Transmission System Management & Pricing

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FOREWORD

For more than a century, Parsons Brinckerhoff has been committed to providing advanced state-of-the-art engineering services to its clients. The deregulation of the U.S. power industry has provided some of our clients with an opportunity to reduce the cost of electric energy by millions of dollars annually. PB clients poised to take advantage of the changes in the energy market are typically independent power producers, large industrial and commercial companies and transit/transportation authorities. Specifically, large users of electric energy may choose to procure power from lower-cost sources beyond their immediate local utility, generate power for on-site use and sell surplus off-site, and manage their on-site load as a function of time by alternative pricing options such as real-time pricing. However, with the opportunities of a free marketplace come complexities and risks that demand well-informed decision-making. This monograph, under the auspices of the William Barclay Parsons Fellowship program, is one method by which PB intends to support existing and new clients during the deregulation of the U.S. electric power industry.

The Energy Policy Act of 1992 sets the stage for the vast changes that are being applied throughout the U.S. electric utility market today. There is general consensus in the industry that change is needed in the sale and generation of electric energy. How that change will be implemented will be decided by the Federal Energy Regulatory Commission, public utility commissions, or local power authorities. Because of the wide diversity of opinions about the subject, there exists today as many different ways to accomplish this goal as there are opinions.

Generation, transmission and distribution systems planning, as performed in the past, was the process whereby long-term load forecasting was correlated with future supply and delivery system projections. When future supply shortages were noted, new power plants and power delivery systems were incorporated into the rate base and reasonable returns on investments were granted by the state public utility commissions. In a restructured utility environment, there will be no guarantee of return on future investment.

The objectives of this monograph are to evaluate the changes occurring in the U.S. electric power industry, demonstrate the importance of the transmission system in a competitive power industry, identify new power purchase options available to end-use customers, and propose an approach, tools and methodology to fully exploit these opportunities. To satisfy these objectives, the monograph has been divided into two sections, each consisting of three chapters.

Section I, Competitive Marketplace, describes the utility industry during its transition from fully regulated to its present state of proposed deregulation. A brief history of the electric utility industry describes the elements of an electric system, the cost structure of vertically integrated utility companies, and the roles of state and federal regulatory agencies and reliability councils in the U.S. power industry. This section also outlines three specific models (regulatory, wholesale competition and retail access) that could evolve or be adopted by different states over the next 5 to 10 years.
Section II, *Economic and Technical Considerations for the Competitive Marketplace*, outlines economic and technical considerations for generation, transmission and retail customers and, more importantly, provides the tools and methodology to enable power consumers to make informed decisions concerning the opportunities available within each of the models outlined in Section I. Case studies employ these tools and methodologies for generation price projections in a competitive marketplace and transmission pricing and wheeling analyses. Considering retail access to electric power, the approach, methodology and tools necessary to sort out available options for end-use customers are developed and the projected savings for large industrial customers illustrated.

The annual revenues generated by the sale of electric energy in the U.S. with a deregulated electric utility industry are valued at more than $220 billion, and the savings to end-use customers are expected to range annually from $20 to $40 billion. Customers who evaluate their power delivery options with a full understanding of the deregulation process will benefit the most. The management of the economics and the technical issues associated with the commercial transactions in this new marketplace is an unfamiliar role for most new players. There is a need for additional services to maintain system security and efficiency as previously provided by the controlling utility in the area. Each of these requirements will need an approach that is flexible enough for application to the varied models employed in the industry. This monograph outlines such an approach and explains the nuances of the new marketplace and its primary stakeholders.

Since utility deregulation is an ongoing process, many issues such as transmission cost methods, stranded cost recovery, system reliability assessment, and environmental impacts are still unresolved. In addition, the circumstances and conditions that control the variables that define the values used will affect the actual economic figures. Therefore, the results and recommendations from cases presented in this monograph are for demonstration purposes only and should not be used otherwise.
ACKNOWLEDGMENTS

The completion of this monograph represents an important milestone in my professional career. It also brings the realization that a large part of my personal and professional success is due to the incredible support received each day from my friends, family and colleagues.

The William Barclay Parsons Fellowship research program was created in recognition of the founder of Parsons Brinckerhoff. It provides the recipient with the opportunity and means to become thoroughly knowledgeable in a chosen field of interest, to develop specific professional skills and to publish findings for the use of colleagues and the profession as a whole. In the summer of 1996, when my proposal was submitted to the Career Development Committee, I was not fully aware of the complexity of the tasks proposed. The U.S. electric power network is one of the most complex and challenging man-made devices on earth, and determination of its cost structure in a deregulated marketplace was a formidable task. The industry framework was not in place and necessary tools to perform economic studies were not available. However, with the help and support of PB management and colleagues, the last 2 years have been the most challenging and informative of my professional career.

My sincere thanks and gratitude go to the members of the Career Development Committee and to Paul Gilbert, who provided direction and constant encouragement. I would also like to thank the board of directors of Parsons Brinckerhoff for supporting this program, and Bob Prieto and Bill Roman for their sponsorship.

The development of this monograph would not have been possible without the many conversations, continual feedback and constant support provided by my two technical advisors, Jay Bednarz and Bill Smith. While Jay provided day-to-day support and kept me focused on the task at hand, Bill helped me obtain the fellowship and provided unending support. I am also thankful to Bob Fishman for allowing me to work on this project during difficult years.

For their hospitality, professional support and valuable guidance, I also owe many thanks to my colleagues at PB Merz and McLellan in Newcastle, especially to David Bailey, Paul Dudley and Bob Whitelaw. Paul's comments on my initial draft were especially valuable. I am also thankful to my friends at NewEnergy Associates in Atlanta, especially Paul Turner. Without their support and contribution of the PROMOD IV software, the technical studies included in this monograph would not be as realistic. A great deal of thanks is extended to my former colleagues in the Dallas office, Barbara Wegner, Ray Harold and Simon Schuer, and others who have supported this research project.

Additionally, I would like to acknowledge the assistance of my reviewers, who graciously donated their time to provide technical feedback on this monograph. These individuals include Ken Johnson, Ken Johnson & Associates; Dr. Paul MacGregor, GE Harris; Dr. Wei-Jen Lee, Energy System Research Center at the University of Texas at Arlington; Paul Cunningham, The Altus Group; and Gregory P. Gilbert, PE, Tacoma Public Utilities.
Special acknowledgments are also due to Randi Aronson and Richard Mangini and other members of the Business Services Group who provided much-needed editorial and graphical assistance for the successful production of this document.

Lastly, and most importantly, I would like to thank my wife, Preeti, our son, Rahul, and my parents for their support during the development of this monograph. This is just one more example of their continued and unselfish support of my professional career. I thank God for his blessing on us.

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SECTION I: COMPETITIVE MARKETPLACE
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1.0 HISTORICAL DEVELOPMENT OF
THE ELECTRIC POWER INDUSTRY
1.0 HISTORICAL DEVELOPMENT OF THE ELECTRIC POWER INDUSTRY

The electric power industry is only a little more than 100 years old. While scientific study of electrical phenomena dates back more than 200 years, Thomas Edison did not produce his incandescent light bulb, one of the first commercial applications of electric power, until 1879. Pearl Street Station, the first commercial generating station, was put in service by Edison in 1882.

Edison’s system was a low-voltage, direct current (DC) system, with limited ability to transmit power over long distances. As a result, it was not unusual for many small, non-interconnected companies to operate in the same city. The independently owned companies competed for customers in overlapping service areas, keeping the cost of service relatively low.

In 1886, George Westinghouse purchased the rights to an alternating current (AC) system from an English firm, Gaulard and Gibbs. The AC system had a distinct advantage over Edison’s DC system, in that it could be transformed to a higher voltage or “stepped up” for transmission over long distances, then “stepped down” for safe utilization. This enabled companies to serve larger areas and more customers. At the same time, improvements were being made in generator technology, producing larger outputs at lower cost. This was particularly true after Westinghouse bought the rights to Nicola Tesla’s polyphase AC system.

As the industry evolved, technology moved from DC to almost exclusively AC by the early 1900s. Along with this shift in technology came a shift in the commercial nature of the business. Smaller companies began to consolidate, serving larger areas from larger and more expensive generating stations. By 1917, after 30 years of steady increase, the number of independently owned electric systems began to decline. In this era of consolidation, holding companies began to take control of the industry, acquiring stock in electric companies for a variety of reasons. This change was brought about because of the benefits associated with economies of scale, market power and the potential growth of the business.

By the early 1930s, a handful of holding companies controlled a substantial portion of the electric generating capacity in the U.S. In 1932, 76.4 percent of the electrical energy generated in the U.S. were controlled by 16 holding companies, 44.5 percent of which were controlled by three companies. Such market power and lack of regulation within the industry led to practices that were against “consumer” interests. Holding companies engaged in financial and accounting irregularities and charged markup fees to the companies they served.

The Federal Trade Commission (FTC) recognized the disproportionate amount of market power held by holding companies, and the potential drawbacks for the consumer if they continued to operate unchecked. As a result of the FTC’s investigation and recommendations, Congress enacted the Public Utility Act (the Wheeler-Rayburn Act) in 1935, which contained within it the Public Utility Holding Company Act (PUHCA).
PUHCA addressed malpractice among holding companies by increasing federal oversight of financial and accounting practices. The Securities and Exchange Commission (SEC) was given jurisdiction over the issuance of new securities, and could effectively veto the purchase and sale of assets by a holding company. The act also dictated that the structure of holding companies be greatly simplified, limiting the holding company to controlling ownership in a “single integrated public utility system.” Holding companies that only owned or controlled other holding companies were abolished.

1.1 ELEMENTS OF AN ELECTRIC POWER SYSTEM

Generation

Power generation in the electric utility industry means conversion of energy from a primary form to an electrical form. The current sources of nearly all the electrical energy distributed by utilities come from the conversion of chemical energy of fossil fuels such as coal, oil and natural gas. Hydroelectric generation is a common source since the early days of electrical generation. Over the last 40 years, nuclear fuels utilizing uranium compounds have been a significant power source. Renewable energy sources, such as solar, wind, and geothermal power, also contribute a small percentage of power generation in the U.S.

Traditionally, generating plants were designed and constructed to produce as much power as possible, given the available technology. Large-size units ranged from 600 to 1,500 megawatts (MW). The construction of such plants incorporated a concept commonly referred to as “the economy of scales.” Loosely defined, this meant that it was less expensive to construct and operate one large generating plant than several small ones to produce a given amount of power.

This concept held true from the late 1940s through the early 1970s. As the cost of building large plants and fuel costs continued to escalate, with resulting higher electrical rates, it became economically feasible for some private companies to install smaller generating stations to serve their own electrical load. The concept of installing smaller scale, independently owned generating plants is commonly referred to as self-generation in the case of electric-only generation or cogeneration in the case of both thermal and electrical generation. The Public Utility Regulatory Policy Act (PURPA) defined these plants as qualifying facilities if they met plant efficiency and definition requirements. This concept was promoted by a federal regulation, introduced in 1978, that required utility companies to buy the “excess” energy (i.e., energy not consumed by the owning entity) produced by these plants. However, the utilities were required to pay for the energy at a rate commonly referred to as “avoided cost.” This refers to the cost that the utility avoided by not having to build new generation. In the late 1970s, this cost was based on the largest nuclear or fossil plant installed on the grid. Thus the avoided costs were initially in excess of the average cost to a utility. The regulation that introduced this requirement is discussed in Chapter 2.
The evolution of generation continues today but in the opposite direction, where the avoided cost is now based on very efficient cogenerators with lower fuel costs and thus is less than the average cost. As the electric power industry moves from a regulated environment to a competitive one, virtually all generation capacity will be bought and sold on the open market. The price to individual consumers will be primarily determined by market forces, but still subject to regulatory agencies’ approvals to address both consumer and utility economics.

**Transmission**

The transmission system is the tie that links the producers of electric energy to the users. It consists of high voltage AC (usually between 69 kilovolts (kV) and 750 kV) or DC overhead lines and underground cables carrying large amounts of electric power from the generating stations where it is produced to substations in the general proximity of where it is used. Large transformers in the substation lower the voltage to a level that is feasible for distribution to individual customers.

The transmission system is highly interconnected, both within individual utilities and between companies in the same geographic area. Many, if not most, substations have at least two separate transmission lines serving them. The reason for the high degree of interconnection is to improve reliability. While transmission lines serve a few customers directly, the power they deliver to substations is distributed to large numbers of customers. The interconnected transmission system provides multiple routes to deliver power to a utilization point.

As with generation, transmission lines have traditionally been owned and operated by utility companies. While not as expensive to construct as generating plants, transmission lines require extensive purchase of land rights to transmit the power from generating stations to the communities they serve. Individual utilities currently own and maintain their transmission systems, creating intercompany ties between systems where it is mutually advantageous. Since interconnecting transmission lines create large networks, they do more than transmit power from generating plants to load centers. They provide paths for alternate power flow; serve as a source of reactive power (vars), and provide stability and other ancillary supports.

**Distribution**

As shown in Figure 1.1, power delivered by the transmission system to local substations is distributed throughout a utility’s service area distribution system using overhead lines and underground cables. While distribution voltages are much lower than those used in the transmission system, they are still typically much greater than the utilization voltage of most customers, necessitating further transformation and secondary distribution systems.

Because distribution systems serve specific geographic areas, and each individual circuit serves a limited number of customers, their interconnectivity is limited. Distribution circuits typically have ties to other distribution circuits to help restore power in the event of an outage, but rarely do they have ties to facilities owned by other companies. Interconnectivity is further limited by the fact that the distribution system also usually contains one of the most critical components of the entire electrical system—revenue metering.
Distribution facilities are owned, operated and maintained by a variety of business and government entities. Often an investor owned utility (IOU), which usually owns generation and transmission facilities, will have a regulated service territory in which it is legally required to provide distribution facilities. In some cases, however, a political entity, city, municipality or power authority will construct its own distribution system to serve its customers, and purchase bulk power from companies with generation and transmission facilities. In the case of some very large industrial complexes, a private company will construct its own system to serve individual buildings or plants, and purchase power at high voltage from the local utility. An illustration of the complete power delivery system is shown in Figure 1.1.

![Figure 1.1 Power Delivery System](image)

**1.2 COST STRUCTURE**

Another key element to understanding the state and direction of the electric power industry is the cost structure. Currently, IOUs and municipalities operate as statutory monopolies. State regulatory agencies define their service territories, specify their allowable return on investment, set rates for different types of services, define allowable costs and monitor the level of reliability and service that they provide to their customers. In exchange for such close regulation, utilities operate without competition within their given service territories. This arrangement guarantees utility investors a reasonable rate of return and, at the same time, allows regulators to ensure that consumer rates remain reasonably stable.

The cost structure associated with utilities operating under this arrangement was simple on the surface but included subsidies to meet political needs. All generation, transmission and distribution costs allowed into a utility’s “rate base” were combined into an energy rate, and
consumers paid for the amount of energy they used. Such rates were typically in the form of $/kWh used, with adjustments made for the actual fuel cost for a given period. Some rates incorporated demand charges ($/kW) to compensate the utility for the capacity of the system constructed to serve a customer. In each case, however, the consumer was required to purchase energy from the company that had the right to serve the consumer’s locale at the prices specified by the regulatory agencies.

Deregulation of the power industry will offer consumers more choices in their energy purchases. However, the cost structure as seen by the consumer will become more complicated. Each market sector—generation, transmission and distribution—will still incur costs in delivering power to the customer. Likewise, the bill that the customer ultimately pays will still have to cover those costs. The business entities that will provide services to the various market sectors are described below along with the government and industry bodies responsible for their oversight. The means for computing and allocating the cost of these services are discussed in subsequent chapters.

1.3 MARKET PARTICIPANTS

Electric power in the United States is supplied by approximately 3,500 separate electric systems. The largest 200 provide almost 90 percent of the industry’s generating capacity and directly serve nearly 80 percent of the industry’s ultimate customer load. The remaining 3,300 systems have little or no generation or transmission of their own, and function as distributors of electric energy purchased on the wholesale market from other utilities.

IOUs have historically been by far the largest single group of energy suppliers in the United States. They have traditionally supplied over 70 percent of the generation available in the country. Independent power producers, cogenerators and other non-utility suppliers have continued to make small but steady gains within the power market since 1978. Figure 1.2 illustrates the market share of the various generating entities from 1980 to 1992.
Power marketers have also begun to play a role in the power industry. Nearly 100 companies have received approval from the Federal Energy Regulatory Commission (FERC) to buy and sell wholesale interstate power, and many applications are pending. Though currently restricted to wholesale transactions, these companies anticipate being able to enter the retail supply market when it is established.

The role of these companies in the industry is essentially that of a broker. They typically do not generate power, or even own electrical facilities of any kind. Instead, by evaluating the power market across the country, they arrange for the transmission and sale of power between entities that might otherwise not have come in contact. An extreme example of this type of transaction involved the purchase of power from the California Department of Water Resources in Sacramento, California, and its delivery to the Jacksonville Electric Authority in Jacksonville, Florida. The power marketer identifies a $19/MW cost differential between California and Florida, and would be able to make the necessary arrangements to wheel power almost coast to coast. However, after paying for system losses and transaction charges to various entities, such transactions may not be feasible.

Another emerging market player is energy service companies (ESCos). Some companies are already operating in a limited sense as ESCos, offering energy audits, financing energy-related system improvement projects, and entering into performance-based contracts. As retail competition becomes a reality, ESCos will be able to offer a wider range of services, including:

- Retail power marketing
- Advanced metering and automated meter readings
- Power quality monitoring and other ancillary services

In a restructuring of the industry, each IOU will be required to separate out generation, transmission and distribution as separate operating companies. Common terminology used for these new entities are GENCo for generation companies; TRANCo for transmission companies; DISCo for distribution companies; and ESCo for energy service companies. ESCos will serve as competition for the local distribution companies (DISCos) in supply. The DISCos will in all likelihood continue to own and maintain local distribution lines and receive payment for their use, but will not necessarily meter or sell energy to individual customers.

1.4 REGULATORY AGENCIES AND RELIABILITY COUNCILS

A number of regulatory agencies, with various degrees of authority, exist at the federal and state levels. The most recognized of these at the federal level is the Department of Energy (DOE). Receiving cabinet-level status in 1977, this department sets policy for energy-related industries in the United States. In addition, the DOE funds and administers a variety of energy and technology-related research projects throughout the country.

FERC, the arm of the DOE charged with implementing policy decisions, has broad powers in price, terms and conditions of power sold in interstate commerce, and also regulates the
price, terms and conditions of all transmission services. FERC is a counterpart to state utility regulatory commissions. For wholesale competition, where state regulation is inapplicable, ineffective or unconstitutional, FERC has the power to:

- Regulate rates and earnings
- Prescribe an accounting system
- Control issuance of securities, mergers and facility transfers
- Order interconnection and coordination of utility systems
- Order access and wheeling
- Approve applications for transaction services

Additionally, FERC regulates the tariffs of the federal power marketing authorities (PMAs) such as the Alaska Power Administration, Bonneville Power Administration, Southeastern Power Administration, Southwestern Power Administration, and the Western Area Power Administration.

The counterparts of FERC at the state level are the public utility commissions (PUCs). While their names and levels of regulatory authority vary from state to state, PUCs are generally charged with regulating rates, controlling service territories, monitoring quality of service and determining allowable earnings. While FERC has broad authority in wholesale competition, for the most part, PUCs are the only agencies with authority to order retail competition, and will control to a great extent the competitive form adopted for a given state.

In addition to the agencies that have legal authority to establish industry policy, the utility industry has also established cooperative organizations intended to improve the overall reliability of the electrical supply system. These organizations, collectively known as reliability councils, develop voluntary standards and criteria for the planning, design and operation of the bulk power system. The intent of these organizations is to mitigate the impact of local outages on the area-wide power system by encouraging greater intersystem connectivity and responsible design practices. Figure 1.3 illustrates the service areas of the North American Electric Reliability Councils (NERC).
The relationships of the various regulatory agencies and reliability councils are illustrated in Figure 1.4. Note that connections in Figure 1.4 represent the existence of a relationship, and not necessarily strict jurisdiction or control.
Recent actions by both FERC and various states PUCs, and how these actions are changing the face of the industry are discussed later. New functional, financial and operational industry models have been developed to allow the industry to adapt to the regulatory directives. As a point of reference, the current industry model is illustrated in Figure 1.5. While the basic building blocks remain in place, additional market participants and relationships are being developed. Few existing participants appear to be waiting to engage in the retail/supply market and the extent of this participation may depend on PUC proposals for market reform. This reform may influence cost standards within the industry and the development of the generation sector.

**Figure 1.4 Industry Relationship**

Recent actions by both FERC and various states PUCs, and how these actions are changing the face of the industry are discussed later. New functional, financial and operational industry models have been developed to allow the industry to adapt to the regulatory directives. As a point of reference, the current industry model is illustrated in Figure 1.5. While the basic building blocks remain in place, additional market participants and relationships are being developed. Few existing participants appear to be waiting to engage in the retail/supply market and the extent of this participation may depend on PUC proposals for market reform. This reform may influence cost standards within the industry and the development of the generation sector.
In conclusion:

“The future is here—and the future is competition. It is a global trend, and in North America, we are at the forefront in embracing it. There is no turning back.”

Elizabeth A. Moler
Chair, Federal Energy Regulatory Commission
2.0 FEDERAL AND STATE PERSPECTIVES
From the 1940s through the 1960s, the electrical generating industry experienced steady growth and lower average generating costs each year due to economies of scale and low fuel costs. In the 1960s, a number of significant events occurred in the electric industry that changed the perception of utilities by government and consumers. This was the beginning of a period of rapid inflation, increased fuel costs, high interest rates, the Arab oil embargo, and the Three Mile Island nuclear accident, resulting in increased electricity costs. As consumers became concerned about higher electricity rates, they questioned requests for rate increases filed by utilities but still accepted the regulated approach and allowable cost recovery.

During this same time frame, planning was based on substantial growth in electrical demand that had historically occurred for 30 years, and high oil prices leading to construction of nuclear and other large coal-fired baseload facilities. These investments were made based on the assumptions that there would be steady increases in the demand for electricity, full cost and investment recovery and continued large increases in the price of oil.

However, due to energy conservation programs encouraged by higher costs and government regulations, coupled with a change in the American economy to a service industry focus, the expected demand increases did not materialize. Load growth virtually disappeared in some areas, and many utilities unexpectedly found themselves with excess capacity. In addition, by the 1980s, the deregulation of the gas industry, coupled with low-priced oil, resulted in lower generating costs for smaller units. At the same time, regulation of the nuclear and coal industries substantially increased the costs of these large baseload-generating plants. Surging interest rates further increased the cost of the capital needed to finance these projects and more stringent safety and environmental requirements significantly extended completion schedules.

Between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25 percent after adjusting for inflation (based on retail prices reported in Energy Information Administration (EIA), Monthly Energy Review, January 1995). Moreover, the average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86 percent after adjusting for inflation. The rapidly increasing rates for electric power during this period, together with the repeal of the prohibition on the use of natural gas as fuel (through PURPA) and deregulation of the gas industry prompted some industrial customers to bypass utilities by constructing their own generation facilities. This further exacerbated rate increases for remaining customers—primarily residential and commercial customers. The reasons for the tariff increases, namely excess capacity, caused utility company management to review their plans. The nuclear program was largely abandoned for plants ordered after 1979. When PUC stated that overcosts associated with nuclear plants were unallowable, between 1985 and 1992, write-offs of nuclear power plants totaled $22.4 billion. These write-offs significantly reduced the earnings of the affected utilities. These earnings were further reduced by delays in obtaining rate increases from regulators. Thus, many utilities became reluctant to commit capital to long-term construction decisions involving large scale generating plants.

2.0 FEDERAL AND STATE PERSPECTIVES

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During this same time frame, planning was based on substantial growth in electrical demand that had historically occurred for 30 years, and high oil prices leading to construction of nuclear and other large coal-fired baseload facilities. These investments were made based on the assumptions that there would be steady increases in the demand for electricity, full cost and investment recovery and continued large increases in the price of oil.

However, due to energy conservation programs encouraged by higher costs and government regulations, coupled with a change in the American economy to a service industry focus, the expected demand increases did not materialize. Load growth virtually disappeared in some areas, and many utilities unexpectedly found themselves with excess capacity. In addition, by the 1980s, the deregulation of the gas industry, coupled with low-priced oil, resulted in lower generating costs for smaller units. At the same time, regulation of the nuclear and coal industries substantially increased the costs of these large baseload-generating plants. Surging interest rates further increased the cost of the capital needed to finance these projects and more stringent safety and environmental requirements significantly extended completion schedules.

Between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25 percent after adjusting for inflation (based on retail prices reported in Energy Information Administration (EIA), Monthly Energy Review, January 1995). Moreover, the average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86 percent after adjusting for inflation. The rapidly increasing rates for electric power during this period, together with the repeal of the prohibition on the use of natural gas as fuel (through PURPA) and deregulation of the gas industry prompted some industrial customers to bypass utilities by constructing their own generation facilities. This further exacerbated rate increases for remaining customers—primarily residential and commercial customers. The reasons for the tariff increases, namely excess capacity, caused utility company management to review their plans. The nuclear program was largely abandoned for plants ordered after 1979. When PUC stated that overcosts associated with nuclear plants were unallowable, between 1985 and 1992, write-offs of nuclear power plants totaled $22.4 billion. These write-offs significantly reduced the earnings of the affected utilities. These earnings were further reduced by delays in obtaining rate increases from regulators. Thus, many utilities became reluctant to commit capital to long-term construction decisions involving large scale generating plants.
There has been a transition since the 1980s, moving from an emphasis on large scale nuclear technology to medium scale units using fossil fuel technology. From the 1940s through the early 1970s, bigger was thought to be better in the generation sector because of the actual economies of scale from larger and larger plants. As a result, large utility companies that could finance and manage large scale construction projects were thought to have a price advantage over smaller utility companies and customers who might otherwise have considered building their own generating units. Scale economies encouraged power generation by large vertically integrated utility companies that also transmitted and distributed power. By the late 1970s, bigger was no longer thought to be better, and it was recognized that large units caused increased penalties to the overall system, relative to smaller units, because of their effect on lost output during both scheduled and unscheduled maintenance periods. If there were two units instead of one large unit, only one of the two units was likely to be out for maintenance at any given time, thereby improving the availability of power. Furthermore, the larger units required longer start-up and shut down periods, which caused them to be less flexible in operation. Therefore, the unit size needed to consider both the economics and economies of scale for the system.

Further facilitating the decline of larger generation units were advances in gas turbine technologies and low gas prices that allowed economies of scale to be exploited by smaller sized units, allowing smaller new plants to be brought on line at $/kW below those of the large plants of the 1970s and earlier. Such new technologies included combined cycle units, integrated gasification combined cycle (IGCC) as well as conventional steam units that used circulating fluidized bed boilers.

