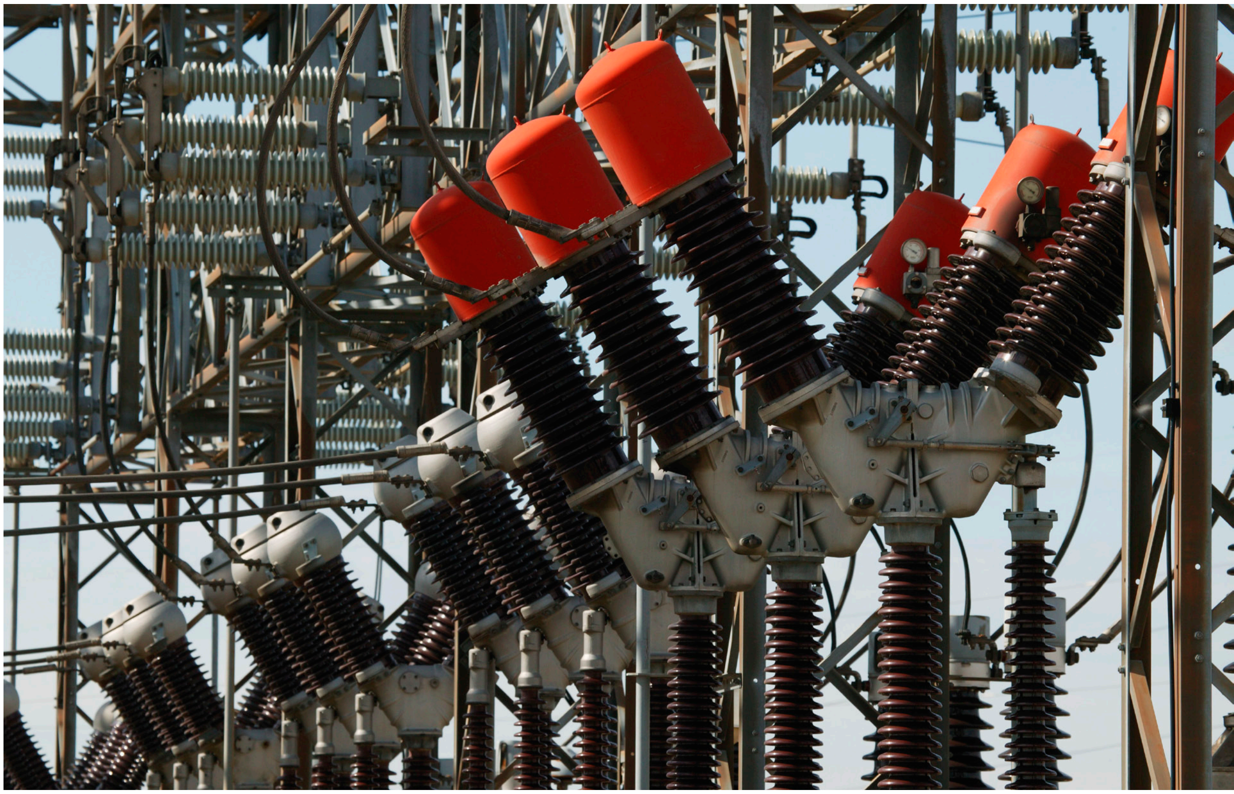
Deloitte.

Regulated utilities manual
A service for regulated utilities



Deloitte Center for Energy Solutions

Contents

Foreword		**1**
I.	**Utilities and their regulators**	**2**
	General characteristics	2
	Objectives of regulation	4
	State and local regulation	4
	Federal regulation	5
	Rate regulation	7
II.	**Cost-of-service ratemaking concepts**	**8**
	Cost-of-service ratemaking methodologies	8
	Rate base	9
	Test-period cost of service	13
	Rate of return	17
	Pricing utility services	19
III.	**Accounting characteristics of utilities**	**24**
	Effect of regulation	24
	Uniform systems of accounts	24
	Nature of differences	25
	FASB Statement No. 71	26
	Other FASB statements	28
	Plant accounting	29
	Revenue accounting	32
	Inventory accounting	32
	Income tax accounting	32
	Regulatory cost deferrals	34
	Form of financial statements	35
	Notes to financial statements	36
	Example financial statements – electric and gas utility	37
IV.	**Utility finance**	**42**
	Bond ratings	42
	Capitalization ratios	42
	Bond terms and covenants	42
	Preferred stocks	43
	Dividend policy	43
Appendices		**44**
	Glossary	44
	The 50 largest public and private electric and gas utilities	47

Foreword

The principal purpose of this manual is to assist the accountant familiar with accounting for businesses in general in applying his or her training to the specialized accounting practices of public utilities. The discussion of the utility industry here is intended to include those enterprises generally considered public utilities. Emphasis is given to the electric industry, but the principles are also applicable to the gas, telecommunications, water, and wastewater industries. The manual focuses on cost of service ratemaking concepts for public utilities.

Currently, state and federal legislation is addressing deregulation and competition. Utilities are involved in mergers and acquisitions, becoming large national and international organizations. Through restructuring, many aspects of the regulated utility are opening up to competition in the form of nonutility players in the marketplace. The applicable cost basis is generally market-based rates, under the Federal Energy Regulatory Commission's (FERC) re-regulation, as opposed to deregulation, structure. An electric power generator's wholesale rates continue to fall under the FERC regulatory structure.

Almost every industry has unique problems or practices that affect its accounting. In certain industries the unusual features are more obvious or perhaps more common than in other industries; such industries, including the public utility industry are frequently considered fields for specialists. The accounting practices of utility companies differ in many ways from those of other businesses; the use of systems of accounts prescribed by regulatory authorities is not the least of the differences. There are, however, more similarities than differences; generally accepted accounting principles apply to utilities just as to other industries, although their application at times may be different.

Some of the material that follows also deals with nonaccounting aspects of the industry. Moreover, there is little or no discussion of those aspects of accounting and auditing that are substantially the same as the practices in other businesses. This manual is not intended to be an exhaustive study of the industry but rather a summary of the unusual features of most interest to accountants and auditors. The appendices provide a glossary and statistical information about the largest public and private electric and gas utilities.

Deloitte & Touche USA LLP
February 2004

I. Utilities and their regulators

General characteristics

From the viewpoint of public utility law, utilities are distinguished as being a class of business "affected with a deep public interest" and therefore subject to regulation. Actually, many businesses have this characteristic – some of the leading court cases on regulation affect activities such as grain warehousing and railroads. Those businesses generally classed as public utilities, however, are further distinguished in that in most jurisdictions it is considered desirable for them to operate as regulated monopolies. As such, they are obligated to charge fair, nondiscriminatory rates and to render satisfactory service to the entire public on demand. In return, they are generally free from substantial direct competition and are permitted, although not assured of, a fair return on investment.

The industries generally classified as public utilities are:

1. Electric
2. Gas
3. Telephone
4. Water and sewerage

Certain other industries may also be classed as public utilities. The services provided by these industries, however, are generally not considered utility services when furnished under private contract or when packaged as a commodity for competitive sale (for example, electricity generated by an unregulated power production facility, or bottled gas or water). For our purposes, companies dealing in utility services will be considered public utilities, whether or not regulated. Although this discussion applies particularly to regulated utility companies, much of it also applies to any supplier of utility services, including governmental units.

Some of the economic characteristics of the utility industry are discussed briefly in the following paragraphs.

Monopoly. Utilities are often referred to as "natural" monopolies. As capital-intensive enterprises, utilities operate most efficiently as the sole providers of services in a given area. A single system has access to economies of scale that may not exist with multiple systems. In addition, the existence of a single system avoids the costly duplication of facilities. For example, competitive services by two electric utilities in a single residential neighborhood would require the installation and maintenance of duplicate distribution lines; a condition that would require duplicate investments that in turn would increase the costs per kwh delivered. This situation, which is undesirable for reasons of public safety and aesthetics, would lead either to unnecessarily higher costs or to insufficient earnings by the utility. The latter may be as undesirable to the public as the former, for protection of the investor is necessary to attract capital. Some element of competition does exist – electricity and gas compete with each other and with other fuels, and companies compete for industrial customers and wholesale sales – but competition at the retail level is relatively limited. Likewise, the process of deregulation of aspects of electric generation, natural gas transmission, electric and natural gas wholesale pricing, and long-distance telephone service, which began in the late 1970s and continued through today, has brought about a significant change and increase in competition.

Regulation. Utilities generally are subject to regulation, which becomes a substitute for the economic controls of competition in assuring fair prices and adequate service. A chief objective of the regulatory process is to secure the efficiency of monopolistic operation without allowing the enterprise to take advantage of its customers.

Necessary service. Utility services are essentials of modern living rather than mere luxuries or conveniences. In any large population center even a temporary failure is serious, and a prolonged interruption is disastrous. Many nonutility products and services, such as food and housing, are necessities, but generally no one company has a monopoly or even a large share of a given market. Since utility services are a necessity, they must be available to all customers on demand.

Single service. Utilities generally deal in a single service – or at least offer a limited number of services; many companies offer electric and gas service. Unlike industrial companies, which may market a variety of products, utilities may not alter or discontinue their output merely because it might appear profitable to do so. An electric utility is an excellent example of vertical integration – it produces, transforms, transmits, and distributes energy to the ultimate consumer. Telephone and water service are generally similarly integrated. With some exceptions, natural gas producers and transmission companies generally do not engage in retail distribution. To a great extent, a utility plant can be used only for producing and delivering the single service for which it is designed.

Franchises and eminent domain. Utilities are enfranchised by government and have the right of eminent domain. Their property is dedicated to the public service, and in general they must serve all who apply. Plant must be adequate to meet demand at any time, despite seasonal, weather, and other factors. On the other hand, franchises are ordinarily exclusive, and utilities usually have the right to use streets and highways and to condemn property needed for the construction of facilities.

Site restriction. Utilities are prevented, both by economics and by regulation, from moving to another location, changing the character of service, or discontinuing service. Their operations are localized and limited by the necessary direct connection between production plant and every piece of customer equipment. In contrast, other businesses have considerable freedom. This restriction of site requires intensive cultivation of the local market and a sound public relations program to maintain favorable public opinion.

Nonstorable service. Utility service generally must be produced and delivered as used. This is particularly true of electricity and telephone. Some gas and water operations have storage facilities near the customer service area, but the ability to produce in advance of delivery is limited.

Large plant investment. An extremely important characteristic of utilities is that they are capital-intensive industries. Historically, the average ratio of gross plant to annual revenues has been approximately 2.8 for electric and 0.7 for gas utilities. In contrast, an average manufacturing company's investment in capital assets is usually less than its annual sales, and for a merchandising company it is many times less. Large plant investment requirements (to replace equipment, add new pollution-control equipment, and meet the continued growth in the industry) impose heavy and frequent capital requirements. Accordingly, it is important that utilities be well regarded in the investment community.

