Sizing Generators for Leading Power Factor

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Generator Operation with a Leading Power Factor

Generators operating with a leading power factor may experience unstable voltage regulation and increased heating. The following paragraphs define power factor and describe various generator characteristic that impact operation with a leading power factor load.

An understanding the load being powered by the generator allows the generator supplier to work with the customer to choose a generator and system design that will provide trouble free operation. Suggestions for specifying a generator for leading power factor operation are provided.

Excitation of Synchronous Machines

Rotating electrical machines in general have a component that produces a magnetic field and a component that interacts with the magnetic field. In synchronous generators a stator (armature) winding produces voltage in response to a magnetic field produced when a rotor winding is "excited" by field current. The field current is controlled by a voltage regulator. In the no-load condition, increasing the magnetic field results in an increase in voltage. The generator field current must increase and the voltage level must be maintained to provide power output.

Real vs. Reactive power

Electrical power is the product of volts and amperes. Over a complete cycle of AC waveform, the voltage and current wave forms may not line up, resulting in the peak voltage occurring when the current is less than its maximum, and vice-versa. In this case the average power calculated over the complete cycle is less than the "apparent" power, which is the product of RMS voltage and RMS current. This average power is the "real" or active power that produces useful work. Real power is measured in watts and is the power that shows up on your electric bill.

To help understand this we divide the current flowing in a circuit two parts: the real current, which is in-phase with the voltage and causes net average (real) power flow, and the reactive current, which is 90° out of phase with the voltage and transfers no average (real) power. The product of reactive current and voltage is sometimes called "reactive power" (though no actual power is being supplied) or VARs for "volt-amperes reactive". The relationship between active (real), reactive, and apparent power is shown in the power right triangle (Figure 1). Apparent power S = $\sqrt{(P^2 + Q^2)}$ where P is active power (watts) and Q is reactive power (VARs).

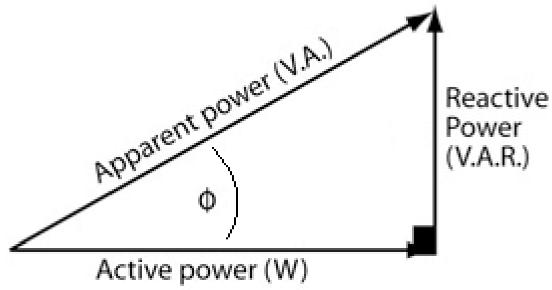

Figure 1: Relationship between real, reactive, and apparent power (Power Right Triangle).

Power Factor

Power factor (PF) is defined as the ratio between the *active* (real) power (the average value of *instantaneous* product of voltage and current, as measured by a wattmeter) and the apparent power. Power factor is the cosine of the angle Φ as shown in Figure 1. Historically, power factor less than unity was considered to be caused by a phase difference between voltage and current. This is called “displacement” power factor. Displacement power factor is the primary concern in this paper, although the definition of power factor includes other types of current that do not produce real power, particularly harmonic current. The “harmonic” power factor has the effect of extra heating in the damper cage of the machine but does not affect the excitation or stability of the machine. Harmonic power factor will not be addressed.

In the following graphs [**Error! Reference source not found.**] red represents voltage and blue represents current. In the first graph labeled “PF = 1.0”, the voltage and current are aligned (in phase) and the average power is equal to the RMS voltage times the RMS current. The graph directly below shows the power is flowing only in the positive direction. Moving to the right each graph shows a decreasing power factor. As the power factor decreases the average power decreases, and during part of the cycle the power flows in reverse, until at zero power factor, as much power flows forward as backward, and no average power is delivered. In each case

