CHAPTER 1

FUNDAMENTALS OF ELECTRIC POWER SYSTEMS

Xiao-Ping Zhang

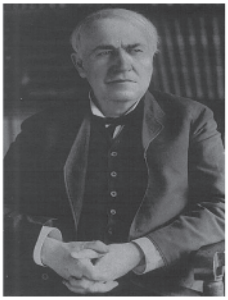
1.1 INTRODUCTION OF ELECTRIC POWER SYSTEMS

Commercial use of electricity began in the late 1870s when the inventive genius of Edison (Fig. 1.1) brought forth the electric incandescent light bulb. The first complete electric power system was the Pearl Street system in New York, which began operation in 1882 and was actually a DC system with a steam-driven DC generator. With the development of the transformer, polyphase systems, and AC transmission, the first three-phase line in North America was put into operation in 1893. It was then found that AC transmission with the help of transformers was preferable because DC transmission was impractical due to higher power losses.

With the development of electric power systems, interconnection of neighboring electric power systems leads to improved system security and economy. However, with the advent of interconnection of large-scale power systems, operation, control and planning of such systems become challenging tasks. With the development of digital computers and modern control techniques, automatic generation control (AGC) and voltage and reactive power control techniques have been introduced to operate and control modern large-scale power systems. Load flow solution has become the most frequently performed routine method of power network calculation, and can be used in power system planning, operational planning, operation control, and security analysis. With the advent of interconnected large-scale electric power systems, new dynamic phenomena, including transient stability, voltage stability, and low-frequency oscillations, have emerged. With the development of an electricity market, electricity companies engage in as many transactions in one hour as they once conducted in an entire day. Such increased load demand along with uncertainty of transactions will further strain electric power systems. Moreover, large amounts of decentralized renewable generation, in particular wind generation, connected with the network will result in further uncertainty of load and power flow distribution and impose additional strain on electric power system operation and control. It is a real challenge to ensure that the transmission system is flexible enough to meet new and less predictable supply and demand conditions in competitive

Restructured Electric Power Systems: Analysis of Electricity Markets with Equilibrium Models,
Edited by Xiao-Ping Zhang

George Westinghouse



Thomas Alva Edison

Nikola Tesla

Figure 1.1 Pioneers of electric power systems

electricity markets. FACTS (flexible AC transmission systems) devices are considered low-environmental-impact technologies and are a proven enabling solution for rapidly enhancing reliability and upgrading transmission capacity on a long-term cost-effective basis. FACTS can provide voltage regulation, congestion management, enhancement of transfer capability, fast control of power oscillations, voltage stability control, and fault ride-through. The ever-increasing frequency of blackouts seen in developed countries has increased the need for new power system control technologies such as FACTS devices. With the development of advanced technologies and operation concepts such as FACTS, high voltage DC (HVDC), wide area measurements, microgrid systems, smart metering, and demand-side management, the development of smart grids is underway. It has been recognized that SCADA/EMS Supervisory Control and Data Acquisition/Energy Management System plays a key role in the operating electricity networks and that state estimation is the key function of an EMS.

1.2 ELECTRIC POWER GENERATION

1.2.1 Conventional Power Plants

1.2.1.1 Fossil Fuel Power Plants Basically, fossil fuel power plants burn fossil fuels such as coal, natural gas, or petroleum (oil) to produce electricity. Traditionally, fossil fuel power plants are designed for continuous operation and large-scale production, and they are considered one of the major electricity production sources. The basic production process of a fossil fuel power plant is that the heat energy of combustion is converted into mechanical energy via a prime mover, a steam or gas turbine, then the mechanical energy is further converted into electrical energy via an AC generator, a synchronous generator.

It should be mentioned that the by-products of power plant production such as carbon dioxide, water vapor, nitrogen, nitrous oxides, and sulfur oxides need to be considered in both the design and operation of the power plant. Some of these by-products are harmful to the environment. In dealing with this, clean coal technology can remove sulfur dioxide and reburn it, which can enhance both the efficiency and the environmental acceptability of coal extraction, preparation, and use.

In addition to coal, natural gas is considered another major source of electricity generation, using gas and steam turbines. It is well known that high efficiencies can be achieved by combining gas turbines with a steam turbine in the so-called combined cycle mode. Basically, natural gas generation is cleaner than other fossil fuel power plants using oil and coal, and hence produces less carbon dioxide per unit energy generated. It is worth mentioning that fuel cell technology may provide cleaner options for converting natural gas into electricity, though such a generation technology is still not competitive in terms of generation costs.

1.2.1.2 CCGT Power Plants The combined cycle gas turbine (CCGT) process utilizes rotational energy produced from gas turbines driving AC generators as well as the additional power made available from the waste heat contained in the gas turbine exhaust. The heat is passed through a heat recovery steam generator, one for each gas turbine, and the steam generated is then used to produce rotational energy in a steam turbine driving a second AC generator.

For a thermal power station, high-pressure steam requires strong, bulky components and high temperatures require expensive alloys made from nickel or cobalt. Due to the physical limitation of the alloys, practical steam temperatures do not exceed 655 °C, while the lower temperature of a steam plant is determined by the boiling point of water. Considering these constraints, the maximum efficiency of a steam plant is between 35% and 42%.

In contrast, for a combined cycle power plant, the heat of the gas turbine's exhaust can be used to generate steam driving a heat recovery steam generator with a steam temperature between 420 and 580 °C. This will in turn increase the CCGT plant thermal efficiency to 54%.

1.2.1.3 Nuclear Power Plants Nuclear power technology extracts usable energy from atomic nuclei via controlled nuclear reactions and includes nuclear fission, nuclear fusion, and radioactive decay methods. Nuclear fission is the one most widely used for power generation today. The production process of a nuclear power plant is that nuclear reactors are used to heat water to produce steam, the steam is converted into mechanical energy via a turbine, and the mechanical energy can then be further converted into electrical energy via an AC generator, a synchronous generator. More than 15% of the world's electricity comes from nuclear power, where nuclear electricity generation is nearly carbon-free. It is estimated that replacing a coal-fired power plant with a 1 GW nuclear power plant can avoid emission of 6–7 million tons of CO_2 per year.

According to data from the International Energy Agency, existing nuclear power plants in operation worldwide have a total capacity of 370 GW. Most of them are second-generation light-water reactors (LWR) that were built in the 1970s and 1980s. Around 85% of the nuclear generation capacity is in US, France, Japan, Russia, the UK, Korea, and India. Third-generation nuclear power plant technology was developed in the 1990s to improve the safety and economics of nuclear power. However, due to the Chernobyl nuclear power accident in 1986, demand for constructing new nuclear power plants was much reduced and hence only a limited number of third-generation reactors have been built. The fourth generation of nuclear reactors has been developed within an international framework where safety and economic performance are improved, nuclear waste is minimized, and proliferation resistance is enhanced.

Nuclear power is a capital-intensive technology where the cost of electricity generated from new power plants depends on investment cost, discount rate, construction time (typically 5–7 years or even longer), and economic lifetime (say 25–40 years). It was estimated by the International Energy Agency in 2006 that, with an assumed carbon price of $25/t$CO_2$, the contribution of nuclear power generation to global electricity supply would increase to some 19–22% by 2050, where global nuclear power plant capacity would be at least doubled. Nuclear power could reduce global CO_2 emissions by 6% to 10%. With increasing oil prices and concerns about CO_2 emissions, there is growing interest in nuclear power generation. It has been recognized that nuclear power is one of the options to secure the supply of energy.

With the development of hydrogen technology, it will be important to find ways to produce hydrogen more efficiently. Hydrogen does not occur freely in nature in large quantities. Nuclear power could be used to generate hydrogen when load demand and electricity prices are low. The generated hydrogen could be stored to generate electricity and be fed back to the power grid when load demand and electricity prices are high. Alternatively, the stored hydrogen could be used to power hydrogen vehicles. Such a scenario would have a great impact on the operations of nuclear power plants, power grids, and electricity markets. The economics of a mixed portfolio of nuclear power and hydrogen energy need further research.

1.2.2 Renewable Power Generation Technologies

1.2.2.1 Wind Energy Generation Wind energy is a clean, renewable, and relatively inexpensive source of renewable energy. It is considered one of the most developed and cost-effective renewable energy technologies. Electricity from wind generation is generally competitive with electricity produced by conventional power plants. Wind turbines can be situated either onshore or offshore. According to the Global Wind Energy Council, global wind power capacity has continued to grow at an average cumulative rate of over 30%, and in 2008 there was more than 27 GW of new installations. By the end of 2008, the total installed global wind power capacity was over 120 GW. It has been recognized that the United States overtook Germany to become the number one market in wind power while China's total capacity doubled for the fourth year in a row. The ten countries with the highest installed wind power capacity are the US (25 GW), Germany (24 GW), Spain (16.8 GW), China (12 GW), India (9.6 GW), Italy (3.7 GW), France (3.4 GW), UK (3.2 GW), Denmark (3.2 GW), and Portugal (2.9 GW).

With implementation of European Commission targets on the promotion of electricity produced from renewable sources in the internal electricity market, wind power in Europe increased from 48 GW in 2006 to 65 GW in 2008. According to [9], by the end of 2008, there was 65 GW of wind power capacity (63.5 GW onshore and 1.5 GW offshore) installed in the EU-27, of which 63.9 GW was in the EU-15. Among the EU countries, Germany and Spain continue to be Europe's leaders with total installed wind energy capacities of 24 GW and 17 GW, respectively where 63% of the EU's installed wind energy capacity is located in these two countries.

With the development of wind power generation, there is growing penetration of wind energy into power grids. A wind power generation system normally consists of a wind turbine, a generator, and grid interface converters, if applicable, among which the generator is one of the core components. In the development of wind power generation techniques, synchronous generators, induction generators, and doubly fed induction generators have been employed to convert wind power to electrical power. Wind turbines usually rotate at a speed of 30–50 rev/min, and generators should rotate at the speed of 1000–1500 rev/min, so as to interface with power systems. Hence, a gearbox must connected between a wind turbine and a generator and requires regular maintenance; it also causes unpleasant noise and increases the loss of wind power generation. In order to overcome these problems, wind power generation with a direct-drive permanent magnet generator without a gearbox was developed. The permanent magnet generator driven directly by the wind turbine is a multi-pole and low-speed generator. Different types of direct-drive permanent magnet generators were developed for wind power generation, such as axial-flux and radial-flux machines.

Rapid technology development has enabled these prices and market growth. There are technical and economic challenges for large-scale deployment of wind power generation due to the intermittent nature of wind power and unpredictability in comparison to traditional generation technologies. Hence, increasing levels of wind power generation on the system will increase the costs of balancing the system and managing system frequency within statuary limits. With the increase of wind power penetration on the system, the impact on system operations as well as market operations should be examined. With the development of advanced energy storage technologies, it is expected that the intermittency of wind power generation can be handled in more effective ways.

1.2.2.2 Ocean Energy Generation The oceans cover more than 70% of the earth's surface and are the earth's largest collector and retainer of the sun's vast energy. Ocean energy includes tidal and wave energy.

Tidal power generation is nonpolluting, reliable, and predictable, and most modern tidal concepts use a dam approach with hydraulic turbines where tidal energy exploits the natural ebb and flow of coastal tidal waters due to the interaction of the gravitational fields of the earth, moon, and sun. Coastal water levels change twice daily, filling and emptying natural basins along the shoreline. In order to be practical for energy production, the height difference needs to be at least 5 meters. The tidal currents flowing in and out of these basins can be used to drive mechanical devices to generate electricity. The first large-scale tidal power plant in the world was built in 1966 at La Rance, France, and can generate 240 MW. There is another related tidal energy technology called tidal stream technology. Tidal streams are fast sea currents caused by the tides, often magnified by topographical features such as headlands, inlets, and straits that force water through narrow channels due to the shape of the sea bed. According to the World Offshore Renewable Energy Report 2002–2007 generated in the UK, worldwide, the potential capacity of tidal energy is around 3000 GW. It is estimated, however, that less than 3% is located in areas suitable for power generation.

Wave energy, with its high energy density, has been the focus of research since the 1970s and has attracted more interest recently. The wave energy resource is substantial, and the total resource around the world is 10 TW in the open sea, which is comparable to the world's total power consumption. Research and development projects with wave energy have been carried out around the world.

In the past, a number of wave power devices have been developed and demonstrated, each having its merits and limitations. Research is needed to predict the performance of wave power systems and to develop grid interface and control systems to collect and transmit wave power to the power grid. In the development of wave energy conversion techniques, different types of devices have been proposed, such as Archimedes Wave Swing (AWS), Oscillating Water Column (OWC), Pelamis, Wave Dragon, Mighty Whale, etc. Among these wave energy conversion techniques, AWS, invented in the early 1990s is the first wave energy conversion device to adopt the direct-drive power takeoff. AWS is completely submerged, which makes the device less vulnerable in a storm. Since an AWS is invisible, public acceptance is better than for wind farms.

1.2.2.3 Photovoltaic Generation Systems One of the most attractive potential sources of energy able to meet future energy needs is solar energy, which has enormous long-term potential as a large-scale, carbon-neutral source of power. Installations of photovoltaic (PV) cells and modules around the world has grown rapidly in the past few years, at an average annual rate of more than 35%. However, for large-scale use of solar energy, a significant reduction in the cost-to-efficiency ratio is required. It has been indicated that, with the development of new technologies, the cost of PV systems is falling as the efficiency of solar panels increases and the cost of manufacturing decreases. It is estimated that solar PV could become cost-competitive for electricity generation by 2020–2030. In an ambitious scenario analysis, it is estimated that PV could cover 20% of global electricity consumption by 2040. With the increase of PV power penetration into power grids, the impact of PV power on power system operations and electricity market trade should be researched.

1.2.2.4 Bioenergy Bioenergy and biomass resources include forestry and agriculture crops, biomass residues, and wastes, which provide about 14% of the world's primary energy supplies. As a carbon-neutral carrier, biomass can be used for production of heat, power, transport fuels, and bioproducts. Bioenergy offers cost-effective and sustainable solutions, has the potential to provide a large fraction of world energy demand over the next century, and will contribute to the requirements of reducing carbon emissions from fossil fuels.

1.2.2.5 Geothermal Energy Geothermal energy is heat from within the earth, and the hot water or steam from geothermal energy can be used to produce electricity or applied directly for building heating and industrial processes. Geothermal energy can help offset the emission of carbon dioxide from conventional fossil-powered electricity generation, industrial processes, and building thermal energy supply systems, and it has great potential to contribute enormous quantities of clean, carbon-free energy.

1.2.2.6 Hydrogen In the longer term, hydrogen is considered to be one of the most promising clean, sustainable energy supply technologies. Hydrogen can be used for all of the energy sectors—transportation, buildings, electricity supply, and industry—and can also provide storage options for intermittent renewable technologies such as solar and wind. Although hydrogen does not occur freely in nature in large quantities, it can be extracted from a variety of sources such as natural gas, biomass, coal, and water. The desirable feature is that end uses of hydrogen are basically clean and pollution-free. Hydrogen can be used in fuel cells for the clean production of electricity, powering vehicles and heating and cooling buildings while providing electricity.

Hydrogen is a versatile energy carrier and, unlike electricity, it is easy to store. Energy storage is a big challenge for the operation of electric power systems and electricity markets. When hydrogen is coupled with electric power systems, the impact on the operations of future electric power systems and electricity markets will be significant. This will affect the dependence of different energy carrier systems and further research is required in this area.