Fixed charges and marginal costs. The large investment in fixed property causes utilities to operate with relatively high fixed costs (depreciation, property taxes, insurance, and interest). Thus utilities, particularly electric utilities, are significantly affected by the economics of mass production. The incremental cost of producing additional quantities of energy decreases progressively until growth requires a major plant addition. For this reason it is desirable to utilize new facilities fully at the earliest possible date. Decreasing incremental costs over a wide range make it desirable for a utility to serve large numbers of customers in order to achieve lower unit costs. Economy of load diversity is obtained from the staggered demand of many customers of a single class and from the combined effect of different types of customers that have peak demands at different times.

Deregulation. A more appropriate term for deregulation is "reregulation." As discussed subsequently in more detail, utility companies have historically been regulated by local, state, and federal authorities. The initial transition to competition in the electric utility industry began with the Public Utility Regulatory Policies Act of 1978 (PURPA), which allowed the development of cogeneration and small power production facilities that are exempt from federal and state regulation, and required utilities to purchase the power from these "qualifying facilities."

The Energy Policy Act of 1992 (the 1992 Act) permitted the generation and sale of wholesale power by "exempt wholesale generators" without being subject to the Public Utility Holding Company Act of 1935 (PUHCA); however, the sale of this power remains subject to regulation under the Federal Energy Regulatory Commission (FERC). The 1992 Act also allowed investment in power generation facilities outside of the United States and allows transactions between related utilities with state authority approval. In addition, the 1992 Act allows open access to transmission facilities of noncontiguous utilities or facilities. The trend toward decreasing regulation under PUHCA is continuing.

Since 1996, numerous states have either passed legislation or issued comprehensive restructuring orders deregulating the electric utility industry, primarily the generation portion of operations in their respective states. However, these changes are being revisited by many of these regulators as a result of the energy crisis in California that occurred in 2000 and early 2001.

The Natural Gas Policy Act of 1978 (NGPA) deregulated the prices that producers could charge for natural gas from certain newly developed sources and began the complete deregulation of prices that producers could charge. Various FERC orders continued the transition to competition. In 1992 FERC Order No. 636 ensured any buyer access to gas suppliers and the effective unbundling of services in the natural gas marketplace.

Objectives of regulation

Control of the obligations and rights inherent in the characteristics described above is the broad objective of public utility regulation. Regulators attempt to obtain for the public both the benefits that would be achieved by competition and the efficiency of operation as a monopoly. Public utility regulation as now conceived is the consequence of many years of experimentation and change, developing with the growth and technological advancement in the utility industry and the economy. This development has culminated in administration by commissions characteristic of the governmental process in the United States.

Although the regulatory commissions have many powers and duties, perhaps the principal reason for their existence is the regulation of rates. Many of their other powers are necessary adjuncts of rate regulation, and the extent of commission jurisdiction varies from state to state and among federal agencies. In addition to rates, the areas of regulation include accounting, financing, rules of service, safety, licensing of major construction projects, sale and purchases of property, mergers and securities acquisitions, determination of service areas, and issuance of certificates of public convenience and necessity. Regulation of accounting and the uniform systems of accounts are discussed in Chapter 3. The rest of the present chapter is concerned primarily with regulatory history and rate regulation. Most other aspects of regulation are not discussed, because they do not relate directly to the purpose of this booklet.

State and local regulation

Municipal franchises were the first form of control exercised over public utilities in this country except for some attempts at regulation directly by state legislatures. There has been a gradual shift from local franchises to permits (certificates of public convenience and necessity) under the jurisdiction of state commissions as the basic authority to operate. However, local franchises are generally required to grant utilities the use of streets, highways, and other easements for distribution lines and other facilities. The granting of competing franchises is extremely rare, and in a number of states franchises or permits are exclusive by law. Franchises are either for fixed terms or perpetual (the term may be governed by state law), while state permits generally are for an indeterminate period.

Municipal regulation was reasonably satisfactory when operations of a company were confined to a single community. With the development of interconnected systems serving numerous towns and adjacent rural areas, the inadequacy of local franchise regulation became apparent. Uniformity of rates and other standards was difficult to attain, and conflicts were frequent when the service territory of a single utility included numerous regulating bodies. Local regulation, which still prevails to a limited extent, was predominant until about 1920. From then on there was a growing shift to state or federal regulation.

Most retail gas and electric rates are now regulated by state commissions. When state laws do not provide for regulation by state commissions, local rates are ordinarily regulated or set by municipal bodies. In May 1983 the Supreme Court affirmed the right of state commissions to regulate the rates of the generation and transmission cooperatives and a number of states are beginning to exercise authority over the cooperatives in their states.

With the transition in the electric and natural gas industries to competition, each state determines whether to allow competition, the reregulation rules to apply, and the timing for customer choice of their electricity or natural gas supplier. Some states have customer choice plans in place, others have passed legislation to allow competition, and others continue to evaluate the move to competition. The aspects of competition include: the customer's ability to choose its supplier, industrial self-generation, the shift from conventional vertically integrated electric utilities, convergence of several types of utilities, investment in and by foreign utilities, the unbundling and rebundling of utility services, and the development of regional and national energy trading.

Federal regulation

Federal regulation was originally considered necessary only in circumstances where regulation could not be provided by any state, such as in the case of sales of utility service in interstate commerce (gas pipelines and wholesale interstate power). Intrastate retail rates are still regulated only by the states (or municipalities), but there has been a gradual shift toward federal regulation because of the growing interstate aspects of many utility operations and the general trend toward federal dominance in many matters. Electric companies, for example, were at one time confined largely to single states, but interstate interchanges and "pooling" of power have become common and area and regional transmission organizations are forming. The present tendency seems to be for federal agencies to assume jurisdiction in all matters not specifically reserved to the states.

The first of the federal regulatory bodies was the Interstate Commerce Commission (ICC), established in 1887. It regulated railroads, oil pipelines, and certain other carriers in interstate commerce. The ICC was abolished in 1996 and recreated as the Surface Transportation Board. The Federal Communications Commission (FCC) was created in 1934 to regulate interstate communications, including long-distance (interstate) telephone and telegraph. The FCC exercises regulatory authority over a wide variety of telecommunications industry providers. It regulates the interstate-related services of local telephone companies, long-distance telephone companies (interchange carriers), and alternative telecommunication service providers (cellular and paging services).

The original Federal Power Act of 1920 was confined largely to hydroelectric projects on navigable streams. The Federal Power Commission (FPC) became a five-member independent agency in 1930, when its powers were broadened. FPC authority was increased substantially in 1935, when its jurisdiction over the electric industry in interstate commerce was expanded, and again in 1938 with the passage of the Natural Gas Act. Rate regulation by the FPC was limited to wholesale sales of gas and electricity in interstate commerce, but with the support of court decisions, the FPC began asserting increasing authority over accounting and other matters, such as interconnections, construction of major electric facilities, and gas financing. In 1977 the FPC was consolidated, along with the Federal Energy Administration and the Energy Research and Development Administration, into the cabinet-level Department of Energy (DOE). Most of the powers of the FPC were assumed by the FERC within the DOE.

The Securities and Exchange Commission (SEC), a five-member group, was created to administer, along with other statutes, the Securities Act of 1933, the Securities Exchange Act of 1934, and PUHCA. The first two apply to industry generally, PUHCA applies solely to certain public utility arrangements. Under these statutes the SEC has broad power over utility as well as nonutility securities transactions and special authority with respect to electric and gas holding companies and their subsidiaries. Most states also have some degree of securities regulation. The FERC has jurisdiction over securities transactions of those electric companies whose securities issues are not regulated by a state public service commission. If an electric company is subject to securities regulation by both the SEC under PUHCA and the FERC, SEC regulation prevails unless an exemption from the Act has been granted.

PUHCA provided for the simplification of electric and gas public utility holding company systems and for regulation of some of their transactions, particularly with respect to finance and acquisitions of utility assets or securities. Other types of utility systems were not covered for various reasons, including regulation by other agencies.

PUHCA contained the famous section 11, which was designed to and did bring about in one way or another the dissolution of the nationwide electric and gas holding companies. An electric holding company system could serve only in one state or adjoining states, and all properties were to be either interconnected or capable of being interconnected. Retention of gas properties by electric holding companies was made practically impossible, although a few exceptions still exist. Units of holding company systems furnishing management or other services (service companies) must be separately incorporated and render their services to system companies at cost.

PURPA began the process of deregulating the business of generating electricity by encouraging nonutility enterprises to participate in owning and operating electric generating facilities. PURPA, in addition, required state regulatory authorities and public utilities to consider standards on rate design; provided for FERC rules favoring cogeneration facilities and requiring public utilities to purchase power from cogenerators at reasonable rates; authorized the FERC to (1) require interconnection of transmission facilities, (2) ordered facilities to provide transmission service between noncontiguous utilities; and required reporting of anticipated power shortages.

The 1992 Act eliminated PUHCA as a barrier to the development of a wholesale electric power market by exempting wholesale generators of electricity, including affiliates of regulated public utilities, from its restrictive provisions. The 1992 Act also amended PUHCA to permit utility investments outside the United States. Important provisions of the 1992 Act include:

- Natural Gas. Exempts natural gas imported from a nation with a free trade agreement and liquified natural gas from FERC regulation.
- Electricity. Requires owners of electric power transmission facilities to provide competitive electric power marketers with open access to their lines under specified rules in FERC Orders Nos. 888 and 889. It also establishes a category of power plant ownership, "exempt wholesale generator" (EWG) that allows multiple power plant ownership without being subject to the SEC authority under PURPA.
- Nuclear Energy. Provides for certifying standardized designs for nuclear plants and combining construction and operating licensing; requires specified utility payments for decommissioning of DOE enrichment facilities; and requires the DOE to set public health and safety standards for the Yucca Mountain repository site.
- Alternative Fuels. Requires federal and state governments to convert vehicle fleets to alternative fuels.
- Energy Efficiency. Sets energy efficiency standards for buildings and equipment and encourages energy efficiency by utilities.

In 1936, the Rural Electrification Act established, under the Department of Agriculture (DOA), the Rural Electrification Administration (REA), to offer federal assistance to bring modern utilities to rural America through rural electric and telephone cooperatives. Through the DOA the REA, now the Rural Utilities Service (RUS), helps rural utilities expand, keep their technology up to date and develop rural infrastructure. In May 1983, the Supreme Court affirmed the right of state commissions to regulate the wholesale rates charged by generation and transmission cooperatives.