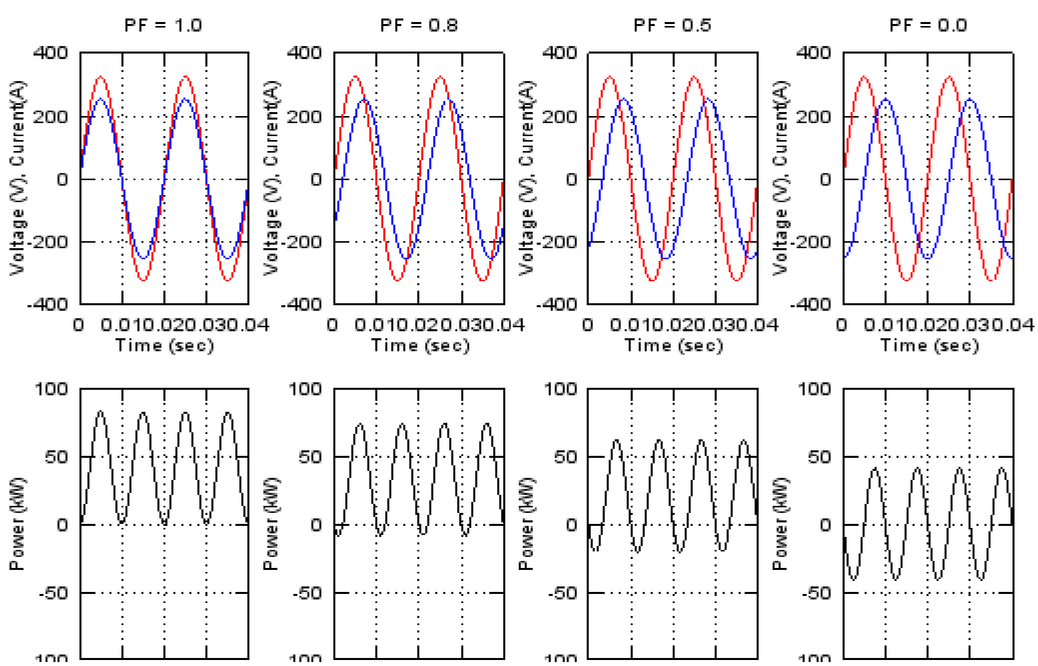

Figure 2: Power factor illustrated

voltage, current, and apparent power are constant. These graphs are for lagging power factor.

Lagging vs. Leading Power Factor

Inductive loads such as electrical motors, which make up a large part of the load on the grid, draw *lagging* power. That is, the power factor is less than 1.0 (typically around 0.8), and the current waveform *lags* the voltage – the peak of the current occurs after the peak of voltage. The opposite is true of capacitive loads – in this case the power factor is less than 1.0 but the peak of the current occurs before the peak of the voltage, and we call the power factor *leading*. In either case the power factor is positive, but the direction of flow of reactive current is opposite. (The term “negative power factor” does not apply as it would mean a reversal of *real* power flow.)

Effect of reactive load on generator excitation

The current in a generator (rotor or stator) creates magnetic flux, and the voltage in the stator coils is related to the *rate of change* of flux, so maximum voltage in a coil occurs when the flux is changing most rapidly, which is when the stator coil is aligned with the space between two adjacent poles. For operation at 1.0 PF, this occurs at approximately the instant the current is maximum. So the flux created by in-phase (1.0 PF) current is aligned between the poles, where there is the least sensitivity to the flux created. For this reason, in-phase current or real power does not have a great effect on the field current required to produce rated voltage. On the other hand, reactive power produces flux that is aligned with the poles, and depending on the polarity, has either a magnetizing or demagnetizing effect. Leading power factor current produces a magnetizing effect, which means that less field current is required to produce rated voltage. Lagging power factor produces a demagnetizing effect, requiring additional field current to maintain the magnetic field level and thus rated voltage. (This is why lagging power factor load results in increased rotor heating.) The field excitation determines the peak torque the generator can accept, and if it is reduced too much, the engine may try to supply more torque than the generator can accept, leading to instability. [1]

Stability in Island Operation

In island operation, a generator is supplying power, by itself or in a small group of identical generators, to a load that is not connected to the grid. In this configuration, the frequency is determined by the speed setting of the engine governor, the voltage by the voltage regulator controlling the generator excitation, and the load power and power factor are completely determined by the load.