1.3 STRUCTURE OF ELECTRIC POWER SYSTEMS

1.3.1 Structure

An electric power system is used to generate, transmit, and distribute electrical energy in secure, reliable, and economic ways. Normally, electricity generation and transmission are using three phase AC systems while distribution of electrical energy may involve single-phase or two-phase systems. For interconnected AC systems in North America and some countries in Asia the system frequency is 60 Hz, while for the interconnected systems in Europe, Australia and Asia the system frequency is 50 Hz. In principle, systems with different system frequencies cannot be interconnected directly; rather they can be interconnected via HVDC links. Typically, a traditional electrical power system consists of three subsystems according to their different functionalities:

- Generation systems, which are used to generate the electrical energy from primal energy fuels;
- Transmission systems, which are used to transmit the electrical energy, over long distance, from where it is generated to either distribution systems or load centers;

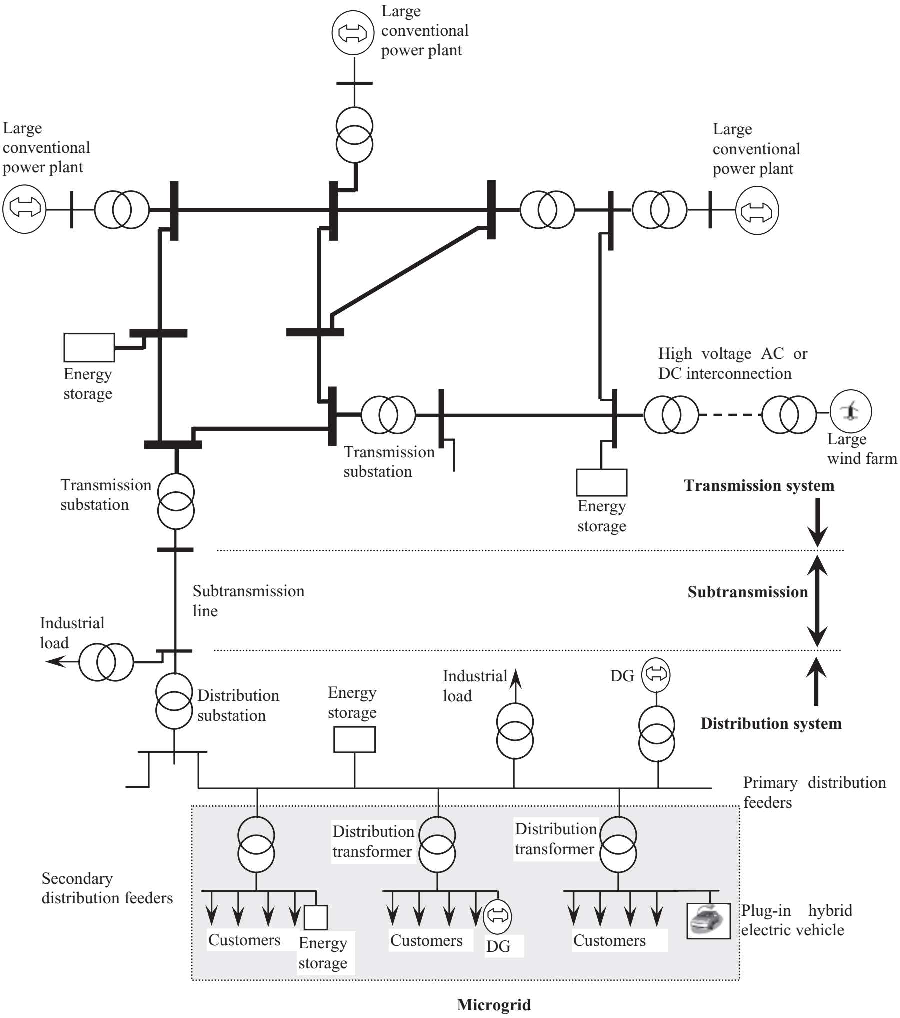


Figure 1.2 Structure of electric power systems

- Distribution systems, which are used to deliver the electrical energy to the end-use customers.

Structure of electric power systems is schematically shown in Figure 1.2. The highest transmission voltage level now in practical operation is 765 kV. The next voltage level is 1000 kV or above. Basically, high voltage (HV) transmission levels are between 100 and 275 kV, extra-high voltage transmission levels (EHV) are between 330 and 765 kV, and ultra-high voltage (UHV) levels are AC voltages higher than 765 kV and DC voltages higher than 600 kV. Subtransmission lines are used to interconnect high-voltage substations with distribution substations. The voltage levels of subtransmission are between 45 kV and 138 kV. Large synchronous generators are commonly used in conventional large generating power plants (including coal, gas, nuclear, and hydro) for electrical energy conversion where the output voltages of large generators are up to 25 kV.

According to IEC Standard 60038, low-voltage levels are between 100 and 1000 V including 230/400, 400/690, and 1000 V (at 50 Hz) and 120/208, 240, 277/480, 347/600, and 600 V (at 60 Hz). Medium voltage levels are between 1 and 35 kV, including 3.3, 6.6, 11, 22, and 33 kV. Low voltage and medium voltage levels belong to distribution voltage levels.

Distributed generation (DG) can either be connected to medium voltage levels or low voltage levels, depending on the size of the DG. Large decentralized power plants, such as wind farms and Combined Heat and Power (CHP) plants, are connected to high-voltage or extra-high voltage transmission system. Large offshore wind farms can be connected with transmission systems in three different ways: high-voltage AC interconnection, voltage sourced converter (VSC) based HVDC, or conventional line commutated HVDC.

In the UK, the transmission system consists of 275 kV and 400 kV, while 132 kV is considered as subtransmission voltage level and the distribution voltage levels include 0.4, 6.6, 11, and 33 kV. DG with a capacity up to 0.5 MW may be connected to a 400 V distribution network. It is a rule of thumb that DG with a capacity up to 5 MW may be connected to an 11 kV distribution network while DG with a capacity up to 20 MW may be connected to a 33 kV distribution network.

In addition, it can be anticipated that plug-in hybrid electric vehicles will be connected to distribution systems. With the development of energy storage technologies, various energy storage devices will be connected to electrical power systems at different voltage levels.

It has been pointed out that indiscriminant application of individual distributed generators can cause as many problems as it may solve [7]. It would be better to view distributed generation resources, energy storage devices, and associated loads as a subsystem. Such as subsystem of part of the distribution network is called a microgrid as indicated in Figure 1.2. The microgrid approach allows for local control of distributed generation in a coordinated ways and hence reduces the need for central dispatch or control. It is assumed that when there are disturbances in the distribution network, with which the microgrid is connected, the microgrid can separate from the distribution system to isolate the microgrid from the disturbance while the load can be supplied by the microgrid with coordination. It should be pointed out that the microgrid is a dynamic approach. From the viewpoint of distribution network operations and system developments, two more microgrids may be merged into one microgrid. A review of current worldwide R&D activities on microgrid technologies can be found in [8].

1.3.2 Benefits of System Interconnection

The benefits of an interconnected transmission system include:

- *Bulk Power Transfers*. There are a number of factors that influence the decision to site a power station at a particular location. These may include fuel availability, fuel price, fuel transport costs, financing, cooling water, land availability and the level of transmission system charges. Due to environmental concerns and other reasons, it may not be possible to site large power stations close to demand centers. This is also the case for renewable energy generation technologies such as wind or wave, which are location-based resources and will need to be connected to power grids and transmitted to load centers. One of benefits of an interconnected transmission system is that it can provide for the efficient bulk transfer of power from remote power plants where power is generated to demand centers where power is consumed. Transmission of electricity at high voltage is more efficient than transfer at lower voltage due to the lower capital cost per unit transmitted, the lower power losses, and the lower voltage drops.

- *Economic Operation and Electricity Trade*. An interconnected transmission system can also provide the main national electrical link between all market participants, including generation and demand, and it is then possible to optimize the generation portfolio available and hence provide the cheapest possible generation. In electricity market environments, for such an interconnected system, market participants can have the opportunity to choose to trade with the most competitive participants. The interconnection of different national transmission systems would provide the opportunity to optimize generation portfolio across region.
- *Security and Reliability of Supply*. Security and reliability of supply is a key issue for electricity supply. The system must be able to provide continuously an uninterrupted supply of electricity to customers under conditions of plant breakdown, transmission outages, or weather-induced failures for a wide range of demand conditions while the intact system is maintained and power quality standards in terms of voltage, waveform, and frequency are satisfied. Transmission circuits are more reliable than individual generating units, and hence an interconnected transmission system can enhance the security and reliability of supply in terms of breakdown of individual generating units.
- *Reduced Power Plant Capacity Margin.* In the operation of a transmission system, installed generation capacity should not be less than the forecast maximum demand. If a plant becomes unavailable due either to routine maintenance or a breakdown, extra demand under extreme weather conditions, or transmission line outages, additional capacity is required for security reasons to cover shortfalls. An interconnected transmission system enables surplus generating capacity in one zone to be used to cover shortfalls in other zones on the system. The requirement for additional installed generating capacity, to provide sufficient generation security for the whole system, is therefore smaller than the sum of individual zonal requirements of the subsystems when they are not interconnected.
- *Reduced Frequency Response and Active Power Reserve Requirements*. A transmission system operator has the responsibility to maintain frequency between certain specified limits, as large deviations in frequency can lead to widespread demand disconnections, generation disruptions, and even system splitting or collapse. If demand is greater than generation, frequency falls and,

if generation is greater than demand, frequency rises. Basically, the frequency response of an interconnected transmission system should be less than the sum of each separate system.

1.4 ULTRA-HIGH VOLTAGE POWER TRANSMISSION

1.4.1 The Concept of Ultra-High Voltage Power Transmission

With the development of large-scale transmission systems, voltage levels have been increased continuously to achieve greater economies of scale. The highest transmission voltage level now in practical operation is 765 kV. The next voltage level is 1000 kV or above. High voltage (HV) transmission levels include 100 (110), 125, 132, 138, 161, 230 (220), an 275 kV; extra-high voltage levels (EHV) include 345 (330), 400, 500, and 765 (750) kV; and ultra-high voltage (UHV) levels are AC voltages higher than 765 kV and DC voltages higher than 600 kV.

The ultra-high voltage grid being considered in China and elsewhere is the transmission grid with voltages higher than 750 kV. It is mainly suitable for transferring bulk electricity energy over a very long distance.

It was recognized that a higher voltage grid should be introduced when the capacity of a power system is doubled. For this reason, the research on super-high voltage transmission grid became more important. Many countries, such as the US, Russia, Italy, France, Japan, and Sweden, have designed and planned at the development of ultra-high voltage grids in the past. However, these projects were not completed because of political and economic factors.

A ultra-high voltage grid research project in China has been conducted since 1986. China is a vast territory with great resources in hydro and coal, and less in oil and gas. Hydro resources and coal reserves are the most important energy resources in China. However, the distribution of electricity energy sources and electricity demand are seriously unbalanced. Nearly two thirds of hydro resources are distributed in the southwest and west of China, including Sichuan, Yunnan, and Tibet provinces. Two thirds of the coal reserves are distributed in the northwest and north of China. On the other hand, two thirds of electricity loads were mainly in the east areas of China, where there is a lack of electricity energy sources. The distances between the areas of energy resources and energy demand are up to 2000 km, which is a more reasonable transportation distance for an AC ultra-high voltage grid than for transportation of energy resources by train. Research has shown that it is more economical to transfer the electricity than to transport coal within 1500 km.

For the reasons mentioned above, the need for development of a super-ultra electricity transmission grid is clear. At the end of 2007, the installed generation capacity of 700 GW made China the second highest in the electricity production in the world. As China transforms into the manufacturing center of the world, the increase of electricity demand is tremendous. A new electric energy infrastructure is required to transfer bulk electricity energy over a very long distance. Although 500 kV AC and 500 kV DC transmission systems exist, such transmission networks are considered inadequate for bulk electricity energy transmission.

It is estimated that in China in 2020 the installed generation capability will be 1000 GW. Large amounts of hydro and coal resources are distributed in the southwest and northwest of China. In order to meet the energy consumption more generating plants will be constructed in these regions by 2020. On the other hand, load centers are situated in the east costal areas of China. According to the experience of the international power industry, when the capacity of power grid is expanded by 4 times, a higher voltage level should be introduced. The current 500 kV power grid is 30 years old, and the installed generation capability in 2004 was around 6 times that of the installed generation capability in 1982. Presently, the transmission of electricity across provincial power networks is mainly based on the 500 kV AC and ±500 kV DC transmission grids. Such transmission power grids will not meet the bulk power transmission requirements in 2020. Clearly, power grids of higher voltage levels are required. Long-distance bulk power transmission can satisfy future power growth, secure energy supply, and optimize energy resource allocation. Furthermore, overall social benefits will be increased by enhancing power grid security and reliability, saving right-of-way, coordinating the development of power plants and grids, alleviating coal transportation pressure, and boosting the harmonious development of regional economies.

Some general arguments for moving to higher voltages are:

- The higher the voltage of a transmission line, the higher the power that can be transported over a particular conductor of a transmission line, reducing line costs per power unit transferred.
- At the same time the space (right of way) required per transferred power unit decreases. The need for slightly higher insulation distances is compensated for by having to build fewer lines provided that the needed power transfer is beyond the capabilities of a single line.
- With the same transferred power, losses decrease with higher voltage levels due to the lower currents needed to sustain the power transfer.

Note that 1000 kV AC and ±800 kV DC transmission grids have different features. They are complementary. Historically, AC and DC have had clearly distinguishable application areas based on the following characteristics:

- AC connections can be more easily meshed and connected with the rest of the network. An AC/AC substation with breakers and transformers is less expensive and has lower losses than a converter station between AC and DC for the same power level. Reactive power compensation and insulation issues become more difficult to resolve with larger distances and higher AC voltages, so that scaling up has its limits. There is also a concern about the exposure to high electromagnetic fields at 50/60 Hz, particularly in populated areas.
- DC connections result in lower losses on the line and lower line costs per unit of transmitted power. When connecting two AC subnetworks with DC,

stability and oscillation problems on both AC subnetworks are effectively shielded from each other.

1.4.2 Economic Comparison of Extra-High Voltage and Ultra-High Voltage Power Transmission

The natural single circuit power transmission capacity of a 1000 kV AC transmission line is about 5 GW, and the maximum transmission power of a ±800 kV DC transmission line is at most 6.4 GW. The transmission capacity of a DC transmission line depends on the power system connection and is restricted by its maximum stability limit. Its capacity should be uplifted gradually. In contrast, the transmission capacity of a DC transmission line could achieve the design power capacity level as soon as an AC supply source is available. For the right of way, a transmission of 6 GW of power requires two parallel transmission lines, both for 500 kV DC and for 1000 kV AC, whereas only one transmission line is needed for 800 kV DC. The reasonable transmission distance of a 1000 kV AC transmission line is up to 2000 km. On the other hand, ±800 kV DC transmission is the most economical way of long distance power transmission when transmission distance is larger than 1000 km, for which the one-time conversion cost pays off through reduced line costs and losses.

A 1000 kV AC transmission grid, which has the general features of an AC transmission grid, can form a super backbone grid of a national power system. A "direct super high way," ±800 kV DC transmission, which is complementary to an AC transmission grid, can be used to transmit bulk power from large power generating bases to large load centers over long distances. However, ±800 kV DC transmission will not be suitable for forming a national backbone high-voltage power grid due to the limitation of interconnection.

Another option is to move primary energy, such as gas, and coal, closer to the place of consumption and convert it to electrical power there. However, this is not possible for hydropower. Besides the infrastructure costs for transportation (gas pipelines, railway infrastructure to transport coal), the issue of producing pollutants close to major population areas has to be taken into account.

Assume that 6 GW of power must be transported point to point over either 1000 km or 2000 km. In this scenario analysis, three transmission lines are necessary for 800 kV AC transmission while two lines are needed for 500 kV DC or 1000 kV AC and one line is sufficient for 800 kV DC. It has been found that, for the assumed power level, moving to higher voltages leads to reduced costs for both AC (moving from 800 kV to 1000 kV) and for DC (moving from 500 kV to 800 kV). For a bulk power transmission need of 6 GW, the losses for various transmission distances are compared. For this analysis, it is assumed that the conductor cross-section area is the same for the different transmission distances. It has been found that beyond a distance of 500 km, line losses dominate the station losses and thus DC solutions become more efficient than their AC counterparts. The comparison shows that for a distance of 1000 km (for which the various options are optimized in this example), losses for an 800 kV DC set-up are around 1% lower than for a 500 kV DC set-up.