From the mid-1980s, the optimum size of generation plants had shifted from more than 500 MW (with a 10-year lead time) to multiple smaller units in the 50 MW to 150 MW range (with a 1-year lead time). Depending upon the price of gas, smaller and more efficient gas-fired combined-cycle generation facilities can produce power on the grid at a cost ranging from 5 cents/kWh to less than 3 cents/kWh. This is significantly less than the costs for large plants constructed and installed by utilities over the last decade, which were typically in the range of 4 to 7 cents/kWh for coal plants and 9 to 15 cents for nuclear plants.

The combined cycle generating plants generally used natural gas as their primary fuel. This technology has been made possible by the development of gas turbines that are more efficient, require shorter construction lead times and lower capital costs, and have increased reliability and relatively minimal environmental impacts.

Technological advances have made possible the economic transmission of electric power over long distances at higher voltages. This has made it technically feasible for utilities with lower cost generation sources to reach previously isolated systems where customers had been captive to higher cost generation. Due to interconnecting transmission systems throughout the country, the nature and magnitude of coordinated transactions have changed dramatically allowing increasingly coordinated operations and reduced reserve margins. Substantial amounts of electricity now move between regions as well as between utilities in the same region. Hence, the development of the transmission system has increased the market size for the generator.
2.1 THE ENERGY POLICY ACT

Even with an expanding market, resulting in an increase in the number of new entrants into the generation sector since PURPA, some barriers to entry exist. These barriers are related to the conditions for an organization to enter the market (PUHCA), and the conditions for the generation to access the transmission network.

To reduce these barriers and increase competition, Congress enacted Title VII of the Energy Policy Act of 1992 (EPAct). The EPAct was established to promote greater competition in bulk power markets by encouraging new generation entrants, known as exempt wholesale generators (EWGs), and by expanding FERC's authority to approve applications for transmission services.

EWGs differ from qualifying facilities (QFs) in several ways. Under PURPA, QFs were allowed to sell their electric output to the local utility at avoided cost basis. To become a QF, the independent power supplier had to produce electricity with a specified fuel and meet certain ownership, size and efficiency criteria established by FERC. Utilities are not obligated to purchase power from EWGs. EWG status is not subject to restrictions related to fuel type, maximum size, or eligible technologies as QFs are. Utilities may own all of an EWG. Unlike a QF, an EWG may sell power generated by others, along with the power it generates itself. However, these wholesale generators are exempt from certain financial and legal restrictions stipulated in the Public Utility Holding Company Act of 1935. In an exemption separate from the EWG exemption, the EPAct exempts foreign utility companies from PUHCA. A foreign utility company is one owning electric or natural gas facilities that are not used to serve U.S. retail consumers.

The EPAct also provides the FERC with broad authority to order utilities to wheel power for wholesale electricity market participants, including electric utilities, federal power marketing agencies, or any other person generating electric energy for sale or resale. Additionally, the EPAct clearly precludes FERC from ordering retail wheeling. However, it does not rule out the individual states' authority to order retail wheeling.

Other broad issues addressed by the EPAct include energy efficiency, integrated resource planning, demand side management, renewable resources, environmental research and development and alternative transportation fuels. But these issues are merely given philosophical encouragement and not meaningful consideration. Many issues are not resolved in the EPAct. One key consideration for federal/state regulators is "stranded investment." Should stranded investment costs be charged to ratepayers or to shareholders? The EPAct has given broader responsibilities to FERC, which may create federal and state disputes that may not be readily resolved.
2.2 FERC OPEN ACCESS NOTICE OF PROPOSED RULE MAKING (FINAL RULE)

Following the EPAct, FERC issued its Open Access Final Rule on May 10, 1996. Through this 1,000-page document, FERC issued three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the nation's electricity consumers. FERC Final Rules may be summarized as follows:

All public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce should:

• File open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service
• Take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs
• Develop and maintain a same-time information system (Open Access Sametime Interaction System (OASIS)) that will give existing and potential transmission users the same access to transmission information that the public utility enjoys, and further require public utilities to separate transmission from generation marketing functions and communications

The Final Ruling also:

• Clarifies federal and state jurisdiction over transmission in interstate commerce and local distribution and provides for deference to certain state recommendations
• Permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access
• Requires the functional unbundling of wholesale services necessary to implement non-discriminatory open access transmission

Since the time the Final Rule was issued, FERC staff has completed a federal environmental impact statement (EIS) that provides a quantitative estimate of some of the net cost savings expected from this rule: approximately $3.8 to $5.4 billion per year. Other non-quantifiable benefits are also expected from this rule, including:

1. Better use of existing assets and institutions
2. New market mechanisms
3. Technical innovation
4. Less rate distortion

These potential benefits to the nation's electricity consumers and the economy as a whole confirm the need to act to remove barriers to competition.
2.3 STATE PERSPECTIVES

In addition to FERC's actions, a number of states have initiated proceedings or proposed legislation concerning retail wheeling, which allows the ultimate consumers of electric energy to choose their supplier.

At the time of this publication, at least 10 states have retail wheeling proposals, legislation, or pilot programs under way—California, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, New York, Oklahoma, Pennsylvania, and Rhode Island. Another 14 states are investigating retail wheeling. According to a report of the National Association of Regulatory Utility Commissioners (NARUC), an affiliated national council on competition and the electric industry, 41 states are actively involved in investigating whether and how to restructure their respective electric power markets. Of this total, 29 state regulatory authorities have initiated investigations. In addition, five state legislatures are involved in similar investigations, while seven other states have joint regulatory/legislative proceedings under way. The power industry restructuring proposals being discussed by Texas, New York and California are investigated later in this publication. Figure 2.1 provides the status of state electric utility deregulation activities as of December 2, 1997. The National Regulatory Research Institute (NRRI) at Ohio State University also provides a current summary of regulatory and legislative action in all 50 states and the District of Columbia at www.nrri.ohiostate.edu (updated monthly).

![Figure 2.1 Status of State Electric Utility Deregulation Activity as of April 1, 1998](image-url)
2.4 INDUSTRY RESTRUCTURING MODEL FOR THE STATE OF TEXAS

The PUC of Texas adopted a rule requiring electric utilities to provide transmission service to other utilities and non-utility power suppliers on a basis comparable with their own use of their transmission facilities. This rule allows utilities and non-utility power suppliers to transmit power to their customers using the transmission lines of other utilities, permitting them to buy power from remote utilities and other non-utility suppliers.

The rule adopted by the commission will:

• Require that utilities provide unbundled transmission service.
• Require that utilities provide, on an unbundled basis, services that are ancillary to basic transmission service.
• Establish a pricing mechanism for transmission service that determines the cost of the service, in part, on the basis of a wholesale customer’s electrical load (postage stamp method) and, in part, on the basis of the impact of transmitting power to the customer (megawatt-mile method).
• Require utilities to separate their personnel engaged in selling power in the wholesale market from personnel who operate the transmission system.
• Require the establishment of an information network that will allow utilities, qualifying facilities, power marketers, and EWGs to have access to information concerning the availability of transmission service and availability and cost of ancillary services on a non-discriminatory basis.
• Require the utilities in the Electric Reliability Council of Texas (ERCOT), the state’s intrastate electrical network, to establish an independent system operator as a point of contact for initiating transmission service and to make decisions concerning the use of transmission facilities when demand for the use of the facilities is high.

The PUC of Texas has adopted a pricing mechanism based on dividing the costs of providing transmission service among the wholesale customers who use the transmission network. Seventy percent of the costs will be divided among the customers on the basis of each customer’s load, and 30 percent will be divided among them on the basis of the impact, in megawatt-miles, of transmitting power from the producer to the areas where the wholesale customer delivers the power to its customers. Under this pricing mechanism, a customer using planned transmission service will pay an appropriate share of the costs of the transmission facilities, but utilities and non-utility suppliers will also be able to use the transmission system for unplanned transmission service, without paying a facility charge.

The PUC of Texas has also adopted a rate-moderation plan that will minimize the rate impact of the new pricing mechanism for the first 3 years that the new rules are in effect. Utilities that own transmission facilities are required to file cost information and proposed tariffs. The rule also directs the utilities to develop a proposal for the independent system operator and submit the proposal for the commission’s review.

Historically, many utilities have provided only “bundled” electric service to their customers. In other words, they provided both electric power and the means for delivering the power to
customers. The rule that the PUC of Texas adopted will require that power be delivered to wholesale customers that is produced by other utilities or non-utility suppliers. The adoption of this rule will permit other utilities and independent power producers to compete in order to meet a wholesale customer's power needs.

2.5 INDUSTRY RESTRUCTURING MODEL FOR THE STATE OF NEW YORK

The State of New York Public Service Commission has issued several documents pertaining to the restructuring of the electric power industry in New York. These documents include:

- Opinion No. 95-7 on Case 94-E-0952, which sets forth the principles to be used as a transition guide to competition
- A Staff Position Paper on Case 94-E-0952, which describes the market model recommended by the commission, the goals and interests to be served by transition to the model and the implementation steps necessary
- A Notice of Schedule for Filing Exceptions on Case 94-E-0952, which establishes procedures and schedules for those entities who wish to contest or modify portions or all of the commission's recommendations

These documents represent significant progress in the restructuring process. The Staff Position Paper, in general, summarizes the commission's desires and recommendations relative to the issue. Companies and organizations on both sides of the issue may respond to, object to and offer alternatives to the recommendations in accordance with the schedule and procedures established in the Notice of Schedule. This procedure is typically the precursor to the commission issuing a final ruling to which all parties will be bound.

The restructuring model for the State of New York is somewhat more progressive than that of the State of Texas, in that the New York model addresses both retail and wholesale competition. However, the New York commission recognizes the importance of establishing a viable wholesale market before proceeding with full-scale retail competition. The restructuring model for the State of New York is summarized below.

**Generation**

Pricing mechanisms would be composed of both an active spot market and the opportunity for energy service companies, marketers, brokers, and customers to contract for electricity directly with generating companies. Customers may enter into contracts with individual generators for physical delivery of electricity or may choose financial contracts for differences. Initially, a wholesale-only competitive market would be formed. Independent system operator (ISO) rules and market mechanisms, however, should be established so as to quickly and efficiently accommodate retail access, including physical bilateral retail contracts, once such access is allowed in the various utility service territories. Once retail access exists, generation would be required to be both physically and functionally unbundled from other services.
Nuclear plants may require special consideration because of their relatively high capital costs, the need to baseload these units, and the uncertainty of future cost obligations such as decommissioning and spent fuel disposal.

**Transmission - Independent System Operator**

The ISO would have complete responsibility for providing reliable service and would probably be regulated by FERC with input from the state. FERC would determine proper enforcement rules, including financial penalties, to ensure the continued provision of reliable service at the transmission level. Further, the ISO can be expected to remain bound by reliability criteria established by the NERC and NPCC.

The ISO must be truly independent of players in the generation market in order to avoid the risk that those players gain undue market power. Mechanisms must be in place to ensure this independence, and the ISO must be explicitly prohibited from owning any generation assets that are used in a functioning competitive market (however, it may be acceptable for the ISO or a distribution company to own generation used primarily for reliability purposes). The ISO could be owned and operated in any of the following three ways:

1. As a separate non-profit entity, independent from any utility or power producer
2. As a jointly owned entity, controlled by the distribution companies and energy service companies
3. As a state-owned entity, operated by the New York Power Authority

The ISO would coordinate the supply of electricity and maintain the reliability, security, and stability of the bulk power system. Its major responsibilities would include scheduling power transactions, managing transmission congestion, and providing non-discriminatory access to the grid. It also would provide control area services (including voltage support, spinning reserve, and load balancing) and could assess penalties against generators for failure to meet specified criteria. The ISO would not participate directly in the purchase or sale of power in the competitive market, except as needed for reliability purposes. It would determine the day-ahead schedule, which all suppliers must comply with, and would ensure that system information was available fairly and rapidly to all participants.

The ISO would charge those participants who use its services, either on a fixed or variable basis (or both) that properly reflects its cost of doing business.

It is likely that the ISO would charge additional fees to those participants with bilateral contracts to compensate for the additional cost of providing balancing services or other services provided by the ISO as needed to maintain system integrity. In any bilateral contract, a generator would be prohibited from anything that violates the ISO’s operating procedures, and the ISO will be able to override any contract provision that could potentially impair system integrity or increase system risk.

Transmission tariffs, setting rates, and terms and conditions would be under FERC jurisdiction. The regulated transmission and distribution companies would continue to be
responsible for owning, operating, and maintaining the transmission and distribution systems. A non-bypassable wire charge would be assessed to all customers to pay for certain charges, including those strandable generation costs and other costs deemed necessary for public policy reasons.

**Distribution**

Customer services (including meter reading, billing and payment collection, and responses to consumer inquiries) would initially continue to be regulated and provided by transmission and distribution companies.

Energy efficiency services and the packaging of other innovative services may continue to be provided by ESCos, including marketers, brokers, and aggregators. When full retail access becomes available, deregulated ESCos could become the primary interface between customers and the distribution company. Customers would then contract with ESCos for essential services, including power purchased on their behalf in the competitive generation market.

### 2.6 INDUSTRY RESTRUCTURING MODEL FOR THE STATE OF CALIFORNIA

The California Public Utilities Commission (CPUC) has progressed perhaps the furthest of any state in providing direction to the industry regarding restructuring within a state. CPUC has issued a final ruling that establishes specific steps and schedules for the transition to a competitive market. The California model includes both wholesale and retail competition, and incorporates concepts that are under discussion in many other states.

**Overview**

By April 1, 1998, a representative number of customers from all customer groups (residential, industrial, commercial, and agricultural) will be able, singularly or in aggregate, to participate in the first phase of direct access, which will last for 1 year. Consumers will be able to negotiate and contract directly with generation providers (direct access) or they may seek a marketer or broker to negotiate power purchase on their behalf. Consumers may also choose to continue to have their utility purchase and deliver electricity to them just as it does now. After the first year, there will be no limit on participation in direct access service except for technical constraints (i.e., transmission overloading, voltage support, etc.). The commission will regulate the rates, terms, and conditions of utility services not subject to competition using performance-based regulation (PBR) instead of cost-of-service regulation. Under PBR, utilities will have greater flexibility in running their operations and their shareholders will profit from efficiencies or pay for poor performance. PBR should improve service quality and encourage innovation.
New Electric Industry Market Structure

ISO will enable competing power producers to have equal opportunity to deliver their supplies. Utilities must transfer operational control of their transmission facilities to the ISO. The ISO will control and operate the state's transmission system, schedule delivery of electric power supplies to ensure sufficient power to meet demand, and make sure all standards for transmission service are satisfied. It will also communicate any problems in delivering power supply.

An independent power exchange (exchange) will operate as a voluntary wholesale power pool allowing power producers to compete on common ground using transparent rules for bidding into the exchange. The exchange will match the bids with bids submitted by utilities, power marketers, brokers, or others on behalf of end-use customers, ranking the least-cost bids according to yet-to-be-delivered protocols, and then submitting its delivery schedule to the ISO for integration with other schedules submitted under different arrangements.

Purchasing from and selling to the exchange is not voluntary for California utilities under CPUC jurisdiction except for divested generation plants. The utilities must bid all their generation output into the exchange, and purchase their energy from the exchange. The commission anticipates that the state's municipal utilities, independent power producers, and out-of-state producers will see economic benefits of selling into the exchange. In turn, those municipal utilities, retail aggregators, and individual purchasers will see benefits in purchasing from the exchange.

The ISO and power exchange would be separate, independent entities under FERC jurisdiction. Utilities will continue to have direct control and operation of their distribution system, power production, and procurement of generation services for their customers. They would also continue to own, but not operate, their transmission facilities.

The commission concluded that market power problems will require existing investor-owned utilities to divest themselves of a substantial portion of their generating assets, and provides an incentive to encourage voluntary utility divestiture of 50 percent of their fossil fuel generating assets. Existing utility generation assets would undergo a commission-reviewed market valuation process within the first 5 years of implementation of the new market structure.

Utilities will be obligated to provide distribution service to all customers, and least-cost generation service to those customers who do not choose or are not eligible for direct access. Rates for customers taking both generation and distribution utility service will be capped at levels established by CPUC-approved January 1, 1996, revenue requirements. However, a portion of the rate will be recoverable through a non-bypassable charge called the competition transition charge. All customers who take retail service as of the date of this decision or who begin utility service after this decision will pay this charge whether they choose to receive bundled utility service (generation and distribution) or purchase electricity from a provider other than the utility.
The initial phase of retail competition, or “direct access,” shall be implemented simultaneously with the establishment of a power exchange and ISO. Table 2.1 is an anticipated schedule of the total MW available for participation in direct access. At a minimum, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) will phase in direct access according to the following schedule:

<table>
<thead>
<tr>
<th>Year</th>
<th>PG&amp;E/SCE</th>
<th>SDG&amp;E</th>
</tr>
</thead>
<tbody>
<tr>
<td>1998</td>
<td>800</td>
<td>200</td>
</tr>
<tr>
<td>1999</td>
<td>1,400</td>
<td>350</td>
</tr>
<tr>
<td>2000</td>
<td>2,200</td>
<td>550</td>
</tr>
<tr>
<td>2001</td>
<td>4,000</td>
<td>1,000</td>
</tr>
<tr>
<td>2002</td>
<td>8,000</td>
<td>2,000</td>
</tr>
<tr>
<td>2003</td>
<td>All remaining load</td>
<td>All remaining load</td>
</tr>
</tbody>
</table>

**Table 2.1 TOTAL MW AVAILABLE FOR PARTICIPATION IN DIRECT ACCESS**

**The Opportunity for Customer Choice**

1. During the transitional phase of direct access, a representative group of retail customers can choose to arrange the purchase of electric generation services at negotiated prices directly from non-utility generation providers, including marketers, brokers, and supply aggregators. This transitional phase will lead to the availability of direct access to all retail customers.

2. Increased availability of real-time and time-of-use rate options to customers who have the appropriate metering equipment. Both of these choices provide consumers with the opportunity to make informed decisions about the services they wish to receive.

3. A third choice is the opportunity for customers to arrange contracts for differences, which allow the parties to allocate the risks associated with market uncertainty.

4. Aggregation may include the loads of multiple customers or a customer may aggregate loads at several sites with appropriate identification of location consistent with the requirements of the dispatch. Aggregation may be limited to a particular customer class or may include customers from different classes.

5. Third-party intermediaries, such as power marketers and brokers, will be able to purchase unbundled electricity from individual suppliers and bundle that with various energy services to meet customers’ specific needs or unique operational requirements.

6. Supplies arranged by direct access contracts would be scheduled directly with the ISO. Suppliers who have arranged direct access contracts will be required to comply with the operating protocols of the ISO, but they will not be required to disclose any information about their costs of generation or the negotiated price for the sale. They will be allowed to submit increment or decrement bids for use in any redispatch determined by the ISO.

7. Suppliers or third party intermediaries and direct access customers will be responsible for the costs of ancillary services and other charges as communicated by the ISO.
8. Barring technical concerns, it is anticipated that a majority, if not all, of California electricity consumers will have the opportunity to directly purchase generation services no later than 5 years from implementation of the initial phase of direct access. Each customer class will be represented in each year and phase.

**Function and Responsibilities of ISO**

The ISO will have primary responsibility for the determination of the final operation and dispatch of the system to preserve reliability and achieve the lowest total cost for all uses of the transmission system. The ISO will have control over the operation of the transmission facilities. The participating investor and publicly owned utilities will continue to own those facilities and be responsible for their maintenance.

The ISO will have no financial interest in the power exchange or in any source of generation or load. This restriction will ensure that the ISO will have no bias in favor of or against generators who participate in the pool, or against suppliers with direct access contracts. The ISO will own no generation, transmission, or distribution facilities and will have no affiliation with any companies that own those facilities.

The ISO will maintain frequency control and comply with all standards of the NERC and the Western Systems Coordinating Council (WSCC). The ISO will provide open and non-discriminatory services and access to the transmission grid for all users of the transmission system, including purchasers and suppliers in transactions arranged through the power exchange and suppliers contracting directly with customers. All market participants will be subject to the same protocols and prices regarding transmission access and treatment of transmission congestion.

The ISO will procure from suppliers ancillary services needed to support transmission and dispatch. Where possible, this procurement should be from suppliers on a non-discriminatory, competitive, unbundled basis. The ISO will offer ancillary services to users either as competitive, unbundled activities for those services that can be metered and measured separately for individual users, or as cost-effective joint products for those inherently inseparable network services.

The ISO will coordinate day-ahead scheduling and balancing for all uses of the transmission grid. For both the day-ahead schedules and the hourly balancing transactions, the ISO will accept nominations from the market participants. The nominations from the power exchange will include the tentative dispatch, the locations of the generation and loads, and the associated bids for generation and loads. The nominations from the bilateral participants must include the amount and timing of power deliveries, along with the source and destination for power transmission. In addition, the ISO will accept bids from bilateral participants for increments and decrements of nominated inputs or outputs that would be available from the bilateral transaction as needed to redispacht the system.

The ISO will coordinate the scheduled nominations from the power exchange and the bilateral transactions to determine any redispatch that would be necessary to meet the twin
objectives of assuring operational reliability and achieving least-cost use of the system. Along with this redispatch, the ISO will determine the locational marginal costs incorporating the cost of generation, losses, and congestion that will define the market clearing prices for the power exchange and the price of transmission use for the bilateral transactions. The marginal costs of redispatching to provide an increment of load at each location will define the purchase and sale prices through the power exchange. The differences in the locational marginal costs between source and destination will define the price of transmission applied to the bilateral transactions. The ISO will notify the power exchange and the bilateral participants of the final redispatched and associated prices that will be charged for transactions.

The ISO will coordinate the implementation of the final schedules and adjust as necessary to ensure the reliability and least cost for the actual hourly dispatch. Again, the ISO will accept supply and demand bids from the power exchange and increment or decrement bids from the bilateral participants for their transactions. Over the course of the day, the ISO will order any redispatch adjustments as necessary to balance the system. Associated with this actual dispatch, the ISO will again compute locational marginal costs. These actual dispatch locational marginal costs will define the locational prices to apply to any imbalances relative to the scheduled generation and loads. With this pricing, there will be no need for any other limitations or penalties for any participants for load or generation in the actual dispatch.

The revenue collected for transmission use from direct access participants and the power exchange will include payments of congestion costs arising from the redispatch of the system in the face of transmission constraints. The ISO will administer a system of transmission congestion contracts to redistribute the congestion payments and provide a set of tradable instruments to support long-term commercial transactions across locations in the grid.

The ISO will provide a system for the open communication of information for the scheduling market. Individual bids and nominations will be confidential, but all other reasonable information on market clearing prices, power flows, and the state of the transmission system will be made available to all participants in an appropriate, timely, and non-discriminatory manner. The ISO will also provide information necessary for long-term studies by market participants to support commercial contracting and investment decisions.

**Functions and Responsibilities of the Power Exchange**

The principles and characteristics of the power exchange are similar to those adopted for the ISO. The power exchange's form and function are summarized below. The power exchange:

1. Will have no financial interest in any source of generation to ensure that it will have no bias in favor of or against specific generators.
2. Will be prohibited from owning generation, transmission or distribution facilities and will have no affiliation with any companies that own those facilities.
3. Will have no financial interest in or relation to the ISO.
4. Will be allowed to recover those costs associated with implementing a bid process for
generation and establishing a one-hour or half-hour market-clearing price.
5. Will oversee the ranking of least-cost generation facilities according to established
protocols.
6. Will establish non-discriminatory and transparent bidding protocols, including provisions
for unit commitment in the day-ahead schedule and the procedures for payment of any
minimum load or start-up costs not covered through the market clearing prices for
energy.
7. Should establish the appropriate computer links necessary for information exchange.

The power exchange will conduct an auction in which generators will submit bids under
transparent bidding procedures. These bids should state the minimum price for which
suppliers are willing to dispatch a specified amount of power the next day in hourly or half-
hourly time increments. The power exchange will then match the generators' bids with
demand bids submitted by utilities, brokers, marketers or any authorized entity on behalf of
end-use customers. As specified by the ISO, the power exchange will determine and submit
a contingent dispatch for generators. Using its established scheduling protocols, the ISO will
then integrate the power exchange's preferred schedule with the schedule nominations
arranged under direct access contracts and communicate system information affecting the
submitted dispatch schedules. The power exchange will, in turn, notify generators of
accepted or revised dispatch schedules.

The market-clearing locational prices will be obtained from the ISO (by a certain time) as part
of the integration and coordination of the alternative nominations and bids. Every winning
generation bidder will be paid the market-clearing price at its location, which is consistent with
both the bid and the supply and demand equilibrium. The power exchange will average the
locational clearing prices such that end-use customers served by the exchange will see one
clearing price. The net payments to the power exchange will be disbursed through the ISO to
pay for transmission losses or as congestion payments under transmission congestion
contracts.

On the day it begins to function, the power exchange will be the market institution in which all
generators are able to compete on the basis of short-run incremental electricity costs in an
open setting and on what is literally a level playing field. Equally important, all buyers of
electric energy will derive basic consumer protection in their ability to freely monitor the
results of that competition. The transparent price will also be revealed in "real time" so that
clear market signals can be sent to buyers and end users as to the significant difference in
the cost to California's economy of meeting their energy needs at any point during the day.
The value of this pricing revelation will be significant after the first week of exchange
operations, but will grow with the passage of time and the acquisition of experience. Once
this price is revealed and tracked, market participants will be able to make essential
decisions.
Customers who desire stability or certainty over time will find the revealed exchange price signals vital to electing among an enhanced set of options. A customer who, for any reason, desires a price structure that differs from day to day or hour to hour, will be afforded the opportunity to purchase a financial hedge, or “contract for differences,” from any counterpart party who may or may not own or have contractual rights to any specific generation. Even more dramatically, such a customer may elect a direct access contract. But irrespective of the alternatives, the only way in which choice can be effectively made is for the potential buyers and sellers to compare the costs, terms, and conditions to something readily known and reliably revealed. Until they have gained sufficient experience or devised alternative means to gain discovery over comparable information, a readily available and reliable reference point is the alternative to wholesale transactions revealed through the exchange.
NOTE: The author is no longer employed with Parsons Brinckerhoff. This monograph is for reference/research purposes only and not for distribution.
3.0 COMPETITIVE MODELS AND MARKET PLAYERS
Most state PUCs have begun at least a preliminary investigation of the avenues available for deregulation. Different industry models are currently under consideration by various state regulatory agencies. Each represents a stage in the evolution from the current regulatory model to a completely competitive market. Discussed below are different models for the restructured industry that could evolve or be adopted by different states in the U.S. over the next 5 to 10 years. The objective of this chapter is not necessarily to identify likely modes but rather models that incorporate most of the key features of the structure alternatives that are under consideration or have been implemented elsewhere in the United States. From the analysis of the models and review of the utility industry structure in various regions, there appears to be a more likely evolutionary path for the industry in the United States—a path that might include elements from several of each of the models or entirely new elements. Clearly, no one can know precisely how the industry will evolve. Alternatives include:

1. Current industry structure with enhanced regulation
2. Competition at the wholesale level
3. Competition at the retail level

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3.1 CURRENT INDUSTRY STRUCTURE WITH ENHANCED REGULATION – THE REGULATORY MODEL

The regulatory model represents a modest evolution of the current system wherein utilities, regulators, and others respond to enhanced pressures in the context of the current industry structure and regulatory institutions. With this model, it is not necessary to physically separate generation, transmission, distribution, and other energy services within a company. A company may instead functionally unbundle its services and offer available generation at a separate price on the open market. It may sell power to its distribution arm to meet its own load requirements or buy from other utilities if it can purchase power more cheaply than it can produce it. This model preserves, in principle at least, the economies of scale typically associated with large, vertically integrated power companies. Additionally, companies are not burdened with a large “stranded investment” to be passed on to consumers.

