Electricity Markets

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Preface

The electricity sector is undergoing a profound transformation. As the world grapples with the challenges of climate change, energy security, and economic development, the way we generate, transmit, and consume electricity is being reshaped. At the heart of this transformation are electricity power markets, complex systems that enable the buying and selling of electricity across vast distances and among diverse stakeholders.

This book aims to provide a comprehensive guide to the economics, politics, and technologies that underpin electricity power markets. From the fundamentals of supply and demand to the intricacies of market design and regulation, we explore the key concepts, theories, and practices that are shaping the future of electricity systems.

Through a combination of theoretical insights, practical examples, and case studies, this book offers a nuanced understanding of the opportunities and challenges facing electricity power markets today. Whether you're a policymaker, industry professional, or simply a curious observer, our goal is to equip you with the knowledge and perspectives needed to navigate the rapidly evolving landscape of electricity markets and to contribute to the development of more sustainable, efficient, and equitable electricity systems."

chapter one

The evolution of the electric power industry

1.1 Energy conservation in the pre-energy crises environment

During the past 75 years, the experiences of the electric power industry have been heavily conditioned by economic regulation at the state and federal levels. Starting in the 1920s, policymakers at the state level* began subjecting power utilities within their respective jurisdictions to regulatory oversight based upon two premises: (1) the industry had natural monopoly cost characteristics, and (2) the industry was imbued with the public interest. These premises supported the continued regulation of power markets through the 1990s when a number of these underlying premises, particularly the notion of the industry being characterized as a natural monopoly, began to unravel.

A natural monopoly is a special case in the economic organization of markets. A natural monopoly is perhaps the only case where allowing one firm to operate is more efficient than promoting production between several firms. When a natural monopoly exists, the technology of production is such that economies of scale (declining average cost per unit of output) are said to exist over the entire range of market demand for that good or service. If this firm was broken into several smaller firms, these economies (and lower average costs) would not be achieved, and prices to end users would be higher than if the good or service was produced by only one company. Hence, early support for regulation was built on trying to maintain this natural monopoly, and at the same time tempering its potential excesses.

The problem with natural monopolies is that if left unchecked, they have the ability to increase costs to levels that are considerably higher than current costs. Figure 1.1 presents the cost and pricing characteristics of natural monopoly firms. Prices and costs are represented on the vertical axis, while

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* There is a corresponding level of regulation at the federal level that began in the 1920s with the passage of the Federal Power Act (FPA) and its subsequent revisions in the 1930s, in addition to the passage of the Public Utilities Holding Companies Act (PUHCA).

sometimes regional, government institution. Such an approach was followed in many countries in Europe and Latin America. Nationalization is premised upon the belief that the government will be able to operate a natural monopoly effectively and in the public interest. The common criticism of this form of regulation, however, is that public institutions do not face profit-maximizing incentives to keep costs down. In later decades, this criticism was seen by many as particularly true and led to calls for privatization.

For the most part, the United States' model for containing potential natural monopoly abuses has rested with price and earning regulations of private industries. This approach is commonly referred to as rate of return (ROR) regulation. Under the ROR model, utilities are allowed to set prices in a manner that allows them to recover their ongoing operational costs, as well as the opportunity to earn a reasonable ROR on their investments. Prices are set on an average cost basis that includes both of these cost components. This method worked well through the better part of the 20th century, particularly in the electric power industry. During this period, the industry was able to garner significant economies of scale in the production, transmission, and distribution of electricity. A number of benefits to utilities were associated with pushing technological innovations. If utilities could lower costs while keeping rates constant, then they could increase profits between periods where no regulatory rate cases existed and maximize earnings for their shareholders. It has been noted that during this period regulators tended to pursue a live-and-let-live policy with regard to utilities. The primary concern of regulators was to keep nominal prices from increasing. Firms were allowed to earn generous rates of return if they could increase their achievement rates without raising prices, provided that costs continued to decrease for their captive ratepayers.[1]

ROR regulation is not without its own set of criticisms, many of which became strikingly evident in the late 1970s and early 1980s. The primary criticism levied against traditional or ROR regulation rests with the "overcapitalization" hypothesis. As regulated utilities, these firms have incentives to make significant investments to increase their overall earnings. The higher the investment, the higher the overall allowed returns. Such a regulatory approach could lead to "gold plating" and overinvestment.

The idea of gold plating, or overcapitalization, was the attention of much scholarly debate during the 1960s and 1970s. Averch and Johnson (1962) formed a static, deterministic model of the regulated firm subject to a regulatory constraint. The regulatory constraint is merely a cap, set by the regulatory body, on the maximum allowable ROR that the regulated firm can earn. In the model, depreciation is assumed to be zero, and the only cost of acquiring capital is the interest to be paid on the plant and equipment.

After formulating this model, Averch and Johnson reached two controversial conclusions. Specifically, they concluded that a regulatory bias exists, which encourages the regulated firm to make inefficient capital-intensive investments.[2] A second, but often overlooked conclusion is that regulated firms also have the incentive to cross-subsidize less profitable operations at

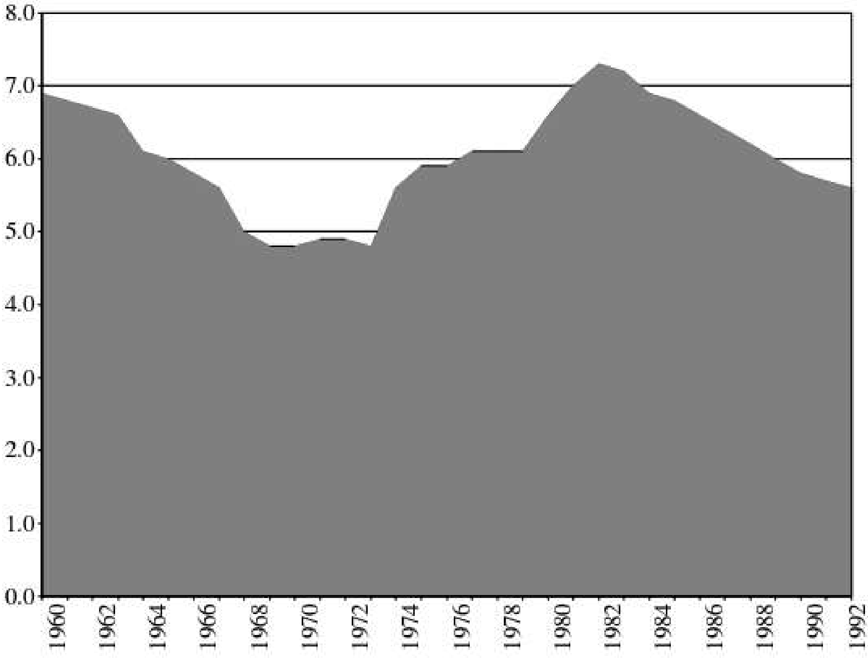

Figure 1.2 Historic electricity prices (1960–1992).

rate of electricity followed a steady and gradual decline. This decline was the result of a number of factors, including low fuel costs and tapping the economies of scale present in large central station electric generation, as well as high voltage transmission. It was the advantages created during this period that allowed utilities to continue to maintain strong earnings for their shareholders, while at the same time keeping regulators happy with decreasing rates.

However, the good times in the power business were soon to end. Between 1973 and1974, the first year following the OPEC oil embargo, electricity prices jumped 17%. The cost of electric generation continued to escalate throughout the late 1970s, mainly because of the increased capital cost of generation. By 1982, the year following the Iranian revolution and a second world price increase, a combination of high capital and fuel costs forced the real price of electricity to an all-time high of 7.3 cents kWh, 52% higher than the pre-1973 rate. Fortunately, these levels were not sustained, and beginning in 1982 the real price of electricity began to fall as fuel prices eased and utility construction programs were all but phased out.* Unfortunately for utilities, these decreases in rates came a little too late for the irreversible changes in market structure that arose in the early to mid-1980s.

One of the primary culprits for increased power generation was associated with fossil fuel prices. Figure 1.3 shows how dramatically real fossil fuel prices (oil, natural gas, and coal) increased in 1973. In 1973, real oil prices were 50% higher than their 1972 levels. On the other hand, coal was only

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* Fuel expenses were 67, 84, and 77% of power production expenses (excluding capital expenditures) for major investor-owned utilities (IOUs) in 1990, 1980, and 1970, respectively. Energy Information Administration. Financial Statistics of Selected Investor-Owned Electric Utilities 1990. (Washington: U.S. Department of Energy, 1992): 26. See predecessor issues for 1980 and 1970 expenses.

chapter two

Restructuring and the transition to more competitive power markets

2.1 The fundamentals and terminology of power industry change

The current changes now under way in the electric power industry are often referred to in different manners. Three terms that are most commonly associated with these changes are wheeling, deregulation, and restructuring. While wheeling and deregulation are important considerations, they do not completely or accurately reflect all of the changes ongoing in the industry. A closer examination of both of these terms provides greater insights into their descriptive limitations.

Wheeling is a term primarily used by power-industry professionals that describes the third-party transportation of power on the behalf of another utility. Because electric power systems throughout the U.S. are integrated, transporting power cannot be done without the approval of neighboring utilities. Philosophically, a wheeling transaction was not seen as a sanctioned responsibility of utilities; instead, it was something that might be accommodated as a discretionary matter. Locally franchised utilities received regulatory approval at the state and local levels to provide service within a designated territory. Providing power outside that service area represented a deviation from the status quo and was often viewed in a less than favorable light.[1]

A number of events changed the nature of interconnected relationships between utilities. The first fundamental shock to these relationships came in 1969 when the great Northeast blackout forced utilities to reexamine their relationships with one another in order to ensure power supply reliability. As a result of the blackout, the industry took preemptive measures* to form

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* The move was preemptive in the sense that the industry formed this voluntary organization before policymakers at the federal and state levels had the opportunity to dictate an alternative reliability arrangement.

a situation, Utility B would be using its vertical market power, that is, ownership of generation and transmission, to favor its own operations over those of Utility A. In order to make these types of competitive transactions work, some system of providing open and nondiscriminatory service would need to be developed.

