2. Technical Aspects of Grid Interconnection

2.1. Introduction

2.1.1. The Evolution of Interconnected Systems

Electricity grid interconnections have played a key role in the history of electric power systems. Most national and regional power systems that exist today began many decades ago as isolated systems, often as a single generator in a large city. As power systems expanded out from their urban cores, interconnections among neighboring systems became increasingly common[8]. Groups of utilities began to form power pools, allowing them to trade electricity and share capacity reserves. The first power pool in the United States was formed in the Connecticut Valley in 1925[9]. As transmission technologies improved, long distance interconnections developed, sometimes crossing national borders. The first international interconnections in Europe came in 1906, when Switzerland built transmission links to France and Italy.

One of the great engineering achievements of the last century has been the evolution of large synchronous alternating current (AC) power grids, in which all the interconnected systems maintain the same precise electrical frequency. Today, the North American power system is composed of four giant synchronous systems, namely the Eastern, Western, Texas, and Quebec interconnections. The Eastern interconnection by itself has been called the largest machine in the world, consisting of thousands of generators, millions of kilometers of transmission and distribution lines, and more than a billion different electrical loads. Despite this complexity, the network operates in synchronism as a single system. So does the Western European interconnection, which reaches from the UK and Scandinavia to Italy and Greece, embracing along the way much of Eastern Europe (for example, Poland, Hungary, Slovakia, and the Czech Republic). Synchronous interconnections among countries are expanding in Central and South America, North and Sub-Saharan Africa, and the Middle East[10].

At the same time that synchronous AC networks have reached the continental scale, the use of high voltage direct current (HVDC) interconnections is also rapidly expanding as a result of technical progress over the last two decades. HVDC permits the asynchronous interconnection of networks that operate at different frequencies, or are otherwise incompatible, allowing them to exchange power without requiring the tight coordination of a synchronous network. HVDC has other advantages as well, especially for transmitting large amounts of power over very long distances. Fundamentals of both AC and DC interconnections are discussed below in Sections 2.2, 2.3, and 2.4 of this Chapter.

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8 T. Hughes (1983), *Networks of Power: Electrification in Western Society, 1880-1930*, Johns Hopkins University, Baltimore, MD.

9 Rincliffe, R.G. (1967), "Planning and Operation of a Large Power Pool.". *IEEE Spectrum*: 91-96. January 1967. The PJM (Pennsylvania/New Jersey/Maryland) grid was next to be developed, in 1927.

10 F. Meslier (1999), "Historical Background and Lessons for the Future," in J. Casazza and G. Loehr, *The Evolution of Electric Power Transmission Under Deregulation*, IEEE, Piscataway, NJ; pp. 28-31.

2.1.2. General potential benefits of grid interconnections

There are number of technical rationales for grid interconnections, many of which have economic components as well (as described in Chapter 3 of this Report). Technical rationales for grid interconnection include:

- Improving reliability and pooling reserves: The amount of reserve capacity that must be built by individual networks to ensure reliable operation when supplies are short can be reduced by sharing reserves within an interconnected network.
- Reduced investment in generating capacity: Individual systems can reduce their generating capacity requirement, or postpone the need to add new capacity, if they are able to share the generating resources of an interconnected system.
- Improving load factor and increasing load diversity: Systems operate most economically when the level of power demand is steady over time, as opposed to having high peaks. Poor load factors (the ratio of average to peak power demand) mean that utilities must construct generation capacity to meet peak requirements, but that this capacity sits idle much of the time. Systems can improve poor load factors by interconnecting to other systems with different types of loads, or loads with different daily or seasonal patterns that complement their own.
- Economies of scale in new construction: Unit costs of new generation and transmission capacity generally decline with increasing scale, up to a point. Sharing resources in an interconnected system can allow the construction of larger facilities with lower unit costs.
- Diversity of generation mix and supply security: Interconnections between systems that use different technologies and/or fuels to generate electricity provide greater security in the event that one kind of generation becomes limited (e.g., hydroelectricity in a year with little rainfall). Historically, this complementarity has been a strong incentive for interconnection between hydro-dominated systems and thermal-dominated systems. A larger and more diverse generation mix also implies more diversity in the types of forced outages that occur, improving reliability.
- Economic exchange: Interconnection allows the dispatch of the least costly generating units within the interconnected area, providing an overall cost savings that can be divided among the component systems. Alternatively, it allows inexpensive power from one system to be sold to systems with more expensive power.
- Environmental dispatch and new plant siting: Interconnections can allow generating units with lower environmental impacts to be used more, and units with higher impacts to be used less. In areas where environmental and land use constraints limit the siting of power plants, interconnections can allow new plant construction in less sensitive areas.
- Coordination of maintenance schedules: Interconnections permit planned outages of generating and transmission facilities for maintenance to be coordinated so that overall cost and reliability for the interconnected network is optimized.

Some costs and benefits of interconnections are difficult to quantify, but as a rough figure of merit it has been estimated that interconnections in North America have resulted in an overall annual cost savings of $20 billion in the 1990s, and that the Western European interconnection has resulted in reduced capacity requirements of 7-10 percent.

2.1.1. Technical complexities and risks of grid interconnections

The fact that interconnections between power systems are increasingly common does not imply that they are as simple as connecting a few wires. Interconnections obviously entail the expense of constructing and operating transmission lines and substations, or in the case of HVDC, converter stations. Interconnections also entail other costs, technical complexities, and risks. For AC interconnections especially, a power system interconnection is a kind of marriage, because two systems become one in an important way when they operate in synchronism. To do this requires a high degree of technical compatibility and operational coordination, which grows in cost and complexity with the scale and inherent differences of the systems involved. To give just one example, when systems are interconnected, even if they are otherwise fully compatible, fault currents (the current that flows during a short circuit) generally increase, requiring the installation of higher capacity circuit breakers to maintain safety and reliability. To properly specify these and many other technical changes required by interconnection requires extensive planning studies, computer modeling, and exchange of data between the interconnected systems.

The difficulties of joint planning and operation of interconnected systems vary widely. As with marriages, from the institutional and administrative standpoint, coupled systems may become a single entity, or they may keep entirely separate accounts. Within the North American interconnections, for example, there are hundreds of electric utility companies that are entirely separate commercial entities. Customers receive power from, and pay bills to, the utility that serves their area, for example Consolidated Edison. They may do so without even knowing of the existence of the Eastern interconnection. Yet all the utilities in the Eastern interconnection are in a technical marriage that dictates or constrains key aspects of their technology choices and operating procedures.

Within countries, there are typically common technical standards for all utilities, which reduces the complexity of interconnecting separate systems. In different countries, on the other hand, power systems may have evolved quite separately, with very different standards and technologies, which adds an extra layer of technical complexity to interconnections. Institutional and administrative features of power systems in different countries are also likely to differ in many ways, and these differences invariably affect the technical and operational dimensions of an interconnection. Issues ranging from power trading agreements to reliability standards, while expressed in technical terms, often must be resolved within the realm of policy and political economy. As one expert on international interconnections has remarked, "many technical, organizational, commercial and political problems have had to be solved to get large networks linked by international interconnections to operate"[11].

The greatest benefits of interconnection are usually derived from synchronous AC operation, but this can also entail greater reliability risks. In any synchronous network, disturbances in one location are quickly felt in other locations. After interconnecting, a system that used to be isolated from disturbances in a neighboring system is now vulnerable to those disturbances. As major blackouts in North America

11 F. Meslier (1999), "Historical Background and Lessons for the Future," in J. Casazza and G. Loehr, *The Evolution of Electric Power Transmission Under Deregulation*, IEEE, Piscataway, NJ; p. 32.

and Europe in 2003 demonstrated, large-scale disturbances can propagate through interconnections and result in cascading outages, bringing down systems that had previously been functioning normally. In addition, long-distance interconnections with long transmission lines have potentially greater stability problems than is the case for shorter lines. Finally, many systems that have undergone electricity liberalization in recent years have experienced large increases in transmission capacity utilization, reducing reserve margins. Minimizing the likelihood that an interconnection will lead to such problems as voltage collapse, dynamic and transient instability, or cascading outages due to propagated disturbances requires careful planning and well-coordinated operation.

2.2. Technical parameters of interconnection

2.2.1. Basic Electrical Parameters

This section describes the basic electrical parameters and units of measurement used in electric power systems. It is meant to provide the non-technical reader with the concepts needed for a general understanding of the technical issues discussed in subsequent sections.

AC & DC

Electric power comes in two forms: alternating current (AC) and direct current (DC). These forms are characterized by the behavior of their waveforms: AC alternates between positive and negative polarity with respect to ground, while DC does not. In power systems, AC is generally a sine wave, while DC is a constant value. Early electricity systems, such as Thomas Edison's Pearl Street Station in New York City, which provided the world's first public electric service in 1882, were DC. However, by the beginning of the 20th century AC systems had become standard worldwide. The main reason for the adoption of AC was that it is relatively simple to change AC voltage levels by using transformers, while it is difficult to change DC voltages. The development of solid-state power electronics in recent years has allowed an increased use of DC in the form of HVDC interconnections, but otherwise power systems remain AC.

Frequency

Frequency is the rate at which an alternating current changes from positive to negative polarity, measured in cycles per second, or hertz (Hz). There are currently two widespread world standards for power system frequency: 50 Hz in most of Europe and Asia, and 60 Hz in North America and in other places strongly influenced by the U.S. power industry, such as South Korea. The choice of 50 and 60 Hz systems in different locations is a consequence of historical legacies rather than the inherent technical superiority of one or the other. However, the range of possible frequencies for power systems is constrained by practical concerns. For example, a century ago many electric railroads operated at a frequency of 25 Hz, but 25 Hz was never adopted for general use in power systems because frequencies at that level cause electric lights to flicker. At the other end of the scale, frequencies well above 60 Hz result in higher impedances, leading to unacceptably high transmission and distribution losses.

Voltage

Voltage is the difference in electric potential between two points in an electric circuit. A difference in potential causes electric charges to flow from one place to another, just as a difference in heights causes water to flow from one level to another. Voltage is measured in volts (V), and sometimes in thousands of volts or kilovolts (kV).

In power systems, two important measures are the maximum voltage and average voltage at any particular point. Maximum voltage is important because insulation and safety equipment must be designed to protect against the highest voltage encountered. Average voltage is important because the amount of energy supplied to an end user or lost in transmission lines is a function of the average voltage and current. For DC systems, maximum and average voltages are the same, because DC voltage doesn't oscillate. For example, the output of a 120 V DC power supply is a continuous 120 V relative to ground, and this is both the maximum and average voltage.

For AC systems, different measures are required. In a 120 V AC system, the voltage actually oscillates in a sine wave between + 170 V and – 170 V relative to ground. The maximum voltage, also called amplitude or peak voltage, is thus 170 V. The simple arithmetic average of this waveform is actually 0 V, since the positive and negative voltages cancel each other out. Hence, another type of average is used, called root-mean-square (RMS). RMS is obtained by squaring the values of the voltage over one complete sine-wave cycle, determining its average value, and then taking the square root of that average. The result (true for any sine wave) is that $V_{RMS} = V_{PEAK} / \sqrt{2} = 0.707\ V_{PEAK}$. For a household system with a $V_{PEAK} = 170$ V, $V_{RMS} = 0.707$ (170 V) = 120 V. Thus the common designation of a household electric outlet as "120 V AC" refers to the RMS value of the voltage. The voltages of power system components, such as transformers and transmission lines, are also generally given in RMS terms.