In island operation, the power factor of the connected load may be leading, and, if so, it will tend to magnetize the rotor and so reduce the required excitation current of the generator. If the excitation current is reduced to zero, the voltage regulator will have no more control over the voltage, which will rise to a value determined by the saturation of the generator. Even if the excitation is reduced close to zero, there may be insufficient torque capability for the applied load power. In this case, the generator will operate as a very poor induction generator and the voltage will drop until the regulator kicks in again. The voltage will surge and oscillate, leading to overheating and rotor damage if it is not shut down.

Stability in Grid-Connected Operation

In grid-connected operation, the generator is connected to a utility or to a large group of generators approximating a utility. The frequency is set by the grid. The load real power is completely determined by the engine governor, and the reactive power (i.e. power factor) is determined by the excitation applied to the generator field.

Since the power factor is controlled by the generator in this mode of operation, the main concern is to make sure that the excitation remains high enough that the generator can accept the torque supplied by the engine. Many digital regulators have a minimum excitation setting that can perform this function.

If the excitation does fall too low, the engine will cause the generator to "slip poles" and operate at a speed higher than synchronous speed. This will cause harmful currents in the generator rotor and large pulsating torque on the shaft, which can damage the generator, coupling, or engine crankshaft.

Because the torque is the limiting factor for both modes, the limits of leading power factor operation are effectively the same for either island or grid-connected operation.

Reactive Capability Curves

The interaction between field current and output voltage and current is complex, especially when saliency and saturation of the magnetic material are considered, so usually simplified but conservative rules are used to determine generator sizing. For instance, a cylindrical rotor may be assumed. The tool most commonly used to determine excitation limits is the reactive capability curve, which is derived from these simplified rules.

The generator parameters that control this are saturated short-circuit ratio (SCR or, in Europe, Kcc) and saturated synchronous impedance Xds. These both represent the same quantity and are reciprocals of each other. High SCR and low Xds make the machine more stable. To a first approximation, if Xds is less than 1, or SCR greater than 1, the machine will be stable with any leading power factor down to zero. To achieve this usually requires a very oversize machine. For larger values of leading power factor, the reactive capability curve should be consulted. This curve gives the power factor or leading VAR limit for all values of real load. A sample capability curve is shown in Figure 2. The same curve is often drawn with the axes swapped as in Figure 3. These graphs are most useful when the axes are plotted at the same scale, since then all the curves are arcs of circles.

With lagging power factor, the limits on generator output are caused by heating. At leading power factor, on the other hand, the limits are concerned with the stability of the machine, meaning its ability to supply power at a steady rate at constant speed and voltage.

Examining the two graphs illustrated, we see that the shapes of the leading portions of the curve are quite different. Each manufacturer decides what criteria to use to draw this curve, and there is no standard procedure. We will show some of the criteria here, based on Figure 2.

The right-hand part of the leading power factor curve is based on the 2600 kVA limit due to stator heating.

The intersection of the leading power factor curve with the negative Y axis is located at about -1430 kVAR, which is just the kVA rating (2600 kVA) times the short-circuit ratio SCR (0.55). This represents the point where the excitation becomes zero with no real load. We will call this point P. It is not a practical operating point, but with a modern digital regulator it is possible to come close. The distance from P to the operating point, divided by the absolute value of Y at point P, is approximately the per-unit excitation current (where 1 PU represents the no-load unsaturated excitation). The diagram of Figure 4 shows an excitation limit of about 25% of the no-load value.