Providing wheeling, or third-party transmission service on an open and nondiscriminatory basis allows competitive providers of electricity to move their power freely across utility systems throughout the U.S. Wheeling can be broken into two categories: wholesale wheeling and retail wheeling. Wholesale wheeling refers to the transfer of power to customers who are not end users, such as wheeling power on behalf of an independent power producer (IPP) selling power to a municipal utility. Or, as in the example above, it could mean transmitting power from one utility (Utility A) to another (Utility C).

Retail wheeling, on the other hand, refers to the physical (and contractual) transfer of power to customers that are end users. For instance, a business choosing to be served by another power provider would have to pay a wheeling or transportation fee to its host utility to receive power from another provider. In this example, a nondiscriminatory system of both transmission and distribution access is needed.

Deregulation is another term that is often used to describe changes now occurring in the electric power industry. However, deregulation is a misnomer when it comes to describing the changes that have and are currently taking place in the power industry. Regulation takes many forms within the power industry. Utilities are currently subjected to significant economic, environmental, and safety regulation at the state and federal levels. Proposed changes in the industry do not refer to removing all forms of regulation. As noted earlier, the prices and earnings of vertically integrated utilities have been regulated. The current changes in the industry envision relaxing price and earnings regulation on the generation and energy sales portion of the industry alone. As will be explained in greater detail later, price and earnings regulation will still remain on the transmission and distribution portions of the industry.

Despite the relaxation of price and earnings regulation on the generation sector of the industry, not all economic regulation will be removed. Rather, economic regulation will be transformed from earnings and price regulation to a market oversight function. Some traditional rate of return (ROR) regulation will remain with the monopoly transmission and distribution (T&D) functions. New players serving electricity customers will require regulators to set and enforce certification requirements, as well as minimum standards for quality of service. In addition, regulators will be required to adjudicate service standard and interconnection disputes between competitive providers of electricity and between competitors and regulated distribution companies. Thus, the use of the term "deregulation" is clearly not an appropriate reference to future industry structure.

sions (PUCs) regulate these rates. The broad classes that comprise the retail sector include residential, commercial, industrial, and other customer classes. The retail market of the industry exchanged more than 3.2 billion kWh in 1998, which amounted to $217 billion in retail sales.

The restructuring of the electric power industry comes from breaking off sections of the industry into competitive and regulated entities. During the past several years, electric generation has become more competitive. As noted in earlier chapters, the fundamental premise of the power generation portion of the business being a natural monopoly does not hold. Hence, competitive forces in the power generation and sales business have resulted in the removal of price regulation. Nevertheless, the lines sectors of the electric power industry (transmission and distribution) are still considered a monopoly.

In the future, competition will govern transactions in electric power markets. Customers will no longer be assigned to utilities and, alternatively, utilities will no longer have guaranteed customers for their electricity. Utilities of the future will compete for end-use customers much like any other good or service. Utilities will be able to contract directly with these customers. Alternatively, middlemen can enter into contracts either linking buyers to sellers (aggregators) or sellers to buyers (marketers) to reduce market informational costs.

Figure 2.2 presents a simple schematic of how the power industry has become restructured at the retail level. On the left side of the figure are a number of power generation facilities and companies. These companies usually sell their power through power (or energy) marketing groups. Their sole purpose is to "market" the output of the facilities. The actual operation, maintenance, and development of these facilities is usually handled through separate affiliated groups within the company.

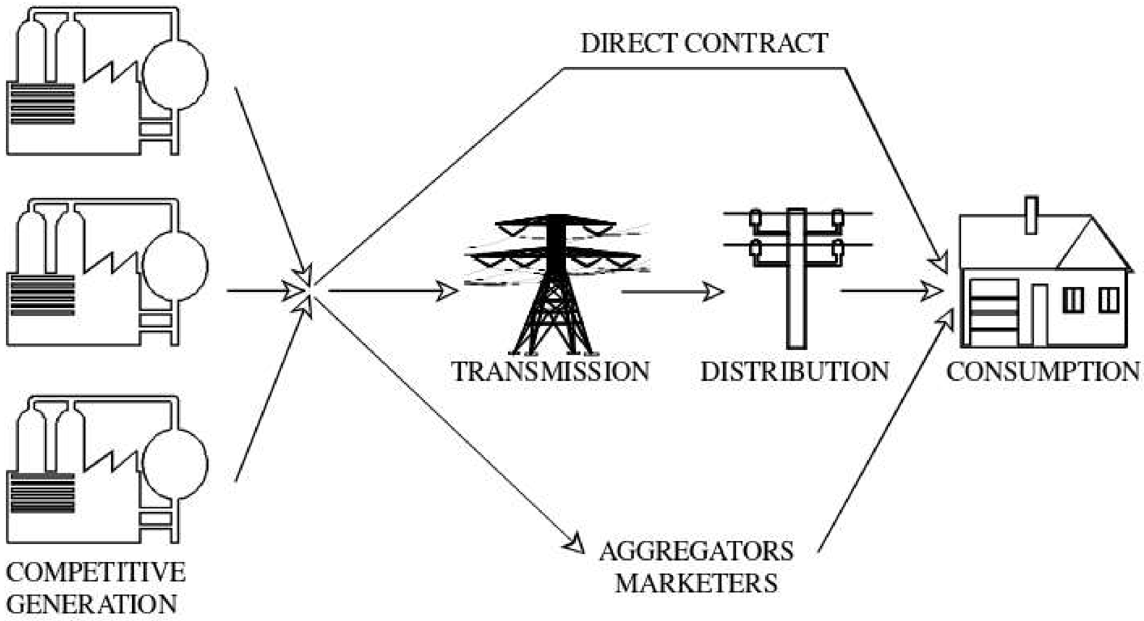

Figure 2.2 Restructured electric power industry.

chapter three

The first major challenges to the system: the California restructuring experience

3.1 Introduction

The passage of the Energy Policy Act of 1992 (EPAct) began the process of opening electric power markets to competition. Soon after its passage, California became one of the first states to examine, adopt, and implement electric restructuring at the retail level. At the time, California was considered the "poster boy" for opening retail markets to customer choice and competition. However, as was soon to be seen, the devil of restructuring was in the details, and the California approach was filled with them. As a result, the once-touted state for restructuring has now become one that is disparaged for having moved too quickly, in too much detail, on an issue that many see as being too complex.

The problems with California power markets were amplified during the summer of 2000 and through the better part of 2001, when prices in the state's wholesale power markets surged to unprecedented levels. These price increases were immediately felt by some of the state's ratepayers, since price cap protections, initially established to protect customers during the transition period, were removed. As a result, customers in the greater San Diego area saw their bills more than double their already nationally high levels. Customers in other regions of the state, on the other hand, will probably only be temporarily sheltered from these significant rate increases, since the remaining price-capped utilities in the state are already calling for recovery of the additional costs of making purchases on the wholesale market.

The current events in California have government regulators and policymakers at all levels scrambling to assure their constituents. Committee meetings are being held, investigations are being conducted, and even the courts may see some of the action from these events. The two most pervasive the belief that utility regulation and planning should consider a wide range of utility planning implications, including the environment, the economy, and social goals. Thus, policies like demand-side management, renewable set-asides, standard-offer contracts for qualifying facility (QF) power, revenue neutrality and decoupling, and incentive returns on energy conservation programs became the vogue in California regulatory design.

In addition to the state's progressive nature in regulatory policy, there was a veritable cadre of stakeholders that intervened in the regulatory process in California. All wanted their voices to be heard and their special programs to be continued. These intervention groups ranged from consumer advocacy groups to environmental groups to utility shareholder groups, low-income groups, and utility worker unions, to name a few. The California regulatory process, to its credit, was open and encouraged this activism. However, the development of regulatory policy over the years rested on the belief that all of these different interests could be accommodated to one degree or another.

This expansive precedent for regulatory activism is the backdrop for electric restructuring in California. Starting in 1995, the California Public Utilities Commission (CPUC) adopted a general approach for opening the state's retail markets for competition. The debate in these proceedings heralded the two opposing market structure paradigms: a bilateral market approach vs. a centralized pool, or "poolco," approach. Eventually, the poolco model became the marginally preferred approach. Soon following the 1995 ruling, the commission moved forward with proceedings to discuss how the actual poolco approach would be implemented.

However, within a year, the California Assembly decided that it would like to get involved in the electric restructuring debate. As a result, AB 1890 was passed and signed into law by Governor Pete Wilson on September 23, 1996.[2] The bill, in true California fashion, had a number of perks for stakeholder groups engaged in this debate. For the IOUs, there was a guarantee for stranded cost recovery. For the ratepayer advocates, a 20% rate reduction and rate freeze were offered as long as the utilities continued to collect their surcharges, known as competitive transition charges (CTCs). For the environmentalists and other public interest groups, long-support public programs were guaranteed to be maintained in the near future through other bill surcharges and collections. The statute codified the poolco approach into law and put the wheels in motion to create two large, nonprofit power institutions: the California Independent System Operator (Cal-ISO or ISO) and the California Power Exchange (CalPX or PX).

The Cal-ISO was created to independently operate 75% of the state's extensive transmission system. The California transmission network consists of 21,000 circuit miles of power lines that deliver about 165 billion kilowatt-hours (kWh) of electricity every year.[1] Power plants connected to the Cal-ISO have a total capacity of approximately 45,000 megawatts (MW).