Current

Current is the flow rate of electric charge. In an electric circuit, charge flows from a point of higher voltage to a point of lower voltage through a conductor, just as water flows from a higher spot to a lower one through a pipe. Current is measured in amperes (A) or kilo-amperes (kA), where one ampere is a certain number of charges (to be precise 6.25×10^{18} charges, called one coulomb) flowing per second. As is the case for voltage, AC currents are generally described in terms of their RMS values.

Resistance and Conductance

Conductance describes the ability of an object, such as an electric wire, to allow electric currents to flow. The reciprocal of conductance is resistance, which describes how much the object resists the flow of current. Resistance is measured in ohms (Ω). The resistance of wire is a product of its resistivity (an inherent property of the material from which it is made, such as copper or aluminum, for a given temperature) and the dimensions of the wire. For a given material, the longer the wire is, the greater the resistance, and the larger in diameter the wire is, the smaller the resistance. In the analogy of water flowing from a higher to a lower spot through a pipe, resistance is analogous to the friction of the pipe. A narrow pipe has a higher resistance; a wide pipe has a lower resistance.

Ohm's Law

Ohm's Law describes the relationship between voltage (V), current (I), and resistance (R) across any element of a DC electric circuit: $V = I*R$. Thus, for a fixed value of resistance – say for an HVDC transmission line of a certain length and diameter – if the voltage is made larger, the current will decrease, and vice versa. For example, if the resistance of a line is 25 Ω, and the current through the line is 1 kA, then the voltage drop across the line is V = 1 kA * 25 Ω = 25 kV. If the voltage on the sending side was 500 kV, then the voltage on the receiving side must be 25 kV less, or 475 kV.

Power and Energy

Power is the rate of energy flow, measured in watts (W), and sometimes in thousands of watts or kilowatts (kW), or in millions of watts or megawatts (MW). For a DC circuit, the power passing through any element of the circuit (e.g. a transmission line, a generator, an electrical appliance) is the product of the voltage across it and the current passing through it: P = I*V.

The energy delivered by a power system is measured in kilowatt-hours (kWh), and sometimes megawatt-hours (MWh). In general, energy is equal to power times time. For example, a light bulb that draws 100 W of power and is in use for 10 hours consumes a total amount of energy, E = 0.1 kW * 10 h = 1 kWh. Note that power and energy are quite different concepts. If an electric oven draws 1 kW of power and is in use for an hour, E = 1 kW * 1 h = 1 kWh. In these two examples, the power levels are different but the energy consumed is the same, the difference being the length of time that each device is operated.

Note that the basic unit of energy is the joule (J), while the basic unit of power is the watt, where 1 W = 1 J/s. Thus 1 kWh = 1 kW * 1 h = 1000 J/s * 3600 s = 3.6 million J.

Resistive Losses

When current flows against a resistance, some of its energy is lost in the form of heating. For a DC circuit, the resistive losses can be calculated using Ohm's Law: $P_{LOSS} = I*V = I(I/R) = I^2R$. To continue with the example under "Ohm's Law" above, consider a 500 kV HVDC transmission line with 25 Ω of resistance, with 1 kA of current passing through it, and which has a voltage on the sending end of 500 kV, and a voltage on the receiving end of 475 kV. The total power being transmitted at the sending end of the transmission line is P = 500 kV * 1 kA = 500 MW. Out of this 500 MW, the amount being lost to heating is $P_{LOSS} = (1\text{ kA})^2 * 25\ \Omega = 25$ MW. This constitutes 25 MW/500 MW = 5 percent of the power being transmitted.

Very high voltages are used in transmission in order to reduce resistive losses to a tolerable level. In the example above, if the same amount of power were being transmitted (500 MW) but the sending voltage were 125 kV instead of 500 kV, the current through the line must be I = P/V = 500 MW/125 kV = 4 kA; the current is four times higher to yield the same amount of power, because the voltage is four times less. The power lost in the transmission line is then $P_{LOSS} = (4\text{ kA})^2 * 25\ \Omega = 400$ MW = 80 percent of the power being transmitted. In general, line losses are inversely proportional to the square of the sending voltage; this is true for AC lines as well as DC. For this reason, historically power systems have sought to increase their transmission voltages as distances and amounts of power transmitted have grown. The highest common AC transmission voltages, sometimes referred to as extra high voltage (EHV), are 380 kV in Europe and 765 kV in the US. Voltages as high as 1200 kV have been used in Russia for some long-distance lines across Siberia. Above 1000 kV, however, the practical difficulty and expense of equipment and insulation that can withstand such high voltages becomes prohibitive.

Impedance, Reactance, Inductance, Capacitance

AC circuits involve not only resistance but other physical phenomena that impede the flow of current. These are inductance and capacitance, referred to collectively as *reactance*. When AC currents pass through a reactance (e.g. in transmission and distribution lines, in transformers, or in end-use equipment such as electric motors) some of the energy is temporarily stored in electro-magnetic fields. This has three important implications. (1) Even though energy is not "lost" to the environment as in the case of resistive heating, it must still be supplied to the reactive elements. This is known as reactive power. (2) Voltage decreases when current flows across a reactance, just as it does across a resistance. For AC circuits, Ohm's Law must be modified: $V = I*Z$, where Z is the sum of resistance and reactance, called impedance, and is measured in ohms. (3) V, I, and Z are all complex numbers, meaning that they express not only magnitudes in volts, amps, and ohms, but also phase angles. Voltage and current waveforms both oscillate at same frequency - either 50 Hz or 60 Hz depending on the system – but they can differ in terms of the angular location within a cycle at which the maximum voltage or current occurs. This difference in angular location is referred to as phase difference, often symbolized by ϕ (phi) or θ (theta) and measured in degrees (or radians). Passing through an inductance causes an AC current waveform to fall behind, or *lag*, the voltage waveform. Passing through a capacitance causes AC current to move ahead of, or *lead*, the voltage. Equivalent amounts of capacitance and reactance cancel each other out.

Complex Power: Real, Reactive, Apparent

For AC systems, there are three kinds of power: real, reactive, and apparent. Real power (sometimes called active power) is what is consumed by resistances, and is measured in W (or kW, or MW). Reactive power is consumed by reactances, and is measured in volt-amperes reactive, or VAR (sometimes kVAR, or MVAR). Apparent power is the complex sum of real and reactive power, and is measured in volt-amperes, or VA (or kVA or MVA). $S = \sqrt{(P^2 + Q^2)}$, where S is apparent power, P is real power, and Q is reactive power. Apparent power is what must be supplied by the generators in a power system to meet the system's electrical load, whereas end-use is generally measured in terms of real power only. Utilities always seek to minimize reactive power consumption, among other reasons because it is difficult to measure and be compensated for reactive power by customers.

Loads and Power Factors

An electrical load is the power drawn by an end-use device or customer connected to the power system. (Sometimes, "load" is used to refer to the end-use devices or customers themselves, but among engineers it usually refers to the power demand.) Loads can be resistive or reactive, and are often a combination of both. The extent to which a load is resistive is measured by its *power factor*, (p.f.), which is equal to the cosine of the phase difference between the current and voltage through the load: p.f. = $\cos \phi$. When the power factor is at its maximum value of one, the load is purely resistive. On the other hand, the smaller the power factor, the greater the phase difference and the greater the reactive power component of the load. Inductive loads, such as electric motors, have a *lagging* power factor (see 2.1.9), and are said to *consume* reactive power. Capacitive loads have a *leading* power factor and are said to be sources of reactive power.

Given the voltages and currents through a circuit element, apparent, real, and reactive power can be calculated respectively as follows:

$$S = I_{RMS} * V_{RMS}$$

$$P = S * \text{p.f.} = I_{RMS} * V_{RMS} * \cos \phi$$

$$Q = I_{RMS} * V_{RMS} * \sin \phi$$

Reactive loads can have a large effect on line losses, because the current flowing through a line, and the associated heating, is a function of the apparent power S rather than the real power P. For example, consider a load of 150 kW with a lagging power factor of 0.75, which is supplied by a 10 kV distribution line with a resistance of 10 Ω. The apparent power drawn by the load is S = P/p.f. = 150 kW/0.75 = 200 kVA. The current to the load is then I = 200 kVA/10 kV = 20 A. The line loss is $P_{LOSS} = I^2 * R = (20\ A)^2 * 10\ \Omega = 4$ kW. If there were no reactive power consumption by the load, the power factor would be equal to one. In that case, S = P = 150 kW. Then I = 150 kW/10 kV = 15 A, and $P_{LOSS} = (15\ A)^2 * 10\ \Omega = 2.25$ kW. Thus the reactive load in this example increased the line losses from 2.25 kW to 4 kW, an increase of 78 percent.

Three-Phase Systems

House current is generally single-phase AC power, but the rest of the power system from generation to secondary distribution employs 3-phase AC. This means that transmission lines have three separate conductors, each carrying one-third of the power. The waveforms of the voltage in each phase are separated by 120°. There are two major reasons that 3-phase power became dominant. (1) As long as the electrical loads on each phase are kept roughly balanced, only three wires are required to transmit power. Normally, any electric circuit requires both an "outbound" and "return" wire to make a complete circuit. Balanced 3-phase circuits provide their own return, and thus only three, rather than six, wires are required to transmit the same amount of power as three comparable single-phase systems. (2) Since the invention of polyphase induction motors by Nikola Tesla in the 1890s, 3-phase motors have been the workhorse of industry. More than one phase is required to balance torque, which increases the effectiveness and lifetime of both motors and generators.

Voltage and Power in Three-Phase Systems

The voltage in 3-phase systems can be specified in two different ways. One is *phase to ground*, which as it sounds is the voltage between any one of the three phases and ground. The other is *phase to phase*, which is the voltage between any two of the three phases. Power lines are conventionally described by their phase to phase voltage, also called the *line* voltage. Phase to phase voltage is greater than phase to ground voltage by a factor of the square root of three. Thus, a 500 kV line has a phase to phase voltage of 500 kV, and a phase to ground voltage of 500 kV/√3 = 289 kV. In both cases, the voltage referred to is the RMS value.

The amount of power transmitted in a three-phase system is three times the power in each line. Thus $S = 3\ (I * V_{LINE}/\sqrt{3}) = \sqrt{3}\ I * V_{LINE}$, where V_{LINE} is the phase to phase voltage. For example, the apparent power transmitted by a 500 kV circuit with a current of 1 kA is S = √3 * 500 kV * 1 kA = 866 MVA. The real and reactive components can be calculated easily if the load power factor or phase difference is known (see 2.1.10). In this example, if $\phi = 25°$, the real power P = S cos 25° = 866 MVA * 0.906 = 785 MW, and the reactive power Q = S sin 25° = 866 MVA * 0.422 = 366 MVAR.