1.4.3 Ultra-High Voltage AC Power Transmission Technology

The enabling technologies for establishing ultra-high voltage AC (U-HVAC) are breakers and gas insulated substations (GIS). Furthermore, current sensors, transformers, and FACTS devices should also be designed specifically. It has been already proven that ultra-high voltage level power transmission is technically feasible. Some manufacturers have gained experience that can be used in the actual development of ultra-high voltage level power transmission in China.

It should be mentioned that for building a 1000 kV AC network, a careful consideration of stability issues, compensation, and protection is required. Furthermore, the vulnerability to cascading blackouts in case of emergencies should be considered in the design and operations and special system supervision and emergency schemes need to be implemented.

1.4.4 Ultra-High Voltage DC Technology

There are a number of special R&D tasks to be executed to get a proper design of an 800 kV ultra-high voltage DC technology (U-HVDC):

- AC/DC converter transformer
- DC bushings
- External insulation
- Control and protection
- DC valves and thyristors
- System reliability and main circuit design

The last item is of great importance. Concentrating the power transfer on a smaller number of overhead lines obviously increases the operational risks posed by these lines being taken out of operation in an unplanned fashion (either due to random reasons, such as weather-related incidents or technical failures, or due to malicious attacks and sabotage). This would provide an argument against moving to 800 kV DC, for example, based on homeland security concerns. It would, however, also apply to some extent to 1000 kV AC links. On the other hand, this risk can be mitigated by a number of measures:

- The converter stations are designed in such a way as to employ redundancy (e.g., for protection and control) to reduce the likelihood that technical failures lead to a line trip.
- The two poles (+/−) of an HVDC line are designed to be as independent as feasible. Thus, even when one pole is tripped, a monopolar operation with the other pole remains possible.
- If a sufficient number of HVDC lines is available (the upper Jinsha River hydropower development shall be connected to East China with three 800 kV DC connections), when one of the lines is completely taken out of operation, the other lines are designed with an overload capability so that they can take up load from the lost line for a certain time period.

- The complete power system should be designed in such a way that the overall system stability would be maintained even if the power from one of the 800 kV DC links was suddenly completely lost. In the worst case, load shedding of noncritical loads may be employed.

1.4.5 Ultra-High Voltage Power Transmission in China

According to the strategic planning of State Grid Co., the national ultra-high voltage grid, which covers the majority of China, should be operated and dispatched through a united national control center. The national grid is mainly based upon AC interconnected networks with the assistance of DC interconnected networks. The backbone grid will be interconnected by 1000 kV AC transmission with the assistance of ±800 kV DC transmission. The northwest power grid will be interconnected by 750 kV AC transmission.

According to the design and planning of the national ultra-high voltage grid, two large capacity transmission channels should be constructed. One is the north-south channel from north via central to east, forming a huge UHV AC synchronizing power grid. The other is the west-east channel from Sichuan via central to east. The transmission of the electric energy in northwest coal bases should merge into this super UHV grid channel.

The 1000 kV UHV AC transmission grid should be constructed above 500 kV EHV AC transmission grid, and will be used to transfer the electricity from the coal bases in the northwest and north China to central and east China. To transfer the electric energy from the southwest hydro bases to east areas ±800 kV DC should be primarily used. Through the national super-high voltage backbone grid, coal transportation could be substituted for electricity transmission. In addition, the united national grid will promote bulk nationwide electricity trading between different regions.

As shown in Figure 1.3, the first UHV project connects North China and Central China. The UHV grid will expand to East China. A strong super UHV power grid will cover North, Central, and East China. The UHV grid therefore will cover major energy centers and load centers in China. It is estimated that the UHV capacity and regional transfer capacity will exceed 200 GW.

A feasibility study of the 1000 kV UHV AC pilot project has been carried out. The optimal option for the UHV AC pilot project has been identified. The project now enters the preliminary design stage. A 1000 kV UHV AC pilot demonstration project, from Jindongnan, southeast of Shanxi Province, via Nanyang, Henan Province, to Jinmen, Hubei Province, will be built. The total length of the pilot demonstration 1000 kV UHV AC line is a 640 km single line. Along with the 1000 kV UHV AC line, two 1000 kV UHV substations and one switching station have been built and the system has been put into operation since January 2009.

Taking the distribution of energy resources in China into consideration, the transportation expenses will rise because the quantity of coal transportation will greatly increase as demands increase with the development of national economy. It is much more economical to transfer electricity than to transport coal from north to

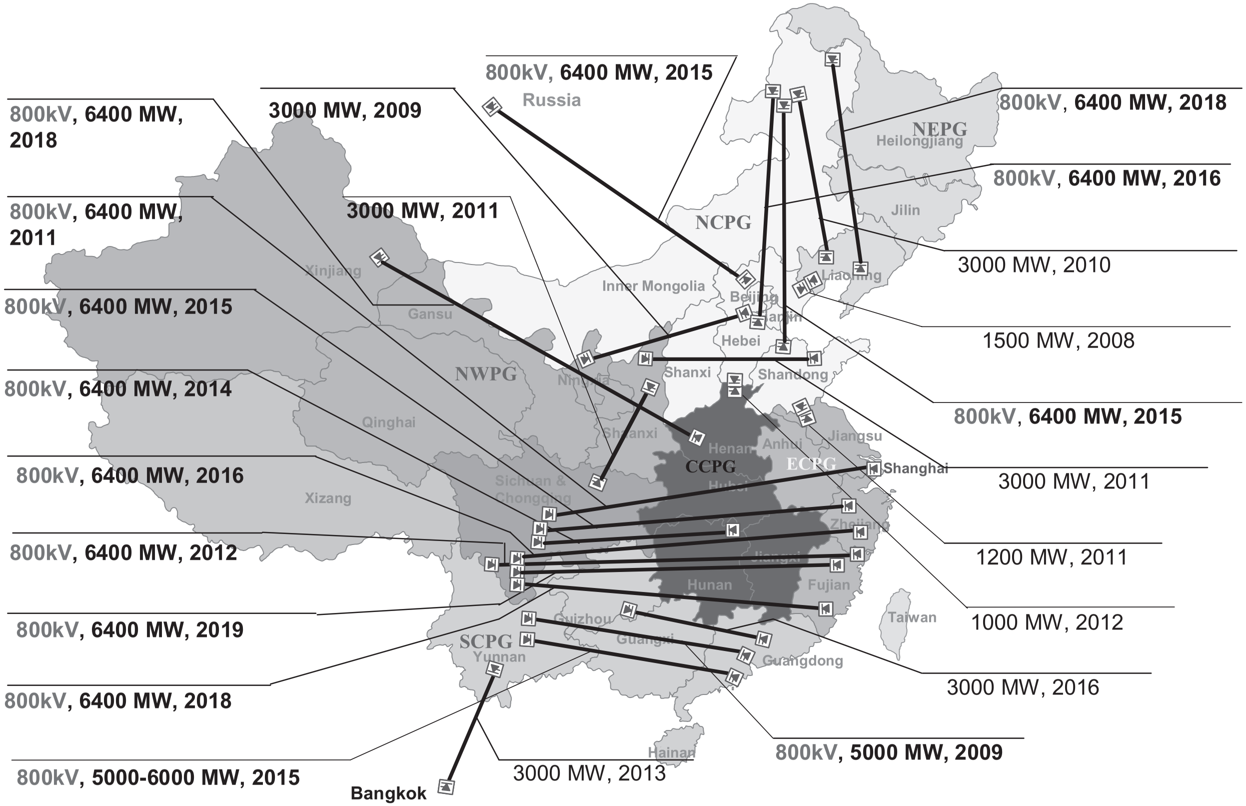


Figure 1.3 U-HVAC and U-HVDC projects in China

south in China. Therefore, the construction of the national super-high voltage transmission grid in China is not only necessary but also timely.

The national ultra-high voltage grid should have the basic function of transmitting bulk capacity of electricity through very long distances and across different regions with lower power losses. The present imbalance between the electricity supply and demand would be remedied with the national ultra-high voltage grid. Furthermore, the national super-high voltage transmission grid will promote electricity trading between different regions over different scales, optimizing the utilization of energy sources within larger areas, meeting the requirements of economic development and creating competitive national energy markets.

1.4.6 Ultra-High Voltage Power Transmission in the World

There has been increasing interest worldwide in HVDC applications involving voltage levels above 500 kV. In Asia, in addition to the U-HVDC projects in China, India has announced an intention to go for ±800 kV. In Brazil, U-HVDC is also under consideration and Africa has also shown an interest in U-HVDC power transmission.

In Europe, the idea of a super power grid, which would link Africa and Europe, is being discussed. The super grid would connect geothermal energy in Iceland, biomass power in Poland, and solar power in the Sahara. For the super power grid, U-HVDC technologies would be one of the options.

In the US, a continental super grid has been discussed that envisions the use of underground, superconducting direct current cables for long-distance power transmission at levels of perhaps 5 to 10 GW. It has been suggested that, in addition to carrying electricity, the superconducting cables could also be used as a multiple energy carrier to transport hydrogen for use both as a cryogen and for end-use energy consumption with a significant development in hydrogen energy market in the future.

1.5 MODELING OF ELECTRIC POWER SYSTEMS

In power system analyses such as load flow, power system stability studies, power system components such as transmission lines, transformers, and static loads may be represented by algebraic equations. Synchronous generators are the most important components in power system analysis. They are usually represented by algebraic and differential equations in stability studies [1, 2]. The modeling philosophy of synchronous generators is applicable to modeling of HVDC and flexible AC transmission systems [3–6].

1.5.1 Transmission Lines

If it is assumed that angular frequency of the system is nearly constant and the three-phase transmission line is balanced in parameters, then the transmission line can be represented by a single-phase π section equivalent circuit as show in Figure 1.4.

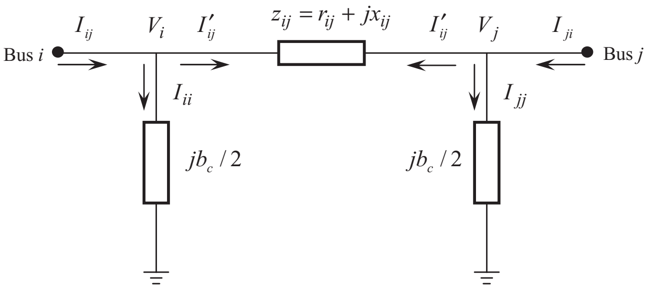


Figure 1.4 Equivalent π circuit model of transmission line

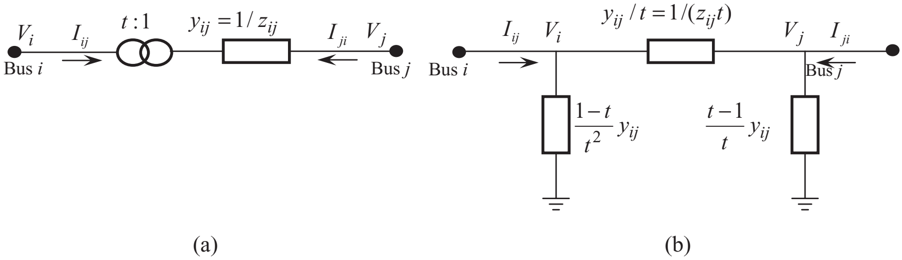


Figure 1.5 Transformer equivalent circuit with off-nominal tap ratio

In Figure 1.4, $z_{ij} = r_{ij} + jx_{ij}$, jb_c are the series impedance and shunt admittance of the transmission lines.

According to Kirchoff's current law, we have

$$I_{ij} = I'_{ij} + I_{ii} = (V_i - V_j)/z_{ij} + V_i(jb_c/2) \tag{1.1}$$

$$I_{ji} = I'_{ji} + I_{jj} = (V_j - V_i)/z_{ij} + V_j(jb_c/2) \tag{1.2}$$

Equations (1.1) and (1.2) may be written in a compact form as follows

$$\begin{bmatrix} y_{ij} + jb_c/2 & -y_{ij} \\ -y_{ij} & y_{ij} + jb_c/2 \end{bmatrix} \begin{bmatrix} V_i \\ V_j \end{bmatrix} = \begin{bmatrix} I_{ij} \\ I_{ji} \end{bmatrix} \tag{1.3}$$

where y_{ij} is the series branch admittance and given by $y_{ij} = 1/z_{ij}$. Equation (1.3) is bus voltage equation of the transmission line, which can be directly incorporated into the network voltage equation for system analysis.

1.5.2 Transformers

Similar to the modeling of transmission lines, transformers can also be represented by the equivalent circuit and bus voltage equation. A transformer represented by an ideal transformer $t:1$ in series with an impedance z_{ij} is shown in Figure 1.5 (a). The equivalent circuit in Figure 1.5 (a) can be transformed into Figure 1.5 (b). In Figure 1.5, t is the off nominal tap ratio, y_{ij} is the short-circuit or leakage admittance.

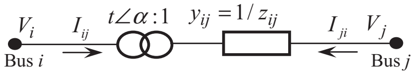


Figure 1.6 Transformer equivalent circuit with off-nominal tap ratio

The bus voltage equation of the transformer is given by

$$\begin{bmatrix} \dfrac{y_{ij}}{t^2} & -y_{ij}/t \\ -y_{ij}/t & y_{ij} \end{bmatrix} \begin{bmatrix} V_i \\ V_j \end{bmatrix} = \begin{bmatrix} I_{ij} \\ I_{ji} \end{bmatrix} \tag{1.4}$$

Basically, phase-shifting transformers (PST) are used to control the real power flow of in transmission lines by regulating the phase angle difference. Both the magnitude and the direction of the power flow can be controlled by varying the phase shift. Under electricity market environments, transmission congestion can be managed by PST in a very economical way.

A phase shifting transformer represented by an ideal transformer in series with an impedance z_{ij} is shown in Figure 1.6. In Figure 1.6, $t\angle\alpha:1$ is the off nominal tap ratio, which is a complex number. y_{ij} is the short-circuit or leakage admittance. Then we have the following equations:

$$I_{ij}\ t\angle-\alpha = (V_i/t\angle\alpha - V_j)\,y_{ij} \tag{1.5}$$

$$I_{ji} = (V_j - V_i/t\angle\alpha)\,y_{ij} \tag{1.6}$$

The bus voltage equation of the PST is given by

$$\begin{bmatrix} \dfrac{y_{ij}}{t^2} & -y_{ij}/t\angle-\alpha \\ -y_{ij}/t\angle\alpha & y_{ij} \end{bmatrix} \begin{bmatrix} V_i \\ V_j \end{bmatrix} = \begin{bmatrix} I_{ij} \\ I_{ji} \end{bmatrix} \tag{1.7}$$

In comparison to (1.4), the system admittance matrix of (1.7) is unsymmetrical due to the complex off-normal tap ratio, and in this situation, the model shown in (1.7) cannot be represented by an equivalent circuit.

1.5.3 Loads

The static loads may be classified into three categories:

1. Constant power:

$$P = P_0(V)^0, \quad Q = Q_0(V)^0 \tag{1.8}$$

   where P_0, Q_0 are constant powers at nominal voltage.

2. Constant current:

$$P = P_0(V)^1, \quad Q = Q_0(V)^1 \tag{1.9}$$

3. Constant impedance:

$$P = P_0(V)^2, \quad Q = Q_0(V)^2 \tag{1.10}$$

A general representation of the static loads as functions of voltage magnitude and frequency deviation may be given by

$$P = P_0\left[a_0(V)^0 + a_1(V)^1 + a_2(V)^2\right](1 + K_P\Delta f) \tag{1.11}$$

$$P = P_0\left[b_0(V)^0 + b_1(V)^1 + b_2(V)^2\right](1 + K_Q\Delta f) \tag{1.12}$$

where a_0, a_1, a_2, b_0, b_1, and b_2 are voltage coefficients while K_p and K_Q are frequency coefficients.

