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Substations

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5.1 Gas Insulated Substations

Philip Bolin

A gas insulated substation (GIS) uses a superior dielectric gas, SF6, at moderate pressure for phase-to-phase and phase-to-ground insulation. The high voltage conductors, circuit breaker interrupters, switches, current transformers, and voltage transformers are in SF6 gas inside grounded metal enclosures. The atmospheric air insulation used in a conventional, air insulated substation (AIS) requires meters of air insulation to do what SF6 can do in centimeters. GIS can therefore be smaller than AIS by up to a factor of ten. A GIS is mostly used where space is expensive or not available. In a GIS the active parts are protected from the deterioration from exposure to atmospheric air, moisture, contamination, etc. As a result, GIS is more reliable and requires less maintenance than AIS.

GIS was first developed in various countries between 1968 and 1972. After about 5 years of experience, the use rate increased to about 20% of new substations in countries where space is limited. In other countries with space easily available, the higher cost of GIS relative to AIS has limited use to special cases. For example, in the U.S., only about 2% of new substations are GIS. International experience with GIS is described in a series of CIGRE papers (CIGRE, 1992; 1994; 1982). The IEEE (IEEE Std. C37. 122-1993; IEEE Std C37. 122.1-1993) and the IEC (IEC, 1990) have standards covering all aspects of the design, testing, and use of GIS. For the new user, there is a CIGRE application guide (Katchinski et al., 1998). IEEE has a guide for specifications for GIS (IEEE Std. C37.123-1996).

SF6

Sulfur hexaflouride is an inert, non-toxic, colorless, odorless, tasteless, and non-flammable gas consisting of a sulfur atom surrounded by and tightly bonded to six flourine atoms. It is about five times as dense as air. SF6 is used in GIS at pressures from 400 to 600 kPa absolute. The pressure is chosen so that the SF6 will not condense into a liquid at the lowest temperatures the equipment experiences. SF6 has two to three times the insulating ability of air at the same pressure. SF6 is about one hundred times better than air for interrupting arcs. It is the universally used interrupting medium for high voltage circuit breakers, replacing the older mediums of oil and air. SF6 decomposes in the high temperature of an electric arc, but the decomposed gas recombines back into SF6 so well that it is not necessary to replenish the SF6 in GIS. There are some reactive decomposition byproducts formed because of the trace presence of moisture, air, and other contaminants. The quantities formed are very small. Molecular sieve absorbants inside the GIS enclosure eliminate these reactive byproducts. SF6 is supplied in 50-kg gas cylinders in a liquid state at a pressure of about 6000 kPa for convenient storage and transport. Gas handling systems with filters, compressors, and vacuum pumps are commercially available. Best practices and the personnel safety aspects of SF6 gas handling are covered in international standards (IEC, 1995).

The SF6 in the equipment must be dry enough to avoid condensation of moisture as a liquid on the surfaces of the solid epoxy support insulators because liquid water on the surface can cause a dielectric breakdown. However, if the moisture condenses as ice, the breakdown voltage is not affected. So dew points in the gas in the equipment need to be below about –10°C. For additional margin, levels of less than 1000 ppmv of moisture are usually specified and easy to obtain with careful gas handling. Absorbants inside the GIS enclosure help keep the moisture level in the gas low, even though over time, moisture will evolve from the internal surfaces and out of the solid dielectric materials (IEEE Std. 1125-1993).

Small conducting particles of mm size significantly reduce the dielectric strength of SF6 gas. This effect becomes greater as the pressure is raised past about 600 kPa absolute (Cookson and Farish, 1973). The particles are moved by the electric field, possibly to the higher field regions inside the equipment or deposited along the surface of the solid epoxy support insulators, leading to dielectric breakdown at operating voltage levels. Cleanliness in assembly is therefore very important for GIS. Fortunately, during the factory and field power frequency high voltage tests, contaminating particles can be detected as they move and cause small electric discharges (partial discharge) and acoustic signals, so they can be removed by opening the equipment. Some GIS equipment is provided with internal "particle traps" that capture the particles before they move to a location where they might cause breakdown. Most GIS assemblies are of a shape that provides some "natural" low electric field regions where particles can rest without causing problems.

SF6 is a strong greenhouse gas that could contribute to global warming. At an international treaty conference in Kyoto in 1997, SF6 was listed as one of the six greenhouse gases whose emissions should be reduced. SF6 is a very minor contributor to the total amount of greenhouse gases due to human activity, but it has a very long life in the atmosphere (half-life is estimated at 3200 years), so the effect of SF6 released to the atmosphere is effectively cumulative and permanent. The major use of SF6 is in electrical power equipment. Fortunately, in GIS the SF6 is contained and can be recycled. By following the present international guidelines for use of SF6 in electrical equipment (Mauthe et al., 1997), the contribution of SF6 to global warming can be kept to less than 0.1% over a 100-year horizon. The emission rate from use in electrical equipment has been reduced over the last three years. Most of this effect has been due to simply adopting better handling and recycling practices. Standards now require GIS to leak less than 1% per year. The leakage rate is normally much lower. Field checks of GIS in service for many years indicate that the leak rate objective can be as low as 0.1% per year when GIS standards are revised.

Construction and Service Life

GIS is assembled of standard equipment modules (circuit breaker, current transformers, voltage transformers, disconnect and ground switches, interconnecting bus, surge arresters, and connections to the rest of the electric power system) to match the electrical one-line diagram of the substation. A cross-section view of a 242-kV GIS shows the construction and typical dimensions (Fig. 5.1). The modules are joined using bolted flanges with an "O" ring seal system for the enclosure and a sliding plug-in contact for the conductor. Internal parts of the GIS are supported by cast epoxy insulators. These support insulators provide a gas barrier between parts of the GIS, or are cast with holes in the epoxy to allow gas to pass from one side to the other.

Up to about 170 kV system voltage, all three phases are often in one enclosure (Fig. 5.2). Above 170 kV, the size of the enclosure for "three-phase enclosure," GIS becomes too large to be practical. So a "single-phase enclosure" design (Fig. 5.1) is used. There are no established performance differences between three-phase enclosure and single-phase enclosure GIS. Some manufacturers use the single-phase enclosure type for all voltage levels.

Enclosures today are mostly cast or welded aluminum, but steel is also used. Steel enclosures are painted inside and outside to prevent rusting. Aluminum enclosures do not need to be painted, but may be painted for ease of cleaning and a better appearance. The pressure vessel requirements for GIS enclosures are set by GIS standards (IEEE Std. C37.122-1993; IEC, 1990), with the actual design, manufacture, and test following an established pressure vessel standard of the country of manufacture. Because of the moderate pressures involved, and the classification of GIS as electrical equipment, third-party inspection and code stamping of the GIS enclosures are not required.

Conductors today are mostly aluminum. Copper is sometimes used. It is usual to silver plate surfaces that transfer current. Bolted joints and sliding electrical contacts are used to join conductor sections. There are many designs for the sliding contact element. In general, sliding contacts have many individually

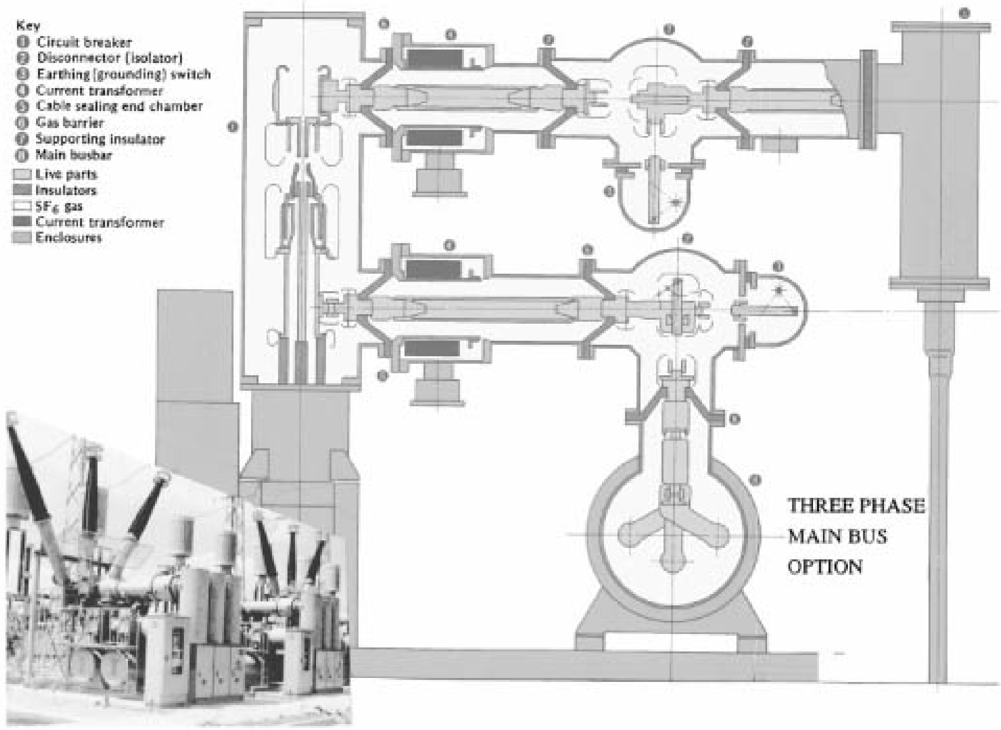


FIGURE 5.1 Single-phase eclosure GIS.

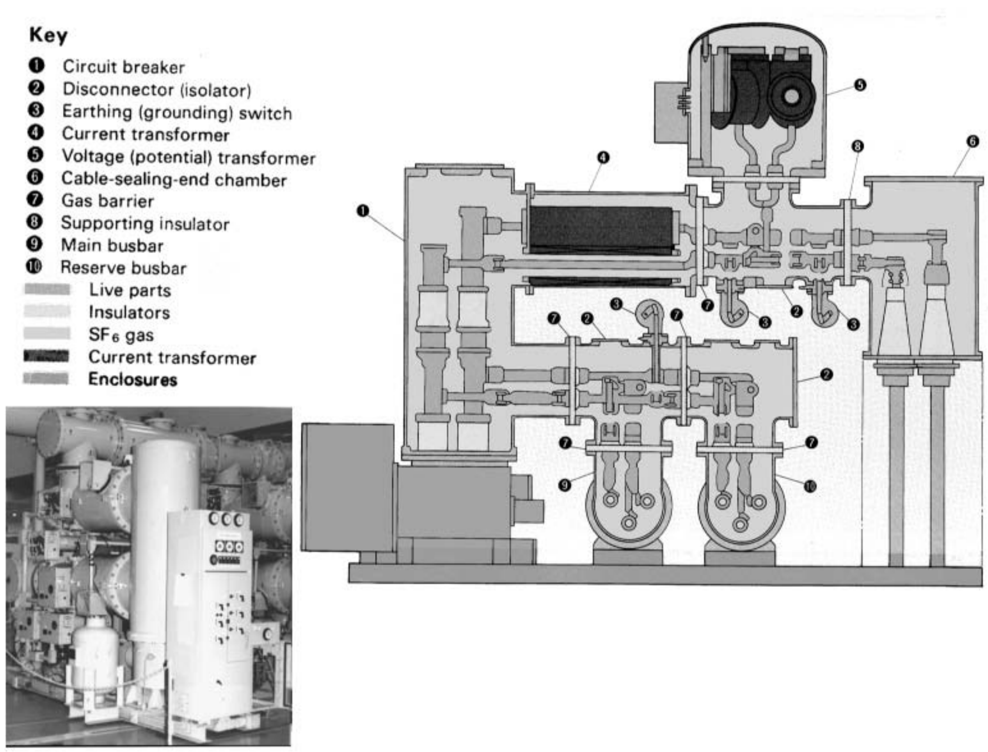


FIGURE 5.2 Three-phase enclosure GIS.

sprung copper contact fingers working in parallel. Usually the contact fingers are silver plated. A contact lubricant is used to ensure that the sliding contact surfaces do not generate particles or wear out over time. The sliding conductor contacts make assembly of the modules easy and also allow for conductor movement to accommodate the differential thermal expansion of the conductor relative to the enclosure. Sliding contact assemblies are also used in circuit breakers and switches to transfer current from the moving contact to the stationary contacts.

Support insulators are made of a highly filled epoxy resin cast very carefully to prevent formation of voids and/or cracks during curing. Each GIS manufacturer's material formulation and insulator shape has been developed to optimize the support insulator in terms of electric field distribution, mechanical strength, resistance to surface electric discharges, and convenience of manufacture and assembly. Post, disc, and cone type support insulators are used. Quality assurance programs for support insulators include a high voltage power frequency withstand test with sensitive partial discharge monitoring. Experience has shown that the electric field stress inside the cast epoxy insulator should be below a certain level to avoid aging of the solid dielectric material. The electrical stress limit for the cast epoxy support insulator is not a severe design constraint because the dimensions of the GIS are mainly set by the lightning impulse withstand level and the need for the conductor to have a fairly large diameter to carry to load current of several thousand amperes. The result is space between the conductor and enclosure for support insulators having low electrical stress.

