets which increases the force being applied to the turbine buckets which increases the torque being produced the turbine.

A certain amount of torque is required to keep the generator rotor spinning at the same speed as the grid frequency dictates. If the turbine supplies only that amount of torque when the generator breaker is closed, the "load" on the turbine will be 0.0 MW. As the steam flow is increased, and the force on the turbine buckets increases, the torque produced by the turbine will increase. The generator, held at a constant speed by the frequency of the grid with which it is synchronized, cannot increase its speed so it converts the torque into amperes.

Load (motors driving pumps and fans, and air conditioners, and lights, and computers) tends to slow down a generator or grid. Think about the bicycle. Think about pedalling a bicycle at a constant speed and all of a sudden your friend jumps on the handlebars. Or someone throws a heavy package into the basket. Now, to maintain the same speed you have to pedal harder. You are applying more force to the pedals, and that produces more torque which is then applied to the rear wheel of the bicycle to maintain the speed. If you apply the extra force to produce the extra torque fast enough then the speed of the bicycle will not change (appreciably).

In reality, as the extra "load" is added to the bicycle, the speed of the bicycle will tend to decrease. But, if you increase the force you are applying to the pedals , the speed won't change by much.

The same is true for an electrical grid. As motors are turned on, and lights are turned on, and air conditioners are turned on, and computers and monitors are turned on the initial effect on the grid is to decrease the frequency of the grid (and the speed of the generators and prime movers). That's because torque is being "taken" from the grid to power these loads and something has to increase the torque being supplied to the grid to return the grid frequency to normal. So, someone or something has to increase the torque being provided to one or more of the generators to return, or maintain, the grid frequency to normal. But, for most loads on a large grid the speed decrease is almost imperceptible.

Excitation is required to maintain generator terminal voltage, and to keep the generator rotor magnetic field strong enough to prevent slipping a pole, and to maintain a desired power factor, or to maintain a particular kVAr reading.

When you synchronize a generator and its prime mover to the grid and start to load the generator, presuming the number of motors and lights and air conditioners and computers and monitors is relatively constant what will tend to happen is that the grid frequency will tend to rise. That's because more "torque" is being added to the grid by the generator from the prime mover than is required by the load, so the frequency will increase. The amount the frequency increases is a function of how much total load is on the grid and how much "load" is being added to the turbine.

Actually, the turbine isn't "adding" anything, it's just taking a portion of the existing load and unless the load decreases (the number of motors being run is reduced, or the number of lights is reduced, or the number of air conditioners running is reduced, or the number of computers and monitors is reduced) as you "increase" the load on your turbine, the grid frequency will increase. Or, unless some prime mover somewhere is unloaded by an amount exactly equal to the load being "added" to your machine as you "load" your unit, the grid frequency will increase.

The opposite happens when you are "unloading" your machine. You are reducing the amount of torque being supplied to the load. Unless some load is reduced somewhere or some prime mover increases its torque output by amount exactly equal to the amount of load "decrease" on your machine, the grid frequency will decrease.

That's the balancing act that grid regulators have to contend with every day, every hour of every day. They have to monitor and anticipate load swings as best as they can, and they have to try to time increases in generation or decreases in generation in order to maintain frequency. If they see frequency beginning to decrease, they have to be able to call on plants to increase their generation. Or, if they see frequency beginning to increase they have to call on plants to decrease their generation. Or, if a generator suddenly trips off line they have to be able to call on a plant or plant to increase its generation by an amount equal to the amount of generation that just tripped off line.

If there was a single prime mover operating in Isochronous Speed Control mode somewhere on the grid, as load changed (the number of motors and lights and air conditioners and computers and monitors), and frequency changed as a result of the load change, that prime mover would automatically, and very quickly, change its power output to keep the total amount of generation equal to the total load. But, if load changes are much bigger than the capacity of the prime mover, then grid regulators have to call on other plants to help maintain frequency by increasing or decreasing their "load".

Again, going back to the analogy of the bicycle with multiple cranksets and riders. It takes coordination to keep the bicycle running at a constant speed. Now think about adding or deleting packages (load) from the bicycle while it's moving and trying to maintain that constant speed.

In many parts of the world, when a power plant wants to go on line, they have to call some "agency" and then the agency will tell them when it's possible to go on line, and usually they want to know how much power the plant is going to be producing and for how long and then they "schedule" the plant to go on line at a certain time, knowing what the loading rate will be. They then have to reduce the load on some other generator or plant by an equal amount in order to keep the grid frequency constant as another plant is being brought on line.

Power plant operators, nor grid regulators, control the "load" per se. The load is what the load is; and the total amount of generation must equal the total amount of load otherwise the grid frequency will not be at rated. Small variations (hundredths of Hz, or in worst cases, a tenth of a Hz) are to be expected, but not large variations on well-regulated grids.

Recall: There is current, and there is reactive current. When you hold excitation constant and increase the energy flow-rate to the prime mover and the AC synchronous generator is synchronized to a grid with other generators and their prime movers that the speed DOES NOT increase but the amperes flowing in the stator DO increase, and the wattmeter increases and the kVAr meter doesn't really move very much.