The goals for the Cal-ISO are to run the state's transmission system like an independent air traffic controller. The ISO's primary responsibility is the

3.3 *The capacity availability dilemma*

Electricity is a unique commodity in the sense that it cannot be stored and must be produced simultaneously with demand. In the past, and even into the present, generation planning has consisted of developing and having a portfolio of generation facilities available to meet the various types of electricity loads that occurred in any given hour, across any given day, in any given season. In the past, reliability tended to be the most important planning consideration, followed closely by cost. Thus, generation planning strategies consisted of constructing and operating enough power plants to meet demand on a cost-effective basis. In many instances, having the ability to meet sudden surges in demand entailed constructing and maintaining large capacity reserve margins that remained idle during large parts of the year. In the past, regulators determined the degree of reliability. Today, that degree of reliability is determined in large part by the market.

Since load varies considerably across hour, day, and year, the power industry has traditionally recognized three different classifications for power facilities: baseload generation, intermediate or cycling generation, and peaking generation. Baseload generators are typically steam generation facilities that are used to service minimum system load and, as such, are run at a continuous rate. While these units are the most efficient to operate, they are costly to start up from a cold shut down, therefore, they are usually run at a near-constant rate. Intermediate load plants are typically older steam units or combustion turbines that are brought online during periods of forced or planned outage of baseload units. Intermediate units can also be thought of as units that bridge the dispatch of baseload and peaking units during periods of unusually high demand. These units can be older and are less efficient than baseload units. Peaking units are typically combustion turbines that have the ability to generate electricity immediately and serve temporary spikes in demand, such as during a heat wave when residential and commercial air conditioning demands begin to surge.

In the past, electric utilities dispatched generating units to meet demand on a lowest- to highest-cost basis. This form of dispatch is commonly referred to as "economic dispatch." The marginal or incremental cost of dispatching units is traditionally the benchmark used to rank order available generators. These marginal costs, in the very short run, are typically associated with changes in fuel costs and other variable operating and maintenance (O&M) costs. Historically, baseload units, almost always large coal, hydro, or nuclear units, had the lowest incremental costs and were dispatched first to meet load. As load increases during the day, or across seasons, less efficient intermediate or cycling units, which generate electricity at slightly higher costs, were brought online. Higher-cost peaking units would be the last types of units brought online under an economic dispatch regime. The cost of the last dispatched unit therefore defines the system marginal costs, often referred to as the system "lambda."

chapter four

Power marketers in a restructured power industry

4.1 Introduction

In their simplest form, power marketers buy and sell power just as a utility would. Unlike a utility, power marketers do not generally own generation, transmission, or distribution facilities, but rely on others to physically deliver the products sold. Power marketers also offer a wide variety of other services, such as risk management and tolling services, and act as middlemen for both buyers and sellers of power. The purpose of this chapter is to provide an understanding of what power marketers and their markets and services are, as well as look at recent events and the near future of the power-marketing industry.

4.2 What is a power marketer?

Power marketing refers to wholesale and retail transactions of electric power by companies other than the regulated utilities that own the distribution lines. Power marketers may buy from utility and nonutility generators, as well as other power marketers, and at the wholesale level may sell to private and public utilities, other marketers, and resellers. At the retail level, they may sell to industrial, commercial, residential, and governmental end users. Some key features of power marketers are:

1. They take title to the power being transacted, thus they assume price and market risk.
2. They must register with the Federal Energy Regulatory Commission (FERC).
3. They are not subject to state regulation.*

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* In some pilot programs in New Hampshire and Massachusetts, power marketers were required to meet some state requirements to participate in the programs.

in business that is essential and appropriate for the operation of a single integrated utility. EPAct also contains transmission provisions that have led to a nationwide open-access electric power transmission grid for wholesale transactions. Anyone selling power at wholesale, including power marketers, gains the ability to seek orders from FERC that require utilities who own transmission to provide service at "just and reasonable" rates, as defined by the FERC. EPAct also gives FERC broad authority to order transmission-owning utilities to wheel, or move, power for wholesale power transactions.

4. The 1994 establishment of a "comparability standard" stating that transmission-owning utilities should offer other transmission users access to their transmission systems under the same conditions as their own use of the systems
5. The Mega-NOPR, released in 1995 by FERC, which had two goals: (1) facilitate the development of bulk power markets by ensuring that wholesale purchasers and sellers of electric energy can reach each other by eliminating anticompetitive practices in transmission services, and (2) address the transmission costs associated with the development of competitive wholesale markets
6. Order 888, released in 1996 by FERC, which (1) serves to eliminate anti-competitive practices and undue discrimination in transmission services through a universally applied, open-access tariff system in which all terms and specifications for system use are filed with FERC, and (2) ensures the recovery of stranded costs accrued by utilities in the transition to competitive markets. FERC also issued Order 889, which requires transmission facilities to electronically post information about their available capacities.
7. FERC's approval of the use of market-based rates as opposed to traditional cost-plus pricing, which led to the creation of power exchanges

4.4 *Who are power marketers?*

As of September 2001, there were 497 independent power marketers and 167 affiliated power marketers registered with FERC. Table 4.1 lists the purchases and sales made by both types of marketer in 2000 by quarter.

As shown in Table 4.2, for each of the four quarters, Enron Power Marketing topped the list with more than 100 million megawatt hours (MWhs) purchased. This table is a selection of major players that repeatedly follow Enron in the top ten in terms of quarterly purchased volumes. These eight major players represent more than 63% of the total purchases in 2000.*

Table 4.3 shows the number of customers, revenue, and sales for power marketers in 1999. Eighty-one percent of power marketers' customers are residential; however, these customers represent only 5.5% of sales. More than 50%

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* This list is a selection of those companies in 2000 with the largest amounts of purchases.

Table 4.3 Number of Ultimate Consumers, Revenue, Sales, and Average Revenue per Kilowatt-Hour for Power Marketers, 1999

	Number of Consumers	Revenue (000 $)	Sales (thousand kWh)	Average Revenue per kWh (cents)
Residential	566,181	170,147	4,162,053	$4.09
Commercial	109,827	1,187,693	31,394,777	$3.78
Industrial	25,361	1,299,595	40,433,571	$3.21
All Sectors	702,420	2,664,184	76,188,042	$3.50

Source: Electric Sales and Revenue, Energy Information Administration.

The forward market, often referred to as the "futures" or "contract" market, is a response to the need for planning of business activities. Forward and futures contracts also allow for varying amounts of flexibility that are not present in spot transactions.[1]

A forward contract is an agreement for the delivery of a commodity in the future at a price determined at the inception of the agreement. Terms may extend from the next day to years ahead. Forward contracts can be risky; for example, if a marketer agrees to deliver 100,000 MWh of electricity over a 1-year period at a fixed price of $20/MWh, and the actual cost of obtaining and delivering power is $30/MWh, the marketer will lose $10/MWh for a total loss of $1 million. In the absence of hedging mechanisms, discussed later in this book, a marketer will only offer forward contracts to the customer at relatively high prices.[3]

A future is a standardized contract where all terms, including delivery date, location, quality, and quantity, have been predetermined and standardized. Price is excluded from the terms and is open to negotiation. Futures are traded on exchanges such as the New York Mercantile Exchange (NYMEX)[4] and the Chicago Board of Trade (CBOT).* The exchange is responsible for reporting all transaction prices, so there is a resulting price transparency, or an ability to see, at any given time, the price at which a given future is trading. Most futures contracts are used as financial vehicles, with no intention of taking delivery of the commodity. Less than 2% of futures contracts end in delivery.[5]

There are five NYMEX electricity futures contracts that differ only in their delivery locations. Delivery locations include California–Oregon Border (COB), the Palo-Verde substation in Arizona, Cinergy, Entergy, and PJM. The CBOT has two futures contracts, one for delivery at the Commonwealth Edison hub and the other for delivery at the Tennessee Valley Authority hub.* The seller of a contract commits to deliver 736 MWh firm, or uninterruptable, electricity each month at the agreed contract price. The contract amount of 736 MWh is derived from the requirement that electricity be

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* Energy Information Administration.

chapter five

The role of distributed energy resources in a restructured power industry

5.1 Introduction

One of the more interesting technological innovations during the past several years has been associated with distributed energy resources (DER). DERs, simply put, are small power generation and storage applications, usually located at or very near customer loads. The application of these small-scale power technologies is gaining widespread interest and acceptance due to their ability to further customer choice and competition. Locating power generation and storage technologies allows customers to balance their cost/reliability preferences in ways that were previously very limited. The prime benefits of DER, however, are associated with their interconnected nature with the utility distribution company (UDC) grid. Under a properly structured environment, these benefits can run in two directions: one for the customer, and the other for the UDC.

The flexibility, size, cost, and modularity of DER create significant benefits. These benefits include:

1. Reliability: DER can provide on-site backup close to customer loads. High reliability is becoming increasingly important for high technology and digital applications that are sensitive to outages.
2. Power Quality: Voltage sags and surges can damage digital equipment, including computers, Internet servers, and telecommunications equipment. Many DER technologies can deliver high power quality, but in many instances, there has to be balance with cost.
3. Energy Efficiency: DER can be used to customize usage profiles for peak shaving applications. For some larger uses, combined heat and power (CHP) applications further on-site energy efficiency opportunities.

Table 5. 1 Examples of DER Costs under Differing Technologies

Cost and Operating Performance Categories	Fuel Cell	Microturbine	Microturbine/CHP	Reciprocating Engines	Reciprocating/CHP
Capital costs ($/kW)	2000	800	800	450	450
Capacity (kW)	200	400	400	400	400
Capacity Factor	0.95	0.95	0.95	0.95	0.95
Net Annual Generation (kWh)	16,644,000	3,328,800	3,328,800	33,288,000	33,288,000
Total Capital Cost ($)	400,000	320,000	320,000	180,000	180,000
Finance Costs ($)	40,000	32,000	32,000	18,000	18,000
Capital Costs ($/kWh)	0.2644	0.1057	0.1057	0.0595	0.0595
O&M ($/kWh)	0.05	0.005	0.005	0.005	0.005
Heat Rate (Btu/kWh)	6000	10,000	8000	13,000	10,000
Fuel Costs ($/MCF)	2.25	2.25	2.25	2.25	2.25
Gas Use (MMBtu)	9986	33,288	26,630	43,274	33,288
Total Fuel Cost ($)	22,469	74,898	59,918	97,367	74,898
Fuel Costs ($/kWh)	0.0135	0.0225	0.0180	0.0293	0.0225
Estimated Levelized Cost	0.2829	0.1332	0.1287	0.0937	0.0870
Intererst (Annual Percent)	0.1000	0.0800	0.0800	0.0800	0.0800

Source: From Priddy, R.D. and Dismukes, D.E., *Distributed Energy Resources: A Practial Guide for Service*, Ft Energy, Boulder, CO, 2000: 74. With permission.