2.2.2. Basic Design Features

The basic design features of an interconnection include the following elements:

- whether it is AC or DC

  - if DC, whether it is single-pole or double-pole (+/-)
  - transmission capacity (in MVA)
  - transmission voltage (in kV)
  - system components and overall design
  - operating agreement

These features are dictated by the answers to the following questions:

- Will the interconnected systems operate synchronously or asynchronously? To operate synchronously, at a minimum the systems must have the same nominal frequency (50 Hz or 60 Hz). Even if frequencies are the same, technical and operational differences can make synchronous operation too difficult or expensive to pursue. Many synchronous networks with the same nominal frequency, including the four North American interconnections, have only asynchronous DC connections between them.

- What are the magnitudes and directions of the anticipated power flows? The basic rationales for the interconnection must be expressed quantitatively, using models that forecast the power flows through the interconnection among constituent systems. The forecasts must be conducted on different time scales: diurnal, seasonal, annual, and multi-year projections.

- What physical distance and terrain will the interconnection span? The peak power flows and the physical length of the interconnection will influence the choice of AC or DC, the size of conductors, and requirements for other system components, such as series capacitors or phase-shifting transformers. Terrain, geology, and land use considerations (such as urban areas, environmentally sensitive areas) will determine whether overhead lines or underground cables are used, the layout and design of substations or converter stations, grounding and lightning protection schemes, and the most suitable kinds of support structures. Undersea transmission requires the use of special cables that are quite different from terrestrial cables and overhead lines. Terrain and land use also dictate construction and maintenance methods.

- What are the key technical and operating differences among the systems to be interconnected? These include differences in the hardware, control systems, and procedures used for frequency regulation, voltage regulation, and fault protection.

2.2.1. Interconnection Elements

A listing of the basic elements of an interconnection is provided below.

Technical Objectives

The ultimate objective of an interconnection, like the power systems it is part of, is to provide power to customers economically, safely, reliably, efficiently, and with minimal environmental impact. Each of these aspects has one or more quantitative measure, such as price per kilowatt-hour, number and lethality of accidents, frequency and duration of service interruptions, generating plant heat rate, transmission and distribution losses, and emissions factors. Interconnections are designed, and their individual components selected, with all of these objectives in mind, though they may be optimized differently in different systems.

Transmission Lines

Transmission lines come in two basic varieties: overhead lines and underground (or undersea) cables. Overhead lines are more common and generally less expensive than cables. The main design consideration for overhead lines is the choice of conductor type and size, which must balance the need to minimize impedance (and the associated losses), minimize cost, and minimize the weight that must be carried by support structures. Although copper is a better conductor, it has been overtaken in recent years by aluminum, which is lighter, cheaper, and in abundant supply. The most common variety of overhead conductor for high-capacity, long-distance transmission is stranded aluminum wire reinforced with steel (known as ACSR, for "aluminum conductor steel reinforced"). Other design considerations for overhead lines are the type of support structures (such as transmission towers and insulators) used, and the configuration of conductors on the support structures, which affects the reactance of the conductors and the strength of electromagnetic fields (EMFs) around the lines.

Underground cables are used where overhead conductors are inappropriate due to environmental or land use considerations, such as in high-density urban areas or ecologically sensitive areas. Cables are insulated and are typically routed through underground conduits, and often require cooling systems to dissipate heat. Cables may use copper instead of aluminum, balancing the greater cost of copper against its superior conductivity and lower resistive heating. Undersea cables are usually made of copper, and may be surrounded by oil or an oil-soaked medium, then encased in insulating material to protect from corrosion. Undersea cables often have a coaxial structure, which has an inherently high capacitive reactance; therefore undersea cables are usually DC, which is not affected by reactance. Conductor cross-sections are typically measured in square centimeters (cm^2) in the metric system, or thousands of circular mils (kcmil) in the American system[12]. The capacity of a conductor to carry current without exceeding thermal limits is called its ampacity, measured in kA for large conductors.

Support Structures

There are many possible types of support structures for overhead transmission lines. In developed countries, transmission lines are supported on structures made out of steel lattice, tubular steel, wood, and concrete. Of these, steel lattice has the highest strength to weight ratio, and is the easiest to assemble in areas that are difficult to access[13]. Where aesthetics are an important factor, however, other materials are often used. The main function of support structures is to keep the conductors from contacting trees or other objects, including people and animals; thus the structures must be tall enough to do so even when the conductors sag due to high temperatures caused by resistive heating. All things being equal, taller structures also minimize ground-level EMFs. Because overhead transmission lines are not insulated, they are typically suspended from towers on strings of ceramic insulators, which are designed to prevent flashover, or the leakage of current from the conductors to the tower, which would present a lethal prospect to anyone touching the

12 1 kcmil = 0.0051 cm^2

13 John Reason, "Special Report: Transmission Structures," Electrical World, 206, 3 (March 1992), pp. 31-49.

tower. AC transmission towers are usually designed to carry three conductors: the three phases of AC power systems. Towers that hold these in an equilateral triangle shape (called a "delta") keep the mutual reactances of the three phases balanced; non-delta configurations often require that conductors be *transposed*, or switch places, at regular intervals along the transmission path. Some towers carry more than one circuit, with three phases per circuit; for example, a double-circuit tower will have six conductors. (The conductor for each phase may also be subdivided into "bundles" of two or more conductors, which are physically close together.) DC transmission towers carry two conductors per circuit. Figure 2-1 on the following page shows various options for transmission tower design.

Transformers and Substations

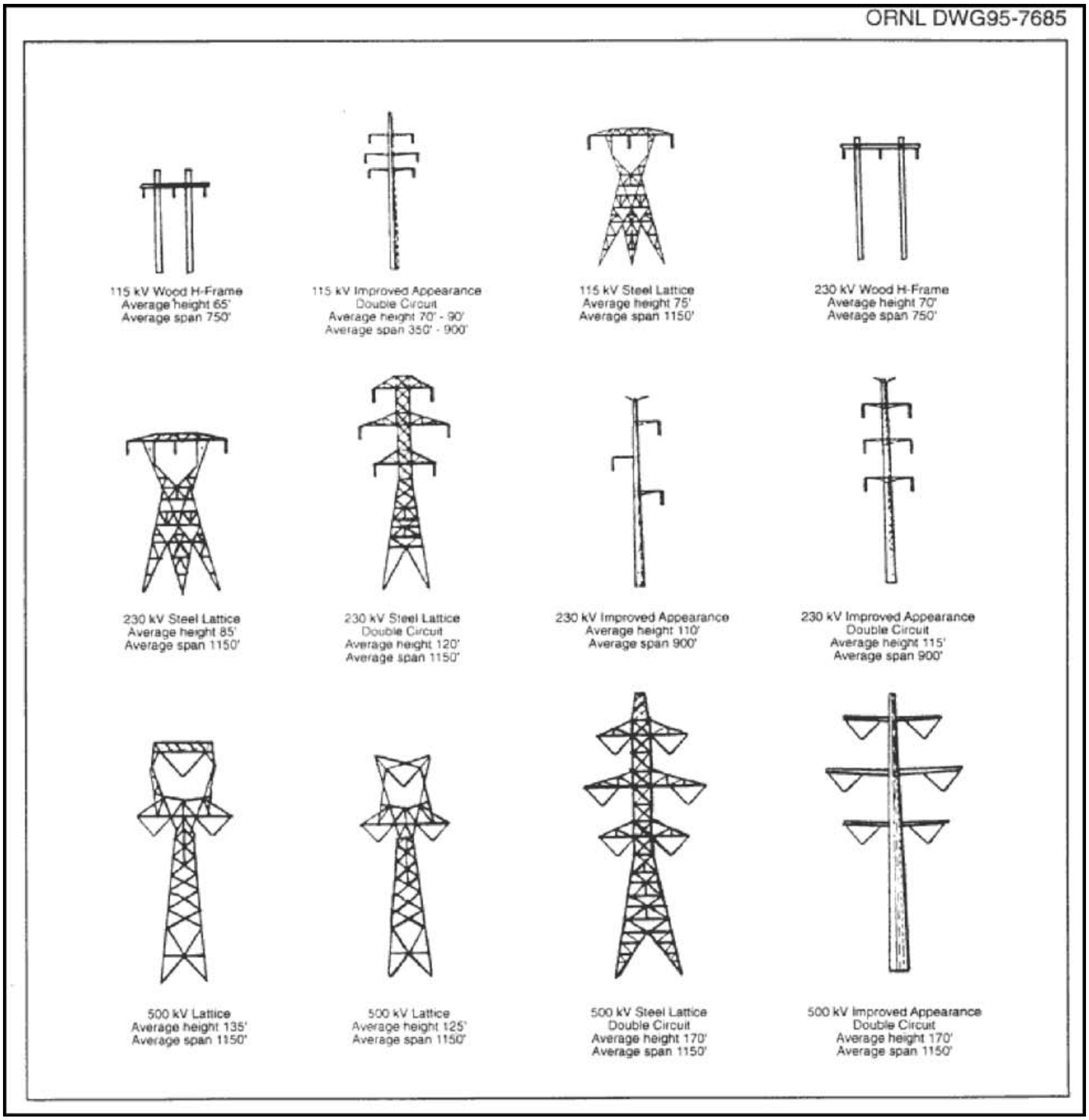
Transformers are used to change voltage levels in AC circuits, allowing transmission at high voltages to minimize resistive losses, and low voltages at the customer end for safety. This ability, following the development of transformers by William Stanley in 1885, led to the rapid adoption of AC systems over DC systems. The essential element of a transformer consists of two coils of wire wrapped around an iron core. An alternating current in one coil produces a changing electromagnetic field that induces a current in the other. The voltages on either side are in the same ratio as the number of turns on each coil. For example, a transformer with a 10:1 "turns ratio" that is connected to a 15 kV supply on its *primary* side, will have a voltage of 150 kV on its *secondary* side. Transformers step up the voltage from generator to transmission system, and other transformers step it down, often in several stages, from transmission to sub-transmission to primary distribution to secondary distribution, and finally to the end-user voltage, such as 120 V. At the distribution level, transformers often have *taps* that can be used to change the turns ratio; this allows operators to maintain customer voltage levels when system voltages change. Modern transformers are extremely efficient, typically greater than 99%, but even small losses can produce a great deal of heat, which must be dissipated to prevent damage to the equipment. Large transformers are cooled by circulating oil, which also functions as an electrical insulator.

Large transformers are housed in substations, where sections of a transmission and distribution system operating at different voltages are joined. Larger substations have a manned control room, while smaller substations often operate automatically. In addition to transformers, important substation equipment includes switchgear, circuit breakers and other protective equipment (see next section), and capacitor banks used to provide reactive power support.