Rate regulation

The basic principles of rate regulation rest on concepts of fairness and equity and avoidance of unreasonable discrimination. The concept of just and reasonable and non-discriminating rates is the theory that rates should be based on the allocation of costs to customers who cause their incurrence. In the 1944 FPC versus Hope Natural Gas Company case, the Supreme Court upheld the FPC's position that the controlling test in determining "just and reasonable" rates is the end result, not the method of reaching the result. The utility is entitled to rates that are fair to it, but not to rates that are unfair to its customers. With the move to competition in the electric utility industry, where there is no presence of market power, market rates are, however, deemed just and reasonable.

Ratemaking ordinarily occurs in two steps: (1) the determination of total allowable revenues for the utility and (2) the establishment of individual rates or rate schedules for various classifications of customers that will yield this amount. Individual rates are in theory based on an individual utility's specific cost of service, including cost allocations.

Supreme Court utility rate decisions have been based on the constitutional prohibitions against confiscation of private property. They have followed the principle of a fair return on the fair value of the investment used in providing service.* Over the years there have been many changes in methods and standards, and over time decisions began to emphasize the end result rather than the method, but the basic principle has not changed. Regulation has evolved, to a considerable extent by trial and error, in decisions of commissions and in state and federal courts.

Court cases that have had a bearing on utility rates over the years will not be explored in detail here. Generally they have dealt with the two principal aspects of the ratemaking process: (1) the investment on which utilities are permitted to derive earnings and (2) the compensation or return to be allowed the investors on their investment. The normal rate formula for determining overall return is a simple one and is developed in some detail in Chapter 2.

Some recent court cases have dealt with regulatory jurisdictional issues. One case addressed the issue of whether local regulators are preempted from disallowing costs of a multistate project where the costs were allocated to separate jurisdictions by the FERC; in the particular case, the courts determined that the local regulator was so preempted. In another case, the courts ruled that the FERC could not impose a market price limitation on charges for fuel supplied by an affiliate where the affiliate charges were based on costs, as required by the SEC under the Holding Company Act.

II. Cost-of-service ratemaking concepts

Cost-of-service ratemaking methodologies

The basic objective of utility ratemaking is to determine the total amount of revenues a company must generate from its operations in order to achieve its own objectives and yet, at the same time, meet the needs and objectives of its customers.

Two methods of ratemaking have been traditionally used to achieve this objective for electric and gas utilities: the cost-of-service and the debt-service methods. While each permits the recovery of operating expenses and taxes, they differ in the techniques by which they measure the utility's revenue needs beyond these elements (i.e., their required return on and of capital).

The cost-of-service method is by far the most widely used. The debt-service method is most common in the regulation of cooperatives or government entities that are financed primarily with debt securities.

Cost-of-Service method. This method equates "revenue requirements" or "cost of service" with the total of: operating expenses, depreciation, taxes, and a rate-of-return allowance on the utility's investment in rate base.

The total recorded or estimated amounts for operating expenses, depreciation, and taxes for the period under review, or test period, are deducted from revenues generated during the test period to determine net operating income realizable at current rates. This represents the amount available for return.

The utility's investment in facilities and other assets used in supplying utility service (rate base) is also determined. The required rate of return is determined by analyzing the components of the capital structure to produce the composite rate of return required to adequately meet the utility's capital requirements. Rate base multiplied by this composite rate of return results in the required return, or net operating income.

By comparing the required return with the net operating income realizable at current rates, the net-operating-income surplus or deficiency can be determined. This amount, adjusted for income tax and other factors, is then converted to a gross revenue surplus or deficiency in order to determine the required rate increase of decrease. This method can be illustrated by a simplified example.

Rate base	
Plant in Service	$1,200
Accumulated Depreciation	(300)
Net Plant	900
Fuel Inventories	90
Materials and Supplies	30
Cash Working Capital	10
Deferred Income Taxes	(30)
Total	**$1,000**

Cost of capital	Ratio	Cost	Weighted Cost
Debt	50%	10%	5%
Equity	50%	14%	7%
	100%		12%

Revenue requirement calculation			
Operating revenues			$660
Operating expenses other than income taxes		$510	
Interest expense required ($1,000 x 5%)		50	
Equity return required ($1,000 x 7%)	$ 70		
Income tax conversion factor (1-40% tax rate)	÷ .60		
Equity return and income tax		117	
Revenues required			677
Gross revenues increase required			$ 17
Proof			
Revenue			677
Operating expenses other than income tax			(510)
Interest expense			(50)
-Taxable income			117
-Income tax @ 40%			47
Equity return ($1,000 x 7%)			70

Alternative forms of regulation have been used in recent years, particularly in connection with utility industry restructuring. The most common alternative form is referred to as incentive regulation, which is designed to provide economic incentive to the utility to improve cost control and income efficiency through the sharing of earnings over a pre-established rate of return. A portion of the utility's earnings in excess of the pre-established rate of return is usually used to reduce the customer's rates or is set aside for technological improvements through increased capital additions. The measurement of the utility's performance under incentive regulation is largely based on application of the cost-of-service method.

Debt-service method. This method equates revenue requirements to the total of operating expenses (other than depreciation) and the amount necessary to meet debt-service (principal and interest) requirements (or some multiple thereof). The times-interest-earned ratio (TIER) method is a variation under which revenue requirements are equal to operating expenses and some multiple of interest on long-term debt. For example, if relevant operating expenses totaled $550 and total interest requirements were $100, a 1.5 TIER would require revenues of $700 ($550 + 1.5[$100]).

Rate base

In designing a rate base, regulators must decide what costing method to use (e.g., original cost, fair value or some combination); whether to measure the investment as of a past, current, or future time; and what components to allow in the total.

Costing methods. Balancing the interests of the customer and the utility is the basic objective in selecting a costing method. The two historic measures have been fair value and original cost. The "end-result doctrine" holds that the propriety of the choice in any given case lies in which of the two produces results that are both fair to the consumer and reasonable for the investor. As a practical matter, the fair-value concept has been abandoned, and original-cost concepts dictate the results of the ratemaking process.

Fair value. Proponents of fair value hold that it provides reasonable earnings for the investor by overcoming various deficiencies in the original-cost method. One fair-value approach is to adjust original-cost figures by trending changes in cost levels to establish "trended original cost," which is usually assumed to represent a measure of "reproduction cost." Another approach is to make an inventory of existing plant and appraise it at reproduction cost (assuming the replacement of identical plant at current prices) or replacement cost (assuming replacement with a plant not of identical design but capable of rendering identical service).

Fair value does not have the advantage of using a recorded plant amount that is easily determinable and relatively noncontroversial. It is expensive to determine, it leads to considerable controversy, and when used it is generally modified by offsetting limitations on its theoretical goals. The fair value allowed by commissions is generally closer to an original cost than the value suggested by studies presented to them, and the commissions typically do not reveal in full the methods they have used in determining fair value or the specific allowances permitted.

Rates of return allowed on a fair-value basis are consistently lower than those allowed on original cost, primarily because capital structure, expressed at historical level, must be related to an increased base at fair value. This is not necessarily inequitable to the utility, because a lower rate (e.g., 7 percent) on the fair-value base may result in the same return as a higher rate (e.g., 9.5 percent) on the original-cost base. If the higher rate were used on the fair value base, it could result in an unjustifiably high return on equity capital. This raises the question of whether to apply fair value to the total plant or only to the portion supported by equity capital. If applied to the whole plant, the increment will flow to equity, since the returns to preferred stock and long-term debt are contractual. This excess flow to equity is often avoided by applying fair value only to the plant portion supported by common equity and limiting the debt and preferred-supported portion to original cost.

Original cost. This approach uses the cost incurred by the first person to dedicate a facility to public service. If utility property changes hands, the original cost identified remains, even though the new operator may get full recognition of the purchase price through other means.

The rules of most regulators require the use of original costs for regulatory accounting purposes, whether a facility was constructed or acquired. If an acquired property has already been in public service, any difference between the seller's recorded cost, net of accumulated depreciation, and the current fair value of the plant is recorded as an "acquisition adjustment" so that the original cost remains intact.

Original-cost ratemaking is the formal posture for rate-base determination by all federal jurisdictions and most states, probably in large part because the amounts involved are readily accessible, and their use minimizes the expense and controversy entailed by plant measurement under fair value. The remaining states, even though labeling their process as representing fair value or some other standard, in fact typically produce original-cost results by adjusting the rate of return.

Allowable components. Certain basic components are frequently encountered in determining the rate-base investment. Other miscellaneous components are found less often.

Plant in service. This is the most important rate-base item, since it usually represents over 90 percent of the total (after deducting related accumulated depreciation). As the discussion of "test period" will indicate, there are three alternatives for deciding the time period to be used in determining this portion of the rate base: average monthly balances over the period used for determining operating income; end-of-period balance; or a projected amount, either averaged into the future or stated at a specific future time.

Accumulated depreciation. Since the life of a plant normally spans many operating periods, systematic recovery of the investment is permitted by depreciation. Recovery is normally on a straight-line basis, in which an equal portion of the investment is recovered in each period. Deduction of the accumulated depreciation is an accepted principle in developing a rate base, since it has presumably already been collected from customers through rates in effect.

Construction Work in Progress (CWIP). Historically, CWIP was not included in the rate base in most jurisdictions under the theory that it was not used in providing service to current customers. Companies were therefore allowed to capitalize the financing costs of their CWIP (allowance for funds used during construction or AFUDC). This is still the position in many regulatory jurisdictions.

During the late 1970s, there was a trend toward allowing CWIP in rate base and toward discontinuing the capitalization of AFUDC. The trend was the result of financial stress in the utility industry. The tremendous amounts of capital invested in CWIP produced amounts of AFUDC capitalized that often exceeded net income. Because of these conditions, many regulators concluded that the customer was better off paying for this financing cost as incurred rather than paying for the additional financing costs over the life of the assets, through capitalizing and depreciating financing costs.

As discussed in later sections, the reporting of income generated by AFUDC is proper; however, it does not produce current cash-flow dollars. As cash flow was one of the most severe problems of the industry, allowing CWIP in the rate base was a natural solution to the problem. The reply to the argument that current customers are being asked to pay for facilities to be used in supplying future customers is that the building of new facilities is to maintain a viable system to continue service to the existing customers and, more important, that the loss of financial integrity, which would affect current customers adversely, is being avoided.

Plant held for future use. This includes property acquired for future utility service. Land is frequently acquired in advance and held for transmission and distribution facilities, generating units, and substations. It is usually allowed in the rate base if there is a definite plan for its use, but the cost is sometimes not allowed if the use is to occur after some arbitrary time period. Commissions closely scrutinize any transfers of plant from this category to nonutility accounts, and any sales of such plant resulting in gains that commissions might decide should be passed on to customers.