With any real load above zero, the torque angle δ is the limiting factor. A generator with cylindrical rotor reaches the limit of its stable torque when δ = 90°. Again, this is not a practical operating condition, since any disturbance will cause the generator to lose sync. The torque angle δ is represented by the angle between the y axis and the line drawn from point P and the operating point. Figure 4 shows a curve with a δ limit of 75°, considered to be a practical limit.

The graph of Figure 2 has a curved line for the stability limit. This is meant to compensate for external impedance between the load and grid for grid-parallel operation, and comes from a 1954 AIEE paper by Rubenstein and Temoshok [2].

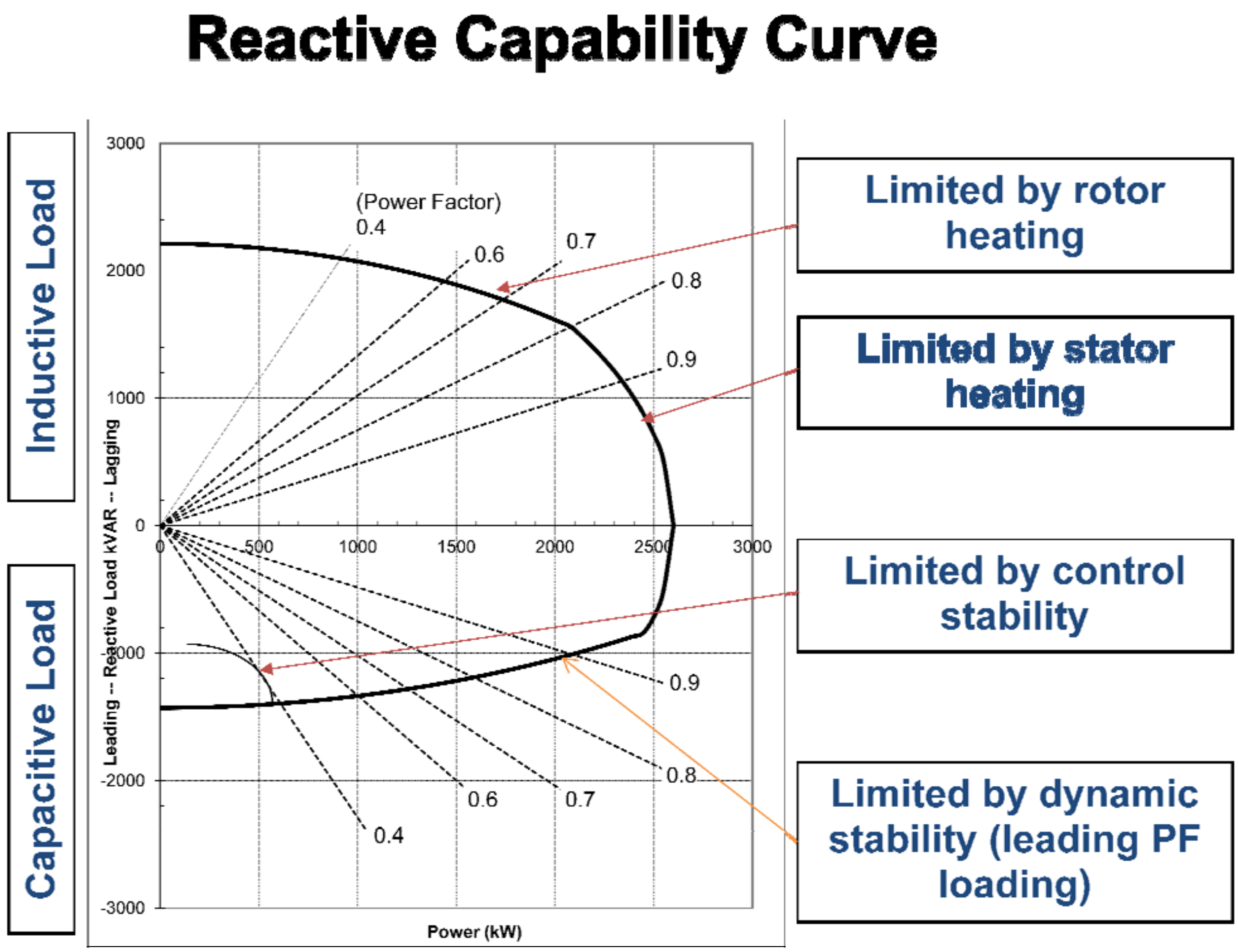

Figure 2: Typical Reactive Capability Curve.