Yes, the kVAr meter does move, but it's because of the EMFs and counter-EMFs and back-EMFs and interactions between magnetic fields changing.

If alone (Islanded):……

Essentially, increasing the speed setting increases the fuel flow and increases the speed of the turbine/generator. The voltage will increase as the volts are proportional to some extent to the speed of the rotor/field. However, the voltage is varied by increasing/decreasing the field current. This has a more immediate and influential effect than varying the speed. It is independent of the speed controls and it does not affect the speed. So, set the speed first with speed/fuel controls and then when happy, set the voltage.

If you are connected to a grid:

Because the generator is "synchronized" with the grid, and the grid is so much larger than the generator in capacity, the grid determines the speed of the generator and thus of the turbine.

You cannot change the speed of the turbine when it is connected to the grid. There is a very large generator on the grid somewhere whose job is to hold 50Hz and all other generators are tied to that frequency.

In the case of a generator where speed control (steam flow control) is not configured to keep the speed at a particular setpoint, it is then instead, configured to maintain a certain load/speed profile. This is called "droop control". This is normally set to 4%, depending, What this means is that if you load your turbine to, say 50 % load and it is sitting there at 50Hz (assuming your grid is 50), if the grid speed slips to, say, 59Hz, the turbine fuel/speed controls will increase the fuel supply in order to pick up MORE LOAD and not MORE SPEED. The drop in grid frequency approximates to a 2% drop in speed. At 4% "droop" setting, the turbine will pick up 2/4X100% load, or half load. So added to the half load it is already on this will mean that it will be fully loaded.

The reason for this fuel control method is to ensure that all of the turbines on the grid pick up the same proportion of their full load (or drop off in the case of an increase in frequency) As the frequency of the grid returns to normal, your turbine controls will lower the fuel in accordance with the 4% droop curve. It is important to understand this if you are connected to a grid.

Manual/Automatic increase of speed setpoint

If the grid frequency is constant, as you increase the speed setpoint on your TA manually/automatically, as explained before, the speed cannot change so as more fuel flows, the turbine takes on more load. Normally some central systems operator asks individual turbine operators to take on or drop off load. So, the turbine controls only affect the load (in kW) of the generator not the voltage. This is all "real" power.

The above was all about power and speed control. As regards to the voltage, this is also held constant by the grid. Analogously, the voltage controls i.e. increase/decrease in field current which would increase/decrease the terminal voltage of the generator if you were not connected to the grid will actually result in the acceptance or rejection of Volt Amp Reactive (VARs). This is to do with the power factor, etc. and normally all voltage controls on a grid are set to the same droop settings so that as the power factor changes on a grid, all of the generators pick up the same VARs. Voltage control/VARs/PF is all very much less intuitive than speed control and more difficult to understand. So you can see that you can vary neither speed nor volts when connected. And there is no connection between voltage control and speed control.

VArs are like Watts; you can't make more than is required by the load. If you try to make more Watts than is required, then the frequency is going to increase. If you try to make more VArs than required by the load, then the terminal voltage is just going to go up.

The "A" in AVR means Automatic (Automatic Voltage Regulator). When the AVR is in Automatic mode, it's trying to keep the generator terminal voltage relatively constant.

Grid voltage does change throughout the day and the year. That's a function of load and impedances and many factors. As the grid voltage changes, then VARs and power factor will change. It's the operator's (or control system's) responsibility to keep the VAr value at where it's supposed to be or the power factor to be at where it's supposed to be. Some turbine control systems, and some AVRs, have VAR and/or Power Factor control implying automatic control of one or the other parameter. Excitation will be adjusted as necessary to maintain the setpoint of one or the other, automatically.

Pre-Selected Load Control and **Base Load** can only be selected by an operator when the unit is in Droop Speed Control governor mode. In Isochronous Speed Control mode, the load of the unit (the power being produced by the unit) is varied in response to changes in frequency. That's how frequency is controlled, by varying generation to match load. As load increases, generation must increase to maintain frequency. As load decreases, generation must decrease to maintain frequency. If you set a Pre-Selected Load Control Setpoint and enabled Pre-Selected Load Control (the Speedtronic/control system is smart enough not to allow an operator to do this), then the turbine wouldn't respond to changes in load to maintain frequency and the whole concept of Isochronous goes out the window along with frequency control. If the grid load increases above the Base Load capability of the machine, then grid frequency will decrease.

In the same way that any system, finite or infinite, can't make more watts (real power) than the load on the system present, generators can't produce more VArs (reactive power) than the load on the system present. Now, if you have three generators on a small system and the total reactive load is 30 MVArs, if two of the generators are carrying 15 MVArs each, and the excitation of the third generator is increased then it's likely the reactive power from either or both of the other generators might shift to the third generator but the total VARs is not going to change and if one generator is carrying all of the reactive load and the excitation of that generator is increased further, then the voltage of the system is going to increase.