Protection Systems

Protection systems are an extremely important part of any power system. Their primary function is to detect and clear *faults*, which are inadvertent electrical connections – that is, short circuits – between system components at different voltages. When faults occur, very high currents can result, typically 2-10 times as high as normal load currents. Since power is proportional to I^2, a great deal of energy can be delivered to unintended recipients in a very short time. The goal of protection systems is to isolate and de-energize faults before they can harm personnel or cause serious damage to equipment. Note that protection systems are designed to protect the power system itself, rather than end-user equipment.

Figure 2-1: Common Configurations for Transmission towers. Source: Oak Ridge National Laboratory[14]



14 From Chapter 4 of US Nuclear Regulatory Commission (NRC, 1996), *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (Report # NUREG-1437 Vol. 1), available as *http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437/v1/*. Original source: R. L. Kroodsma and J. W. Van Dyke (1985), *Technical and Environmental Aspects of Electric Power Transmission*, Report # ORNL-6165, Oak Ridge National Laboratory, Oak Ridge, Tennessee.

The key components of protection systems are circuit breakers, instrument transformers, and relays. Circuit breakers are designed to interrupt a circuit in which high levels of current are flowing, typically within three voltage cycles (about 50 milliseconds in a 60 Hz system). To do this they must quench the electric arc that appears when the breaker contacts are opened; this is usually accomplished by blowing a gas, such as compressed air or sulfur hexafluoride (SF_6) across the contacts. Since human operators generally could not respond to a fault in time to prevent damage, circuit breakers are operated by automatic relays that sense faults or other undesirable system conditions. To distinguish between normal operations and fault conditions, relays are connected to instrument transformers – voltage transformers (VT) and current transformers (CT) – that reflect the voltages and currents of the equipment they are connected to. Relays themselves can be either electromechanical or solid state devices.

Essential aspects of protection system design include determining the specifications and placement of protection equipment, and also the correct timing and sequence of relay operations. Protection engineers must determine how long an undesirable condition should be allowed to persist before opening a circuit breaker, and the order in which circuit breakers must open to correctly isolate faults in different zones[15].

Communications, Monitoring, and Control Systems

Power system operations take place within geographically well-defined *control areas*, which traditionally corresponded to a utility's service territory. With market liberalization, individual utility control areas have sometimes been combined into larger control areas under the jurisdiction of an independent system operator (ISO). In either case, system operations are coordinated by a central control center, the responsibility of which it is to keep the entire system running safely and reliably. This entails continuously monitoring system conditions and deploying system resources as the situation requires.

Traditionally, monitoring and control have been conducted semi-manually, with a heavy reliance on telephone communications with plant operators and field personnel. Increasingly, these activities are automated. Supervisory control and data acquisition (SCADA) systems combine remote sensing of system conditions with remote control over operations. For example, control center SCADA systems control key generators through automatic generator control (AGC), and can change the topology of the transmission and distribution network by remotely opening or closing circuit breakers. This monitoring and control is enabled by dedicated phone systems (often fiber-optic based), microwave radio, and/or power line carrier signals.

2.3. Technical Issues Associated with AC Grid Interconnection

2.3.1. General Requirements for AC Interconnection

AC interconnection usually provides the greatest interconnection benefits, except in certain cases for which DC is the preferred option (see Section 2.4.1). Synchronous interconnection of different systems is, however, technically demanding. At a general level, the first requirement is that the systems share the same nominal frequency, either 50 Hz or 60 Hz. Then, they must regulate frequency so that they achieve and remain in synchronism (see Section 2.3.4, below). They must also interconnect at a common voltage level.

15 J. Blackburn (1998), *Protective Relaying: Principles and Applications*, 2nd ed. Marcel Dekker, New York.

This is easier if the countries involved have agreed to a common standard for transmission voltage, such as the 380 kV standard in Europe. It is still possible for countries with different voltage schemes to interconnect by using transformers (if voltages are not very different, *autotransformers* are often used, which have only a single winding and are less expensive than ordinary transformers). Having to use an excessive number of transformers is, however, undesirable, since transformers are costly, add impedance to the line, and may require lengthy repair after a fault, keeping the transmission intertie out of operation for an extended period[16]. Other, more specific technical issues are discussed in the remainder of this section.

Good engineering must be complemented by good cooperation among the interconnected systems. In both planning and operation phases, this requires extensive data sharing, joint modeling, and clear communication.

2.3.2. Technical Issues for AC Interconnection

One way of thinking about the technical issues of AC interconnections is to group them into those associated with the transmission interconnection itself, and those associated with operating the larger interconnected system. Transmission issues are discussed in 2.3.3. Key issues include thermal limits, stability limits, and voltage regulation, which are the main constraints on transmission line operation. Other transmission issues include loop and parallel path flows, available transfer capacity, and FACTS technologies. System-wide issues are discussed in 2.3.4, including frequency regulation, power quality, the coordination of planning and operations, political and institutional cooperation, systems that are aging or in poor repair, and the operation of nuclear power plants. The implications of electricity market liberalization for interconnected systems are also discussed.

2.3.3. Transmission Issues

Thermal limits

The capacity of transmission lines, transformers, and other equipment is determined by temperature limits. If these limits are exceeded, the equipment can be damaged or destroyed. Equipment ratings have traditionally been conservative, and operators have stayed well below the rated limits, but increased power trading in liberalized markets has created pressure for higher utilization. Instead of a single thermal limit, dynamic ratings are now often used. For example, transmission lines can carry more current when heat is effectively dissipated, and thus will have a higher rating on cold, windy days without direct sunlight.

When transmission lines heat up, the metal expands and the line sags. If the sag becomes too great, lines can come into contact with surrounding objects, causing a fault. Excess sag can also cause the metal to lose tensile strength due to annealing, after which it will not shrink back to its original length. Important transmission lines are often monitored by a device called a "sagometer", which measures the amount of sag, making system operators aware of dangerous sag conditions.

Stability limits

The stability limit of a transmission line is the maximum amount of power that can be transmitted for which the system will remain synchronized if a disturbance occurs. The power flow through a transmission line is governed by the difference in power angle between the sending and receiving sides:

$$P = V_R * V_S * \sin\delta \ / \ X$$

16 Charles Concordia (1999), *IEEE Power Engineering Review*, Feb. 1999; p.7-8.

All other factors being equal, the power transmitted from the sending side to the receiving side increases as the difference in power angle between the two points, called δ (delta), approaches 90°, and decreases as it approaches 0°. However, the feedback mechanism that keeps generators in synchronism and returns them to synchronous operation if they are disturbed becomes more tenuous as δ approaches 90°. The stability limit represents the value of the power angle that allows the highest power transfer while maintaining stability; a typical maximum value of δ is around 45°.

In general, stability limits are more important than thermal limits for long transmission lines, while thermal limits are more important for shorter lines. In the United States, for example, thermal limits are more important in the Eastern interconnection, while stability limits play a larger role in the Western interconnection.

Voltage Regulation

Utilities generally maintain system voltages within 5-10 percent of nominal values in order to avoid the risk of voltage collapse, which can lead to a major interruption of service. Power system voltages are primarily governed by reactive power flows. Voltages along a transmission link are a function of the physical length of the circuit, the impedance per unit length, and the flow of real power: the higher the current and the greater the reactance, the larger the voltage drop (if the reactance is predominantly inductive) or gain (if capacitive). Voltage collapse can be triggered when reactive demand is high and systems are operating near their stability limits, then undergo a disturbance that triggers a quick downward spiral. To maintain voltages along long AC transmission lines, reactive compensation of various kinds can be employed, such as series and shunt capacitors, and shunt reactors. (See section on FACTS, below).

System operators also maintain voltage levels in order to protect end-use equipment (for example, low voltages cause motor currents to increase, and higher currents can cause thermal damage). Utilities are usually obliged to provide power to customers within prescribed voltage tolerances. Devices called tap-changing transformers in the local distribution system are used to ensure that customer voltages are maintained even when system voltages change substantially. Note, however, that the power quality experienced by the customer is generally more affected by local conditions in the distribution system, such as switching, lightning strikes, and the loads of other customers, than by conditions in the transmission system. Protecting sensitive electronic end-use equipment is the responsibility of the customer rather than the utility.

Loop and parallel path flows

In power systems, power flows do not necessarily follow a specified transmission path – for example, from seller in system A to buyer in system B - but divide themselves among various connected transmission paths according to the voltage levels and impedances of the path. To put it another way, power flows conform to physical laws rather than economic agreements. In some cases, a power transaction can take quite unwanted paths, resulting in line losses and possibly overloading lines of neighbors having nothing to do economically with the transaction. In general, these phenomena are referred to as circulating power, loop flows, and parallel path flows. A well-known example of these flows is that in a power transfer from the U.S. Pacific Northwest to the state of Utah, one-third of the power flows through Southern California, and another one-third flows through Arizona.[17] What is important for the reliability of an interconnected

17 John Casazza (1998), "Blackouts: Is the Risk Increasing?". *Electrical World*, April 1998, p.63.

system is that operators know the sources and destinations of all transactions and where the power will flow, and are able to calculate the resulting reliability risks (see section on power flow modeling, below).

Available Transmission Capacity (ATC)

An important measure of transmission capacity is transmission transfer capability (TTC), which is the maximum power flow that a line can accommodate at any given time and still be able to survive the loss of a major generator or transmission link elsewhere in the system. Available transmission capacity (ATC) is the TTC of a line minus the amount of capacity already committed to other uses on that line. ATC is thus the measure of how much power can be safely transmitted over a transmission line at a given time while ensuring overall system reliability.

Flexible AC Transmission System (FACTS)

Flexible AC Transmission System (FACTS) refers to a number of different technologies based on power electronics and advanced control technologies, which are used to optimize power flows and increase grid stability[18]. FACTS equipment is expensive, but it can pay for itself by directing power flows with precision, eliminating loop flows, and relieving transmission bottlenecks without requiring that new lines be built. It can also improve frequency and voltage stability, decrease transmission losses and voltage drops, and improve power quality. FACTS equipment includes static compensators, static VAR compensators, thyristor-controlled series capacitors, phase-shifting transformers, interphase power controllers, universal power flow controllers, and dynamic voltage restorers. With FACTS, AC transmission over distances that were not previously possible due to stability limits has become possible. Figure 2-2 shows, on the following page, applications for different FACTS technologies. FACTS devices have been used extensively in the North American and European interconnections, and increasingly in developing regions, including the South Africa-Zimbabwe interconnection, the Brazil north-south interconnection, and other interconnections in Latin America, Africa, and South Asia.

Transmission upgrades

If existing transmission facilities are to be used in the interconnection but are not adequate to transmit the expected volume of power, they can be upgraded either by adding additional lines in parallel or increasing the transmission voltage. If these options are not available, FACTS or HVDC solutions can be explored.

2.3.4. Systems Issues

Key technical systems issues that must be addressed in planning and implementing a grid interconnection include frequency regulation, coordination of operations, interconnections of power systems with weak grids, and aspects of interconnection that are associated with electricity market liberalization.

