CHAPTER 4

Interconnecting with the Grid

> Once you interconnect a generator and operate it in parallel with the utility network, it becomes part of a vast sophisticated machine. So it needs sophisticated protection; protection against what the network can do to the generator, and protection against what the generator can do to the network. And right now, no one, including your utility, knows how much protection is prudent and how much is overkill, in your specific interconnection situation.
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> *Power* magazine, June 1982

The Public Utility Regulatory Policies Act (PURPA) gives the qualifying facility (QF) the right to interconnect with the electric grid system. It gives the utility the right and the responsibility to impose interconnection standards necessary to protect its workers, the equipment of its other customers and the overall quality of electricity in the system.[1]

Utilities are used to dealing with other utilities and to linking together a few dozen billion-dollar power plants. Under PURPA, utilities will have to interconnect with hundreds of thousands, possibly millions of power plants, some costing no more than $2,000 to $5,000. Standards relevant to central power plants that serve thousands of customers may not be relevant to thousands of dispersed power plants.

Meanwhile, as more and more dispersed plants come on-line, a demand for low-cost, high-quality interconnection equipment is created. Already the electronics industry is introducing products to meet this demand. Standards are thus being developed even as the technologies are rapidly evolving.

No one knows just what type and level of protection is required; yet the costs of interconnection can vary by an order of magnitude (ten to one) depending on the standards imposed. For small power producers, especially those with a capacity less than 50 kilowatts (kw), the level of the standard can spell the difference between a profitable and unprofitable facility.

Even in an ideal situation with mutual respect and understanding prevailing, the utility and the QF approach the interconnection issue differently. The utility engineer plans for the worst case—the worst combination of theoretical circumstances that could harm the system. In doing this he errs on the side of caution. The QF, on the other hand, wants to maximize its revenue and errs on the side of aggressiveness.

Often these different approaches breed mistrust and suspicion. Lacking the electrical expertise and caution of utility engineers, the QF may believe the very sophisticated standards required by the utilities are nothing but a ploy to discourage independent power produc-

Photo 4–1: The basic components for interconnecting a wind system to a utility are the wind machine control panel (the box at the left) and the synchronous inverter (the second box from the left). The other boxes are for data collection for this particular installation. *Photograph courtesy of Joe Carter.*

tion—and sometimes they are. On the other hand, worried about the possibility of legions of small generators owned by amateurs primarily motivated by visions of instant wealth, utility engineers may view the entire category of small power producers as a nuisance and a danger.

Compounding this problem is the fact that no interconnection standards are yet in effect. Some national organizations, like the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association, have formulated general guidelines. The International Electronic and Electrical Engineers are developing draft

Photo 4–2: Shown here is a dual metering system. Reverse flow equals total wind system output to the grid (surplus overload), and the billing meter equals the total house load minus any wind system input to the house load. *Photograph courtesy of Joe Carter.*

standards. Several utilities have also developed general guidelines. But in most situations, interconnection policies are developed on a case-by-case basis. The customer submits detailed plans to the utility, and the utility's engineers approve, revise or disapprove these plans.

Moreover, public service commissions have tended to stay out of the interconnection regulatory area. They leave this up to the individual utilities. Some commissions, such as Michigan's, have established investigating commissions with QFs on the advisory board to assist in the setting of interconnection standards. Most commissions prefer to wait for sufficient data about possible safety and protection problems before making final decisions.

PURPA makes little mention of interconnection except to note that the QF must pay all reasonable costs. These include costs of connection, switching, metering, telemetering, dispatching, transmission, distribution, safety provisions and administrative costs incurred by the electric utility that are directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a QF. However, PURPA regulations limit the amount the QF must pay to that portion of the interconnection costs in excess of the corresponding costs the electric utility would have incurred if it had not engaged in interconnected operations, but instead, had generated an equivalent amount of energy itself.

Protecting the Worker, the Customer and the Network

When a large number of small, dispersed generators are added to the grid system, three possible problems arise. One concerns the safety of people working on the line. The second relates to the quality of electricity in the system and the impact of the dispersed power plant on equipment owned by the QF and other customers. The third concerns the additional costs that QFs might impose on the grid system, for example, if the QF's equipment draws a large amount of reactive power (explained later in this chapter) from the grid.

The problem of worker safety is relatively straightforward. Utility personnel working on the transmission and distribution (T&D) system face the danger of receiving a shock or even of being electrocuted if a line or a piece of equipment undergoing service suddenly becomes energized by a cogenerator or small power producer. To resolve this problem, all utilities require the QF to install disconnect switches that can be locked in an open position while the workers are servicing that part of the line. The major controversy about such switches is where they are to be located and whether in remote locations they can be controlled automatically by utility personnel. Linesmen may spend little time manually disconnecting one or two generators, but if the penetration of small power plants reaches a large level, manual disconnection will take quite a number of hours. On the other hand, if the utility can disconnect from its central headquarters, the QF may relinquish control over the generator.

The problem of equipment protection and maintaining the overall quality of electricity in the system is a more difficult one. Appliances and other equipment are designed to operate with alternating current of a certain quality. Equipment damage is likely to occur if the voltage and frequency deviate too much from certain values. In addition, all types of electrical equipment will be damaged if supplied with excessive current.

Utilities try to protect against these distortions by installing relays and circuit breakers, and they may require over/under current relays, over/under voltage relays or over/under frequency relays. These disconnect the QF automatically when the current or voltage of frequency vary by more than a predetermined amount. Relays vary significantly in price depending on their reliability and the range within which they operate.

The small wind machine or cogeneration owners may find it hard to believe that anything their generators do can affect the utility system. In fact, their generators will not affect the entire system, but rather those customers with whom they share a transformer. Five to 20 customers may share the same transformer. If the generator is large enough, it could even affect larger numbers of customers that share the primary feeder.