Utilities will still have the obligation to both connect and serve customers in their designated service territory. Accordingly, generation planning will continue to be based on demand and consumption projections, with each utility responsible for long-term forecasting within its territory. Existing owners of generation facilities will continue to operate and maintain their facilities. However, competition among generators is expected to force inefficient units off-line and ultimately out of a utility’s rate base. Lower utility rate bases should result in lower consumer rates.

Industry structure in this model is shown in Figure 3.1. Generation and distribution will be functionally unbundled. A regional transmission group (RTG) will be formed and operated by
the interconnected companies to manage access to the transmission system and provide 
information about interchange capacity. As with generation, the existing owners will retain 
ownership and maintenance responsibility for individual transmission lines. However, the 
dispatch of power over those lines will no longer be controlled by the owning company. 
Long-term planning for transmission line expansions may also be coordinated among 
interconnected companies, with oversight by the RTG.

3.2  COMPETITION AT THE WHOLESALE LEVEL – THE WHOLESALE 
MODEL

In the wholesale competition model, generation would become fully competitive and 
unregulated with multiple independent generating companies competing to sell power to 
distribution companies. The ISO/RTG would be responsible for reliability and security of the 
bulk power market, and would coordinate auxiliary services, control generation and 
transmission, and dispatch power through a regional pool. The market structure under the 
wholesale model is shown in Figure 3.2. As shown in this figure, distribution companies 
would have a choice of supplier and can purchase energy for their customers from any 
competing generators such as IOUs, independent power producers (IPPs) or others. The 
distribution companies would maintain a monopoly over energy sales to the final customers.

Generators will continue to provide necessary maintenance of their facilities. However, close 
coordination between ISO and current contractual requirements will be essential. Under this 
model, generators with the least marginal cost would negotiate bilateral contracts with 
distribution companies. However, generators with higher operating and maintenance costs 
may not be able to negotiate long-term contracts and may not be adequately maintained, 
leading to increased generator outage and lower system reliability during peak demand 
periods.

For must-run generating plants, some type of regulation may be needed. Must-run 
generating plants are located in an area where competition does not currently exist and due
Transmission pricing that reflects the marginal costs of transmission will be based on users paying a pro-rated share of the cost of the transmission system, based on their individual usage. The transmission provider recovers all of its fixed and variable costs from those using the transmission facilities. For firm point-to-point service, a per-unit rate based on the provider's transmission revenue requirement and the total transmission usage would be developed. This approach is called a "postage-stamp" method because the rate is uniform and is based on the amount of service required. It is not distance-sensitive and is independent from the price of generation, energy service, and distribution services. The postage-stamp method is anticipated to represent 10 to 15 percent of the total unbundled price of electricity.

Distance-sensitive methods, like the megawatt-mile method, consider actual power flows. In addition to the charge for demand, distance-sensitive pricing methods assess a "surcharge" for the impact of the transaction on the transmission system. Like the postage stamp method, they are independent of energy pricing.

Any wholesale power purchaser (municipalities, distribution companies, etc.) would have two fundamental contractual options: purchase power from the regional pool or contract directly with a generating company. In the competitive environment, load forecasting becomes a critical issue. Distribution companies would be regulated by local public service commissions using performance-based regulation.

In summary, essential elements of the wholesale model are:

• Generation would be separated from the transmission and distribution business, either functionally with separate subsidiaries, or by being fully divested into independent companies.
• Generation would become a fully competitive, unregulated wholesale market with many independent generating companies competing to sell electricity to investor-owned, regulated distribution utilities, and municipal distribution entities.
• A regulated ISO would be responsible for reliability and security of the bulk power system, would coordinate ancillary services, would control generation output and transmission services, and set rules for market participants. The ISO would also determine installed and operating reserve requirements.
• Open access would be allowed to the transmission system for purchase by distribution entities from generation companies; transactions on the transmission system would be regulated by the FERC.
• An RTG could probably coordinate transmission planning and set rules for transmission access and use of the transmission system. Alternatively, the ISO may perform this function.
• Regulated utilities would provide customers with transmission, distribution, and energy related services. Energy service companies would continue to provide services as they do today.

FIGURE 3.2  MARKET STRUCTURE UNDER WHOLESALE COMPETITION

Generation planning would no longer be based solely on the load forecasts of individual companies. Instead, the market would guide generators. The ISO would provide systemwide load forecasts based on forecasts supplied by wholesale power purchasers. Suppliers would then evaluate the construction of new facilities based on market demand, transmission congestion, etc. In the wholesale model, each electric utility that owns transmission facilities will be required to provide comparable wholesale transmission services to other electric utilities, power manufacturers, exempt wholesale generators, and qualifying facilities. Additionally, a utility will be required to provide these services under the same terms and conditions that it provides transmission services to itself.

It is likely that existing transmission owners, aggregators and even customers, operating privately or in partnership with the ISO, will perform transmission planning. In a competitive environment, some parties believe an RTG consisting of transmission owner(s), transmission users, generators, and regulatory agencies would determine transmission cost allocations and could plan transmissions for new generation and interconnections.
Regulated DISCos would obtain supply from the wholesale market and bundle it with other retail services for sale to end users. DISCos would have the obligation to connect and provide retail functions to customers.

DISCos would make load forecasts and forward them to the ISO.

Two pricing mechanisms are possible: POOLCo (a spot market or power exchange for electricity into which buyers and sellers of electricity bid to establish a spot price for electricity (on an hourly or half-hourly basis)) and bilateral (a forward market in which the parties can contract bilaterally with each other).

The wholesale model results in certain costs that cannot be recovered in a competitive generation market. Some or all of those costs could be recoverable as a non-bypassable wire charge to all ratepayers.

By 1992, 50 percent of the eligible customers were buying electricity directly from a generating company, bypassing the distribution company entirely, at a 20 percent discount to prior rate schedules. But, more importantly, customers who had not switched from their distribution company were paying lower electricity prices and were experiencing better service from their distribution company. As shown in Figure 3.4, by 1994, customer peak load requirement was reduced to 100 kW and, by 1998, this limit will be eliminated completely.

The industry structure proposed in the wholesale competition model is similar to the system in England and Wales as it operated immediately after the privatization in 1970. Figure 3.3 shows industry structure before privatization and Figure 3.4 represents industry structure after privatization. The nationalized electricity supply industry in England and Wales was replaced by 16 separate entities:

Generation sector was divided among three generating companies (National Power, PowerGen & Nuclear Electricity)

Bulk power transmission responsibility was assigned to National Grid Company (NGC)

Transmission was divided among 12 Regional Electricity Companies (RECs) for supply. They are also first-tier suppliers.

At the time of vesting, customers with a peak load exceeding 1 MW (about 30 percent of the total load) were permitted to buy either from a generating company or a distribution company at the current market price.

Regulatory responsibilities were assigned to the Office of Electricity Regulation (OFFER), headed by the Director General of Electricity Supply (DGES).

The buying and selling of electricity in England and Wales is conducted through an energy pool (pool), an independent entity administered by its members (i.e., generators and suppliers). Generators with a power station greater than 50 MW are required to sell their electricity through the pool. Currently, NGC is operating the pool on behalf of the pool members, however, NGC is not a pool member.

Regulated DISCos would obtain supply from the wholesale market and bundle it with other retail services for sale to end users. DISCos would have the obligation to connect and provide retail functions to customers.

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FIGURE 3.3  INDUSTRY STRUCTURE BEFORE PRIVATIZATION

FIGURE 3.4  INDUSTRY STRUCTURE AFTER PRIVATIZATION

3.3 COMPETITION AT THE RETAIL LEVEL – THE RETAIL MODEL

In the retail model, all customers have access to competing generators either directly or through their choice of retailer. The retail model is illustrated in Figure 3.5. Customers may buy electricity through short-term or long-term bilateral contracts or on the spot market. Retail competition requires complete separation of generation, transmission and distribution functions. However, delivery services would continue to be provided at regulated prices by regulated transmission and distribution utilities, and generation companies and energy/customer services would be deregulated.

With retail competition, there should be free entry and exit to the generation markets. This means there would be no regulation of generation planning or new generation requirements by utility companies. For existing generation plants there would be no requirement to maintain capacity in production when they have passed their economic lives.
In the retail model, the responsibility for forecasting required purchases will be borne by the ESCos and aggregators that buy power from the market for resale to end customers. Customers themselves may need to make their own forecasts. Short-term forecasting may vary substantially depending on whether a POOLCo or bilateral model is adopted. With the bilateral model, day-ahead demand forecasts must be made each day by retail customers or the ESCos and marketers that purchase on their behalf. With the POOLCo model, individual customers need not provide any information to the ISO about their expected purchases; they can simply buy at the POOLCo’s spot price. Similarly, ESCos need not provide information about their expected purchases, at least with regard to their spot purchases. In a flexible POOLCo model, substantial bilateral transactions may take place alongside spot purchases. The quantities associated with the bilateral transactions (sometimes called “nominations”) would be reported to the ISO.

In a retail market, it is likely that more customers will be involved in the resource planning process (for example, in direct contracting with developers to supply load). The financial market will play an increased role in the planning process. All market participants will have a strong interest in ensuring generation adequacy. Consumers will not want outages, and generators and merchants will view outages as lost sales opportunities.

In wholesale or retail models, there are potentially significant differences between the POOLCo and bilateral models in terms of the pricing provisions and how they will affect generation adequacy. In a bilateral model, part of a contract that a buyer of generation, energy, and capacity would enter into would reflect the customer's evaluation of reliability. If a customer wanted more reliability, then it would invest in increased reserves. If the customer wanted less reliability, then it would invest in fewer reserves. So, to some extent, the bilateral approach incorporates the determination of reserves and the pricing of reserves into the price formation process.

A strict POOLCo model pricing process has a more short-run orientation than the bilateral approach. Consequently, the POOLCo may not provide as clear a price signal to generators, customers, and energy service companies as to the long-term value of reliability. Reliance solely on current spot market prices may provide a poor link to the development of a forward market in generation capacity and therefore the maintenance of adequate reserve levels. Failure to penalize inadequate reserves provides an incentive for parties to lean on the interconnected system.

In summary, the essential elements of the retail model include:

- Generation would become deregulated and separated from transmission and distribution, either functionally with separate subsidiaries, or by being fully divested into independent companies.
- Generation and transmission would be coordinated by an ISO to ensure reliability. Reserve requirements would be determined either by the market or rules of the ISO.
- An RTG could coordinate such activities as transmission planning, maintenance, and dispute resolution. Alternatively, the ISO may perform this function.
that pressures to reduce rates in response to competitive uncertainty could result in some actions or lack of actions that compromise reliability. Individual utility reserve margins will be reduced, but the growing wholesale spot market should mitigate this concern. Because many utilities are still vertically integrated, there is some concern about cost cutting in transmission and distribution being used to subsidize unregulated wholesale generation. There also may be some concern that divestiture of transmission assets could be forced in the future, perhaps serving as a disincentive to maintenance investment. However, the unbundling of retail rates (charging separately for these services) should mitigate cost pressures on transmission and distribution. Moreover, utilities recognize that reliability is a service characteristic valued by customers.

The power system has historically operated at a high level of efficiency. The regulatory model, which adds a competitive pressure, may increase that efficiency although not to the degree of the models with greater generation competition. Both the wholesale and retail models should ultimately yield high levels of efficiency in the utilization of generation resources, assuming there actually is sufficient competition. If there is insufficient competition, an entity with higher market power can take advantage of the market conditions. In the pool model, the integrated operation of the combined generation and transmission systems by the ISO should be very efficient. The pool and ISOs provide a means of establishing congestion pricing on the transmission system, providing efficient signals for generation and transmission expansion.

The pool model incorporates real-time pricing. More efficient system utilization can be realized as consumers act in response to real-time price signals. Time-differentiated pricing is also expected in the other models, although perhaps not to as great an extent. Unbundling of products and pricing, common to all models, should improve efficiency to the extent utilized.

The wholesale model will provide more consumer choice than has been historically available. Greater market segmentation and unbundling of products will allow consumers to better match needs. The retail model provides greater consumer choice in the sense that consumers can choose to respond to real-time price signals. As discussed in Chapter 6, consumers may also enter into contracts for differences (CFD) to match their risk or volatility preferences or even to support specific kinds of resources.

In none of these models do utilities or other suppliers have an incentive or a regulatory requirement to take into account environmental costs that are not incorporated into existing regulation. Unless all are required to incorporate those costs, competitive pressures will prevent them from doing so on an individual basis.

In all of the models, some conservation, renewable resource development, and research, development and demonstration (RD&D) will be accomplished. In none of the models, however, is it possible to support these activities through utility programs to the degree that may be in the region's best interest. In the wholesale and retail models, the uncertainty about the security of the customer base means that the rate impacts of conservation, above market price renewable, and RD&D are perceived as disincentives. The lack of financial flexibility

### 3.4 ANALYSIS OF ALTERNATIVE INDUSTRY MODELS

A side-by-side comparison of the key points of the analysis is presented in Table 3.1. The analysis is summarized in the following paragraphs.

Each model will probably result in a power system that is adequate or reliable over the long-term. In all of them, there will be greater risk in the development of new generating resources, resulting in higher financing costs for generation. However, there is some concern

- Open access would be allowed to the transmission system, which would be regulated by FERC.
- Purchase and sale of spot power (and resulting economic dispatch of generators) would be handled by a combination of competing marketers and a centralized economic dispatch entity that would work in coordination with the ISO.
- The ISO would use short-run bid prices to coordinate the hour-to-hour operation of the system, and would coordinate ancillary services to ensure reliable operation.
- The provision of electricity would be unbundled into four components: generation, transmission, distribution, and energy/customer services.
- Customers would have a choice among suppliers of electricity according to long-term contracts or on the spot market.
- Bilateral contracts between generating companies, marketers, ESCos, and customers would be allowed. The quantities, locations, and timing (but not the prices) in the bilateral contracts would be shared with the ISO.
- A regulated DISCo would operate and maintain the distribution system in each service territory. The DISCo would have the obligation to connect customers.
- Delivery services would be provided at regulated prices by transmission and distribution utilities.
- Unregulated ESCos would be the primary interface with customers and would act as intermediaries between customers and the generators providing the power. Some retail customers could serve as their own ESCo. Load forecasting responsibility would be borne by the ESCos and aggregators.
- ESCos would contract with generating companies, transmission companies, and distribution companies to purchase power and delivery services, which would be packaged and resold to end users.
- Customers could choose to have direct access to the spot market to make spot purchases that could be combined with strictly financial instruments (contracts for differences).
The regulatory, and to some extent the wholesale, model involves only a modest evolution.

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Table 3.1 COMPARISON OF MODEL CHARACTERISTICS

<table>
<thead>
<tr>
<th>Generation Planning</th>
<th>Enhanced Regulatory Model</th>
<th>Wholesale Wheeling Model</th>
<th>Retail Wheeling Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant location</td>
<td>Responsibility will be with existing vertically integrated power companies.</td>
<td>GENCos, IPPs, and QFs will provide necessary generation based on wholesale power requirements.</td>
<td>GENCos will be completely marketed driven. Independent analysis of optimum plant size, location, timing and fuel source will be performed by consultants.</td>
</tr>
<tr>
<td>Environment Impact</td>
<td>Size, location, timing and fuel source will be based on long range planning studies similar to those currently performed.</td>
<td>Location, size, timing and fuel source will be driven by market conditions.</td>
<td></td>
</tr>
<tr>
<td>Technology</td>
<td></td>
<td>GENCos, IPPs, and QFs may market these ancillary services to the ISO.</td>
<td></td>
</tr>
<tr>
<td>Fuel type</td>
<td></td>
<td>GENCos, IPPs, and QFs may market these ancillary services to the ISO.</td>
<td></td>
</tr>
<tr>
<td>Ancillary Service</td>
<td>Responsibility will be with existing vertically integrated power companies.</td>
<td>ISO will perform short-term load forecasting. Long-term forecasting may be performed by GENCos, IPPs, QFs or independent consultants.</td>
<td>ISO will perform short-term load forecasting. Long-term forecasting may be performed by GENCos, IPPs, QFs or independent consultants.</td>
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<tr>
<td></td>
<td></td>
<td>ISO will perform short-term load forecasting. Long-term forecasting may be performed by GENCos, IPPs, QFs or independent consultants.</td>
<td>Refurbishment/demolition efforts will be market driven. Demand will be managed by wholesale market through scheduling and using existing plants.</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>Responsibility will be with existing vertically integrated power companies.</td>
<td>ISO will perform short-term load forecasting. Long-term forecasting may be performed by GENCos, IPPs, QFs or independent consultants.</td>
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<tr>
<td></td>
<td></td>
<td>ISO will perform short-term load forecasting. Long-term forecasting may be performed by GENCos, IPPs, QFs or independent consultants.</td>
<td>Deregulated electric supply services and POGOs will also be available to others.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ISO will perform short-term load forecasting. Long-term forecasting may be performed by GENCos, IPPs, QFs or independent consultants.</td>
<td>Retail wheeling agreements with consumer, businesses, aggregators and ESCOs available to all suppliers.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ISO will perform short-term load forecasting. Long-term forecasting may be performed by GENCos, IPPs, QFs or independent consultants.</td>
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<td></td>
<td>ISO will perform short-term load forecasting. Long-term forecasting may be performed by GENCos, IPPs, QFs or independent consultants.</td>
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<tr>
<td>Energy Management System (EIMS)/Supervisory Control and Data Acquisition (SCADA)</td>
<td>A part of the integrated control system within existing vertically integrated companies.</td>
<td>ISO will control system dispatch with direct communication links to individual plant controls.</td>
<td>ISO will control system dispatch with direct communication links to individual plant controls.</td>
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<td>ISO will control system dispatch with direct communication links to individual plant controls.</td>
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<tr>
<td>Asset Evaluation</td>
<td>Not required.</td>
<td>With functionally and physically separate generation, transmission and distribution companies, independent evaluation of existing assets is necessary.</td>
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<tr>
<td>Operations &amp;</td>
<td>Responsibility will be with existing vertically integrated power companies.</td>
<td>GENCos, IPPs, and QFs will either perform these themselves or contract it out.</td>
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<td>Maintenance</td>
<td></td>
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<td>Transmission Planning</td>
<td>Enhanced Regulatory Model</td>
<td>Wholesale Wheeling Model</td>
<td>Retail Wheeling Model</td>
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<tr>
<td>Responsibility will be with existing vertically integrated power companies.</td>
<td>Responsibility of ISO (or other independent entity). Possible review by industry, government or consumer panels to ensure reliability is maintained.</td>
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<tr>
<th>Ancillary Service</th>
<th>Enhanced Regulatory Model</th>
<th>Wholesale Wheeling Model</th>
<th>Retail Wheeling Model</th>
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<tbody>
<tr>
<td>Responsibility will be with existing vertically integrated power companies.</td>
<td>GENCo, IPPs, and QFs may market these ancillary services to the ISO.</td>
<td>GENCo, IPPs, QFs, etc. may market these ancillary services to the ISO.</td>
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<tr>
<th>Market Analysis</th>
<th>Enhanced Regulatory Model</th>
<th>Wholesale Wheeling Model</th>
<th>Retail Wheeling Model</th>
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<tbody>
<tr>
<td>Power Agreements</td>
<td>Enhanced Regulatory Model</td>
<td>Wholesale Wheeling Model</td>
<td>Retail Wheeling Model</td>
</tr>
<tr>
<td>- Bilateral contracts</td>
<td>-POOLCo contracts</td>
<td>Existing engineering and marketing staff of vertically integrated companies perform all analysis.</td>
<td>GENCo, IPPs, and QFs may perform these functions or may rely on the POOLCo or consultants to perform them.</td>
</tr>
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<thead>
<tr>
<th>Asset Evaluation</th>
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<td>Not required.</td>
<td>With functionality and physically separate generation, transmission and distribution companies, independent evaluation of existing assets is necessary.</td>
<td>Detailed technical and transaction based economic analysis is necessary to compete effectively. Independent consultants may perform these tasks.</td>
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<tbody>
<tr>
<td>Load Forecasting</td>
<td>Responsibility will be with existing vertically integrated power companies.</td>
<td>Responsibility will be with existing distribution companies.</td>
<td>Distribution companies, ESCos, marketers, ISO and market participants will share the responsibility.</td>
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<th>Meter Reading</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Not required.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Operations &amp; Maintenance</th>
<th>Enhanced Regulatory Model</th>
<th>Wholesale Wheeling Model</th>
<th>Retail Wheeling Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Responsibility will be with existing vertically integrated power companies.</td>
<td>Existing distribution companies will be responsible for maintenance and reliable operation of the distribution network.</td>
<td>Existing distribution companies will be responsible for maintenance and reliable operation of the distribution network.</td>
<td>Existing distribution companies will be responsible for maintenance and reliable operation of the distribution network.</td>
</tr>
<tr>
<td>Available Options for End Users</td>
<td>Regulatory Model</td>
<td>Wholesale Wheeling Model</td>
<td>Retail Wheeling Model</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>------------------</td>
<td>--------------------------</td>
<td>----------------------</td>
</tr>
<tr>
<td><strong>Do Nothing</strong></td>
<td>Continue service from local vertically integrated power company.</td>
<td>Continue service from local company. May be in the form of an ESCo or a DISCo.</td>
<td>Continue service from local company. May be in the form of an ESCo or a DISCo.</td>
</tr>
<tr>
<td><strong>Bilateral Contract with Generation Provider</strong></td>
<td>Not available.</td>
<td>Available only to MUNIs, ESCOs, and DISCos.</td>
<td>Available to all customers; may only be practical for larger customers with some level of market power.</td>
</tr>
<tr>
<td><strong>Time of Use Metering</strong></td>
<td>Available from local power company, discounted rates for off-peak usage.</td>
<td>Available from distribution service provider. Discounts will vary with generation contracts obtained by service provider.</td>
<td>Available from distribution service provider or directly from generation provider if a bilateral contract is in place. Discounts will vary with provider.</td>
</tr>
<tr>
<td><strong>Demand Side Management (DSM)</strong></td>
<td>Available from local power company. Incentives for DSM to offset the need for increased generation.</td>
<td>Incentives may be available from the ISO or distribution provider.</td>
<td>Individual incentives available from distribution provider or generation provider. Incentives may be negotiated as part of the power purchase contract.</td>
</tr>
<tr>
<td><strong>Pool Purchase</strong></td>
<td>Existing engineering and marketing staff of vertically integrated companies performs all analyses.</td>
<td>Rely on distribution provider to “shop” for power from pool.</td>
<td>Buy power at the market rate directly from pool. Price elasticity (i.e., high power price—curtailed operations).</td>
</tr>
<tr>
<td><strong>Aggregators</strong></td>
<td>Not available.</td>
<td>Operating at the MUNI/DISCO level only.</td>
<td>Residential and small commercial users can gain market power by purchasing power in a block. Diversity and DSM can enhance market power.</td>
</tr>
<tr>
<td><strong>Ancillary Services</strong></td>
<td>Available from local power company or outside consultants.</td>
<td>New services may be available from DISCos and ESCos.</td>
<td>New services may be available from DISCos and ESCos. Increased consumer power for enhanced reliability and power quality.</td>
</tr>
</tbody>
</table>
SECTION II: ECONOMIC AND TECHNICAL CONSIDERATIONS FOR THE COMPETITIVE MARKETPLACE
4.0 COMPETITIVE GENERATION SECTOR
Generation planning, as performed in the past, was the process whereby long-term load forecasting was correlated with future supply projections. When future supply shortages were noted, new power plants were incorporated into the rate base and reasonable returns on investments were granted by the state PUCs. In a restructured utility environment, there will be no guarantee of return on investment for future power plants. Planning and capacity commitment by market participants will take place as a component of commercial market activities. Additionally, most if not all, market participants will be actively involved in planning for their future operations and investment within a competitive environment. Considering the industry changes outlined in the previous section, this chapter addresses economic and technical considerations for the generation sector. It also outlines different price components of the plant’s production costs and shows how these cost components will affect a unit’s competitive position in a merit-order dispatch system. It also discusses how the bidding process will take place in a pool-based model such as that used in California and the United Kingdom (UK), and how transmission congestion will affect generation dispatch and locational pricing. Through three separate case studies, tools and methodologies are outlined for generation price projections in a competitive marketplace. Case Study 1 demonstrates how power exchange or power pools behave under the generation bidding process; Case Study 2 extends it a step further with transmission constraints; and Case Study 3 provides a marketing and economic analysis for the Southern Electric Reliability Council (SERC) and the Florida area.

4.1 ECONOMIC CONSIDERATIONS

The electric generation sector of the U.S. power industry is currently the largest and most competitive segment of the industry. As of year-end 1995, electric utility generation in the United States totaled 705,328 megawatts (Energy Information Administration/Electric Power Annual 1995, Volume 1). Figure 4.1 shows the 1995 breakdown of the generating capacity at U.S. electric utilities by energy source. Of the total capacity, U.S. utilities and independent power producers generated over 3 trillion kilowatt-hours of electricity.

Figure 4.2 shows representative electricity cost by function. Overall, cost of the electricity varies from state to state. These cost variations occur due to different types of technology used for the power plants, types of fuel, fuel delivery cost, operating efficiency, and many other variables. For 1995, the estimated average cost of electricity for a typical retail customer was 6.96 cents per kilowatt-hour. The estimated revenue from the sale of 3,009 billion kilowatt-hours of electrical energy would be approximately $227 billion. Of this $207 billion, generation represents the largest cost component and comprises approximately 62 percent ($128 billion) of utility revenues.

In general, an electric utility plant contains generating units and auxiliary equipment that are used to convert various types of fuel or energy into electrical energy. Based on the loads, availability of fuel in the vicinity, environmental and energy requirements of the utility, electric utilities use a variety of prime movers for the generators. As shown in Table 4.1, the most
common types of power plants are the steam turbine, gas turbine, internal combustion engine, and hydroelectric. The energy sources most often used with these plants are radioactive material, potential energy in falling water, and fossil fuels—coal, petroleum, and natural gas.