1.5.4 Synchronous Generators

In load flow analysis, a synchronous generator is simply represented by algebraic constraints. For instance, a slack generator is represented by a constant voltage source. A PV generator is represented by constant active power injection and controlled voltage bus.

In power system stability studies, synchronous generators are usually represented by equivalent circuits and algebraic and differential equations [1, 2]. Similarly, dynamic motors can also be represented by algebraic and differential equations. In addition to the modeling of synchronous generators, excitation systems and speed-governing systems, which are usually described by differential equations, are also need to be represented.

1.5.5 HVDC Systems and Flexible AC Transmission Systems (FACTS)

In load flow analysis, HVDC systems and Flexible AC Transmission Systems are represented by algebraic equations while in stability studies they are represented by algebraic and differential equations [6].

1.6 POWER FLOW ANALYSIS

It is well known that load flow solution is the most frequently performed routine power network calculations, which can be used in power system planning, operational planning, and operation/control. It is also considered as the fundamental of power system network calculations. From a load flow solution, the voltage magnitude and angle at each bus and active and reactive power flows and power losses in each line can be obtained. In the following, classifications of buses for load flow analysis are introduced first. Then load flow solution methods are presented. Numerical examples on a simple system are used to show the principles of load flow analysis.

1.6.1 Classifications of Buses for Power Flow Analysis

1.6.1.1 Slack Bus For load flow analysis, a slack bus should be selected where the voltage magnitude and angle are given and kept constant while the active and reactive power injections are not known before a load flow solution is found. The slack bus basically performs two functions:

- the reference of the system;
- balancing the active and reactive powers of the system.

In load flow analysis, usually there is only one slack bus in the system. For a slack bus, the active and reactive power injections need to be determined once a load flow solution has been found.

In some situations, a distributed slack bus concept may be used for large-scale power systems where a number of buses can be selected as a slack bus group and the system active and reactive power can be balanced by a group of buses rather a single bus.

1.6.1.2 PV Buses A PV bus, also called a voltage-controlled bus, is a bus where the voltage magnitude is given and kept constant and the active power injection is specified while the voltage angle and the reactive power injection need to be determined by load flow analysis. A generator bus may be considered as a PV bus if the voltage of the bus and the active power output from the generator are controlled to the specified values. Sometimes a bus, which a reactive control resource like a synchronous condenser is connected with, may also be taken as a PV bus. For a practical interconnected power system, there may be one or more PV buses.

1.6.1.3 PQ Buses A PQ bus is a bus where the active and reactive power injections are given and kept constant. Usually a nongenerator bus is considered as a PQ bus.

1.6.2 Formulation of Load Flow Solution

The features of load flow solution will be shown on a three-bus power system as shown in Figure 1.7. In the system, there are two generators, which are connected to bus 1 and 2, respectively. A load is connected with bus 3 of the system. In the figure, we assume that the generator bus 1 is taken as the slack bus; the generator

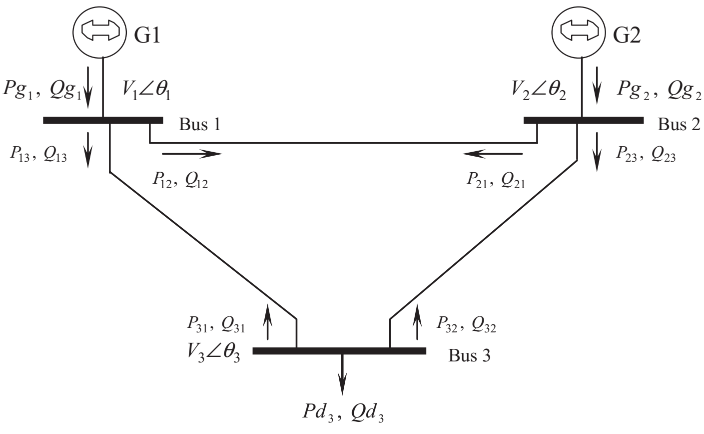


Figure 1.7 A three-bus system

bus 2 is taken as a PV bus; and the load bus 3 is considered as a PQ bus. For the three-bus system, we assume that the transmission lines are represented by series impedances only.

According to Kirchoff's voltage law, the relationship between the bus voltages and current injections is given by

$$\begin{bmatrix} \mathbf{I}_1 \\ \mathbf{I}_2 \\ \mathbf{I}_3 \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} & Y_{13} \\ Y_{21} & Y_{22} & Y_{23} \\ Y_{31} & Y_{32} & Y_{33} \end{bmatrix} \begin{bmatrix} \mathbf{V}_1 \\ \mathbf{V}_2 \\ \mathbf{V}_3 \end{bmatrix} \tag{1.13}$$

where, $Y_{11} = 1/z_{12} + 1/z_{13}$, $Y_{22} = 1/z_{12} + 1/z_{23}$, $Y_{33} = 1/z_{13} + 1/z_{23}$, $Y_{12} = Y_{21} = -1/z_{12}$, $Y_{13} = Y_{31} = -1/z_{13}$, $Y_{23} = Y_{32} = -1/z_{23}$. z_{12}, z_{13}, and z_{23} are the impedances of transmission lines 1–2, 1–3, and 2–3, respectively. The bus voltages and current injections are phasors. However, in load flow analysis, usually active and reactive power injections rather than current injections are given. For this reason, equation (1.13) needs to be transformed into the following power equation:

$$P_i + jQ_i = \boldsymbol{V}_i \boldsymbol{I}_i^* = \boldsymbol{V}_i \sum_{j=1}^{N} (Y_{ij} \boldsymbol{V}_j)^* \tag{1.14}$$

where * represents the conjugate operation. N is the total number of buses. For the three-bus system, N equals 3. In the polar coordinates, assuming that $\boldsymbol{V}_i = V_i \angle \theta_i$ ($i = 1, 2, \ldots, N$) and $Y_{ij} = G_{ij} + jB_{ij}$, the active and reactive power injection equation (1.14) may be represented separately as

$$P_i = V_i \sum_{j=1}^{N} V_j (G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}) \tag{1.15}$$

$$Q_i = V_i \sum_{j=1}^{N} V_j (G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}) \tag{1.16}$$

As pointed out above, in load flow analysis, active and reactive power injections are known, then the following power mismatch equations can be obtained:

$$\Delta P_i = P_i^{Spec} - P_i \tag{1.17}$$

$$\Delta Q_i = Q_i^{Spec} - Q_i \tag{1.18}$$

where P_i^{Spec} and Q_i^{Spec} are the specified active and reactive power injections, respectively. $P_2^{Spec} = Pg_2$, $P_3^{Spec} = -Pd_3$, and $Q_3^{Spec} = -Qd_3$. The objective of a load flow solution is to find a solution to equations (1.17) and (1.18) while the voltage of bus 1 and the voltage magnitude of bus 2 are given.

1.6.3 Power Flow Solution by Newton-Raphson Method

Equations (1.17) and (1.18) represent a set of nonlinear equations of the system studied. The most efficient method for solving nonlinear equations may be the well-known Newton-Raphson method. For the following nonlinear equations with three unknown variables:

$$f_1(x_1, x_2, x_3) = 0 \tag{1.19}$$

$$f_2(x_1, x_2, x_3) = 0 \tag{1.20}$$

$$f_3(x_1, x_2, x_3) = 0 \tag{1.21}$$

we use a Taylor expansion of the functions about x_1^0, x_2^0, x_3^0.

$$f_1(x_1^0, x_2^0, x_3^0) + \frac{\partial f_1(x_1^0, x_2^0, x_3^0)}{\partial x_1}\Delta x_1 + \frac{\partial f_1(x_1^0, x_2^0, x_3^0)}{\partial x_2}\Delta x_2 + \frac{\partial f_1(x_1^0, x_2^0, x_3^0)}{\partial x_3}\Delta x_3 = 0 \tag{1.22}$$

$$f_2(x_1^0, x_2^0, x_3^0) + \frac{\partial f_2(x_1^0, x_2^0, x_3^0)}{\partial x_1}\Delta x_1 + \frac{\partial f_2(x_1^0, x_2^0, x_3^0)}{\partial x_2}\Delta x_2 + \frac{\partial f_2(x_1^0, x_2^0, x_3^0)}{\partial x_3}\Delta x_3 = 0 \tag{1.23}$$

$$f_3(x_1^0, x_2^0, x_3^0) + \frac{\partial f_3(x_1^0, x_2^0, x_3^0)}{\partial x_1}\Delta x_1 + \frac{\partial f_3(x_1^0, x_2^0, x_3^0)}{\partial x_2}\Delta x_2 + \frac{\partial f_3(x_1^0, x_2^0, x_3^0)}{\partial x_3}\Delta x_3 = 0 \tag{1.24}$$

The above equations may be written as the compact form

$$\begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \frac{\partial f_1}{\partial x_3} \\ \frac{\partial f_2}{\partial x_1} & \frac{\partial f_2}{\partial x_2} & \frac{\partial f_2}{\partial x_3} \\ \frac{\partial f_3}{\partial x_1} & \frac{\partial f_3}{\partial x_2} & \frac{\partial f_3}{\partial x_3} \end{bmatrix} \begin{bmatrix} \Delta x_1 \\ \Delta x_2 \\ \Delta x_3 \end{bmatrix} = -\begin{bmatrix} f_1(x_1^0, x_2^0, x_3^0) \\ f_2(x_1^0, x_2^0, x_3^0) \\ f_3(x_1^0, x_2^0, x_3^0) \end{bmatrix} \tag{1.25}$$

With the initial point x_1^0, x_2^0, x_3^0, the incremental changes of Δx_1, Δx_2, and Δx_3 can be obtained, then a new point $x_1 = x_1^0 + \Delta x_1$, $x_2 = x_2^0 + \Delta x_2$, and $x_3 = x_3^0 + \Delta x_3$ can be found. With this new point, a new Newton-Raphson equation like (1.24) can be reformulated, then incremental changes of Δx_1, Δx_2, and Δx_3 can be obtained and a new point can be found. The iterating process continues until $f_1(x_1^0, x_2^0, x_3^0)$, $f_2(x_1^0, x_2^0, x_3^0)$, and $f_3(x_1^0, x_2^0, x_3^0)$ are very close to zero.

Applying the Newton-Raphson method to the load flow problem: (1.17) and (1.18), we have the following Newton iterative equation:

$$\begin{bmatrix} \frac{\partial \Delta P_1}{\partial \theta_1} & \frac{\partial \Delta P_1}{\partial V_1} & \frac{\partial \Delta P_1}{\partial \theta_2} & \frac{\partial \Delta P_1}{\partial V_2} & \frac{\partial \Delta P_1}{\partial \theta_3} & \frac{\partial \Delta P_1}{\partial V_3} \\ \frac{\partial \Delta Q_1}{\partial \theta_1} & \frac{\partial \Delta Q_1}{\partial V_1} & \frac{\partial \Delta Q_1}{\partial \theta_2} & \frac{\partial \Delta Q_1}{\partial V_2} & \frac{\partial \Delta Q_1}{\partial \theta_3} & \frac{\partial \Delta Q_1}{\partial V_3} \\ \frac{\partial \Delta P_2}{\partial \theta_1} & \frac{\partial \Delta P_2}{\partial V_1} & \frac{\partial \Delta P_2}{\partial \theta_2} & \frac{\partial \Delta P_2}{\partial V_2} & \frac{\partial \Delta P_2}{\partial \theta_3} & \frac{\partial \Delta P_2}{\partial V_3} \\ \frac{\partial \Delta Q_2}{\partial \theta_1} & \frac{\partial \Delta Q_2}{\partial V_1} & \frac{\partial \Delta Q_2}{\partial \theta_2} & \frac{\partial \Delta Q_2}{\partial V_2} & \frac{\partial \Delta Q_2}{\partial \theta_3} & \frac{\partial \Delta Q_2}{\partial V_3} \\ \frac{\partial \Delta P_3}{\partial \theta_1} & \frac{\partial \Delta P_3}{\partial V_1} & \frac{\partial \Delta P_3}{\partial \theta_2} & \frac{\partial \Delta P_3}{\partial V_2} & \frac{\partial \Delta P_3}{\partial \theta_3} & \frac{\partial \Delta P_3}{\partial V_3} \\ \frac{\partial \Delta Q_3}{\partial \theta_1} & \frac{\partial \Delta Q_3}{\partial V_1} & \frac{\partial \Delta Q_3}{\partial \theta_2} & \frac{\partial \Delta Q_3}{\partial V_2} & \frac{\partial \Delta Q_3}{\partial \theta_3} & \frac{\partial \Delta Q_3}{\partial V_3} \end{bmatrix} \begin{bmatrix} \Delta \theta_1 \\ \Delta V_1 \\ \Delta \theta_2 \\ \Delta V_2 \\ \Delta \theta_3 \\ \Delta V_3 \end{bmatrix} = -\begin{bmatrix} \Delta P_1 \\ \Delta Q_1 \\ \Delta P_2 \\ \Delta Q_2 \\ \Delta P_3 \\ \Delta Q_3 \end{bmatrix} \tag{1.26}$$

For the slack bus, θ_1, and V_1 are given and kept constant. In the above equations, the differentials with respect to these variables are zero and the first two equations at the slack bus are not needed and should be removed. For the PV bus, the bus voltage magnitude V_2 is given and kept constant. The differentials with respect to this variable should be zero and the fourth equation (reactive power mismatch equation at the PV bus) in (1.18) should be removed. Then we have the following reduced order Newton equation

$$\begin{bmatrix} \frac{\partial \Delta P_2}{\partial \theta_2} & \frac{\partial \Delta P_2}{\partial \theta_3} & \frac{\partial \Delta P_2}{\partial V_3} \\ \frac{\partial \Delta P_3}{\partial \theta_2} & \frac{\partial \Delta P_3}{\partial \theta_3} & \frac{\partial \Delta P_3}{\partial V_3} \\ \frac{\partial \Delta Q_3}{\partial \theta_2} & \frac{\partial \Delta Q_3}{\partial \theta_3} & \frac{\partial \Delta Q_3}{\partial V_3} \end{bmatrix} \begin{bmatrix} \Delta \theta_2 \\ \Delta \theta_3 \\ \Delta V_3 \end{bmatrix} = - \begin{bmatrix} \Delta P_2 \\ \Delta P_3 \\ \Delta Q_3 \end{bmatrix} \tag{1.27}$$

The load flow solution of the three-bus system can be found by iteratively solving (1.27). For a system with N buses, the Newton load flow model may be given by the following compact form:

$$\begin{bmatrix} \frac{\partial \mathbf{P}}{\partial \boldsymbol{\theta}} & \frac{\partial \mathbf{P}}{\partial \mathbf{V}} \\ \frac{\partial \mathbf{Q}}{\partial \boldsymbol{\theta}} & \frac{\partial \mathbf{Q}}{\partial \mathbf{V}} \end{bmatrix} \begin{bmatrix} \Delta \boldsymbol{\theta} \\ \Delta \mathbf{V} \end{bmatrix} = - \begin{bmatrix} \Delta \mathbf{P} \\ \Delta \mathbf{Q} \end{bmatrix} \tag{1.28}$$

1.6.4 Fast Decoupled Load Flow Method

Noting the physical coupling between P and V and between Q and θ in (1.28), the differentials $\frac{\partial \mathbf{P}}{\partial \mathbf{V}}, \frac{\partial \mathbf{Q}}{\partial \boldsymbol{\theta}}$ may be simply set to zero. Then we have the decoupled load flow model

$$\left[\frac{\partial \boldsymbol{P}}{\partial \boldsymbol{\theta}}\right][\Delta \boldsymbol{\theta}] = -[\Delta \boldsymbol{P}] \tag{1.29}$$

$$\left[\frac{\partial \boldsymbol{Q}}{\partial \boldsymbol{V}}\right][\Delta \boldsymbol{V}] = -[\Delta \boldsymbol{Q}] \tag{1.30}$$

The above two equations can be further simplified such that the system matrix becomes constant. Then we have

$$[\boldsymbol{B}'][\Delta \boldsymbol{\theta}] = -[\Delta \boldsymbol{P}/\boldsymbol{V}] \tag{1.31}$$

$$[\boldsymbol{B}''][\Delta \boldsymbol{V}] = -[\Delta \boldsymbol{Q}/\boldsymbol{V}] \tag{1.32}$$

The model in (1.31) and (1.32) is the well-known fast decoupled load flow. The fast decoupled load flow method is much faster than the standard Newton-Raphson load flow method. The fast decoupled load flow method can be used in security analysis in the real-time environment of energy management systems due to its superior computational performance. However, the fast decoupled load flow method may have difficulty modeling novel power system controllers like flexible AC transmission systems (FACTS). Most production-grade load flow programs usually include both the load flow solution algorithms.