Table 5.2 Stakeholder Benefits Associated with DER

Stakeholder Group	Combined Heat and Power	Standby Power	Peak-Shaving	Grid Support	Stand-Alone
Customer	Lower energy costs, higher overall reliability	Avoid economic loss due to system outage and satisfy critical support systems	Lower peak-period energy costs	Customers generally benefit from the enhanced service provided, but may be isolated from competition markets as a result	Customer option to avoid high-cost backup service, remote communications, and control systems
T and D System	Positive to negative, depending upon the application	Can be integrated with utility needs to provide both customer and grid benefits	Can be integrated with utility needs to provide both customer and grid benefits	Enhances grid stability and economic customer service	Loss of customer load and associated revenues
Energy Service Provider	Power and heat can be separately marketed; ESPs can also provide ancillary services to CHP customers	Can facilitate ESP marketing of interruptible power supplies; widely used strategy of municipal systems	Can aggregate and sell customer peak-period generation	Possible benefits as an owner/operator of the system	Possible benefits as an owner/operator of the system
Natural Gas Industry	Benefit from high gas consumption, possible fuel switching benefit for oil-fired boilers	Minimal impact, but cost to service customers is high	Good match of gas off-peak period with electric on-peak period	Generally similar to peak-shaving benefits	Benefit from high gas consumption
Society	Environmental benefits with some technologies, energy efficiency, economic development	Public health and safety	Environmental and energy-efficiency benefits	Environmental and energy-efficiency benefits	Less likely in a competitive market to represent an optimum allocation of resources

Source: From Priddy, R.D. and Dismukes, D.E., *Distributed Energy Resources: A Practial Guide for Service*, Ft Energy, Boulder, CO, 2000: 74. With permission.

chapter six

Independent power generation

6.1 Introduction

One of the pressing challenges in today's energy industry is the development of supporting infrastructure. Nowhere is this more readily apparent than in the electric power industry. Years of upheaval, uncertainty, and regulatory change have clearly had consequences that are taking their toll today. What is unique about today's energy industry revival is the development of competitive, as opposed to regulated, forces for driving the nature and the direction of energy infrastructure investments.

The power generation sector, in particular, has seen a virtual explosion in announced construction activity during the past several years. This increase in industry activity is the result of a confluence of different factors, including the following:

1. Technological: Over the years, smaller, more modular, and more efficient power-generation technologies have emerged.
2. Economic: The nature of wholesale* power markets has changed from one in which pricing and market conditions were determined by regulation to one in which the market determines the amount and prices of electricity to be offered.
3. Public Policy: Transmission systems have been legally opened to support open access and nondiscriminatory transportation of power across utility power grids.
4. Institutional: New market mechanisms and institutions have arisen that facilitate the trade of bulk (wholesale) power as a commodity.

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* This chapter focuses exclusively on the impact that merchant facilities have on wholesale power markets. Here, wholesale power markets are defined as bulk power markets where purchasers are not the ultimate end users of electricity. A wholesale power market transaction is one where a utility that is short on capacity purchases electricity from another utility (or merchant plant) in order to supply power to its own customers. Wholesale competition allows these trades to occur outside regulation with prices being negotiated between the two utilities. Retail markets, on the other hand, are defined as markets where the customers are the ultimate end users of the energy being purchased.

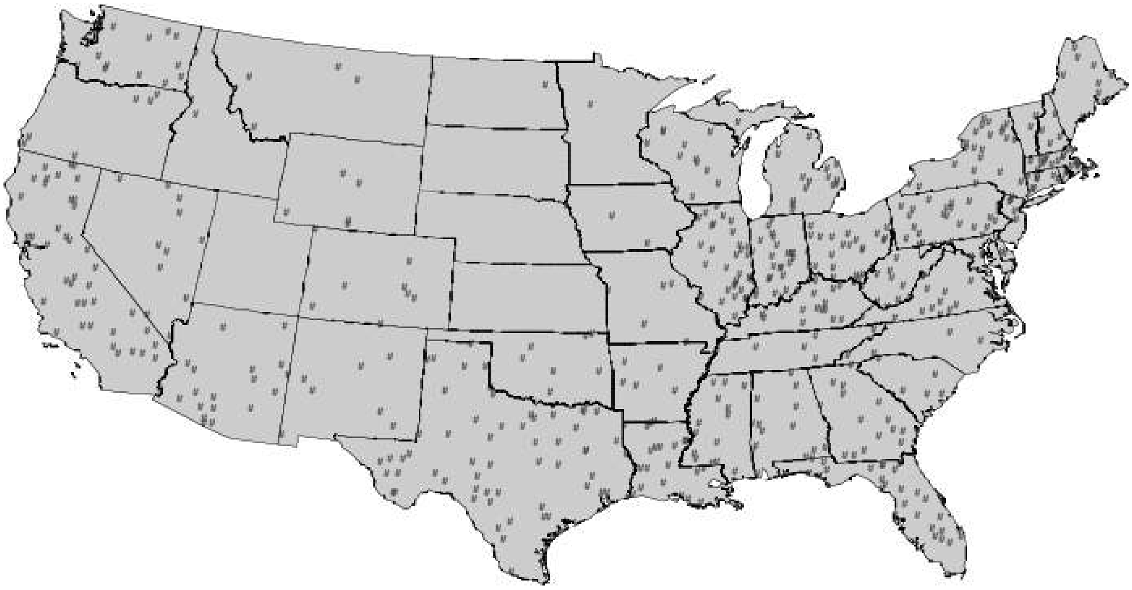

Figure 6.2 Announced independent power projects in the United States.

The San Francisco Fed also noted that these decreases in household income have been substantially lessened because of subsidized prices by the state of California. The recent study noted the following:

> If the full rise in wholesale electricity prices — much of which currently is being covered by the state as a result of the procurement of power by the Department of Water Resources — was taken into account, our estimate of the increase in energy-related expenditures by the average California household would rise substantially.[1]

Fortunately, market incentives in most regions of the United States seem to be working. Industry changes and market forces have stimulated new power plant construction activity. Today, for-profit independent power providers are constructing the next generation of power facilities; this is unlike the past when power generation facilities were built almost exclusively by regulated utilities. Figure 6.2 shows the number of independent power plant construction projects throughout the United States.

6.2 The origins of competitive wholesale markets

One important factor changing the nature of electric power markets has been the advent of competitive opportunities for new sources of power generation. Quickly fading is the past regime of regulated prices, as well as limited opportunities for trading, profits, and energy efficiency. The origins of competition, however, are not new and can be dated to the late 1970s when the energy crises changed public policy. This is when the notion came about that utilities were "natural monopolies" and should be the only regulated providers of electricity in the marketplace.

would have been required to deal directly with transmission-owning utilities for moving their power to wholesale customers. Without these rules in place, transmission-owning utilities would have been able to give preference to their own competitive (or regulated) generating facilities at the expense of their potential competitors. This new order helped create a system in which transmission lines, regardless of ownership, would serve as a common carrier to facilitate wholesale trade. From 1996 on, competitive sources of electricity have been able to compete on a level playing field with incumbent utility generation.

The promulgation of Order 888 transformed the industry. In addition to creating a competitive power market, it also helped facilitate the growing convergence between the power business and other energy industries. New trading mechanisms and institutions that arose in the aftermath of Order 888 served to facilitate this process.

Today, independent power providers play an important role in regional power markets. The nature of these providers, however, is often misunderstood. Independent — or merchant — power plants are those facilities that are usually constructed and operated by independent companies (i.e., nonutility companies) for a potential profit. These facilities, and their developers, differ in important ways from other utility and nonutility sources of power generation.

Utilities, for instance, are regulated monopolies that have a guaranteed retail customer base. Prices are set by state regulators to curb potential monopoly abuses. As monopolies, utilities are allowed to recover their prudently incurred costs, and to have the opportunity to earn a reasonable rate of return on prudently incurred capital investments. In return for their monopoly status, utilities are required to provide safe, reliable, and economic service to their customers.

Other nonutility power generating sources, primarily qualifying facilities or cogenerators under PURPA, are not in the primary business of producing electricity. These facilities typically produce some product and generate electricity as a secondary endeavor. If these types of nonutility cogenerators meet thermal and other ownership and operating requirements established by FERC, they are entitled to sell their power to utilities based upon the utilities' avoided cost. They are also entitled to emergency, standby, and backup power should their on-site generating facilities go down for planned or unplanned outages.

Competition in wholesale markets over the past several years has not come without its share of growing pains. Some of the more painful recent experiences of this process have included the following:

1. The past several summers have seen an increase in the price volatility of wholesale power markets.
2. In addition to price volatility, wholesale markets have experienced a number of incredible price increases in absolute magnitude. In some

chapter seven

Understanding both technical and business factors

7.1 A brief history

Toward the end of his career, Thomas Edison was asked, "What was your greatest invention?" In response, he said, "incandescent electric lighting and the power system." Edison's answer indicates that he saw the importance of technological innovation, but was also an entrepreneur. He understood that a complete electrical power system would be required to make incandescent electric lighting useful and enable competition with gas lighting companies. The idea of competition was part and parcel of the electric power industry from its very inception.