**TABLE 4.1  TYPES OF GENERATING UNITS AND THEIR APPLICATIONS**

<table>
<thead>
<tr>
<th>Type of Power Plants</th>
<th>Application</th>
<th>Typical Range</th>
<th>Fuel Type</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam Turbine</td>
<td>Base Load</td>
<td>1 MW to 1,000 MW</td>
<td>Fossil Fuel</td>
<td>Most of the electricity in the United States is produced by steam turbine generating technologies.</td>
</tr>
<tr>
<td>Nuclear</td>
<td>Base Load</td>
<td>75 MW to 1,000 MW</td>
<td>Uranium</td>
<td>These units have high construction costs and higher O&amp;M cost.</td>
</tr>
<tr>
<td>Gas Turbine</td>
<td>Peaking</td>
<td>20 MW to 500 MW</td>
<td>Gas, Oil</td>
<td>These units have a quick start-up time compared with steam turbine units. Consequently, gas turbine units are suitable for peaking, emergency, and reserve power requirements.</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>Peaking</td>
<td>40 MW to 500 MW</td>
<td>Gas, Oil</td>
<td>This efficiency of the gas turbine is increased when coupled with a steam turbine. Higher efficiency.</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>Peaking, spinning reserve</td>
<td>1 MW to 750 MW</td>
<td>Water</td>
<td>Because of their ability to start quickly and make rapid changes in power output, hydroelectric units are suitable for serving peak loads and providing spinning reserve power, as well as serving base load requirements.</td>
</tr>
</tbody>
</table>

Utilities also have reserve or standby power requirements. During normal operating conditions, if a base-load unit fails (due to unexpected conditions), there will be an imbalance between power demand and generation capabilities. If the on-line units cannot immediately...
provide the extra demand for power (i.e., spinning reserve), or if the load is not reduced proportionately, system frequency and voltage will drop and may result in a brown-out or eventually a black-out. Utility companies either buy power from neighboring utilities or bring their own plants on line to relieve overload conditions and methodically bring the system back to a normal operating mode.

**Conditions of Static Equilibrium**

As shown in Figure 4.3, electric power systems consist of a number of individual nodes (or buses) connected by transmission and distribution networks. These buses represent generation locations, points where transmission lines are joined together, or distribution lines that provide power to customers. For a power system to be in static electric equilibrium, the sum of power demanded at load buses must equal the sum of power supplied at generation buses minus the power losses in transformers and transmission and distribution networks.

Individual generators within a power system cannot physically direct their output to any particular demand (load) point. A generating plant can control only the mechanical energy applied to the generation itself by increasing or reducing fuel consumption. Power is transferred from generation at point A to generation at point B by increasing the power output of generation at point B and reducing, by the same amount, the power output of the generation at point A. During operational hours, the electrical system must maintain this electric equilibrium. Power transfer from one system to another is called wheeling. Wheeling requires an appropriate adjustment of generation levels within the sending and receiving systems.

### 4.2 COST COMPONENT OF GENERATION

#### Type of Fuel

Nearly all the electrical energy currently distributed by utilities comes from the conversion of chemical energy of fossil fuels, nuclear fission energy and the potential energy of water, which is allowed to fall through a difference of elevation.

During the next few decades, petroleum, coal, nuclear, and hydro energy will supply the majority of the energy necessary to produce electricity. Declining, long-term domestic supplies of oil and gas, combined with high prices and uncertain availability of foreign oil supplies, make it difficult to plan for the continued use of oil and gas as major sources of electrical energy. Under these circumstances, development of new energy sources is essential.

Fuel costs are a function of the type of unit and the type of fuel being used, as well as its source. Nuclear fuel costs are a special category since they consist of two components, the first being the variable cost of burn-up, expressed in Ç/mBtu, and the second being the fixed carrying charges on the inventory, expressed in $/yr./kW.

Table 4.2 provides approximate full-load heat rates for the various types of thermal units. Pumped-storage hydro units normally have an overall conversion efficiency of about 70 percent. The heat rates of Table 4.2, multiplied by fuel prices in Ç/mBtu, give the production cost (Ç/kWh or $/Mwh) of the units. To the delivered price of each fuel type, it is also necessary to add those components needed for maintenance, any cost of fuel treatments, start-up fuel requirements, and variable costs associated with stack gas clean-up (scrubbers) or waste product handling.

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>Full Load Heat Rates (BTU/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil-fired steam units</td>
<td>9,000 - 10,000</td>
</tr>
<tr>
<td>Nuclear units</td>
<td>10,000 - 11,000</td>
</tr>
<tr>
<td>Combustion turbine</td>
<td>12,000 - 14,000</td>
</tr>
</tbody>
</table>

**Table 4.2 Typical Heat Rates for Different Fuel Types**
Cost of fuel also varies from location to location. Following is a brief description of the other factors affecting fuel cost.

**Coal**
The cost of coal delivered to electric utilities can vary significantly from state to state. Environmental restrictions within a state may require electric utilities to burn only the more expensive, low-sulfur coal, resulting in a higher delivery cost. In the west, coal-burning plants are often built close to the mine, thus reducing transportation costs. In addition, the cost of mining coal from large surface mines located in the western United States is significantly less than that of underground eastern mines, resulting in a delivered cost of under $15 per short ton for states such as Montana and Wyoming.

**Petroleum**
Although nationwide fuel receipts for petroleum at electric utilities are less than one-half of the volume of the 1970s, several electric utilities in New England, New York, Florida, and Hawaii still depend on petroleum for a significant portion of their fossil fuel requirements. Receipts can vary widely from year to year at electric utilities due to changes in the cost and transport of petroleum. Fuel oil numbers 4, 5, and 6 (heavy oil) constitute the majority of all petroleum receipts at electric utilities. Smaller amounts of fuel oil number 2 (light oil) are also used by electric utilities primarily for start-up and flame stabilization of the boilers.

The cost of petroleum delivered to electric utilities varies considerably from state to state. The most important factor in determining cost is the type of fuel oil that is being delivered. States receiving only low-grade heavy oil will show a delivery cost much lower than a state receiving only light oil. Most of the petroleum delivered to the New England, Middle Atlantic and South Atlantic areas, California, and Hawaii is the number 6 fuel oil. The cost of fuel oil can also vary because of its sulfur content. Electric utilities that are required to meet stringent environmental standards must purchase low-sulfur fuel oil at premium prices.

**Gas**
Gas is used extensively as a primary fuel throughout areas of the country where it is readily accessible. Large volumes of gas are also transported by pipeline to the Middle Atlantic and Southern states. Gas receipts in these areas and in California can vary considerably from year to year because some electric utilities switch between the use of petroleum and gas in dual-fired generating units. The highest volume of gas use at most electric utilities occurs during the summer months when demand for electricity peaks and when there is a greater amount of gas available to electric utilities because of lower demands from residential and commercial consumers. In some northern parts of the United States, use of gas at electric utilities is limited during the winter months due to the priority given to residential heating and industrial needs. Many electric utilities have the capability of burning either petroleum or gas. The cost of the fuel is usually the determining factor. One major advantage of gas over all other fossil fuels is that it is a clean burning fuel. Therefore, some electric utilities use gas in order to comply with environmental regulations.

Table 4.3 shows average delivered cost of fossil fuel receipts for utilities in selected states.

<table>
<thead>
<tr>
<th>State</th>
<th>Coal</th>
<th>Petroleum</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cents Per 10^6 BTU</td>
<td>Cents Per 10^6 BTU</td>
<td>Cents Per 10^6 BTU</td>
</tr>
<tr>
<td>Texas</td>
<td>133.7</td>
<td>374.4</td>
<td>188.9</td>
</tr>
<tr>
<td>New York</td>
<td>141.2</td>
<td>285.2</td>
<td>208.0</td>
</tr>
<tr>
<td>Florida</td>
<td>166.8</td>
<td>249.5</td>
<td>223.6</td>
</tr>
<tr>
<td>U.S. Average</td>
<td>131.8</td>
<td>267.9</td>
<td>198.4</td>
</tr>
</tbody>
</table>

**Fixed and Variable Operations and Maintenance (O&M) Costs**
Another cost component is the O&M costs associated with the unit. These costs should include the operational and maintenance labor required by the unit, as well as the material needed to keep the unit in an operating mode. For base-load units, O&M cost is usually represented as a fixed cost for the year, independent of the energy production of the unit. For some peaking-type units, however, the O&M costs are a function of the number of hours that the unit is run and, for this reason, should be handled as a variable cost.

The other fixed operating cost includes all those non-capital expenditures that result from the commitment to operate, but are largely independent of the amount of use, such as the fixed part of O&M costs.

The variable operating cost includes those expenditures that are directly dependent on the unit's use. Two examples in this category are the variable cost of O&M and the fuel cost for the power plant. In expressing costs or making an economic study, many factors must be known or assumed. For a general study, these factors must be assumed. Figure 4.4 shows the variable O&M cost relationships between several different kinds of power generation.
Power Generation Reliability

The most frequently used indices of reliability of generating units is the forced outage rate (FOR). The Edison Electric Institute, which collects and publishes outage data, defines FOR as follows:

\[
\text{FOR} = \frac{\text{FOH}}{\text{CPH} - \text{PMH} - \text{MOH}} \times 100
\]

- **FOH** = Forced Outage Hours
- **PH** = Period Hours
- **PMH** = Planned Maintenance Hours
- **MOH** = Hours the Unit is out of service for deferrable forced maintenance outage

In system reliability studies, FOR is taken as the best estimate of the probability that a generating unit will not be available to serve the load when needed. The impact of the forced outage rate on system design can be quite substantial as measured by reserve requirements.

Forced outage rates vary according to the type of prime mover, the unit size, and the age of the unit. In addition, it is usually expected that prototype designs will have higher than normal forced outage rates. Considering variations of all these parameters, values of FOR can be anywhere between 1 to 15 percent. An immature generating unit usually suffers a higher
incidence of forced outages than it will later in its lifetime. An edging-generating unit also usually suffers a higher incidence of forced outages.

The forced outage rate of the unit also states the probability that a unit is not available to serve load when needed, given that the unit is not on a planned outage. In order to predict the cost of the electricity for an extended period, an accurate assessment of the forced outages is very important. Numerical example for calculating FOR given period hours = PH = L744 Hours:

Plant Availability = 528 Hrs.
Planned Maintenance Hours = PMH = 96 Hrs
Forced Outage Hours = FCH = 72 Hrs.
Maintenance Outage Hours = MOH = 48 Hrs.
F.O.R. = 72(744-96-48) x150 = 12%

Currently, there are two approaches to accurately estimate a generator’s forced outage rates and future energy production of power system generating units and their associated cost:

• Analytical Simulation
• Hourly Monte Carlo (HMC) Simulation

The analytical approach relies on a process that convolutes random variables of outage capacity with random variables of system load. In the Monte Carlo simulation, large populations of (N) system states are specified by random draws to simulate the chronological random outage events of system generating units.

An important concept in a Monte Carlo simulation is that, as scenarios are randomly drawn from all of the possible combinations of unit outage states, the results will begin to develop into the shape of a true probability distribution. Events that are relatively high in likelihood will appear in more draws than those that occur only rarely. The expected value for a result, such as the system production cost, is simply the average of the results over all of the draws.

Multi-draw Monte Carlo analysis resembles the process of drawing conclusions about a population by examining random samples. The resulting mean value (average) and standard deviations (a number indicating the range of values above and below the mean) for the sample will accurately represent a reasonably smooth distribution, as long as the sample size is large enough. As the number of draws increases, the completed mean value will converge towards the analytical expected-value results. For this monograph, forced outages are predicted using the HMC method.

4.3 GENERATION PRICING IN A DEREGULATED MARKETPLACE

It is increasingly important that generators have sufficient information within which to evaluate price signals and market conditions. A fundamental issue is early prediction of the market conditions. Investors need sufficient market information to evaluate whether new investments will be supported by market price. The potential builder of a power plant in a region must be competitive with all existing and future generation selling into the market. A plant must be supported by the market value of its generation in the control area in which it resides. For a plant to be constructed, generators expect that the plant output will be sold at a profitable market price. Consequently, it may be useful to have a forecast accompanied by sufficient information to understand its underlying dynamics.

In models using competitive generation, the owner of generation would have the authority and responsibility to schedule maintenance outages with the ISO. Some believe the economics of the market would provide the incentive for maintenance expenditures. Others are concerned that generation perceived to be uneconomical will not be adequately maintained, which could lead to increased generator outages and short term supply shortages during peak demand periods due to lack of sufficient generating capacity.

Under the pool model with an ISO, the ISO would commit and dispatch generation through the bidding process. With the bilateral competitive model, individual market suppliers would commit units based on their market for power or their contracts. All bilateral transactions would be scheduled through the ISO or RTG. The ISO would be responsible for monitoring the system and controlling the generation necessary to ensure reliability. With either type of competitive model, generation owners and participants in supply contracts would monitor and evaluate the performance of generation.

For a key local generator in a competitive environment, power could not be readily sold into the market and bought through competitive bidding because no other competitors would exist to serve the load pocket. However, some type of regulation may ultimately be required for generators serving load pockets.

In a competitive wholesale model with bilateral contracts, the price for capacity and energy would be negotiated between customers and suppliers. A transparent spot market price would be necessary for a forward market to emerge. The transparent spot price could be facilitated by the use of a bulletin board service or other similar mechanism. The Internet could be used as a technical medium for this application. The pool purchase price would be based on the bidding process and adjusted for any locational variations and additional costs incurred by the ISO required to ensure reliable system operation.
Under all competitive models, supply shortages would cause an increase in the spot market price. This approach should work effectively with both wholesale and retail competition when customers see real-time prices and are able to respond to those prices. The greater the price elasticity of electricity, the less likely that supply shortages will result.

However, this approach can work only if a sufficient number of customers receive real-time prices (hourly or half-hourly) to rapidly respond to price changes. Without the development of a large amount of customer demand that is either interruptible or responsive to high price signals, energy prices would not have adequate control mechanisms.

For instance, on a heavy demand day with adequate generation reserves, the market-clearing price may range from $0.03 to $0.04 per kWh. However, with the loss of several major generators and the subsequent drop in reserves, the clearing price could jump to $0.15 to $0.20 per kWh. Because all generators would be paid the market-clearing price, suppliers with only a modest share of the market may be tempted to withdraw supply from the market in an effort to increase their overall revenues. With low reserves, a reduction in supplies could trigger a severe shortage along with accompanying large increases in price. Large amounts of interruptible and/or price responsive load may be needed to break the link between the withdrawal of supply and large increases in price. Otherwise, during peak periods the system is vulnerable to the generators exercising their influence on the market, resulting in excessive prices and poor reliability.

Alternately, if a sufficient number of suppliers participate in the market with an adequate composite level of generation reserve, then withholding supply from the market would be counterproductive to the individual supplier’s revenues. Under these circumstances, one supplier intentionally withdrawing generation from the market would lose revenue and would have a negligible impact on market prices. The significance of this problem is proportional to the amount of power transactions that will flow at the spot price. More energy will tend to flow at the spot price in pool models than in bilateral models.

**Hourly Spot Market Mechanism (California Model)**

As shown in Figure 4.6 and discussed in Chapter 3, the California Independent Power Exchange (C-PX) will operate as a voluntary wholesale power pool allowing power producers to compete on common ground using rules for bidding into the PX. This section summarizes how such a bidding process works and the significant role it plays in the generation company’s cost recovery.

The process is divided into two time frames: the day-ahead schedule, to be completed approximately 5-10 hours before the beginning of the operating day (12 a.m.), and hour-ahead schedule changes, which occur approximately 1 hour prior to each hour within the operating day.

The day-ahead schedule is derived after one iteration between market participants and the ISO, where the ISO uses computer modeling tools to evaluate whether all schedules that it receives can be accommodated at the same time on the transmission system. If it finds congestion, it informs scheduling parties how, based on modeling results, it would eliminate congestion and at what price.

Near the beginning of the day before the next operating day, all eligible parties will submit to the ISO balanced energy transaction schedules and schedules for so-called self-provided ancillary services and optional ... boosted its output to serve an increment of load and the load increase was spread equally over all load buses.)

Alternately, if a sufficient number of suppliers participate in the market with an adequate composite level of generation reserve, then withholding supply from the market would be counterproductive to the individual supplier’s revenues. Under these circumstances, one supplier intentionally withdrawing generation from the market would lose revenue and would have a negligible impact on market prices. The significance of this problem is proportional to the amount of power transactions that will flow at the spot price. More energy will tend to flow at the spot price in pool models than in bilateral models.

**Figure 4.6 Proposed Industry Model for the State of California**

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Direct-Access Schedules

Direct-access parties will submit their proposed schedules to the ISO. Like the PX parties, direct-access parties will indicate whether they intend to provide ancillary services or whether they want the ISO to provide these services. The direct-access parties may also note the availability and price of ancillary services to be bid into the ISO’s auction of ancillary services. Finally, they may also provide incremental and decremental bids, which will be used by the ISO in its congestion management protocol to adjust schedules (called redispatch) for congestion.

Hour-Ahead Schedule Adjustments

The day-ahead accepted schedules become the basis for settlement in the real-time market. Parties will, however, be able to ask the ISO for schedule adjustments near real-time. The
goal is to move the time at which the last schedule adjustments can be accepted by the ISO to as near real-time as possible. This will permit suppliers to optimize generation to meet the requirements of their customers and reduce changes. In contrast to the day-ahead scheduling process, there will be no iteration between the ISO and market participants in response to congestion.

As illustrated in Figure 4.9, the same supply curve is assumed to apply throughout the day, but three different periods have been selected to show different levels of customer demand. Market-clearing price in period is the price at which supply satisfies demand. In the time when there is little demand, the market equilibrium price settles at the marginal running cost of the cheapest generators. As demand increases, so does the equilibrium price. At this time, every customer that actually consumes power pays the market-clearing price, and every generator running is paid this same price. For the generators, the difference between the market price and their individual marginal cost contributes to recovery of capital.

As long as the generator receives the market-clearing price, and there are enough competitors so that each generator assumes that it will not be providing the marginal plant, then the optimal bid for each generator is the true marginal cost. To bid more would only lessen the chance of being dispatched, but that would not change the price received. To bid less would create the risk of running and being paid less than the cost of generation for the plant. Hence, with enough competitors and no collusion, the short-run central dispatch market model can elicit cost bids from buyers and sellers. The dispatcher can treat these bids as the supply and demand curves of Figure 4.8 and determine the balance that maximizes benefits for producers and consumers at the market equilibrium price.

In the short term, electricity is a commodity, freely flowing into the transmission grid from selected generators and out of the grid to willing customers. Every half-hour, customers pay and generators receive the short-run marginal-cost (SRMC) price for the total quantity of energy supplied in that half-hour. Everyone pays or receives the true opportunity cost in the short run. Payments follow in a settlement process with a single dispatch and single price that is simple by comparison with the settlements required under the multiple dispatch and multiple costs of traditional split-savings systems.

Transmission Losses

Transmission of power over conductors encounters resistance, and resistance creates losses. Hence, the marginal cost of delivering power to various locations differs and is affected by the marginal effect of losses in the system. With a few exceptions, the marginal losses on high voltage transmission grids are relatively small, amounting to only a small percent of the cost of delivered power. Incorporating these relatively small losses do not require a major change in the theory or practice of competitive market implementation. Economic dispatch would take account of losses and the market equilibrium price could be adjusted accordingly. Technically, this would yield slightly different marginal costs and slightly different prices, depending on location, but the basic market model and its operation in the short run would be preserved.

Transmission Congestion

Transmission congestion is another matter entirely. Limitations in the transmission grid for the short run may constrain long-distance movement of power and thereby impose a higher marginal cost in certain locations. In the simplest case, consider the generators separated into low cost and high cost groups connected by a single transmission line. Under simplistic conditions, if all the customers are located in the high cost region, power will flow over the transmission line from the low cost to the high cost region. If this line has a capacity limit, then in periods of high demand not all the power that could be generated in the low cost region can be used, and some of the cheap plants are "constrained off." In this case, the demand is met by higher cost plants that normally would not run, but due to transmission congestion must now be used to meet the demand. The marginal cost in the two regions differs because of the transmission congestion. The marginal cost of power in the low cost region is no greater than the cost of the cheapest constrained-off plant; otherwise, the plant would run. Similarly, the marginal cost in the high cost region is no less than the cost of the
most expensive constrained-on plant; otherwise, the plant would not be in use. The difference between these two costs, net marginal losses, is the congestion rental. The congested-induced marginal-cost difference can be as large as the cost of the generation in the unconstrained case. If cheap Plant A is constrained off and Plant B, which costs more than twice as much to run, is constrained on, the difference in marginal costs by region is greater than the cost of energy at Plant A. In a real network the interactions are more complicated—but the result is the same.

If there is transmission congestion, the short-run market model and determination of marginal costs must include the effects of these constraints. This extension presents no difficulty in principle. The only impact is that the market now consists of a set of prices, one for each location. Economic dispatch will still be the least-cost equilibrium. Generators will still bid as before, with the bid understood to be the minimum acceptable price at their location. Customers will bid also, with dispatchable demand and the bid setting the maximum price that will be paid at the customer’s location. The economic dispatch process will produce corresponding prices at each location, incorporating the combined effect of generation, losses and congestion. In terms of their own supply and demand, everyone sees a single price, which is the SRMC price of power at their location. If a transmission price is necessary, the natural definition of transmission is supplying power at one location and using it at another with the corresponding transmission price as the difference between the prices at the two locations.

This short-run competitive market with bidding and centralized dispatch is consistent with least-cost dispatch. The locational prices define the true and full opportunity cost in the short run. Each generator and each customer sees a single price for the half-hour, and the prices vary over half-hours to reflect changing supply and demand conditions. All the complexities of the power supply grid and network interactions are subsumed under the economic dispatch and calculation of the locational SRMC prices.

4.4 TECHNICAL CONSIDERATIONS

Discussed below are the technical recommendations/considerations for the connection of embedded generating plants to existing electrical networks. It sets out the factors to be considered in providing a connection from generating plants with a transmission or distribution system. These recommendations are provided as a general guideline only. Actual system studies and design documents should comply with the requirements set by the local utility company, ISO, and the National Electrical Safety Code (NESC).

Voltage Considerations

The connection and operation of new generating plants must consider the effect on system voltage profiles to ensure compliance with requirements set by the ISO. The addition of new generating plants may significantly alter the system load profile. In such cases it will be necessary for the ISO to assess the equipment and circuit ratings of the transmission system against the most onerous conditions to which it will be subjected.

System voltage disturbances caused by the connection and removal of an embedded generating plant should be assessed against voltage recommendations set by the ISO. These requirements may recommend limits for system voltage disturbances caused by the fluctuation of load, and connection, operation, and removal of generating plants.

Voltage unbalance caused by uneven loading of three-phase supply systems should not exceed requirements set by the ISO.

Total Harmonic Distortion

The ISO may also require that the connection of a generating plant and any associated equipment not cause the levels of harmonic voltage distortion, measured at the appropriate supply terminals, to exceed the recommended limit.

Power Factor

It is industry practice that all generating plants other than small independent plants be capable of delivering their rated power output between power factors 0.95 leading and 0.85 lagging at the generating unit terminals.

Frequency

The frequency of supply to consumers is to be maintained with +1 percent of the declared frequency. As the declared frequency is 60.0 Hz in the U.S., industry practice is for generating plants to be capable of supplying rated active power output within the range of 59.4 Hz to 60.6 Hz. Under normal conditions, generating plants are expected to operate at a target system frequency of 60.0 Hz and required generators shall be encouraged to remain in parallel.

Short Circuit

One of the main effects of connecting large generating plants to a transmission network is to raise short circuit levels. Short circuit current calculations should take into account contributions from synchronous and asynchronous sources, including induction motors. Short circuit study results should be compared with the switchgear’s short-circuit withstand rating to ensure that the plant is not overstressed. The short circuit level may be different under different operating conditions; therefore, studies must consider all possible supply system running arrangements that are likely to increase system short circuit levels.

Connection of generating plants can raise the system reactance/resistance (X/R) ratio. In some cases, this will place a more severe duty on switchgear by prolonging the duration of the direct current component of the fault current and, in extreme cases, by delaying the occurrence of current zeros with respect to voltage zeros during the interruption of fault current. Hence, the performance of connected switchgear must be assessed to ensure safe
Reliability
Improved reliability can be achieved by installing at least two connections between the generating plant and a substation. In case of loss of one circuit, the remaining circuit, or circuits, should be capable of carrying the full output of the plant. Steady state and transient stability studies of the supplying system can demonstrate the reliability of the system under different operating conditions.

Other Considerations
The operational characteristics of a generating unit’s controls together with its associated governor and automatic voltage regulator must be coordinated with the other in-feeds to the substation. Generating plants may well be operated in load-following mode during normal operation, and have control settings to prevent circuit ratings from being exceeded in the event of a loss of one or more of the busbar in-feeds.

A generating plant located within a large industrial facility may feed existing circuits that have load connected to them, and power flow from the generating plant will directly supply this local load. The difference between local load and generating plant output represents the actual power available to be taken by existing circuits to a substation. Existing circuits may be capable of supporting actual power flows. However, this approach should be used with some caution, bearing in mind the minimum load conditions and future loss of load. For example, relocation of companies or change in the manufacturing process may alter the connected loads.

It is important to note that plant operation may affect system losses and, consequently, financial considerations may influence the technical consideration used to achieve a desired configuration.

4.5 CASE STUDIES
As discussed above, under a competitive power industry, generation planning will be the responsibility of an entrepreneur who is willing to take a risk for a new power plant. Regulatory changes discussed earlier will provide the necessary forum to buy and sell electricity, capacity, ancillary services, and/or future energy contracts. However, projecting forward market conditions will be an essential factor for the success or failure of a project. Forward market represents a commitment made today to buy or sell a commodity in the future. Price in a forward market—out 1 to 2 years—is a function of a seller’s and buyer’s estimated cost for a particular commodity. When the forward price equals or exceeds the cost of production, it will provide a market signal to build new capacity. Conversely, when production cost exceeds the future price for the commodity, facilities will be shut down and/or new capacity may not be built. In some states, the ISO will provide non-confidential pricing information to market participants to facilitate future investment decisions. However, ISO price projections may be limited to the next 24 hours and it may not provide long-term
projections necessary for business decisions. Such a market assessment will be the responsibility of the participants and they may have to assess their own risk.

Three separate case studies outline tools and methodologies used for such price projections. These case studies also demonstrate the relationships between cost components and other economic considerations for generation planning and its effect on the market clearing price or energy price projections. These case studies were conducted using New Energy Associates (NEA) PROMOD IV® computer software program. Necessary data for the first two case studies were established from past experience. Data for Case Study 3, Economic and Marketing Assessment for the Florida Area, were obtained from NEA and Resource Data Institute (RDI). Many large utility companies use computer software such as PROMOD IV® for generation planning purposes. In adapting to a competitive market structure, NEA modified PROMOD IV® to include the power exchange simulation with the generation bidding process.