1.6.5 DC Load Flow Method

With certain assumptions, the AC load flow models discussed in Sections 1.6.2–1.6.4 can be simplified. The basic assumptions for the DC load flow model are as follows:

- Only the angles of the complex bus voltages vary, and the angle differences of transmission lines are small.
- Voltage magnitudes are assumed to be constant (usually set to 1.0 in per unit).
- Transmission lines are assumed to have no resistance, and therefore no losses.
- Transformer tap ratio control is not considered (usually tap ratio is set to 1.0), though the transformer shifting can be modeled if applicable.

With the above assumptions, a DC load flow model, which has advantages for speed of computation, can provide a reasonable approximation of the real power system. In addition, such a model has the following properties:

- *Linearity*: The power flow of a particular transmission line is the linear combination of the power injections of the system.
- *Superposition*: The power flows can be broken down into a sum of power flow components of different transactions.

With the DC load flow model assumptions, the power flows of transmission line *i-j* are given by the following linear function of the angles of the transmission line:

$$P_{ij} = \frac{\theta_i - \theta_j}{x_{ij}} \tag{1.33}$$

$$P_{ji} = \frac{\theta_j - \theta_i}{x_{ij}} \tag{1.34}$$

Taking the three-bus system shown in Figure 1.3 as an example, we have the following power flow equations:

$$P_{12} = \frac{\theta_1 - \theta_2}{x_{12}}, P_{21} = \frac{\theta_2 - \theta_1}{x_{12}}, P_{13} = \frac{\theta_1 - \theta_3}{x_{13}}, P_{31} = \frac{\theta_3 - \theta_1}{x_{13}}, P_{23} = \frac{\theta_2 - \theta_3}{x_{23}}, P_{32} = \frac{\theta_3 - \theta_2}{x_{32}}$$

Considering the power balance at each bus of the system, we have

$$Pg_1 = P_{12} + P_{13}, Pg_2 = P_{23} + P_{21}, -Pd_3 = P_{31} + P_{32}$$

hence we have the following compact format:

$$\boldsymbol{B'\theta} = \boldsymbol{P} \tag{1.35}$$

where diagonal elements of $\mathbf{B'}$ are given by $B_{ii} = \sum_{i=1}^{N} 1/x_{ij}$ and off-diagonal elements are given by $B_{ij} = -1/x_{ij}$. $\boldsymbol{P = Pg - Pd}$. In (1.29), if we take bus 1 as the reference bus, the row and column related to bus 1 should be removed and then the dimension of equation (1.29) becomes $N - 1$. Equation (1.29) now gives the DC load flow model. Unlike the solving of AC load flow problems, direct solution of DC load flow problem (1.29) can be obtained without any iterations. However, the deficits of the DC load flow model are obvious: a) in the model, power loss is not considered; b) reactive power and control is excluded. For heavily loaded system conditions, the DC load flow analysis may bring significant errors.

1.7 OPTIMAL OPERATION OF ELECTRIC POWER SYSTEMS

1.7.1 Security-Constrained Economic Dispatch

Economic dispatch determines the optimal power output of each generating unit while minimizing the overall cost of fuel to serve the system load. Normally any operational limits of generation and transmission facilities should be recognized. In the next section, we will start with classic economic dispatch with transmission network power loss. We will then introduce the security-constrained economic dispatch (SCED).

1.7.1.1 Classic Economic Dispatch Without Transmission Network Power Loss The classic economic dispatch can be formulated as:

$$\text{Minimize } f(Pg) = \sum_{i}^{Ng} f_i(Pg_i) = \sum_{i}^{Ng} \left(\alpha_i * Pg_i^2 + \beta_i * Pg_i + \gamma_i\right) \tag{1.36}$$

while subject to the following constraints:

Equality constraint:

$$\sum_{i=1}^{Ng} Pg_i - Pd - P_L = 0 \tag{1.37}$$

Inequality constraints

$$Pg_i^{\min} \leq Pg_i \leq Pg_i^{\max} \tag{1.38}$$

where Ng is the total number of generators. $f_i(Pg_i)$ is the fuel cost of generator i. P_L is the total transmission network power loss. Pd is the total system demand and it is assumed that this is constant. Now the key issue is to represent the total transmission network power loss P_L. Assume that the inequality constraints above are not binding, the Lagrange function of the above problem will be:

$$L(Pg) = \sum_{i}^{Ng} f_i(Pg_i) - \lambda\left(\sum_{i=1}^{Ng} Pg_i - Pd - P_L\right) \tag{1.39}$$

where λ is the incremental fuel cost of the system, which is called the Lagrange multiplier. The necessary optimization conditions for (1.39) are:

$$\frac{\partial L(Pg_i)}{\partial Pg_i} = \frac{\partial f_i(Pg_i)}{\partial Pg_i} - \lambda\left(1 - \frac{\partial P_L}{\partial Pg_i}\right) = 0 \tag{1.40}$$

where these are called the classic coordination equations.

Then we have:

$$\lambda = \left(\frac{1}{1 - \frac{\partial P_L}{\partial Pg_i}} \right) \frac{\partial f_i(Pg_i)}{\partial Pg_i} \tag{1.41}$$

where $\frac{\partial P_L}{\partial Pg_i}$ are the incremental losses. The above equation can be rewritten as:

$$\lambda = PF_i \frac{\partial f_i(Pg_i)}{\partial Pg_i} \tag{1.42}$$

where PF_i is called the penalty factor of generator i, and is given by

$$PF_i = \left(\frac{1}{1 - \frac{\partial P_L}{\partial Pg_i}} \right) \tag{1.43}$$

The penalty factor can be determined in two different ways. The first approach is based on the so-called B coefficient model [30–32]. The calculations of B coefficients have been improved upon in [33] for efficient implementation by using sparsity techniques. The B coefficients calculations are based on an approximation of the system losses as a quadratic function of the generation powers:

$$P_L = \boldsymbol{Pg}^T \boldsymbol{B}\boldsymbol{Pg} + \boldsymbol{Pg}^T \boldsymbol{B}_0 + B_{00} \tag{1.44}$$

where $Pg = [Pg_1, Pg_2, \ldots, Pg_{Ng}]^T$. $\boldsymbol{B}$ is a square matrix, $\boldsymbol{B}_0$ is a vector.

The second approach is based on Newton's method [34]. Assume bus 1 is a slack bus or a reference bus and Pg_1 is the active power of the generator at bus 1, we have:

$$\begin{bmatrix} \frac{\partial \boldsymbol{P}}{\partial \boldsymbol{\theta}} & \frac{\partial \boldsymbol{P}}{\partial \boldsymbol{V}} \\ \frac{\partial \boldsymbol{Q}}{\partial \boldsymbol{\theta}} & \frac{\partial \boldsymbol{Q}}{\partial \boldsymbol{V}} \end{bmatrix}^T \begin{bmatrix} \frac{\partial Pg_1}{\partial \boldsymbol{Pg}} \\ \frac{\partial Pg_1}{\partial \boldsymbol{Qg}} \end{bmatrix} = - \begin{bmatrix} \frac{\partial Pg_1}{\partial \boldsymbol{\theta}} \\ \frac{\partial Pg_1}{\partial \boldsymbol{V}} \end{bmatrix} \tag{1.45}$$

Note in the above equation, the system matrix is the transpose of the Newton power flow Jacobian Matrix in (1.28). The equation (1.45) can be solved very efficiently using sparsity matrix techniques.

We know $P_L = \sum_{i=1}^{Ng} Pg_i - Pd$, then we can get

$$\frac{\partial P_L}{\partial Pg_i} = \frac{\partial Pg_1}{\partial Pg_i} + \frac{\partial \sum_{k=2}^{Ng} Pg_k}{\partial Pg_i} = \frac{\partial Pg_1}{\partial Pg_i} + 1 \tag{1.46}$$

Rewriting the above equation, we have

$$-\frac{\partial Pg_1}{\partial Pg_i} = 1 - \frac{\partial P_L}{\partial Pg_i} \tag{1.47}$$

Then the penalty factors are given by

$$PF_i = \frac{1}{-\dfrac{\partial Pg_1}{\partial Pg_i}} \tag{1.48}$$

where $-\dfrac{\partial Pg_1}{\partial Pg_i}$ can be found by solving (1.45).

1.7.1.2 Security Constrained Economic Dispatch

In comparison with the classic economic dispatch problem, a security constrained economic dispatch problem can consider transmission line thermal limits, which are also called security constraints. The security-constrained economic dispatch can be formulated as follows:

$$\text{Minimize } f(Pg) = \sum_{i}^{Ng} f_i(Pg_i) = \sum_{i}^{Ng} (\alpha_i * Pg_i^2 + \beta_i * Pg_i + \gamma_i) \tag{1.49}$$

while subject to the following constraints:

Equality constraint:

$$\sum_{i=1}^{Ng} Pg_i - PL - P_{Loss} = 0 \tag{1.50}$$

Inequality constraints:

$$Pg_i^{\min} \le Pg_i \le Pg_i^{\max} \tag{1.51}$$

$$P_{ij}^{\min} \le P_{ij}(\mathbf{Pg}) \le P_{ij}^{\max} \tag{1.52}$$

where P_{ij} is the power flow of line ij and given by (1.33). From (1.35), the angles in (1.33) can be represented as a function of **Pg** by solving equation (1.35). Survey papers on economic dispatch can be found in [36–39]. In comparison to an economic dispatch problem, an optimal power flow problem is a more general optimization problem, which can include detailed network representation and various operating, control, and contingency constraints. Consider variables of various control devices such as generators, transformers, reactive compensation devices, FACTS devices, load shedding actions, DC lines, and network switching, and adopt various objective functions concerning economy and security. In the next section, optimal power flow techniques are reviewed, then detailed formulations and solutions of optimal power flow problems are introduced.

1.7.2 Optimal Power Flow Techniques

1.7.2.1 Development of Optimization Techniques in OPF Solutions

The optimal power flow (OPF) problem was initiated by the desire to minimize the operating cost of the supply of electric power when load is given [31, 32]. In 1962 a generalized nonlinear programming formulation of the economic dispatch problem including voltage and other operating constraints was proposed by Carpentier [35]. The OPF problem was defined in early 1960s as an expansion of conventional economic dispatch to determine the optimal settings for control variables in a power network considering various operating and control constraints [40–44]. The OPF method proposed in [40] has been known as the reduced gradient method, which can be formulated by eliminating the dependent variables based on a solved load flow. Since the concept of the reduced gradient method for the solution of the OPF problem was proposed, continuous efforts in the development of new OPF methods have been found. Several review papers were published [39, 45–47]. Among the various OPF methods proposed, it has been recognized that the main techniques for solving the OPF problems are the gradient method [40], linear programming (LP) method [49, 50], successive sparse quadratic programming (QP) method [52], successive nonsparse QP method [54], Newton's method [55], and Interior Point Methods [61–66]. Each method has its own advantages and disadvantages. These algorithms have been employed with varied success.

OPF problems are very complex mathematical programming problems. Numerous papers on the numerical solution of the OPF problems have been published [39, 42, 45–47]. In this section, a review of several OPF methods is given.

The widely used gradient methods for the OPF problems include the reduced gradient method [40] and the generalized gradient method [48]. Gradient methods exhibit slow convergence characteristics near the optimal solution. In addition, the methods are difficult to solve in the presence of inequality constraints.

LP methods have been widely used in the OPF problems. The main strengths of LP-based OPF methods are summarized as follows: a) efficient handling of inequalities and detection of infeasible solutions; b) dealing with local controls; and c) incorporation of contingencies.

It is quite common in OPF problems that nonlinear equalities and inequalities and objective function need to be handled. In this situation, all the nonlinear constraints and objective functions should be linearized around the current operating point such that LP methods can be applied to solve the linear optimal problems. For a typical LP-based OPF, the solution can be found through the iterations between load flow and linearized LP subproblem. The LP-based OPF methods have been shown to be effective for problems where the objectives are separable and convex. However, the LP-based OPF methods may not be effective where the objective functions are nonseparable, for instance in the minimization of transmission losses.

QP based OPF methods [51–54] are efficient for some OPF problems, especially for the minimization of power network losses. In [54], the nonsparse implementation of the QP-based OPF was proposed while in [51–53], the sparse implementation of the QP-based OPF algorithm for large-scale power systems was presented. In [51, 52], the successive QP-based OPF problems are solved through a sequence of linearly constrained subproblems using a quasi-Newton search direction. The QP formulation can always find a feasible solution by adding extra shunt compensation. In [53], the QP method, which is a direct solution method, solves a set of linear equations involving the Hessian matrix and the Jacobian matrix by converting the inequality constrained quadratic program (IQP) into the equality constrained quadratic program (EQP) with an initial guess at the correct active set. The computational speed of the QP method in [53] has been much improved in comparison to those in [51, 52]. The QP methods in [51–53] are solved using MINOS, developed at Stanford University.

The development of the OPF algorithm by Newton's method [55, 57, 58], is based on the success of the Newton's method for the power flow calculations. Sparse matrix techniques applied to the Newton power flow calculations are directly applicable to the Newton OPF calculations. The major idea is that the OPF problems are solved by the sequence of the linearized Newton equations where inequalities are treated as equalities when they are binding. However, the most critical aspect of Newton's algorithm is that the active inequalities are not known prior to the solution and the efficient implementations of the Newton's method usually adopt the so-called trial iteration scheme where heuristic constraint enforcement/release is iteratively performed until acceptable convergence is achieved. In [56, 59], alternative approaches using linear programming techniques have been proposed to identify the active set efficiently in the Newton's OPF. In principle, the successive QP methods and Newton's method both using the second derivatives, considered a second-order optimization method, are theoretically equivalent.

Since Karmarkar published his paper on an interior point method for linear programming in 1984 [60], a great interest on the subject has arisen. Interior point methods have proven to be a promising alternative for the solution of power system optimization problems. In [61, 62], a security-constrained economic dispatch (SCED) is solved by sequential linear programming and the IP dual-affine scaling (DAS). In [63], a modified IP DAS algorithm was proposed. In [64], an interior point method was proposed for linear and convex quadratic programming. It is used to solve power system optimization problems such as economic dispatch and reactive power planning. In [65–70], nonlinear primal-dual interior point methods for power system optimization problems were developed. The nonlinear primal-dual methods proposed can be used to solve the nonlinear power system OPF problems efficiently. The theory of nonlinear primal-dual interior point methods has been established based on three achievements: Fiacco and McCormick's barrier method for optimization with inequalities, Lagrange's method for optimization with equalities, and Newton's method for solving nonlinear equations [71]. Experience with application of interior point methods to power system optimization problems has been quite positive.