VArs can be thought of exactly like watts. If you increase the torque above what's required to keep the power being produced equal to the power being consumed, then the frequency of the system is going to increase. If you increase the excitation above what's required to supply the reactive load on the system then the system voltage is going to increase.

If you reduce the torque being supplied to the generator below what's required to keep the generator running at a speed equal to 50 Hz, the speed of the generator is NOT going to change. That is because that unit will draw amperes from the grid (reverse power) to keep the generator (and turbine) running at synchronous frequency and speed. (In reality, the grid frequency will decrease by an almost imperceptible amount that is a function of the amount of power being drawn from the grid versus the total generation on the grid.

If you reduce the excitation to your generator below what's required to keep your generator terminal voltage equal to the system voltage, reactive power will flow into the generator trying to keep the generator voltage equal to grid voltage. In reality, the voltage on your generator will decrease by a small amount, but for all intents and purposes, it will be an imperceptible amount.

The Speedtronic will not allow a turbine operating in Isochronous mode to enable Pre-Selected Load Control or Base Load. Isochronous mode is going to adjust the steam flow in response to speed changes and the load is going to be what the load is going to be.

Frequency High: The turbine is going to unload VERY quickly, because the loading/unloading rate in Isochronous mode is VERY quick. It might even trip on reverse power.

Frequency very low: The turbine is going to load VERY quickly and because the loading/unloading rate is MUCH faster in Isochronous mode, the unit could trip on exhaust over temperature.

A turbine produces torque, which a generator converts to amps, which are transmitted over wires to motors which convert the amperes back into torque that is used to perform work. So, in reality, the turbine is actually doing work in a LOT of remote locations because the turbine is providing the torque to do the work at the locations where the motors are. And electricity is just the way the torque is transmitted from one place to another, to many places.

In an AC system, the transmission of amperes occurs at a particular frequency, 50 Hz. That's akin to a bicycle, or bicycles, or bicycles with several riders and cranksets, moving a load at a particular speed. Because speed and frequency are directly related, if you provide too much torque to the bicycle, the load will move at a faster speed than desired. If you increase the load above the torque being supplied to the pedals, the load will move at a slower speed.

A generator is exactly the same. Provide torque in excess of the load being produced by the motors connected to the generator, the frequency will increase. If the increase the number of motors and the work being performed by the motors in excess of the torque being provided to the generator and the frequency will decrease.

Now, think of a grid (large or infinite) as the sum of all the motors (and lights and computers and monitors) and of all the generation (the amount of torque being produced by the prime movers driving the generators which are actually doing the work at the other end of the wires connected to the generators). If you increase the torque above what's required to keep the frequency constant, the load doesn't change (the number of motors and lights and computers and monitors), the frequency increases.

If you allow the number of motors and lights and computers and monitors to increase above the amount of torque being provided to the generators by the prime movers, then the frequency will decrease.

Now, excitation, what we're trying to do is to keep our generator terminal voltage equal to grid voltage. And as long as generator terminal voltage is equal to grid voltage then there will be NO reactive current flowing in the generator stator windings.

In the same way that grid frequency is never perfectly constant, grid voltage is never perfectly constant either. And that means that excitation is going to have to change to keep the relationship between generator terminal voltage and grid voltage in check. If for a constant load (watts), the grid voltage increases and the excitation remain constant, then leading VArs will flow in the generator stator windings. If for a constant load the excitation is reduced below that required to make generator terminal equal to grid voltage, then leading VArs will flow in the generator stator winding.

Does the generator terminal voltage actually change? Imperceptibly so, depending on the magnitude of excitation change. Just like the frequency changes on a grid as load or generation changes, imperceptibly on a properly regulated grid, so does the generator terminal voltage change as excitation changes. By changing the excitation on one generator to try to raise grid voltage or lower grid voltage, the voltage is not going to change by very much at all because there are a lot of other generators out there all connected to the same grid.

It's just like what happens when you load your generator (watts), you can't appreciably change the grid frequency but if the load on the grid remains constant and you increase the torque being provided to the generator, the grid frequency will increase, by an amount that's proportional to the increase in torque with respect to the total amount of torque being provided to the grid. The larger the grid, the smaller the effect.

Excitation and VArs are very difficult to explain. There are all kinds of maths and vectors, but the upshot of all that stuff is this: If the excitation exceeds the amount required to make the generator terminal voltage equal to the grid voltage, then lagging VArs will flow in the generator stator windings and if excitation is less than the amount required to maintain generator terminal voltage equal to grid voltage then leading VArs will flow in the generator stator windings. VArs flowing in the stator windings reduce the efficiency of the generator.

The AVR is a control system for keeping the excitation stable, just as the governor function of the Speedtronic turbine control system keeps the torque production stable. The AVR can be used to increase or decrease VArs, just as the Speedtronic can be used to increase or decrease watts.