Thomas Edison's Pearl Street power system in New York City became fully operational in 1882. The Pearl Street power system is sometimes cited as the first electric power system. This power system was different from modern power systems in several respects:

1. The Pearl Street system was a direct current (D.C.) system.
2. All of the power generation facilities were in a single location.
3. The low-voltage power delivery system was entirely underground.
4. The system provided electricity for a single application: street lighting.

After a debate between Thomas Edison and George Westinghouse about the relative merits of alternating current (A.C.) systems vs. D.C. systems, the architects of the early power systems finally decided to use three-phase A.C. generators with step-up transformers, high-voltage transmission systems, and step-down transformers at the point of customer service. Three-phase A.C. systems delivered a constant power supply and reduced transmission losses, but required synchronizing generation units as they were added to the system. The need to cope with increased system operating complexity to reduce power supply costs has always been recognized by power system engineers.

> The purpose of the NESC is the practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and associated equipment. The NESC contains the basic provisions that are considered necessary for the safety of employees and the public under the specified conditions. The NESC covers supply and communication lines, equipment, and associated work practices employed by a public or private electric supply, communications, railway, or similar utility in the exercise of its function as a utility. It covers similar systems under the control of qualified persons, such as those associated with an industrial complex or utility interactive system.

The National Electrical Code (ANSI/NFPA-70) focuses on customer installations. The following is from the NEC:*

> The National Electrical Code, NFPA-70, addresses proper electrical systems and equipment installation to protect people and property from hazards arising from the use of electricity in buildings and structures. The NEC covers: 1) Installations of electric conductors and equipment within or on public and private buildings or other structures, including mobile homes, recreational vehicles, and floating buildings; and other premises such as yards, carnivals, parking lots, and industrial substations. 2) Installations of conductors and equipment that connect to the supply of electricity. 3) Installations of other outside conductors and equipment on the premises. 4) Installations of optical fiber cable. 5) Installations in buildings used by the electric utility, such as office buildings, warehouses, garages, machine shops, and recreational buildings that are not an integral part of a generating plant, substation, or control center.

The NEC and the NESC were written as voluntary standards. Some portions of these codes have been subsequently adopted by some local authorities and nonadherence, in some cases, is a violation of state laws. Furthermore, the National Society of Professional Engineers (NSPE) Code of Ethics points out that professional engineers are expected to conform to applicable standards and "hold paramount the safety, health, and welfare of the public."

Electrical equipment suppliers are increasingly functioning in global markets and, consequently, international standards activities are of increased

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* National Electrical Code

The Northeast Blackout was initiated when relays opened a transmission line near the Niagara Falls generating facility. Opening this line reduced power flows from the generating facility and caused several other lines to be overloaded. After this, "cascading outages" occurred in Ontario, New York State, New Jersey, Pennsylvania, and parts of New England.

After the Northeast Blackout, U.S. electric utility industry executives recognized the need for a "National Electric Reliability Council" (NERC). NERC was initially established as a nonprofit, voluntary organization owned by Regional Reliability Councils. At the outset, utility managers and utility technical experts were invited to participate to serve the mutual self-interests of those involved. The NERC evolved into the North American Electric Reliability Council in recognition of the fact that the electric power system of the United States was integrated with the electric system in Canada and part of the Mexican power system. NERC hired a small staff located in Princeton, NJ, and structured its committee system to include an engineering/planning committee and an operating committee.

The efforts of NERC and its members have helped to make the North American electric system the most reliable electric system in the world. NERC has served as a forum for information exchange, developed operating and planning standards for its members to follow, reviewed planned generation and transmission systems, studied past electric system disturbances, and provided education and coordination for various groups. NERC played an important coordinating role with respect to "Y2K" concerns.

NERC is now in the process of dramatically changing its structure and operations to address the profound changes taking place in the structure and operations of the electric power industry. NERC has restructured its board of trustees to include all segments of the electric industry, including investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal, and provincial utilities; independent power producers; and power marketers. The NERC Regional Councils, now ten in number, have also opened up their membership to include all of the industry stakeholders and independent participants.

In 1996, NERC began formalizing its transmission operations policies and called for the establishment of regional security coordinators to proactively monitor system conditions and mitigate potential reliability problems. Once security coordinators were identified by the region, NERC formed a security coordinator working group. The 22 members of the security coordinator working group developed improved procedures for interregional coordination.

NERC has charged security coordinators with seeing the big picture, assessing the moment-to-moment reliability of the grid, taking actions necessary to maintain reliability in the best interests of the interconnection, and being responsible for coordination during emergencies. Security coordinators have a central role in maintaining reliability.

NERC has recognized that a voluntary system of compliance is no longer adequate and has begun transforming itself into a new organization to be

chapter eight

The North American bulk electric system

8.1 The evolution of system operations and control

Understanding how the methods for power system operations and control have evolved during the last century can provide insight into the methods used for the operation of modern power systems. The pioneering efforts of power system operators (or dispatchers) and power engineering innovations have made it possible for North American electric systems to achieve a very high level of efficiency. Today the bulk electric systems in North American are the most reliable systems in the world. Whether this level of reliability will continue during and after the transition to "restructuring and deregulation" is an interesting subject for discussion.

Central dispatching systems were not used in the first power systems from the early 1880s to the early 1920s. Generation control was accomplished at power plants by local equipment. The Philadelphia Electric Company in Pennsylvania installed one of the first central dispatch generation control systems in 1923. At that time, power systems were still operated as "islands," that is, there were no interconnecting tie lines and, consequently, no wholesale power sales between electric utility systems.

The first interconnections between electric utility systems were not constructed until later in the 1920s, also in the Pennsylvania-New Jersey-Maryland area (now referred to as the PJM system). Having physical tie lines or interconnections between power systems provided advantages to system operators, but also introduced new operating complexities. The advantages of interconnections are that they permit sharing generation reserves during emergency conditions and allow interconnected electric systems to make economic transactions when load diversities and generation scheduling plans create opportunities. To obtain these benefits, electric systems are required to coordinate their operations. Coordination initially involved basic control concepts, such as the "load-balancing function" and "time-error correction." However, coordination has become increasingly more complex and now requires very elaborate procedures for monitoring "inadvertent interchange,"

8. SERC: The Southeastern Electric Reliability Council serves electrical demands in parts of Virginia, the Carolinas, Kentucky, Tennessee, Texas, Louisiana, Mississippi, Arkansas, Georgia, and Florida.
9. SPP: The Southwest Power Pool serves electrical demands in parts of Oklahoma, Missouri, Kansas, Colorado, Texas, Louisiana, Arkansas, and Mississippi.
10. WSCC: The Western Systems Coordinating Council serves electrical demands in parts of Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, Wyoming, Alberta, British Columbia, and the northern portion of Baja California Norte, Mexico.

8.2 The big machines

From an electrical point of view, there are three systems in North America. These systems are called "interconnections." They are:

1. The Western Interconnection, generally including the states west of the Rocky Mountains and the Western Canadian provinces.
2. The ERCOT Interconnection, including most of Texas. ERCOT does not have synchronous interconnections to other states and is not under the jurisdiction of the Federal Energy Regulatory Commission (FERC).
3. The Eastern Interconnection, including the Eastern Canadian provinces and most of the United States, east of the Rocky Mountains.

Each one of the Interconnections is comprised of a group of loads, transmission systems, and generators operating in synchronism. The Interconnections are not connected to each other by synchronous interconnections. However, there are D.C. tie lines between the Eastern Interconnection and ERCOT, and between the Eastern Interconnection and the Western Interconnection.

Interconnections can be viewed as a single machine consisting of many synchronous elements. An interesting debate has recently been initiated on the engineering community's "power globe" comparing the two "very large machines" that have been created during the last century: the electric power system and the World Wide Web. The question is, "Which is the most complex machine?" It has been noted that from a purely financial point of view, the investment in equipment and the annual revenues are greater for the electric power system. The presumption is that the more expensive machine is more complex.

On the other side of the coin, current average starting salaries for computer system/Internet engineers are higher than current average salaries for power systems engineers. Here the presumption is that the more complex machine requires higher-paid engineers. As a practical matter, we should probably not be concerned about separating the two big machines, because deregulation and restructuring are causing the two machines to merge into a single machine. The computer technology and the Internet are increasingly used for the management and control of the power system, both to maintain system reliability and to facilitate real-time markets.

8.3 End-of-chapter questions

1. One disadvantage of having an extremely reliable bulk electric system is that operators gain little experience with restoration techniques. Also, in some cases, U.S. electric utility executives have been criticized for spending too much money and "gold plating" their systems. Do you think that many electricity customers would be willing to accept a lower level of reliability for slightly reduced rates?
2. Is the regional reliability council of NERC organized so that each state belongs to a single regional council, or is the organization based on some other system? Explain.
3. How is an Interconnection defined? Note that there is a difference between an "interconnection" (lower case) and an "Interconnection" (upper case).
4. How many "Interconnections" are there in the United States? Geographically, which is the largest of the Interconnections?
5. Why are the power systems in ERCOT the only power systems in the United States that are not under FERC's jurisdiction?
6. Is it possible to move power from one Interconnection to another Interconnection? If so, how is this accomplished?

chapter nine

Methods for economically operating a power system

9.1 Operating economics, control systems, and power systems reliability

We have devoted one chapter in this book to the subject of operating economics, as indicated by the title of this chapter. This was done to focus on key concepts and to facilitate teaching using this book. However, in the "real world" (or the physical world), it is impossible to separate operating economic considerations from power system control considerations. Additionally, power system operating or control decisions involve taking into consideration possible impacts on power system reliability and environmental performance.

Possibly the best way to begin to understand operating economics and the related issues of control, reliability, and environmental performance is to begin by considering a power system consisting of a single generating unit attached to a single variable load. After this, a power system with multiple generating units is considered, and the classical "economic dispatching" problem and the classical "unit commitment" problem defined. These problems are presented both with and without consideration of transmission losses. Finally, to make this treatment more realistic, the additional complexities of allowing power purchases and sales between interconnected power systems are considered. This level of understanding is necessary to understand the operating economics/systems control approaches used by the industry prior to deregulation and restructuring. Other chapters of this book extend this discussion to the new business environment in which open access and power marketing considerations must also be taken into account.