1.7.2.3 OPF Formulation

The OPF problem may be formulated as follows:

$$\text{Minimize: } f(\mathbf{x}, \mathbf{u}) \tag{1.53}$$

subject to:

$$\mathbf{g}(\mathbf{x}, \mathbf{u}) = 0 \tag{1.54}$$

$$\mathbf{h}_{\min} \leq \mathbf{h}(\mathbf{x}, \mathbf{u}) \leq \mathbf{h}_{\max} \tag{1.55}$$

where

u-the set of control variables

x-the set of dependent variables

$f(\mathbf{x}, \mathbf{u})$-a scalar objective function

$\mathbf{g}(\mathbf{x}, \mathbf{u})$-the power flow equations

$\mathbf{h}(\mathbf{x}, \mathbf{u})$-the limits of the control variables and operating limits of power system components.

TABLE 1.1 Objectives, constraints, and control variables of the OPF problems

Objectives	• Minimum cost of generation and transactions • Minimum transmission losses • Minimum shift of controls • Minimum number of controls shifted • Mininum number of controls rescheduled • Minimum cost of VAr investment
Equality constraints	• Power flow constraints • Other balance constraints
Inequality constraints	• Limits on all control variables • Branch flow limits (amps, MVA, MW, MVAr) • Bus voltage variables • Transmission interface limits • Active/reactive power reserve limits
Controls	• Real and reactive power generation • Transformer taps • Generator voltage or reactive control settings • MW interchange transactions • HVDC link MW controls • FACTS voltage and power flow controls • Load shedding

The objectives, controls and constraints of the OPF problems are summarized in Table 1.1. The limits of the inequalities in Table 1.1 can be classified into two categories: a) physical limits of control variables; b) operating limits of power system. In principle, physical limits on control variables cannot be violated while operating limits representing security requirements can be violated or relaxed temporarily.

In addition to the steady state power flow constraints, for the OPF formulation, stability constraints, which are described by differential equations, may be considered and incorporated into the OPF. In recent years, stability constrained OPF problems have been proposed [72–74].

1.7.2.4 Optimal Power Flow Solution by Nonlinear Interior Point Methods

1.7.2.4.1 Power Mismatch Equations The power mismatch equations in rectangular coordinates at a bus are given by:

$$\Delta P_i = Pg_i - Pd_i - P_i \tag{1.56}$$

$$\Delta Q_i = Qg_i - Qd_i - Q_i \tag{1.57}$$

where Pg_i and Qg_i are real and reactive powers of generator at bus i, respectively; Pd_i and Qd_i the real and reactive load powers, respectively; P_i and Q_i the power injections at the node and are given by:

$$P_i = V_i \sum_{j=1}^{N} V_j \left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}\right) \tag{1.58}$$

$$Q_i = V_i \sum_{j=1}^{N} V_j \left(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}\right) \tag{1.59}$$

where V_i and θ_i are the magnitude and angle of the voltage at bus i, respectively; $Y_{ij} = G_{ij} + jB_{ij}$ is the system admittance element while $\theta_{ij} = \theta_I - \theta_j$. N is the total number of system buses.

1.7.2.4.2 Transmission Line Limits The transmission MVA limit may be represented by:

$$(P_{ij})^2 + (Q_{ij})^2 \le (S_{ij}^{\max})^2 \tag{1.60}$$

where $S_{ij}^{\max}$ is the MVA limit of the transmission line ij. P_{ij} and Q_{ij} are given by:

$$P_{ij} = -V_i^2 G_{ij} + V_i V_j \left(G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}\right) \tag{1.61}$$

$$Q_{ij} = V_i^2 b_{ii} + V_i V_j \left(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}\right) \tag{1.62}$$

where $b_{ii} = -B_{ii} + bc_{ij}/2$. bc_{ij} is the shunt admittance of transmission line ij.

1.7.2.4.3 Formulation of the Nonlinear Interior Point OPF Mathematically, as an example, the objective function of an OPF may minimize the total operating cost as follows:

$$\text{Minimize } f(x) = \sum_{i}^{Ng} \left(\alpha_i * Pg_i^2 + \beta_i * Pg_i + \gamma_i\right) \tag{1.63}$$

while being subject to the following constraints:
Nonlinear equality constraints:

$$\Delta P_i(x) = Pg_i - Pd_i - P_i(t, e, f) = 0 \tag{1.64}$$

$$\Delta Q_i(x) = Qg_i - Qd_i - Q_i(t, e, f) = 0 \tag{1.65}$$

Nonlinear inequality constraints:

$$h_j^{\min} \le h_j(x) \le h_j^{\max} \tag{1.66}$$

where

$x = [Pg, Qg, t, \theta, V]^T$ is the vector of variables

α_i, β_i, γ_i	coefficients of production cost functions of generator
$\Delta P(x)$	bus active power mismatch equations
$\Delta Q(x)$	bus reactive power mismatch equations
$h(x)$	functional inequality constraints including line flow and voltage magnitude constraints, simple inequality constraints of variables such as generator active power, generator reactive power, and transformer tap ratio
Pg	the vector of active power generation
Qg	the vector of reactive power generation
t	the vector of transformer tap ratios

θ the vector of bus voltage magnitude

V the vector of bus voltage angle

Ng the number of generators

By applying Fiacco and McCormick's barrier method, the OPF problem equations (1.63)–(1.67) can be transformed into the following equivalent OPF problem:

$$\text{Objective:} \quad Min\left\{ f(x) - \mu \sum_{j=1}^{M} \ln(sl_j) - \mu \sum_{j=1}^{M} \ln(su_j) \right\} \tag{1.67}$$

subject to the following constraints:

$$\Delta P_i = 0 \tag{1.68}$$

$$\Delta Q_i = 0 \tag{1.69}$$

$$h_j - sl_j - h_j^{\min} = 0 \tag{1.70}$$

$$h_j + su_j - h_j^{\max} = 0 \tag{1.71}$$

where $sl > 0$ and $su > 0$.

Thus, the Lagrangian function for equalities optimization of equations (1.67)–(1.71) is given by:

$$L = f(x) - \mu \sum_{j=1}^{M} \ln(sl_j) - \mu \sum_{j=1}^{M} \ln(su_j) - \sum_{i=1}^{N} \lambda p_i \Delta P_i - \sum_{i=1}^{N} \lambda q_i \Delta Q_i$$
$$- \sum_{j=1}^{M} \pi l_j \left(h_j - sl_j - h_j^{\min}\right) - \sum_{j=1}^{M} \pi u_j \left(h_j + su_j - h_j^{\max}\right) \tag{1.72}$$

where λp_i, λq_i, πl_j, πu_j are Langrage multipliers for the constraints of equations (1.68)–(1.71), respectively. N represents the number of buses and M the number of inequality constraints. Note that $\mu > 0$. The Karush-Kuhn-Tucker (KKT) first order conditions for the Lagrangian function shown in equation (1.72) are as follows:

$$\nabla_x L_\mu = \nabla f(x) - \nabla \Delta P^T \lambda p - \nabla \Delta Q^T \lambda q - \nabla h^T \pi l - \nabla h^T \pi u = 0 \tag{1.73}$$

$$\nabla_{\lambda p} L_\mu = -\Delta P = 0 \tag{1.74}$$

$$\nabla_{\lambda q} L_\mu = -\Delta Q = 0 \tag{1.75}$$

$$\nabla_{\pi l} L_\mu = -\left(h - sl - h^{\min}\right) = 0 \tag{1.76}$$

$$\nabla_{\pi u} L_\mu = -\left(h + su - h^{\max}\right) = 0 \tag{1.77}$$

$$\nabla_{sl} L_\mu = \mu - Sl \Pi l = 0 \tag{1.78}$$

$$\nabla_{su} L_\mu = \mu + Su \Pi u = 0 \tag{1.79}$$

$$\nabla_{\lambda q} L_\mu = -\Delta Q = 0 \tag{1.80}$$

where $Sl = diag(sl_j)$, $Su = diag(su_j)$, $\Pi l = diag(\pi l_j)$, $\Pi u = diag(\pi u_j)$. As suggested in [65], the above equations can be decomposed into the following three sets of equations:

$$\begin{bmatrix} -\Pi l^{-1} Sl & 0 & -\nabla h & 0 \\ 0 & \Pi u^{-1} Su & -\nabla h & 0 \\ -\nabla h^T & -\nabla h^T & H & -J^T \\ 0 & 0 & -J & 0 \end{bmatrix} \begin{bmatrix} \Delta \pi l \\ \Delta \pi u \\ \Delta x \\ \Delta \lambda \end{bmatrix} = \begin{bmatrix} -\nabla_{\pi l} L_\mu - \Pi l^{-1} \nabla_{Sl} L_\mu \\ -\nabla_{\pi u} L_\mu - \Pi u^{-1} \nabla_{Su} L_\mu \\ -\nabla_x L_\mu \\ -\nabla_\lambda L_\mu \end{bmatrix} \tag{1.81}$$

$$\Delta sl = \Pi l^{-1}(\nabla_{sl}L_\mu - Sl\Delta\pi l) \tag{1.82}$$

$$\Delta su = \Pi u^{-1}(-\nabla_{su}L_\mu - Su\Delta\pi u) \tag{1.83}$$

where $H(x, \lambda, \pi l, \pi u) = \nabla^2 f(x) - \sum \lambda\nabla^2 g(x) - \sum(\pi l + \pi u)\nabla^2 h(x)$,

$$J(x) = \left[\frac{\partial\Delta P(x)}{\partial x}, \frac{\partial\Delta Q(x)}{\partial x}\right], \; g(x) = \begin{bmatrix}\Delta P(x)\\ \Delta Q(x)\end{bmatrix}, \quad \text{and} \quad \lambda = \begin{bmatrix}\lambda_p\\ \lambda_q\end{bmatrix}.$$

The elements corresponding to the slack variables *sl* and *su* have been eliminated from equation (1.81) using analytical Gaussian elimination. By solving equation (1.81), $\Delta\pi$l, $\Delta\pi$u, Δx, $\Delta\lambda$ can be obtained, then by solving equations (1.82) and (1.83), respectively, Δsl, Δsu can be obtained. With $\Delta\pi l$, $\Delta\pi u$, Δx, $\Delta\lambda$, Δsl, Δsu known, the OPF solution can be updated using the following equations:

$$sl^{(k+1)} = sl^{(k)} + \sigma\alpha_p\Delta sl \tag{1.84}$$

$$su^{(k+1)} = su^{(k)} + \sigma\alpha_p\Delta su \tag{1.85}$$

$$x^{(k+1)} = x^{(k)} + \sigma\alpha_p\Delta x \tag{1.86}$$

$$\pi l^{(k+1)} = \pi l^{(k)} + \sigma\alpha_d\Delta\pi l \tag{1.87}$$

$$\pi u^{(k+1)} = \pi u^{(k)} + \sigma\alpha_d\Delta\pi u \tag{1.88}$$

$$\lambda^{(k+1)} = \lambda^{(k)} + \sigma\alpha_d\Delta\lambda \tag{1.89}$$

where k is the iteration count, parameter $\sigma \in [0.995 - 0.99995]$ and αp and αd are the primal and dual step-length parameters, respectively. The step-lengths are determined as follows:

$$\alpha_p = \min\left[\min\left(\frac{sl}{-\Delta sl}\right), \min\left(\frac{su}{-\Delta su}\right), 1.00\right] \tag{1.90}$$

$$\alpha_d = \min\left[\min\left(\frac{\pi l}{-\Delta\pi l}\right), \min\left(\frac{\pi u}{-\Delta\pi u}\right), 1.00\right] \tag{1.91}$$

for those sl < 0, Δsu < 0, $\Delta\pi$l < 0, and $\Delta\pi$u > 0.
The barrier parameter μ can be evaluated by:

$$\mu = \frac{\beta \times Cgap}{2 \times M} \tag{1.92}$$

where $\beta \in [0.01 - 0.2]$ and Cgap is the complementary gap for the nonlinear interior point OPF and can be determined using:

$$Cgap = \sum_{j=1}^{M}(sl_j\pi l_j - su_j\pi u_j) \tag{1.93}$$

1.8 OPERATION AND CONTROL OF ELECTRIC POWER SYSTEMS—SCADA/EMS

1.8.1 Introduction of SCADA/EMS

SCADA/EMS (Supervisory Control and Data Acquisition/Energy Management System) is a computer monitoring and control system that can be used to supervise,

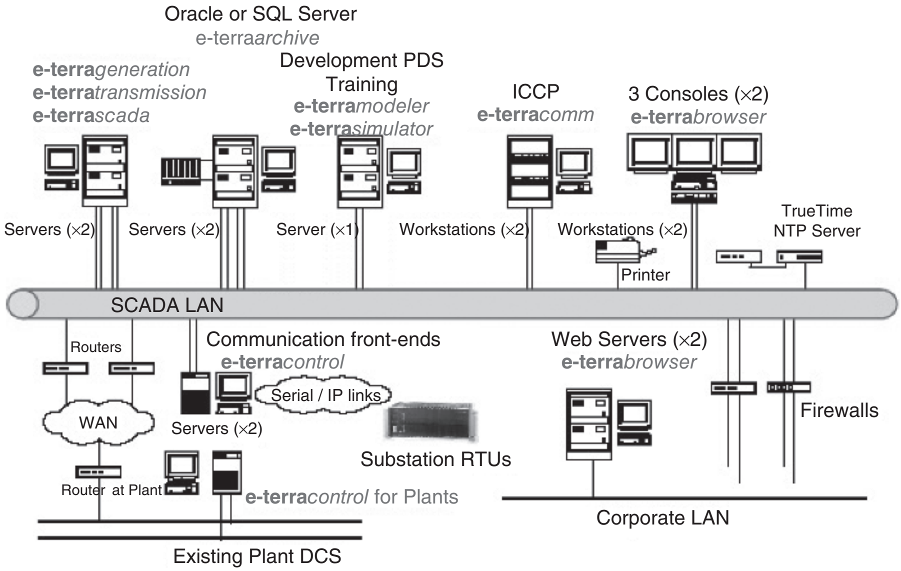


Figure 1.8 Schematic diagram of SCADA/EMS of energy control centers (courtesy of AREVA T&D)

control, optimize, and manage interconnected transmission systems. Electric power networks are complex systems that cannot be efficiently and securely operated without a SCADA/EMS. In contrast to SCADA/EMS for electric transmission networks, SCADA/DMS (Distribution Management System) is applied for electric distribution networks performing the very similar functions. A schematic diagram of SCADA/EMS of energy control centers is shown in Figure 1.8.

In Figure 1.8, e-terra*scada* is a distributed, scalable SCADA system that gathers real-time data from remote terminal units (RTUs) and other communication sources in the field and enables control of field devices from consoles. e-terra*generation* includes a suite of software applications such as real-time automatic generation control (AGC), transaction and unit scheduling, unit commitment, product costing, and load forecast. e-terra*simulator* provides training functionalities by helping operators acquire more knowledge, skills, and experience to operate real-time systems with the highest reliability standards. e-terra*transmission* is a suite of integrated network analysis applications designed for the support of real-time operation of a large electric power transmission network: network topology, state estimator, contingency analysis, dynamic stability, and short-circuit analysis as well as optimization and security constrained dispatch. A secure intercontrol center communication (ICCP) gateway facilitates the open exchange of data between interconnected and interdependent electric power utilities while e-terra*control* is a network-based distributed system that implements SCADA across a wide area network (WAN) while e-terra*control* for substations provides an access gateway into substations.

The energy control center is considered the central nerve system of the power system, which senses the status and measures the power, voltage, and current of the

Figure 1.9 The energy control center of Midwest Independent System Operator (MISO) (© Midwest ISO, all rights reserved)

power system, adjusts its operating conditions, coordinates its controls, and provides defense against abnormal events. After the 1965 power blackout in the US, great efforts in the development of energy control centers occurred in improving power system monitoring, operation, control, and planning using advanced computer techniques. Basically, the power system operation, control, planning, and intelligent management functions form the Energy Management System (EMS), which has the nature of centralized control. An energy control center is shown in Figure 1.9.