**CASE STUDY 1—POWER EXCHANGE SIMULATION WITHOUT TRANSMISSION CONSTRAINTS**

This case study demonstrates the power exchange or power pool’s behavior under the generation bidding process and summarizes data needed for such studies. To illustrate the pool’s behavior, input parameters are simplified and transmission constraints are ignored. Figure 4.10 shows a simple one-line diagram for this case study. The system has a peak load of 2,800 MW and four generators with 3,200-MW capacity to support it.

![Figure 4.10 Single Line Diagram](image)

Figure C1.1 indicates the number of companies associated with this system and the number of areas it is divided among. Each bus with its corresponding load is assigned to one of these areas and similarly each generating plant is assigned to each company. Figure C1.2 shows input parameters required for the simulation. For this study, the data are obtained from other relevant studies. However, for actual studies, data are available from the state PJUIC, Department of Energy (DOE) and RDI covering plant capacity, fuel type, projected cost for the fuel contracts, and other cost data for each generating plant in the U.S. For simplicity, variable and fixed O&M costs and start-up costs are not considered. However, the program has the capability to include these costs in determining the actual production cost.

Figure C1.3 is a projected load profile for the next 24 hours. This will be similar to the requirement of the ISO or power exchange for generation bidding. The ISO will request this information from potential energy buyers, such as distribution companies, large industrial companies, and energy broker/marketers who purchase electricity from the pool. To satisfy these load requirements, the ISO will request generating companies to submit their bids for energy, capacity, and for other ancillary services. Figures C1.4 and C1.5 indicate generation bidding to the ISO. Figure C1.6 indicates hourly generation for each plant for the next 24 hours. Figure C1.7 indicates the calculated market clearing price for the next 24 hours. For simplicity purposes, plant bids are submitted in two segments only and cost for the startup, no-load cost, and capacity changes are assumed to be zero. As all units are bid-based only on their marginal cost of fuel, the cost of electricity ranges from $20/MWh for the BSGEN to $50/MWh for the PKGEN. Figure C1.5 also provides an explanation for each column used for the generation bidding process.

From this simulation, the program will also produce a generating unit operating report, Figure C1.6, and a unit profitability report, Figure C1.9. Generating unit operating reports can be generated on an hourly, daily, weekly, or monthly basis; however, Figures C1.8 and C1.9 represent weekly reports. Obviously, profitability for the PKGEN will be zero, as it does not provide any power. As shown in these two figures, ECOGEN provided almost 100 GWh of electricity to the pool. However, as this unit was the marginal unit for all hours, this unit and all other units would be paid based on the market-clearing price set by this unit. Accordingly, its profitability is also zero. As ECOGEN submitted its bid based on a marginal cost of fuel only, it will not recover any other operating costs, such as fixed and variable O&M, fuel handling, capital recovery, etc. However, if ECOGEN can predict that it is going to be a marginal unit and the cost difference between its unit and the next unit is $10/MWh, it can increase its bid up to $49.99/MWh and still be a marginal unit. Figures C1.10 and C1.11 indicate a power exchange report for a particular hour and week. Figure C1.12 demonstrates the power flow in each transmission line and the amount of power dispatched by each plant.

Considering the energy purchase cost of $16.8 M per week, this became the pool purchase price. Adding to the cost of other ancillary services, transmission losses, transmission congestion and other administrative costs will be the pool-selling price, which will be the cost of energy at the wholesale level.
NOTE: The author is no longer employed with Parsons Brinckerhoff. This monograph is for reference/research purposes only and not for distribution.

5.0 TRANSMISSION SECTOR
5.0 TRANSMISSION SECTOR

In the case of the development of a retail market for power, customers will increasingly need to do their own planning. Availability of price forecasts for transmission services, capacity and supply, as well as the price of generation, is important so entities can look at the price of transporting generation to their customers and evaluate the cost of the alternative systems.

The principal focus of the transmission planning process resides within the utility, although transmission planning is highly coordinated on a regional and statewide basis. Each utility is responsible for making sure that generation can be delivered to its customers through the vertically integrated corporate and network structure.

As the market for power evolves, it is likely that there will be a broader range of responsibilities for evaluating adequacy and reliability. The ISO or transmission system operator will likely have responsibility for evaluating whether or not desired transactions can be supported by the transmission system. Market participants, both buyers and sellers, will need to evaluate availability of firm and interruptible transmission capacity for a variety of reasons. The first reason is to determine what transactions are capable of being supported, and the second is to ensure that access is available to all parties on a non-discriminatory basis. A third issue is to ensure that the transactions utilizing the system are efficient.

The purpose of this chapter is to outline economical and technical considerations for a fully competitive transmission sector. It briefly describes the existing transmission system in the U.S. and discusses changes occurring in the marketplace. It also covers cost components of transmission systems, its effects on price determination of transmission, and other ancillary services. From the pool purchase price and pool-selling price discussed at the end of Chapter 4, this chapter will introduce other cost components for the power delivery system. Transmission cost methods proposed by the states of Texas and California, and actual transmission methods used in the United Kingdom, Chili, and Argentina are also presented. Technical studies necessary for safe and reliable operation of the transmission system are covered and an overview of data needed for the system studies is presented. Technical studies are also presented for a potential 250-MW plant in the Florida or SERC region (Case Study 3-Economic and Marketing Assessment for SERC Region, Chapter 4). These studies include the present conditions of the transmission network, impacts due to additional generation, and contingency studies. For the power system discussed under Case Studies 1 and 2, line losses and megawatt-mile calculations are also presented.

5.1 THE PRESENT TRANSMISSION SYSTEM IN THE U.S.

The industrialized economy of the United States depends on a reliable electricity infrastructure. The reason for such high levels of reliability within the U.S. is the interconnecting transmission network. Transmission lines connect loads with generation sources and integrate various geographically separate parts into a single network. Network
Interconnections have developed to the point where there are now three large networks in the U.S. As shown in Figure 5.1, the three networks comprise:

1. The eastern interconnected system consisting of the eastern two-thirds of the United States
2. The western interconnected system consisting primarily of the southwest and the Rocky Mountain region
3. The Texas interconnection

Each of these networks is made up of many interconnected utility systems.

In the vertically integrated U.S. electric industry, transmission system planning is carried out by IOUs, REAs, and others who have territorial rights in the area. For long-term planning purposes, forecasts of future loads are developed by respective utility companies. From these load forecast scenarios, requirements for new plants are determined. To comply with economic, environmental and many other competing factors, large power plants typically are built away from large load areas. The day-to-day management of the physical network is the responsibility of the transmission group of each company, which is responsible for the construction, repair, maintenance and refurbishment of the transmission system. The control center runs the transmission system with the dual objectives of producing secure supplies of electricity at minimum operating cost and ensuring that it can deliver usable power. The control centers also maintain proper voltage and frequency.

**Figure 5.1 Interconnections**
Transmission Sector under Competitive Power Industry

The transmission system is the center of debate in the restructuring of the electrical power industry in the U.S. Since enactment of the EPAct of 1992 and FERC Order 888 (see Chapter 2), it has been recognized that a competitive power industry is only possible through open and non-discriminatory access to the transmission system. FERC Order 888 also requires that all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce should:

- File open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service
- Take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs
- Develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that public utilities enjoy, and further require public utilities to separate transmission from generation marketing functions and communications

In response to FERC Order 888, a number of states have initiated restructuring activities. The most common aspects among them is to allow utilities to transmit power to their customers using the transmission lines of other utilities. Permitting them to buy power from remote utilities and non-utility suppliers requires that utilities provide unbundled transmission service, establish a pricing mechanism for transmission service that determines the cost of the service, and form Regional Transmission Groups (RTG) and/or create an ISO to manage regional transmission systems. Such RTGs would consist of transmission owner(s), the ISO, transmission users, generators, and regulatory agencies that could determine transmission cost allocations and plan transmission for new generation and interconnections.

Under a competitive environment, the ISO and/or RTG would interpret reliability criteria and transmission limit analyses. Reliability criteria would presumably continue to be established by regional reliability councils. The ISO would forecast transmission loading capabilities, limits, losses, and maintenance outages with possible oversight by an RTG and/or regulatory bodies. The ISO would operate the statewide transmission system and accept schedules for transmission services for bilateral contracts. The ISO would also have control over transmission operations through the use of congestion charges (i.e., locational pricing) and coordination of advance scheduling.

With the bilateral wholesale model, all generators would be free to contract with any system. The ISO would have the responsibility to meet reliability standards for the state. With bilateral retail competition, external generators and marketers/brokers could enter the retail market as energy service companies (ESCos). This may require changes in a control center's ability to handle communication and metering needs depending on the number of transactions involved. The ISO would schedule flows to allow lowest total costs while adhering to transmission constraints and reliability standards.
Bilateral and Pool Models

With either the bilateral or pool model, transmission prices initially could be based on "postage stamp" rates. Alternately, transmission could be priced using a congestion charge, which would equal the difference in locational-based spot prices between two nodes (specific buses) or two zones (general areas having no effective transfer constraints within themselves). Congestion charges would tend to be lower than embedded costs on transmission lines that are lightly loaded, and higher than embedded costs on lines that are constrained. Total revenue received from congestion charges across the transmission system is anticipated to fall short of total embedded costs. One way of collecting the shortfall would be through an additional end-user charge.

Some versions of a pool-based model envision that transmission owners would define transmission rights, and then auction them in the marketplace as transmission congestion contracts (TCC). These contracts could be long term arrangements that would give the TCC holder the benefit of moving a specified amount of power from point A to point B, or its economic equivalent. TCCs could be resold in an unregulated secondary market.

Both bilateral and pool-based systems require comparability in pricing, and both benefit from pricing of transmission services that includes both space and time. The bilateral model could price transmission by using the following:

- A pool-based method in which the ISO would estimate the cost of transmission along with an additional charge to make up revenue shortfalls
- A charge applied to all end-users to fulfill transmission owners’ revenue requirements
- Postage stamp rates (based upon the amount of transfer, but not transmission distances or constraints) with some flexibility to lower prices between low and high cost areas

Parties have not yet reached an agreement regarding transmission pricing and recognize that these issues are being debated before FERC.

The bilateral model requires the independent calculation of either a nodal or zonal transmission price based on the short run marginal cost (SRMC), which can then be applied to all transactions occurring in the system. Under these circumstances, some believe that the bilateral model provides the same operational signals to both the supply and demand sides as the application SRMC based prices in the pool model. Some argue that a bilateral model using locational based spot prices is virtually a pool model; energy prices would differ based on location, taking the cost of transmission constraints into account.

Under all competitive models, loss computations and allocations will be handled by the ISO. With retail competition, the ISO would include losses in service costs. Additionally, as cost based regulation is replaced by market based prices, ESCos would need to account for and ensure the correct payment or price adjustment on losses.

In all competitive models, the ISO would specify the levels of operation necessary for reliable operation. The ISO would obtain the necessary reserves and would call on their use when needed, with appropriate compensation to the providers. Penalties for non-performance would be assessed, based on rules and regulations similar to existing operational requirements.
Under the pool version of either the wholesale or retail models, the ISO would make decisions and commitment and dispatch. The power exchange (as proposed by the California PUC) or similar kind of market mechanism would be the entity primarily responsible for running the short-term dispatch in a bid-based system. It may also be involved in purchasing operating reserve and reactive power, load following, and other ancillary services from generation companies as specified by the ISO to maintain system reliability.

Under the bilateral versions of the wholesale or retail models, the ISO's duties are more restricted, and do not involve either unit commitment or most dispatch decisions. Most unit commitment and dispatch decisions would be made by the competing ESCos and generation companies in the competitive market. Those decisions would be forwarded to the ISO. The ISO may still make some unit commitment decisions with regard to ensuring that sufficient operating reserve and other reliability needs are available. The ISO would make dispatch decisions only with regard to calling on such resources when needed to respond to imbalances or reliability problems.

Imbalances can be resolved in several ways. An imbalance is a situation where bilateral trade involving two parties has been pre-scheduled and the actual amount, either committed or consumed, deviates from its pre-scheduled level. Under pool versions or either a wholesale or retail model, the ISO would make up the imbalances and would charge a price equal to the spot price that the pool had helped coordinate with the pool market mechanism. Under a bilateral trading version of either the wholesale or retail models, if imbalances should occur, the ISO would take care of them and penalties might be assessed.

With wholesale competition, a regulated ISO would be responsible for reliability and security, would coordinate ancillary services, control generation and transmission, and set rules. The ISO would need to establish contracts with the generators to provide some of these services or would establish a bidding process for the services.

With increased competition, market efficiency will require that ancillary services be unbundled and individually acquired, in all likelihood, through a bidding process. Where feasible, some ESCos may decide to provide their own ancillary services rather than purchase them. Because some (and perhaps all) ancillary services are distance/region sensitive, locational based ancillary service prices may need to be invoked. In many instances, production and delivery of ancillary services from one area to another will be restricted so that at least some of the services will have to be supplied locally. Furthermore, because ancillary service supplies and requirements both vary through time, real-time pricing of ancillary services (particularly for reactive power) may be needed as well.

The determination of customer requirements and use of ancillary services could require extensive metering and monitoring. Due to uncertainties and natural variations, these services will need to be backed up by the system, which some parties believe could provide opportunities for free riders on both the demand and supply sides.
5.2 ECONOMIC CONSIDERATION FOR TRANSMISSION SECTOR UNDER COMPETITIVE POWER INDUSTRY

Transmission Lines/Cables

Most of the power networks in North America transmit three-phase, 60-Hz AC power. Overhead transmission circuits consist of conductors, insulators, supports, and shield wires. The conductors generally used in overhead transmission lines are aluminum cable, steel reinforced (ACSR) or other aluminum construction. These conductors are supported by transmission towers or poles, usually constructed of steel or wood and designed to be strong enough to support the conductors and shield wires under design operating conditions. Insulators are used to connect the conductors across the transmission towers or poles. Shield wires are used to protect the energized conductors from lightning strikes.

Where a right-of-way is not available for the use of overhead transmission lines because of population density or because sufficient land is not available, underground cables may be used. Cables are used only where the use of overhead lines is restricted because of the relatively greater expense. In addition, cables can produce large amounts of reactive power, which may create operating problems during light load conditions.

Power Substations

Power substations are constructed wherever transmission lines terminate or connect to one another. The major components of a typical power substation are large power transformers, protective devices, interconnecting buses, and reactive power equipment:

1. Transformers are used to transfer power between electrical circuits and buses that are operated at different voltages. Transformers often have tap changing equipment to vary the voltage levels and to help compensate for voltage variations on the system.

2. Protective devices include switchgear, circuit breakers, disconnect switches, and protective relays. These devices can open connections and interrupt the flow of electricity between circuits, busbars, and transformers under normal and emergency conditions. The main types of switching devices are circuit breakers and disconnect switches.

3. Buses are used within substations to continue the circuits of the same voltage level with one another and with transformers. Buses within substations are generally aluminum pipes to prevent contact with grounded surfaces during high winds, seismic activity, etc.

4. Reactive power is required for electrical equipment that uses magnetic fields, e.g., rotating machinery. It uses no energy and produces no useful work in and of itself. The unit for reactive power is the volt-ampere reactive (VAR), but the practical unit used in electrical power system operations and design is the megavar (MVAR), equal to 1 million VARs. Almost all types of load require the supply of some reactive power along with the active power that produces useful work, e.g., megawatts (MW). When the reactive power supply in a transmission network is insufficient, voltages decline to unacceptable levels. Reactive power can be produced or absorbed by several types of equipment. Reactive equipment commonly used by the utility companies are static VAR compensators, synchronous condensers, shunt reactor banks, series capacitor banks, etc.
Capital Costs

Capital costs associated with transmission service include the required return on investment for installed equipment plus depreciation on that equipment. Also included are insurance on the equipment, taxes on the equity return on investment, various property taxes, and other taxes.

System Operations and Maintenance Costs

The provision of a transmission service to a customer may affect the transmission owner’s cost in a number of ways and depends upon the characteristics of the transmission service offered. Providing transmission service affects the operation of the system both by changing actual power flows with its direct consequences, and by forcing the transmission owner to restrict its operations in order to provide the contracted transmission service. Even a transmission service that does not result in an actual change in power flow may affect the operating costs to the system. One example is transmission capacity that is "reserved" for a customer for reliability purposes, but is never called upon to deliver power; capacity reserved for such purposes must still be energized and maintained. Costs associated with the operation of the transmission system can be grouped into the following classes:

- Operations and maintenance (O&M)
- Energy losses
- Administrative transactions
- System control
- Operational constraints
- Other miscellaneous costs

O&M costs associated with transmission equipment are the cost elements requiring manpower and supplies. O&M costs include labor and materials for maintaining transmission lines, towers, insulators, transformers, and substation equipment. These are predominantly fixed costs that do not vary substantially with loading or use of the installed facilities. However, some O&M costs do vary with the utilization of equipment and could affect repair requirements or ultimate service life. For example, high thermal stress on transmission lines or frequent operation of a load tap changer on a transformer could require additional (or more frequent) maintenance and cause an associated increase in O&M costs.

The cost of line losses is the cost of generation needed to make up for line losses. Since energy is converted to heat in conductors, transformers, and other circuit equipment, more than 100 MW of generation is needed to deliver 100 MW of power to retail customers. Line losses depend on the size of the line, load already on the network, line length, network configuration, weather conditions, etc. The cost of line losses depends on the amount of network losses and which generators supply the additional power. The two main sources of energy losses in transmission systems are "conductor losses" associated with the lines, and "core losses" associated with the transformers. Conductor losses are generated whenever current flows in the transmission system conductors vary with the square of the current flow and the resistance and reactance of the conductors. All current flow results in energy losses for real power flow or reactive power flow. Due to the "square" relationship between losses
and power flows, an increase in real or reactive power flow causes a more than proportional increase in transmission losses. Because conductor losses vary with the square of the real and reactive power flows, losses are much higher at times of heavy transmission system loading. Transformer core losses are independent of current flow and are constant.

All of these energy losses on the transmission system must be provided by generators connected to the transmission system or imported from neighboring systems. VAR requirements may also be satisfied by installing static VAR compensators, capacitors and shunt reactors. These installations may be on the transmission system, the distribution system, or at the customer load point and would not be associated with fuel cost or generator expense. Since the marginal cost of generation increases with load, and losses also increase with load, the marginal cost of the generator required to save the losses also increases with load.

The effect of losses on the price of electricity between the generator and the customer is illustrated below. For an electrical system discussed in Case Studies 1 and 2, Figure 5.2 shows a hypothetical case of a generator (BSGEN) supplying 100 MWh at $40/MWh to bus #1. The total cost of this transaction is $4,000. At the receiving end (the customer's load) the customer with 10 MW of losses draws 90 MWh (typical loss for a transmission system within 1-3 percent of the system demand). The electricity price at the customer end would be $44.4/MWh, and the cost of the transmission losses is $4.4/MWh.
Transmission losses are proportional to the line resistance and current flow. Line resistance increases with distance, which makes line losses also proportional to the distance. Returning to Figure 5.2, if generator PKGEN is providing power to the load at bus 3, line loading between bus 1 and bus 3 will be reduced. In this case, the effect of moving electricity against the current net flow reduces the price of electricity.

In practice, wheeling (defined later in this chapter) does not take place over a single line, but over a network of interconnected lines of various lengths and voltages. Line loss costs can be high on some lines and low on others; they can be positive along some lines and negative along others. However, as power flow divides itself over more lines, the losses on any one line usually decrease. The true line loss cost is the sum of the costs over all affected lines. Accurate determination of the costs of line losses requires computer software. The various line flows can be determined with a load flow study; losses can be found and costs can be calculated with a generation dispatch model for each company supplying the power to cover the line losses.

The cost of the power lost in the transaction depends on whether the seller, the buyer, or a third party like a power broker pays for the losses. In reality, it is possible to wheel 100 MW by letting the buyer receive 100 MW minus the power losses. However, in practice, the amount said to be wheeled is always the amount the buyer needs to receive. If power losses are estimated as 5 percent, then the seller supplies an extra 5 MW and pays for the appropriate cost of 105 MW of demand.

Administrative transactions are responsible for the accounting and billing functions. These administration, metering, scheduling, accounting, and billing costs are generally lumped under the heading of transaction costs. While many of these costs are associated with the buying and selling of electric capacity and energy, a portion is required by the transmission function.

The control of the transmission system and the equipment dedicated to this task were discussed in connection with elements partially attributable to transmission. The control functions require substantial manpower at manned substations and control centers. The associated labor costs may be attributed to system control in addition to routine operating costs such as space conditioning, power, light, and other support services.

When the ability of the transmission network is constrained from transmitting the energy that is associated with the optimal dispatch of the generation system, including transacting economic power sales and purchases, and when the provision of requested transmission services is constrained, these constraints must be met by alteration of the optimal dispatch.

There are several other operating costs that are wholly or partly attributable to the transmission function. Some of these costs include:

- Research and development
- Training
- Participation in reliability councils and regional transmission associations
- Corporate administration and general
The cost components discussed above are used in determining the appropriate transmission pricing methods (discussed later in this chapter). The transmission network distinguishes itself from the generation part of the business by its economic size. The transmission network is the single electric business where competition may not be practical and natural monopolies exist. Fixed cost components discussed above establish the asset value for a regional transmission network. The variable operating cost components make up the expense for the operation of a regional transmission network. The challenge in defining and selecting appropriate transmission pricing schemes is to provide necessary return on investment, recovery of expenses, and economic incentives for the business to efficiently operate and expand. If marginal costing is used to price transmission services, it may not provide enough income to finance the expansion projects.

### 5.3 TRANSMISSION WHEELING

When power is moved (transmitted) from Utility A to Utility B via Utility C, it is called "wheeling." Accordingly, the type of service offered may depend on how much power is being moved, the transmitting distance, duration, etc. Before completing any wheeling transaction, the generator and/or the customer must secure the right to transmit electricity from point A to point B. This service can be provided for single units with short notice. However, most networks do not let traders start trading without securing firm transmission rights to use system capacity for a specified time period such as a day, a month, or year. Following is a summary of different types of transmission services and wheeling.

**Interutility Wheeling**

Interutility or bulk power (coordination) wheeling involving wholesale power transactions between utility systems is the most common form of transmission wheeling to date. Such transactions are coordinated among several utility systems: a supplying system, a receiving system, and one or more utility’s transmission systems. This arrangement is illustrated in Figure 5.3.

![Figure 5.3: Interutility Wheeling](image)

In such a transaction, two utility systems that are not directly interconnected, Utility A and Utility B, enter into a power transfer schedule whereby the transmission network of the intervening utility, Utility C, is used as the transfer, or contract, path. The power transfer is accomplished by increasing generation in the supplying utility system, Utility A, and reducing generation by an equal amount in the receiving system, Utility B. The result is a change of power flow pattern, including those of the intervening wheeling utility system, Utility C.
C is directly involved in the transaction and is compensated for the use of its transmission system. Generation output in Utility C is unchanged unless Utility C agrees to supply the increase in losses on its transmission network caused by the wheeling transaction. Alternately, losses in Utility C may be supplied by Utility A or Utility B by an appropriate adjustment of interchange schedules.

**Supplier Wheeling**

In supplier wheeling, power is transmitted for and from a particular generating source, such as an independent power producer (IPP) or qualifying facility (QF). QFs could be a cogenerator or small power producer, as defined by the Public Utility Regulatory Policies Act (PURPA). Again, three or more parties are involved, but the supplier is not a utility system. This type of transaction is illustrated in Figure 5.4.

**Figure 5.4. Supplier Wheeling**

In supplier wheeling, the QF/IPP generator is connected to the transmission network of the wheeling utility, Utility A, and the QF/IPP output is delivered to the receiving system, Utility B, via the transmission network of Utility A. To accomplish the transfer, Utility B’s generation is reduced by an amount equal to the output of the QF/IPP supplier. Utility A’s own generation output can be affected by the transaction if it is required to supply losses on its transmission network that are caused by the wheeling transaction. By virtue of its control area responsibility, Utility A may also be required to provide back-up and load following capacity, as described later in this section. Again, there could be one or more utilities located between Utilities A and B whose systems would be affected by the power transfer from A to B.

**Customer Wheeling**

In customer wheeling, power is transferred from an outside supplier into the system of the host, or wheeling utility—and through the contractual and accounting features of the arrangement—the wheeled power is credited to or designated "for the account of" a specific customer connected to the host utility's system. In this case, at least four parties, namely supplier, utility company associated with outside supplier, utility company associated with customer, and customer are involved but the recipient is not a utility system.
Customer wheeling is accomplished by increasing the output of Utility A's generation equal to the customer load being supplied and by reducing Utility B's generation by an equal amount, assuming that the customer's load was previously supplied from Utility B's own generation (see Figure 5.5). In this transaction, Utility B is the wheeling utility; however, for all practical purposes, this really amounts to a transaction between Utility A and Utility B where the power import is designated for the specific customer. The power flow patterns on the transmission networks of the supplying and receiving system are no different from the patterns that would exist if Utility B purchased power from Utility A for its own use. Therefore, customer wheeling can only take place when the customer's host utility (Utility B) permits its own generation to be displaced by the new supplier's generation. This distinction differentiates this process from other forms of wheeling. In this case, it also may be necessary for Utility B to adjust its generation for changes in system losses incurred as a result of this transaction. Utility B may be required, by virtue of its control area responsibility, to provide back-up and load following capacity (see ancillary services).

![Figure 5.5 Customer Wheeling](image)

**Self-Serving Wheeling**

In self-serving wheeling the customer is moving power from its facility in Utility A's area into another facility in Utility B's area. Large corporations with multiple plants located in different utility areas may be able to take advantage of these transmission services where available. The main condition for self-serving wheeling is to have a large enough generating plant within the customer's facility. Self-serving wheeling is accomplished by increasing the customer generating plant output equal to the load at another facility (within Utility B), and reducing Utility B's generation (assuming that facility's load was supplied from Utility B), by an equal amount.

Self-serving wheeling includes at least Utility B's transmission system, because it's a wheeling utility. However, it may also include Utility A's transmission system.
5.4 TRANSMISSION SERVICES

Firm Versus Interruptible

The wheeling utility, RTG, or the ISO may offer either firm or interruptible wheeling services. Per FERC Order 888, in firm wheeling transactions, the obligation of the wheeling utility is similar to the obligation it has to its own firm customers. With an interruptible service, the wheeling utility has the right to interrupt the wheeling transaction under specified conditions usually involving transmission network limitations. Such wheeling transactions have to be accompanied with assurance that the proposed transaction will not compromise system quality and reliability.

Point-to-Point and Network Service

For transmission systems that presently have adequate service capacity, but are expected to be constrained in the future, short-term service may be the preferred choice because it costs less than long-term service. The exact boundary between firm and non-firm and between short-term and long-term is arbitrary and will vary from one situation to another or from one region to another.