The tires of a bicycle require air to stay inflated so that there is sufficient traction. A poorly inflated tire also requires more torque to travel at the same speed because of the increased contact with the road. A poorly inflated tire will also have reduced life because the side walls will wear out faster due to heat and contact with the road. An over-inflated tire will not have as much traction because of reduced contact with the road, and it will be more prone to puncture and flattening if over-inflated. I guess you could consider excitation to be the air in the tires of the bicycle. The ability to maintain traction to maintain speed without requiring excessive torque to overcome under-inflation can be equated to excitation keeping the generator terminal voltage equal to grid voltage.

When a synchronous generator is being synchronized, the usual practice is to make the speed of the generator (the frequency) slightly higher than grid frequency. This is so that when the generator breaker is closed and the generator slows down to match grid frequency the "excess" torque will result in a slight positive power flow (watts) out of the generator.

In the same way, when synchronizing a generator, the terminal voltage is usually slightly higher than grid voltage, or at least equal to grid voltage, so that when the generator breaker is closed there will be a slight "positive" VAr indication (lagging VArs) or zero VArs.

This can all be summarised as follows:

There are two magnetic fields in the generator: the one produced by the excitation applied to the generator rotor, and the one produced by the current flowing in the generator stator windings.

The strength of any magnetic field is proportional to the amount of current flowing in that field. As the generator is "loaded", the amount of current flowing in the generator stator windings increases, and the strength of the magnetic fields of the generator stator windings therefore increases.

The two fields "interact" with each other in many different ways. As one field's strength is increased, this can have an impact on the strength of the other magnetic field. In fact, as the strength of the stator field increases, it tends to "reduce" the effects of the rotor field, and if allowed to continue unchecked what will happen is that leading reactive current (VArs) will flow in the generator stator windings. And most synchronous generators are not built to withstand the effects of a lot of leading reactive current flowing in the generator stator windings.

So, what usually happens is that as a generator is "loaded", meaning that the torque being applied to the generator rotor is increased, and the generator excitation is not changed, the operator will see that the VAr meter, which was probably at 0 VArs or at some small leading value initially after synchronization, starts moving in the Leading direction. So, the operator will need to increase the excitation to keep the VAr meter at 0 or in the Lagging direction.

Some turbine-generator units have something called VAr Control. VAr Control will automatically adjust excitation as required to maintain the VAr setpoint as the unit is loaded or unloaded, relieving the operator of the responsibility to do this. And, since Power Factor and reactive current are related, many turbine-generators also have Power Factor control, which will adjust the excitation as required to maintain a Power Factor setpoint as the machine is loaded and unloaded. This is all done systems such as the Dawson Technology incorporating the DECS.

Once you reach the desired load (watts) for your unit and have adjusted the excitation to the desired reactive current or power factor, the operator's job is NOT finished. During the course of the day the grid voltage will change, just by a few volts, or tens of volts, or sometimes a hundred volts or so, but that change is relatively imperceptible on high-voltage systems (11kW, etc.). BUT, if the excitation on the generator remains constant, that difference will result in a change in reactive current flow (and Power Factor) in the generator stator windings. And, so the operator will need to continually monitor the VAr meter, or the Power Factor meter, and adjust the excitation as required to maintain the setpoint required, in response to grid voltage changes. This is not all done electronically with new turbine generator control systems.

If the unit has VAr Control, or Power Factor Control, the operator can enable either of those functions (they both can't be running at the same time) and the excitation will be adjusted as necessary as grid voltages changes throughout the day, even if the load (watts) on the generator remain relatively stable throughout the day.

It's all about "relativity". If the grid voltage is "constant" and the operator increases the generator rotor excitation above the amount required to keep the generator terminal voltage equal to the grid voltage, then lagging reactive current will flow in the generator stator windings. Likewise, if the generator excitation is equal to the amount required to keep the generator terminal voltage equal to the grid voltage and the grid voltage decreases then lagging reactive current will flow in the generator stator windings.

Think about real power (watts) now. When the generator breaker is closed if the torque being applied to the generator by the turbine is exactly equal to the amount required to keep the generator spinning at synchronous speed (frequency) there will be NO real power flowing in the generator stator windings. If the torque is then increased above the amount required to keep the generator rotor spinning at synchronous speed (frequency) then real power will flow "out" of the generator, to the load. If the torque is decreased below the amount required to keep the generator rotor spinning at synchronous speed then real power will flow "into" into the generator and it will in effect become a motor driving the turbine.

Well, it's basically the same for the voltage, excitation more than required to keep generator terminal voltage equal to grid voltage means reactive power will flow "out" of the generator (Lagging VArs are perceived to flow "out" of a generator), and excitation below the amount required to keep generator terminal voltage equal to grid voltage means that reactive current will flow "into" the generator (Leading VArs are perceived to flow "into" a generator).

As the load angle increases, if the excitation is held constant, then the increased stator current will cause the stator magnetic field to strengthen, which will "reduce" the effect of the rotor magnetic field which will affect the reactive current flowing in the generator stator windings.

The AVR usually has two modes: "Manual" and "Automatic", or "DC" and "AC".