Service life of GIS using the construction described above has been shown by experience to be more than 30 years. The condition of GIS examined after many years in service does not indicate any approaching limit in service life. Experience also shows no need for periodic internal inspection or maintenance. Inside the enclosure is a dry, inert gas that is itself not subject to aging. There is no exposure of any of the internal materials to sunlight. Even the "O" ring seals are found to be in excellent condition because there is almost always a "double seal" system — Fig. 5.3 shows one approach. The lack of aging has been found for GIS, whether installed indoors or outdoors.

Circuit Breaker

GIS uses essentially the same dead tank SF6 puffer circuit breakers used in AIS. Instead of SF6-to-air as connections into the substation as a whole, the nozzles on the circuit breaker enclosure are directly connected to the adjacent GIS module.

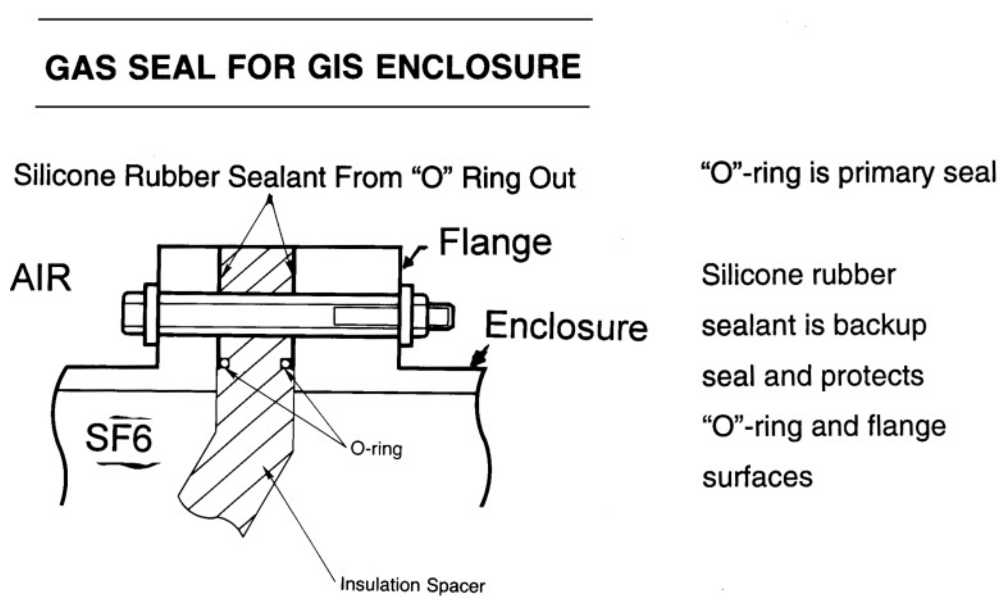


FIGURE 5.3 Gas seal for GIS enclosure.

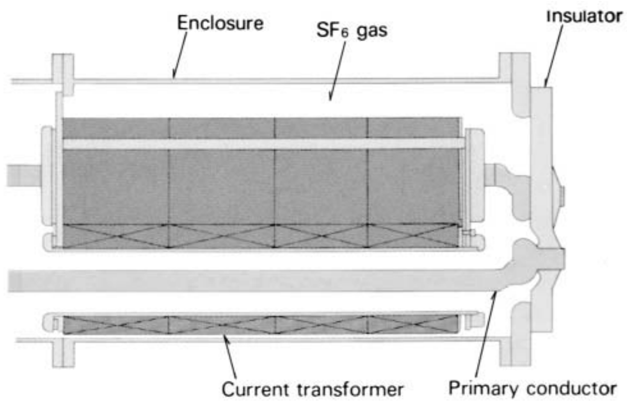


FIGURE 5.4 Current transformers for GIS.

Current Transformers

CTs are inductive ring type installed either inside the GIS enclosure or outside the GIS enclosure (Fig. 5.4). The GIS conductor is the single turn primary for the CT. CTs inside the enclosure must be shielded from the electric field produced by the high voltage conductor or high transient voltages can appear on the secondary through capacitive coupling. For CTs outside the enclosure, the enclosure itself must be provided with an insulating joint, and enclosure currents shunted around the CT. Both types of construction are in wide use.

Voltage Transformers

VTs are inductive type with an iron core. The primary winding is supported on an insulating plastic film immersed in SF6. The VT should have an electric field shield between the primary and secondary windings to prevent capacitive coupling of transient voltages. The VT is usually a sealed unit with a gas barrier insulator. The VT is either easily removable so the GIS can be high voltage tested without damaging the VT, or the VT is provided with a disconnect switch or removable link (Fig. 5.5).

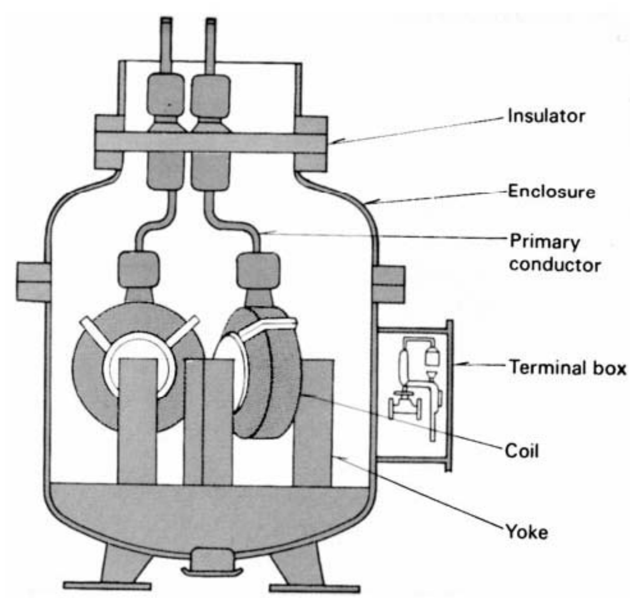


FIGURE 5.5 Voltage transformers for GIS.

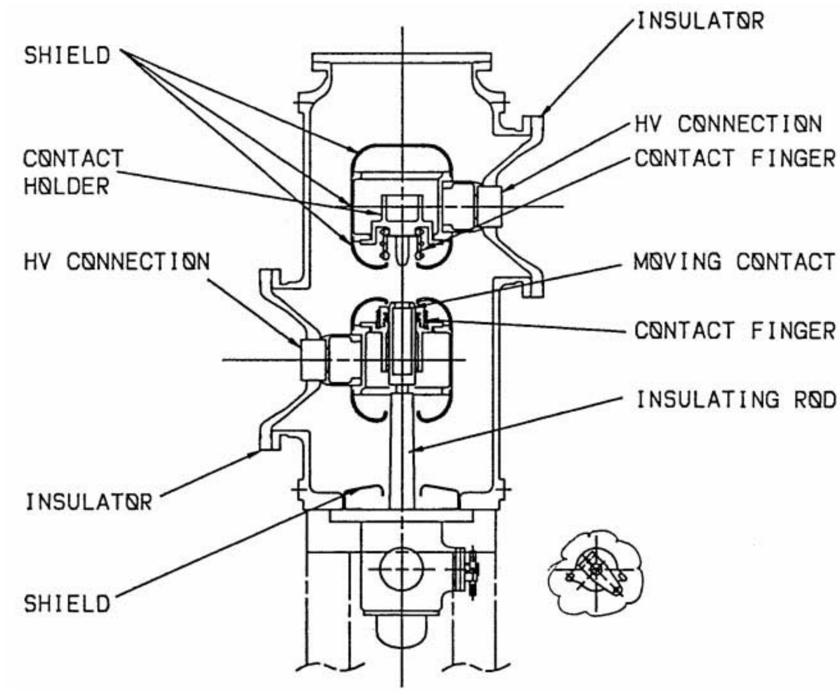


FIGURE 5.6 Disconnect switches for GIS.

Disconnect Switches

Disconnect switches (Fig. 5.6) have a moving contact that opens or closes a gap between stationary contacts when activated by a insulating operating rod that is itself moved by a sealed shaft coming through the enclosure wall. The stationary contacts have shields that provide the appropriate electric field distribution to avoid too high a surface stress. The moving contact velocity is relatively low (compared to a circuit breaker moving contact) and the disconnect switch can interrupt only low levels of capacitive current (for example, disconnecting a section of GIS bus) or small inductive currents (for example, transformer magnetizing current). Load break disconnect switches have been furnished in the past, but with improvements and cost reductions of circuit breakers, it is not practical to continue to furnish load break disconnect switches, and a circuit breaker should be used instead.

Ground Switches

Ground switches (Fig. 5.7) have a moving contact that opens or closes a gap between the high voltage conductor and the enclosure. Sliding contacts with appropriate electric field shields are provided at the enclosure and the conductor. A "maintenance" ground switch is operated either manually or by motor drive to close or open in several seconds and when fully closed to carry the rated short-circuit current for the specified time period (1 or 3 sec) without damage. A "fast acting" ground switch has a high speed drive, usually a spring, and contact materials that withstand arcing so it can be closed twice onto an energized conductor without significant damage to itself or adjacent parts. Fast-acting ground switches are frequently used at the connection point of the GIS to the rest of the electric power network, not only in case the connected line is energized, but also because the fast-acting ground switch is better able to handle discharge of trapped charge and breaking of capacitive or inductive coupled currents on the connected line.

Ground switches are almost always provided with an insulating mount or an insulating bushing for the ground connection. In normal operation the insulating element is bypassed with a bolted shunt to the GIS enclosure. During installation or maintenance, with the ground switch closed, the shunt can be removed and the ground switch used as a connection from test equipment to the GIS conductor. Voltage

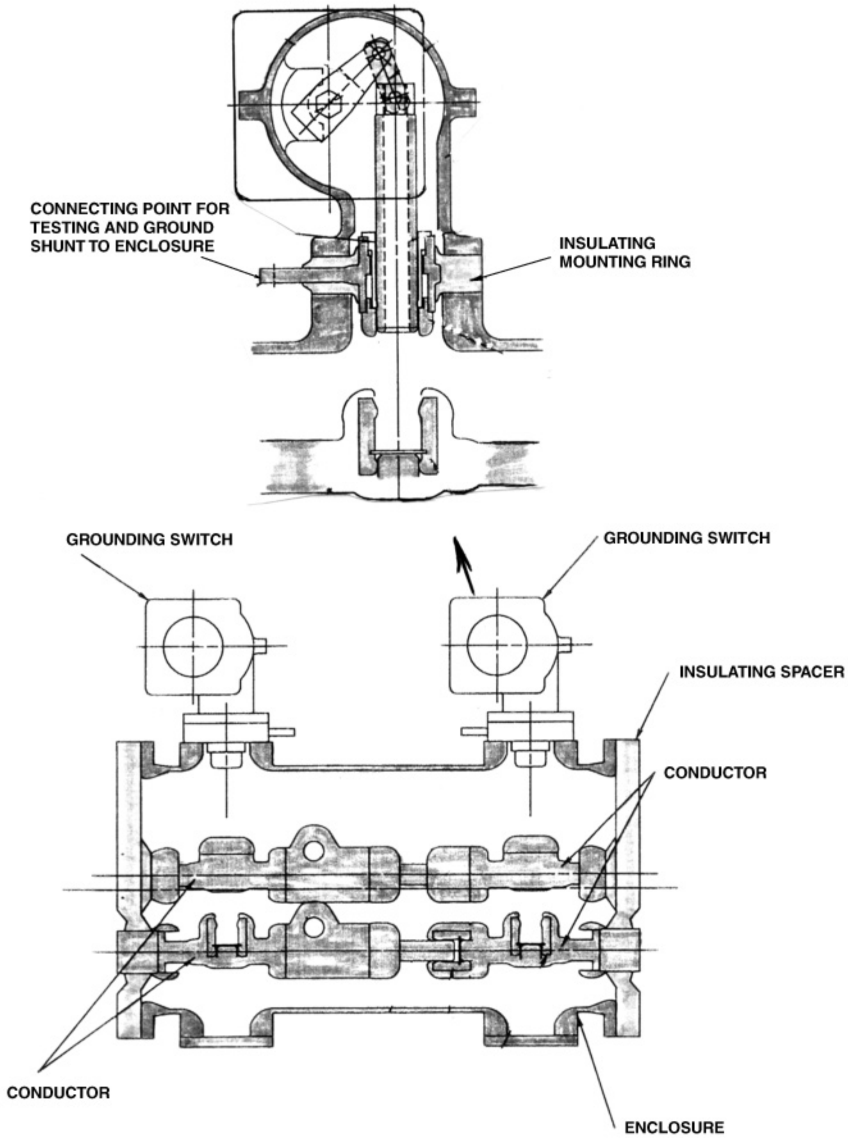


FIGURE 5.7 Ground switches for GIS.

and current testing of the internal parts of the GIS can then be done without removing SF6 gas or opening the enclosure. A typical test is measurement of contact resistance using two ground switches (Fig. 5.8).