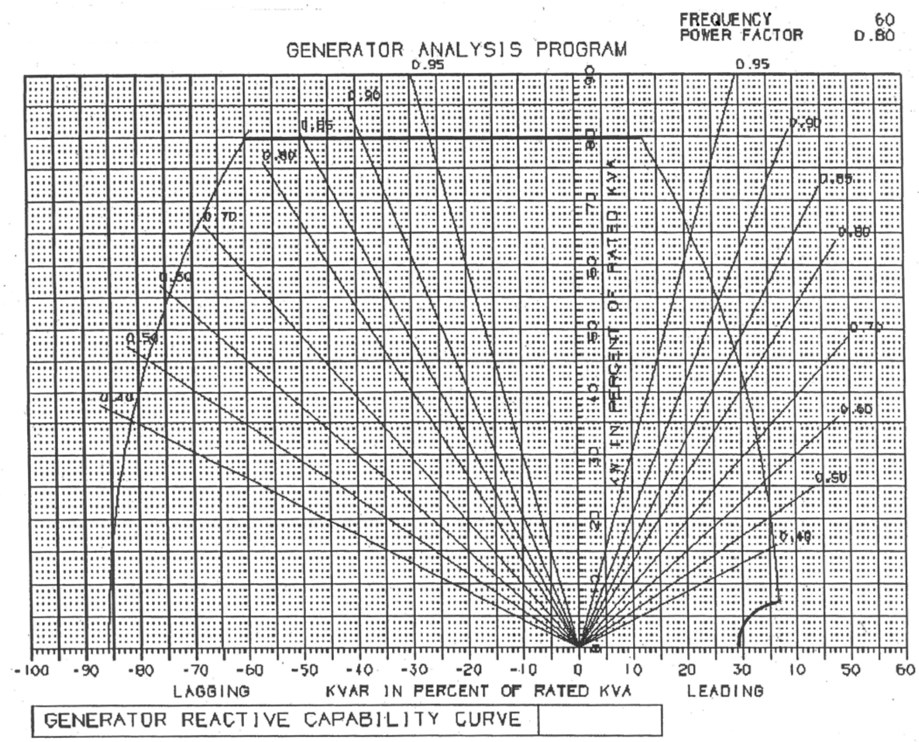

Figure 3: Alternative Reactive Capability Curve Format.