Manual mode means the excitation is monitoring the DC current (or DC voltage) being applied to the generator rotor and the setpoint is generator rotor current (or DC voltage) to keep the current (or voltage) equal to the setpoint. It's the operator's responsibility to monitor the generator terminal voltmeter, or the VAr- or Power Factor-, meter and adjust the rotor current (or voltage) to maintain the desired volts/VArs/Power Factor.

In **Automatic mode**, the setpoint is AC generator terminal voltage, and the excitation is adjusted to keep the generator AC terminal voltage equal to the generator AC terminal voltage setpoint. If the relationship between the generator terminal voltage changes (whether it's because the excitation changes or the grid voltage changes) then the VArs and the Power Factor will also change.

If the unit has VAr Control and/or Power Factor Control, then the excitation will be adjusted as necessary to maintain the VAr or Power Factor setpoint, and the amount of current (and voltage) being applied to the generator rotor, and therefore the generator terminal voltage (in relation to the grid voltage) will be changed as necessary. Think of the "Manual" regulator as the "main" regulator, and the "Automatic" regulator "driving" the "Manual" regulator (this is sometimes referred to as "inner loop" and "outer loop"), and if either VAr Control or Power Factor control is active then that is "driving" the "Automatic" regulator (which is driving the Manual regulator). Isn't this fun?!?!???!!!

It is very similar to considering what will happen if the torque being provided to the generator rotor is being maintained at or near the amount required just to keep the generator rotor spinning at synchronous speed. An increase in torque will cause real power (watts) to flow "out" of the generator stator windings, and a decrease in torque will cause real power (watts) to flow "into" the generator stator windings ("motorizing" the generator--which is not a desirable condition to occur for very long).

If you ask about 'on-load' tap changers and how that affects reactive current flow. Well, when the transformer taps are changed, then the relationship between the low-voltage "voltage" and the "high-voltage" voltage changes, and that means the magnitude of the voltage that is "seen" at the generator terminals changes, which means that the reactive current will also change. It's another method of controlling the relationship between grid voltage and generator terminal voltage, and therefore the amount (and type or "direction") of reactive current flowing in the generator stator windings. An 'on-load' tap changer means that the taps of the transformer can be changed when current is flowing through the transformer (real power current, watts). Some taps can't be changed when current is flowing through the transformer; some transformers don't have adjustable taps at all--the relationship between low- and high-voltage voltages is not adjustable at all.

Some confusion may be how increasing or decreasing the torque being applied to the generator rotor might have an effect on the reactive current flowing in the generator stator windings. And, that's a function of the relative strengths of the two magnetic fields at work in the generator, that are keeping the generator rotor locked in step with the "rotating" magnetic fields of the generator stator and therefore keeping the generator rotor spinning at synchronous speed equal to the speed that is directly proportional to the frequency of the grid with which it is connected.

The interaction between the two magnetic fields as the strengths of the two magnetic fields are varied with respect to each other is called "armature reaction".

- **Do you need to know exactly what the pure definition of armature reaction is to be a good operator or technician?** NO.
- **Do you need to know all of the maths and vectors to be a good operator or technician?** NO.
- **Do you need to understand the fundamentals to be a good operator or technician?** YES.

The designers of the equipment (the turbines and the generators and the AVRs and the transformers) they need to know all of that stuff to make it operate in the desired ranges and to have a long life and to be reliable and safe. If it's not operated within the limits of the design, then it's not going to last very long, to begin with, and it's not going to "behave" as it should and that's where a more detailed understanding of the maths and vectors will be more helpful.

As an operator and/or a technician you need to remember this:

--Real power is a function of the energy being admitted to the prime mover of the generator.

--Reactive power is a function of the excitation being applied to the rotor of the generator.

Because we consider the voltage of most generators to be constant (within a small range, usually no more than approximately +/- 5% of nameplate rated) and since generator terminal voltage is primarily a function of excitation, and since we consider the Power Factor to be relatively stable (which is also a function of excitation--which should be relatively stable), the only variable in the power equation is Ia, which is directly proportional the amount of torque being applied to the generator rotor by the prime mover. The amount of torque is directly proportional to the amount of energy being introduced into the prime mover. So, if you vary the fuel (or steam) into the prime mover, you vary the torque being produced by the prime mover, which varies the amount of current flowing in the generator stator windings (armature), which affects the real power being produced by the generator.

Can you change the real power by changing the excitation? Yes, but not by very much. As you vary excitation, the generator terminal voltage will change. But, we said the amount is usually limited to +/ 5%, so for a generator rated at 13,800 Volts that means only about +/- 700 Volts. That change in excitation not only affect generator terminal voltage but it also affects the Power Factor, which is a measure of the efficiency of the generator at producing "real" work (watts) for the energy being applied to the generator rotor by the prime mover. Again, if we can only change the generator terminal voltage by no more than 5%, then we can't have a very large effect on power less than 5%.

As an operator or technician, if the watts being produced by the turbine-generator are not stable, you need to know if that's because the fuel (or steam) flow is not stable or if it's because the excitation is not stable. Or, if the VAr meter (or the Power Factor meter) is not stable, you need to know is that a function of the fuel (or steam) flow being unstable or of the excitation being unstable. Then you can begin to troubleshoot the problem or understand the event.