Bus

To connect GIS modules that are not directly connected to each other, an SF6 bus consisting of an inner conductor and outer enclosure is used. Support insulators, sliding electrical contacts, and flanged enclosure joints are usually the same as for the GIS modules.

Air Connection

SF6-to-air bushings (Fig. 5.9) are made by attaching a hollow insulating cylinder to a flange on the end of a GIS enclosure. The insulating cylinder contains pressurized SF6 on the inside and is suitable for exposure to atmospheric air on the outside. The conductor continues up through the center of the insulating cylinder to a metal end plate. The outside of the end plate has provisions for bolting to an air

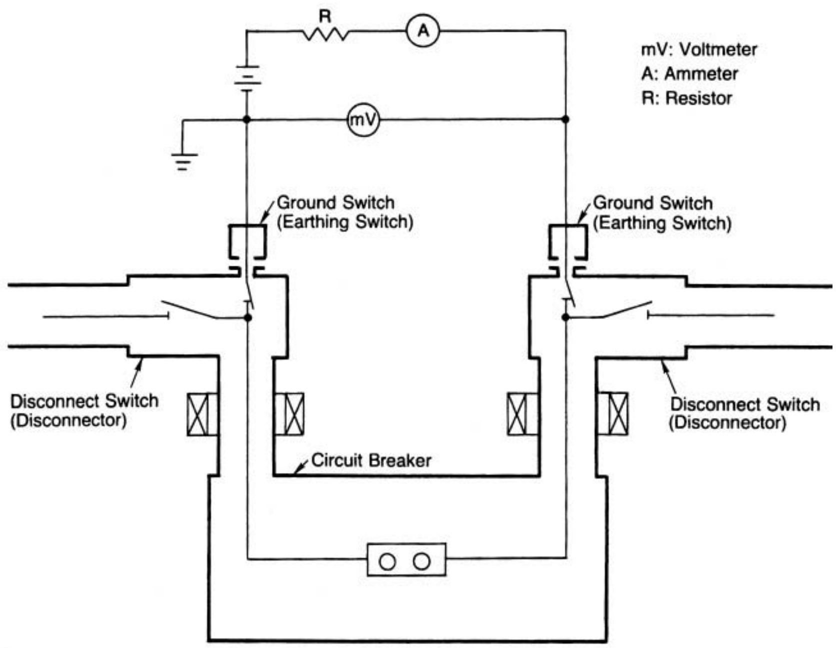


FIGURE 5.8 Contact resistance measured using ground switch.

insulated conductor. The insulating cylinder has a smooth interior. Sheds on the outside improve the performance in air under wet and/or contaminated conditions. Electric field distribution is controlled by internal metal shields. Higher voltage SF6-to-air bushings also use external shields. The SF6 gas inside the bushing is usually the same pressure as the rest of the GIS. The insulating cylinder has most often been porcelain in the past, but today many are a composite consisting of a fiberglass epoxy inner cylinder with an external weather shed of silicone rubber. The composite bushing has better contamination resistance and is inherently safer because it will not fracture as will porcelain.

Cable Connections

A cable connecting to a GIS is provided with a cable termination kit that is installed on the cable to provide a physical barrier between the cable dielectric and the SF6 gas in the GIS (Fig. 5.10). The cable termination kit also provides a suitable electric field distribution at the end of the cable. Because the cable termination will be in SF6 gas, the length is short and sheds are not needed. The cable conductor is connected with bolted or compression connectors to the end plate or cylinder of the cable termination kit. On the GIS side, a removable link or plug in contact transfers current from the cable to the GIS conductor. For high voltage testing of the GIS or the cable, the cable is disconnected from the GIS by removing the conductor link or plug-in contact. The GIS enclosure around the cable termination usually has an access port. This port can also be used for attaching a test bushing.

Direct Transformer Connections

To connect a GIS directly to a transformer, a special SF6-to-oil bushing that mounts on the transformer is used (Fig. 5.11). The bushing is connected under oil on one end to the transformer's high voltage leads. The other end is SF6 and has a removable link or sliding contact for connection to the GIS conductor. The bushing may be an oil-paper condenser type or more commonly today, a solid insulation type. Because leakage of SF6 into the transformer oil must be prevented, most SF6-to-oil bushings have a center section that allows any SF6 leakage to go to the atmosphere rather than into the transformer. For testing, the SF6 end of the bushing is disconnected from the GIS conductor after gaining access through an opening in the GIS enclosure. The GIS enclosure of the transformer can also be used for attaching a test bushing.

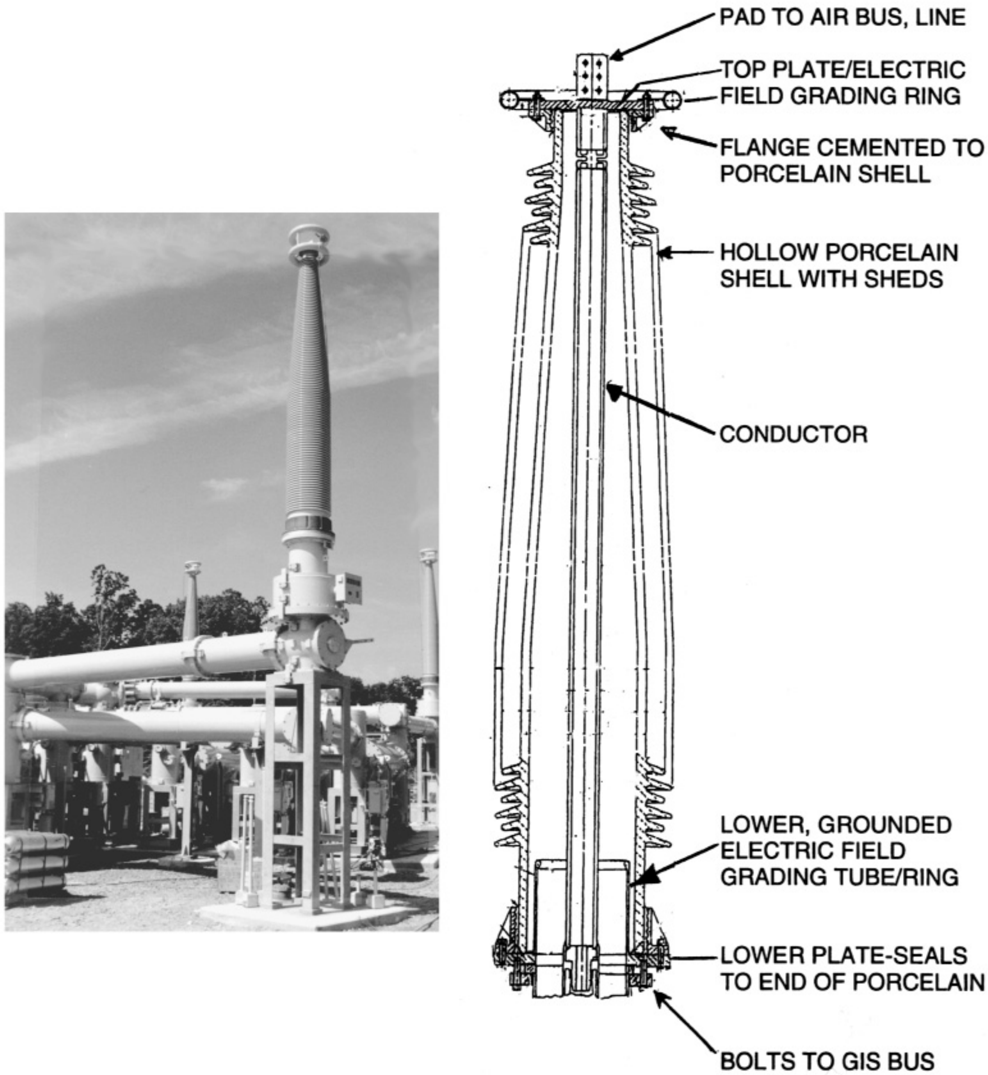


FIGURE 5.9 SF6-to-air bushing.

Surge Arrester

Zinc oxide surge arrester elements suitable for immersion in SF6 are supported by an insulating cylinder inside a GIS enclosure section to make a surge arrester for overvoltage control (Fig. 5.12). Because the GIS conductors are inside in a grounded metal enclosure, the only way for lightning impulse voltages to enter is through the connections of the GIS to the rest of the electrical system. Cable and direct transformer connections are not subject to lightning strikes, so only at SF6-to-air bushing connections is lightning a concern. Air insulated surge arresters in parallel with the SF6-to-air bushings usually provide adequate protection of the GIS from lightning impulse voltages at a much lower cost than SF6 insulated arresters. Switching surges are seldom a concern in GIS because with SF6 insulation the withstand voltages for switching surges are not much less than the lightning impulse voltage withstand. In AIS there is a significant decrease in withstand voltage for switching surges than for lightning impulse because the longer time span of the switching surge allows time for the discharge to completely bridge the long insulation distances in air. In the GIS, the short insulation distances can be bridged in the short time span of a lightning impulse so the longer time span of a switching surge does not significantly decrease

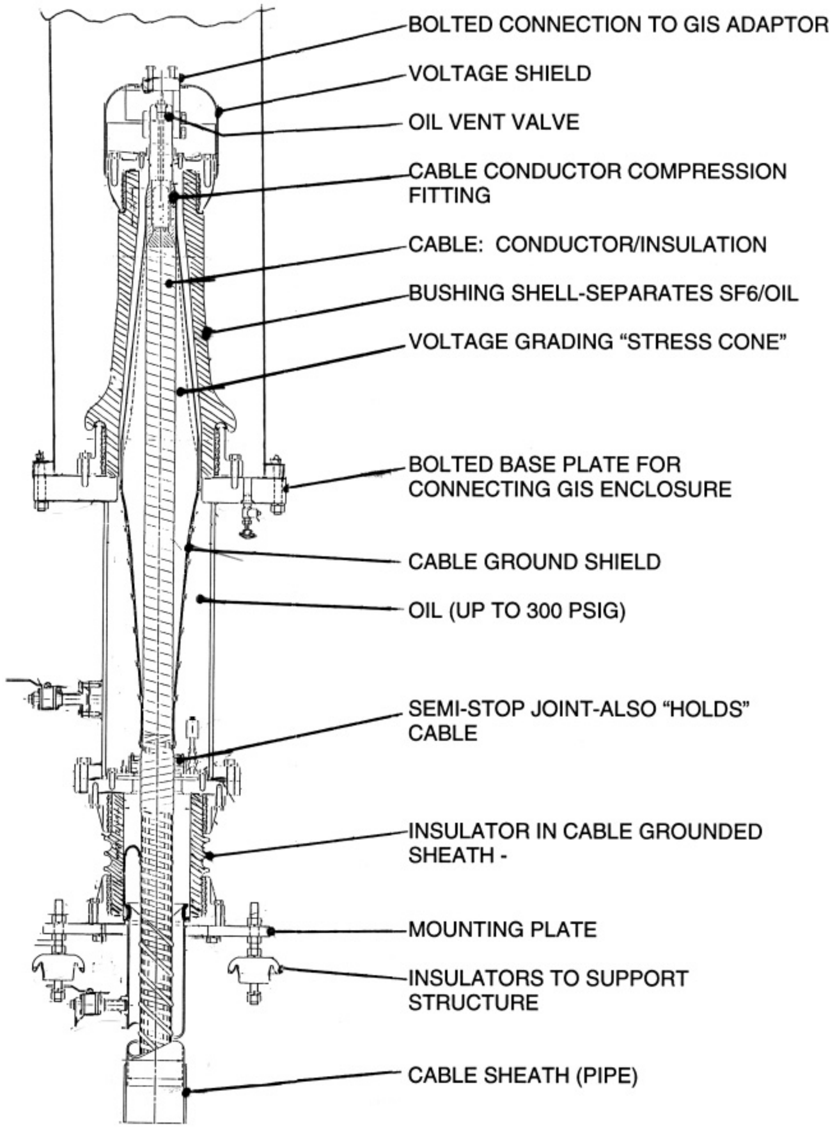


FIGURE 5.10 Power cable connection.

the breakdown voltage. Insulation coordination studies usually show there is no need for surge arresters in a GIS; however, many users specify surge arresters at transformers and cable connections as the most conservative approach.