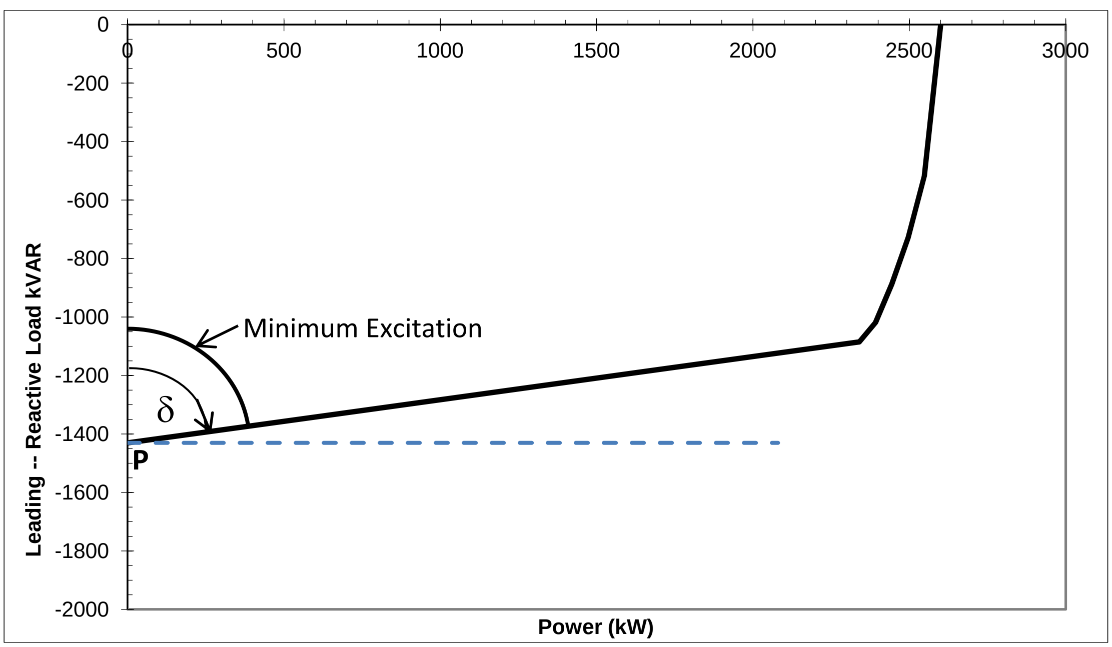

Figure 4: Illustration of Minimum Excitation and Angle δ.

Some generators have additional limitations on leading power factor operation due to end-turn heating or other factors [3]. Other authors propose different safety factors, including fixed torque margin or fixed excitation margin [3] [5] [6] [6], so the limits illustrated do not cover all cases.

Effect of Transient Performance on Stability

A synchronous generator has a rotor field winding to provide magnetic flux during steady-state operation, and typically a damper (amortisseur) winding, which consists of a number of conducting bars embedded in the rotor pole face. The damper winding bars may only be interconnected within each pole, or they may be also connected between poles [Figure 5]. Completely connecting the bars and poles together provides superior transient performance.

The rotor field winding and damper cage act to resist sudden changes in flux in the rotor. When there is a sudden load change, the currents conducted in these circuits act in a manner to prevent a corresponding sudden change in load angle or voltage. This helps to stabilize the system. The cage currents decay very quickly (subtransient time constant) whereas the rotor currents persist longer (transient time constant). The effect only persists until the transient period has passed (on the order of a second or two), so it can prevent a brief event (e.g. a voltage dip or short-circuit) from driving the system into instability, but it will have no effect on steady-state stability. Nevertheless, a robust damper cage is an advantage in keeping the system stable.