Point-to-point service requires that a transmission user define the point at which power is to be received by the transmission service provider and the point at which the power is to be delivered. Firm point-to-point transmission service may be reserved and/or scheduled between specified points of receipt and delivery. Non-firm point-to-point transmission may be reserved and scheduled on an as-available basis and is subject to curtailment or interruption as set forth by the ISO. Non-firm point-to-point transmission service may also be available on a stand-alone basis for periods ranging from 1 hour to 1 month.

The term "network service" usually refers to Network Integration Tariff, in that it refers to long-term firm full or partial requirement of service, and generally billed upon coincident peak usage rather than demand, as in point-to-point. It does not have the provisions for secondary point usage, and was intended to serve native load customers without the accommodation of third party wheeling. It also permits the transmission user to use a certain quantity of transmission capacity (in MW) over multiple paths between multiple source and delivery points. The physical distances over which such service is provided change depending upon the specific source and delivery points selected.

Per FERC pro forma open access transmission tariff, long-term, firm point-to-point transmission service shall be available on a first-come, first-served basis (i.e., in the chronological sequence in which each transmission customer has reserved service). Reservations for short-term services will be conditional upon the length of the requested transaction. If the transmission system becomes oversubscribed, requests for longer-term service may preempt requests for shorter-term service up to the following deadlines: 1 day before the commencement of daily service; 1 week before the commencement of weekly service; and 1 month before the commencement of monthly service. Before the deadline, if
available transmission capability is insufficient to satisfy all applications, an eligible customer with a reservation for shorter-term service has the right of first refusal to match any longer-term reservation before losing its reservation priority. Firm service will always have a reservation priority over non-firm service. All long-term firm service will have equal reservation priority with native load and network customers.

**Ancillary Services**

Ancillary services are needed with transmission service to maintain reliability within and among the control areas affected by the transmission service. The transmission customer located within the transmission provider's control area may be required to acquire these ancillary services, whether from the transmission provider, from a third party, or by self-supply. The transmission customer may not decline the transmission provider's offer of ancillary services unless it demonstrates that it has acquired the ancillary services from another source. The transmission customer should list in its application which ancillary services it will purchase from the transmission provider. The transmission provider is required to offer the following ancillary services within its control area:

a) Scheduling, Dispatch, and System Control. Scheduling, dispatch and system control service is required to schedule the movement of power through, out of, within, or into a control area. This service can be provided by the ISO of the control area in which the transmission facilities used for transmission service are located. This service can also be provided directly by the transmission provider, or indirectly by the transmission provider by making arrangements with the control area operator that performs this service for the transmission provider's transmission system. The transmission customer must purchase this service from the transmission provider or the control area operator. To the extent the control area operator performs this service for the transmission provider, charges to the transmission customer may reflect only a pass-through of the costs charged to the transmission provider by that control area operator.

b) Reactive Supply and Voltage Control. In order to maintain transmission voltages within acceptable limits, generation facilities are operated to produce (or absorb) reactive power. Thus, reactive supply and voltage control from generation sources must be provided for each transaction on the transmission provider's transmission facilities. The amount of reactive supply and voltage control is determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the ISO. The transmission customer must purchase this service from the control area operator or make alternative comparable arrangements to satisfy this reactive requirement.

c) Regulation and Frequency Response. Regulation and frequency response service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interconnection frequency at 60 cycles per second (Hz). Such service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the ISO. The transmission provider may offer this service when the transmission service is
used to serve load within its control area. The transmission customer may either purchase this service from the transmission provider or make alternative comparable arrangements to satisfy this obligation.

d) Energy Imbalance. Energy imbalance service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a control area over a specified hour. The transmission provider has to offer this service when the transmission service is used to serve load within its control area. The transmission customer will either purchase this service from the transmission provider or make alternative comparable arrangements to satisfy its energy imbalance service obligation.

e) Spinning Reserve. Spinning reserve service is needed to serve load immediately following a system contingency. Such service may be provided by generating units that are on-line and loaded at less than maximum output. The transmission provider will offer this service when the transmission service is used to serve load within its control area. The transmission customer must either purchase this service from the transmission provider or make alternative comparable arrangements to satisfy its spinning reserve service obligation. The amount and charges for spinning reserve service will be set forth by the individual ISO.

f) Supplemental Reserve. Supplemental reserve service or black start service is a service needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Such service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. The transmission provider will also offer this service when the transmission service is used to serve load within its control area. The transmission customer must either purchase this service from the transmission provider or make alternative comparable arrangements to satisfy its supplemental reserve service obligation.

5.5 TRANSMISSION COST METHODS

As long as transmission is vertically integrated with generation, transmission pricing is not important since there is no need to unbundle its cost from the utility company's total cost of power system delivery. However, as we move from a vertically integrated system to a wholesale or retail competitive power industry, transmission price becomes more important. With availability of open access to transmission systems, generators will deliver power at one end, wheel it through the transmission network, and deliver it to the customer at the other end. A fair transmission price structure should include a pricing system that properly reflects all of the costs of providing transmission services, both long and short term, direct and indirect, and will best serve to encourage efficiency in the overall use of the transmission system. So that consumers, generators and distributors can trade equitably, it is necessary that transmission service charges be transparent to all members of the market. The charges should also send signals to the market that will encourage investors to extend and reinforce circuits at the appropriate time.
Transmission charges may be considered as having two components, connection charges and use of system charges:

a) Connection charges are intended to cover costs incurred in providing connection to the transmission system and the provision of ancillary services. Connection charges are sometimes categorized as "entry" charges (for generators) and "exit" charges (for distributors and large consumers). It is important when analyzing these charges that the pricing structure does not discourage access to the system except where such discouragement is a true reflection of the costs incurred. Non-discriminatory economic access to the transmission system requires the avoidance of capacity rights to the system.

b) The use of system charges reflects those parts of the system that are themselves dependent on the geographical configuration of demand and generation as a whole and can only be attributed according to the geographical location of the demand and generation. It is generally not possible on a large interconnected grid system to identify infrastructure costs with specific users.

Traditionally, FERC allocated to all users a share of the historical accounting costs of the transmission system, so-called embedded cost pricing, for establishing transmission service rates. When new facilities were constructed, the cost of those facilities was "rolled in" to the total embedded costs and again allocated to all users. However, transmission pricing based on these traditional embedded cost methods tends to reduce efficiencies in use and expansion of the transmission system.

Through the EPAct 92 and Order 888, FERC has begun to recognize the importance of improved transmission price signals in ensuring efficient use and expansion of the system. It has become apparent that as utilities have significantly increased the level of transmission services provided over the past decade, and as more utilities have begun to rely on purchased and/or wheeled power to meet their resource needs, significantly more attention needs to be paid to appropriate pricing of transmission services.

Various transmission methods are being debated and implemented by regulators and utility companies. As each method offers its advantages and disadvantages, there is no consensus among policy makers. Discussed below are different transmission pricing methods being implemented in various state PUCs. Where applicable, cost methods are also supported by actual examples.

**Postage Stamp Method**

The postage stamp method is so called because the price of electricity is the same regardless of the receipt and delivery points, and it is independent of the distance between point of delivery and point of receipt. The postage stamp rate is derived from the total cost of transmission services and total system demand as an average cost ($/MW). However, this method may not provide full recovery of investment.
Example of Postage Stamp Method (State of Texas)

The Texas Public Utility Commission (PUC) has established the pricing mechanism for transmission service that determines the cost of the service. This pricing mechanism is based on dividing the costs of providing transmission service among wholesale customers that use the transmission network. Seventy percent of the costs will be divided among the customers on the basis of each customer's load (postage stamp method), and 30 percent will be divided among the wholesale customers on the basis of the impact, in megawatt-miles, of transmitting power from the generators to the areas where wholesale customers deliver the power to their respective customers (vector absolute megawatt mile-VAMM). Under this pricing mechanism, a customer using planned transmission service will pay an appropriate share of the costs of the transmission facilities, but utilities and non-utility suppliers will also be able to use the transmission system for unplanned transmission service, without paying a facility charge.

To assist in calculating the cost of transmission services, PUC staff have prepared cost schedules that show the impact of the rate provisions based on the method discussed above. This information is contained in three separate spreadsheets (see Texas PUC's Internet Web site (http:\www.puc.texas.gov). The first schedule indicates the allocation of 70 percent of the transmission cost for each transmission owner among the transmission customers, using the postage stamp mechanism. The second schedule indicates allocation of 30 percent of the transmission cost for each transmission owner among the transmission customers, using the VAMM method. The third schedule sums the results of the first two schedules and shows allocations of 100 percent of the transmission costs for each transmission owner among the transmission customers.

According to these calculations, total annual cost of the transmission system in the ERCOT system will be $631,633,088. Based on an estimated load in the ERCOT system of 44,567 MW, the postage stamp portion of the transmission cost would be:

Postage stamp portion of cost = ($631,633,088 x .7)/44,567 MW
= $9.92/kW/year

These calculations are based on the estimated value of transmission and generation systems on line for the year 1996. If new capacity is added or deleted from the system or new transmission lines are added, the load ratio will change as will wheeling cost calculations. However, for the next 5 years, new transmission capacity not anticipated and net load increases will be small. Considering these factors, wheeling costs are not anticipated to change significantly.

Contract Path Method

A contract method computes the cost of a particular service based on a designated path connecting the receipt point to the delivery point. The path may not necessarily correspond to how the power actually flows on the transmission system. The contract path method is also used for power wheeling across multiple utility systems and costs are computed by
summing postage stamp costs or other applicable costs for all systems along the path. In vertically integrated utility systems this is the most common method used in the U.S. The contract path approach ignores the actual flows on the system. As the number and magnitude of such multi-system transfers have increased, concerns have risen that this method does not compensate any transmission systems off the contract path.

**MW-Mile Method**

The MW-mile method reflects a cost depending on the distance and quantity of power transmitted. It allocates cost on a MW-mile basis. As such, transmission of 10 MW between receipt and delivery points that are 100 miles apart would cost twice as much as transmission of 10 MW between receipt and delivery points that are 50 miles apart.

**Nodal Spot Price**

This approach assumes detailed dispatch and power flow modeling into an optimization methodology to develop nodal spot price on an AC network (Schweppe, Fred C., Carmanis, Michael C., Tabors, Richard D., and Bohn, Roger E., 1988). This method incorporates the physical laws governing the flow of AC power, including reactive power and voltage support. It computes the SRMC at each node of the transmission network for any set of system conditions. This SRMC includes losses and the effects of congestion, including out-of-merit generation necessitated by bottlenecks on the transmission network.

According to the basic principles of economic theory, optimal economic efficiency in the short and long term is obtained when perfect competition conditions exist and both consumers and generators pay or are paid at spot prices for the complete amount of power consumed or produced. A major obstacle to the achievement of this ideal scenario is the existence of economies of scale in the available options for transmission investments, resulting in a tendency for transmission systems to be "overbuilt." The economic consequence is that spot price based network revenue may be insufficient to recover the network costs. The precise effect depends on the nature of the spot pricing mechanism used, and it may be possible to incorporate a means of stabilizing the income to the transmission company while minimizing the damage to the signaling of the pricing system to generators and consumers. Penalties and incentives can be incorporated within the pricing mechanism, based on the ability to avoid costs and the economic consequences of system performance.

**Example of Nodal Spot Price (Case Study 3, Chili and Argentina)**

Case Study 3, Economic and Marketing Analysis of the SERC Region, was conducted using the nodal spot price method. For each selected node in the SERC and Florida region, AC power flow for each operating hour was calculated using the SRMC method, which includes losses and the effects of congestion. The resultant value was the hourly marginal bus cost. The cost difference between the nodes represents the cost of transmission services. For example, Table 5.1 shows the average monthly cost difference for buses 7120 and 8900. Accordingly, for the month of July 1999, the average cost of wheeling power from bus 8900 to bus 7120 would be $.74/MWh. Depending upon system constraints, availability of plants and
system losses, the value of the nodal price will change. However, the difference shown will recover only the marginal cost of system transmission congestion and line losses. It does not provide the necessary cost component for return on investment on existing assets or incentive for future expansion. The SRMC method is also applied to Argentinean and Chilean schemes (Rudnick, Hugh, Varela, Ray, and Hogan, William, IEEE Transactions on Power Systems, May 1997). Both countries implemented a two-part pricing method for transmission cost recovery. The first part was based on the marginal cost method and takes into account the effect of marginal losses applying a nodal or penalty factor to each bus energy price. In Chile, penalty factors based only on marginal losses were applied to bus capacity and energy prices. In Argentina, an adaptation factor was also applied to the capacity price factor that reflected network reliability upon out-of-merit dispatch and unserved energy.

In Chile, the second part of the transmission cost recovery component was based on replacement investment values as well as operation and maintenance costs. In Argentina, the second part of payment was based on plant availability. If the facility was out of service due to a planned or unplanned outage, a penalty factor was applied. Penalty calculations were based on outage duration and facility importance. In Argentina, an additional component included a penalty or bonus factor based on pre-established quality standards. If plant performance was above this quality standard, the bonus was given and, conversely, when performance was below expectations, the penalty factor was applied.

<table>
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<th>1999</th>
<th>BUS 7120 AVG. MARGINAL COST $/MWh</th>
<th>BUS 8900 AVG. MARGINAL COST $/MWh</th>
<th>NODAL PRICING BETWEEN BUS 8900 and 7120 $/MWh</th>
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<td>18.86</td>
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<td>1.74</td>
</tr>
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</table>

**Table 5.1 Nodal Pricing for Buses 7120 and 8900**
Vector Absolute Megawatt-Mile Method

The VAMM method is an extension of the megawatt-mile method. The VAMM calculation is simply a measurement of a generator's impact on a transmission system in the normal process of serving that generator's load (determined by ownership or contractual arrangement). To determine impacts in the VAMM test data, increments of testing have to be applied using load flow techniques. The assumption is made that the MW-mile impacts are linear given the amount of change normally seen on the system as a generator's power output varies during peak conditions.

Example of VAMM Method (State of Texas)

As discussed above (postage stamp method), 30 percent of the transmission revenue for the Electric Reliability Council of Texas (ERCOT) will be divided among the wholesale customers on the basis of the VAMM method. Under this pricing mechanism, a customer using planned transmission service will pay an appropriate share of the costs of the transmission facilities, but utilities and non-utility suppliers will also be able to use the transmission system for unplanned transmission service without paying a facility charge.

To assist in calculating the cost of transmission services, the Texas PUC staff prepared cost schedules that show the impact of the rate provisions based on the above discussed method. For the VAMM portion of the cost, the megawatt-miles are calculated for each wholesale customer from the power suppliers. For year 1996, the PUC calculation shows that the total cost of the transmission system would be $631,633,088; the total MW-miles impacted would be 9,672,119 and the total system demand would be 44,567 MW.

\[
\text{VAMM portion of the cost} = \frac{(631,633,088 \times .3)}{(44,567 \text{ MW} \times 9,672,119 \text{ miles})} = \$0.0004/\text{kW/mile/year}
\]

These calculations are based on the estimated value of transmission and generation systems for the year 1996. If new capacity is added or deleted from the system or new transmission lines are added, the load ratio and MW-mile impact calculations will change as well wheeling cost calculations. However, for the next 5 years, new transmission capacity is not anticipated and net load increases will be small. Considering these factors, wheeling costs are not anticipated to change significantly.

Investment Cost Related Pricing Method

The investment cost related pricing (ICRP) is an alternative approach to spot pricing for the use of the transmission system and is the method adopted in England and Wales. It employs a long-run marginal cost concept and marginal cost is computed at each node on the network. The analytical method applied for the computation of marginal cost is based on the transportation model. ICRP comprises two components. The first is related to the capital charges associated with the incremental investment in the system, and with operating and maintenance costs associated with providing bulk transfer power to different locations. The second incorporates the cost of providing security.
The resulting use of the system pricing structure:

- Is intended to reflect the cost of installing, operating, and maintaining the transmission system
- Charges generators on a per kW of capacity basis
- Charges demand on a per kW of peak demand basis
- Gives locational signals to grid users as the charges are based on geographical tariff zones (into which system users are grouped on a locational basis)
- Consists of payments to grid users (in this case to generators) as well as charges when the location of a user is beneficial to the grid and avoids owning or operating costs for the grid system

Once the planned minimum "takes" have been contracted, the generators would be free to compete for the remaining market. Transmission charges are applied separately to recover the cost of construction and operation of the transmission system.

**Example of Investment Cost Related Pricing (England and Wales)**

In England and Wales, the National Grid Company (NGC) owns and operates the network of high voltage transmission lines and associated equipment. This network is also referred to as National Grid. It enables the bulk transfer of electricity from the power stations to the distribution systems of the regional electricity companies (RECs), and directly to large customers. Transmission system customers are the companies that hold generation or supply licenses and a small number of large power consumers. These customers are charged for connection to the transmission system (connection charge or stand-by charge) and for use of the system charge:

a) **Connection Charge:** Charges for connections made since vesting are calculated with reference to the particular cost of making connections. There are two principal charging mechanisms: one is based on the actual cost indexed annually by the retail price index (RPI); the other is based on the actual cost revalued annually in line with the modern equivalent asset value.

b) **System Charge:** The use of the system charge depends upon the:
   - Type of customer-supplier or consumer
   - Level of associated activities
   - Location of operation

The use of the system tariff is calculated using a transport model. The ICRP-based transport model calculates the marginal cost of investment in the transmission system that would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system. This nodal charge is then aggregated with a security charge to form the zonal tariff.

The cost of transmission may be determined by the difference in charges for a generating source about 125 miles (200 km) from the load center, and one local to the load center. For example: a 100-MW plant in zone 1 charging $787,000 compared with say $103,000 in zone 11, yields a "transmission" charge of $684,000 for 100 MW.
c) Transmission Losses: In addition to connection and use of system charges, customers must pay for transmission losses, certain transmission support services and for the higher cost of generation that results from constraints (also defined as "uplift charges"). The cost of the losses is allocated to customers by combining the losses of the entire network. There is no geographic differentiation in charges nor is any proportion of these losses charged to generators. In 1995/96, NGC was financially exposed to the actual volume of losses at a pre-determined price of £25 per MWh. There is a proposal presently with the pool which, in the absence of any agreement within the pool, may be the subject of a ruling by OFFER. The proposal indicates that payment to the generators reflects small losses, i.e., northern generators may be paid for only 95 percent of energy supplied, whereas southern generators may be paid for 105 percent.

d) Demand Charge for Generation Facilities: Every user who takes or expects to take demand directly from the NGC transmission network is required to provide NGC with its demand forecasts.

5.6 TECHNICAL CONSIDERATIONS FOR TRANSMISSION SECTOR UNDER COMPETITIVE POWER INDUSTRY

In a vertically integrated utility industry, transmission planning is the responsibility of the utility companies and other transmission owning entities. However, in a competitive power industry with wholesale, pool or bilateral models, transmission planning will also be the responsibility of each industry participant. The addition of a new power plant by a generating company, or the establishment of a bilateral contract between two parties, will require an in-depth evaluation of the transmission system. When such changes to the system are proposed, the ISO or the RTG will perform the system studies and will determine whether the schedules submitted can be simultaneously accommodated on the transmission system. If system study results indicate that proposed changes will compromise transmission system reliability or create congestion, the ISO would have the option to reject the proposed changes or suggest alternative arrangements. However, these arrangements will not be on a least-cost basis and may not be economically accepted.

Under the circumstances, it is anticipated that, in a competitive power industry, transmission planning studies will play an important role and it will be the responsibility of market participants. Following are the technical recommendations/considerations for necessary transmission studies in a competitive power industry. These recommendations are provided as a general guideline only. Actual system studies and design documents should comply with requirements set by the local utility company, ISO, the National Electrical Safety Code (NESC), the National Electrical Code (NEC), equipment manufacturers, and standard design practice.

The principal system studies undertaken are:

a) Load flow
b) Short circuit
c) Stability
d) Relay coordination protection
To perform these studies, most utilities and other consulting companies use a computer package similar to PSS/E® (power system simulation for engineers) from Power Technologies Incorporated of Schenectady, New York. Other specialized studies may be required to include 60 Hz and high frequency overvoltage or resonance aspects of a system. Commercially available programs are used for the analysis of disturbing loads, harmonic penetration, and electromagnetic interference.

**Load Flow Studies**

The load flow study program uses the appropriate data related to the projected generation pattern, system data, and transmission station demands and an output is obtained that indicates what current flows and voltages result on different parts of the system (or on a section of it). The output may be indicated visually on a monitor or in the form of a printout or plot. There is a facility to draw attention to circuits loaded above a certain fraction of their thermal ratings or to voltages outside certain limits. The consequences of individual contingencies are studied by repeating the base-case with such items as are assumed to not be in service. Where conditions are found to be substandard relative to predetermined criteria, and there are no reasonable operational options that would serve to avoid such conditions, network strengthening is considered and different strategies or options are tested by repeating load-flow studies with the different alternatives under consideration.

These studies relate to such demand conditions as are considered relevant for the plan and the system under examination. For each region, studies vary depending upon weather conditions, transmission system maintenance procedures, system reserve requirements, and many other conditions. However, the conditions normally studied are:

- Annual peak
- Maintenance season
- Minimum demand
- Maximum demand
- Loss of generation
- Loss of transmission line

The following data are needed to perform a load flow study. Minor differences exist between the details of the information required by various computer programs, but the list is fairly representative:

1. One-line diagram.
2. MVA-rating, impedance, voltage ratio, and available taps of all transformers. The present voltage tap setting is also required. Load tap changing transformers should be identified.
3. At the utilization voltage buses, the total expected motor and static-type load in MVA and power factor should be furnished.
4. Ratings of all shunt or series capacitors, reactors, and synchronous condensers.
5. Nameplate rating of generators, including MW-loading schedule, reactive limits, and the voltage level desired at the generator bus.
6. Type, size, and number of conductors and lengths of all interconnecting power cables, and configuration of aerial lines.
7. If both local generation and a power company supply the plant load tie, the MW and MVAR limits of the tie circuit should be stated. The power company voltage level at the tie transformer or plant entrance should be indicated.

**Short Circuit Studies**

Power systems are subject to damaging effects of high magnitude currents flowing from short circuits occurring in system components.

A short-circuit study calculates the short-circuit current available under specified circumstances at one or more points in the power system. The most common short-circuit study assumes that a bolted or impedanceless fault is applied across all three phases of the circuit at each fault point, because the three-phase short circuit almost always produces greater magnitudes of short-circuit current than any other type of fault. In many cases, however, a bolted single-line-to-ground fault is studied as well. While transient values are acceptable on distribution networks or in areas remote from generation, subtransient values are required for the main system, particularly in the vicinity of the generation plants or where fast operating relays and/or switchgear are in use. The cases generally studied are maximum and minimum demand in the first and last years of a plan, respectively. Peak and minimum demand conditions are studied to assist in the selection of suitable settings for protection relays. Short circuit studies with future expected peak conditions might be necessary to evaluate adequate switchgear ratings. A short circuit analysis can be used to determine any or all of the following:

- Calculated system fault current duties that can be compared with the first cycle (momentary) and interrupting short-circuit current rating of circuit interrupting devices, such as circuit breakers and fuses.
- Calculated system fault current duties to compare with short-time, or withstand ratings of system components such as cables, transformers, and reactors.
- Selection and rating or setting of short-circuit protective devices, such as direct-acting trips, fuses, and relays.
- Evaluation of current flow and voltage levels in the overall system for short circuits in specific areas.

The data needed to perform a short circuit study is listed below. Minor differences exist between the details of the information required by various computer programs, but the list is fairly representative:

1. One-line diagram.
2. Short-circuit contribution from power company source and the X/R ratio of this contribution (three-phase and phase to ground).
3. Impedance, voltage ratio, MVA-rating, winding connection, and method of neutral grounding of all power transformers.


5. Characteristics of all induction and synchronous motors. Data on medium-voltage motors, 2400 V and above, should include full-load amperes, voltage, speed, and reactance values, subtransient plus transient if motors are synchronous. The low-voltage motors may be grouped on a bus and simulated as one machine, using an equivalent value of reactance.

6. MVA, voltage rating, method of neutral grounding, and all subtransient reactance values of all synchronous generators, synchronous condensers, and frequency changers.

7. Type, size, and number of conductors and lengths of all interconnecting cables. For overhead conductors include spacing between phases.

8. Indication as to which tie breakers or switches are normally closed or cannot be closed for certain reasons.

**Stability Studies**

A transient stability study simulates the performance of a power system under specified abnormal transient conditions. Stability studies are applied to industrial and commercial facilities that have installed local generation, large synchronous motors, or both.

Stability is lost if a network disturbance such as a fault, the loss of a generator or a utility tie line, or a sudden change in load causes large synchronous machines to lose synchronism with each other or with the rest of the system. A transient stability study provides a means of predicting whether this loss of synchronism or network instability will occur.

Stability studies are very demanding of computer time; consequently, much care should be taken in selecting the type and location of disturbances for the study. Where the same network, or substantially the same network, exists for some years without strengthening, it is likely that conditions in one year, possibly immediately before or after network strengthening, will be more severe than in other years. The nature of system load has a strong influence on stability and consequently proper modeling of the load is important. Stability studies generally are transient stability studies that normally study the response of the system for approximately 5 to 10 seconds so that steady state stability may also be checked.

The following is a list of data needed to perform a transient stability study. Minor differences exist between the details of the information required by computer programs, but the list is fairly representative:

1. A prerequisite load flow study. The requirements listed below are in addition to those listed for a load flow study.

2. For induction motors (desired to be individually represented):
   - kVA- and voltage-rating
   - Power factor
• Rated speed
• Stator resistance RS and reactance XS
• Rotor resistance RR and reactance XR
• Magnetizing reactance Xm
• Inertia constant H of motor and load

3. For synchronous motors and generators (desired to be individually represented):
• kVA- and voltage-rating
• Power factor
• Rated speed
• Armature resistance Ra
• Potier (leakage reactance XL)
• Synchronous reactances: direct axis Xd and quadrature axis Xq
• Transient reactances: direct axis Xdl and quadrature axis Xq
• Subtransient reactances: direct axis Xd" and quadrature axis X(I")
• Time constants (open circuit) for transient reactance: direct axis Tdo' and quadrature axis Tqo'
• Time constants (open circuit) for subtransient reactance: direct axis Tdo" and quadrature axis Tqo"
• Inertia constant H (including load or prime mover)
• Saturation at 1.0 pu voltage SAT and 1.2 pu voltage SAT1.2

4. Type and description of voltage regulator and excitation system.

5. Type and description of generator control system.

6. Motors of relatively small ratings of the low- or medium-voltage levels, for which individual performance data are not desired, should be grouped and simulated as one machine of constant power. Static-type loads should be grouped and represented as a constant impedance.

**Protection and Coordination Studies**

A protection and coordination study determines the characteristics and settings of protective devices, fuses, and overcurrent trips that provide the optimum combination of protection for the power system and reliable service to the loads. Ordinarily, these two objectives are to some extent mutually exclusive.
Power systems should be designed to incorporate the following features:

- Quickly isolate the affected portion of the system while maintaining normal service for the rest of the system and minimizing damage to the affected portion.
- Minimize magnitude of the available short-circuit current to limit potential damage to the system, to components, and the utilization equipment it supplies.
- Provide alternate circuits, automatic throw-overs, and automatic reclosing devices, where applicable, to minimize the duration and the extent of supply and utilization equipment outages.