Control System

For ease of operation and convenience in wiring the GIS back to the substation control room, a local control cabinet (LCC) is provided for each circuit breaker position (Fig. 5.13). The control and power wires for all the operating mechanisms, auxiliary switches, alarms, heaters, CTs, and VTs are brought from the GIS equipment modules to the LCC using shielded multiconductor control cables. In addition to providing terminals for all the GIS wiring, the LCC has a mimic diagram of the part of the GIS being controlled. Associated with the mimic diagram are control switches and position indicators for the circuit breaker and switches. Annunciation of alarms is also usually provided in the LCC. Electrical interlocking

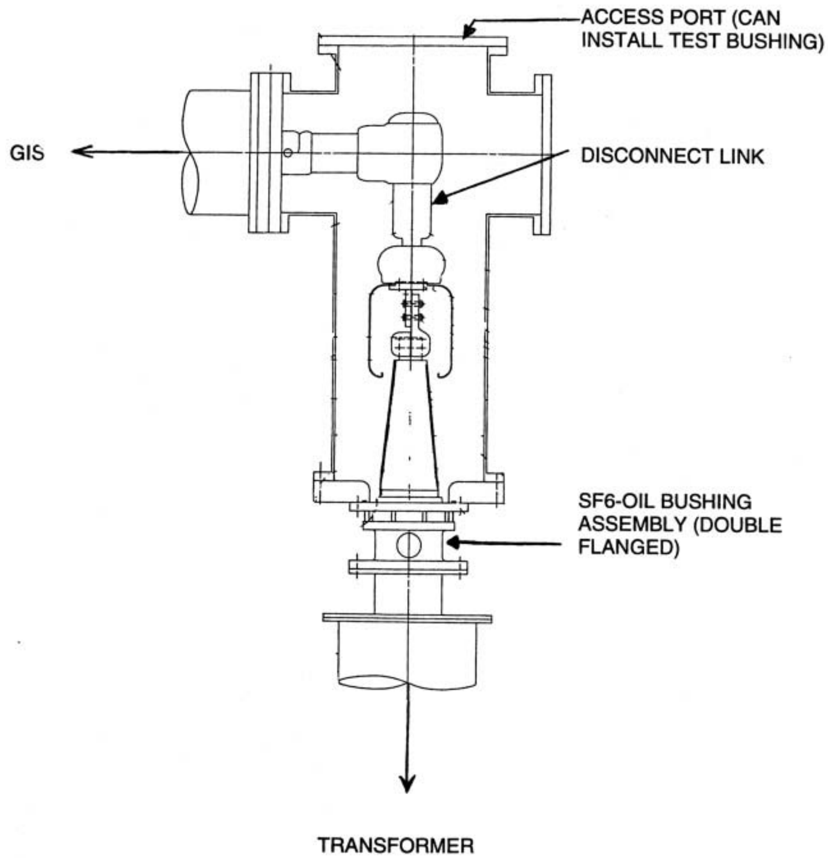


FIGURE 5.11 Direct SF6 bus connection to transfromer.

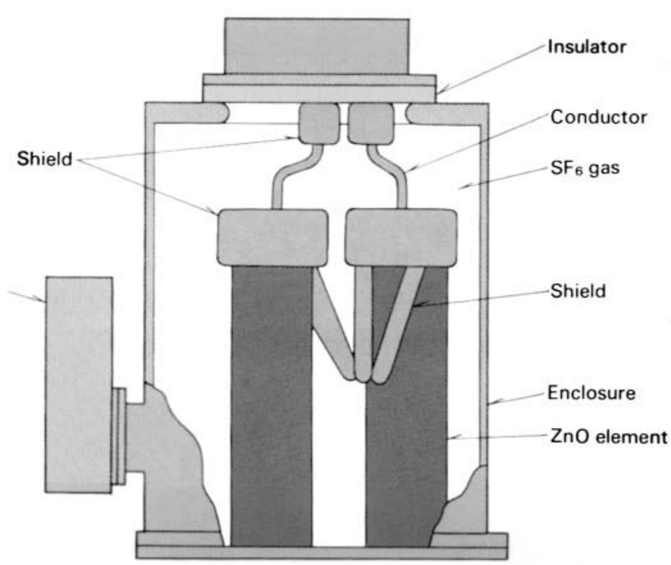


FIGURE 5.12 Surge arrester for GIS.

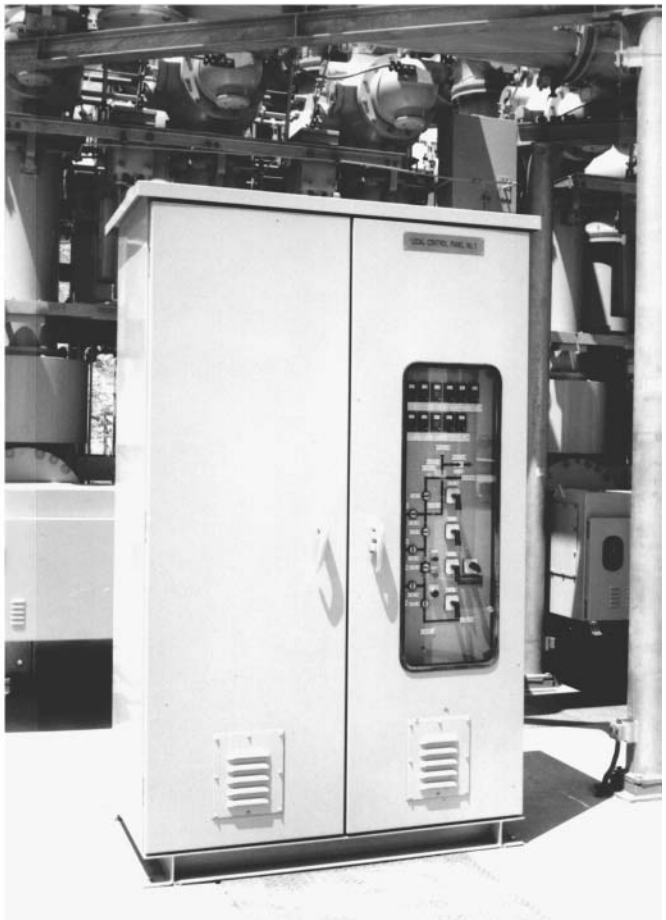


FIGURE 5.13 Local control cabinet for GIS.

and some other control functions can be conveniently implemented in the LCC. Although the LCC is an extra expense, with no equivalent in the typical AIS, it is so well established and popular that attempts to eliminate it to reduce cost have not succeeded. The LCC does have the advantage of providing a very clear division of responsibility between the GIS manufacturer and user in terms of scope of equipment supply.

Switching and circuit breaker operation in a GIS produces internal surge voltages with a very fast rise time on the order of nanoseconds and a peak voltage level of about 2 per unit. These "very fast transient overvoltages" are not a problem inside the GIS because the duration of this type of surge voltage is very short — much shorter than the lightning impulse voltage. However, a portion of the VFTO will emerge from the inside of the GIS at any place where there is a discontinuity of the metal enclosure — for example, at insulating enclosure joints for external CTs or at the SF6-to-air bushings. The resulting "transient ground rise voltage" on the outside of the enclosure may cause some small sparks across the insulating enclosure joint or to adjacent grounded parts. These may alarm nearby personnel but are not harmful to a person because the energy content is very low. However, if these VFT voltages enter the control wires, they could cause faulty operation of control devices. Solid-state controls can be particularly affected. The solution is thorough shielding and grounding of the control wires. For this reason, in a GIS, the control cable shield should be grounded at both the equipment and the LCC ends using either coaxial ground bushings or short connections to the cabinet walls at the location where the control cable first enters the cabinet.

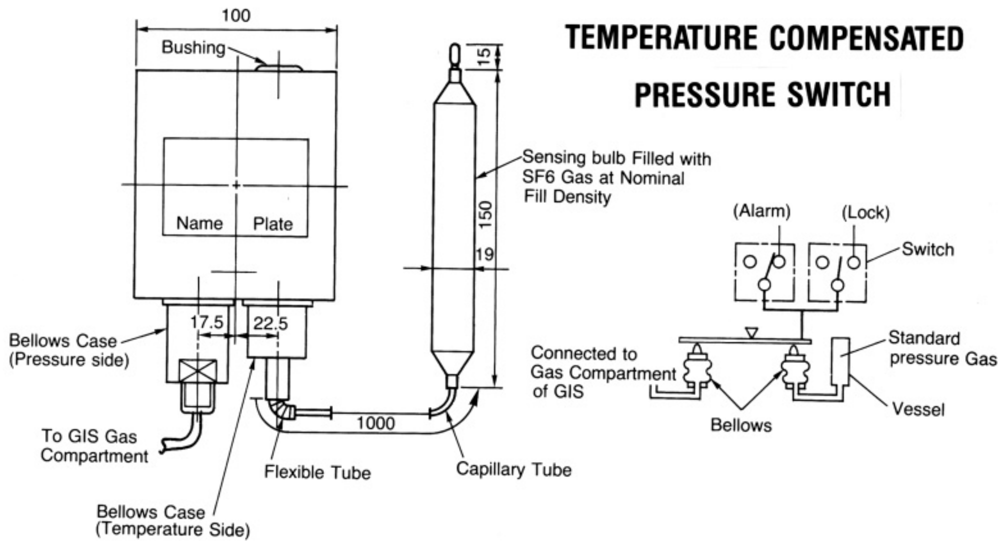


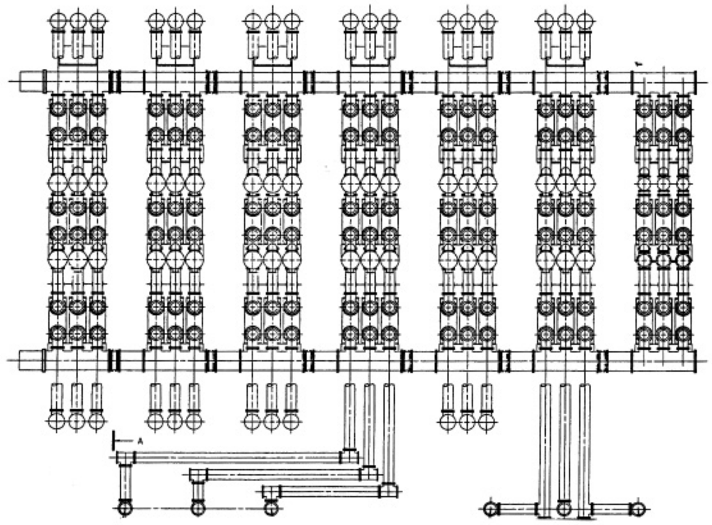
FIGURE 5.14 SF6 density monitor for GIS.

Gas Monitor System

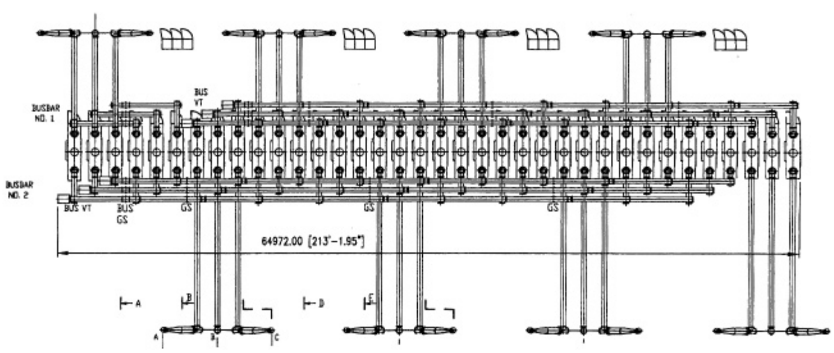
The insulating and interrupting capability of the SF6 gas depends on the density of the SF6 gas being at a minimum level established by design tests. The pressure of the SF6 gas varies with temperature, so a mechanical temperature-compensated pressure switch is used to monitor the equivalent of gas density (Fig. 5.14). GIS is filled with SF6 to a density far enough above the minimum density for full dielectric and interrupting capability so that from 10% to 20% of the SF6 gas can be lost before the performance of the GIS deteriorates. The density alarms provide a warning of gas being lost, and can be used to operate the circuit breakers and switches to put a GIS that is losing gas into a condition selected by the user. Because it is much easier to measure pressure than density, the gas monitor system usually has a pressure gage. A chart is provided to convert pressure and temperature measurements into density. Microprocessor-based measurement systems are available that provide pressure, temperature, density, and even percentage of proper SF6 content. These can also calculate the rate at which SF6 is being lost. However, they are significantly more expensive than the mechanical temperature-compensated pressure switches, so they are supplied only when requested by the user.

Gas Compartments and Zones

A GIS is divided by gas barrier insulators into gas compartments for gas handling purposes. In some cases, the use of a higher gas pressure in the circuit breaker than is needed for the other devices, requires that the circuit breaker be a separate gas compartment. Gas handling systems are available to easily process and store about 1000 kg of SF6 at one time, but the length of time needed to do this is longer than most GIS users will accept. GIS is therefore divided into relatively small gas compartments of less than several hundred kg. These small compartments may be connected with external bypass piping to create a larger gas zone for density monitoring. The electrical functions of the GIS are all on a three-phase basis, so there is no electrical reason not to connect the parallel phases of a single-phase enclosure type of GIS into one gas zone for monitoring. Reasons for not connecting together many gas compartments into large gas zones include a concern with a fault in one gas compartment causing contamination in adjacent compartments and the greater amount of SF6 lost before a gas loss alarm. It is also easier to locate a leak if the alarms correspond to small gas zones, but a larger gas zone will, for the same size leak, give more time to add SF6 between the first alarm and second alarm. Each GIS manufacturer has a standard approach to gas compartments and gas zones, but will, of course, modify the approach to satisfy the concerns of individual GIS users.