For most people electricity is a rather abstract commodity. It is hard to imagine an electron, let alone the wave form of voltage or current. Yet these insubstantial characteristics of electricity play an important role in operating the machines around us. For example, variations in the frequency from the basic 60 cycles per second (60 hertz) can change the way modern appliances operate. Timers in the kitchen range, microwave oven or clock use this power frequency. If the frequency were allowed to err by only 1 hertz (Hz), that is, 1 cycle per second, the electric clock would gain or lose 1 minute per hour or 24 minutes per day. The TV may be afflicted with fluttering or creeping ghosts. The stereo may play sharp or flat. Indeed, many appliances simply will not operate on abnormal frequencies. They contain circuits, like power factor correction or filtering circuits, that rapidly unbalance as a function of power frequency. Unless the appliance carries the legend 115 v/50–65 Hz or something similar, it may not function with "off frequency" power.

Significant voltage fluctuations can also damage equipment. Utilities normally provide their customers with power within 5 percent of the nominal voltage level. The most common type of electric service is 120/240 volts (v), single phase. The acceptable limits for this particular type of service are 114 to 126/228 to 252 v. Very few customers will experience the full 12-v to 24-v variation. Typically, customers near the distribution substation will receive the top end of the range, while those at the end of the service line will receive voltages around the middle or low end. In order to maintain proper voltage levels, utilities install voltage regulators throughout the T&D system.

Voltage regulation could become a problem if dispersed power generators with highly fluctuating outputs come on-line. When considered per unit of dispersed generator capacity, technologies such as wind turbines and photovoltaic systems present a greater voltage regulation problem than conventional level-running cogeneration systems. One study assessed the voltage response in a distribution feeder when many small wind turbines were introduced.[2] This study is important because the highly fluctuating nature of outputs from wind turbines may represent the worst-case scenario for such interconnection problems as voltage regulation. The study concluded that at wind turbine (market) penetration levels below 20 percent only minimal changes in the voltage profile throughout the feeder were observed. Even with 50 percent penetration, the voltage levels in the feeder generally remained within the plus or minus 5 percent utility norm.

Voltage flicker is another common problem. For customers in rural areas, voltage flicker is often the norm. The surge of current to an induction machine during start-up can cause a fluctuation in the voltage in the rest of the utility's distribution system. In 120-v residential systems, a sudden voltage change of 6 v to 8 v or more will result in objectionable light flicker. For example, light flicker is common in homes when the refrigerator turns on and off. Induction generators in particular can cause voltage flicker, since they draw a large inrush current for a few cycles while starting. Voltage flicker problems are most likely to arise in a distribution secondary if a small induction generator shares a distribution transformer with other customers.

Most utilities have general guidelines pertaining to voltage flicker, but they have not tended to adopt requirements related to voltage flicker when establishing interconnection policies under PURPA.

Faults and Reclosers

Fluctuations in current levels often result from faults in the electrical system. A fault is any failure that interferes with the normal flow of current. There are two types of faults: shorts and opens. *Shorts*, or short circuits, occur when there is an unintentional connection between parts of the circuit, which results in high current flow in the supply conductor. The undesired connection of one or more lines to ground results in unbalance, and is called a *ground fault. Opens* occur when the circuit is broken; the result is that no current flows. Faults in the electrical transmission and distribution system are caused by occurrences such as equipment malfunction, adverse weather conditions and tree limbs contacting lines.

To prevent equipment damage, utilities use protective devices to isolate faulted sections. These devices are located throughout the T&D system. They contain the fault to as small a section as possible. Since many faults are of a transient nature, fault protection devices include devices called *reclosers.* These open and close the faulted line a set number of times before permanently disconnecting it if the fault persists. Automatic reclosers can close and open as many as five times until the fault clears. After that the recloser locks out, isolating the line for manual intervention.

Most often manual intervention isn't necessary, and the customer experiences only a modest voltage flicker. But even the short interval the automatic recloser cuts in and out can have a damaging effect on the dispersed generator. One possible problem is that the recloser could connect two live generating systems at a moment that the voltages and frequencies of the dispersed generator and the utility's generators are not exactly in phase. If they're not, the utility system, with the inertia of several large generators behind it, can jerk the generator into phase in a fraction of a second. "If all you get is a sheared generator shaft, consider yourself lucky," *Power* magazine advises.[3]

Fortunately, induction generators and line-commutated inverters (see below for description) will normally shut down much faster than the reclose interval when utility power is lost. Furthermore, reclosers are in some cases equipped with a voltage relay that prevents them from reclosing on an energized line. The utility is just as interested as the QF that it not remain connected when the reclosing circuit breaker is attempting to clear the fault. The QF could continue to feed the fault, keeping the arc alive.

The dispersed generator must be in phase with the utility generators. If they are out of phase, the power flow from the combined or interconnected systems can cause damage to electrical machinery. Dispersed generators must be equipped with a device that properly synchronizes the electrical wave patterns that are produced with alternating current.

Synchronization is useful even if the small power producer is not interconnected with the grid but is operating two machines in synchronization in a load-sharing manner. For example, a home or commercial establishment might have a hydro plant and a wind turbine. When the wind is blowing strongly, the hydro could be shut down entirely, and vice versa. This would conserve water in the impoundment, an important consideration in most hydro installations.

Protective Relays

To protect other customers and maintain system quality, relays are needed. The purpose of protective relays is to detect unsafe or out-of-limit conditions in a power system and to trip appropriate circuit breakers. The prime intent of the protective relay circuit is to isolate the faulty section of the circuit so that the remainder of the network can continue to deliver power without interruption.

Relays are a relatively esoteric topic even for professional engineers. *Power* magazine, a journal for professional engineers, admits that even "electrical engineers usually have little more than a casual understanding of protective relaying, and even most power plant engineers are only dimly aware of its existence. It's a foreign subject, talked and written about with foreign symbols that the average power user doesn't (usually) need to understand. . . . But for the utility engineer, protective relaying is a way of life. The utility's relay engineers spend all day figuring out possible combinations of faults that might occur in the network, and designing relay circuits to protect against them. In the process, they have developed a highly systematic approach to relaying and an efficient shorthand for designing circuits and specifying relays. . . . Most small customer/generators know nothing about relay engineering, and the utility engineer is faced with the job of teaching them. It's a lesson that the customer doesn't want to learn and the relay engineer doesn't want to teach."[4]

Utilities usually demand the highest quality relays, appropriately called *utility-grade relays*. These devices are very reliable and should last for 40 years. They have a relay trip setting that can be adjusted accurately to known values. Each is equipped with indicators showing that it has tripped and why it has tripped (over or under voltage, for example). The insides of utility-grade relays can be removed for servicing.