Contributions in aid of construction. This represents nonrefundable funds contributed by customers for property construction. Electric and gas utilities do not maintain contributions in aid of construction as a separate account. These accounts are maintained as credits in the plant accounts supported by contributed funds. Water companies still maintain such accounts as deferred credits or equity, and they are frequently quite substantial as a source of plant support. They are generally deducted from rate base.

Customer advances for construction. These amounts are similar to contributions in aid of construction, but are refundable to the contributor if certain conditions are met. In most instances, these items are deducted from the rate base because, although temporary, they represent a source of cost-free funds supporting facilities included in the rate base.

Operating reserves. These represent advance provisions for the cost of service in the event of anticipated future losses. When the expense provision is allowed as part of cost of service, rates produce funds in advance of need. Since these cost-free funds may be used in supporting the rate-base investment, they are frequently deducted from the rate base, although in rare cases the reserves are segregated and not deducted.

Deferred income taxes. When deferred income tax liabilities accumulate as a result of liberalized depreciation, accelerated amortization, or other temporary differences, the balances are frequently deducted directly from the rate base, although they are sometimes treated as an element of cost-free capital recognized in the rate of return. Both methods produce similar effects on revenue requirements.

Although the Tax Reform Act of 1986 phased out investment tax credits (ITC), the Internal Revenue Code (IRC) generally requires a sharing (between investors and customers) of the benefits of existing investment tax credits by providing the utility the option of reducing rate base or amortizing the deferred balance in operating income. The IRC prohibits ratemaking treatment that would do both, because it would result in the entire benefit going to the consumer.

Working capital. This term refers to various rate-base funding requirements other than the utility plant in service. These funding requirement would include inventories, prepayments, minimum and compensating bank balances, cash working capital, and other nonplant operating requirements. When these assets or operating requirements are funded by investors, they are legitimate rate-base allowances. Note that working capital as defined and used for ratemaking purposes as a measure of capital funding requirements is quite different from the accounting use of the term as a measure of a company's liquidity position.

Inventories. Inclusion is normally permitted for three categories (fuel stocks, construction materials in inventory, and materials and supplies held for operating and maintenance purposes) because they represent a permanent investment, although dollar amounts vary as items move in and out. Average or year-end balances for the test period are used but are compared with historical experience to ensure that the levels are not abnormal.

Prepayments. This component also represents an investment of funds, which is generally included in rate base if the investment has not been recognized elsewhere. The amounts allowed are normally based on an average or normal level.

Minimum and Compensating Bank Balances. Minimum bank balances that are required to avoid bank service charges and to meet daily operating requirements may be included in the rate base to the extent that related costs have not been recognized elsewhere in the determination of revenue requirements. Even though their inclusion is theoretically sound, they may be omitted from the rate base if utilities fail to establish their claims by presenting adequate objective evidential support. An alternative to including these balances in rate base would be to claim, as part of operating expenses, the estimated bank charges that would be incurred if the minimum balances were not maintained.

As normal and customary practice, public utilities finance a portion of their current construction and other expenditures by use of bank loans under lines of credit. Banks extending credit to borrowers may require that balances equivalent to specified percentages of amounts borrowed be maintained on deposit. Compensating bank balances, therefore, are those dollars required for retention on deposit with a lender as a basis for making interim financing credit available. Compensating bank balances, while properly claimed in many rate cases, are often not recognized. Theoretically, there are three ways in which the utility could be compensated for the investment in these balances:

1. The utility could be awarded the effective cost of the usable funds borrowed as an element of rate of return.
2. An adjustment could be made in the effective rate for capitalization of allowances for funds used during construction.
3. The compensating bank balances could be included in the rate base.

The rate-base treatment is the alternative most often used by regulators when compensation is allowed.

Cash Working Capital. This term refers to the amount of investor-supplied funds needed to finance operations. A generally accepted definition is the average amount of capital, over and above the investment in plant and other separately identified rate-base components, provided by investors to bridge the gap between the time expenditures are made to provide service and the time collections are received for that service. This component is the most controversial of the working capital group because it is difficult to measure the amount of investor-supplied cash needed to finance operating costs during the time lag before revenues are collected. Measurement is often based on the use of a standardized factor (typically 45 days of operating expenses less depreciation, taxes, purchased gas, or purchased and interchanged power). Measurement may also be based on extensive lead-lag studies, which essentially determine the net difference, in terms of days, between the point at which service is rendered and revenues are collected from customers, and the point at which costs are incurred until they are paid. Multiplying this net difference by average daily operating expenses provides an estimate of the cash working capital required to support these operations. To this total, any other identifiable sources of or requirements for working capital not affecting operating expense should be deducted or added to arrive at total cash working capital requirements.

Miscellaneous items. Other rate-base components that may be encountered include the following:

Leasehold improvements, as an investment in a right to use property, are normally treated the same as plant in service but are given a separate accounting classification.

Acquisition adjustment represents either a positive (debit) or negative (credit) difference between the fair value of a property when it is purchased and its depreciated original cost. Most original-cost jurisdictions do not recognize its inclusion in the rate base or its amortization under cost of service unless the utility can show that the acquisition, at the price paid, is of direct benefit to the customers. Fair-value ratemaking jurisdictions may recognize an arm's-length purchase as a measure of fair value.

Extraordinary retirements sometimes occur when a partially depreciated unit of property is retired earlier than anticipated and the reduction of accumulated depreciation is substantially greater than the amount provided. When this occurs, and accumulated depreciation would be unduly depleted, the utility can request permission to charge the loss to a deferred debit account and either amortize it over several periods or otherwise dispose of it as directed by the appropriate regulatory body. The loss recovery is sometimes permitted by amortization to operating expenses for establishing cost of service, although the deferred debit may not be allowed in rate base. Other deferred costs of an extraordinary nature (e.g., major storm damages or rate-case expenses) may also be excluded from the rate base, but the amortization is often allowed in cost of service. Similar treatment is generally accorded the cost of abandoned construction projects.

Customer deposits are generally not deducted from the rate base if interest is paid to customers, although they are sometimes used in measuring cost of capital. In other cases, customer deposits are deducted from base, and related interest expense is included in cost of service. If interest is not paid, the deposits may be considered fully deductible, since they represent advances supplied by the customer but available for company use.

Test-period cost of service

Computing the test-period cost of service is the crux of the ratemaking process. An important factor in the determination of cost of service to be recovered in rates is the regulatory approach to the selection of the test period.

Test period. Three basic approaches can be used in selecting a test period, and they may be used in various combinations. They are (1) the historic-average test year, (2) the year-end (point-in-time) approach, and (3) the projected test year. Most regulators have adopted a particular approach and require that rate filings be made in that manner unless another approach can be justified based on the particular circumstances.

Normally, the approach used for determining operating results will also be used in determining the rate base. The only exception to this is the use of a year-end investment rate base along with the operating results of the preceding twelve months, unadjusted to match the year-end investment. This combination produces a "mismatching," since the investment at the end of the period may contain substantial property additions relating solely to requirements of the immediate future, especially if the point selected for measurement happens to fall at the beginning of a high-use period. This mismatch is quite often retained, however, and is justified as an offset to the detrimental effects of regulatory lag when the utility is experiencing a declining pattern of earnings. This decline, called attrition, usually results from a combination of plant growth and inflationary prices, which combine to depress realizable earnings under fixed rates for service.

Historic-average test year. This approach uses the most recent 12-month period for which financial data are available at the time of filing for a rate proceeding. Investment in plant and working capital is tabulated for each month (usually using a 13 month-end simple averaging technique), and the rate base thus measured is compared with earnings. Operating results (expense, depreciation, taxes, and return) are presented in conjunction with this average investment rate base, and it is primarily based on recorded results for the period, although adjustments of these results that are designed to shape the recorded year into a "normal" representation of the period are often recognized.

This concept has the advantages of using recent historical data that are easily obtained and of being consistent in relating investment to operating results. Its disadvantage, however, is that it emphasizes past conditions in measuring future rate requirements. This is particularly unsatisfactory at times when conditions are changing rapidly, which may be the reason why rate proceedings are being held in the first place. This deficiency is not countered satisfactorily by attempting to normalize conditions unless both the investment and the operating results are completely restructured through extensive adjustments, and this is rarely permitted. In fact, to do so would detract from the appeal of the concept, because it does, indeed, deal with historical data. The most common type of adjustment permitted is the one affecting contractual wage increases that take effect at some point during the test period. Such increases produce costs that will not generate additional revenues and that can be recovered only by adjusting the test-year cost of service.

Year-end (point-in-time) approach. Many jurisdictions use this approach in measuring cost of service because it tends to close the time lag between the test period and the implementation of rates. While retaining the use of historical data to the greatest extent possible, it does so with less complete reliance on such data. Its disadvantage is that, as frequently applied, it requires substantial adjustment of the recorded results of operations, because revenues and expenses are usually adjusted for measurable changes known to have occurred through the end of the test period or for a stipulated number of months thereafter.

With this method, new plant added during the test period is usually included in the plant investment used. If the added plant (e.g., a new customer extension) will produce additional revenues, some commissions recognize the added revenue and expense effect in measuring cost of service. This inclusion of the revenue and expenses of the added plant produces a result that closely resembles that of the historic average approach but moves the picture forward. Some commissions use the year-end investment and the operating results of the preceding 12 months. This combination may effectively serve as an offset to the effects of attrition and avoid the complications of annualizing the year-end level of operations.

Projected test year. In this method, the investment outstanding and the operating results are usually measured for a "current" test period that ends at a date after the filing or for a fully prospective period that encompasses a full 12 months of operations after new rates are implemented. (For example, an estimate of plant investment for a calendar year might be developed from actual recorded amounts for January - April and from projections, based on budgeted results, for May - December. Alternatively, the projected test year may be for January - December of the year after the rate filing when new rates will be in effect on the first day of the projected year.) The projection concept is an extension of the year-end concept, since it requires projection of revenues and expenses and the investment base. Although many regulators have been reluctant to rely on the budget estimates required, this method has become more widely adopted as projection techniques are better understood by regulators. Also, its adoption by leading authorities such as the FERC has had a positive effect.

Cost of service. Determining cost of service requires consideration of rate base; revenues; operating expenses; depreciation and amortization; taxes other than income taxes; income taxes; the net operating income required to meet capital costs; and such miscellaneous items as charitable contributions, merchandising and jobbing costs, capitalized administrative expense, and unusual or nonrecurring items.