Natural – Each Bay Between Main Busbars Has Three Circuit Breakers



Linear – Circuit Breakers Are Side by Side

FIGURE 5.15 One-and-one-half circuit breaker layouts.

Electrical and Physical Arrangement

For any electrical one-line diagram there are usually several possible physical arrangements. The shape of the site for the GIS and the nature of connecting lines and/or cables should be considered. Figure 5.15 compares a "natural" physical arrangement for a breaker and a half GIS with a "linear" arrangement.

Most GIS designs were developed initially for a double bus, single breaker arrangement (Fig. 5.2). This widely used approach provides good reliability, simple operation, easy protective relaying, excellent economy, and a small footprint. By integrating several functions into each GIS module, the cost of the double bus, single breaker arrangement can be significantly reduced. An example is shown in Fig. 5.16. Disconnect and ground switches are combined into a "three-position switch" and made a part of each bus module connecting adjacent circuit breaker positions. The cable connection module includes the cable termination, disconnect switches, ground switches, a VT, and surge arresters.

Grounding

The individual metal enclosure sections of the GIS modules are made electrically continuous either by the flanged enclosure joint being a good electrical contact in itself or with external shunts bolted to the

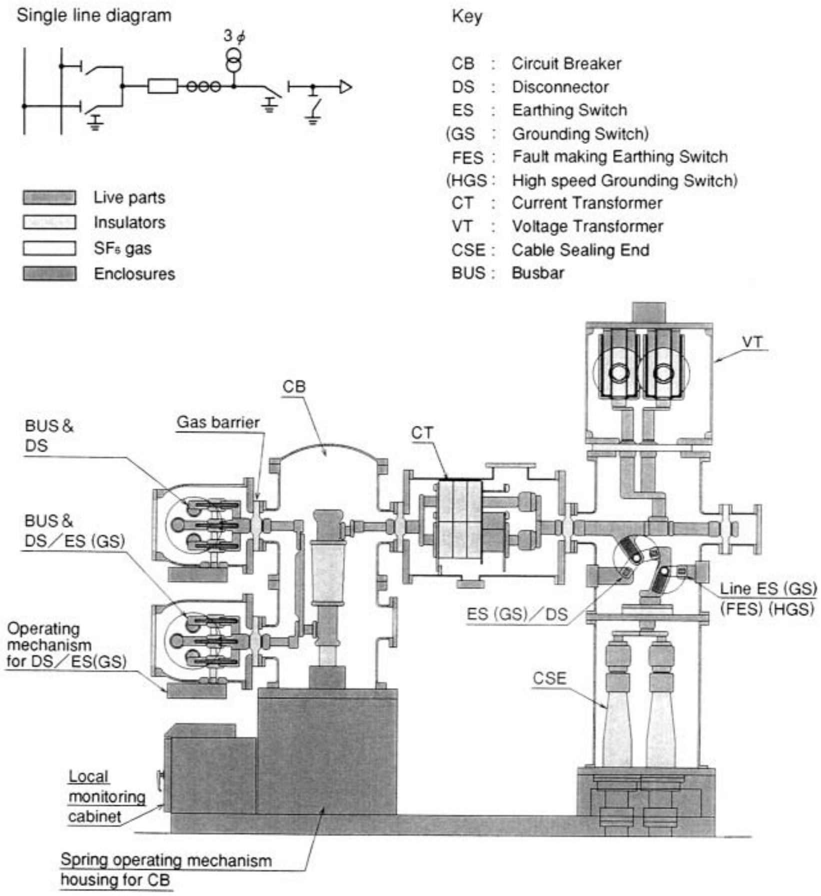


FIGURE 5.16 Integrated (combined function) GIS.

flanges or to grounding pads on the enclosure. While some early single-phase enclosure GIS were "single point grounded" to prevent circulating currents from flowing in the enclosures, today the universal practice is to use "multipoint grounding" even though this leads to some electrical losses in the enclosures due to circulating currents. The three enclosures of a single-phase GIS should be bonded to each other at the ends of the GIS to encourage circulating currents to flow. These circulating enclosure currents act to cancel the magnetic field that would otherwise exist outside the enclosure due to the conductor current. Three-phase enclosure GIS does not have circulating currents, but does have eddy currents in the enclosure, and should also be multipoint grounded. With multipoint grounding and the resulting many parallel paths for the current from an internal fault to flow to the substation ground grid, it is easy to keep the touch and step voltages for a GIS to the safe levels prescribed in IEEE 80.

Testing

Test requirements for circuit breakers, CTs, VTs, and surge arresters are not specific for GIS and will not be covered in detail here. Representative GIS assemblies having all of the parts of the GIS except for the circuit breaker are design tested to show that the GIS can withstand the rated lightning impulse voltage, switching impulse voltage, power frequency overvoltage, continuous current, and short-circuit current. Standards specify the test levels and how the tests must be done. Production tests of the factory-assembled GIS (including the circuit breaker) cover power frequency withstand voltage, conductor circuit resistance, leak checks, operational checks, and CT polarity checks. Components such as support insulators, VTs, and CTs are tested in accordance with the specific requirements for these items before assembly into the GIS. Field tests repeat the factory tests. The power frequency withstand voltage test is most important as a check of the cleanliness of the inside of the GIS in regard to contaminating conducting particles, as explained in the SF6 section above. Checking of interlocks is also very important. Other field tests may be done if the GIS is a very critical part of the electric power system, when, for example, a surge voltage test may be requested.

Installation

The GIS is usually installed on a monolithic concrete pad or the floor of a building. It is most often rigidly attached by bolting and/or welding the GIS support frames to embedded steel plates or beams. Chemical drill anchors can also be used. Expansion drill anchors are not recommended because dynamic loads may loosen expansion anchors when the circuit breaker operates. Large GIS installations may need bus expansion joints between various sections of the GIS to adjust to the fit-up in the field and, in some cases, provide for thermal expansion of the GIS. The GIS modules are shipped in the largest practical assemblies. At the lower voltage level, two or more circuit breaker positions can be delivered fully assembled. The physical assembly of the GIS modules to each other using the bolted flanged enclosure joints and sliding conductor contacts goes very quickly. More time is used for evacuation of air from gas compartments that have been opened, filling with SF6 gas, and control system wiring. The field tests are then done. For a high voltage GIS shipped as many separate modules, installation and testing takes about two weeks per circuit breaker position. Lower voltage systems shipped as complete bays, and mostly factory-wired, can be installed more quickly.

Operation and Interlocks

Operation of a GIS in terms of providing monitoring, control, and protection of the power system as a whole is the same as for an AIS except that internal faults are not self-clearing so reclosing should not be used for faults internal to the GIS. Special care should be taken for disconnect and ground switch operation because if these are opened with load current flowing, or closed into load or fault current, the arcing between the switch moving and stationary contacts will usually cause a phase-to-phase fault in three-phase enclosure GIS or to a phase-to-ground fault in single-phase enclosure GIS. The internal fault will cause severe damage inside the GIS. A GIS switch cannot be as easily or quickly replaced as an AIS switch. There will also be a pressure rise in the GIS gas compartment as the arc heats the gas. In extreme cases, the internal arc will cause a rupture disk to operate or may even cause a burn-through of the enclosure. The resulting release of hot, decomposed SF6 gas may cause serious injury to nearby personnel. For both the sake of the GIS and the safety of personnel, secure interlocks are provided so that the circuit breaker must be open before an associated disconnect switch can be opened or closed, and the disconnect switch must be open before the associated ground switch can be closed or opened.

Maintenance

Experience has shown that the internal parts of GIS are so well protected inside the metal enclosure that they do not age and as a result of proper material selection and lubricants, there is negligible wear of the switch contacts. Only the circuit breaker arcing contacts and the teflon nozzle of the interrupter experience wear proportional to the number of operations and the level of the load or fault currents being interrupted. Good contact and nozzle materials combined with the short interrupting time of modern circuit breakers provide, typically, for thousands of load current interruption operations and tens of full-rated fault current interruptions before there is any need for inspection or replacement. Except for circuit breakers in special use such as at a pumped storage plant, most circuit breakers will not be operated enough to ever require internal inspection. So most GIS will not need to be opened for maintenance. The external operating mechanisms and gas monitor systems should be visually inspected, with the frequency of inspection determined by experience.

Economics of GIS

The equipment cost of GIS is naturally higher than that of AIS due to the grounded metal enclosure, the provision of an LCC, and the high degree of factory assembly. A GIS is less expensive to install than an

AIS. The site development costs for a GIS will be much lower than for an AIS because of the much smaller area required for the GIS. The site development advantage of GIS increases as the system voltage increases because high voltage AIS take very large areas because of the long insulating distances in atmospheric air. Cost comparisons in the early days of GIS projected that, on a total installed cost basis, GIS costs would equal AIS costs at 345 kV. For higher voltages, GIS was expected to cost less than AIS. However, the cost of AIS has been reduced significantly by technical and manufacturing advances (especially for circuit breakers) over the last 30 years, but GIS equipment has not shown any cost reduction until very recently. Therefore, although GIS has been a well-established technology for a long time, with a proven high reliability and almost no need for maintenance, it is presently perceived as costing too much and is only applicable in special cases where space is the most important factor.

Currently, GIS costs are being reduced by integrating functions as described in the arrangement section above. As digital control systems become common in substations, the costly electromagnetic CTs and VTs of a GIS will be replaced by less-expensive sensors such as optical VTs and Rogowski coil CTs. These less-expensive sensors are also much smaller, reducing the size of the GIS and allowing more bays of GIS to be shipped fully assembled. Installation and site development costs are correspondingly lower. The GIS space advantage over AIS increases. GIS can now be considered for any new substation or the expansion of an existing substation without enlarging the area for the substation.

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5.2 Air Insulated Substations — Bus/Switching Configurations

Michael J. Bio

Various factors affect the reliability of a substation or switchyard, one of which is the arrangement of the buses and switching devices. In addition to reliability, arrangement of the buses/switching devices will impact maintenance, protection, initial substation development, and cost.

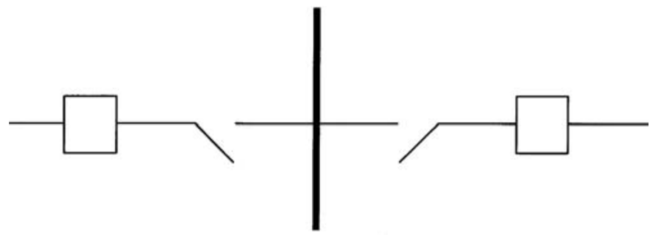

FIGURE 5.17 Single bus.

There are six types of substation bus/switching arrangements commonly used in air insulated substations:

1. Single bus
2. Double bus, double breaker
3. Main and transfer (inspection) bus
4. Double bus, single breaker
5. Ring bus
6. Breaker and a half

Single Bus (Fig. 5.17)

This arrangement involves one main bus with all circuits connected directly to the bus. The reliability of this type of an arrangement is very low. When properly protected by relaying, a single failure to the main bus or any circuit section between its circuit breaker and the main bus will cause an outage of the entire system. In addition, maintenance of devices on this system requires the de-energizing of the line connected to the device. Maintenance of the bus would require the outage of the total system, use of standby generation, or switching, if available.

Since the single bus arrangement is low in reliability, it is not recommended for heavily loaded substations or substations having a high availability requirement. Reliability of this arrangement can be improved by the addition of a bus tiebreaker to minimize the effect of a main bus failure.

Double Bus, Double Breaker (Fig. 5.18)

This scheme provides a very high level of reliability by having two separate breakers available to each circuit. In addition, with two separate buses, failure of a single bus will not impact either line. Maintenance of a bus or a circuit breaker in this arrangement can be accomplished without interrupting either of the circuits.

This arrangement allows various operating options as additional lines are added to the arrangement; loading on the system can be shifted by connecting lines to only one bus.

A double bus, double breaker scheme is a high-cost arrangement, since each line has two breakers and requires a larger area for the substation to accommodate the additional equipment. This is especially true in a low profile configuration. The protection scheme is also more involved than a single bus scheme.

Main and Transfer Bus (Fig. 5.19)

This scheme is arranged with all circuits connected between a main (operating) bus and a transfer bus (also referred to as an inspection bus). Some arrangements include a bus tie breaker that is connected between both buses with no circuits connected to it. Since all circuits are connected to the single, main bus, reliability of this system is not very high. However, with the transfer bus available during maintenance, de-energizing of the circuit can be avoided. Some systems are operated with the transfer bus normally de-energized.