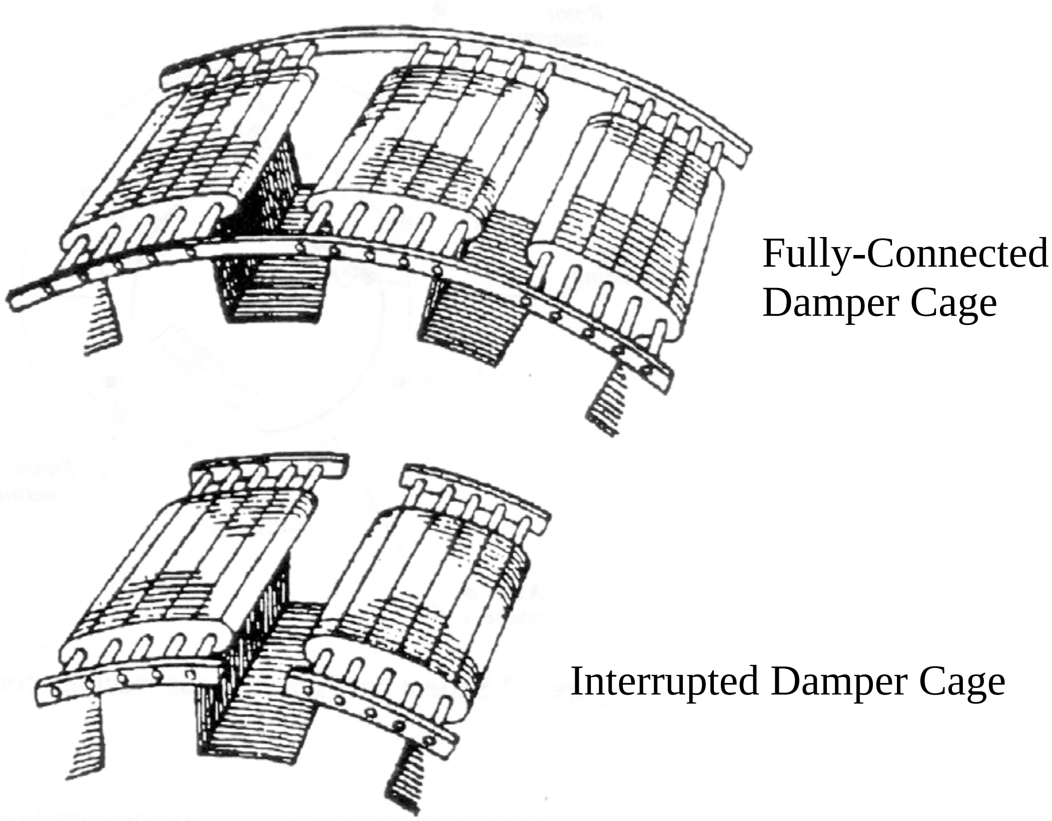

Figure 5: Damper Windings.

Effect of the Regulator on Stability

For the island mode case, the voltage regulator will generally be set for a fixed generator voltage output, and will not affect steady-state stability. However, sudden application of a leading power factor load may cause the regulator to shut off and produce a temporary undershoot of excitation, which could cause transient instability. It will generally be advisable to set an underexcitation limit to prevent this from happening.

In the case of a grid-connected generator, the voltage regulator in droop mode will cause much the same effect as for island mode. On the other hand, if the regulator is set for power factor control, addition of leading power factor load will cause an increase in excitation in order to maintain constant power factor, so in this case the regulator will have a stabilizing effect. [8]

How to Specify Generators for Leading Power Factor

Ideally, the generator OEM and the user (or site engineer) should work together to select a generator design that will meet the requirements of the site. In addition to the normal rating data, the manufacturer will benefit from the following information:

- Whether the site will run in island or grid-connected mode, or both.
- In island mode, what sort of capacitive load will be connected, and how it will be coordinated with other loading. For example, large UPS sets will generally have a fixed capacitive reactance on the input due to the input filters, but these UPS sets will have variable real power load depending on how their output is loaded. Other loads on the circuit (e.g. chillers) may provide lagging load to counterbalance the leading load, but if they are started *after* the leading load, the system must be stable without them.
- In grid-connected mode, the user has control over the VAR loading, but if leading power factor operation is required (possibly for local voltage control at light load), the generator manufacturer needs to know the possible range of real and reactive loading.

To meet the site requirements, the manufacturer may:

- Propose an oversize generator in order to keep the synchronous reactance low.
- Use a special design that is more saturated than normal for the same reason.
- Include special testing to insure that the generator will meet requirements.
- Propose additional protective relaying and controls to detect or prevent unstable conditions.

At a minimum, a reactive capability curve as well as saturation curves and V-curves should be requested for the proposed generator before ordering, and carefully examined by the site engineer to make certain the generator will always operate within the safe region. Because the leading power factor capability depends strongly on factors that vary by manufacturer, frame size, pole count, and model, it is not possible to use a “rule of thumb” for sizing the generator. The voltage regulator specified should have internal provision for over- and under-excitation limits. If the generator is connected to the grid, the voltage regulator should also have power factor control. Protective relaying should include over- and under-voltage as well as excitation failure relays.

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