Revenues. These are representative of the test period under review and of normal conditions. Revenues may not require adjustment when a rate base developed on averaging concepts is used, since a direct correlation will exist between test-year revenues and the rate base. However, when a year-end (point-in-time) base is used, revenues may be adjusted so as to establish a correlation between revenues of the test year and customer consumption levels as of the time when the rate base was measured. Other factors that may require adjustment include:

1. Rate changes that occurred during the test period and result in a mix of rates for recorded revenues, which must be adjusted using latest rates
2. Changes in customer composition or product usage during (or subsequent to) the test period
3. Customers added or lost during (or subsequent to) the test period
4. Abnormal weather conditions affecting consumption and revenues
5. Revenues unbilled at the end of the period or recorded at its beginning but representing prior-period sales
6. Nonrecurring, special, or out-of-period items.

Operating expenses. Expenses normally allowed are those recorded under the applicable jurisdictional uniform system of accounts as "operating expenses" incurred in servicing utility customers. Measurement of expenses is not affected by whether the rate base is derived from fair value or original costs, but it is affected by the time period used. If an average period is used, expenses are generally taken directly from the records and adjusted only as needed to normalize the period (e.g., for abnormal weather); but if a year-end (point-in-time) period is used, they may be adjusted to reflect the level of operations at year-end.

Jurisdictions that use an average-rate base also adjust recorded expenses for "misclassified" and "abnormal" (or "nonrecurring") items, and some of these jurisdictions also adjust for certain changes in price or cost levels during or after the test year.

"Misclassified" items are those not attributable to cost of service, an example being nonutility activities misclassified as operating expenses. "Abnormal" (or "nonrecurring") items are those that cannot be attributed either in part or in whole to the test year because they do not represent normal conditions. Typical examples are costs of wage negotiation in a multiyear contract; rate case costs; abnormal maintenance expenditures; and casualty losses that are material and unusual.

Changes in price or cost levels that can lead to adjustments must be measurable, permanent, beyond the direct control of management, and not the result of changes in operating conditions. Examples are increases in wage rates, post employment benefits, and other fringe benefits (including related taxes); postage rate increases; and changes in the contract price of fuel.

Jurisdictions in which the rate base is measured on a year-end (point-in-time) basis usually adjust for misclassified and abnormal items or for changes in price or cost levels just as those jurisdictions that use an average-rate base do. But they often go further and attempt to normalize both cost levels and operational levels.

Costs that would normally be charged to operating expenses but are unusual and would distort results if so charged are sometimes deferred and amortized to cost of service over a reasonable period.

Depreciation and amortization. Amounts allowed are frequently restricted to recorded amounts for the test period (whether original-cost or fair-value base measures are used). Some jurisdictions (normally those using year-end and original cost) allow adjustments for a full year's depreciation on year-end plant. Adjustments are also frequently made when depreciation rate changes occur during or shortly after the test period, so as to annualize the expense on the basis of the latest applicable rate.

Amortization or depreciation is generally allowed in most jurisdictions for all utility property accounts, except for acquisition adjustments, which may not be allowed for rate-base or cost-of-service purposes.

Taxes other than income taxes. These present little difficulty since they can usually be identified easily with the utility function (as contrasted with nonutility operations) and are normally recognized in full, except for misclassified, abnormal, or non recurring items. If tax rates have risen during or subsequent to the test period, many jurisdictions will allow appropriate adjustments so long as the increases are measurable, permanent, and beyond the direct control of management and do not apply to particular levels of operations. Jurisdictions using year-end (point-in-time) rate-base determination sometimes adjust tax amounts to reflect year-end levels of investment and operations.

Income taxes. There has been considerable disagreement about the approach to be taken in measuring the income tax component of cost of service. This has particular significance when a company has taken advantage of the benefit of liberalized depreciation and other accelerated deductions for tax purposes. Historically, many of the state commissions viewed the resulting benefits as savings and therefore allowed only the liability for current tax payments (i.e., current tax expense) as part of cost of service, thus requiring the utility to let the current tax benefits (i.e., deferred tax payments) flow through to the customer. The remaining state commissions viewed the tax benefits as temporary savings and required that normalized expenses be used in measuring the tax expense. The FERC has adopted the normalization technique. The Economic Recovery Tax Act of 1981 (ERTA) required that utilities employ income tax normalization for both accounting and ratemaking purposes in order to avail themselves of the accelerated cost recovery system (ACRS). If normalization is not properly followed, utilities are restricted to using straight-line depreciation on their tax returns. This requirement has been retained in subsequent tax legislation.

Similar problems arose in the treatment of the ITC. Some commissions normalized the benefits, and some used flow-through principles. However, ERTA limited the scope of regulatory action in this area by requiring normalization of the ITC to allow the utility to share in the benefits arising therefrom. Depending on the option elected by the utility, amortization of the deferred balance may be in operating income (in which case the deduction of the accumulated balance from rate base is prohibited) or excluded from operating income (in which case rate-base reduction may be permitted). Although the ITC was discontinued by the 1986 Tax Reform Act, the limitations on the disposition of ITC balances were continued.

Miscellaneous considerations. Several miscellaneous items are occasionally allowed in determining cost of service:

1. Charitable contributions are typically classified as nonutility expenses. Utilities sometimes claim them as operating expenses, but they are frequently disallowed by regulators.
2. Merchandising and jobbing costs are sometimes proposed for inclusion on the grounds that they represent promotional efforts that benefit utility customers as a whole, but they generally have not been allowed, on the grounds that activities not directly involved in the utility function should not be included in cost of service.
3. Costs relating to legislative activities (e.g., lobbying expenses) are generally disallowed for rate purposes. However, if a utility can show that the costs were incurred on behalf of customer interests, the costs may be allowed.

Rate of return

Compensation of the investor is expressed in terms of a percentage rate of return that, when multiplied by the dollar rate base, produces a dollar return. A fair rate of return should fall somewhere between inadequate earnings and excessive earnings, and in its determination, consideration is normally given to several factors, including maintenance of financial integrity, ability to attract capital, business risk, quality of service provided, and cost of capital.

Some jurisdictions espouse the end-result doctrine, which holds that the mechanics of establishing rate base and rate of return are of little consequence so long as the resultant revenues permit the company to provide adequate and efficient service at reasonable rates. In other jurisdictions, however, statutory requirements specify concepts to be used for establishing both rate base and cost of service.

The applicable rule of law prohibits a rate of return that provides earnings that are inadequate and therefore confiscatory, and it assures an opportunity to earn a fair return. However, utilities are not assured that a fair return will be realized (i.e., there is no guarantee of a fair return). If revenues received actually produce a satisfactory net operating income to meet the cost of debt and provide a fair return on equity capital, then the rate regulation process has functioned properly.

In order for the utility to provide proper service and to maintain its financial integrity, its return must be adequate to service existing debt requirements and to attract the new capital needed for plant replacement and expansion. It is impossible to establish the precise rate of return or dollar revenue requirements that will give the customer full protection. A just and reasonable rate of return can be developed only by weighing all circumstances impartially.

In arriving at the authorized rate of return, little controversy is occasioned by debt and preferred stocks. The return they require is a matter of contractual necessity. Common equity does create controversy, however, because its cost cannot be measured definitively, although the various attempts at measurement include comparative statistics, capital markets pricing methods, price/earnings ratios, and discounted-cash-flow methods. All of these techniques either compare past, present, or anticipated prices of the company’s stock or compare its earnings with those of comparable companies.

Capital structure. Maintaining appropriate utility capital structures is a complex undertaking. It is generally assumed that utility capital structures, which traditionally reflect high debt-to-equity ratios that result in increased financial risks, are strongly influenced by the relatively low level of utility business risks (e.g., protected service areas, fixed rates, stable earnings, etc.). Further, it is assumed that utility capital structures influence overall capital costs, and that the actual capital structure is maintained in a range that minimizes capital costs. In sustaining the ability to meet utility service obligations, it is also necessary to maintain capital structures that are flexible enough to raise any class of capital whenever necessary. In addition, the capital structure should result in the ability to generate needed capital at reasonable costs.

Short-term funds are borrowed by utilities to provide funds for construction and other purposes pending permanent financing. The costs associated with these borrowings are generally deferred for future recovery through capitalization of AFUDC. In some cases, however, the construction financing costs are recovered on a current basis through inclusion of CWIP in the rate base.

When the test-period capitalization ratios are seriously out of line with past or prospective practice, they may be adjusted to calculate earnings requirements. For example, if financing after the test period produces capitalization ratios that significantly differ from those of the test period and are likely to continue to differ in the future, those of the test period are often adjusted. Controversy sometimes arises as to the proper capital structure when significant nonutility operations exist.

Debt and preferred earnings requirements. Earnings requirements of debt securities and preferred stocks are generally determined easily, since there is a contractual obligation to pay a fixed annual amount of interest or preferred dividends, and their "embedded" costs can be calculated on the basis of a stated interest rate or preferred dividend, net proceeds at time of sale, and expenses of issuance. If new financing is carried out or becomes necessary after the test period, its effect on embedded costs may be considered in rendering a decision on rate of return.

Common equity earnings requirements. The most difficult and most important issue in rate determination is that of finding the appropriate level-of-earnings requirement or rate of return on common stock equity. Common equity is the foundation of the capital structure and makes it possible for a company to issue debt securities. The U.S. Supreme Court, in its 1942 decision in Hope Natural Gas Company (320 US 591), held that "the return to the equity owner should be commensurate with returns on investments in those enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital . . . "

In the years since the Hope decision, regulators have struggled with varied interpretations of the method to be used in applying its criteria. As a 1962 committee report of the National Association of Regulatory Utility Commissioners (NARUC) said,". . . the cost of equity cannot be obtained from any tables similar to bond yield tables." It added that expectations of future earnings, dividends, and market prices "cannot be determined by any mathematical or statistical formula but must be approached on the basis of long experience and sound judgment." There are several approaches to determining a proper rate of return on common equity. In reviewing some of these approaches, however, it must be stressed that no single one can be considered the only correct method and that a proper return on equity can be determined only by the exercise of regulatory judgment that takes all evidence into consideration. Each of these methods suffers in some respect from the need to rely on historical data to predict future return expectations, and each is sometimes modified by the addition of such factors as market pressure, financing costs, and judgment.

Price-Earnings (P/E) ratio. This approach is based on earnings from some past period and concurrent or present market prices. Its acceptance may be due partly to the fact that the basic figures are readily available. When this method first came into use, utility common stocks were selling at or near book value per share, and the calculations used were considered to be reasonably realistic. Since then, market price variations have produced highly volatile swings in P/E ratios and the measure has not been widely used.

To illustrate the approach, if a stock with a book value of $10 earns $1 per share (or 10 percent of book) and trades at $15 (15 times earnings), use of the P/E method would produce an allowed return on equity of 6.67 percent. Earnings per share would then be reduced to $0.67 (6.67 percent of $10), and, if the market continued to pay 15 times earnings, the market price would drop to $10 per share.