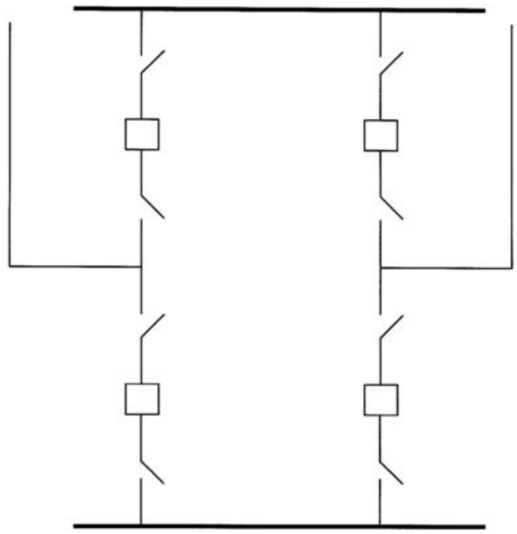

FIGURE 5.18 Double bus, double breaker.

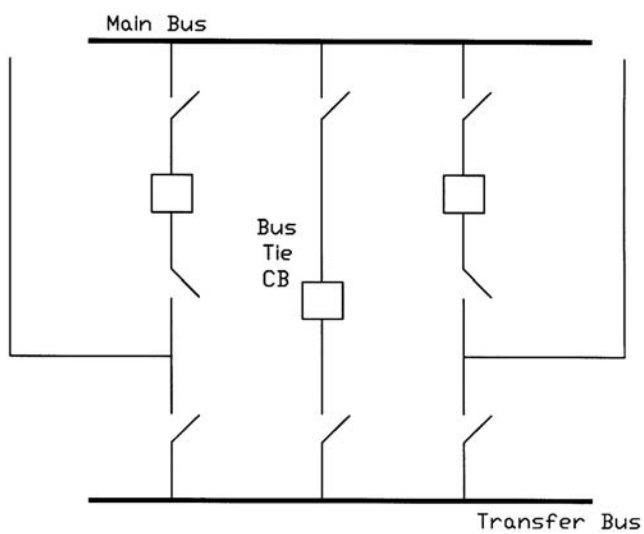

FIGURE 5.19 Main and transfer bus.

When maintenance work is necessary, the transfer bus is energized by either closing the tie breaker, or when a tie breaker is not installed, closing the switches connected to the transfer bus. With these switches closed, the breaker to be maintained can be opened along with its isolation switches. Then the breaker is taken out of service. The circuit remaining in service will now be connected to both circuits through the transfer bus. This way, both circuits remain energized during maintenance. Since each circuit may have a different circuit configuration, special relay settings may be used when operating in this abnormal arrangement. When a bus tie breaker is present, the bus tie breaker is the breaker used to replace the breaker being maintained, and the other breaker is not connected to the transfer bus.

A shortcoming of this scheme is that if the main bus is taken out of service, even though the circuits can remain energized through the transfer bus and its associated switches, there would be no relay protection for the circuits. Depending on the system arrangement, this concern can be minimized through the use of circuit protection devices (reclosure or fuses) on the lines outside the substation.

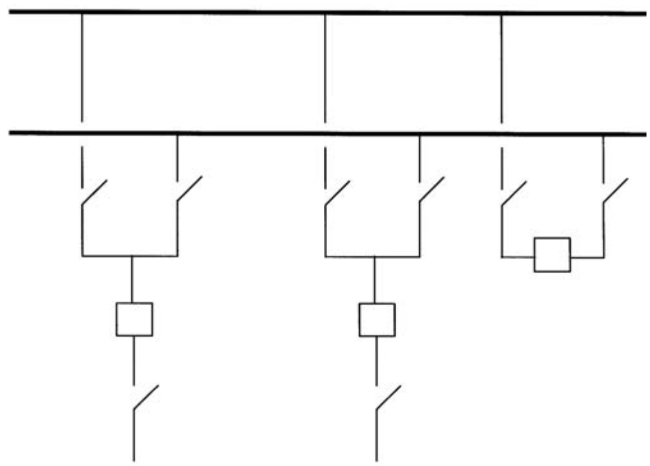

FIGURE 5.20 Double bus, single breaker.

This arrangement is slightly more expensive than the single bus arrangement, but does provide more flexibility during maintenance. Protection of this scheme is similar to that of the single bus arrangement. The area required for a low profile substation with a main and transfer bus scheme is also greater than that of the single bus, due to the additional switches and bus.

Double Bus, Single Breaker (Fig. 5.20)

This scheme has two main buses connected to each line circuit breaker and a bus tie breaker. Utilizing the bus tie breaker in the closed position allows the transfer of line circuits from bus to bus by means of the switches. This arrangement allows the operation of the circuits from either bus. In this arrangement, a failure on one bus will not affect the other bus. However, a bus tie breaker failure will cause the outage of the entire system.

Operating the bus tie breaker in the normally open position defeats the advantages of the two main buses. It arranges the system into two single bus systems, which as described previously, has very low reliability.

Relay protection for this scheme can be complex, depending on the system requirements, flexibility, and needs. With two buses and a bus tie available, there is some ease in doing maintenance, but maintenance on line breakers and switches would still require outside the substation switching to avoid outages.

Ring Bus (Fig. 5.21)

In this scheme, as indicated by the name, all breakers are arranged in a ring with circuits tapped between breakers. For a failure on a circuit, the two adjacent breakers will trip without affecting the rest of the system. Similarly, a single bus failure will only affect the adjacent breakers and allow the rest of the system to remain energized. However, a breaker failure or breakers that fail to trip will require adjacent breakers to be tripped to isolate the fault.

Maintenance on a circuit breaker in this scheme can be accomplished without interrupting any circuit, including the two circuits adjacent to the breaker being maintained. The breaker to be maintained is taken out of service by tripping the breaker, then opening its isolation switches. Since the other breakers adjacent to the breaker being maintained are in service, they will continue to supply the circuits.

In order to gain the highest reliability with a ring bus scheme, load and source circuits should be alternated when connecting to the scheme. Arranging the scheme in this manner will minimize the potential for the loss of the supply to the ring bus do to a breaker failure.

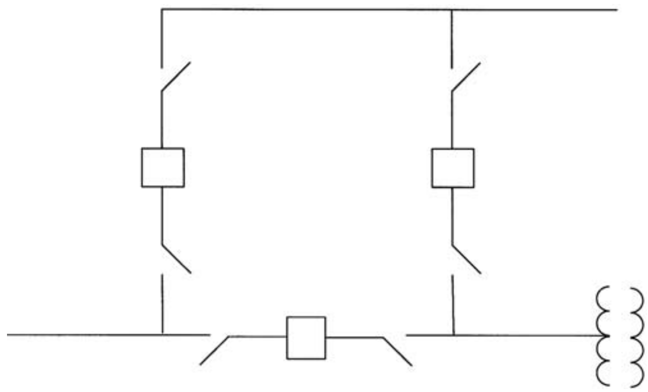

FIGURE 5.21 Ring bus.

Relaying is more complex in this scheme than some previously identified. Since there is only one bus in this scheme, the area required to develop this scheme is less than some of the previously discussed schemes. However, expansion of a ring bus is limited, due to the practical arrangement of circuits.

Breaker-and-a-Half (Fig. 5.22)

The breaker-and-a-half scheme can be developed from a ring bus arrangement as the number of circuits increase. In this scheme, each circuit is between two circuit breakers, and there are two main buses. The failure of a circuit will trip the two adjacent breakers and not interrupt any other circuit. With the three breaker arrangement for each bay, a center breaker failure will cause the loss of the two adjacent circuits. However, a breaker failure of the breaker adjacent to the bus will only interrupt one circuit.

Maintenance of a breaker on this scheme can be performed without an outage to any circuit. Furthermore, either bus can be taken out of service with no interruption to the service.

This is one of the most reliable arrangements, and it can continue to be expanded as required. Relaying is more involved than some schemes previously discussed. This scheme will require more area and is costly due to the additional components.

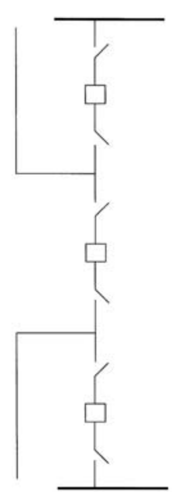

FIGURE 5.22 Breaker-and-a-half.

TABLE 5.1 Comparison of Configurations

Configuration	Reliability	Cost	Available Area
Single bus	Least reliable — single failure can cause complete outage	Least cost (1.0) — fewer components	Least area — fewer components
Double bus	Highly reliable — duplicated components; single failure normally isolates single component	High cost (1.8) — duplicated components	Greater area — twice as many components
Main bus and transfer	Least reliable — same as *Single bus*, but flexibility in operating and maintenance with transfer bus	Moderate cost (1.76) — fewer components	Low area requirement — fewer components
Double bus, single breaker	Moderately reliable — depends on arrangement of components and bus	Moderate cost (1.78) — more components	Moderate area — more components
Ring bus	High reliability — single failure isolates single component	Moderate cost (1.56) — more components	Moderate area — increases with number of circuits
Breaker-and-a-half	Highly reliable — single circuit failure isolates single circuit, bus failures do not affect circuits	Moderate cost (1.57) — breaker-and-a-half for each circuit	Greater area — more components per circuit

Note: The number shown in parenthesis is a per unit amount for comparison of configurations.

Comparison of Configurations

In planning an electrical substation or switchyard facility, one should consider major parameters as discussed above: reliability, cost, and available area. Table 5.1 has been developed to provide specific items for consideration.

In order to provide a complete evaluation of the configurations described, other circuit-related factors should also be considered. The arrangement of circuits entering the facility should be incorporated in the total scheme. This is especially true with the ring bus and breaker and a half schemes, since reliability in these schemes can be improved by not locating source circuits or load circuits adjacent to each other. Arrangement of the incoming circuits can add greatly to the cost and area required.

Second, the profile of the facility can add significant cost and area to the overall project. A high-profile facility can incorporate multiple components on fewer structures. Each component in a low-profile layout requires a single area, thus necessitating more area for an arrangement similar to a high-profile facility.

Therefore, a four-circuit, high-profile ring bus may require less area and be less expensive than a four-circuit, low-profile main and transfer bus arrangement.

5.3 High Voltage Switching Equipment

David L. Harris

The design of the high voltage substation must include consideration for the safe operation and maintenance of the equipment. Switching equipment is used to provide isolation, no load switching, load switching, and/or interruption of fault currents. The magnitude and duration of the load and fault currents will be significant in the selection of the equipment used.

System operations and maintenance must also be considered when equipment is selected. One significant choice is the decision of single-phase or three-phase operation. High voltage power systems are generally operated as a three-phase system, and the imbalance that will occur when operating equipment in a single-phase mode, must be considered.

Ambient Conditions

Air-insulated high voltage electrical equipment is generally covered by standards based on assumed ambient temperatures and altitudes. Ambient temperatures are generally rated over a range from –40°C to

+40°C for equipment that is air-insulated and dependent on ambient cooling. Altitudes above 1000 meters (3300 feet) may require derating.

At higher altitudes, air density decreases, hence the dielectric strength is also reduced and derating of the equipment is recommended. Operating (strike distances) clearances must be increased to compensate for the reduction in dielectric strength of the ambient air. Also, current ratings generally decrease at higher elevations due to the decreased density of the ambient air, which is the cooling medium used for dissipation of the heat generated by the load losses associated with load current levels.

Disconnect Switches

A disconnect switch is a mechanical device used to change connections within a circuit or isolate a circuit from its power source, and are normally used to provide isolation of the substation equipment for maintenance. Typically a disconnect switch would be installed on each side of a piece of equipment to provide a visible confirmation that the power conductors have been opened for personnel safety. Once the switches are placed in the open position, safety grounds can be attached to the de-energized equipment for worker protection. Switches can be equipped with grounding blades to perform the safety grounding function.

Disconnect switches are designed to continuously carry load currents and momentarily carry higher capacity for short-circuit currents for a specified duration (typically specified in seconds). They are designed for no load switching, opening or closing circuits where negligible currents are made or interrupted, or when there is no significant voltage across the open terminals of the switch. They are relatively slow-speed operating devices and therefore are not designed for arc interruption. Disconnect switches are also installed to bypass breakers or other equipment for maintenance and can also be used for bus sectionalizing. Interlocking equipment is available to prevent inadvertent operating sequence by inhibiting operation of the disconnect switch operation until the fault and/or load currents have been interrupted by the appropriate equipment.

Single-phase or three-phase operation is possible for some switches. Operating mechanisms are normally installed to permit operation of the disconnect switch by an operator standing at ground level. The operating mechanisms provide a swing arm or gearing to permit operation with reasonable effort by utility personnel. Motor operating mechanisms are also available and are applied when remote switching is necessary.

Disconnect switch operation can be designed for vertical or horizontal operating of the switch blades. Several configurations are frequently used for switch applications including:

- Vertical break
- Double break switches
- V switches
- Center-break switches
- Hook stick switches
- Vertical reach switches
- Grounding switches

Phase spacing is usually adjusted to satisfy the spacing of the bus system installed in the substation.

Load Break Switches

A load break switch is a disconnect switch that has been designed to provide making or breaking of specified currents. This is accomplished by addition of equipment that increases the operating speed of the disconnect switch blade and the addition of some type of equipment to alter the arcing phenomena and allow the safe interruption of the arc resulting when switching load currents.