Another common type of relay is an *industrial-grade relay*, often found inside factories. This kind of relay is much less reliable than a utility-grade relay and lasts for only four to five years. They are also about a third less expensive than utility-grade relays. Some utilities, such as Pacific Gas and Electric Company (PG&E), permit the use of industrial-grade relays with small and medium-size dispersed generators (less than 1,000 kw). The company does not feel that the higher reliability and accuracy of utility-grade relays are necessary for these applications. On the other hand, one hydro developer in Pennsylvania who initially fought against Pennsylvania Power and Light's requirement that utility-grade relays be purchased later changed his mind and believed that the longer life and higher reliability actually made them a better purchase, even for his relatively small facility.

After the relays are installed, the next issue is what their trip settings should be. Standard relay settings have not been established. Typical settings are plus or minus two cycles per second on frequency and plus or minus 10 to 20 percent on voltage. Relay settings are a source of misunderstanding between the utility and the dispersed generator. The utility's standard approach is to drop a generator off-line the moment trouble is detected. The QF, on the other hand, wants uninterrupted power for his or her household or business, or wants uninterrupted revenue from exporting the electricity.

A typical problem for industrial cogenerators occurs when the voltage surges on the utility's line as a result of switching of banks of power-factor correction capacitors (see the discussion of power factor below). Often these surges are sufficient to trip the under-voltage relays and drop out the customer's generator. The utility doesn't give any notice about these surges. According to *Power* magazine, "Right now, customers that are interconnected to relatively small utility feeders, rather than to a utility substation, are having a whole lot of trouble merely staying on-line."[5]

Harmonic Distortion

Another problem concerning the quality of electricity relates to *harmonics*. These are waveforms whose frequencies are multiples of the fundamental (60 Hz) waveform. The combination of harmonics in conjunction with the fundamental waveform produces a nonsinusoidal, periodic wave. Harmonics in electric utility transmission lines are a result of rapidly changing loads within the system.

There are voltage harmonics and current harmonics. *Voltage harmonics* can adversely affect customer loads, while *current harmonics* can adversely affect capacitor banks and telecommunications systems. If the current harmonics are of a sufficient magnitude, significant voltage distortion due to voltage drop can occur, especially in the absence of capacitors on the utility's system. If the current results in interference with communication lines (e.g., telephone companies sharing the same distribution system), then special filters may be required.

Harmonics are not a problem with synchronous and induction generators but they are with some inverters, particularly those of the line-commutated variety (discussed later in this chapter). The exact impact of harmonics is not fully understood. General harmonics standards have not yet been developed in the United States. However, total harmonic distortion (THD) values of 5 or 10 percent on current harmonics and 2 percent on voltage harmonics have been mentioned as preliminary maximum limits.

Excessive THD can be eliminated by adding filters to the power conditioning system. However, adding filters can be relatively complicated and expensive. It would probably cost less to buy a high-quality inverter with minimal THD than to purchase an inferior inverter and add harmonic filters to it.

Dedicated Transformers

In the distribution secondary, a number of customers may share a transformer. When this situation exists, it may be possible for an individual generator or a number of generators to carry the load in the distribution secondary and continue to operate even if this small section is cut off from the central power source via a switch at the transformer. This would not occur if the dispersed generator had a *dedicated transformer* connected in parallel with other distribution secondary sections along a distribution lateral. If the entire lateral is cut off from the utility, then the load applied to the generator is likely to be larger than its capacity. In this case the generator will be overloaded and its voltage will collapse (decrease), shutting off the generator. Many utilities require the installation of a dedicated transformer to prevent a dispersed generator from being isolated along with a relatively small load.

However, a dedicated transformer is expensive. Residential customers are normally served by a shared transformer paid for by the utility. If a dedicated transformer is installed with a residential cogeneration or small power production system, the customer is generally expected to pay for the transformer.

The characteristics of small, three-phase distribution transformers also complicate the dedicated transformer option. At present, three-phase distribution transformers under about 100 kw generally have a wiring arrangement which is ungrounded on the primary side. This makes it difficult to detect unbalanced conditions. Therefore, it may be necessary to use three single-phase transformers, instead of one three-phase transformer.

The dedicated transformer approach to preventing isolated operation with small induction generators and line-commutated inverters is possible only as long as there is not a high number of dispersed generators. If the dispersed generator capacity becomes large enough to carry the load along the distribution lateral, then protective relaying must be used to prevent isolated operation due to self-excitation.

Ground Faults

Ground-fault protection is much more complicated than protection against short circuits. Fortunately, separate ground-fault protection may not be necessary for small dispersed generators. Southern California Edison and San Diego Gas and Electric are among those utilities that do not require fault protection for units less than 100 kw. PG&E specifies ground fault protection only for those QFs of 40 kw and over.

These utilities believe that the existing ground-fault protection equipment at distribution substations is adequate for detecting ground faults from dispersed generators. This equipment will isolate the distribution feeder primary containing the faulted generator. Once the generator is isolated from the central power source, voltage and frequency relays on the generator will trip, and parallel operation under fault conditions is discontinued.

Ground-fault protection for three-phase generators is affected by the way the different phases are connected at the distribution transformer. With the wye or star connection, the center point is often connected to *ground*. (The ground is a reference point that remains at zero voltage.) A line connected to ground frequently extends to customers as well. If this is the case, two voltage levels result: the line voltage between any two nongrounded lines and the phase voltage between the ground line and a nongrounded line. This is how the common voltage combinations of 120/208 v or 240/415 v are obtained. With the delta connection, a fourth neutral line is not present, and thus there is only one voltage level.