Discounted cash flow. This method generally proposes a rate of return equal to current annual dividends divided by current market price plus the anticipated annual rate of growth (i.e., dividends, earnings, and/or market value of the stock). The current dividend and market prices are easily determined; however, predicting investors' growth expectations is much more subjective. Generally, one or a combination of three indices (dividends per share, earnings per share, and book value per share) are used to determine the growth factor. Each of these indicators requires the use of historical data to predict future expectations.

Comparable earnings or opportunity cost. This method seeks to determine what the capital that investors have placed in a utility could earn if it were invested in other enterprises with similar risks and uncertainties, either in the utility industry or in other industries, since investors are entitled to a return at least equal to what they could get elsewhere. The overall approach is to choose other utilities or industries having comparable characteristics (operations, size, capital structure, geographic location, etc.) and calculate a historic average rate of return on common equity. This average return is considered representative of the appropriate future rate of return for the subject utility.

The two main difficulties affecting this method are that (1) it is difficult to establish comparability and (2) using other regulated enterprises for comparison produces a high degree of circularity.

Capital Asset Pricing Model (CAPM). This model assumes that the expected rate of return consists of a risk-free return (which includes a pure rent cost and an inflation allowance to compensate for expected loss in purchasing power) plus compensation for the risk of the security to be invested in. This risk compensation is determined by multiplying the excess of the current "market" rate of return over the "risk-free" return by a relative-risk (beta) factor. This relative-risk factor is determined by correlating the respective fluctuations in returns over time.

To illustrate, assume that for a specified period the average risk-free rate of return (perhaps based on rates for 90 day U.S. Treasury bills) is 8 percent and the average market rate of return (perhaps based on the Dow Jones Index) is 15 percent. It is further assumed that for every 1-percent fluctuation in the market return over the period, the specific security price changes by .9 percent. Then the expected security return would be calculated as 14.3 percent (8% +.9%[15 – 8]).

Risk-differential method. This is another risk-oriented technique, which recognizes that common equity requires higher returns to compensate investors for the added risk they assume. Under this approach the risk premium is measured by determining the historic-average difference or spread between realized yields on common equity securities and on long-term utility bonds with similar ratios (e.g., AA, A, etc.). If this spread averages 4 percent and the subject utility's bonds are currently yielding 10 percent, the indicated required return on common equity would be 14 percent.

Pricing utility services

Problems of rate design are many and varied, but they must be solved if a utility is to function effectively. The basic objective of a rate structure is to enable a company to generate its revenue requirements without unduly burdening one class of customer to the benefit of another. Classes of customers include residential, commercial, industrial, and other. Proper rate design thus results in rates for classes of customers proportionate to the cost of serving each class of customer. The rate structure should also serve to encourage the efficient utilization of a system. If adequate consideration is not given to rate design and the distribution of rates, the ultimate effect can be either excessive rates for the customer or depressed levels of earnings for the utility.

The first step in rate design is to develop the utility's total revenue requirements (operating expenses, depreciation, taxes, rate base, and return) based upon its overall needs. These requirements are functionalized and then allocated to individual customer classes and groups in order to form the basis for establishing appropriate rates for each class or group.

Pricing structures necessarily fall between the two extremes of individual tariffs for each individual customer (which would be impossible to determine even in the smallest utility) or identical tariffs for all customers (which would be unsatisfactory to both the utility and its customers). Some of the rate design concepts predominant in electric and gas utilities include the following.

Classes and groups. Utilities normally seek to limit the number of rate schedules used to those necessary to recognize broad categories of customer service characteristics, designing the schedule for each so as to recover the costs allocated to it and to encourage, through appropriate unit prices, the optimum utilization of service in areas of lowest cost.

Some electric and gas utilities separate customers into the broad classes of "residential," "commercial," and "industrial," preparing schedules for each. Most utilities, however, while using these classes, break each of them down into subsidiary groups as necessary. For example, in the electric industry the class of residential customers might be broken down into special-use groups such as those using electric water heaters, space heating, and the like. These would have special rates, on the grounds that the services they receive have cost factors peculiar to themselves or because the services have special value to the customer.

Allocating costs. In establishing rate groups and schedules for special services within the groups, the first step is to determine the cost of servicing the particular function. In the electric utility industry typical functions are production, transmission, distribution, customer service, and general and administrative. The uniform system of accounts facilitates functionalization. Costs for which the service is directly responsible must be identified and assigned directly. Costs for which the service may share responsibility with others must be allocated to it.

Direct assignment. Very few investment costs can be directly assigned, but it is appropriate to do so whenever possible. This happens most often in the case of facilities required by large industrial or commercial customers that are their sole users and to which investment costs (and related operating costs) should be assigned directly. Examples would be a lateral gas line running from a main line to a single customer or a bank of electric transformers installed on a customer's premises but owned by the utility. Adequate property records are also essential for the direct assignment of costs.

Allocated costs. Most plant facilities (Production, Transmission, Distribution, Customer, and General) serve large blocks of customers of varying classes and characteristics. Costs of these facilities should be allocated in such a way that each class of service is assigned responsibility for its fair and reasonable portion of the investment. This is frequently difficult to do. It is essential that adequate property records be maintained in order to establish unit identification and to determine the total amount of investment in a given facility that is subject to allocation. Service characteristics such as demand usage, energy consumption, and the number of customers served provide the basis for allocation.

Operating expenses. Allocation of these costs to customer groups presents difficulties similar to those that arise in allocating investment costs. Although a few are directly allocable to a specific customer or class, in most cases it is impossible to identify any particular recipient as benefiting from them exclusively. Difficulty of allocation varies with the type of expenditure involved. For example, costs of fuel used in electric generation, or of gas purchased for distribution, can usually be allocated without difficulty to the customer using the system output, but other costs (e.g., maintenance and repair costs, administrative costs, and taxes) are not easily traceable. They seldom have a direct relationship to identifiable customers or groups and must be allocated. Depreciation expense and its counterpart, depreciation reserve, are usually allocated on the basis of the plant to which they relate.

Allocation factors. The factors commonly considered in the allocation process are demand (fixed or capacity) costs, energy (variable or commodity) costs, and customer costs. Plant and operating costs are isolated into one or another of these categories, and appropriate factors are applied to allocate each.

Within the broad groups of demand, energy, and customer factors, there may be special circumstances that affect the cost of serving a particular class of customer, and the cost allocation must consider such special circumstances if costs are to be assigned equitably.

Demand (fixed or capacity) costs. These are costs related to the fixed-plant investment and level of operations needed to meet the maximum service demands placed on a system. Even if service is not being rendered at any given moment, the costs continue, since the service must be available when demanded. The degree to which a given customer uses the service over a period of time does not change these costs.

Much of the plant investment is designed to meet customer needs at the time and levels required. Costs such as interest, depreciation, and general maintenance associated with this plant do not diminish or cease even when the plant is inactive. The best example is that of the electric production plant, which must be able to generate enough power to meet total system needs at the moment of peak use, even though much of its capacity is not used during a large part of the remaining time.

Demand-related costs are usually allocated to customer classes on the basis of the contribution each class makes toward total demand at the maximum operating level. This contribution can be measured in several ways: coincident peak demand, noncoincident peak demand, and various other methods.

Energy (variable or commodity costs). These relate to functions that fluctuate as a system is used. The best example is fuel expense, which is incurred only when power is being produced and can therefore be allocated to those who use the power. The allocation is easily made on the basis of kwh consumed.

Customer costs. These are similar in nature to fixed costs because they arise by virtue of the fact that a particular customer exists, regardless of the amount of service used or when it is used. An example is the cost of preparing bills for a customer; it is incurred regardless of how much service is used. These costs are usually assigned to a customer class on the basis of the ratio of the number of customers in that class to the total number of customers in the system.

Other costs. These are costs that cannot be directly related to service demands, energy consumed or to customers. They represent costs that are necessary to operate the system without regard to the levels of usage or the numbers of customers. Most administrative and general costs fit this category, and a good example within this group would be the officers' salaries; costs that normally cannot be directly associated with levels of service or numbers of customers. These costs are normally allocated to usage based on some grouping of other costs that reflect composites of a variety of measures (e.g., the composite of customer, plant investment, kwh sales, and other operating expenses ratios).

Rate design. The basic rate design found in electric and gas companies is either a two-part rate or a step rate that decreases as the consumption level increases. In addition, a separate customer or service charge may be included.

Two-part rate. This is designed to meet both the fixed and the variable costs of the system for which the individual customer is responsible. It is made up of a demand charge and a commodity charge and consists of a maximum charge related to the maximum demand placed on the system at any time and a charge per unit of energy drawn from the system over a period of time. Two meters must be installed on the customer's premises, one to measure the maximum level of demand and the other to measure the consumption. Since demand meters are expensive, use of the two-part rate is generally limited to large industrial customers.

One-part rate. The one-part rate, which uses no demand meter, attempts to compensate for this lack by recovering both demand and commodity costs through a single unit charge. The per unit charge may decrease as consumption increases (declining block rate) or remain level (flat rate). It often includes a minimum bill feature to permit recovery of the customer costs and certain other fixed costs without use of a demand meter.

Time-of-use rate. This may be illustrated by the case of water-heating rate that offers power at lower rates during such off-peak periods as late evening or early morning when energy can be generated at low incremental unit costs because generating facilities might otherwise be idle.

Interruptible rate. This may be illustrated by the case of an industrial customer that can curtail operations easily or that has alternative fuel capabilities that can be easily switched. Service to such a customer can be interrupted by the utility during periods of peak demand on the system. In such instances, the price for electricity or natural gas is adjusted to reduce (or eliminate) the demand costs that would otherwise apply.

Competitive rate. With the decline in fuel costs during the 1980s, a new rate design problem arose. As oil and gas prices began to decline, many large electric and gas customers found that conversions to alternative sources of energy or fuel were very attractive. In order to avoid the loss of these customers, who most often were high-use, high-load-factor customers, many electric and gas companies have been forced to offer price concessions below fully allocated costs. In many instances, these price concessions have been approved by regulators because the retention of the large-use customers at prices in excess of variable costs benefited the remaining customers of the system (i.e., the retained customer shared part of the fixed costs that otherwise would be passed on to other customers).

Peripheral issues. While allocating cost of service is certainly the central focus in rate design, there are nonetheless certain other questions that must be carefully considered concurrently. Otherwise, after rates have been set, difficulties may arise that could prevent them from being implemented successfully.

Rate history. Whenever rates have been in effect over long periods, customer groups tend to become accustomed to them, particularly if they have been receiving special benefits. These may no longer be justified, and a utility may feel that a disproportionate share of the rate increase is required to recover adequately the cost responsibility assigned to them. When this happens, it is important that convincing data be presented in order to overcome the inevitable opposition of these customer groups.