Frequency Regulation

Controlling frequency in a synchronous network is ultimately an issue of precisely matching generation to load. This load-matching occurs on several time scales. System planners and operators plan generation from hours to months in advance, coordinating the dispatch of generating units and power exchanges with other systems based on factors such as historical load patterns, weather predictions, maintenance

18 A. Edris (2000), "FACTS Technology Development: An Update," *IEEE Power Engineering Review*, March 2000.

Figure 2-2: Applications of FACTS technologies

Issue	Device	Device
Steady-state voltage control	MSC SVC SC	Stepwise, infrequent ctrl. only Continuous control inherent Continuous control inherent
Dynamic and Post-contingency voltage support	SVC Statcom	Compact design
Improvement of steady-state load sharing	PST IPC SC	Easily expandable rating Very low losses
Post-contingency load sharing	PST TCSC	Faster
Transient stability improvement	SC SVC Statcom	Inherently self-regulating Compact design
Power oscillation damping	SVC TCSC	Location critical Insensitive to location and load type
Power quality improvement	SVC Statcom DVR	Voltage fluctuation mitigation Flicker mitigation Voltage sag mitigation

Terminology:

MSC	Mechanically-switched Capacitor*
SVC	Static Var Compensator
SC	Series Capacitor*
Statcom	Static Compensator
PST	Phase-shifting Transformer
IPC	Interphase Power Controller
TCSC	Thyristor-controlled Series Capacitor
UPFC	Unified Power Flow Controller
DVR	Dynamic Voltage Restorer

*Not strictly FACTS but closely related in its application.

schedules, and unplanned outages. At the scale of minutes to seconds, frequency is maintained by Automatic Generator Control (AGC), which precisely controls the real and reactive power output of certain generators that are able to respond rapidly to changes in load. Hydroelectric and gas turbine units are generally used for regulation and load following; nuclear plants and large coal-fired plants can be damaged by rapid changes of output and are not used in this function.

At the instantaneous time scale, frequency synchronization is a self-regulating phenomenon. When loads suddenly increase, generators slow down slightly, giving up some of their mechanical energy of rotation to supply the additional electrical energy required; when loads suddenly decrease, generators speed up. Through feedback among the different generators in the system, synchronism is maintained, at a frequency slightly higher or lower than nominal. When the control center computers sense these frequency movements, AGCs are notified to increase or decrease generator output to the amount necessary to balance load and return frequency to nominal levels. System operators also have a variety of off-line reserves or "ancillary services" available upon need to assist in frequency regulation and other aspects of reliable system operation. The theory of parallel operation of generators in large networks, once a daunting engineering problem, was established in the 1930s. Modern networks seldom deviate from nominal frequency by more than 0.1 Hz, and generally operate within 0.01 Hz of nominal.

In an interconnected system, except where DC links are used, frequency synchronization must be accomplished through the means above, jointly administered across the interconnected systems.

Coordinating Operations

The basic geographical unit of a power system is the control area, which typically has a single control center responsible for monitoring system conditions and scheduling the dispatch of all generation. In interconnected systems, transmission lines to neighboring control areas are metered and the incoming and outgoing power flows are scheduled and continuously monitored. A continuous record of the balance of load, generation, and exchanges with other control areas called the Area Control Error (ACE) is used to plan real-time corrections to maintain load-generation balance.

Interconnections create a number of coordination challenges, both institutional and technical. For example, reliability standards and constraints may differ, and there may be differences in regulation and control schemes and technologies. It is important for the operators and planners of interconnected systems to be aware of the conditions and practices in their neighboring control areas. Good communication between different system operators is important for agreeing on and coordinating interchange schedules, transmission loading, maintenance schedules, procedures for fault clearing, and emergency protocols[19].

As interconnected systems expand to encompass large geographical scales, technology is striving to keep up with the associated complexities and risks. Some important trends in grid technologies related to the problems of maintaining reliability in large AC systems include[20]:

(1) Faster physical control over the system, for example FACTS technologies with solid state controls that allow rapid adjustment of reactive power flows.

19 John Casazza (1998), "Blackouts: Is the Risk Increasing?". *Electrical World*, April 1998, p.62.

20 Karl Stahlkopf and Philip Sharp (1998), "Reliability in Power Delivery: Where Technology and Politics Meet," *Public Utilities Fortnightly*, January 15, 1998.

(2) Improved real-time monitoring ability, for example the development of wide area monitoring systems (WAMS).
(3) Faster analytical capability to complement improved monitoring.
(4) Improved communications.

Interconnection of power systems with weak grids

Not all interconnections take place between power systems in top technical condition. In the developing world, many power systems bear the marks of age, poor repair, and insufficient investment, ranging from corroded conductors and deteriorating insulation to leaking transformers, worn out switchgear, and a variety of inoperable equipment. Equipment is often obsolete, and operations that are automated elsewhere may be carried out manually. Systems in poor repair generally perform poorly, have serious reliability problems, and often fail to comply with safety or environmental standards. As one scholar described the difficulties of interconnection among sparse, poorly maintained systems:

> "The vastness of the area and the low power consumption density in most African countries makes the operation of the interconnection difficult from an operational point. Many of the loads are connected to spurs off a grid that has a low level of interconnectivity. In addition, most of the networks have suffered from a lack of maintenance due to a shortage of funds. This has dramatically reduced the reliability of the system and outages frequently occur in many places. The combination of these factors has forced industries to provide their own generating facilities in the form of diesel power. These plants then operate in island mode and will often also provide power to towns and villages in the immediate vicinity of the plant. Some utilities are discouraging this practice, but need to convince these clients to connect to a grid that may not be that reliable in the first place, particularly in areas connected to spurs."[21]

Interconnection can improve such systems, by providing emergency reserves and more reliable supplies. However, careful planning must ensure that the interconnection doesn't lead to additional stresses elsewhere in the interconnected system.

Countries with weak or isolated grids are usually poor candidates for siting nuclear power plants (NPP). NPPs have much more stringent requirements regarding grid stability than do fossil fuel thermal plants, for two reasons. First, the auxiliary systems in a NPP are much more sensitive to power conditions than such systems at other plants because of the potential consequences – namely, that a major failure could lead to a nuclear accident. Second, NPPs have large amounts of decay heat to remove long after the chain reaction is shut down, and require power to operate cooling water pumps during this extended period. With weak grids, large variations in voltage and frequency will trip a NPP off-line; worse, the sudden loss of a large power plant start a cascading failure that collapses the grid altogether. With intercon-

21 Jan A de Kock (2004), "Status of International Interconnections and Electricity Deregulation in Africa". P. 77 in *IEEE Power Engineering Society Energy Development and Power Generating Committee, Panel Session: Status of International Interconnections and Electricity Deregulation in Africa*, Proceedings of IEEE 2004 General Meeting, Denver, 6-12 June 2004. Available as 2004GM_Africa.pdf from *http://www.ewh.ieee.org/cmte/ips/index.html.*

nection to other grids, however, siting a NPP in a country with a weak or isolated grid becomes a plausible option. The interconnection can help to stabilize the weak grid, and it can also provide access to an independent back-up grid connection, which is a safety requirement for NPPs[22].

Interconnections and electricity market liberalization

Electricity market liberalization presents a combination of opportunities, challenges, and risks for interconnection projects. From the economic standpoint, the opportunity of greater access to lower-cost supplies is balanced against the challenge of operating competitive markets and the risk of market breakdowns of the type that occurred in California in 2000-2001. From the technical standpoint, the focus is on the impact of liberalization on reliability[23]. Some of the main concerns that have been raised include:

- Increased or excessive utilization of transmission capacity, reducing reliability margins
- Reduced information exchange among system operators due to proprietary concerns in a competitive environment
- Reduced investment in reliability as companies cut costs due to competitive pressures, a concern for transmission especially as generation and distribution are liberalized
- Increased complexity in planning and operations as the number of players and transactions increases, and dispatch is based on changing market prices
- The intentional creation of congestion, or the appearance of congestion, on transmission lines to drive up prices, as done by Enron and others during the California crisis
- Transaction costs associated with replacing experienced organizations and procedures with new ones as ISOs and TRANSCOs replace integrated utility control areas

Requirements for successful interconnection operation in a liberalized, more market-driven electricity sector environment include[24]:

- Make knowledge of all transactions available to system operators
- Improve cooperation between network managers of different countries
- Improve incentives for investing in infrastructure
- Clearly define the rights and obligations of all parties
- Monitor behavior and rigorously enforce rules

2.4. Technical Issues Related to DC Interconnections[25]

2.4.1. Why Use HVDC?

The first electrical transmission systems built in the 1880s were DC. However, because DC could not be readily transformed to higher voltages for long distance transmission, AC systems quickly became the standard. It

22 John Bickel (2001), *Grid Stability and Safety Issues Associated with Nuclear Power Plants*. Paper prepared for the Workshop on Grid Interconnections in Northeast Asia, May 14, 2001, and available as *http://nautilus.org/archives/energy/grid/papers/Bickel.pdf.*

23 George C. Loehr (1998), "Ten Myths about Electric Deregulation". *Public Utilities Fortnightly*, April 15, 1998.

24 F. Meslier (1999), "Historical Background and Lessons for the Future," in J. Casazza and G. Loehr, *The Evolution of Electric Power Transmission Under Deregulation*, IEEE, Piscataway, NJ; p.37.

25 This section draws heavily on R. Rudervall, J. Charpentier, and R. Sharma, *High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper.* Joint World Bank-ABB Paper, available as *http://www.worldbank.org/html/fpd/em/transmission/technology_abb.pdf.* Date not provided, but likely 2000 or later.

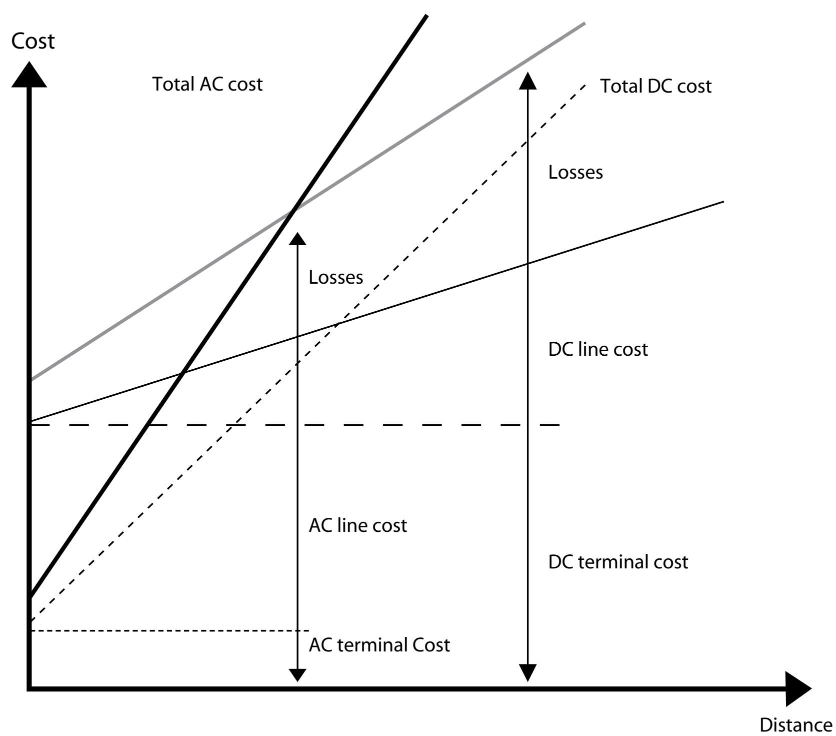
was many years before technological development again made DC competitive for some applications. The first commercial use of modern HVDC transmission was in Sweden in 1954. It has been since the 1980s, however, when high-voltage solid state converters were developed to replace mercury arc converters, that the use of HVDC transmission in interconnection projects has taken off. While still expensive, costs of converter stations have been steadily falling, and HVDC must be considered as an option for many interconnection projects.