1.8.2 SCADA/EMS of Conventional Energy Control Centers

SCADA/EMS of energy control centers have evolved over the years into a complex computer based information and control system. For a SCADA system, the functions may include:

- Data acquisition
- Device and sequence control
- Events management
- Dynamic network coloring
- Intercontrol center communications

A SCADA/EMS system in an energy control center plays a very important role in the operation of a power system. The functions of SCADA/EMS are usually called applications. The major functions of EMS may include the following categories:

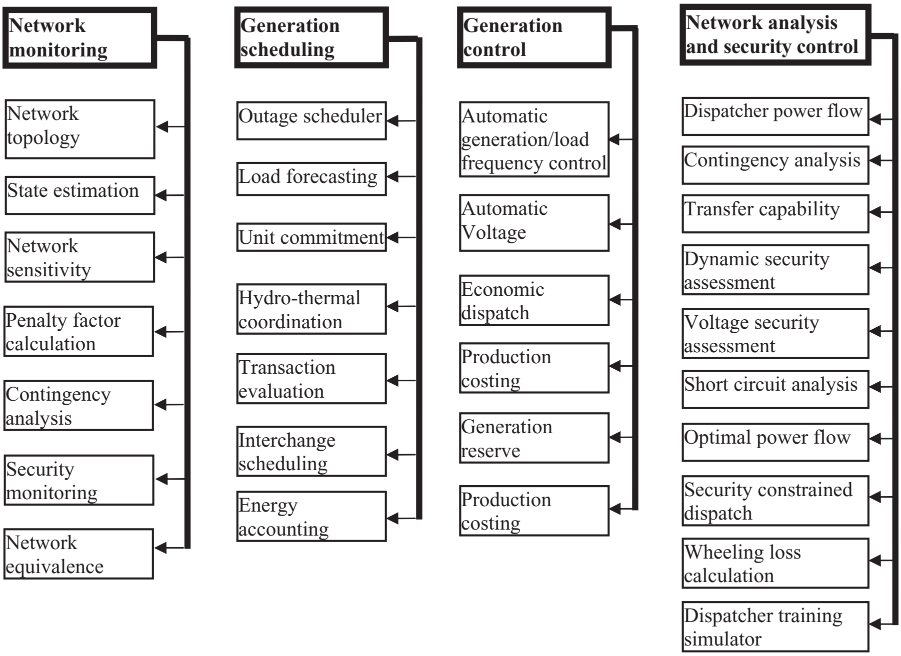


Figure 1.10 Functions of EMS

- Network monitoring
- Generation scheduling
- Generation control
- Network analysis and security control

The detailed functionalities are shown in Figure 1.10.

1.8.3 New Development Trends of SCADA/EMS of Energy Control Centers

1.8.3.1 New Environments Early SCADA and EMS of energy control centers were developed for the industry of a vertically integrated monopoly. Significant changes have taken place in the deregulated industry environment. The functionalities of energy control centers need to be reshaped with increased complexities, flexibility, and openness in response to the fasting-changing of rules for market operations and regulatory framework and the increasing information exchange requirements between energy control centers. Advances in technology provide great opportunities to integrate different automation and information products more efficiently and reliably. For instance, the integration of various automation products, such as SCADA, EMS, DA (distribution automation), AM/FM/GIS (automated mapping and facility management, geographic information system), and MIS (management information system), has been implemented.

1.8.3.2 Advanced Software Technologies With the development of information and control technologies, along with the development of worldwide electricity markets, the current EMS may need to migrate into a more decentralized environment while new emerging technologies would speed up this migration process.

Communications protocols play a key role in the development of SCADA/EMS of energy control centers. With standard protocols, computer communications can be implemented either via the Internet or in LANs. Standard protocols are based on the so-called open system interconnection (OSI) layered model, which is an industry standard framework including the functions of networking divided into seven distinct layers: physical, data link, network, transport, session, presentation, and application layers. The TCP/IP suite of protocol is the dominant standard for internetworking, which specifies how packets of information are exchanged between computers over one or more networks. The standard IP protocol provides a high degree of interoperability. Within the power industry, the intercontrol center protocol (ICCP) for intercontrol center communications based on the OSI model has been developed and is an IEC standard. For communications, electricity market operations use e-commerce standards like XML (eXtensible Markup Language) for documents containing structured information.

In the past 20 years or so, distributed system technologies, including distributed file systems, distributed memory storage systems, network operating systems, and middleware systems, have been developed, along with the recent advances in high-speed networking. Object-oriented concepts and methodology were developed along with the development of object-oriented programming in the late 1980s as a revolutionary attempt to change the paradigm of software design and engineering. Object-oriented programming provides a modular approach for software design. Each object combines data and procedures where object-oriented languages can provide a well-defined interface to their objects through classes and encapsulation, leading to more self-contained verifiable, modifiable, and maintainable software. By reusing developed classes, new applications can be built up much faster than in the traditional paradigm of software design in terms reliability, efficiency, and consistency of design. Based on the object design paradigm, C++, Java, and UML (the Unified Modeling Language) have been developed.

Another software technology is called component technology, where components consist of multiple objects and functionalities of the objects can be combined to offer a single software building block that can be adapted and reused. A component should have a standard interface, via which other components of the application can invoke its functions and access and manipulate the data within the component. The benefit is that software components can be independently developed, and they can be assembled and deployed, very much like standard reconfigurable hardware. The well-recognized component models include Enterprise JavaBeans, CORBA Components, and Microsoft COM/DCOM. In distributed object design technology, complex applications are usually decomposed into software components. Middleware technology was developed based on distributed object technology. Middleware is computer software that connects software components or applications.

Online power system security analysis and control for future smart grids requires a significant amount of computational power. Grid computing technology is an emerging technology for providing high-performance computing capability and a collaboration mechanism for solving complex problems while using the existing distributed resources. It can be used in the computation of intensive power system operation and control problems.

There is a need for synchronizing fast measurements across wide areas for online security analysis and stability control and coordination using phasor measurement units (PMUs). Industry research and development is working towards the systematic deployment of these PMUs and their integration into the existing energy control center design.

An energy control center with SCADA and EMS provides real-time data acquisition, monitoring, security, and control functions so as to support the operation of a power system and ensure the reliability and security of power system operations and the efficiency of electricity market operations. Systematic integration of enabling and emerging technologies such as PMUs, FACTS, and HVDC technologies, advanced energy storage technologies, advanced information technologies, and demand side management along with advanced operating concepts such as virtual power plants and microgrids will shape the way towards smart grids or intelligent grids. Such a trend of integration will facilitate the advanced energy control centers with the features of decentralization, flexibility, and openness in a more complicated industry environment.

1.9 ACTIVE POWER AND FREQUENCY CONTROL

1.9.1 Frequency Control and Active Power Reserve

A transmission system operator has the responsibility to maintain frequency between certain specified limits as large deviations in frequency can lead to widespread demand disconnections, generation disruptions, and even system splitting or collapse. If demand is greater than generation, frequency falls, and, if generation is greater than demand, frequency rises. The frequency control requirement of an interconnected transmission system should be less than the sum of that of each separate system. In order to fulfill the frequency control requirement, the system should have sufficient active power reserve. The active power reserve may be classified into the following categories in terms of system contingencies [10, 11]:

- *Spinning reserves:* Power generating units, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output, for instance, within 10 minutes to comply with NERC’s Disturbance Control Standard.
- *Supplemental reserve:* Same as spinning reserve, but need not respond immediately; units can be offline but still must be capable of reaching full output within the required 10 minutes.
- *Replacement reserve:* Same as supplemental reserve, but with a 30-minute response time; used to restore spinning and supplemental reserves to their precontingency status.

The definition of the various reserves may vary for different system operators. In electricity market environments, the above reserve provisions are available in the framework of ancillary services. In addition to these active power reserve services for frequency control in terms of system contingencies, there is also the so-called "regulation and load following" service, which is provided by the real-time energy market and is used to continuously balance generation and load under normal conditions. Load following and regulation can be implemented in AGC.

1.9.2 Objectives of Automatic Generation Control

For the normal operation of an interconnected power system, frequency of the system and bus voltages should be controlled within limits in order to provide satisfactory service to the customers and to ensure the security operation of equipment. Due to the different physical characteristics, frequency and voltage can controlled in decomposed manner and in different time scales. The active power and reactive power in a transmission network are relatively independent of each other and their control can be implemented separately. System frequency control is more relevant to active power control while voltage control is more related to reactive power control.

As system load is continuously changing, the output of generators should be changed automatically. Automatic generation control (AGC) is a control system used in active power and frequency control. AGC has three major objectives:

- To maintain system frequency at or very close to a specified nominal value (e.g., 50 Hz).
- To maintain the scheduled tie-line loading of interchange power between control areas.
- To maintain each generator's output at the most economic value.

AGC systems have many advantages over governor speed control systems. The AGC systems transmit control signals to the governor systems and operate the control valves to decrease or increase the input to turbines to restore and maintain correct frequency if required. AGC systems have the capability to allocate the governing responses among generators of power plants. AGC systems have more powerful control ability to keep the system frequency within limits than that of conventional governing control systems.

1.9.3 Turbine-Generator-Governor System Model

A diagram that integrates the turbine, generator and governor into a system is shown in Figure 1.11. The characteristics of the turbine and generator as well as the primary control of governor have been included in the diagram. The AGC is related to the supplementary control and tie-line control that will be discussed later.

In Figure 1.12, P_{mech} is mechanical power of the generator, P_{elec} is electrical power output of the generator, and ω is rotational speed of the generator. The relationship between mechanical power, electrical power, and speed change may be given by

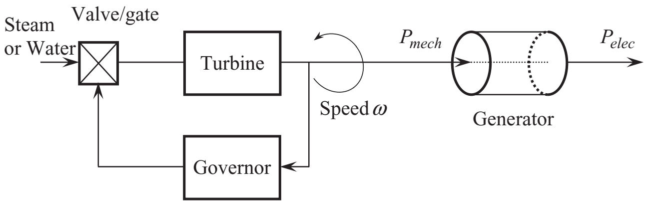


Figure 1.11 Conceptual description of a generator and its associated control

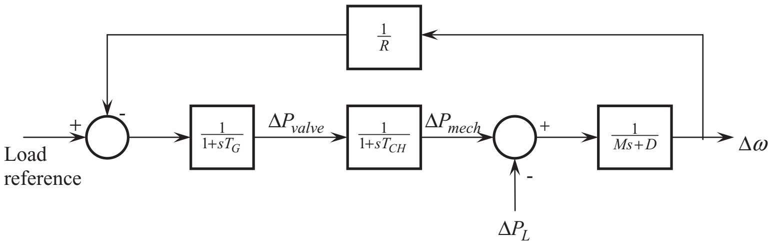


Figure 1.12 Turbine-generorat-governor system model

$$\Delta P_{mech} - \Delta P_{elec} = M\frac{d}{dt}(\Delta\omega) \tag{1.94}$$

where ΔP_{mech}, ΔP_{elec}, and $\Delta\omega$ are mechanical power, electrical power output, and rotational speed change, respectively. The electrical power change ΔP_{elec} can be further represented by nonfrequency sensitive load change and frequency-sensitive load change

$$\Delta P_{elec} = \Delta P_L + D\Delta\omega \tag{1.95}$$

Usually a generator is driven by a steam turbine or a hydro turbine. A non-reheat turbine model, which describes the relationship between the mechanical power and valve position, is shown in Figure 1.12. T_{CH} is the time constant of the turbine system. In the a generator governor model shown in Figure 1.12, the governor has a gain $\frac{1}{R}$ and a time constant T_G. R determines the change of generator's output for a change in frequency.

For normal operation of a power system, system frequency should be controlled within its limits. Because system frequency is common to all parts of the system and is easily measured, it was probably the first quantity applied to system control. The governors of generating units make use of rotating flyballs. These actuate a hydraulic system to open or close the throttle valves of the prime moves of the machines. This action increases or decreases energy input (for instance, fuel in a thermal plant or water in a hydro plant) to maintain speed (and hence frequency) at the desired value. Modern electronic governors sense frequency and actuate hydraulic devices to control gate or throttle position without the use of flyballs.

In order to operate machines stably in parallel with the system, it is necessary that the governors have drooping characteristics. That is, as load increases, speed decreases. Governor droops are expressed in percentage of speed change from no load to full load. If governors had zero droop, or if they were adjusted so that the speed characteristics increased with load, operation would be unstable. If one machine has a lower governor droop setting than others, when two or more generating units are operated in parallel on an AC system, on a system frequency drop the machine with the lower droop characteristic will pick up proportionally more load. Since generators operated in parallel cannot be separated to adjust the governor, when there is a load change each time, the governor droop characteristic is adjusted during a series of tests and is then fixed. Because governors are combination of hydraulic and mechanical components, an appreciable change in system speed is required before the governor can sense it and take corrective action. Consequently, the correction is delayed by a discrete time interval from the time the speed or frequency change occurred. As a result, machines or systems controlled only by governors have a dead band on the order of 0.02 Hz.

1.9.4 AGC for a Single-Generator System

AGC for a single-generator system is shown Figure 1.13. Once a load change has occurred, the generator governing system as shown in Figure 1.12 can reduce frequency deviation, however, it can not restore system frequency back to nominal value. In this situation, a supplementary control by AGC is required to restore frequency to nominal value. The principle of the supplementary control by AGC is to reset the load reference point as shown in Figure 1.13 and to force the frequency error to zero.

The AGC for a single generator system can be very easily extended to multimachine systems by modifying the output of the supplementary control block based on generator's participation factor determined by economic dispatching algorithm. Their allocated load reference P_{ref} is input to corresponding generator.

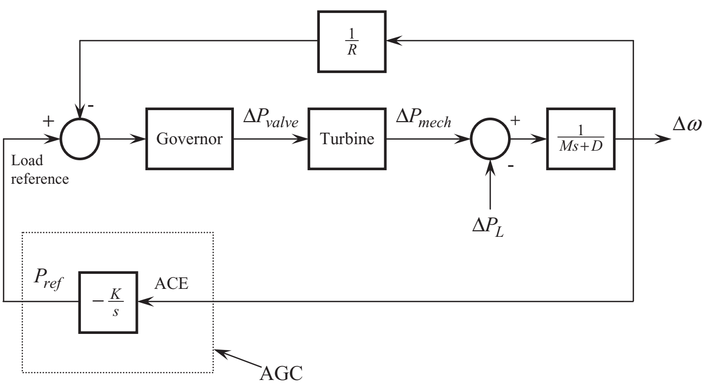


Figure 1.13 AGC for a single-generator system

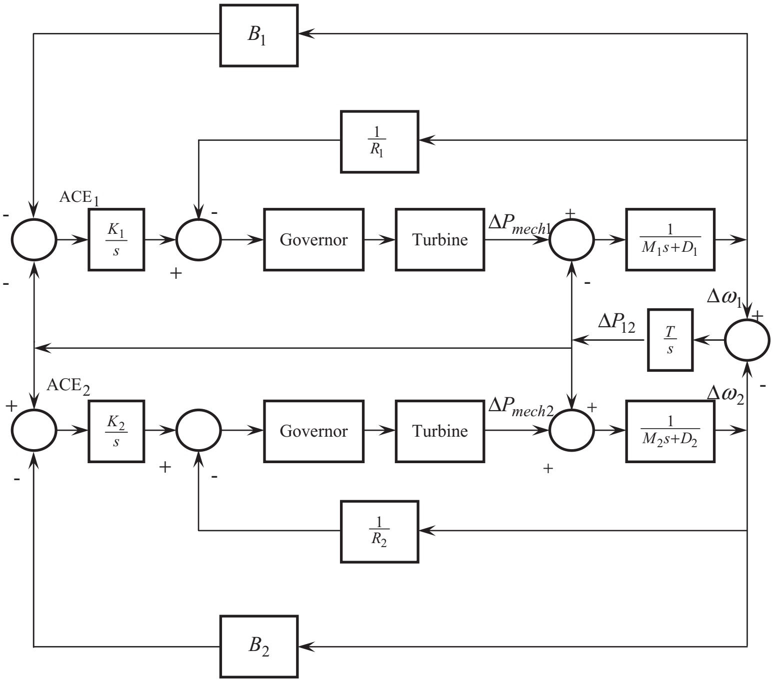


Figure 1.14 AGC for two-area system

1.9.5 AGC for Two-Area Systems

For two-area systems, the basic objective of supplementary control is to restore balance between each area load and generation (Figure 1.14). This is usually done by the following control actions:

1. Maintaining frequency at the scheduled value;
2. Maintaining net interchange power at the scheduled value.

For two-area systems, area control error signals for the two systems are:

$$ACE_1 = -\Delta P_{12} - B_1 \Delta\omega \tag{1.96}$$

$$ACE_2 = \Delta P_{12} - B_2 \Delta\omega \tag{1.97}$$

where ΔP_{12} is the net interchange power change. B_1 and B_2 bias factors.