Public relations. When a utility decides that its rate pattern should be changed, it is bound to face public relations problems with three groups: regulatory commissions, the general public, and investors.

Commissions normally must directly approve the rate levels the utility seeks to change and will examine its proposals carefully to ensure that recommended rate levels are equitable to customer classes, as well as adequate to produce the system's required revenues.

The general public, represented by the utility's customers, must be shown that any rate change the utility proposes is adequately justified, particularly if a shift in structure is planned that will adversely affect certain customers.

Investors will normally welcome rate increases, because these will presumably increase earnings (or at least maintain them at existing levels), but they will also be on the alert to spot any proposed increase that might provoke opposition by particular customer groups in a manner that is likely to adversely affect earnings.

Competition. Although utilities are generally regarded as enjoying monopoly status, the fact is that electric and gas companies are increasingly affected by competition among fuel oil, electricity, natural gas, and bottled gas. Electric utilities also face competition from neighboring utilities in serving wholesale customers and from customer-owned sources (cogeneration, solar, and windmills) in serving retail customers. Utility customers are now beginning to choose their supplier. This competition sometimes forces them to develop market-oriented rates so that customers do not switch to other forms of service and to encourage optimum use of the utility's system.

Load management. Utilities have traditionally charged uniform rates regardless of the period of use. In recent years there has been a growing recognition, particularly in the electric industry of the high cost of plant required to meet peak demands of relatively short duration and of the need to curb the growth in peak demand in order to avoid adding generating capacity in the future. Time-of-use rates (e.g., seasonal or time-of-day rates) that impose higher rates for usage during peak periods have been developed to encourage customers to shift usage from high-cost peak periods to lower-cost off-peak periods. Other demand-side management practices are being employed to reduce peak load. For example, an electric utility may provide customer incentives to replace existing air conditioning equipment with high-efficiency units.

Marginal costs. Conventional rate design has generally been based on recovery of embedded costs of service. In recent years, increased consideration has been given to the direct application of economic theory to ratemaking through the development of rates based on marginal costs. Marginal or incremental cost is defined in general as the expected change in total costs to supply one additional unit of output. Since long-term marginal costs, at present, are generally higher then embedded costs, such rate designs would encourage customer conservation to the extent that service demands are elastic. Difficulties have been encountered in determining precisely what represents the marginal cost and how to modify true marginal cost rates to match total revenue requirements based on embedded costs. The real competition developing between and within utilities (for example, the growth of cogeneration and small power producers, the development of a spot market for natural gas, and the "unbundling" of services provided by electric and gas companies) has been and is giving rise to changes in traditional ratemaking mechanisms. Regulators are beginning to give utilities more freedom to meet competition and, at the same time, protecting consumers that are truly captive customers.

III. Accounting characteristics of utilities

Effect of regulation

Most investor-owned utilities are subject to rate regulation by state or federal commissions. Regulation of rates, and therefore of revenues, would in itself affect accounting, but commissions generally have direct accounting jurisdiction as well. Many utilities are also subject to accounting regulation by federal agencies. Since most utilities frequently engage in financing, they are also subject to certain requirements of the SEC.

Regulation of rates requires accounting information, and sound regulation requires sound accounting, although not necessarily on the same basis as in unregulated business. Accounting supplies the information that is used in rate regulation, and rate regulation and accounting regulation in turn affect the accounting data. Because of this interaction, the accounting used in a regulated business may differ in certain respects from that used in other businesses. These differences in the application of accounting principles are discussed in greater detail later in this chapter.

Accounting is generally regarded as a tool of regulation. Regulatory commissions require substantial uniformity of accounting because uniformity assists in regulation. Transactions must ordinarily be recorded in conformity with commission policy so that accounting information will be usable in rate proceedings. Directly or indirectly, accounting regulation affects published reports and thus financing, which itself is often regulated and in turn affects rates.

The authority granted to commissions with respect to accounting is desirable when it results in comparability. It has also had a beneficial effect in eliminating some of the undesirable accounting practices of the earlier days of the industry (such as property write-up or the failure to provide sufficient depreciation). On the other hand, the accounting required by regulatory bodies sometimes differs from what would have resulted from the application of generally accepted accounting principles (GAAP) by enterprises in general - or from that desired by other regulatory bodies.

Reports to stockholders and others are prepared from the regulated records, so that they conform in general to the accounting policies of the regulator. The FERC generally requires stockholders' reports to conform to its accounting requirements whenever it has jurisdiction over any part of a company's operations. Federal courts have upheld the FERC in this requirement. The states have seemed less inclined than the federal agencies to regulate stockholders' reports directly.

Uniform systems of accounts

The control of accounting is ordinarily accomplished by uniform systems of accounting together with interpretative orders. The uniform systems that most utilities are required to follow consist of lists of the titles and identifying numbers of accounts to be used, together with specific instructions for the use of individual accounts and general instructions as to the basis of accounting. There are, of course, specialized systems for different types of utilities. Most of the systems discussed below are available in booklet or electronic form.

Uniform systems for electric and gas utilities have been issued by both NARUC and the FERC. The NARUC and FERC uniform systems are substantially identical, although there are some differences in the accounts included. The electric and gas systems are quite similar except for differences due to certain individual characteristics of the two industries. Most state commissions prescribe either the NARUC system or the FERC system, with certain modifications to agree with local policy. The similarity of the present systems is the result of a long cooperative effort of the FERC, NARUC, and the utility operating companies.

Water-utility accounting is regulated only by state commissions or municipal bodies, many of which prescribe to the NARUC uniform system. Rural electric cooperatives and other borrowers from the Rural Utilities Service (RUS) are subject to RUS's accounting regulation, which prescribes its own uniform system of accounts. Because the RUS is a direct lender or guarantor to cooperatives, it also includes a number of specific requirements that its borrowers must meet.

Most of the systems group companies by size. The accounting requirements are less complicated for smaller companies, but they may use the system for large companies if they wish.

The uniform systems are quite detailed, and instructions for using the various accounts are quite specific. Interpretations are released from time to time by NARUC (Interpretations of the Uniform System of Accounts for Electric, Gas and Water Utilities) and by the Chief Accountant of the FERC (Accounting Releases). Fortunately, the accounts, the numbering, and the instructions for various systems are sufficiently similar that familiarity with one leads to understanding of any other.

Nature of differences

The uniform systems of accounts basically follow GAAP and the techniques normally employed elsewhere, but accounting specifications for certain matters are designed to meet needs peculiar to regulated utilities. The differences normally result, either directly or indirectly, from the emphasis in regulation on ratemaking objectives, and their effect on financial statements may be significant. Some of the principal differences and their relationships to GAAP are discussed below.

Matching costs and revenues. Many differences between the regulated and unregulated approach to accounting for transactions result from the recognition of operating expenses in rate proceedings at a time different from that when they would be recognized by unregulated business. It is a common practice in the ratemaking process to defer recognition of costs considered abnormal or as having benefits applicable to future rates. In such cases, when it is probable that deferred costs will be recoverable out of future revenues, accounting that follows the timing of the costs used for rate purposes is considered to conform with GAAP. This is in accord with the matching concept, because the deferred costs are being matched against future revenues. Commissions usually require that accounting treatment correspond to the rate treatment, but even if they do not so require, the two treatments should ordinarily conform. It is thus possible to effect a proper matching of costs and revenues unless the revenues cannot reasonably be presumed to be recoverable in the future. (The matching, however, may be only approximate, since rate proceedings usually do not occur annually or guarantee exact recovery of costs.)

Conflicting regulations. Determination of proper accounting may be complicated by conflicting regulations. For example, the FERC asserts jurisdiction over the accounting and financial reporting of all electric utilities that (1) have licensed hydroelectric projects on navigable waters or (2) utilize or sell electric energy, however minor the amount, that crosses state lines. Because of the interconnected power grid that encompasses most of the United States, all but a few of the large privately owned utilities in the United States fall into the second category. These utilities are also subject to state or local jurisdiction, and if they conduct business in more than one state they are subject to several state commissions, whose policies may differ. They must also comply with the requirements of the SEC. With multiple regulatory agencies exercising overlapping authority, the potential difficulties for a utility are obvious. These have been largely minimized in the past through the cooperation of these bodies.

Conflicts between regulation and GAAP. Complications can also arise when accounting rulings are made before ratemaking determinations. For example, commissions may order an accounting treatment without having dealt adequately with the related ratemaking considerations. Other accounting practices may be dictated by regulatory requirements not related directly to ratemaking, or by regulation related to aspects of ratemaking other than the timing of income or expense. Accounting practices that depart from the normal pattern but are not related solely to timing differences or ratemaking considerations must be analyzed to determine whether, for other reasons, they conform to GAAP. Utilities ordinarily follow regulatory accounting requirements in reports to stockholders as long as such requirements produce financial statements that conform with GAAP (including the provisions of the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards No. 71 discussed below). In isolated situations where regulatory accounting requirements differ materially from GAAP, they may constitute what is termed a "comprehensive basis of accounting other than GAAP." The SEC requires that financial statements provided to stockholders and investors that are included in filings under the Securities Act of 1933, Securities Exchange Act of 1934, and PUHCA be in conformity with GAAP.

The effects of rate regulation on the application of accounting principles have long been recognized by standard-setting bodies in establishing accounting principles for use in preparing general-purpose financial statements. The most recent general standards dealing with the subject are contained in Statement Standards No. 71, *Accounting for the Effects of Certain Types of Rate Regulation*, issued by the FASB in 1982. Since the adoption of Statement No. 71, the FASB and its Emerging Issues Task Force (EITF) have expanded their intervention in the regulatory accounting process by the issuance of various other pronouncements.

FASB Statement No. 71

As a condition for its initial and continuing application, Statement No. 71 indicates that it applies to general-purpose external financial statements of enterprises that have regulated operations only if all the following criteria are met:

1. The enterprise's rates for regulated service or products provided to its customers are established by, or are subject to approval by, an independent third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.
2. The regulated rates are designed to recover specific costs incurred by the enterprise in providing the regulated services or products.
3. In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs.

The general standards state that rate actions of a regulator can provide reasonable assurance of the existence of an asset through future cost recovery. However, before an incurred cost that would otherwise be charged to expense is capitalized or deferred, it must be probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable cost for ratemaking purposes, and the clear intent must be to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. The standard also concludes that a regulator can reduce or eliminate the value of an asset, and, accordingly, the carrying amount of any related asset should be reduced to the extent that the asset has been impaired.