HVDC is used in interconnection projects in three principal applications:

1. Transmitting large amounts of power over very long distances.

Unlike long-distance AC transmission, HVDC transmission over long distances has no inherent stability limit. Also, even within AC stability limits (which can be extended through the use of FACTS or other reactive compensation), HVDC can overtake AC on cost grounds alone. This is because HVDC carries more power for a given conductor size, and only requires two conductors while AC transmission requires three. Thus even though converter stations are very expensive, the cost per kilometer of DC transmission lines is lower. Generally, for distances above about 600 km, HVDC transmission is less expensive to build and operate than AC. The relationship between costs of AC and DC transmission lines versus the distance that power must be transmitted is illustrated in Figure 2-3. The dashed lines in this figure illustrate only terminal (converter station for DC, substation for AC) and line costs; the solid lines show that HVDC economics are improved when consideration of the relative line losses of the two technologies are included.

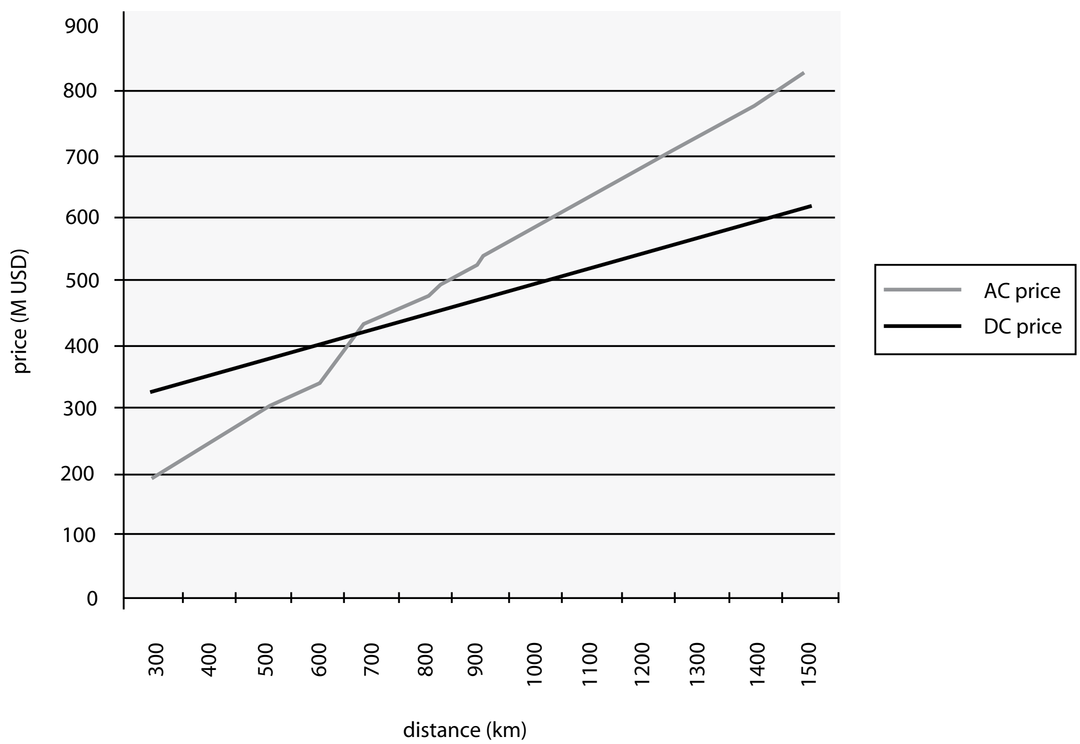
Figure 2-3: The effect of transmission distance on AC and DC transmission line costs[26]



26 From p.7, R. Rudervall, J. Charpentier, and R. Sharma, *High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper.* Joint World Bank-ABB Paper, available as *http://www.worldbank.org/html/fpd/em/transmission/technology_abb.pdf.* Date not provided, but likely 2000 or later.

Figure 2-4 shows the comparison of AC and DC cost curves for an illustrative case. (Note: this figure is for illustrative purposes only.) In this example, for a 2000 MW line, AC is less expensive below 700 kilometers, and DC is less expensive above 700 km.

Figure 2-4: AC and DC line costs for 2000 MW transmission line[27]



2. Transmitting power under water.

HVDC is preferred for undersea transmission. Undersea cables have a coaxial structure in order to minimize space requirements, but coaxial cables have a high capacitance. This presents a high reactive impedance to AC transmission, but DC is unaffected by capacitance, and can therefore be used for high capacity, long-distance undersea cables.

3. Asynchronous interconnections.

HVDC is a viable alternative when synchronous AC connections are difficult or impossible due to different the use of different system frequencies in the systems to be interconnected or other important system differences. As one expert has remarked, "the advent of DC connections has reduced the number of 'islands' that must consider themselves electrically isolated." DC ties between different AC systems deliver some of the benefits of interconnection while avoiding many of the technical problems of synchronous operation. There are two general types of asynchronous interconnection: (1) HVDC transmis-

27 From p. 6, R. Rudervall, J. Charpentier, and R. Sharma, *High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper*. Joint World Bank-ABB Paper, available as *http://www.worldbank.org/html/fpd/em/transmission/technology_abb.pdf*. Date not provided, but likely 2000 or later.

sion over some distance, between two converter stations connected at either end to an AC system. (2) HVDC "back-to-back" interconnection to AC systems on either side, without any intervening transmission. Back-to-back connections have sometimes served as a stepping stone to a later full synchronous interconnection.

In addition to the three applications above, there are other reasons HVDC interconnections are used. A key one is that HVDC carries more power for a given conductor size. Because of this, in situations where existing transmission capacity is constrained, HVDC is an alternative to an AC transmission upgrade. Conversely, to provide a given transmission capacity, HVDC lines, towers, and rights-of-way can be smaller than a comparable AC system, reducing the line's environmental footprint. Another major advantage is that the solid-state controls of HVDC systems offer complete control over the direction of power flow, without unpredictable loop flows. The direction of flow can be reversed, and operating voltages can be reduced if necessary. The track record of HVDC indicates high reliability and availability, and the advantage that in a bipolar system one pole can operate one pole if the other pole is not operational due to maintenance or an outage. Also, HVDC does not increase fault currents in the network it is connected to, so new circuit breakers not required in the rest of the system. HVDC systems, however, are difficult to operate with more than two, or at most three, terminal connections to AC transmission systems, so that HVDC systems are not an optimal choice if power is to be supplied to several intermediate locations along a power line route[28].

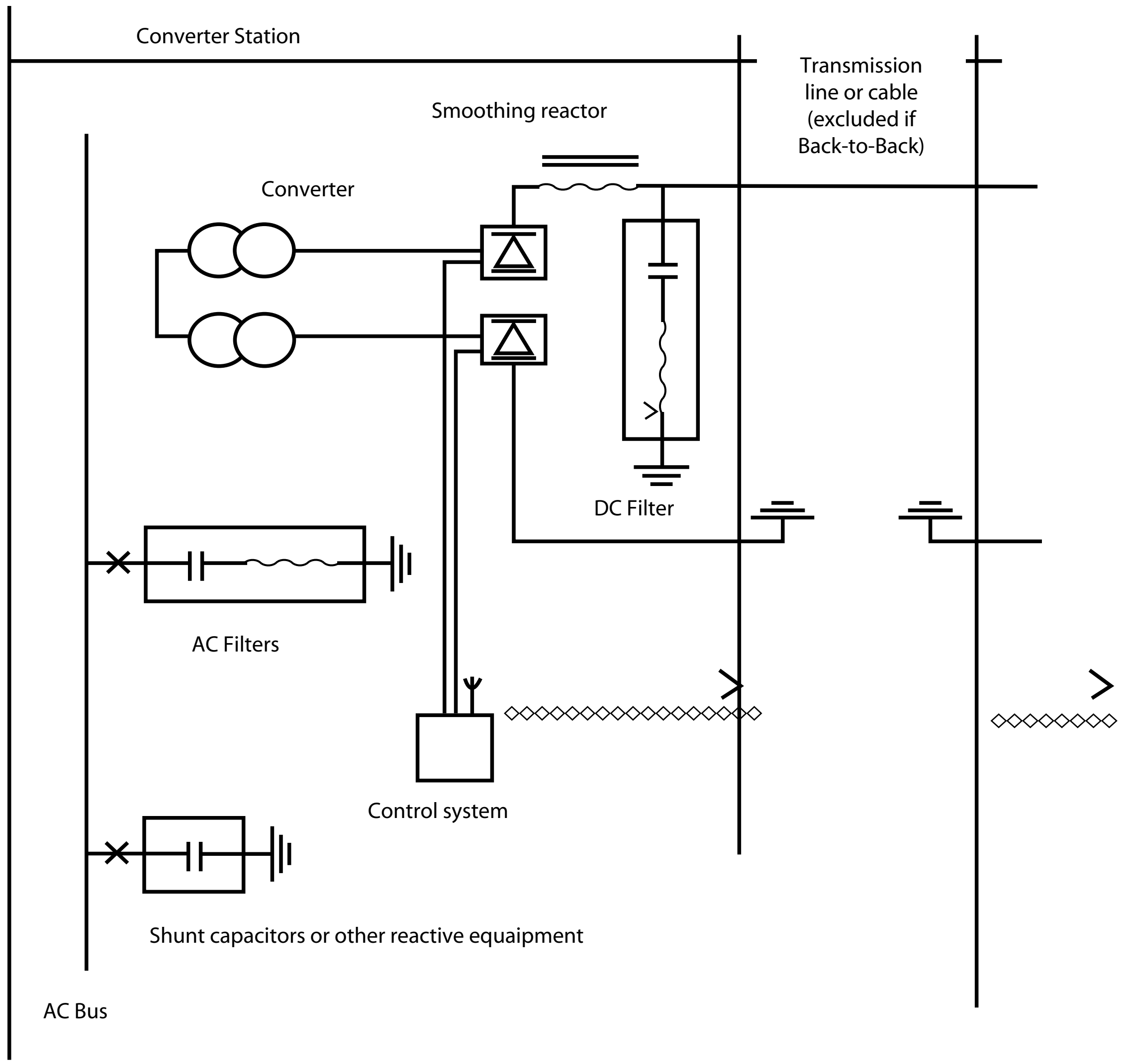
2.4.2. Technical Considerations with HVDC systems

Components of an HVDC System

The main components of an HVDC system are the transmission line and the converter stations at either end of the interconnection. The heart of the converter station is the converters themselves, which are composed of high-voltage solid-state "valves" that perform the AC to DC and DC to AC conversions. The valves are air-insulated, water-cooled, and controlled by optical signals from fiber optic devices (since the valves operate at extremely high voltage and any physical connection to a grounded object, such a wire leading back to a control room, would immediately become a short-circuit path). Converter stations also include transformers to convert to and from the AC transmission voltage to which the DC link is attached. Finally, converter stations include filters on both the AC and DC sides.