A thorough review of some key issues of AGC is found in [12]. AGC logic based on NERC (North American Electric Reliability Corporation)'s new control performance standard and disturbance control standard is discussed in [13, 14].

1.9.6 Frequency Control and AGC in Electricity Markets

It has been reported [10] that hourly markets for regulation and the contingency reserves (spinning, supplemental, and sometimes replacement reserves) are either in operation or are being established in ISO regions, such as New England, New York, PJM (Pennsylvania-New Jersey-Maryland Interconnection), the Electric ERCOT (Electric Reliability Council of Texas), California, Ontario and Alberta, Canada. Design of such ancillary markets is referred to in Chapter 2.

Further discussions on frequency control and active power reserve and AGC in electricity market environments are found in [15–23].

In the UK transmission system, mandatory frequency response, which is an automatic change in active power output in response to a frequency change, is provided by all generators in the light of the requirements of the grid code. The capability to provide mandatory frequency response service is a condition of connection of generators to the system. The purpose of the mandatory frequency response is to fulfill the national grid's obligation to ensure that sufficient generation and/or demand is held in terms of all credible frequency change contingencies. According to the service delivered, a generating unit will be paid according to the Connection and Use of System Code (CUSC) with two types of payment, holding payment (£/h) and response energy payment (£/MWh). The holding payment is made for the capability of the unit to provide the frequency response in responsive mode. Response energy payment (£/MWh) is made for the amount of energy delivered to and from the system in providing the frequency response service.

The holding payment for a generating unit is calculated based on the following:

$$HP_M = P_M + H_M + S_M \tag{1.98}$$

where HP_M is the holding payment in pounds sterling per minute. P_M is the payment per minute for the ancillary service of primary response. H_M is the payment per minute for the ancillary service of high frequency. S_M is the payment per minute for the ancillary service of secondary response.

Response energy payment (£/MWh) is calculated as follows:

$$REP_{ij} = RE_{ij} \times \text{Reference Price} \tag{1.99}$$

where RE_{ij} is the expected response energy for generating unit i in settlement period j, which is given by.

$$RE_{ij} = \int_0^{SPD} [\max(FR_{ij}(t), 0) \times (1 - SF_{LF}) + \min(FR_{ij}(t), 0) \times (1 - SF_H)] \times K_T \times K_{GRC} dt \tag{1.100}$$

where the integral is over the settlement period duration. $FR_{ij}(t)$ is the expected change in active power output for generating unit i at time t. SF_{LF} indicates the provision of primary and secondary services. K_T and K_{GRC} are adjustment factors.

1.10 VOLTAGE CONTROL AND REACTIVE POWER MANAGEMENT

1.10.1 Introduction of Voltage Control and Reactive Power Management

For efficient, secure, and reliable operation of electric power systems, it has been recognized that the following operating objectives should be satisfied:

- *Voltage limits*: Bus voltage magnitudes should be within acceptable limits since electric power equipment and customer equipment can only be safely operated at a voltage very close to its rating. Equipment being operated outside of voltage limits may either not perform properly or be damaged.
- *System stability enhancement*: System transient stability and voltage stability can usually be enhanced by proper voltage control and reactive power (VAR) management. Subsequently the use of the transmission system asset can be maximized.
- *Minimized reactive power flows*: Reactive power flows should be minimized such that the active and reactive power losses can be reduced. In addition, the by-product of the minimized reactive power flows can actually reduce the voltage drop across transmission lines and transformers.

1.10.2 Reactive Power Characteristics of Power System Components

In order to understand the voltage control and VAR management problems of electric power systems, the reactive power characteristics of power system components will be reviewed first.

- *Synchronous generators:* Synchronous generators are very important reactive sources that can generate or absorb reactive power depending on excitation control. Equipped with modern excitation control systems, synchronous generators can provide both static but also dynamic voltage control and reactive power support.
- *Overhead transmission lines:* When load levels are less than the natural load, transmission lines can produce reactive power; when load levels are higher than the natural load, transmission lines absorb reactive power.
- *Underground cables:* Since underground cables usually have high capacitance and high natural load, cables generate reactive power.
- *Transformers:* In transformers, capacitance is usually very small in comparison to their reactance. Transformers always absorb reactive power.
- *Loads:* Most loads absorb reactive power. Usually it is required that larger industry customers maintain high lagging power factors.
- *Conventional HVDC:* Conventional HVDC systems for large power transfer over long distance usually absorb reactive power. Reactive shunt compensating devices must be installed at the terminals of the HVDC system.

1.10.3 Devices for Voltage and Reactive Power Control

In electrical power systems, voltage control and reactive power management requires various voltage control devices installed at different locations of the systems. In addition to the voltage control devices, suitable control algorithms and software tools are needed to determine control settings and coordinate the control actions of the voltage control devices sited at different locations of the systems. The voltage control devices will be briefly introduced and the characteristics of these devices will be discussed.

- *Shunt reactors:* Shunt reactors are used to compensate for the voltage rise effects of line capacitance with light load. The compensation of shunt reactors is useful to long transmission lines.
- *Shunt capacitors:* Shunt capacitors are widely used in transmission and distribution systems. At distribution level, the main purposes of shunt capacitors are power factor correction and voltage control. At transmission level, the purposes of shunt capacitors are to reduce the power losses and voltage drops and provide voltage support when the network is heavily loaded.
- *Series capacitors:* Series capacitors are used to compensate transmission line impedances such that transfer capability of transmission lines can be improved and voltage drops can be reduced. Although series capacitors can be used for voltage control, the control may not be efficient in comparison to the control by shunt capacitors. With use of series capacitors, one must be cautious about Subsynchronous Resonance (SSR) that may be caused by series capacitors.
- *Synchronous condensers:* Synchronous condensers are synchronous generators without active power generating capability. This means that they are pure reactive generating machines. Equipped with a voltage regulator, a synchronous condenser can automatically control its terminal voltage to the specified control target. In comparison to Static VAr Systems, synchronous condensers are expensive. Like synchronous generators, synchronous condensers have very good dynamic voltage control capabilities in power system transients.
- *Static VAr Systems* (SVS): A SVS system may consists of one more of the following components: saturated reactor, thyristor-controlled reactor, thyristor-switched capacitor, or thyristor-switched reactor. SVS are primarily used to control voltages at buses to which they are connected. SVS can also provide temporary overvoltage control, prevent the systems against voltage collapse, enhance transient stability, and increase the damping of power system oscillations. SVS can generate or absorb reactive power depending on the configurations of the systems.
- *Converter-based FACTS controllers:* Converter-based FACTS controllers such as the STATic Synchronous COMpensator (STATCOM), the Static Synchronous Series Compensator (SSSC), the Unified Power Flow Controller (UPFC), the Interline Power Flow Controller (IPFC), and the Generalized Unified Power Flow Controller (GUPFC) can be used to control of voltage, protect the systems against voltage collapse, enhance transient stability, and increase the damping of power system oscillations. In addition, those FACTS controllers that have series converters also have the ability to control active and reactive power flows. Other features of the converter-based FACTS controllers are their responses are very quick and they can provide continuous voltage control and reactive power support from inductive compensation to capacitive compensation. Converter-based shunt compensation, a STATCOM, has better control performance than a conventional Static Var System due to

the excellent dynamic reactive power and voltage control capability of the converter-based FACTS controller.

- *HVDC light:* Back-to-back HVDC light based on converter technologies has very strong voltage control and power flow control capability. In addition, it also protects the system against voltage collapse, enhances transient stability, and increases the damping of power system oscillations. An HVDC light is usually used to link a wind farm to a distribution network.
- *Tap-changing transformers:* Tap-changing transformers are used for voltage control in transmission and distribution systems. The transformers are usually used to control the voltages at buses to which they are connected. The transformers are not reactive power generation devices, however, the tap-changing transformers can alternate the reactive power distribution of the network by changing their tap ratios such that active and reactive losses of the network may be minimized and the voltage profiles may be improved.

1.10.4 Optimal Voltage and Reactive Power Control

Optimal power flow (OPF) is security and economic control-based optimization, which selects actions to minimize an objective function subject to specific operating constraints. Most OPF programs can perform more than one specific function. One of the OPF applications in energy management systems is to minimize active power transmission losses while control of reactive power from generator and compensating devices and control of tap-changing transformers are scheduled and coordinated. The voltage control and reactive power management by OPF tends to reduce circulating reactive power flows, thereby promoting flatter voltage profiles.

1.10.5 Reactive Power Service Provisions in Electricity Markets

In the vertically integrated electricity company including generation, transmission, and distribution, voltage control and reactive power support service are provided together with active power to customers. In electricity market environments, voltage control and reactive power support is considered an ancillary service, which is unbundled from active power supply. Along with the worldwide development of energy markets, frequency control and active power reserve have already been developed in the framework of ancillary markets while the market mechanisms of reactive power service are still under development. In the US, reactive power provided by a generator is considered as an ancillary service and receives a fixed payment for its service. In the UK transmission system, according to the requirement of the grid code, all generators are required to provide frequency response and reactive power to specified capabilities. The mandatory reactive power service is referred to as the Obligatory Reactive Power Service in Schedule 3 of the Connection and Use of System Code (CUSC), where all providers of the Obligatory Reactive Power Service are paid utilization payments via a default mechanism in accordance with Schedule 3 of the CUSC [24].

Further discussions on the development of ancillary service markets for reactive power can be found in [24–27]. Previous research work has indicated that voltage control and reactive power support has significant impact on the outcomes of electricity markets, in particular, when there is congestion in the system or the system is heavily loaded [28, 29].

1.11 APPLICATIONS OF POWER ELECTRONICS TO POWER SYSTEM CONTROL

1.11.1 Flexible AC Transmission Systems (FACTS)

An electrical power network may consist of synchronous generators, transmission lines, transformers, and loads. As discussed in Section 1.1, transmission lines may be represented equivalently by series impedance and shunt capacitance. The series impedance of the transmission lines and the voltage angles and magnitudes at the ends of the transmission lines usually determine the maximum transfer powers on the transmission lines, while the capacitance effects the voltage profiles of the power system. For operating an AC power system, the minimal requirements that should normally be satisfied are a) power generated by the synchronous generators and the power consumed by the loads should be balanced at any instant; b) the synchronous generators should remain synchronously operated with the power system; and c) the voltages at the system buses should be kept within the operating limits.

The concepts of Flexible AC Transmission Systems (FACTS) were initiated in the US by the Electric Power Research Institute (EPRI) in the late 1980s, and FACTS are basically power electronic devices. The basic control principle of FACTS is that the impedances of a power system can be changed by suitable FACTS controls. Then the power flows and voltages of the power system can be controlled. In addition to the power flow and voltage control capabilities, FACTS can also be used to control voltage stability, dynamic stability or small signal stability, and transient stability or angular stability.

In the family of FACTS controllers, two categories can be further classified based the implementation principles. The first category of FACTS consists of static VAr compensator (SVC), thyristor-controlled series capacitor (TCSC), thyristor-switched series capacitor (TSSC), and phase-shifter (PS) based on thyristor technologies without gate-turn-off ability. These thyristor-based FACTS controllers can control voltage, impedance, and angle, respectively. The second category of FACTS controllers is based on self-commutated voltage sourced switching converters technologies to realize controllable, static, synchronous AC voltage or current sources. The FACTS controllers employing switching converter-based synchronous voltage sources, the STATCOM, the SSSC, the UPFC, the IPFC, and the GUPFC. The STATCOM is shunt connected with a bus via a transformer. The UPFC consists of two converters, which are coupled via a DC link. The shunt converter is shunt connected with a local bus while the series converter is series connected with a transmission line.

The next generation FACTS control equipment, named the convertible static compensator (CSC), for the transmission grid was recently installed at Marcy

Substation of New York Power Authority (NYPA) and can increase power transfer capability and maximize the use of the existing transmission network. The salient features of a CSC are its convertibility and expandability, which are becoming increasingly important as electric utilities are being transformed into highly competitive marketplaces. The functional convertibility enables the CSC to adapt to changing system operating requirements and changing power flow patterns. The expandability of the CSC is that a number of voltage-sourced converters coupled with a common DC bus can be operated. Additional compatible converters can be connected to the common DC bus to expand the functional capabilities of the CSC. The convertibility and expandability of the CSC enables it to be operated in various configurations. The CSC installed at NYPA consists of two converters, and it can operate as a STATCOM, a SSSC, a UPFC, or an IPFC, but not as a GUPFC, which requires at least three converters. The IPFC and GUPFC are significantly extended to control power flows of multi-lines or a subnetwork beyond that achievable by the UPFC or SSSC or STATCOM. With at least two converters, an IPFC can be configured. With at least three converters, a GUPFC can be configured.

1.11.2 Power System Control by FACTS

All shunt FACTS controllers such as the SVC and STATCOM can provide voltage and reactive power control, whereas series FACTS controllers can provide power flow control. In addition, FACTS controllers can be used to improve power system angle stability, enhance power system voltage stability, and provide damping of system oscillations. However, the FACTS controllers from the two categories have different control performance.

The SVC (consisting of Thyristor Switched Capacitor—TSC and Thyristor Controlled Reactor—TCR) and the STATCOM have very similar functional compensation capability. The difference of their operating principles accounts for the STATCOM's overall superior performance and greater application flexibility. Due to the fact that the STATCOM can maintain full capacitive output current at low system voltage, it is more effective to improve the power system angle stability than the SVC. The time response of the STATCOM is much quicker than that of the SVC. In contrast to the SVC, the STATCOM can be interfaced with an energy storage system via its DC link. This potential capability can provide a new control for enhancing dynamic compensation.

In comparison to the TCSC and TSSC, the SSSC has the possibility to interface with an energy storage system to increase the power damping. The multi-converter switching converter–based FACTS controllers such as the UPFC, IPFC, and GUPFC have voltage and power flow control capabilities. The IPFC and GUPFC can control power flows on multiple transmission lines.

In the past, there were numerous SVC installations. In recent years, there have also been installations of TCSC, STATCOM, SSSC, UPFC and IPFC.

Further discussions on the modeling of FACTS in power flow and optimal power flow can be found in [6]. Similar to other power system controls, FACTS control has significant impact on system power flows and voltage profiles and hence on electricity market outcomes. The FACTS and HVDC controllers, together with emerging WAMS (wide area measurement systems), will be cost-effective and innovative control devices to effectively manage network congestion while ensuring an electricity network flexible enough to meet new and less predictable supply and demand conditions in competitive electricity markets. In addition, FACTS and HVDC will be key technologies in shaping the way towards smart grids.

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