For medium-size three-phase generators, the primary side of the distribution transformers is often delta connected. This makes ground-fault detection on the primary side difficult because there is no neutral line. (If a neutral line is available, ground faults are easily detected by monitoring the current level on the neutral line.) Without a neutral line, it is possible to detect faults on the primary side of the distribution transformer using either (1) a three-phase potential transformer with a broken delta-connected secondary and an overvoltage relay, or (2) a single-phase potential transformer with an under/over voltage relay. The latter method is likely to cost less but is not as reliable as the former.

As an alternative to measuring ground faults on the primary side of the distribution transformer, ground faults can be detected through measuring unbalance on the generator's side of the transformer. Unbalance detection involves using either a current or voltage balance relay. While the methods for ground-fault protection on the customer's side of the distribution transformer are less expensive than the methods employed on the primary side, the reliability of the detection on the customer's side is less certain.

Power Factor

Unlike the concerns above, low power factors do not harm equipment, but they can impose additional costs on the utility. When providing the consumer with electrical service, the utility is actually furnishing two types of alternating current (AC). The major type is known as the active or *real kilowatt component,* upon which the cost of service is based. This is the component that is usable and does the work. The other kind of energy is the reactive or *magnetizing kilovar component,* which is needed to magnetize any electrical equipment that requires a magnetic flux from the power system to permit operation. This type of energy does not cause the disk of the watt-hour meter to rotate, although it is drawn from the power lines and furnished to the system. Every piece of electrical equipment or appliance whose operation is dependent upon a magnetic circuit requires a supply of existing or magnetizing current. For example, a transformer or a common induction motor receives magnetizing current through the AC distribution systems.

The *power factor* can be defined as the ratio of the working current to the total of the working current plus the magnetizing current. A low power factor means that an excessive amount of magnetizing current is being drawn from the incoming power lines. During the past years when electrical power was cheap and in plentiful supply, the taking of magnetizing current from the AC lines was not considered objectionable if the effect of the extra current on voltage regulation was not too serious.

However, as the total electrical load approaches the capacity of the utility's generators, a low power factor will cause these generators to become overloaded, and additional expensive generation equipment may be needed. Moreover, a low power factor results in the overheating of conductors and transformers and low voltage throughout the distribution system. This results in the inefficient operation of electrical equipment and overheating of induction motors.

To clarify the admittedly murky power factor principle, consider the following example. The power flowing in a direct current (DC) circuit is the product of volts times amperes (amps) and is expressed in watts. A *wattmeter* similar to that measuring the flow of electricity into your house will accurately register this value. In an AC circuit, if the load is pure resistance, then again volts times amps equals watts. However, if the AC circuit contains an induction motor, the wattmeter reading is less than the product of volts and amps. A fraction of the total amperage is consumed in magnetizing the motor, and the balance is used to perform work. Consider the following example of a 240-v motor drawing 10 amps as measured by an *ammeter*. The product of volts times amps would equal 2,400 watts (w). However, when the power is measured with a wattmeter, we find it registers only 1,920 w. It is apparent the current is doing other than providing useful work. The current necessary to provide the useful work is 1,920 ÷ 240 = 8 amps. Since the total current is 10 amps, the power factor becomes 8 ÷ 10 = 0. 80 or as is usually stated, watts ÷ volts x amps = 1,920 ÷ 2,400 = 0.80 or 80 percent.

The crux of the matter is that the magnetizing current constitutes an additional load on the utility without producing revenue. Many utilities now compensate for this loss by including a charge for a low power factor in their rate schedule. The power factor is also a function of the phase angle between the voltage and current signals on a particular line. If voltage and current are in phase, then the power factor equals one. If voltage and current are out of phase, the power factor is given by the cosine of the phase angle. The power factor is said to be lagging if the voltage is slightly behind the current and is said to be leading if the voltage is slightly ahead of the current.

The various types of power are measured in different units. *Real power* is given in kilowatts, *apparent power* in kilovolt-amperes (kva) and *reactive power* in terms of the kilovolt-ampere reactive (kvar).

The size of synchronous generators (a fuller discussion of these types of generators follows below) may be specified in kilowatts or kilovolt-amps. The kilovolt-amp rating is the rated voltage multiplied by the rated maximum current, and the kilowatt output is given by the kilovolt-amp multiplied by the power factor. If a manufacturer rates a machine in kilowatts, he must specify the power factor. A power factor of 0.8 is normally used. Thus a 200-kva generator actually produces 160 kw, but could produce up to 200 kw if the power factor were raised to 1.0.

Generator engineers talk about the flow of watts and the flow of VARs (volt-ampere-reactive). The power output of a generator is controlled by varying the torque applied to its shaft by the prime mover. The VARs output is controlled by varying the generator's field excitation. This function can be valuable in an industrial plant. If an in-plant generator is overexcited, it produces VARs as well as watts, and these VARs flow into the plant's motors to provide their excitation current.

This reduces the amount of VARs the motors draw from the utility system. It is equivalent to installing power factor correction capacitors (see below).

Certain components in the electrical system either generate or absorb reactive power. Generators of reactive power include synchronous generators, capacitors and lightly loaded lines. Absorbers of reactive power include transformers, induction motors and generators and heavily loaded lines. An electrical utility must balance the supply and demand for reactive power as well as the supply and demand for real power. Since induction motors represent up to 70 percent of the overall load in a utility system, there generally tends to be a shortage of reactive power.

Typically residential loads place a lagging VARs load on the utility's distribution system, which lowers the power factor. This reactive power produces no revenue for the utility but does produce real power losses in its system. These needed VARs consumed by the QF are usually supplied by the capacitor bank nearest the lagging VAR load.

Residential power factors are relatively unimportant. Residential customers are billed for true power consumed. The rates they pay are already adjusted for the loss of power the utility incurs. The need for calculating or measuring kvar and kvar hours (kvarh) is thus avoided after the initial determination of residential power factor is made. Residential power factors fall in a range between 0.80 and 0.95. When compared to unity (1.0) power factor, a 0.85 power factor increases kilovolt-amp loading approximately 15 percent and adds a VAR load equal to about one-half of the kilowatt load.