9.2 A single generating unit

First, a power system consisting of a single generating unit attached to a single variable load (or a set of loads which aggregated constitute a single variable load) is considered. Most of the generating capacity used in the

United States involves burning coal to produce steam and turn the shaft of an alternating-current, synchronous generator. Since this is the most common technology, assume that the single generating unit coal-fired. Of course, from an electrical point of view, the fuel source (or heating source) is not important. Any steam power plant (coal-fired, gas-fired, nuclear, etc.) produces steam that impacts the turbine blades causing the shaft in the synchronous generator to rotate. And, of course, we know from physics that voltage is induced in the coils of the generator in the presence of the generator's magnetic field.

For the purposes of this discussion, assume that the load is connected directly at the terminals of the generator. In other words, there are no transformers, transmission or distribution lines, switch gear, protective devices, etc. Of course, in actual power systems, power generators generally have three-phase output voltages in the range of 10 to 24 kV, and it is necessary to use step-up transformers to reduce the losses associated with long-distance transmission. Also, loads are generally at much lower voltages than transmission-level voltages, and, therefore, step-down transformers are required. The use of system protection equipment and other substation or electrical system equipment is outside the scope of this discussion, except to say that its proper operation plays an important role in keeping the power system reliable, thereby enabling economic operations.

The single generating unit problem is almost trivial. If there is no control over the load, the only option is to match the output of the generating unit to the load level. As long as the load level is greater than the unit's minimum possible output and less than the unit's maximum possible output, it is possible to serve the load.

If there is control over the amount of load, the problem becomes slightly more complex. In this case, it is possible to find an optimal level of generating output from an economic point of view. The methods for doing this are in most power systems analysis textbooks. It is normally assumed that the relationship between fuel input (f) and power output (P) can be expressed with an equation of the form:

$$f = a\,P^2 + b\,P + c.$$

Of course, using fundamental calculus, the minimization of this function is accomplished by taking the first derivative and setting it equal to zero. The first derivative of this function is usually called the "incremental cost."

9.3 *Two generating units*

When two generating units are connected together to serve a single variable load (or a set of loads that aggregated constitute a single variable load), a decision has to be made. Should one unit's output be held to a single value and "follow load excursions" with the other unit, or should the power output levels of both units be varied as load varies?

In the early days of interconnected operations, it was common practice to use a single unit for load following and to accomplish frequency regulation. As system operations techniques became more sophisticated, it was recognized that this would not result in an "optimum economic dispatch." Again, recognizing that the relationship between fuel input and power output for each unit (where the units are numbered from i = 1 to i = N) can be expressed with an equation of the form:

$$f_i = a\,P_i^2 + b\,P_i + c.$$

Again, taking the first derivative for each unit, the incremental costs for each unit can be found. Power systems analysis textbooks show that, ignoring transmission losses, optimal economic dispatch is achieved when the incremental costs for all units are equal.

This principle has been implemented in modern energy-management centers and has resulted in billions of dollars of production cost savings.

9.4 *End-of-chapter questions*

1. In what ways are coal-fired power plants different from nuclear power plants? In what ways are they similar?
2. If four identical generating units are in a single power system, and each has a minimum output of 10 MW and a maximum output of 200 MW, how much system load can be served? (Take service reliability into account, but do not consider economic factors at this point.)
3. Using the same four units in question 3, how would you approach the problem of finding the amount of load that could be served if it is desired to minimize fuel costs?
4. Ignoring transmission losses, what is the condition for optimal economic dispatch from a group of units that do not necessarily have the same input/output characteristics?

chapter ten

Power generation control

10.1 The definition of automatic generation control

Automatic Generation Control (AGC) is a means of automatically controlling the outputs of power-generating units to accomplish economic dispatch, and maintain system frequency and power flows over tie lines at desired levels. AGC, sometimes referred to as load control or load frequency control, is performed at energy control centers or energy coordination centers using energy management systems. Energy management systems acquire data from the power system and use computers to process the data. Modern energy management systems usually have sophisticated provisions for operator interaction and include the equipment and communications required to send control signals to generating units.

AGC supplements the local control that occurs at power plants. At thermal generating plants, local control systems regulate turbine-generator speed by responding to changes in system frequency and adjusting steam flows to increase unit power outputs when system frequency is low or decrease unit power outputs when system frequency is high. Speed regulation is also called "governor droop." Governor droop is defined as the percent change in frequency that would cause the unit's generation to change by 100% of its capability.

Traditionally, AGC has been implemented as a simple feedback control system in which the error to be driven to zero is defined as having two components. The first component recognizes differences that may exist between actual and scheduled tie flows, and the second component accounts for deviations from scheduled frequency. The AGC error signal, called area control error (ACE), is mathematically defined as:

$$\mathrm{ACE} = (P_a + P_s) - 10\, B_f\,(f_a - f_s),$$

where P_a is the actual net interchange power over the system's tie lines; P_s is the scheduled net interchange power over the system's tie lines; B_f is a frequency bias constant; f_a is the actual system frequency; and f_s is the scheduled system frequency.

3. Costs for control and telemetry equipment needed to accomplish regulation
4. Costs for wheeling, when appropriate

Models have been proposed for calculating regulation service requirements using statistical data. Since regulation cannot be achieved for all possible load variations, such models require an assumption about the percentage of the time for which regulation is to be accomplished.

10.3 Control performance criteria

NERC has recognized the need to improve its control performance criteria. The old NERC "a1" criteria required that a control area's ACE return to zero every 10 minutes. The 10-minute period coincided with the definition of "operating reserves," that is, reserves used to make up power during contingency events. The old NERC "a2" criteria had to do with the average value of ACE between zero crossings. Averaging ACE was intended to avoid having generation follow very short-term load swings or noisy signals in instrumentation systems. Criteria a1 and a2 were based on operating objectives and helped in system control, but these criteria did not distinguish between ACE values causing increased frequency deviations and ACE values helping to return frequency to scheduled values. More importantly, NERC recognized that criteria a1 and a2 involved economic costs, which are difficult to justify in a competitive business environment.

The new NERC control performance standards are "CPS1" and "CPS2." CPS1 uses an index calculated by taking the average value of ACE, divided by 10, multiplied by the frequency bias constant, multiplied by the difference between actual system frequency and scheduled system frequency. CPS1 recognizes that control areas should increase generation during periods when overall system loads are increasing and should decrease generation during periods when overall system loads are decreasing. CPS2 was designed to allow larger control areas to have greater ACE deviations than smaller control areas during each 10-minute period. Thus, CPS2 recognizes that control areas function as part of the interconnected system and share the responsibility for regulation.

NERC has not only changed the technical definitions for control performance, but also has established procedures to better monitor the performance of individual systems and to make individual systems comply. NERC's vision is to become an independent industry self-regulatory organization that will enforce compliance with reliability standards in a fair and nondiscriminatory manner. At the conclusion of this transition, NERC will be renamed the North American Electric Reliability Organization (NAERO).

Deregulation, restructuring, and competition require modifying the original formulation of the automatic generation control problem and the associated methods of evaluating control performance. Electric power industry restructuring will result in new definitions for control areas and will require innovative methods for calculating and allocating the costs for regulation and frequency response services. These tasks are being addressed by NERC committees and by the new participants in power markets.

10.4 End-of-chapter questions

1. What is the difference between the terms "Automatic Generation Control" and "Load Frequency Control?"
2. How many control areas are there in North America, and what is the function of a control area?
3. How does Automatic Generation Control maintain system frequency near the scheduled value (usually 60 Hz) during normal conditions? How is frequency regulated during emergency or disturbance conditions?
4. What effect will FERC Order 888 have on the way generation is controlled and costs are allocated in the electric power industry?
5. Why did the North American Electric Reliability Council change the methodology for calculating Control Performance Criteria?
6. Can you suggest an alternative formulation for control performance criteria? What are the strengths and weaknesses of the approach you are suggesting as compared to the NERC criteria?

chapter eleven

New reliability and control concepts

11.1 The layman's definition of reliability

Webster's Dictionary defines reliability as "the quality or state of being reliable."

The word reliable is, in turn, defined as "suitable or fit to be relied on." In defining the word rely, *Webster's* refers to trust, confidence, and dependability. So, in other words, power systems are reliable if they can be trusted, if we have confidence in their performance, and/or if we can depend on power being available when we throw the wall switch.

As long as electric power service is reliable, most people are content and unconcerned about pursuing the subject of reliability. However, the general level of interest in reliability peaks when electric power service is *unreliable.* Consequently, our vocabulary for describing unreliability is somewhat richer than our vocabulary for describing reliability.

Unreliable conditions are referred to as "service interruptions," "power disruptions," "power outages," "power failures," "blackouts," and "brownouts." All of these terms were used by those who feared that power industry deregulation would have an adverse effect on power system performance.

11.2 The academic and traditional definitions of reliability

Textbooks on power system reliability often begin with a classical definition, such as "The reliability of a power system is the probability that the system will perform its intended function in an acceptable manner, for some intended period of time, under specified operating conditions."

Within the field of power system reliability analysis there are well-established methods for analyzing and calculating component and system reliability. At the bulk electric system level, U.S. transmission grids have been more than 99.9% reliable. This can be interpreted to mean that the systems are unavailable less than 2 hours per year.

At the power distribution system level, a number of indices have been defined for assessing reliability. The system average interruption duration effective planning in the operations planning time frame (minutes to months) and effective system planning in a time frame of years to decades. The quality of load forecasts is critical to this balancing function. A knowledge of generation maintenance schedules, forced outage rates, and power purchase contracts is also critical to this function.