The following is a list of data needed to perform a protection and coordination study. Minor differences exist between the details of the information required by computer programs, but the list is fairly representative:

1. One-line diagram identifying the location and function of each protective device and power fuse.
2. Ratio of the instrument transformers energizing each protective device and available taps.
3. Type designation, range of adjustment, style or catalog number, and manufacturer of each protective device. The existing settings on each device should be included if applicable.
4. Type designation, voltage, and current rating and manufacturer of all power fuses.
5. Short-time maximum or emergency load current that can be expected on each feeder. For motor circuits, this should include the locked-rotor current, allowable locked-rotor time, and starting time for each medium voltage motor.
6. Type of breaker, type of trip unit, and trip setting for each low-voltage transformer main secondary circuit.
7. Desired coordinating time interval between the settings of adjacent overcurrent devices.
8. Results of the three-phase and line-to-ground short circuit study.
9. Time-current characteristic curves for all protective devices and fuses.
10. ANSI-point of all transformers.
11. Transformer inrush points.
12. Current rating of all feeders protected by protective relays.

Other Studies

Depending on the circumstances, other studies determining the effects of industrial or disturbing loads may be required. Studies may also be required on a transient network analyzer (analog method) or electromagnetic transient analysis program (EMTP) computer program (digital method) to establish insulation levels required for switching surges or overvoltages.
5.7 CASE STUDIES

To demonstrate tools, methodology and approach for the technical and economic considerations discussed above, two separate case studies are presented. Case 4, 250-MW Plant Siting Study, demonstrates necessary tools and methodology for the transmission system assessment for the installation of a new 250-MW plant. Case 5, Unbundled Cost Components of a Transmission System, presents estimated costs for the different components of a transmission delivery system as discussed earlier.

CASE STUDY 4 - 250-MW PLANT SITING STUDY

Considering the 250-MW plant conditions discussed in Chapter 4, this case study determines the impact on the transmission system after connecting the plant at selected buses 7120 and 8900. The study is also an extension of Case Study 3, where market assessment, long-term price forecasts and projected revenue for the 250-MW power plant were presented for buses 7120 and 8900. The economic assessment presented in Case Study 3 was conducted using NEA’s PROMOD IV® software. However, for the load flow, short circuit and stability studies, PSS/E® software was used. Most of the reliability councils in the U.S. provided necessary data in PSS/E® format. This data set included projected summer and winter peak conditions on a yearly basis for the next 5 to 10 years. However, the data provided by reliability councils are suitable for load flow and contingency studies only. To conduct short circuit and stability studies, additional data are necessary, which may be obtained from the planning or marketing group of the local utility company.

The studies presented are based on 1999 summer peak data provided by the Florida Reliability Coordinating Council (FRCC) to model the base case for the transmission system operating conditions. Using PSS/E® and data from the FRCC, a computer model was developed for the transmission lines connected to buses 7120 and 8900. Base case load flow condition results are shown in Figure C4.2. Table C4.1 provides a list of transmission line loading above 75 percent of rating, and buses with voltage greater than +/- 5 percent nominal voltage under base case conditions. A 250-MW plant was individually added to buses 7120 and 8900 in the “base case” to determine how connecting the generator would affect transmission line loading. The resultant load flow cases for bus 7120 are presented in Figure C4.3 and for bus 8900 in Figure C4.4. Results indicate that additional generation at either bus would not impact the system. Impacted transmission line loading and bus voltages due to adding the 250-MW plant at bus 7120 is listed in Table C4.2 and, similarly, impacted transmission line loading and bus voltages due to adding the 250-MW plant at bus 8900 is listed in Table C4.3. To assist in understanding the load flow results, Figure C4.1 illustrates the load flow diagram legend.
**Figure C4.1 Load Flow Diagram Legend**

<table>
<thead>
<tr>
<th>#</th>
<th>Symbol Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Bus name</td>
</tr>
<tr>
<td>2</td>
<td>Bus number</td>
</tr>
<tr>
<td>3</td>
<td>MVA flowing out of bus</td>
</tr>
<tr>
<td>4</td>
<td>Percent line loading</td>
</tr>
<tr>
<td>5</td>
<td>MW contribution of equipment</td>
</tr>
<tr>
<td>6</td>
<td>MVAR contribution of equipment</td>
</tr>
<tr>
<td>7</td>
<td>Bus voltage (KV)</td>
</tr>
<tr>
<td>8</td>
<td>Bus voltage (per unit)</td>
</tr>
<tr>
<td>9</td>
<td>Auto transformer</td>
</tr>
<tr>
<td>10</td>
<td>Auto transformer tap settings</td>
</tr>
<tr>
<td>11</td>
<td>MVA flowing into bus</td>
</tr>
<tr>
<td>12</td>
<td>Generator</td>
</tr>
</tbody>
</table>

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**Figure C4.2 - Base Case**
Figure C4.3 - New Generation at Bus 7120

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### Chapter 5

**NOTE:** The author is no longer employed with Parsons Brinckerhoff. This monograph is for reference/research purposes only and not for distribution.

#### Table C4.1, Transmission & Voltage Condition Base Case

| Base Case Condition - Transmission Line Loadings Above 75.0 percent of Rating Set A: For Areas Associated with Bus 7120 & 8900 |
|---|---|---|---|---|
| From Bus | To Bus | CURRENT (MVA) |
| BUS NAME BSKV AREA | BUS NAME BSKV AREA | Ckt | Loading | Rating Percent |
| 6679 | DR IN TP69.0 | 12 | 6720* LK ASBU 69.0 | 12 | 1 | 20.4 | 25.0 | 81.5 |
| 6803* | CORRETT 138 | 12 | 6815 | LEE | 138 | 12 | 1 | 158.7 | 173.0 | 91.7 |
| 6904* | BELVEW 69.0 | 12 | 6909 | DALLAS 69.0 | 12 | 1 | 42.6 | 52.0 | 82.0 |
| 6909* | DALLAS 69.0 | 12 | 6930 | WILD WD 69.0 | 12 | 1 | 45.2 | 52.1 | 86.8 |
| 6998* | BUCK LK 69.0 | 12 | 7014 | MZCOSK 69.0 | 12 | 1 | 24.6 | 29.0 | 84.9 |
| 7075 | HUDSON 115 | 12 | 7083* | SEA P TP 115 | 12 | 1 | 89.3 | 114.0 | 78.4 |
| 8888* | BUCKEYE 230 | 1 | 8888* | RUSHMTR8 230 | 16 | 1 | 371.3 | 430.0 | 86.4 |
| 8888* | RUSKMTR8 230 | 16 | 8900 | B BEND | 230 | 16 | 1 | 371.3 | 478.0 | 77.7 |

#### Base Case Condition - Buses with Voltage Greater Than 1.050:

| Bus -----X AREA V(PU) V(kv) | Area V(PU) V(kv) |
|---|---|---|---|---|
| 7940 | HARDBECC 13.8 | 16 | 1.0643 | 14.687 | 7961 | APP CCG 13.8 | 16 | 1.1357 | 15.672 |
| 7962 | APP CGC 13.8 | 16 | 1.1013 | 16.302 | 8700 | GANNON 230 | 16 | 1.0500 | 241.50 |
| 8862 | SO GIB 69.0 | 16 | 1.0506 | 72.491 | 8870 | RUSKIN T 230 | 16 | 1.0501 | 241.53 |
| 8872 | RUSKIN 69.0 | 16 | 1.0507 | 72.498 | 8890 | BIGBCT-T 230 | 16 | 1.0550 | 242.65 |
| 8900 | B BEND | 230 | 16 | 1.0550 | 242.65 | 9049 | NWLS 69.0 | 16 | 1.0503 | 72.467 |

#### Buses with Voltage Less Than 0.950:

| Bus -----X AREA V(PU) V(kv) | Area V(PU) V(kv) |
|---|---|---|---|---|
| 6904 | BELVEW 69.0 | 12 | 0.9279 | 64.024 | 6921 | MARION O69.0 | 12 | 0.9109 | 62.852 |
| 6923 | OCALA N 69.0 | 12 | 0.9034 | 62.334 |
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### 250 MW Plant at Bus 7120 - Transmission Line Loadings Above 75.0 percent of Rating Set A:

<table>
<thead>
<tr>
<th>BUS NAME</th>
<th>BSKV AREA</th>
<th>BUS NAME</th>
<th>BSKV AREA</th>
<th>Ckt Loading</th>
<th>Rating Percent</th>
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<td>20.4</td>
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### 250 MW Plant at Bus 7120 - Buses with Voltage Greater Than 1.0500:

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<tr>
<th>BUS NAME</th>
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<th>BUS NAME</th>
<th>BSKV AREA</th>
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<th>V(kv)</th>
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<td>7940 HARDFCC13.8</td>
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### Buses with Voltage Less Than 0.9500:

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**Table C4.2, Transmission & Voltage Condition with 250-MW Plant at Bus 7120**
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<th>BUS</th>
<th>NAME</th>
<th>BSKV</th>
<th>AREA</th>
<th>FROM BUS-----X</th>
<th>CURRENT (MVA)</th>
<th>TO BUS-------X</th>
<th>BUS</th>
<th>NAME</th>
<th>BSKV</th>
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250 MW PLANT AT BUS 8900 - BUSES WITH VOLTAGE GREATER THAN 1.0500:

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<tr>
<th>BUS</th>
<th>NAME</th>
<th>BSKV</th>
<th>AREA</th>
<th>V(PU)</th>
<th>V(KV)</th>
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<th>BSKV</th>
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**TABLE C4.3, Transmission & Voltage Condition with 250-MW Plant at Bus 8900**
CASE STUDY 5 - UNBUNDLED COST COMPONENTS OF POWER DELIVERY SYSTEM

As discussed previously, vertically integrated utility companies will be required to operate their generation, transmission, and distribution units as separate business entities. Therefore, transmission of the electricity must be offered and priced separately from the power itself. Through this case study, an attempt is made to summarize the many components of transmission cost and to show the transmission system as an unbundled service. Necessary data to perform such calculations are difficult to obtain. However, as utilities develop towards a competitive industry, additional information should become available. In the absence of such data and necessary tools, this case study may not provide the most accurate results; however, it does provide the methodology and approach for calculation of different cost components for transmission service.

Chapter 4 discussed the major components of a power delivery system and various methods to determine the cost of generation. One such method is based on generation dispatch, which is based on the spot price of electricity. Case Study 3 uses this method and calculates the marginal generation cost on an hourly basis for buses 7120 and 8900. Table C5.1 duplicates the average monthly marginal cost for bus 7120 for year 1999. On an hourly basis, this will be the cost generators will be paid for their service. In a pool-based dispatch, this will be a pool purchase price (PPP).

**Table C5.1, Average Marginal Cost for Bus 7120 - Year 1999**

<table>
<thead>
<tr>
<th>PPP (US$/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
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In addition to this cost, generators will be paid for other services needed for the safe and reliable operation of the power system. In England and Wales, the term used for these costs is “uplift.” In the absence of any other accepted industry term in the U.S., the same term will be used for the purposes of this study. The cost of uplift includes costs associated with the following components:

* Cost of losses—As discussed in this chapter, the transmission system is not 100 percent efficient, so someone has to pay for the transmission losses. To compensate for losses in the system, the pool will be required to purchase an additional amount of generation and the cost associated with this additional generation is added to the uplift cost.
• Cost of transmission congestion—In a period of high demand, not all the power that could be generated in the low cost region can be dispatched. In this case, the demand is met by higher cost plants that normally would not run, but due to transmission congestion must not be used. The cost difference would be the cost of transmission congestion.

• Ancillary services—Ancillary services include the cost of providing services necessary to maintain voltage, frequency, black start capability, reactive power support, etc.

• Unscheduled availability—Unscheduled availability payments are made to generation capacity that is not scheduled to run, but is nonetheless available to be called on if needed.

• Administrative cost of the pool—Pool-based or any other system model will also include administrative costs for managing the system. If the pool is a non-profit organization, the cost will be limited to the operation cost; however, if pool functions are conducted by a private company, it may also include negotiated profits.

Depending upon various factors discussed above, the cost of the uplift will vary from system to system and it may range from 10 to 15 percent of the pool purchase price. The uplift will be made up of 2 to 3 percent for the cost of system losses, 2 to 4 percent for the cost of transmission congestion, 3 to 5 percent for the cost of ancillary services, and the remaining for other miscellaneous costs. For this study, the cost of uplift is estimated at 12 percent. Adding the cost of the uplift to the PPP will be the pool selling price (PSP), which will be the cost of energy for wholesale buyers and large industrial customers. Column B of Table C5.2 lists the cost of the uplift and PSP for the system under consideration. Under direct access with bilateral contracts, buyers and sellers will decide the cost of energy among them and their dispatch may not effect the PPP; however, they may be required to pay the uplift cost to the pool.

Once energy is purchased through the pool or through bilateral contracts, it has to use the transmission system for delivery of power from the generating point to the point of delivery. This requires payment to the transmission owning utilities. Depending upon the industry model selected, different states in the U.S. will have different transmission cost recovery methods. However, it is anticipated that the overall cost of the transmission system recovery may not be much different among various models. For this study, a transmission cost of 12 percent of PSP is estimated. Depending upon various factors, including amount of constraints, loop flow in the transmission system, political, environmental and regulatory considerations, the transmission wheeling cost will vary greatly. Column D of Table C5.2 shows the transmission wheeling cost of the system under consideration.

During the transitional phase of industry deregulation, it is anticipated that there would be some additional cost recovery for the stranded assets. FERC Order 888 has provisions for public utilities and transmitting utilities to seek recovery of legitimate, prudent, and verifiable stranded costs associated with providing open access. Depending on the type of industry model selected by the states’ PUCs, stranded cost will vary. It is expected that, under retail competition, stranded cost would be much higher than wholesale competition. For this study, the stranded cost recovery is estimated at 10 percent of the PSP. Combining PSP, transmission wheeling cost, and stranded cost will be the cost of electricity for the wholesale
customer. Adding taxes and a small administrative cost would produce the cost of electricity for the large industrial customer with interconnection at the transmission level. For purposes of this study, an estimated value of 8 percent is used for taxes and administrative fees.

Other end-use customers, whose utility interconnection is at the distribution level, would also be paying additional cost to the distribution companies. Similar to the items discussed for transmission system cost recovery, this cost would include cost recovery for the distribution system. For traditional utility companies, the operating cost of the distribution system is twice the cost of the transmission system. Additionally, distribution companies will also provide other services such as meter reading, financial help to end-use customers, aids for demand-side management programs, etc. For the purpose of this study, an estimated value of 22 percent of the wholesale price of electricity is estimated as the cost for the distribution system. Adding taxes and a small administrative fee to this value would produce the cost of electricity for the end-use customer at the retail level. For the system discussed in Case Studies 3 and 4 for year 1999, Table C5.2 summarizes these components for bus 7120, and Table C5.3 summarizes the components for bus 8900.
### Table C5.2, Unbundled Cost Components of Power Delivery System at Bus 7120 – Year 1999 – SERC Region

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### Table C5.3, Unbundled Cost Components of Power Delivery System at Bus 8900 – Year 1999 – SERC Region

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A. Pool Purchase Price (PPP) - Price paid to the generators  
B. Uplift Cost - Additional cost paid to generators for ancillary services and pool administrative cost, estimated at 12 percent (d PPP)  
C. Pool Selling Price (PSP) - PPP + Uplift Cost (A + B)  
D. Transmission Wheeling Cost - Cost of wheeling Power from The point of generation to the Point of delivery, estimated at 12 percent of PSP  
E. Stranded Cost Recovery (SCR) - Cost paid to utility companies for stranded assets, estimated at 10 percent of the PSP  
F. Wholesale Price of Electricity (W P) = PSP + Trans. Cost + SCR (C + D + E)  
G. Taxes and other miscellaneous cost, estimated at 8 percent of W P (W P x .08)  
H. Cost of electricity for the large customer with connection at transmission lines = F + G  
I. Distribution Cost - Cost of wheeling power for (or transmission lines to end-use customer using distribution system, estimated at 22 percent of wholesale price (W P x .22)  
J. Taxes and other miscellaneous cost for the distribution customers - (F + I) x .08  
K. Cost of end-use customer - F + I + J
6.0 POWER SUPPLY OPTIONS FOR WHOLESALE AND RETAIL CUSTOMERS
6.0 POWER SUPPLY OPTIONS FOR WHOLESALE AND RETAIL CUSTOMERS

If changes proposed by the public utility commissions of California, Massachusetts, New York, New Hampshire, and many others (see Figure 2.1) are accepted by FERC, electrical customers of these states will face an impressive array of choices. The world where industrial and institutional facilities only purchase electricity from a single local utility supplier with the only alternative being a substantial capital investment in self-generation equipment is gone. In the new world these customers will be able to purchase from multiple suppliers and electricity purchasing will become another platform of competition. Successful facility owners will manage price risk and physical purchase similar to other process inputs, seeking out alternative supply sources to access bulk power markets.

However, with the opportunities of a free marketplace come complexities and risks that require well-informed decision making. This chapter discusses the opportunities available to end-use customers; provides the approach, methodology and tools used to sort out these options; and illustrates the projected savings for a large industrial customer. Since utility deregulation is still an ongoing process, many issues such as transmission cost methods, stranded cost recovery, system reliability assessment, and system security are still unresolved. It is difficult to evaluate the economic impact of these issues on the industrial power system. In addition, many circumstances and different conditions will affect the actual economic figures. The results and recommendations from cases presented herein are for demonstration purposes only and should not be used otherwise.

Options available for retail customers will depend on the industry model and regulatory changes implemented by the respective state PUC. If the PUC has not considered any changes, available options will not be any different than in the current industry structure. Similarly, under wholesale competition, options for the end-users will be limited. However, under the retail industry structure, many options will be available.

6.1 INDUSTRY STRUCTURE - CURRENT INDUSTRY MODEL

In today’s vertically integrated utility industry structure, the available options for end-use consumers are very limited. For very large facilities, if the manufacturing process requires steam, on-site generation is an option and many customers have already installed cogeneration units to fulfill their requirements. However, due to the initial capital investment and the high cost of maintaining backstanding requirements, this option is not exploited to its full potential. Demand side management (DSM) is another option for both small and large facilities and is widely supported by many utilities by offering cost subsidies to customers who implement DSM programs. In a deregulated marketplace, the future of demand side management is questionable. Under current industry structure, available options for retail customers are:

1. Purchase from local utility company
2. Self-generation
3. Demand side management
6.2 INDUSTRY STRUCTURE - WHOLESALE COMPETITION

Before full-scale competition is reached at the retail level, there will be a transitional phase—competition at the wholesale level. In the wholesale competition model, generation would become fully competitive and unregulated with multiple independent generating companies competing to sell power to distribution companies. The ISO/RTG would be responsible for reliability and security of the bulk power market, and would coordinate auxiliary services, control generation and transmission, and dispatch power through a regional pool. The market structure under the wholesale model is shown in Figure 6.1. As shown in the figure, distribution companies would have the choice of supplier and also maintain a monopoly over energy sales to end-use customers. Competitive bidding at the generation level or through bilateral contracts between wholesale buyers and energy providers will result in lower generation costs. Eventually this will lower the price to the end-use customer. The effect of wholesale competition is already here. Many utility companies are lowering their electricity rates for large customers. However, from the available options point of view, wholesale competition in the transitional phase will be no different from today’s market structure. Although some utility companies are presently offering time-of-use metering and real-time pricing, these are very limited and various options should be considered and compared to determine the best one.
Under an industry structure with competition at the wholesale level, available options for retail customers are:
1. Purchase from local utility company
2. Self-generation
3. Demand side management
4. Real-time pricing from local utility company

**The Option of Real-Time Pricing**

End-use customers may not be aware that the demand for electricity varies dramatically over a 24-hour period. Peak demands on a utility system are generally experienced from 2:00 PM to 6:00 PM; at all other times, the system is underutilized and investment is underproductive. Most customers purchase electricity at a rate that represents the average cost of electricity. Some customers have the opportunity to purchase electricity at real-time or time-of-use (TOU) rates. These rates allow customers to see the price of electricity at specific time periods so that they can adjust their electricity use to off-peak or partial-peak hours.

### 6.3 INDUSTRY STRUCTURE - RETAIL COMPETITION

From an industrial customer's point of view, available options begin with retail level competition. Industry structure under the retail model is discussed in Chapter 3 and illustrated in Figure 6.2 below. As shown in this figure, retail customers will have a choice of...
buying their electricity from the pool, from the broker or making direct bilateral contracts with generation companies. Bilateral contracts will be managed by the ISOs. If such contracts affect system parameters, the ISO will ask the buyer and seller to make alternative arrangements or pay an extra price for the transmission constraints. This is a bid-base industry model with direct access option. This model is similar to the industry model of the United Kingdom and is the one most states are considering.

Available options for retail customers are:
1. Continue with existing utility company
2. Buy from ISO or power pool
3. Buy from broker/power marketer
4. Bilateral contract with a GENCo/IPP/EWG
5. Load aggregation
6. Self-generation
7. Self-generation with optional purchase from pool
8. DSM with real-time pricing
9. Options for ancillary services
10. Other financial instruments

Option 1 - Continue with Existing Utility Company

Any customer will be free to retain its traditional relationship as a full-service customer of the local electric utility (distribution company or DISCo) and continue to rely upon the local distribution utility to procure as well as deliver electricity. These distribution companies will continue to provide regulated distribution service to customers. They will design, construct, own, operate, and maintain the distribution assets necessary to ensure safe and reliable delivery of electric energy to all customers connected to the distribution system. Competition will bring prices down and with already established relationships between existing utility representatives and customers, the customer may get better service quality and peace of mind.

Option 2 - Buy from ISO or Power Pool

As discussed previously, the ISO will be responsible for providing grid information, including conditions that impact routing, any accepted schedules and prices on a daily hour-by-hour basis and any specific operating instructions for the day ahead. Alternatively, the power exchange will establish a competitive spot market for electric power through a day-ahead and hour-ahead auction of generation and demand bids using transparent rules and protocols. This auction will bring together buyers and sellers who have not arranged all of their needs through bilateral contracts. This auction will also allow the power exchange to reveal day-ahead and hour-ahead market-clearing prices in coordination with the ISO. This mechanism has been working in the United Kingdom for the last 8 years and, at least theoretically, provides the least cost to the buyer. However, the day-to-day price of electricity will fluctuate under heavy load conditions and the cost may increase considerably. Economic analysis with generation outages can predict price fluctuations on a hypothetical basis.
Option 3 - Buy from Broker/Power Marketer

The evolution of other industries undergoing the transition toward greater customer choice has meant the entry of new parties who look at things differently than industry incumbents. Not tied to the regulated past, these new entrants, who seek entrepreneurial rather than utility returns, are more willing to do things differently. Notable examples in other industries include MCI in telecommunications, Southwest Air in air transport, and Charles Schwab in financial services. These new entrants act as a catalyst for change, transforming the industry.

In the electric industry, the catalysts for change are the power brokers and power marketers who own neither generation nor transmission and are not affiliated with any entity owning generation or transmission. They make their money by buying and selling power. Power marketers can do this more efficiently than traditional utilities by physically unbundling the kilowatt and separating its functional from its physical aspects.

Power marketers purchase each service from the supplier who can provide it most economically. A marketer might buy energy from producer A, capacity from B, and load following services from C. It might buy interruptible service from a number of suppliers and, in the unlikely event all suppliers fail, back up those supplies with power from an older plant that it was able to buy at a small cost. It might buy a large block of cheap power from one supplier, and then sell that power in discrete blocks as the opportunity arises.

Under the retail models, marketers will almost certainly have a much larger role than under a wholesale-only model.

Option 4 - Bilateral Contract with GENCo/IPP/EWG

Under retail competition, a customer may form a physical, bilateral contract directly with a generator or an aggregator who will then delegate the task of generation to those actually in that business. This contractual arrangement will influence the dispatch of generation and govern the financial consequences of consumption. The financial consequences of direct access contracts involve, at a minimum: those of the customer who consumed a quantity of electricity, those of the generator who simultaneously supplied to the transmission grid a correlative quantity of electricity, and the local utility, which delivered an equivalent amount to the customer's physical premises. In a direct access contract, the parties seek to dispatch specific generation on the part of sellers as well as provide fixed financial terms to the consumer.

Under a bilateral model, transactions will be customized. With bilateral competition, the ISO coordinates transactions for security, but not for economics (although security actions such as dispatch will impact economics). The pool model would result in structured physical transactions and some financial contracts, such as contracts for differences (CFD), which may develop as a secondary market. A pool would provide a market mechanism for a spot market and include a mechanism for ensuring secure operation.
In a competitive market for a tangible commodity, a variety of transaction types emerge to allow market participants to manage their exposure to price fluctuations. These transactions are developed to allow parties to commit to price and other terms to be performed in the future. This market (a "forward market"), as distinguished from a spot market, establishes the market prices today for commodities to be delivered in the future. This enables market participants to: (1) lock in prices in a competitive market and avoid the transaction costs imposed by frequent activity in the spot market and (2) assess the wisdom of, among other things, securing additional reserves, production, or supply, or investing in conservation measures. In competitive commodity markets, the vast majority of transactions, by number and volume, occur in this forward market, while the spot (short-term) market serves as the means for parties to make adjustments (e.g., to account for errors in original forecasts). As a consequence, prices in the forward market are based not so much on what spot prices are expected to be, but on the dynamic interaction of market participants' needs, desires, planning, and appetite for risk.

The Basic Type of Contracts

In a competitive market, electricity can be bought and sold in a number of different ways, using standard forms of contracts. Since the terminology can be confusing, the following sections describe the basic forms of contracts used in the commercial sector. A spot contract, perhaps the simplest form of transaction, is first examined to identify the basic terms of any sale.

Spot transactions are sales of an asset for immediate delivery. Spot sales are often not accompanied by the creation of any formal contract. Money is passed from the buyer to the seller, and the asset changes hands in the opposite direction. However, the terms of the deal are clear and can be specified whether there is a formal contract or not.

Spot Contracts

Spot transactions, like any transaction, involve a specified quantity of a defined asset. The defining characteristic of a spot transaction is that delivery is immediate and unconditional. However, several other terms must also be defined to make the transaction possible, such as the place of delivery. Some spot transactions involve sales of commodities, such as oil or foodstuffs, which are located miles from the market itself. The financial terms of a spot contract include not just the price per unit of the commodity but also the method of settlement. The contract may be settled by an immediate cash payment, or may allow a grace period of 30 or 60 days before payment is due. These terms must all be agreed to before any spot transaction can be completed. Sometimes the terms are agreed informally, but often a formal contract is drawn up.
Forwards and Futures Contracts

A forward contract is a supply contract between a buyer and seller whereby the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of a commodity at a predetermined price on a specified future date. Payment in full is due at the time of, or following, delivery. A futures contract is a supply contract between a buyer and seller whereby the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of a commodity at a predetermined price at a specified location. Futures contracts are traded exclusively on regulated exchanges and are settled daily based on their current value in the marketplace. Forward contracts differ from futures contracts where settlement is made daily, resulting in partial payment over the life of the contract.