28 Prof. Lev Koshcheev, personal communication, 2003. See also L. A. Koshcheev (2001), *Basic Principles of Interstate Electrical Power Links Organization in North-East Asia*, paper prepared for the Workshop on Grid Interconnections in Northeast Asia, May 14, 2001, and available as *http://nautilus.org/archives/energy/grid/papers/koshcheev.PDF*.

Figure 2-5. Schematic of an HVDC converter station[29]



29 From p.3, R. Rudervall, J. Charpentier, and R. Sharma, *High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper*. Joint World Bank-ABB Paper, available as *http://www.worldbank.org/html/fpd/em/transmission/technology_abb.pdf*. Date not provided, but likely 2000 or later.

Overhead HVDC transmission lines can usually be easily identified because they have two conductors per circuit, rather than three as in the AC case. Normally these lines are bipolar, meaning that the two conductors have opposite polarity (e.g., +/- 500 kV). DC conductors are made from the same materials as AC conductors. Cables used for undersea transmission come in two varieties, solid and oil-filled.

Choice of Converter Technology

An important issue in HVDC systems is the choice of converter technology. (Note that AC to DC conversion is often called rectification, and DC to AC conversion is often called inversion. However, the term conversion is applied to both operations.) There are three types of converters:

(1) Natural commutated converters are the most common variety. They use solid-state device called thyristors, which are connected in series to form valves, which operate at the frequency of the AC grid, either 50 or 60 Hz.

(2) Capacitor commutated converters, which have capacitors inserted in series between the valves and transformers. They improve the performance of converters connected to weak networks.

(3) Forced commutation converters, which use rapidly switchable solid-state devices. One variety is the voltage source converter (VSC), composed of high-voltage transistors called IGBTs. The VSC performs conversion at very high frequencies, using a method called pulse-width modulation. This gives the VSC a very high degree of control over the incoming and outgoing waveform, allowing it to change power angles, control both real and reactive power, and maintain high power quality.

Figure 2-6 shows the suitability of the different converter technologies for various applications

	Long distance transmission over land	Long distance transmission over sea	Inter-connections of asynchronous networks	Windmill connection to network	Feed of small isolated loads
Natural commutated HVDC with OH lines	X		X		
Natural commutated HVDC with sea cables		X	X		
Capacitor commutated converters (CCC) in Back-to-Back			X		
Capacitor commutated converters (CCC) with OH lines	X		X		
Capacitor commutated converters (CCC) with sea cables		X	X		
VSC converters in Back-to-Back			X	X	
VSC converters with Land or Sea Cables	X	X	X	X	X

Figure 2-6: Applications of Different HVDC Technologies[30]

30 From p. 9, R. Rudervall, J. Charpentier, and R. Sharma, *High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper*. Joint World Bank-ABB Paper, available as *http://www.worldbank.org/html/fpd/em/transmission/technology_abb.pdf*. Date not provided, but likely 2000 or later.

Proximity to Parallel AC Lines

Parallel operation of high-voltage AC and DC lines in close proximity can create control problems. This must be considered in any siting decisions.

Reactive Power Consumption

Natural commutated converters consume a substantial amount of reactive power in the conversion process, and may require reactive power compensation on the AC side. VSCs by their nature do not consume reactive power.

Harmonics

The process for converting AC to DC power, and vice versa, involves rapid switching, which generates various harmonics that can reduce AC power quality and interfere with telecommunications facilities. AC filters are needed especially to eliminate harmonics of order 11, 13, 23, and 25; the amount of filtering necessary depends on the kind of converter technology employed.

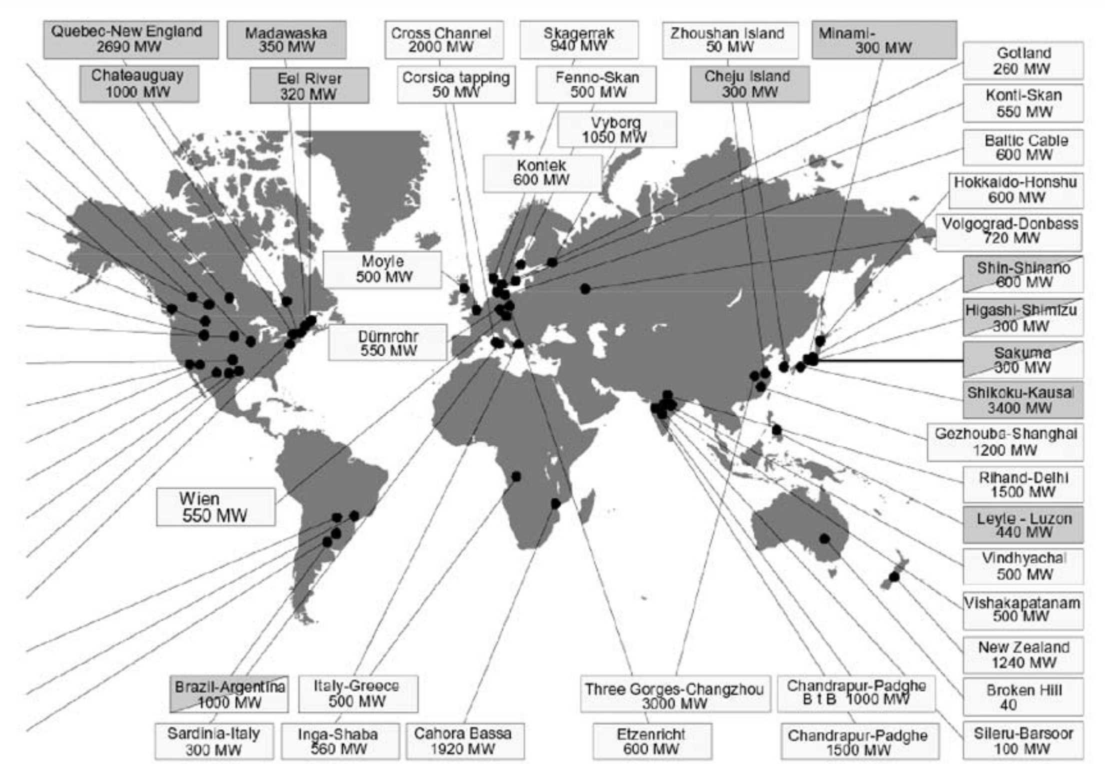
Operation and Maintenance

Because of the high voltage environment associated with them, HVDC systems are designed for remote operation. A relatively few people can operate HVDC links from a central location. The maintenance requirements for HVDC transmission lines are comparable to those for high voltage AC lines. Turnkey systems, where a supplier builds an HVDC system, then turns it over to a line operator, are common, and the supplier should provide the necessary training and support to utility personnel. One week of maintenance per year is the typical anticipated outage time for HVDC systems.

2.4.3. HVDC projects worldwide

The highest capacity HVDC interconnection in the world at present is a bipolar +/- 600 kV line transmitting 6300 MW of power from the Itaipu dam on the Brazilian-Paraguayan border into Brazil over a distance of 800 km. HVDC was selected at the technology for this transmission project for two reasons: (1) the great distance between the dam and demand centers, and (2) because the dam generates power at 50 Hz, while Brazil has a 60 Hz power system. The longest HVDC link currently operating is the 975 km line carrying power from China's Three Gorges Dam. China also has the HVDC link with the highest power per pole, at 1650 MW. Figure 2-7 on the next following page shows the location of major HVDC projects worldwide.

Figure 2-7: HVDC projects worldwide. Lighter boxes are 50 Hz power systems, darker boxes are 60 Hz power systems[31]



2.2. Planning and Modeling of Interconnection Technical Parameters

2.5.1. Planning Steps

There are typically a number of distinct stages in the technical design of an interconnection project (although some of these stages may be combined or their order changed). These stages include:

- **Preliminary electricity supply and demand estimates**, usually based on resource planning and regional market pricing simulations. Project owners make quantitative estimates of time-dependent electricity supply and demand and potential magnitudes of power exchanges between the systems to be interconnected.
- **Technical specification**. Project owners provide potential designers/ contractors with general specifications, including the amount and direction of power to be transmitted, temporary overload levels, voltage levels, distance and terrain, and environmental requirements. Details on the technical status and operations of the different systems must also be provided.
- **Conceptual design**. Potential project designers/contractors provide project owners with a conceptual design for the interconnection, including the preliminary determination of AC or DC interconnection, overhead

31 From p. 19, R. Rudervall, J. Charpentier, and R. Sharma, *High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper.* Joint World Bank-ABB Paper, available as *http://www.worldbank.org/html/fpd/em/transmission/technology_abb.pdf.* Date not provided, but likely 2000 or later.

lines or cable, conductors, support structures, transformers, reactive compensation, substation location and design. For DC systems, conceptual design will also include commutation method and filtering.

- **Tendering**. Potential designers/contractors tender offers to design and/or build the interconnection infrastructure to project owners, followed by review, negotiation, and approval.
- **Final design**. After approval of design/selection of contractors, the project design is finalized. Often, tendering and final design are an interactive process between designer/contractors and the project owners, sometimes also involving other interested parties.

2.5.2. Modeling requirements for transmission interconnections

During the project planning process, the design of the technical and operating parameters of an interconnection requires extensive computer modeling to assure that the interconnection and the systems it connects provide reliable and economical service. The types of modeling required include the following:

Power Flow Modeling

The most important single class of tools in power system engineering is that of power flow models, also called load flow models. These models are used to compute voltage magnitudes, phase angles, and flows of real and reactive power through all branches of a synchronous network under steady-state conditions. Power flow models account for loop flows, and make it possible to understand how much power will actually flow on transmission lines under a given set of circumstances. Modelers vary the initial conditions – for instance, adding a proposed new generator to the network – and determine the impact on power flows throughout the system.

A standard reliability requirement is that utilities meet the "n-1" criterion, meaning that the system is able to continue to supply all loads despite the loss of a large generator or the outage of large transmission line. These "contingencies" are modeled with a power flow model, and if the model results indicate a problem, planners and operators must address it, typically by adding new generation and/or transmission capacity, or by changing operational procedures.

To run power flow models requires that each bus and line in the system be thoroughly described, requiring a great deal of input data. The real and reactive power consumption at each load bus, the impedance of each line and transformer, and the generating capacity of all generators must be known.

Power flow models are used by the North American Electric Reliability Council (NERC) to calculate a power transfer distribution factor (PTDF) for individual power transfers. The PTDF shows the incremental impact of a power transfer from a seller to a buyer on all transmission lines, as a percentage of their transfer capacity. If a line is overloaded, transactions that have PTDF values greater than 5 percent on the overloaded line can be curtailed[32].