11.5 The new paradigm: operating and service functions

The control area approach has worked well as a means of maintaining reliability and meeting the economic needs of electric utility customers (native load customers), as well as a basis for managing wholesale purchases and sales to utilities and using the transmission system for "wheeling services." However, with the advent of deregulation and restructuring, the control area approach has proven to be inadequate in several respects. First, the large number of control areas (approximately 150) made it difficult to coordinate security operations. Recognizing this, NERC created a hierarchical system and established 22 security coordinators, each with coordinating responsibility for large geographic areas, usually involving multiple control areas.

The traditional control area approach also was inadequate, because it was based on the vertically integrated model. It did not take into account the new structure involving unbundled systems with generation, transmission, and customer service functions separated with a utility or offered by entities not under a single corporate ownership umbrella. Additionally, the control area approach needed to be redefined to accommodate innovative approaches taken by power marketers, such as having a single generating unit with power contracts to serve loads in other control areas constitute a control area.

Recognizing a pressing need to rethink control area concepts and define "functional responsibilities" rather than "organizational responsibilities," NERC formed a Control Area Criteria Task Force that produced a final report in 2001. This report identified nearly 100 operating functions that needed to be performed by some entity to maintain reliability and accommodate the new open-access, competitive power markets. One of the reasons for doing this was to be able to assign the various functions to existing and new or emerging organizations, and thereby clarify the responsibility for maintaining system reliability. Of course, it was impossible to anticipate how future organizations may be structured, but the NERC task force believed that the following list of entities currently performing operating functions was reasonably complete as of the date of the final report in 2001:

1. Generators*
2. Transmission service providers
3. Transmission owners*
4. Transmission operators*
5. Distribution providers

6. Load-serving entities*
7. Purchasing/selling entities*
8. Security authorities
9. Balancing authorities*
10. Interchange authorities*
11. Compliance monitors

Asterisks have been added to the above list to indicate the functional roles usually considered to be associated with "control areas." In other words, there are four functional roles without asterisks (transmission service provider, distribution provider, security authority, and compliance monitor). These four functional roles have assumed importance in the new deregulated and restructured electric power industry. The NERC task force report also separated "service functions" from "operating functions." With this bifurcation, of the four functions without asterisks, the transmission service provider function, the security authority function, and compliance monitor function are "service functions," while the distribution provider function is an "operating function."

11.6 End-of-chapter questions

1. What are three terms commonly used to mean that an electric power system has been unreliable?
2. If a 500-kV transmission system has been 99.8% reliable during a given year, how many minutes of unavailability have been experienced?
3. In designing a backup, on-site power supply facility for a hospital, an engineer would like to maintain enough fuel on site for usual outage conditions with a 50% safety factor. Would the engineer need data about SAIDI, SAIFI, or CAIDI?
4. What is meant by the term "power system adequacy," as defined by NERC? Do you think this term is more related to system planning or system operations?
5. What is meant by the term "power system security," as defined by NERC? Do you think this term is more related to system planning or system operations?
6. What conditions will cause frequency to increase within a control area? What could be done to arrest or reverse frequency increases within a control area?
7. How many control areas are there currently in North America? Does it seem practical to coordinate with this number of entities in making a real-time decision to be implemented with a 10- or 15-minute time window?
8. Explain why NERC has defined "operating functions" and "service functions" as a better means of assigning responsibilities after the break up of the vertically integrated traditional electric utility system structure.

chapter twelve

Available transfer capability

12.1 A new methodology for assessing transmission line limitations

When the interconnections in the electric utility industry began to experience increased power flows as a consequence of industry restructuring, it became apparent that improved methods would be needed to calculate "available transmission transfer capabilities" (sometimes called available transfer capability, or ATC).

There are three limiting factors to be considered in determining transmission transfer capability. First, "thermal limits" must be taken into account. Thermal limits have to do with the amount of electrical current that a transmission line or flowgate can accommodate. Of course, the magnitude of current in a transmission line or flowgate can be determined by dividing the total amount of electric power transfer by the voltage level of the transmission line or flowgate. Thermal limits are determined for a specified time period. In other words, a transmission line or flowgate can accommodate a specific amount of current for a certain period of time before overheating.

"Voltage limits" are the second limiting factor. For every transmission line or flowgate there are minimum and maximum acceptable voltage limits. If voltage goes too high or too low, electrical power equipment may be damaged or protective-relaying systems may open breakers, causing customer outages or even widespread cascading blackouts. Most of the textbooks used for the first course in power systems analysis explain why system voltage variations are more sensitive to reactive power flows than to active power flows. These textbooks also typically discuss some of the techniques for maintaining acceptable voltages and var flows, including the use of synchronous machines, static capacitors, tap changing transformers, etc.

"Stability limits" are the third limiting factor. Following a power system fault, very high current flows may occur during the subtransient period (generally considered to include approximately the first 0.05 sec or the first 3 cycles for a 60-Hz system) or dynamic period (the period after the subtransient period, but prior to returning to the steady state, generally considered in the range of milliseconds up to a few minutes). Transmission elements more telemetered data, more powerful computers, and improved power system simulation software. Having a number of simulation studies available provides all market participants with prior knowledge of the characteristics and capabilities of the power system.

12.2 *Guiding principles for ATC calculations*

When NERC issued its report on "Available Transfer Capability Definitions and Determination" in June 1996, it was noted that individual systems, power pools, subregions, and regions would be permitted to develop their own procedures for determining or coordinating ATCs based on a regional or wide-area approach, as long as these procedures were consistent with the following six principles in the NERC ATC report They have been reworded and abbreviated from the NERC report to facilitate presentation to university students:

1. ATCs should realistically indicate the actual transfer capabilities available to the electric power market. ATCs must be accurate and realistic to provide a basis for market decisions, particularly in areas where there is significant congestion or where there are many wholesale power purchases and sales.
2. ATCs should recognize that power flow conditions vary in time and are affected by "simultaneous transfers" and "parallel path flows" on the interconnected transmission network. The ATC of a collection of lines will generally be less than the ATC found by adding the ATCs of the individual lines.
3. ATCs should take into account the direction of power flows on transmission lines and whether active power is injected or extracted at generation and load busses. The ATC from point A to point B is not necessarily equal to the ATC from point B to point A.
4. ATC calculations and results should be coordinated and openly shared on a regional basis.
5. ATC calculations should be consistent with NERC, regional, subregional, power pool, and individual system planning and operating policies.
6. ATC calculations should take into account uncertainties in system conditions and provide operating flexibility.

12.3 *End-of-chapter questions*

1. Under what conditions, or in what kind of systems, is the accurate calculation of available transmission system transfer capability most important?
2. How does available transfer capability (ATC) relate to total transfer capability (TTC)?

3. What is the purpose of power system simulation studies, and how are these studies used in determining ATC?
4. Why are accurate ATCs important to those who are primarily concerned with maintaining reliability? Who are some of the entities with these concerns?
5. Why are accurate ATCs important to those who are primarily concerned with commercial transactions in electric power markets? Who are some of the entities with these concerns?
6. When should "time-variant power flow conditions" be taken into account in calculating ATCs? Make up an example, including variable megawatt flows on a flowgate, to explain your answer.
7. Why should "simultaneous transfers" be taken into account in calculating ATCs? Make up an example, including a network configuration and megawatt flows on flowgates experiencing "simultaneous transfers" to explain your answer.
8. Why should "parallel path flows" be taken into account in calculating ATCs? Make up an example, including a network configuration and variable megawatt flows on the flowgates, to explain your answer. Show how the transfer capability of a single transmission line can be affected by flows on other lines that are part of the interconnected network.
9. Can the ATCs of individual transmission lines be added to determine the ATC of an interface between two systems? Why not? Would the aggregated ATC be generally greater than or less than the sum of the ATCs?
10. Why should "uncertainties in system conditions" be taken into account in calculating ATCs? Make up an example, including variable megawatt flows on a flowgate, to explain your answer.

chapter thirteen

Network congestion and transmission loading relief

13.1 The network congestion problem

Shortly after it became apparent that the electric utility industry would be restructured to create increased competition and provide open access to transmission, it was recognized that increased network congestion could be one of the primary problems associated with electric industry restructuring.

It was anticipated that industry restructuring would lead to a greatly increased number of transactions to purchase and sell electricity on the grid. As a consequence, electric power systems would experience more frequent transmission line overloads. This has certainly proven to be the case, as discussed at the end of this chapter.

Early in the 1990s, the North American Electric Reliability Council (NERC) and the Electric Power Research Institute (EPRI) organized industry efforts to consider various approaches for reducing network congestion in a way that would be equitable and fair to all of the parties involved.

Network congestion can be reduced by cancelling transactions, redispatching generation, reconfiguring transmission, or reducing loads. Obviously, there can be very great financial impacts from taking any of these actions. And, of course, equal or even greater financial impacts can result from allowing network congestion to cause overloads or other operating security limit violations. Consequently, all participants in electric power markets have taken a keen interest in network congestion problems and methods for relieving network congestion.

13.2 The transmission loading relief approach

Following extensive debate within the NERC committee structure, NERC adopted transmission loading relief (TLR) procedures as the primary means to be used by security coordinators for addressing network congestion problems. The TLR approach is intended as a means to mitigate potential and/or actual violations of operating security limits while honoring transmission particular flowgates of interest. If the options identified do not sufficiently reduce loading, calculations are made to determine the MW curtailment that can be achieved using the TLR procedure.

A security coordinator calls a TLR Level 3a to curtail lower-priority nonfirm, point-to-point transmission service and to allow higher-priority transactions to start or increase. A security coordinator calls a TLR Level 3b to curtail firm service and mitigate an operating security violation.

A TLR Level 4 is called when a flowgate is above its operating security limit and there are no nonfirm interchange transactions that can be curtailed to solve the problem. The effect of a TLR Level 4 is to reconfigure transmission systems and avoid curtailing firm interchange transactions.