Special metering is sometimes needed to determine the power factor of certain industrial processes. The utility may either charge a penalty for a low power factor or refuse service until the industry takes measures to adjust the power factor to meet the utility's minimum standards. Utilities normally require dispersed generators to meet minimum power factors (e.g., 85 percent).

Generators, Inverters, Self-Excitation and Power Factors

AC generators and inverters are devices that produce electrical energy in a form compatible with utility systems. Generators are rotating machines driven by engines or turbines, while inverters are electronic devices that convert direct current into alternating current. Inverters are often used in wind, hydro and photovoltaic power systems.

The *synchronous generator* is the machine used to generate the vast majority of AC power today. It contains an exciter, a DC field winding, armature winding and mechanical structure. In all but the smallest synchronous generators, the field winding is part of the rotor, and the armature winding remains stationary.

The rotor, or rotating armature, is driven by a prime mover (either a turbine or engine), and as the magnetic flux generated by the DC field windings crosses the stator windings, a three-phase voltage and current is induced at the output terminals. The exact value of the AC voltage generated is controlled by varying the current in the DC field windings, while the frequency is controlled by the speed of rotation. Power output is controlled by the torque applied to the generator shaft by the prime mover. Thus, the synchronous machine provides very precise control over the power it generates.

Nearly all synchronous generators are three phase with voltage outputs ranging from 120 v to 13,800 v. The full load efficiency of synchronous generators is typically 83 to 96 percent for medium and high speed (less than 200 revolutions per minute) machines in the range of 100 kw to 10,000 kw. The efficiency of synchronous generators increases with generator size and declines as the load decreases. The percent loss of efficiency from the full load level is typically 2 percent at 80 percent of the rated load, 4 percent at 60 percent of full load, 7 percent at 40 percent of full load and 11 percent at 20 percent of full load. The power factor for synchronous generators varies from about 0.80 lagging to 0.90 leading.

Since synchronous generators have an exciter, they can operate without an outside source of power. However, the capability for independent operation necessitates regulating the voltage and frequency outputs from the generator. Voltage and frequency control are accomplished using a voltage regulator and speed governor. Also, when two or more synchronous generators are connected in parallel, their phases must be synchronized. Thus, synchronous generators connected in parallel to a utility system must include a synchronizing device.

The cost of synchronous generators decreases from about $100 per kilowatt for generators of about 10 kw to about $20 per kilowatt for those of more than 1,000 kw. These costs do not include contractor installation and markup. The installation cost for synchronous generators is approximately equal to the capital cost.

The *induction generator* is a much simpler machine than a synchronous generator. It has very little control over its electrical ouput. It is exactly the same in design as an induction motor. It usually cannot generate electric power when isolated, but when coupled to the utility network, it draws a reactive excitation current from the line, and when driven, feeds AC power back into the line. Its advantages for small interconnection applications are that it cannot operate without excitation supplied by the utility system. Very little protective relaying is necessary, and speed control isn't needed at all. The excitation power supplied by the utility also modulates the voltage, frequency and phase of the signal produced by an induction generator.

Induction generator efficiency at full load varies from about 80 percent for small generators to about 95 percent for larger machines. The efficiency of induction generators, like synchronous generators, is relatively constant at part loads down to about 25 percent of full load.

The power factor for induction generators depends on the loading conditions. At full load, induction generators generally have a power factor of about 0.80 lagging. The power factor declines as the load fraction decreases. For example, a 340-kw induction generator has a power factor of about 0.70 at 50 percent load and 0.55 at 25 percent load.

In general, induction generators are simpler and have lower capital and maintenance costs than synchronous generators. For example, one generator manufacturer sells induction generators for about 20 percent less than synchronous generators. Due to their simplicity and lower cost, induction generators are advantageous at sizes on the order of 500 kw and less, if there is no need to operate without the utility. Above 500 kw, the increased power factor and efficiency can outweigh the added expense for an exciter and controls with a synchronous generator.

Many renewable-based technologies, such as wind and photovoltaics, generate direct current. This must be converted into alternating current if it is going to be used to run AC loads or be delivered to the grid system. This conversion is done with an inverter. They are available for generators of under 1 kw to 500 kw. The efficiency of inverters is generally in the range of 90 to 95 percent at full load. The efficiency generally remains above 80 percent at part loads down to 20 percent of full load.

There are two types of inverters: line-commutated and self-commutated (also known as forced commutated). *Commutation* is the switching process that produces the time varying signal. Line-commutated inverters require reactive power from the utility system or some other source in order to operate. Self-commutated or forced-commutated inverters, however, are capable of independent operation, as in a system with battery storage.

The performance of self-commutated inverters is generally superior to that of line-commutated inverters. While self-commutated inverters can have a unity (power factor equals 1) or even slightly leading power factor, line-commutated inverters often operate with a relatively low, lagging power factor. One field test of an 8-kw, line-commutated inverter in a photovoltaic power system yielded power factors of only 0.36 to 0.72.

Self-commutated inverters generally produce THD levels of 5 percent or less, a level that is ordinarily acceptable to utilities. However, excessive levels of THD may be generated with line-commutated inverters. For example, the photovoltaic system noted above operated with a THD level in the current waveform of 28 percent.

At present, inverters are relatively expensive. Self-commutated inverters designed for parallel operation with a utility typically cost about $1,500 per kilowatt for a 5-kw application and $500 per kilowatt for a 300-kw application. Line-commutated inverters can be significantly less expensive. A popular small commutated inverter (under 10 kw) costs $350 to $800 per kilowatt depending on the exact size.