Disconnect switches can be supplied with equipment to provide a limited load switching capability. Arcing horns, whips, and spring actuators are typical at lower voltages. These switches are used to de-energize or energize a circuit that possesses some limited amount of magnetic or capacitive current, such as transformer exciting current or line charging currents.

An air switch can be modified to include a series interrupter (typically vacuum or SF6) for higher voltage and current interrupting levels. These interrupters increase the load break capability of the disconnect switch and can be applied for switching load or fault currents of the associated equipment.

High Speed Grounding Switches

Automatic high-speed grounding switches are applied for protection of transformer banks when the cost of supplying other protective equipment is too costly. The switches are generally actuated by discharging a spring mechanism to provide the "high-speed" operation. The grounding switch operates to provide a deliberate ground on the high voltage bus supplying the equipment (generally a transformer bank), which is detected by protective relaying equipment remotely, and operates the transmission line breakers at the remote end of the line supplying the transformer. This scheme also imposes a voltage interruption to all other loads connected between the same remote breakers. A motor-operated disconnect switch is frequently installed along with a relay system to sense bus voltage and allow operation of a motor-operated disconnect switch when there is no voltage on the transmission line to provide automatic isolation of the faulted bank, and allow reclosing operation of the remote breaker to restore service to the transmission line.

The grounding switch scheme is dependent on the ability of the source transmission line relay protection scheme to recognize and clear the fault by opening the remote line circuit breaker. Clearing times are necessarily longer since the fault levels are not normally within the levels appropriate for an instantaneous trip response. The lengthening of the trip time also imposes additional stress on the equipment being protected and should be considered when selecting this method for bank protection. Grounding switches are usually considered when relative fault levels are low so that there is not the risk of significant damage to the equipment with the associated extended trip times.

Power Fuses

Power fuses are a generally accepted means of protecting power transformers in distribution substations. The primary purpose of a power fuse is to provide interruption of permanent faults. Fusing is an economical alternative to circuit switcher or circuit breaker protection. Fuse protection is generally limited to voltages from 34.5 kV through 69 kV, but has been applied for protection of 115-kV and 138-kV transformers.

To provide the greatest protective margin, it is necessary to use the smallest fuse rating possible. The advantage of close fusing is the ability of the fuse unit to provide backup protection for some secondary faults. For the common delta-wye connected transformer, a fusing ratio of 1.0 would provide backup protection for a phase-to-ground fault as low as 230% of the secondary full-load rating. Fusing ratio is defined as the ratio of the fuse rating to the transformer full load current rating. With low fusing ratios, the fuse may also provide backup protection for line-to-ground faults remote to the substation on the distribution network.

Fuse ratings also must consider parameters other than the full load current of the transformer being protected. Coordination with other overcurrent devices, accommodation of peak overloadings, and severe duty may require increased ratings of the fuse unit. The general purpose of the power transformer fuse is to accommodate, not interrupt, peak loads. Fuse ratings must consider the possibility of nuisance trips if the rating is selected too low for all possible operating conditions.

The concern of unbalanced voltages in a three-phase system must be considered when selecting fusing for power transformer protection. The possibility of one or two fuses blowing must be reviewed. Unbalanced voltages can cause tank heating in three-phase transformers and overheating and damage to three-phase motor loads. The potential for ferroresonance must be considered for some transformer configurations when using fusing.

Fuses are available in a number of tripping curves (standard, slow, and very slow) to provide coordination with other system protective equipment. Fuses are not voltage-critical; they may be applied at any voltage equal to or greater than their rated voltage. Fuses may not require additional structures, and are generally mounted on the incoming line structure, resulting in space savings in the substation layout.

Circuit Switchers

Circuit switchers have been developed to overcome some of the limitations of fusing for substation transformers. They are designed to provide three-phase interruption (solving the unbalanced voltage considerations) and provide protection for transient overvoltages and overloads at a competitive cost between the costs of fuses and circuit breakers. Additionally, they can provide protection from transformer faults based on differential, sudden pressure, and overcurrent relay schemes as well as critical operating constraints such as low oil level, high oil or winding temperature, pressure relief device operation, and others.

Circuit switchers are designed and supplied as a combination of a circuit breaking interrupter and an isolating disconnect switch. Later models have been designed with improved interrupters that have reduced the number of gaps and eliminated the necessity of the disconnect switch blades in series with the interrupter. Interrupters are now available in vertical or horizontal mounting configurations, with or without an integral disconnect switch. Circuit switchers have been developed for applications involving protection of power transformers, lines, capacitors, and line connected or tertiary connected shunt reactors.

Circuit switchers are an alternative to the application of circuit breakers for equipment protection. Fault duties may be lower and interrupting times longer than a circuit breaker. Some previous designs employed interrupters with multiple gaps and grading resistors and the integral disconnect switch as standard. The disconnect switch was required to provide open-circuit isolation in some earlier models of circuit switchers.

Circuit switchers originally were intended to be used for transformer primary protection. Advancements in the interrupter design have resulted in additional circuit switcher applications, including:

- Line and switching protection
- Cable switching and protection
- Single shunt capacitor bank switching and protection
- Shunt reactor switching and protection (line connected or tertiary connected reactors)

Circuit Breakers

A circuit breaker is defined as "a mechanical switching device capable of making, carrying and breaking currents under normal circuit conditions and also making, carrying and breaking for a specified time, and breaking currents under specified abnormal circuit conditions such as a short circuit" (IEEE Std. C37.100-1992).

Circuit breakers are generally classified according to the interrupting medium used to cool and elongate the electrical arc permitting interruption. The types are:

- Air magnetic
- Oil
- Air blast
- Vacuum
- SF6 gas

Air magnetic circuit breakers are limited to older switchgear and have generally been replaced by vacuum or SF6 for switchgear applications. Vacuum is used for switchgear applications and some outdoor breakers, generally 38 kV class and below. Air blast breakers, used for high voltages (≥765 kV), are no longer manufactured and have been replaced by breakers using SF6 technology.

Oil circuit breakers have been widely used in the utility industry in the past but have been replaced by other breaker technologies for newer installations. Two designs exist — bulk oil (dead tank designs) dominant in the U.S.; and oil minimum breaker technology (live tank design). Bulk oil circuit breakers were designed as single-tank or three-tank mechanisms; generally, at higher voltages, three-tank designs were dominant. Oil circuit breakers were large and required significant foundations to support the weight and impact loads occurring during operation. Environmental concerns forcing the necessity of oil retention systems, maintenance costs, and the development of the SF6 gas circuit breaker have led to the gradual replacement of the oil circuit breaker for new installations.

Oil circuit breaker development has been relatively static for many years. The design of the interrupter employs the arc caused when the contacts are parted and the breaker starts to operate. The electrical arc generates hydrogen gas due to the decomposition of the insulating mineral oil. The interrupter is designed to use the gas as a cooling mechanism to cool the arc and to use the pressure to elongate the arc through a grid (arc chutes), allowing extinguishing of the arc when the current passes through zero.

Vacuum circuit breakers use an interrupter that is a small cylinder enclosing the moving contacts under a high vacuum. When the contacts part, an arc is formed from contact erosion. The arc products are immediately forced to and deposited on a metallic shield surrounding the contacts. Without anything to sustain the arc, it is quickly extinguished.

Vacuum circuit breakers are widely employed for metal-clad switchgear up to 38 kV class. The small size of the breaker allows vertically stacked installations of breakers in a two-high configuration within one vertical section of switchgear, permitting significant savings in space and material compared to earlier designs employing air magnetic technology. When used in outdoor circuit breaker designs, the vacuum cylinder is housed in a metal cabinet or oil-filled tank for dead tank construction popular in the U.S. market.

Gas circuit breakers generally employ SF6 (sulfur hexaflouride) as an interrupting and sometimes as an insulating medium. In "single puffer" mechanisms, the interrupter is designed to compress the gas during the opening stroke and use the compressed gas as a transfer mechanism to cool the arc and to elongate the arc through a grid (arc chutes), allowing extinguishing of the arc when the current passes through zero. In other designs, the arc heats the SF6 gas and the resulting pressure is used for elongating and interrupting the arc. Some older two-pressure SF6 breakers employed a pump to provide the high-pressure SF6 gas for arc interruption.

Gas circuit breakers typically operate at pressures between six and seven atmospheres. The dielectric strength of SF6 gas reduces significantly at lower pressures, normally as a result of lower ambient temperatures. Monitoring of the density of the SF6 gas is critical and some designs will block operation of the circuit breaker in the event of low gas density.

Circuit breakers are available as live-tank or dead-tank designs. Dead-tank designs put the interrupter in a grounded metal enclosure. Interrupter maintenance is at ground level and seismic withstand is improved versus the live-tank designs. Bushings are used for line and load connections which permit installation of bushing current transformers for relaying and metering at a nominal cost. The dead-tank breaker does require additional insulating oil or gas to provide the insulation between the interrupter and the grounded tank enclosure.

Live-tank circuit breakers consist of an interrupter chamber that is mounted on insulators and is at line potential. This approach allows a modular design as interrupters can be connected in series to operate at higher voltage levels. Operation of the contacts is usually through an insulated operating rod or rotation of a porcelain insulator assembly by an operator at ground level. This design minimizes the quantity of oil or gas used for interrupting the arc as no additional quantity is required for insulation of a dead-tank enclosure. The design also readily adapts to the addition of pre-insertion resistors or grading capacitors when they are required. Seismic capability requires special consideration due to the high center of gravity of the interrupting chamber assembly.

Interrupting times are usually quoted in cycles and are defined as the maximum possible delay between energizing the trip circuit at rated control voltage and the interruption of the main contacts in all poles. This applies to all currents from 25 to 100% of the rated short-circuit current.

Circuit breaker ratings must be examined closely. Voltage and interrupting ratings are stated at a maximum operating voltage rating, i.e., 38 kV voltage rating for a breaker applied on a nominal 34.5-kV circuit. The breakers have an operating range designated as K factor per IEEE C37.06, (see Table 3 in the document's appendix). For a 72-kV breaker, the voltage range is 1.21, indicating that the breaker is capable of its full interrupting rating down to a voltage of 60 kV.

Breaker ratings need to be checked for some specific applications. Applications requiring reclosing operation should be reviewed to be sure that the duty cycle of the circuit breaker is not being exceeded. Some applications for out-of-phase switching or back-to-back switching of capacitor banks also require review and may require specific-duty circuit breakers to insure proper operation of the circuit breaker during fault interruption.

GIS Substations

Advancements in the use of SF6 as an insulating and interrupting medium have resulted in the development of gas insulated substations. Environmental and/or space limitations may require the consideration of GIS (gas insulated substation) equipment. This equipment utilizes SF6 as an insulating and interrupting medium and permits very compact installations.

Three-phase or single-phase bus configurations are normally available up to 145 kV class, and single-phase bus to 500 kV and higher, and all equipment (disconnect/isolating switches, grounding switches, circuit breakers, metering current, and potential transformers, etc.) are enclosed within an atmosphere of SF6 insulating gas. The superior insulating properties of SF6 allow very compact installations.

GIS installations are also used in contaminated environments and as a means of deterring animal intrusions. Although initial costs are higher than conventional substations, a smaller substation footprint can offset the increased initial costs by reducing the land area necessary for the substation.

Environmental Concerns

Environmental concerns will have an impact on the siting, design, installation, maintenance, and operation of substation equipment.

Sound levels, continuous as well as momentary, can cause objections. The operation of a disconnect switch, switching cables, or magnetizing currents of a transformer will result in an audible noise associated with the arc interruption in air. Interrupters can be installed to mitigate this noise. Closing and tripping of a circuit breaker will result in an audible momentary sound from the operating mechanism. Transformers and other magnetic equipment will emit continuous audible noise.

Oil insulated circuit breakers and power transformers may require the installation of systems to contain or control an accidental discharge of the insulating oil and prevent accidental migration beyond the substation site. Lubricating oils and hydraulic fluids should also to be considered in the control/containment decision.

References

American National Standard for Switchgear — AC High-Voltage, IEEE Std. C37.06-1997, Circuit Breakers Rated on a Symmetrical Current Basis — Preferred Ratings and Related Required Capabilities.

IEEE Guide for Animal Deterrents for Electric Power Supply Substations, IEEE Std. 1264-1993.

IEEE Guide for Containment and Control and Containment of Oil Spills in Substations, IEEE Std. 980-1994.

IEEE Guide for the Design, Construction and Operation of Safe and Reliable Substations for Environmental Acceptance, IEEE Std. 1127-1998.

IEEE Guide for Gas-Insulated Substations, IEEE Std. C37.122.1-1993.

IEEE Standards Collection: Power and Energy — Substations, 1998.

IEEE Standards Collection: Power and Energy — Switchgear, 1998.

IEEE Standard for Interrupter Switches for Alternating Current, Rated Above 1000 Volts, IEEE Std. 1247-1998.

IEEE Standard Definitions for Power Switchgear, IEEE Std. C37.100-1992.