32 A word of caution regarding modeling results from an experienced transmission engineer: "I have found very poor correlation whenever I checked the studies made a number of years in advance against what actually happens in a transmission system. Often a planning study might indicate a 400 MW loading on a line that is really loaded 200 MW for a specified load level and condition. The actual flow patterns are usually quite different from those predicted by load flow studies. The generation in service is never quite what was used in the study. There are some units out that had not been anticipated; there is always some generator maintenance contrary to the planning assumption that no generator maintenance will occur at heavy load times. The generation dispatch is different from what was assumed in the study; the fuel costs are different; the forced outages are different; the heat rates are different. The peak load that occurs is different from the one used in the study. The load distribution is different; it has come in one area when it had been forecast in another area… The message here for the transmission system planner or system designer: the transmission system should provide the flexibility to meet changing conditions." John A. Casazza (1999), "Measuring Use of Transmission", in J. Casazza and G. Loehr, *The Evolution of Electric Power Transmission Under Deregulation*, IEEE, Piscataway, NJ p.95.

Optimal Power Flow (OPF) Modeling

Optimal power flow models take the outputs of power flow models and analyze them according to user-defined *objective functions*, such as least cost or minimization of transmission loading. Where the ordinary power flow model provides only engineering information – voltage, power, and phase angle, for example – OPF models assist operators in ranking alternatives according to economic and other criteria.

Short Circuit Modeling

Short-circuit models are used to compute fault currents for various kinds of short circuits (phase-to-phase and line-to-ground). The results of short-circuit models are used to determine the required specifications for protection equipment such as circuit breakers and relays, and to determine the proper settings for relays to clear faults.

Dynamic Stability Modeling

Dynamic stability models are used to determine whether the synchronous machines in a power system – namely the generators and motors - will remain in synchronism in the case of a disturbance, for example the loss of a generator or transmission line, a fault, or a sudden increase in demand. The models work by calculating the angular swings of synchronous machines during a disturbance, and determining whether they will remain within an envelope of stable operation.

Transient Modeling

Transient models are used to compute the magnitude of transient voltages and current spikes due to sources such as lightning and circuit switching. The model results are used to specify the insulation requirements for lines and transformers, to determine grounding schemes, and to determine surge arrester specifications.

2.5.3. Data Requirements for Planning

Exchange of data between the owners/operators of the systems to be interconnected regarding the technical characteristics and requirements of their respective systems is essential from the outset of an interconnection project. The need for transparency and for the development of mutual understanding cannot be overemphasized. An example of the kinds of technical data that are typically exchanged in an interconnection project can be seen in Table 2-1.

Table 2-1: Sample of Technical Data Requirements for Interconnection[33]

Overhead Transmission Line	Nominal Voltage (kV)
	Length (km)
	Route Map (including transposition locations)
	Plan and profile drawings
	Electrical single line diagram showing transmission line and any other associated devices required for switching, reactive compensation, protection and control and communication and the interface to the generator or end-user facility
	Nominal power transfer rating
	Emergency power transfer rating
	Conductor type and size
	Overhead ground wire type and size
	Configuration of conductors and overhead ground wires on tower (include diagram showing phase spacing and clearances to ground)
	Positive Sequence R_1 , X_1 and B_1 (ohms/km)
	Zero sequence R_o and X_o (ohms/km)
	Description of protections provided
	Description of communication systems
Reactive Compensation device (if applicable)	Connection Location
	Type, make, model
	Configuration
	Rated Voltage (kV)
	Size (MVAr)
	Switching device: type, make, model, interrupting capability, continuous current rating, tripping and closing times and any switching restrictions
	Criteria for automatic switching
	Description of protections provided
Intermediate or terminal substation (if applicable)	Electrical single line diagram
	Circuit Breakers: type, model, interrupting capability, continuous current rating, tripping and closing times
	Description of protections

33 Manitoba Hydro (2003), "Transmission System Interconnection Requirements," December 2003.

Transformer (if applicable)	Type, make, model
	MVA rating— Normal
	MVA rating— Emergency
	Voltage rating of each winding
	Connection configuration of each winding
	Saturaion Characteristics
	Tap-changer nominal tap, tap step size and tap range
	Positive sequence impedance on own base (p.u.) at nominal tap for each winding
	Zero sequence impedance on own base (p.u.) at nominal tap for each winding
	Circuit Breakers: type, make, model, interrepting capability, continuous current tating, tripping and closing times
	Surge arresters: type, make, model and rating
	Description of protection and control provided including block diagrams and shematic diagrams
	List of protection and control settings
	Descripting of interface provided for remote control and monitoring
	Description of facilities for metering
	Description of communication systems provided

2.5.4. Software Tools

Table 2-2 lists several examples of common software packages used for modeling power flow, optimal power flow (OPF), dynamic stability, available transfer capacity (ATC), and fault analysis. The table also includes examples of software used for integrated economic and resource planning, and SCADA software. Please note that this table by no means presents an exhaustive list of the software available to address these needs, nor do UN-DESA or the authors make any claims or recommendations regarding these software tools—the table presents examples for reference only.

Table 2-2: Power System Simulation Software

Company	Software	Function
PowerWorld Corporation	PowerWorld Simulator	power flow, OPF, transfer capacity
http://www.powerworld.com/products/simulator.html		
General Electric	PSLF	power flow, dynamic simulation, fault analysis
http://www.gepower.com/prod_serv/products/utility_software/en/ge_pslf/index.htm		
Siemens	PSS/E	power flow, OPF, dynamic simulation, fault analysis, transfer capacity, pricing

http://www.pti-us.com/PTI/software/psse/index.cfm		
ABB	SIMPOW	Power flow, dynamic simulation, fault analysis
http://www.abb.com		
General Electric	MARS	interconnected system reliability
http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm		
ABB	Network Manager	SCADA software
http://www.abb.com/powerT&D		
General Electric	XA/21	SCADA software
http://www.gepower.com/prod_serv/products/scada_software/en/downloads/xa21_overview.pdf		
LCG Consulting	UPLAN	integrated planning, market price simulation
http://www.energyonline.com/products/mpm.asp		
Global Energy Decisions	ProSym	integrated planning, market price simulation
http://www.globalenergy.com/detailed-zonal.asp		
OLADE and IADB	SUPER	generation and interconnection planning
http://www.worldbank.org/html/fpd/em/power/EA/methods/mtmpspob.stm		
ICF Consulting	IPM	integrated planning, market price simulation
http://www.icfconsulting.com/Markets/Energy/ipm.asp		
Operation Technology, Inc.	ETAP	integrated analysis tool for design, maintenance, and operation of electric power systems; includes modules for HVDC and many other functions
http://www.etap.com/products.htm		

- An example of a software tool for Power Flow modeling with graphic interface features: the PowerWorld Simulator

Figure 2-8 shows a "screen shot" of a PowerWorld simulation of a small network with 9 buses containing both load and generation. The circles with numbers inside indicate the percentage of transmission capacity of each transmission link that is in use under the given scenario. The visual interface helps operators and planning understand the impact of adding or removing generators and transmission lines, or of large changes in real or reactive power consumption by loads.

Fig. 2-8: PowerWorld display of transmission loading on small 9-bus system[34]

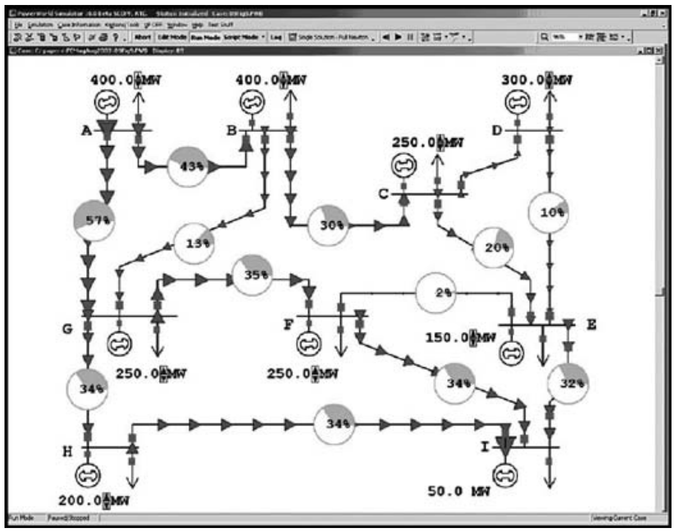
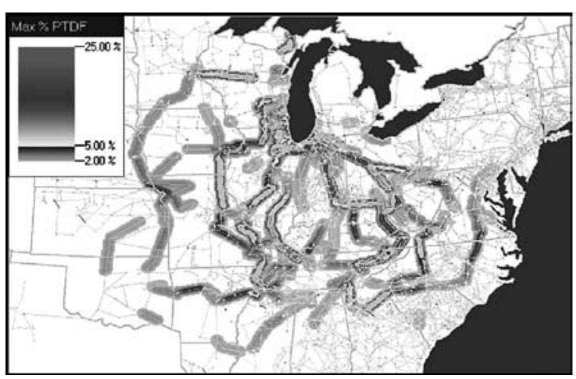


Figure 2-9 shows another graphic interface of the PowerWorld simulator. This figure shows the Power Transfer Distribution Factor (see Section 2.5.2, above) for a proposed power transfer in the north central United States. It illustrates the importance of parallel path flows in loading transmission lines far from the nominal sender and receiver.

Figure 2-9: PowerWorld display of PTDF for transaction in north central United States[35]



34 Thomas Overbye (2004), "Power System Simulation: Understanding Small- and Large-System Operations". *IEEE Power Engineering Society Techtorial*, *http://www.ieee.org/organizations/pes/public/2004/jan/pestechtorial.html* (Figure 9).

35 Thomas Overbye (2004), "Power System Simulation: Understanding Small- and Large-System Operations". *IEEE Power Engineering Society Techtorial*, *http://www.ieee.org/organizations/pes/public/2004/jan/pestechtorial.html* (Figure 12).

2.6. Summary of technical issues in grid interconnection

Several basic technical issues must be addressed early in the planning process for a grid interconnection. Will the interconnected systems operate synchronously or asynchronously? What are the magnitudes and directions of the anticipated power flows? What physical distance and terrain will the interconnection span? What are the key technical and operating differences among the systems to be interconnected?

For AC interconnections, key design and operating issues relate to the constraints on transmission capacity, which include thermal limits, stability limits, and voltage regulation. Where there are liberalized electricity markets, these constraints become more severe as systems are operated closer to capacity. FACTS and HVDC options should be considered as alternatives or complements to traditional transmission upgrades. Simulation software is an essential tool for planning and operating an interconnection. For modeling to be effective, however, extensive technical data must first be gathered and shared between systems, and personnel must be trained. Grid interconnections require a careful calculation of costs, benefits, and risks. Technical planning of a grid interconnection should be coordinated with economic, organizational, legal, and political aspects of a potential interconnection project from the outset of project consideration.

2.7. Resources for Further Analysis

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