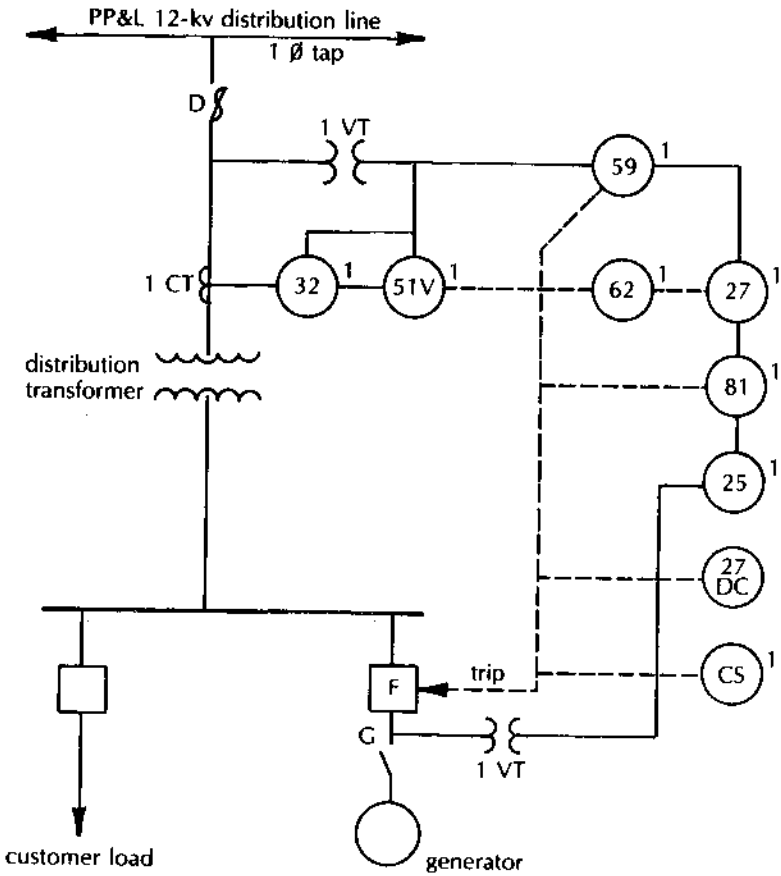
Cheaper solid-state inverters generate square waveforms, which can harm sensitive electrical appliances. These waveforms can be smoothed out to sinusoidal shapes through the addition of filters.

Low power factors can be corrected, but some of the corrections can themselves generate other problems. For example, *capacitors*, devices that temporarily store electricity, can be inserted into the system to bring the voltage and current in phase. However, since the VARs drawn by an induction generator vary from a no-load value to a peak at maximum power output, they cannot be supplied entirely by static capacitors. More important, it is possible for an induction generator with capacitors to self-excite when the capacitor is connected and to generate a voltage, even though it is disconnected from the network. This nullifies the inherent safety feature of an induction generator, that is, its inability to operate in isolation.

(continued on page 148)

Figures 4–1, 4–2, 4–3: The interconnection schematics shown on the following pages were developed by the Pennsylvania Power and Light Company to be used with systems of different sizes. The components shown here are typical of what the Pennsylvania Power and Light Company has determined to be necessary to protect both the utility and the small power producer. These requirements represent almost a full menu of what your local utility might demand, although many utilities require less protective equipment. The small power producer can also play a role in determining the interconnection requirements for the particular utility to which it will connect. The standard numbers in these schematics are those used in *Electric Power System Device Function Numbers* (New York: American National Standards Institute, 1979). Order no. ANSI/IEE 37.2. *Redrawn from schematics provided by Pennsylvania Power and Light Company.*

Figure 4–1
Interconnection Schematic: Single Phase up to 200 kva

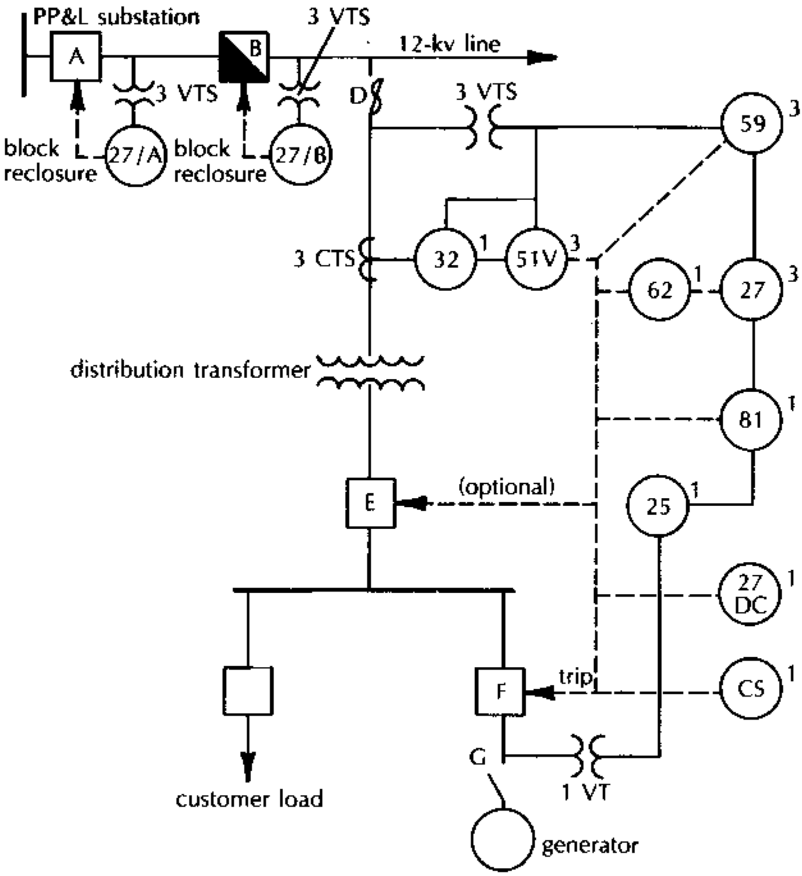


D—fused disconnect
F—generator breaker or contactor (electrically operated)
G—safety switch (lockable in the open position)
CS—PP&L control switch
CT—current transformer
VT—voltage transformer

Intertie Protective Relay Types
25—synchronism check
27—undervoltage
27DC—battery undervoltage
32—directional power
51V—torque controlled time overcurrent
59—overvoltage
62—time delay
81—frequency

NOTE: Safety switch (G) must be located electrically between the generator and the transformer. The specific location will vary based on metering requirements.