IEEE Standard for Gas-Insulated Substations, IEEE Std. C37.122-1993.

5.4 High Voltage Power Electronics Substations

Gerhard Juette

Details on power electronics are provided in Chapter 15, whereas gas insulated and air insulated substations in general are covered in Sections 5.1 and 5.2 of this chapter. This section focuses on the specifics of power electronics as applied in substations for power transmission purposes.

The dramatic development of power electronics in the past few decades made significant progress in electric power transmission technology possible, resulting in special types of transmission substations.

The most important high voltage power electronics substations are frequency converters, above all for High Voltage Direct Current (HVDC) transmission, and controllers for Flexible AC Transmission Systems (FACTS), including electric energy storage, Static VAr Compensators (SVC), Static Compensator (STATCOM), Thyristor Controlled Series Compensation (TCSC), and the Unified Power Flow Controller (UPFC). Detailed descriptions of these circuits can be found in Chapter 15, Power Electronics.

In addition to the conventional substation elements covered in Sections 5.1 and 5.2, high voltage power electronic substations typically include harmonic filtering and reactive compensation equipment, as well as the main power electronic equipment with its dedicated transformers, buildings, coolers, and auxiliaries.

Most high voltage power electronics substations are air insulated, although some use combinations of air and gas insulation. Typically, passive filters and reactive compensation equipment are air insulated and outdoors, while power and control electronics, active filters, and most communication and auxiliary systems are air insulated, but indoors.

Basic community considerations, grounding, lightning protection, seismic, and fire protection considerations also apply. In addition, high voltage power electronic substations may emit characteristic electric and acoustic noise and may require extra fire protection.

The IEEE, CIGRE, and other international technical societies continue to develop technical standards, disseminate information, and facilitate the exchange of know-how in this high-tech power engineering field. Within the IEEE, the following group is concerned with high voltage power electronics substations: Power Engineering Society (PES) — Substations Committee — High Voltage Power Electronics Stations Subcommittee. The related Web page is: http://home.att.net/(gengmann/.

Types

The high voltage power electronic circuits covered here are frequency converters, with an emphasis on HVDC and FACTS controllers, including recent developments.

Frequency Converters (HVDC)

Frequency converters transmit power between systems with different constant or variable frequencies. Some examples are converters between variable speed machines and power grids, energy storage converters, converters for railroad systems, and, most importantly, HVDC (High Voltage Direct Current transmission).

HVDC converters convert AC power to DC power and vice versa. They terminate DC transmission lines and cables or form back-to-back asynchronous AC system couplings. When connected to DC transmission lines, the converter voltages can be on the order of a million volts (±500 kV) and power ratings can reach thousands of megawatts. With back-to-back converters, where DC line economies are not a consideration, the DC voltage and current are chosen so as to minimize converter cost. This choice results in DC voltages up to and exceeding 100 kV at power ratings up to several hundred megawatts.

Most HVDC converters are line commutated Graetz bridge converters that require substantial AC harmonic filtering and reactive compensation. Converters connected to DC lines have harmonic filters on the DC side as well. Traditionally, passive filters which consist of capacitors, reactors, and resistors have been used. Recently, self-commutated HVDC converters are being introduced (Torgerson et al., 1997; Asplund, 1998; EPRI, 1998), as are active (electronic) AC and DC harmonic filters (Pereira, 1995; Andersen, 1997), using GTO thyristors, IGBTs, and other devices with gate-turn-off capability.

The AC system or systems to which a converter station is connected significantly impact the station's design in many ways. This is true for harmonic filters, reactive compensation devices, fault duties, and insulation coordination. Weak AC systems (i.e., low short-circuit ratios), represent special challenges for the design of HVDC converters (IEEE Std. 1204-1997). Some stations include temporary overvoltage limiting devices, which consist of MOV arresters with forced cooling or fast switches (deLaneuville et al., 1991).

Many converter stations, HVDC stations in particular, require DC voltage insulation coordination. Internal equipment insulation, for example the insulation of transformers and bushings, must take the DC voltage gradient distribution in solid and mixed dielectrics into account. Substation clearances and creepage distances must have the proper dimensions. Standards for indoor and outdoor clearances and creepage distances are currently being promulgated (CIGRE Working Group 33-05, 1984). DC electric fields enhance the pollution of exposed surfaces. This pollution, particularly in combination with water, can adversely influence the conductivity, voltage distribution, and withstand capability of insulating surfaces. Therefore, it is especially important with converter stations to apply either grease, special compounds, and/or booster sheds, and to engage in adequate cleaning practices. Insulation problems with extra high voltage DC bushings continue to be a matter of concern and study (Schneider et al., 1991; Porrino et al., 1995).

A specific issue with DC transmission is the use of ground return. Used during contingencies, ground (and/or sea) return can increase the economy and availability of long distance HVDC transmission. The necessary electrodes are usually located at some distance from the station, with a neutral line that leads to them. The related neutral buswork, switching devices, and protection systems form part of the station. Electrode design depends on the local soil or water conditions (Tykeson et al., 1996; Holt et al., 1997). The National Electric Safety Code (NESC) does not allow the use of ground as the sole conductor. Monopolar HVDC operation is permitted only under emergencies and for a limited time. The IEEE-PES is working toward the introduction of changes to the code to better meet the needs of HVDC transmission while addressing potential side effects to other systems.

Disconnect switches are the only mechanical switching devices on the DC side of a typical HVDC converter station. No true DC breakers exist and DC fault currents are best and fastest interrupted by the converters themselves. Mechanical breaker systems with limited DC current interrupting capability have been developed (Vithayathil et al., 1985). They include commutation circuits, i.e., parallel L/C resonance circuits that create current zeroes across the breaker contacts. So far, only experimental "DC breakers" have ever been installed in actual HVDC stations.

Figures 5.23 through 5.26 show photos of different converter stations. The station shown in Fig. 5.23 is one of several asynchronous links between the western and eastern North American power grids. In the photo, one can recognize the control building (next to the communication tower), the valve hall attached to it, the converter transformers on both sides, the AC filter circuits (near the center line), as well as the AC buses (at the outer left and right) with major reactive power compensation and TOV suppression equipment which was used in this low-short-circuit-ratio installation. The valve groups shown in Fig. 5.24 are arranged back-to-back, i.e., across the aisle in the same room. Fig. 5.25 shows a 500 kV long-distance HVDC valve hall, with the valves suspended from the ceiling to withstand major seismic events. The converter station shown in Fig. 5.26 is the south terminal of the Nelson River ± 500 kV HVDC transmission sytem in Manitoba, Canada. It consists of two bipoles completed in 1973 and 1985. The DC yard and line connections are on the left side, while the 230 kV AC yard with harmonic filters and converter transformers is on the right side of the picture. In total, the station is rated 3670 MW.

FACTS Controllers

Different types of FACTS controllers and the theory underlying their function are covered in Chapter 15, Power Electronics. Typical ratings of these controllers range from about thirty to several hundred MVA. Normally, FACTS controllers are an integral part of AC substations. Like HVDC, they require controls, cooling systems, harmonic filters, fixed capacitors, transformers, and building facilities.

FIGURE 5.23 200 MW HVDC back-to-back converter station, at Sidney, Nebraska. (Photo courtesy Siemens.)

Static VAr Compensators (SVC) have been used successfully for many years, either for load (flicker) compensation of large industrial loads, or for transmission compensation in utility systems. Harmonic filter and capacitor banks, as well as (normally air core) reactors, step down transformers, a building, breakers and disconnect switches on the high voltage side, and heavy duty busbars on the medium voltage side characterize most SVC stations. The power electronic (thyristor) controllers can have air or liquid cooling. A new type of controlled shunt compensator, called STATCOM, uses voltage source inverters (Schander et al., 1995). STATCOM requires fewer harmonic filters and capacitors than an SVC, and no reactors at all. This fact makes the footprint of a STATCOM station significantly more compact than that of a conventional SVC.

Thyristor Controlled Series Capacitors (TCSC) (Piwko et al., 1994; Montoya et al., 1990) involve insulated platforms at phase potential, with weatherproof valve housings, as well as communication links between platform and ground. Liquid cooling requires ground-to-platform pipes made of insulating material. Auxiliary platform power, where needed, is extracted from the line current via CTs. As most conventional SCs, TCSCs are typically integrated into existing substations. Upgrading an existing SC to TCSC is generally possible.

While SVC and STATCOM controllers are shunt devices, and TCSC are series devices, the UPFC (Unified Power Flow Controller) is a combination of both (Mehraban et al., 1996). It uses a shunt connected transformer and a transformer with series connected line windings, both of which are inter-connected to a DC capacitor via related power electronic circuits in the control building. The newest FACTS station project (Fardanesh et al., 1998) involves similar shunt and series elements as the UPFC, and can be reconfigured to meet changing system requirements.

The ease with which FACTS stations can be reconfigured or even relocated, may be important and can influence the substation design (Renz et al., 1994; Knight et al., 1998). Changes in generation and load patterns may make such flexibility desirable.

Figures 5.27 through 5.31 are photos of FACTS substations. In Fig. 5.27, one can distinguish the 500-kV feeder (on the left side), the transformers (three single-phase units plus one spare), the medium voltage bus work and three Thyristor Switched Capacitor (TSC) banks, as well as the building which houses the thyristor switches and controls. The SVC shown in Fig. 5.28 is also connected to 500 kV. It uses Thyristor

FIGURE 5.24 600 MW HVDC back-to-back converter valves. (Photo courtesy Siemens.)

Controlled Reactors (TCRs) and TSCs, which are visible together with the 11 kV high current buswork behind the building. The harmonic filters are before the building and are not visible in the photo. Figure 5.29 shows the three 500-kV platforms of one of the world's first commercial TCSC installations in Brazil. The platform-mounted valve housings are clearly visible. Figure 5.30 shows an SVC being relocated. The controls and valves are in container-like e-houses, which allow for faster relocation. Figure 5.31 is a photo of the world's first Unified Power Flow Controller (UPFC) connected to AEP's "Inez" 138-kV substation in eastern Kentucky, U.S. The main components are identified and clearly visible.

Control

HVDC and FACTS controllers allow steady-state, quasi-steady-state, dynamic, and transient control actions and they provide important equipment and system protection functions. Fault monitoring and

FIGURE 5.25 Valve hall of ±500 kV, 1000 MW long-distance HVDC converter station. (Photo courtesy Siemens.)

FIGURE 5.26 Dorsey Terminal of the Nelson River HVDC transmission system. (Photo courtesy Manitoba Hydro.)

sequence of event recording equipment are used in most power electronics stations. Typically, these stations are remotely controlled and offer full local controllability. Man-machine interfaces are often highly computerized, with extensive supervision and control being exercised via monitor and keyboard. All of these functions add to the basic substation secondary systems described in Section 5.4.

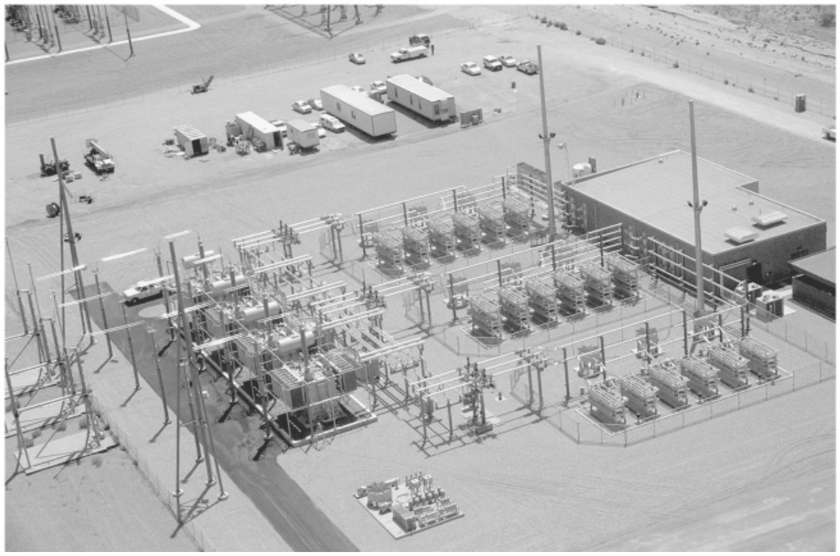

FIGURE 5.27 500 kV, 400 MVAr SVC at Adelanto, California. (Photo courtesy Siemens.)

FIGURE 5.28 500 kV, 400 MVAr SVC Chinu, I.S.A., Colombia. (Photo courtesy Siemens.)

One of the most complex control algorithms applies to HVDC converters. Real power, reactive power, AC bus frequency and voltage, start-up and shut-down sequences, contingency and fault recovery sequences, remedial action schemes, modulation schemes for system oscillation and SSR damping, and loss of communication are some of the applicable control parameters and conditions. Special v/i control characteristics are used for converters in multi-terminal HVDC systems to allow their safe operation even under a loss of inter-station communication. Furthermore, HVDC controls provide equipment and system protection, such as thyristor overcurrent, thyristor temperature, and DC line fault protection.