Do you need to know maths and vectors? It might be helpful, most of the people who know the maths and vectors can't explain the fundamentals to an operator and technicians so they can understand it and operate the turbine-generators better and those who do not really understand or use maths and vectors to explain turbine-generator operation and fundamentals to others so they can operate the turbine-generators better ARE more capable of explaining and teaching others to operate and maintain turbine-generators better.

Clarification about total generation exactly matching total load to keep frequency at nominal

Let's consider the bicycle analogy again, if you remember from previous discussion. To propel the rider (and any load: rider(s) and/or package(s)) at a constant speed, the torque being provided to the crankset pedals has to be sufficient to achieve and maintain the desired speed. If more torque than required (for a particular load) is applied to the pedals, then the speed will be higher than desired and if less torque than required is provided (for a particular load), then the speed will be lower than desired, and if the load varies, then the amount of torque must also vary in order to maintain the same speed.

If the load decreases (some packages fall off the bicycle or are dropped off by the rider(s)) but the torque remained the same, then the speed will increase. That's because the difference between the torque required to move the bicycle at a constant speed with the reduced load and the torque required to move the bicycle at a constant with the higher load has decreased, so, therefore, the speed of the bicycle would increase if the torque didn't change. It doesn't take as much torque to propel the lower load at the same speed as was required before the load was reduced, so if the torque didn't change, then the speed of the bicycle would increase.

Conversely, if the amount of torque being applied to the pedals is sufficient to keep the bicycle moving at the desired speed and suddenly some packages are added to the bicycle (or your friend jumps on the handlebars) but the amount of torque being applied to the *pedals did not change, then the bicycle speed would decrease. Because the difference between the torque required to keep the bicycle at the desired speed before the load was added and the torque required to keep the bicycle moving at the desired speed after the load was added increased, the speed of the bicycle would decrease if the torque being applied didn't change.*

If the load on the bicycle changes but the torque being applied to the bicycle pedals doesn't change, then the speed of the bicycle will change. In other words, the bicycle won't stop just because the amount of torque required changes because the load changed; the bicycle, and the load, will still keep moving.

However, if it is desired to keep the speed of the bicycle constant, if the load on the bicycle changes, then the torque being applied to the pedals must also change. If the torque being applied to the pedals isn't varied as the load on the bicycle is varied the bicycle will still move, along with the load, but it won't do so at a constant speed.

So, it is with AC power generation. The load being provided by the power generators will always match the load required by the system. It just needs to be matched at the system frequency in order for the frequency to remain at nominal (desired). If too much torque is being applied to the generators to produce a particular amount of power at 50 Hz, then the frequency will be higher than 50 Hz. The generation matches the load, but not at the desired frequency.

In other words, if the torque being applied to a load exceeds the torque required to power the load at 50 Hz, then the frequency will be higher than 50 Hz. If the torque being provided to the load is less than the torque required to power the load at 50 Hz, then the frequency will be lower than 50 Hz. The generation "matches" the load, but NOT at the desired frequency. The total generation will (most) always match the total load, but unless the generation matches the load at the nominal frequency, then the frequency will not be as desired. And that's what is meant by saying the total generation "must EXACTLY match" the total load. The total amount of generation must match the load at the nominal frequency, for the grid frequency to remain at nominal and stable. *The torque being provided to the* *bicycle pedals must be sufficient to move the load at the desired speed, or else the speed will be higher or lower than desired.*

If the torque being provided doesn't change but the load increases, then the speed (frequency) will decrease. If the torque being provided doesn't change but the load decreases, then the speed (frequency) will increase.

It works exactly the same for both the bicycle and the generator. If we consider all of the generators connected to a grid as "one" generator, and all of the loads as "one" load, the analogy of the bicycle and load moving at a constant speed regardless of load changes works exactly like maintaining the frequency constant of a grid as load changes. It's all about torque, be it a bicycle or a generator. Even if the torque doesn't change, the load still "moves", just not at the desired speed. Or, if the torque changes but the load doesn't change, the load still "moves", just not at the desired speed.

If only two generators are synchronized together and sharing the same load, then one generator should be operating in Isochronous speed control and the other should be operating in Droop speed control. In this manner, the Isochronous unit will adjust its power output automatically as load is increased or decreased to keep frequency very close to rated. The Droop unit will not do anything as load changes (automatically it won't do anything) as load changes and the Isochronous unit varies its load to maintain frequency. The amount of load carried by each unit is basically a function of how much load is being carried by the Droop unit.