Figure 4–2
Interconnection Schematic: Three Phase up to 1,500 kva



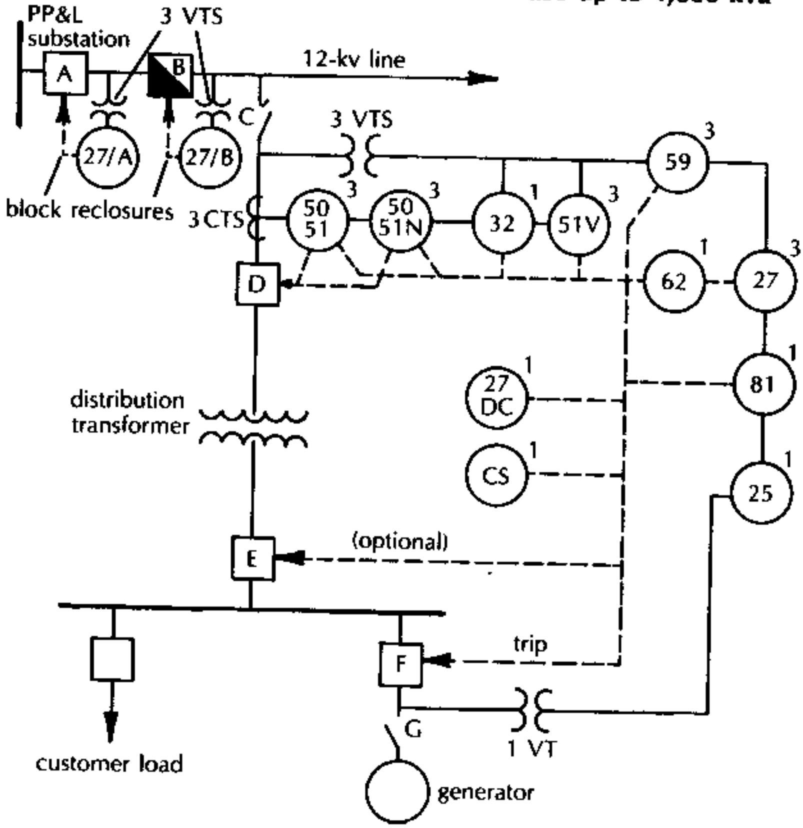
A—substation circuit breaker
B—electronic oil circuit recloser
D—fused disconnect
E—transformer low side breaker (optional)
F—generator breaker (electrically operated)
G—safety switch (lockable in the open position)
CS—PP&L control switch
CTS—current transformers
VT—voltage transformer

VTS—voltage transformers

Intertie Protective Relay Types
25—synchronism check
27—undervoltage
27DC—battery undervoltage
32—directional power
51V—torque controlled time overcurrent
59—overvoltage
62—time delay
81—frequency

NOTE: Safety switch (G) must be located electrically between the generator and the transformer. The specific location will vary based on metering requirements.

Figure 4–3
Interconnection Schematic: Three Phase up to 1,800 kva



A—substation circuit breaker
B—electronic oil circuit recloser
C—disconnect
D—"point of contact" breaker
E—transformer low side breaker (optional)
F—generator breaker (electrically operated)
G—safety switch (lockable in the open position)
CS—PP&L control switch
CTS—current transformers
VT—voltage transformer
VTS—voltage transformers

Point of Contact Relays
50/51
50/51N

Intertie Protective Relay Types
25—synchronism check
27—undervoltage
27DC—battery undervoltage
32—directional power
51V—torque controlled time overcurrent
59—overvoltage
62—time delay
81—frequency

NOTE: Safety switch (G) must be located electrically between the generator and the transformer. The specific location will vary based on metering requirements.

The installation of capacitors is the standard method for increasing a lagging power factor. Capacitor banks are routinely installed throughout the distribution system for power factor improvement. Some industrial customers install their own capacitors near their facility. Large banks of capacitors on the distribution primary are much more economical than smaller units of capacitors distributed throughout the network near generators. If capacitors are installed centrally, the cost for the capacitor bank can be shared among those receiving power factor compensation. Also, as mentioned above, if capacitors are located on distribution secondaries near induction generators and line-commutated inverters, there is the potential for self-excitation.

For dispersed generators under 100 kw, a concern for power factor may be unnecessary if the small generators taken together have a negligible impact on the power factor of the whole utility system. Southern California Edison and San Diego Gas and Electric, for example, are not requiring dispersed generators of less than 100 kw to correct a lower power factor. However, if the penetration of small dispersed generators with low power factors becomes high, then it may be necessary to apply power factor requirements or penalties to small generators and inverters as well as to large industrial or commercial generators. If the power factor of a cogenerator or small power producer is of concern, it may be necessary to monitor power factor. Power factor can be determined by measuring reactive power or reactive energy. Reactive energy meters cost about $500 installed. Also, meters are available that measure power factor directly.

Interconnection Costs

Interconnection costs as a percentage of total project costs vary inversely with the size of the facility. The larger the power plant, the smaller the investment per kilowatt of installed capacity. Table 4–1 provides information on the total interconnection costs for the three sizes of cogeneration systems. The costs for hydroelectric, photovoltaic or wind-powered systems would not differ greatly. The costs for each system are divided into two categories: a best case, which assumes that much of the equipment is already in place or not required (e.g., capacitors, dedicated transformers, protective relays) and a worst case, which assumes this equipment must be purchased. Most of the cost difference comes from the addition of a dedicated utility transformer and more expensive protective relays and other protective devices.