A security coordinator calls a TLR Level 5 when a flowgate is at or approaching an operating security limit violation, and a transmission provider receives a request to implement new interchange transactions and/or increased interchange transactions that will cause an overload. The effect of a TLR Level 5 is to curtail interchange transactions using nonfirm, point-to-point transmission service and allow higher-priority transactions to start or increase.

A security coordinator calls a TLR Level 5a to curtail lower-priority, nonfirm, point-to-point transmission service and to allow higher-priority transactions to start or increase. A security coordinator calls a TLR Level 5b to curtail firm transmission service and mitigate an operating security violation.

A security coordinator calls a TLR Level 6 when the actions associated with TLR Levels 3, 4, and 5 are insufficient to resolve the problem or when the flowgate reaches such a critical level that emergency actions are required.

The effect of a TLR Level 6 is to direct control areas or transmission providers to take actions, such as generation redispatch, transmission reconfiguration, or load shedding, to either mitigate the critical condition or provide time for the actions associated with TLR Levels 3, 4, and 5 to take effect.

TLR Level 0 indicates that the loading on the flowgate is continuing to trend downward and that any operating security limit violations have been addressed. The purpose of TLR Level 0 is to provide a means to notify other security coordinators, transmission providers, control areas, and merchants that all curtailed transactions can be restored.

It should be noted that during any of the TLR levels, transmission providers are not obligated to redispatch their own resources to maintain transactions using firm, point-to-point transmission service prior to being curtailed, according to the FERC Pro Forma Tariff.

13.3 *Criticisms of the TLR approach*

Market participants have complained that the TLR approach has several deficiencies. The complaints primarily identify cases in which there are unnecessary curtailments, a lack of standardized protocols for providing information, and/or discriminatory conduct.

5. According to NERC, are system stability conditions as well as steady-state performance used in determining if operating security limits have been violated?
6. What actions are taken when a security coordinator calls a TLR Level 1?
7. What actions are taken when a security coordinator calls a TLR Level 2?
8. What actions are taken when a security coordinator calls a TLR Level 3?
9. What actions are taken when a security coordinator calls a TLR Level 5?

chapter fourteen

The use of power flow and stability analysis tools

14.1 Operating security limit (OSL) violations

Power system operators maintain the reliability of their systems by anticipating and/or correcting operating security limit violations. An operating security limit violation will not necessarily jeopardize the reliability of the Interconnection or create a widespread problem or cascading blackout, but the existence of an operating security limit implies one of three things:

1. A steady-state rating of a monitored element has been exceeded
2. A voltage limit has been exceeded
3. A stability limit has been exceeded

When any one of these conditions is identified, a component or system failure is imminent. If the failure has not yet occurred, then it is likely that it will occur in the future with additional loading on the power system or with the added stress of a contingency occurring.

14.2 Tools for determining OSL violations

One question related to this discussion is, "How are the limiting conditions established?" Information about the steady-state limiting conditions can be obtained from a power flow analysis. Power flow analyses require information about system configuration (usually in the form of a bus admittance matrix or a bus impedance matrix), information about the net active and reactive power injections at each bus, and information about regulating transformers. The result of a power flow analysis (or the output of a power flow program) is the active and reactive power flow in each flowgate and the voltage magnitude and angle at every modeled bus. System operators anticipate the steady-state effects of increased power system loading or the occurrence of a contingency using power flow analysis tools.

Information about stability limits is obtained from stability analyses. Most of the modern undergraduate power system analysis textbooks devote a chapter to stability analyses. In addition, many other textbooks have been written exclusively about this subject. Stability analyses fundamentally begin with a "swing equation" representing the behavior of a generating unit following a fault or disturbance. Usually, relative stability can be determined from calculating how the machine's rotor angle changes during a very short period of time following a fault or disturbance. Normally, some assumption is made about fault-clearing time, and the key parameter becomes the angular change prior to fault clearing.

For systems with more than two machines, hand calculation becomes impractical, but today many computer programs are available for performing stability analyses. Usually, a power system analysis software package will include a power flow program, a fault analysis (or short-circuit analysis program), and a stability analysis program. Modern versions of these programs are very user-friendly. Models for most equipment are found in the libraries provided with the programs, and the models are modified using manufacturer data.

14.3 *End-of-chapter questions*

1. Will exceeding an operating security limit violation necessarily jeopardize the reliability of the Interconnection or create widespread problems or cascading blackouts? Explain.
2. Operating security limits are exceeded under three conditions. What are the three conditions?
3. How do power system operators anticipate the steady-state effects of increased power system loading or the occurrence of a contingency?
4. Why is fault-clearing time taken into account in analyzing the stability conditions in a power system?
5. Do you think you could determine the stability of a power system with six machines during a 1-hour examination? Explain if or when this may be possible.

chapter fifteen

Technology needs for the electric power industry

15.1 Opportunities and threats

Deregulating and restructuring the North American electric power industry have been advocated as a means of introducing new technologies into the industry. Advocates say, "Look at the effect of deregulation in the telephone industry." It is a fact that technological changes did occur in the telephone industry on the heels of deregulation. Similarly, it seems fair to say that deregulation and restructuring will create opportunities and incentives to introduce new technologies in the North American electric power industry.

Deregulation and restructuring also pose threats in the sense that the reliability and cost of electric service may be adversely impacted if more sophisticated new technologies are not available when they are needed to address the additional problems and complexities associated with deregulation and restructuring. These concerns seem well justified after the serious problems in California in 2000 and the Western system power outages of July and August 1996. Many articles have addressed the potentially adverse reliability implications of restructuring. Clearly, the new business environment will create not only new forms of regulation and competition, but also unprecedented needs for technological solutions to problems in the areas of systems operations and systems planning.

15.2 Lessons from the past

Following the Great Northeast Blackout of 1965, the Federal Power Commission identified several needs for new technologies and techniques. The Federal Power Commission said the industry needed better regional coordination, more transmission where large load centers were separated from generation facilities, better load forecasting techniques, and computer simulation tools for system operators. Many of these technologies and techniques were subsequently addressed by the industry to maintain and enhance the reliability of the power systems during that era.

The time frame for restructuring is a very critical issue from the electric utility point of view, because more time can allow major changes in utility operations. The states with the highest rates have generally shown the greatest interest and activity to initiate electric industry restructuring. In most cases, the states with the highest rates currently have the most difficult operating problems.

The Federal Energy Regulatory Commission (FERC) orders and rulemakings have clarified several restructuring issues, but have also introduced new issues, such as:

1. Defining what is meant by comparable open transmission access, particularly when power pools are involved
2. Functional unbundling to separate transmission system operators from wholesale marketers
3. Allocation of the costs for the real-time information networks
4. Methods for maintaining system reliability, with the new demands being placed on the transmission grid

NERC and the Electric Power Research Institute (EPRI) have focused on the adequacy of transmission capacity and transfer capability determinations, and associated technical problems and challenges. Both organizations have also investigated the various aspects of the recent power outages to determine if restructuring trends are root causes.

One of the technical concerns about power system reliability in the future has to do with the fact that generation capacity reserve margins are declining. Generation reserves are declining for several reasons. The power plants built in the middle 1960s or earlier are reaching the end of their useful lives. Some of these plants are being retired, and others have been derated. Life extension and uprating efforts are being undertaken in some cases, but the net effect is reduced available capacity. The amendments to the Clean Air Act and other environmental requirements are resulting in plant retirements or the nonuse of coal-fired units. Some of these coal-fired units are 500 megawatts (MW) or larger. Hence, a significant amount of generating capacity is unavailable for environmental reasons. Industry restructuring and the trend toward increased competition are forcing the retirement of units that are not competitive from an operating cost point of view. There is uncertainty about the treatment of stranded assets, but unquestionably some of the stranded-generating assets will be removed from service. Electric industry restructuring has stimulated the construction of nonutility generation or exempt wholesale generation (EWG), but has reduced the construction of new utility-owned generating capacity. During the period of transition to increased regional coordination, capacity may not be built where it is needed and when it is needed.

Transmission capacity reserve margins are also declining. Restructuring is increasing the number of transactions and the amount of power purchased and sold over interconnections. Transmission systems were designed to are indications that some of the environmental programs that have been initiated by state public service commissions may not be continued with a restructured regulatory approach.

There is a need to develop improved methods for automatic generation control in a restructured industry and begin the development of more specific proposals and research plans for redesigning each of the other existing energy control center applications.

Unquestionably, with increased "wheeling," the losses associated with the transmission of electricity may become more significant. However, new technologies are currently being developed to reduce losses in individual lines and to give power system operators increased control over power routing. Development of better data and forecasts concerning these technologies as a basis for influencing future technical and policy decisions is needed. Several specific design concepts are now being considered, including the cost and value of replacing mechanical switching systems with new power semiconductors, a technology called FACTS flexible transmission systems. Consideration is also being given to using new materials and new configurations for transmission line design. In addition, several reports have been published on the potential for upgrading existing transmission lines.

The unbundling of power systems services and the transition to having an independent system operator will create opportunities to redesign power system operating procedures to accommodate increased economy interchanges and facilitate environmental dispatching. There is a need to compare the informational requirements and operational guidelines currently used in utility power system control centers with the requirements and guidelines that will best serve the public interest when independent system operators assume the responsibility for economic dispatching decisions. It will be important that redesigned systems and procedures properly incorporate the need for maintaining power system reliability and power quality.

As restructuring is implemented, each of the existing energy-control center applications will need to be revised, and in some cases totally redefined, for the restructured industry to function effectively. Existing energy-control center applications include economic and environmental dispatching, automatic generation control, unit commitment, interchange evaluation, power flow, contingency analysis, state estimation, supervisory control, and data acquisition.

The opportunities associated with open access have to do with the various options for reducing energy costs or preventing the future increase of electricity rates. The options are summarized here:

1. Negotiate favorable long-term contracts with existing energy suppliers during the period when new legislation is being considered. (This has been the strategy of one of the big three automakers in its Michigan operations.)

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