Examples of future and forward contracts:
- Power producers can sell futures contracts to lock in a sales price of their power.
- Large buyers can buy futures to protect their purchase price.
- Power marketers, who have exposure on both sides of the market, can hedge with futures to mitigate that risk, buying or selling contracts as appropriate.
- Integrated utilities may be able to use futures to protect revenue targets. As performance-based ratemaking gains acceptance, futures can be used to achieve performance benchmarks.

Conditions of Delivery: Options

Options are products that give the purchaser the right, but not the obligation, to buy or sell something at a set price. In the context of electric power, they are typically contracts that give the purchaser the right to purchase generating capacity at a fixed price. For this right, the purchaser pays a fee called a "premium." To date, option transactions have been the exception. However, for reasons that will be evident later, this category is ready to boom along with that new class of players, the independent power marketers. The seller of an option, on the other hand, has an obligation to buy or sell futures contracts if a holder of an option chooses to exercise it.

There are two types of options: calls and puts. A call gives the holder the right, but not the obligation, to buy futures at a specified price (the strike or exercise price) for a specified period of time. A put gives the holder the right, but not the obligation, to sell futures at a specific period of time.

Buying a call or a put is similar to purchasing an insurance policy: in return for a one-time up-front premium, the buyer obtains protection against the occurrence of risk for the designated time period. To protect against the risk of a price increase, a hedger would purchase a call; to protect against a price decrease, a put. If prices do not move in an adverse direction, the options buyer forfeits only the premium and is otherwise able to participate fully in any favorable price move.
An options seller (or writer) performs a function similar to that of an insurance company. He collects the premium and is obligated to perform should the buyer exercise the option. If the options contract expires without being exercised, the options seller profits by the amount of the premium.

Unlike futures, which must either be liquidated or held for delivery of the underlying physical commodity, the holder of an option has a third alternative: if the futures price does not move enough to make exercising the option worthwhile, or moves in the opposite direction, the buyer can choose to allow his option to expire worthless. While futures can be held to delivery, options are exercised into the underlying futures contract.

**How Contracts for Differences Work**

As shown in Figure 6.3, contracts for difference (CfDs) are financial instruments through which generators (sellers) and consumers (buyers) can protect themselves against market volatility and uncertainty. CfDs are so named because the settlement involves transferring the difference between two prices. CfDs are particularly important in the electricity markets of England and Wales, where the electricity pool does not arrange for physical delivery of

![Diagram of how contracts for differences work](image-url)

*Figure 6.3 Contracts for Differences*
contracts but rather runs a spot auction for physical delivery and sets a spot market price. This price is used as the numerator for CfDs. Although CfDs are financial instruments, they have the same economic effect as a contract for physical delivery. They simply allow contracts to be settled bilaterally, outside any pooling arrangement.

**Option 5 - Load Aggregation**

Aggregation is a means for small, medium, and even large customers to exercise consumer options. Accordingly, the benefits of aggregation will be determined largely as follows:

- Lower costs for power and a greater variety of diverse products and services will increase the value of using electricity to consumers. In addition, the benefits of competition in wholesale power markets can be extended to smaller customers.
- Transaction costs for aggregation can be more easily absorbed when the benefits of competition are available, especially when the scope of differentiated products and services is increased.
- Consumer benefits will depend on the involvement of aggregators which, in turn, depend on (1) the attractiveness of a market to consumers and providers, and (2) the relative market power of participants in a market. Thus, providers will be discouraged from participating in small consumer markets if they perceive the potential value to be shared as too limited to allow for profitable operations.
- Aggregators will seek to increase value by offering differentiated products such as a portfolio of supply, energy efficiency, and management services.
- Consumers will obtain benefits from aggregation if they have sufficient market power in comparison to the transaction costs to serve them. The extent to which this will occur depends on five primary competitive forces: the threat of substitute products, the threat of new entrants, the bargaining power of suppliers, the bargaining power of buyers, and the rivalry among firms. The greater the strength and balance of these forces within a market, the greater the price and other benefits that will accrue to small consumers.
- To ensure that most consumers have an effective opportunity to significantly benefit from consumer choice, it will be necessary to:
  - Increase the value of benefits to both consumers and providers
  - Increase consumer market power vis-à-vis providers and other consumers
  - Lower the transaction costs to provide consumer choice

**Option 6 - Self-Generation**

As with the current industry model and the wholesale competition model discussed above, large industrial customers with on-site generation will be able to provide their own energy requirements. If a facility does not have enough on-site generation, it can specify to use its own generation for a portion of the load, with the remaining portion of the load at that facility provided by the local distribution company. This provides the customer maximum flexibility in purchasing energy. Large industrial customers with facilities located on two separate sites
can use the generating facility at one site to serve the load of the other site (also called self-serving wheeling). More choices will create greater market forces. There will be a great deal of uncertainty, especially during the initial stages of the restructuring process. Many customers will be hesitant to leave their existing utility connection completely and dive into this new and potentially volatile market. The option of being able to retain a block of one's load (which could represent a critical process) with the existing utility company, and experimenting in the free market with the balance, would be a very attractive and competitive alternative.

**Option 7 - Self-Generation with Optional Purchase from Pool**

Retail customers exercising the alternative for self-generation with option purchase from pool option will encounter situations when the pool price or the market clearing price will be lower than the marginal cost of its own generation. These retail customers will be able to purchase electricity up to the bid price (supply side bidding). If the market-clearing price exceeds the bid price, instead of bringing additional generation on line, load will be curtailed, and the market-clearing price will be decided from supply side bidding. This will provide greater savings to the customer; however, to exercise this option, the retail customer needs tools to predict market clearing prices for longer time periods. Traditionally, the ISO and power exchange provides price signals for the next 24 hours only. If such projections are made well in advance, production schedules for the on-site generating plant can be maintained in an organized way.

**Option 8 - DSM with Real-Time Pricing**

Conservation or DSM, as currently implemented by the utilities, is often a form of subsidy in which non-participants subsidize participants. Participants receive all the direct benefits of lower bills and since the cost of conservation programs are paid by all customers, rates generally increase. Lower consumption outweighs the impact of higher rates, resulting in lower bills to participants. Non-participants, on the other hand, can end up paying higher bills, since their rates increase and their consumption stays the same.

Subsidies are driven out by competition. Increased competition from alternative fuels, other states and self-generation are already having an impact on conservation. Conservation is often an attractive alternative especially for peak capacity. If retail access is allowed, generators would still have incentives to invest in cost-effective conservation measures that do not increase rates. If the cost of conservation is less than the difference between marginal cost and rates, it is beneficial to invest in conservation.

On the customer side of the meter, lower overall rates could discourage conservation investment; however, real-time pricing and new interruptible service options that would likely occur in a competitive market could create greater incentives for customers to reduce peak consumption and switch loads to off-peak or partial-peak periods.
Option 9 - Options for Ancillary Services

Ancillary service providers will include, but not be limited to, the ISO, generators, schedule coordinators, marketers, and aggregators. Ancillary service providers will provide services including spinning reserve, non-spinning generation reserve, interruptible load, regulation, replacement reserves, reactive power and voltage control, and black start capability. Retail customers with on-site generation will have an option to buy some of these ancillary services from the market participants or provide their own.

Option 10 - Other Financial Instruments

Many customers may be not be interested in the many choices of power delivery; however, they would desire price stability and predictability over a defined period of time. Such customers are free to entertain hedging contracts that may be formed with any individual or entity willing to take the counterpart risk. A customer who has formed such a contract continues to receive a bill from the local utility that reflects both the cost of electric power and distribution services. Periodically, such a customer totals the amount of payments to the local utility and determines whether they exceed the price guarantee in the hedging agreement. In that event, a bill is submitted to the other party who reimburses the customer in order to bring the cost of electricity for the period to within the agreed maximum. In the event that excess outlays have not been experienced, the party who sold the guarantee keeps the premium for taking a risk that was never realized.

6.4 CASE STUDIES

To demonstrate the tools, methodology and approach to evaluate available power supply options discussed above, a separate case study is presented. This case study also provides necessary links between the generation cost determination discussed in Chapter 4 (Case 3) and the unbundled cost of transmission systems discussed in Chapter 5 (Case 5). Using detailed data on one industrial plant's electricity use, Case 6, Option Evaluation for a Large Industrial Customer, evaluates available options for large industrial customers in the Florida area.

CASE STUDY 6 - OPTION EVALUATION FOR A LARGE INDUSTRIAL CUSTOMER

As discussed above, from the industrial customer's point of view, available options start with retail-level competition. During the transitional phase of the industry restructuring, most of the small and even a few large customers may decide to stay with the existing utility company (Option 1). With long-term contracts, utility companies will offer lower energy rates and, with already established relationships between existing utility representatives and customers, the customer may get better service quality and satisfaction that their energy cost has gone down. However, many would like to exercise their choice of supplier and the choice may mean real dollars. In order to make a meaningful choice, customers may have to perform a
comparative analysis of all available options. Evaluating each option on a comparative basis requires necessary tools, access to the regional database, an understanding of generation and transmission system cost structures, and a thorough understanding of the customer's energy needs.

To illustrate a comparison of these options, a large industrial manufacturing facility with a peak demand of 43 MW and with an annualized electricity cost of $8.89 million has been reviewed. As shown in Figure C6.1, peak demand for this facility is occurring during the winter months. For simplicity, the power consumption, demand and cost information shown in the following figures are on a monthly basis; however, actual data collection, computation and savings projections were performed on an hourly basis. For uniform cost comparison, the load profile is kept constant for the duration of the study and the inflation factor is not included; therefore, if the customer is willing to sign a 5-year contract, the utility company will not increase its cost. Assuming no load growth, $8.89 million actual cost for electrical energy will be constant for the next 5 years. If a customer decides to stay with the existing utility company (Option 1) and signs a long-term contact, his projected monthly energy cost is shown in Figure C6.2. Considering this as a base cost, a potential saving (or loss) is compared with this cost.

To evaluate other options, especially Option 3, buying it from the pool, requires long-term price projections for the cost of power delivery at the customer facility. The cost of power delivery at the customer facility includes cost of energy purchase through the pool, transmission wheeling cost and cost of other ancillary services. Based on generation dispatched on the spot price of electricity, Case 3, Economic and Marketing Analysis for the SERC Region, provides methodology, approach and necessary tools to determine cost of the generation in a competitive environment.

As a facility under consideration has higher energy consumption, its interconnection with the utility company will be at the transmission level. Case 5, Unbundled Cost Component of Power Delivery System, provides the methodology, approach and necessary tools to calculate the power delivery cost for end-use customers with interconnection at the transmission level (see Tables C5.2 and C5.3, columns F and G).

Considering power delivery costs and power consumption on an hourly basis, the energy cost for Option 2 was calculated. As indicated, the marginal cost of the generation is lower at Bus 8900 than at Bus 7120. If the customer facility is located in the vicinity of Bus 8900, potential savings will be much larger than potential savings at Bus 7120. Figures C6.3, C6.4 and C6.5 provide the potential energy cost for Option 2 for years 1999, 2000 and 2001, respectively. As shown, the pool price will increase each subsequent year; however, it still provides substantial savings.

If the customer decided to purchase power directly from a broker or IPP or EWG, then the customer may have to form a bilateral power purchase agreement with the energy provider. To select such an energy provider, the purchaser may have to send power purchase inquiries to potential energy providers in that area. To gain access to the customers in this competitive environment, under most circumstances, the prices offered by such contracts are lower than
the price offered by the utility company. Brokers and other suppliers are ready to take the risk for the future energy demand, cost, fuel cost or other unknowns. Figure C6.6 shows monthly energy costs and also indicates a projected savings of $530,000/year for this option.

Since the consumer for this case is a large industrial facility, Option 5, load aggregation, is not included here; however, for small- or medium-size facilities, load aggregation may be a viable option as it will improve the buyer's bargaining power and reduce transaction costs.

The cogeneration or self-generation option is also viable; however, with the market price of the electricity below 4 cents/kwh, cogeneration will not provide a viable option. Accordingly, for the next few years, cogeneration may not be a recommended option. Figure C6.7 shows tabulated results and cost comparisons for the cogeneration option. Large industrial customers with facilities located on two separate sites can use the generating facility at one site to serve the load of the other site. More choices will create greater market forces. If an on-site generating facility is used in association with an energy purchase at the spot price, the facility can cut electricity costs considerably. On-site generation will also provide opportunities to offset the need to buy certain ancillary services, including regulation, load following and operating reserves. Assuming an average charge at 10 percent of the total energy cost, the cogeneration option would be much more attractive. Figure C6.8 shows increased profitability due to providing one's own ancillary services. Potential profitability could be greater if this facility can sell operative reserves to the system operator. Such a sale would grant the system operator the right to a certain megawatt-level of purchased-power demand reduction or cogenerator output increased within 10 minutes of notification. Though such an opportunity would provide higher profitability, it may reduce the plant's flexibility to respond to the real-time price change. Thus, the tradeoffs among the facility’s response to real-time pricing and providing its own ancillary services or the sale of ancillary services to the system operator may be complicated.

Table C6.1 summarizes the results of Figures C6.1 through C6.8. From these figures and the summary table, the following recommendations can be provided:

- Continue with the existing utility company from now to the end of 1998.
- From 1999, if retail access is available, buying from the pool may offer maximum savings. If the facility is located in the vicinity of bus 8900, then potential savings would be larger than at bus 7120.
- Implement demand side management with pool purchase.
- From year 2001, higher pool price will justify cogeneration.

**Conclusion**

If changes proposed by the public utility commissions of California, Massachusetts, New York, New Hampshire, and many others are accepted by FERC, consumers in these states are going to see some radical changes in their electricity services. Monopoly power will fall away and consumers will be free to choose new electricity suppliers. The potential market value for this emerging sector of the power industry is unknown, however, leading trade
magazines and other industry analysts expect the market value of power transactions to reach $200 billion. Net cost savings for end-use customers may range anywhere between $5 billion to $20 billion. However, this savings would be for those customers who exercise their choice.

This case study suggests ways that large industrial customers can better manage their electricity purchase price in a competitive power industry. It also emphasizes the requirement of comprehensive consideration of electricity costs and rate tariffs, understanding of regulatory changes, necessary tools to predict future price projections, transmission and generation data, and a thorough understanding of the plant process.
## CASE STUDY RESULTS

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<th>Month</th>
<th>Firm MWh x 10^6</th>
<th>Demand MW</th>
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</thead>
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</tr>
<tr>
<td>February</td>
<td>26.65</td>
<td>42.67</td>
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<td>March</td>
<td>25.76</td>
<td>42.51</td>
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<td>April</td>
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<td>42.91</td>
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<td>May</td>
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<tr>
<td>June</td>
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<td>July</td>
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<tr>
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<td>September</td>
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<tr>
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<tr>
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<td>Total</td>
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**Figure C6.1 - Power Demand and Consumption**
Cost Comparison:
Option 1- Continue with Existing Utility Company

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<th>Monthly Cost</th>
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<tbody>
<tr>
<td>January</td>
</tr>
<tr>
<td>February</td>
</tr>
<tr>
<td>March</td>
</tr>
<tr>
<td>April</td>
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<td>October</td>
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<td>December</td>
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<tr>
<td>Average</td>
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<tr>
<td>Total</td>
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Annualized Base Cost = $ 8.89 M

*Figure C6.2 - Option 1 - Base Cost*
Cost Comparison:
Option 2- Buy from Pool - For Year 1999

<table>
<thead>
<tr>
<th></th>
<th>Base Cost</th>
<th>Pool Cost Bus 7120</th>
<th>Pool Cost Bus 8900</th>
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</thead>
<tbody>
<tr>
<td>January</td>
<td>$824,013</td>
<td>$665,671</td>
<td>$663,663</td>
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<tr>
<td>February</td>
<td>$756,809</td>
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<td>March</td>
<td>$816,986</td>
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<td>April</td>
<td>$798,794</td>
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<td>May</td>
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Annualized Base Cost = $8.89 M
Bus 7120 Cost = $8.03 M
Bus 8900 Cost = $7.80 M

**Figure C6.3 - Option 2 - Buy from Pool - Year 1999**

*NOTE: The author is no longer employed with Parsons Brinckerhoff. This monograph is for reference/research purposes only and not for distribution.*
### Cost Comparison:

**Option 2 - Buy from Pool - For Year 2000**

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**Annualized Base Cost = $8.89 M**
- **Bus 7120 Cost = $8.26 M**
- **Bus 8900 Cost = $8.04 M**

*Figure C6.4 - Option 2 - Buy from Pool - Year 2000*
Cost Comparison:
Option 2 - Buy from Pool - For Year 2001

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Annualized Base Cost = $8.89 M
Bus 7120 Cost = $8.64 M
Bus 8900 Cost = $8.28 M

-figure C6.5 - option 2 - buy from pool - year 2001
Cost Comparison:
Options 3 & 4 - Buy from Broker/IPP/EWG

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Annualized Base Cost = $8.89 M
Broker = $8.36 M

Figure C6.6 - Options 3 & 4 - Buy from Broker/IPP/EWG
**Cost Comparison:**

**Option 5 - Cogeneration/Self-Generation**

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<th>Base Cost</th>
<th>Self Generation</th>
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**Figure C6.7 - Option 5 - Cogeneration/Self-Generation**

Annualized Base Cost = $8.89 M
Cogeneration = $10.90 M
### Cost Comparison:

**Option 6 - Cogeneration/Self-Generation with Own Ancillary Services**

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<th>Self Generation W/ Ancillary Services</th>
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**Figure C6.8 - Option 6 - Cogeneration/Self-Generation with Own Ancillary Services**

- Annualized Base Cost = $8.89 M
- Cogeneration = $10.90 M
- W/ Ancillary Service = $9.82 M
Table C6.1 Option Evaluation Summary

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<th>Month</th>
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</tbody>
</table>

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GLOSSARY OF TERMS AND ABBREVIATIONS
NOTE: The author is no longer employed with Parsons Brinckerhoff. This monograph is for reference/research purposes only and not for distribution.
Co-op: The commonly used term for a rural electric cooperative. Rural electric cooperatives generate and purchase wholesale power, arrange for the transmission of that power, and then distribute the power to serve the demand of rural customers.

Curtailable Demand: A level of load that can be curtailed at the discretion of the ISO in the real-time dispatch of the ISO grid. Customers with curtailable demand (purchased either through the PX or under a bilateral contract) may offer it to the ISO to meet the non-spinning or replacement reserve ancillary service requirements.

Day-Ahead Market: The forward market for the supply of electrical power at least 24 hours before delivery to buyers and end-use customers.

Demand Bid: A retailer's bid into the PX indicating a maximum price the customer is prepared to pay. This demand will only be committed in the PX auction process if the market clearing price is at or below the price of the demand bid.

Demand-Side Management (DSM): Planning, implementing, and evaluating utility-sponsored programs to influence the amount or timing of customers' energy use.

Deregulation: The elimination of regulation from a previously regulated industry or sector of an industry.

Derivatives: A specialized security or contract that has no intrinsic overall value, but whose value is based on an underlying security or factor as an index. A generic term that, in the energy field, may include options, futures, forwards, etc.

Direct Access: The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility.

Distributed Generation: A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

Distribution Utility (DISCo): The regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to the final customer. The DISCo can also perform other services such as aggregating customers, purchasing power supply and transmission services for customers, billing customers and reimbursing suppliers, and offering other regulated or non-regulated energy services to retail customers.

Economic Efficiency: The optimal production and consumption of goods and services. This generally occurs when prices of products and services reflect their marginal costs. Economic efficiency gains can be achieved through cost reduction, but it is better to think of
Generation Company (GENCo): A regulated or non-regulated entity (depending upon the industry structure) that operates and maintains existing generating plants. The GENCo may own the generation plants or interact with the short term market on behalf of plant owners. In the context of restructuring the market for electricity, GENCo is sometimes used to describe a specialized "marketer" for the generating plants formerly owned by a vertically integrated utility.

Grid: A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points. GRIDCo is sometimes used to identify an independent company responsible for the operation of the grid.

Hedging Contracts: Contracts that establish future prices and quantities of electricity independent of the short-term market. Derivatives may be used for this purpose. (See contracts for differences, forwards, futures market, and options.)

Hour-Ahead Market: The electric power futures market that is established 1 hour before delivery to end-use customers.

Independent Power Producer (IPP): A private entity that operates a generation facility and sells power to electric utilities for resale to retail customers.

Independent System Operator (ISO): A neutral operator responsible for maintaining instantaneous balance of the grid system. The ISO performs its function by controlling the dispatch of flexible plants to ensure that loads match resources available to the system.

Integrated Resource Planning (IRP): A public planning process and framework within which the costs and benefits of both demand- and supply-side resources are evaluated to develop the least-total-cost mix of utility resource options.

Investor Owned Utility (IOU): A company, owned by stockholders for profit, that provides utility services. A designation used to differentiate a utility owned and operated for the benefit of shareholders from municipally owned and operated utilities and rural electric cooperatives.

Locational Market Clearing Price: The price at which supply equals demand at a specified location. All demand that is prepared to pay at least this price at the specified location has been satisfied. All supply that is prepared to operate at or below this price in the specified location has been purchased.

Loss Factor: The ratio of the average loss in kilowatts (kW) during a designated period to the peak or maximum loss in kW occurring in that period.
**Options:** A contractual agreement that gives the holder the right to buy (call option) or sell (put option) a fixed quantity of a security or commodity (for example, a commodity or commodity futures contract), at a fixed price, within a specified period of time. May either be standardized, exchange-traded, and government regulated, or over-the-counter customized and non-regulated.

**Parallel Path Flow:** As defined by NERC, the flow of electric power on an electric system's transmission facilities resulting from scheduled electric power transfers between two other electric systems. (Electric power flows on all interconnected parallel paths in amounts inversely proportional to each path's resistance.)

**Performance Based Ratemaking (PBR):** Regulated rates based on performance objectives, not actual costs.

**POOLCo:** A specialized, centrally dispatched spot market power pool that functions as a short-term market. It establishes the short-term market clearing price and provides a system of long-term transmission compensation contracts. It is regulated to provide open access, comparable service and cost recovery. A POOLCo would make ancillary generation services, including load following, spinning reserve, backup power, and reactive power, available to all market participants on comparable terms. In addition, the POOLCo provides settlement mechanisms when differences in contracted volumes exist between buyers and sellers of energy and capacity.

**Power Authorities:** Quasi-governmental agencies that perform all or some of the functions of a public utility.

**Power Exchange (PX):** An independent agency responsible for conducting an auction for the generators seeking to sell energy and for loads that are not otherwise being served by bilateral contracts. The PX will be responsible for scheduling generation in its scheduling (e.g., day-ahead, hour-ahead) markets, for determining hourly market clearing prices for its market, and for settlement and billing for suppliers and buyers of the market.

**Public Utility Holding Company Act of 1935 (PUHCA):** Prohibits acquisition of any wholesale or retail electric business through a holding company unless that business forms part of an integrated public utility system when combined with the utility's other electric business. The legislation also restricts ownership of an electric business by non-utility corporations.

**Public Utility Regulatory Policy Act of 1978 (PURPA):** Among other things, this federal legislation requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate equivalent to what it would have otherwise cost the utility to generate or purchase that power itself. Utilities must further provide customers who choose to self-generate with a reasonably priced back-up supply of electricity.
excess electricity (displacing retail electricity costs minus wheeling charges) on the bills for its other sites.

**Spinning Reserve:** The portion of unloaded synchronized generating capacity, controlled by the ISO, which is capable of being loaded in 10 minutes and running for at least 2 hours.

**Stranded Costs/Stranded Assets:** Assets that cannot be sold for some reason. The British nuclear plants are an example of stranded assets.

**Sunk Cost:** A cost that has already been incurred and therefore cannot be avoided by any strategy going forward.

**Tariff:** A document filed with the appropriate regulatory authority specifying lawful rates, charges, rules, and conditions under which the utility provides service to parties. A tariff typically includes rate schedules, list of contracts, rules and sample forms.

**Transition Period:** The period of time to allow IOUs and local publicly owned utilities an opportunity to continue to recover costs for generation-related assets and obligations that may not be recoverable in market prices in a competitive generation market. The period was defined as January 1, 1998 through December 31, 2001.

**Transmission Congestion:** The condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based on requested/desired schedules.

**Transmission Congestion Contract (TCC):** A financial instrument that provides a hedge against congestion price differences between zones.

**Transmission-Dependent Utility:** A utility that relies on its neighboring utilities to transmit to it the power it buys from its suppliers. A utility without its own generation sources dependent on another utility's transmission system to get its purchased power supplies.

**Transmission Owner:** An entity owning transmission facilities or having contractual rights to use transmission facilities that are used to transmit and distribute power from suppliers to UDCs.

**Transmitting Utility:** A regulated entity that owns, and may construct and maintain, wires used to transmit wholesale power. It may or may not handle the power dispatch and coordination functions. It is regulated to provide non-discriminatory connections, comparable service and cost recovery. According to the EPAct, any electric utility, qualifying cogeneration facility, qualifying small power production facility, or federal power marketing agency that owns or operates electric power transmission facilities used for the sale of electric energy at wholesale.
ABBREVIATIONS

ac  alternating current
CPUC California Public Utility Commission
dc  direct current
DISCo Distribution Company
DOE Department of Energy
EIS Environmental Impact Statement
ERCOT Electric Reliability Council of Texas
ESCo Energy Service Company
EWG Exempt Wholesale Generator
FERC Federal Energy Regulatory Commission
FOR Forced Outage Rate
FTC Federal Trade Commission
GENCo Generation Company
HMC Hourly Monte Carlo
IGCC Integrated Gasification Combined Cycle
IOU Investor Owned Utility
IPP Independent Power Producer
ISO Independent System Operator
kV kilovolts
kvars kilovar
kWh kilowatt-hour
MW megawatt
NARUC National Association of Regulatory Utility Commissions
NERC North American Electric Reliability Council
NESC National Electric Safety Code
NRRI National Regulatory Research Institute
NYPSC New York Public Service Commission
O&M Operations & Maintenance
OASIS Open Access Same-Time Information System
PMA Power Marketing Authority
PUC Public Utility Commission
PUHCA Public Utility Holding Company Act
PURPA Public Utility Regulatory Policy Act
QF Qualifying Facility
RRC Regional Reliability Council
RTG Regional Transmission Group
SERC Southern Electric Reliability Council
SRMC Short Run Marginal Cost
TCC Transmission Congestion Contracts
TRANSco Transmission Company
VAMM Vector Absolute Megawatt Mile
WSCC Western Systems Coordinating Council