Interconnection costs will be an important factor in deciding the economics of very small systems. Table 4–2 gives cost information for a 10-kva system under several interconnection schemes. Scheme 9.1 includes the dedicated distribution transformer, relays, capacitors at

TABLE 4–1
Interconnection Costs for Three Typical Systems

EQUIPMENT	50 KW BEST	50 KW WORST	500 KW BEST	500 KW WORST	5 MW AVERAGE
Capacitors for power factor	*	$1,000	*	$5,000	*
Voltage/frequency relays	$1,000	1,000	$1,000	1,000	$1,000
Dedicated transformer		3,900	*	12,500	40,000
Meter	80	1,000	80	1,000	1,000
Ground fault over-voltage relay	600	600	600	600	600
Manual disconnect switch	300	300	1,400	1,400	3,000
Circuit breakers	620	620	4,200	4,200	5,000
Automatic synchronizers	*	*	2,600	2,600	2,600
Equipment transformers	600	1,100	600	1,100	1,100
Other protective relays	*	3,500	*	3,500	3,500
Total costs ($)	$2,600	$13,020	$11,080	$32,900	$57,800
Total costs ($/kw)	52	260	22	66	12

NOTE: Reprinted from *Industrial and Commercial Cogeneration*, Office of Technology Assessment (Washington, D.C.: Office of Technology Assessment, 1983), p. 37.
*Indicates an optional piece of interconnection equipment that was not included in the requirements and cost calculations.

the generator and a time-of-day meter. This is the most expensive interconnection arrangement. If an ordinary energy meter is used rather than a time-of-day meter (scheme 9.2), the cost drops by 8 percent. Placing the capacitors on the distribution lateral rather than at the generator (scheme 9.3) reduces the total cost 15 percent from the first case. Compared to scheme 9.3, the cost savings is minimal if power factor correction is not included (scheme 9.4).

It may be possible to dispense with the dedicated distribution transformer for a small, single-phase generator or inverter. This would reduce the total interconnection cost by about 25 percent (schemes 9.5 to 9.7). Scheme 9.8, the least expensive arrangement considered, excludes the transformer and includes an ordinary energy meter.

TABLE 4–2

Interconnection Equipment and Systems for a 10-kva (single-phase) Induction Generator or Line-Commutated Inverter

INTERCONNECTION ITEM	INSTALLED COST (1981 $)	INTERCONNECTION SYSTEM SCHEME 9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8
Disconnect switch, 60 amp	176	X	X	X	X	X	X	X	X
Dedicated distribution transformer, 15 kva single phase	865	X	X	X	X				
Potential transformer, 240 v	241	X	X	X	X	X	X	X	X
Over/under voltage relay	436	X	X	X	X	X	X	X	X
Over/under frequency relay	531	X	X	X	X	X	X	X	X
Molded-case, thermal-magnetic circuit breaker, 60 amp	532	X	X	X	X	X	X	X	X
Capacitors, 4 kvar at the generator	621	X	X			X			
within the distribution system	41			X			X		
Meter ordinary kwh	80		X						X
time-of-day meter with dial registers	367	X		X	X	X	X	X	

SOURCE: Howard S. Geller, *The Interconnection of Cogenerators and Small Power Producers to a Utility System* (Washington, D.C.: Self-Reliance, Inc., 1982).

Radial and Network Systems

Two different methods of distributing electricity characterize our electric system. Most of the country is served by so-called *radial systems*. In these there is only one line between the power plant and the customer. The radial system can be visualized as a giant trunk line that has branches and these in turn have subbranches.

The *network system* looks more like a grid system. Here a customer is served through many routes. Network systems are typical of high density urban areas. In many cities, about 15 percent of the service area is served by network systems. In New York City, more than 70 percent of Consolidated Edison's (Con Ed) service area is served in this manner.

Because of their redundant nature, network systems are more reliable than radial systems. However, because of their redundant nature they require more protective relays than a radial system might. Reverse power flows must be prevented from leaking into the system. For example, Con Ed has reverse relays that trip at power flows as small as 10 kw. As a result, dispersed generators in these areas must connect to the primary distribution line or forego selling electricity to Con Ed. These lines carry higher voltages and may be located far enough away from the generator that the interconnection costs rise greatly.

Other Utility System Performance Issues

If many dispersed generators come on-line, the utility might have to replace existing transformers, circuit breakers, cables or other components of the T&D system. That would be necessary if dispersed generators produced current or power at levels that exceed the capacity of existing equipment. Utilities are allowed to charge QFs for the cost of this upgrading.

However, a utility should not have to replace any equipment as long as the peak rating of the dispersed generators is less than the maximum on-site load. In addition, the impact that a dispersed generator has on distribution system capacity should be placed in the broader context of planned operations to the capacity of distribution system equipment.

Even if the generator rating is greater than the on-site load, the utility system will only receive the net power produced by the customer's facility. For example, if an on-site generator produces 100 kw, while other electrical equipment at the site of the generator consumes 75 kw, then 25 kw is the net amount of power delivered to the utility. It may be possible for the utility to use the maximum *net power output* for sizing distribution system equipment. Moreover, the installation of dispersed generators could effectively expand the capacity of existing utility equipment. Reliable QFs could allow the secondary system to serve more homes than normal. However, to do this, the reliability of the generator or load and the number of generators is critical. Utility equipment on the secondary or lateral could become overloaded when the dispersed generator is not operating if utility equipment has been sized based on the assumption that power from the dispersed generator is supplying part of the load.

Another issue related to utility system performance is the amount of fault current that dispersed generators can contribute at certain points in the distribution system. If this contribution is large enough, the utility will have to replace circuit breakers in order to upgrade the short-circuit capacity. One study of wind turbines at different penetration levels found that at the distribution substation, the wind turbines increased the short-circuit current potential less than 10 percent, even with a 50 percent wind turbine penetration. However, the potential short-circuit current at the ends of the feeder increased 10 to 60 percent with a dispersed generator penetration of 20 to 50 percent. Thus the ratings of circuit breakers and other overcurrent protection equipment near the end of the distribution system might be exceeded if dispersed generators reach a high level of aggregate or total capacity.

Another legitimate concern is that cogenerators and small power producers could increase the load factor on some equipment in the utility system. Highly fluctuating power sources such as wind generator and photovoltaic systems are likely to switch capacitors on and off more frequently than they would otherwise be. This would reduce the service life of the capacitors.

The issues and technologies related to interconnection standards are complex. Moreover, the technologies themselves are changing rapidly. The standards required will evolve and probably tighten as more and more dispersed generators come on-line. On the other hand, the technologies, especially those for protective relaying, will probably become cheaper, more reliable and more sophisticated as microprocessor technologies are introduced. This chapter has focused on the multiple issues related to interconnection. Chapter 5 focuses on negotiating with the utility. The question this chapter answers is, how can the QF get the best deal?