Here's an example. *Suppose the total load is approximately 1.0 MW and the two generator-sets are each rated at 1.0 MW. When only one unit is operating, it should be operated in Isochronous speed control to automatically maintain rated frequency as load changes. The second, unit, when synchronized to the first unit should be in Droop speed control when its generator breaker closes. Let's say at the present time, the total load is approximately 0.8 MW, and the Isochronous unit was supplying all of the power and then the second unit was synchronized to the Isochronous unit. As the load on the second unit, which should be* *operating in Droop speed control, is increased, the load on the Isochronous unit will decrease (we are presuming the load is stable at this time and is not changing). So, as the operator increases the load on the Droop unit to 0.1 MW the load on the Isochronous unit will automatically decrease 0.1 MW to 0.7 MW, and as the operator increases the load on the droop unit to 0.2 MW, the load on the Isochronous unit will automatically decrease to 0.6 MW. The total load is still 0.8 MW, but the share of the total load being carried by each unit is determined by how the operator decides to split the load, by controlling the load on the Droop unit (yes, the Droop unit--because the Isochronous unit is automatically adjusting its power output as necessary to maintain rated frequency). If the load on the Isochronous unit gets too close zero MW, the operator will need to unload the Droop unit so that the Isochronous unit will trip on reverse power if the total load decreases such that the load on the Isochronous unit dropped below zero MW.*

Now, let's say the Isochronous unit needs to be shut down for maintenance (an oil- and air filter change, for example). The operator would increase the load on the Droop unit until the load on the Isochronous unit dropped to zero MW, then the operator would open the generator breaker of the Isochronous unit, and quickly switch the governor of the Droop unit to Isochronous so it would automatically adjust its load to maintain rated frequency as load changes.

In this scenario, when one unit is operating in Isochronous speed control and the other is operating in Droop speed control, the amount of load on each machine is a function of how much load the operator chooses to put on the Droop unit. If the operator puts 50% of the present total load on the Droop unit, then 50% of the total load will be on the Isochronous unit and the current outputs of both units will be the same. (Operators cannot change the load on the Isochronous unit by manually adjusting the governor of the Isochronous unit. Isochronous speed control automatically adjusts its governor and the load being carried by the unit to maintain rated speed as the total load on the system changes. If an operator tries to change the load on the Isochronous unit, what will happen (unless there is some kind of unusual Isochronous load control scheme in use) is that the frequency of the system will change from rated. The load on the Isochronous unit is a function of how much of the total load is being carried by the Droop unit, and how much the total load is changing.)

It is possible to have both turbines in the same condition operating in Droop control, however, every time the load changes (every time someone starts or stops a motor, or turns a light on or off, or turns a computer and its monitor on or off) then an operator is going to have to manually change the load of one of the two Droop units in order to maintain rated frequency. Droop speed control doesn't care if the frequency is higher or lower than rated and by that it is meant it doesn't try to automatically adjust its load to maintain rated frequency.

Droop speed control units presume there is a unit operating in Isochronous speed control somewhere on the grid that will adjust its load to maintain rated frequency. (On very large, "infinite" grids, this is not the case; grid operators adjust the loads of one or many Droop units to maintain grid frequency as load changes. Sometimes this is done via some automatic control system; sometimes it's done manually by the grid operators.)

So, if two generator sets are synchronized together supplying a common load and both are operating in Droop speed control mode, then the operator is the one who has to sense changes in load (when the frequency changes) and adjust the load on one or both units to maintain rated frequency which is not automatic control at all. When the operator gets the loads on the two units to the point that the frequency is at rated, if the load doesn't change, the frequency will remain at rated. But, if the load changes, the frequency will change and the operator will have to change load on one or both units to get the frequency back to rated.

If two generator sets were synchronized together supplying a common load and both were operating in Droop speed control, it would be possible for the operator to adjust the loads on the two units such that the current being produced by each machine was equal (which would mean the same share of load being carried by each machine: 50% of the present load). But, as soon as a motor is started or stopped, or lights are turned on or off, or computers and computer monitors are turned on or off, the frequency of both machines will change and the load on both machines will change until the operator makes an adjustment to one or both units to return the frequency to rated. The share of the load on each machine is determined by how the operator adjusts the load on each machine.

Now, some sites use a load-sharing controller/scheme to adjust the loads on multiple units all operating in Droop speed control mode. **Why?** Probably because someone felt it was simpler than relying on operators to balance loads so the Isochronous unit would not be over- or under-loaded. And, probably because someone (in the purchaser's organization or the plant design organization) had a bad experience with operating an island load with one generator-set operating in Isochronous speed control mode. Isochronous speed control mode can be difficult to tune (if the governors of the generator set prime movers are not similar). And, it takes some training and experience for operators to understand how to control load on an island without tripping the generator(s) or causing frequency fluctuations and most operators don't ever get that training, except by experience. And, that usually means bad experience (tripping; frequency fluctuations; etc.).

There are many descriptions of Droop speed control that use the word "share". Share can be interpreted to mean several different things. In this context, "share" means that units operating in Droop speed control will not try to hog all of the load or give up all of the load when the load changes. If two units are synchronized together and supplying a load, they will fight each other to try to maintain frequency and the fight is VERY ugly, with violent load swings and likely breakers tripping and black-outs. (There are some Isochronous Load Sharing control schemes available but they are really just de-tuned Isochronous units and they require additional communication and control between the units. They work, but usually not very well-and again, they still require human, manual supervision to work well.)

Sharing the load also means that when the load on the system (whether it be one Droop unit or hundreds of Droop units) exceeds the torque being produced by the generator prime movers and the frequency begins to decrease, that any Droop unit not operating at its rated power output will pick up part of the load in order to help keep the frequency from spiralling downward (to stabilize the frequency), and the amount of the load they will pick-up is proportional to their rating and to their Droop setpoint. In other words, they will "share" the load change when the frequency changes (decreases or increases) in proportion to their Droop setpoint and the amount of the frequency change. (This is kind of a difficult concept to explain and to understand without an example, and that can fill a large pamphlet/small book.)

Sharing load (current), again, is kind of a poor term to describe Droop speed control which is first and foremost a governor mode that permits many generators and their prime movers to stably produce power at a desired frequency to a load that is much larger than any single generator and its prime mover could provide by itself. Again, two or more units trying to operate in Isochronous speed control when synchronized together (without some kind of Isochronous Load-sharing scheme) will not control frequency very well, and their power outputs will not be very stable or constant (unless the load is very stable and constant). Units operating in Droop speed control will not have such large (violent) load swings; in fact, they are, by definition, producing power at a very stable rate.

It is a side-benefit of Droop speed control, that as frequency begins to drift from rated that it will change the power output in a manner that tends to help stabilize and support grid frequency from spiralling out of control (low or high) until such times as operator(s) somewhere make the appropriate changes to one or more Droop units to return the system frequency to rated. So, be very careful to understand exactly how the word "share" is being used when trying to explain Droop speed control.

Again, the most important aspect of Droop speed control is that it allows multiple units to participate in supplying power to a load that is much larger than any single unit could supply by itself and do so in a stable and controlled manner. This is opposed to what happens when two or more Isochronous speed control units are synchronized together (without some form of Isochronous Load-sharing which is not ever fully automatic and requires additional communication and control). AC power systems operate at desired frequencies, and since generator speed, and hence prime mover speed is proportional to frequency, the frequency can be sensed and controlled by monitoring speed.

At the present time, there are really only two modes of governor control for generator prime movers: Isochronous and Droop, both modes of speed control (and, again, frequency and speed are directly related). And only one of them is the mode that allows multiple generators to "share" in providing power to a much larger load than any single generator could provide by itself without load and/or frequency excursions: **Droop speed control**. The alternative, **Isochronous speed control**, doesn't allow multiple generators to be synchronized together and stably "share" in providing power to large load.

Again, in the power generation industry there are really only two modes of operation: Isochronous speed control and Droop speed control. Speed control is critical because AC power systems are supposed to operate at a particular frequency, and speed and frequency are directly related. And without some special control communications and schemes and de-tuning multiple generators-sets using Isochronous speed control is not well-suited for large or "infinite" systems. Droop speed control is the preferred method for allowing multiple generator-sets to be synchronized together and stably participate in supplying large loads.

There is this conception or tendency for people to say their islanded units are always operated in parallel in Droop mode with no unit in Isochronous mode, or when they say, their islanded units are always operated in parallel in Isochroous mode. The only way this could occur is if there is some kind of external or interconnected control scheme between the two governors, or if the load is very stable. Because, unless there is some kind of control scheme for either of the above scenarios which "supervises" the generator-sets and balances load while maintaining frequency, it's pretty hard to understand how simple governors could do so without frequency excursions and a lot of operator adjustments.

It's a rather common misconception, actually, that two similar or identical generator sets will equally share the load when paralleled together and supplying a small "island" load (independent of a larger grid and other generators and their prime movers). Again, the only "communication" every governor shares with every other governor is speed which is directly proportional to frequency on synchronous AC machines. Something has to tell them to change their energy flow-rates in order to "balance" (equally share) the total load. That could even be a human operator, presuming the load wasn't changing very rapidly.

The unit with the higher current is supplying more power to the total load. And if that is causing the prime mover to be running at full rated power output then it's conceivable that the unit could be tripping on excessive power, and that overloads the remaining on the other generator resulting in a blackout.

Some operator, or some automatic control system, needs to be adjusting the load to more equally balance the loads on the two so that an increase in load doesn't result in a blackout. On two machines running in Droop with no external control scheme, that can be a tricky thing to do while maintaining frequency.

And, that's the part that really piques many curiosities, when people say the frequency is stable. When the load is stable, it can be said that's probably true for two simple governors operating in parallel in Droop mode. But, when the load changes, the frequency isn't going to be at rated, and it may not be very stable, either. If you want good control of frequency with two generator-sets operating in parallel to power a load independent of a larger grid, then one of them should be in Isochronous mode but someone, or some control system, needs to be continually adjusting the load on the Droop machine to make sure the Isochronous machine from reaching maximum, and from reaching minimum, too.

All said and done, the good thing for some is that they do not need to know all this because they do not have to train any operator and also that there are many systems in the market to do all these controls. I call them the “press play” systems. You just press “start” and the rest is history. The most commonly used ones are the Woodward Systems, Rockwell/Allen Bradley Systems, Dawson Technology System, Emerson Systems, GE Systems, Cummins Systems, etc., etc., etc.