The Statement similarly recognizes that a regulator can impose a liability on a regulated enterprise. Examples include refunds ordered to be made to customers, gains to be deferred and amortized over future periods as a reduction of allocable costs, and provisions in rates for costs not yet incurred. It adds to this discussion by pointing out that regulators can eliminate a liability only if the liability was imposed by action of the regulator. Accounting for lease transactions is a good example. Statement No. 71 speaks directly to accounting for leases and concludes that the regulator cannot affect the classification of a lease liability on the balance sheet. Therefore, when a lease is capitalizable under GAAP, but is treated as an operating lease for ratemaking purposes, the balance sheet should still reflect the capitalizable asset and the related lease liability. However, in certain situations not involving a phase-in plan (which are discussed in the following section), the amortization of the leased asset would be modified so that the total expense would equal that allowed for ratemaking purposes.

Statement No. 71 also sets forth specific standards for a few isolated accounting issues. It allows the capitalization of an Allowance for Equity Funds Used During Construction (AFUDC) including equity funds, if the regulator provides for this method, rather than using FASB Statement No. 34, *Capitalization of Interest Costs*, for the purpose of capitalizing funds used during construction. Statement No. 71 also provides that intercompany profits on sales to regulated affiliates should not be eliminated in general-purpose financial statements if the sales price to the regulated enterprise is reasonable and it is probable that future revenues allowed in the ratemaking process will provide for the recovery of such amounts. Additional guidance for applying the general standard to specific situations is provided in an appendix to the Statement.

In 1988, the FASB issued Statement No. 101, *Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71*, which addresses the accounting for an enterprise that ceases to continue to meet the criteria for applying Statement No. 71 to all or a part of its operations. Examples of causes for discontinuance given are (1) deregulation, (2) a change by the regulator from cost-based ratemaking to another form of regulation, (3) increased competition that limits the enterprise's ability to charge rates that will recover costs, and (4) regulatory action resulting from resistance to rate increases that limits the enterprise's ability to charge rates that will recover costs if the enterprise is unable to obtain (or chooses not to seek) relief from prior regulatory actions through appeals to the regulator or the courts.

Statement No. 101 requires that, when an enterprise discontinues application of Statement No. 71 to all or a part of its operations, it eliminate from its statement of financial position prepared for general-purpose financial reporting the effects of any actions of such regulators that had been recognized as assets and liabilities pursuant to Statement No. 71, but would not have been recognized as assets and liabilities by enterprises in general. However, utility plant and inventory are not required to be adjusted except for the effects of impairment. The net effects of the adjustments required by the Statement are included as an extraordinary item in income of the period in which the discontinuance occurs.

Differing views on the accounting implications of the electric utility industry's restructuring resulted in EITF Issue No. 97-4, *Deregulation of the Pricing of Electricity – Issues Related to the Application of FASB Statements No. 71 and 101.* Issue No. 97-4 was condensed into two primary issues:

1. **Statement No. 71 issue.** When should an enterprise facing a typical deregulation sequence of events cease to apply Statement No. 71 to the generation portion of its business?
2. **Statement No. 101 issue.** If an enterprise concludes that a separable portion of its operations (e.g., generation) no longer meets the criteria for application of Statement No. 71, on what basis should regulatory assets and liabilities of the separable portion of the business be determined?

On the Statement No. 71 issue, the EITF reached a consensus that the application of Statement No. 71 to a segment (e.g., generation) that is subject to a deregulatory transition plan should cease no later than the time when the legislation is passed and the details of the plan are known.

The EITF added language to the consensus that requires clear disclosure, through financial statement display or footnotes, of the segments of the enterprise that were applying Statement No. 71 and those that were not.

On the Statement No. 101 issue, the EITF reached a consensus that regulatory assets and liabilities should be recorded based on the separable portion of the business from which the regulated cash flows to realize and settle them will be derived, rather than based on the separable portion for which the costs were initially incurred. Thus, even if generation is deregulated, regulatory assets and liabilities would be retained if stranded cost recovery is provided from customers that remain regulated for distribution or other services. The consensus applies not only to regulatory assets and liabilities already recorded when the separable portion ceases application of Statement No. 71, but also to regulatory assets and liabilities plus any other costs (e.g., purchase power contracts or employee severance costs) that are probable of recovery regardless of when incurred.

Reapplication of statement no. 71. As noted in Statement No. 101, the FASB concluded that the accounting for the reapplication of No. 71 is beyond the scope of No. 101. However, there have been several companies that have reapplied Statement No. 71. When facts and circumstances change so that a utility's regulated operations meet all of the criteria set forth in No. 71, it should be reapplied to all or a separable portion of its operations, as appropriate.

Reapplication includes adjusting the balance sheet for amounts that meet the definition of a regulatory asset or regulatory liability in paragraphs 9 and 11, respectively, of Statement No. 71. AFUDC should commence to be recorded it if is probable of future recovery, consistent with paragraph 15 of Statement No. 71. Previously disallowed costs that are subsequently allowed by a regulator should be recorded as an asset, consistent with the classification that would have resulted had these costs initially been allowed.

The net effect of the adjustments to reapply Statement No. 71 should be classified as an extraordinary item in the income statement.

Other FASB statements

Subsequent to the issuance of Statement No. 71, major events occurring in the electric utility industry caused the FASB to review the effects of that Statement on the accounting for those events. In particular, utilities building electric generating plants encountered unexpectedly high construction costs, which in some instances resulted in abandonment of projects under construction, disallowance of construction costs by regulators, and adoption of plans by regulators for gradual increases in rates over time to phase in the high costs of the new plants. FASB Statements No. 90, *Regulated Enterprise – Accounting for Abandonments and Disallowances of Plant Costs*, and 92, *Regulated Enterprises – Accounting for Phase-in Plans,* address these subjects.

Abandonments. In the event of a plant abandonment, a regulator may permit recovery of all or a portion of the cost of the plant as well as a return on the investment. Statement No. 90 provides that when the abandonment of an operating asset or an asset under construction becomes probable, that asset must be removed from construction work in progress (CWIP) or plant in service. The recoverable costs of the abandoned asset then must be recorded as a new regulatory asset. Statement No. 90 provides the following guidelines for determining the value of that new asset.

1. If the regulator is likely to provide a full return on the recoverable costs, the new asset value should equal the original carrying value of the abandoned asset less any disallowed costs.
2. If the regulator is likely to provide a partial return or no return, the new asset value should equal the present value of the future revenues expected to be provided to recover the allowable cost of the abandoned plant and any return on investment. The discount rate used to compute the present value is the utility's incremental borrowing rate, i.e., the rate that the utility would have to pay to borrow an equivalent amount for a period equal to the recovery period.

The amount of loss an enterprise recognizes at the time of a decision to abandon is calculated as the difference between the net carrying value of the abandoned plant and the present value of the revenue stream provided for recovery of these costs, and must be adjusted for income tax effects.

Disallowances. Statement No. 90 stipulates that, when a disallowance in ratemaking by a regulator of a portion of the cost of a recently completed plant becomes probable and reasonably estimable, the estimated amount of the probable disallowance must be deducted, dollar for dollar, from the reported cost of plant and recognized as a loss.

The Statement also applies this rule to explicit, but indirect, disallowances (such as the disallowance of a return or a reduced return on a portion of plant costs). In the case of indirect disallowances, if the regulator does not specify the amount of the disallowance, the enterprise must determine the effective disallowance by computing the present value, using the last allowed rate of return, of the estimated future cash flow that is not allowed. Under this discounting approach, the remaining asset should be depreciated consistent with its ratemaking and in a manner that would produce a constant return on the undepreciated asset equal to the discount rate.

The accounting for a direct disallowance is straightforward. If it is probable that a utility will not recover some or all costs of a recently completed plant, the unrecoverable amount should be written off. The difficulty in applying Statement No. 90 to direct disallowances arises in determining when the disallowance should be recognized. If the regulator has already disallowed recovery, the decision is not difficult (unless it is possible that the courts will reverse the decision). However, when a utility has a plant for which construction has been recently completed, and the utility is waiting for a rate decision, the accounting is not clear. Sometimes, a regulator may be so unpredictable that probable nonrecoverable amounts cannot be reasonably estimated until a final decision, including the appeals process, is rendered. In instances when the disallowed cost can be estimated, such costs should be written off. If recovery of the cost that is written off is subsequently allowed, the cost should be recapitalized.

Phase-in plans. Due to the high cost of constructing electric generating plants during the 1980s, conventional ratemaking methods would result in significantly increased rates for some utilities when a newly completed plant was placed in service. Some regulators adopted plans to moderate the initial impact on rates by phasing in over a period of time the recovery of costs associated with a new plant. Statement No. 92 specifies the accounting for such phase-in plans.

The Statement defines a phase-in plan as any method of recognizing allowable costs in rates that meet each of three definitional criteria. The term allowable costs refers to all costs for which revenues are intended to provide recovery. These include current operating costs, depreciation, interest on borrowed funds invested in the plant, and an allowance for earnings on shareholders' investment. The three definitional criteria are as follows:

1. The regulator adopted the method in connection with a major newly completed plant (or a major plant scheduled for completion in the near future) of the utility or one of its suppliers.
2. The method defers recovery of allowable costs beyond the period in which they would be charged to expense under GAAP as applied to enterprises in general.
3. The method defers allowable costs beyond the period in which they would have been recovered under the ratemaking routinely used by the regulator prior to 1982 for similar allowable costs of the particular utility.

Under the accounting provisions of Statement No. 92, cost deferral under a phase-in plan is not permitted for plant on which substantial physical construction had not been performed before January 1, 1988. Consequently, for a major, newly completed plant that does not meet the January 1, 1988, cutoff date, post in-service cost deferrals for financial reporting purposes are limited to a time frame that ends when rates are adjusted to include costs associated with the plant. Because Statement No. 92 limited and then eliminated the use of phase-in plans for major, newly completed plant, few examples of such plans exist in utility financial statements today.

Plant accounting

Under the cost-of-service approach to ratemaking, as long used in the utility industry, establishment of the rate base is a crucial factor in setting rates for service. The rate base consists primarily of the utility's investment in plant facilities serving the customer, so it is not surprising that the Uniform System of Accounts (USOA) places considerable emphasis on plant accounting procedures.

As a part of the emphasis, the FERC's USOA requires continuing plant records, controlled by primary accounts and subaccounts classified by type of property. Generally, continuing property records (CPR) record the location, description, date of construction, and cost of units of property. The FERC has prescribed a "List of Retirement Units" for use in accounting for additions and retirements of electric plant, which is composed of "Retirement Units" (e.g., air-conditioning system, boiler, generator, poles, meters, etc.) and "Minor Items of Property" (items not otherwise identified). These property units are guidelines, and smaller units are permitted.

The CPR need not reflect individual costs for each of the retirement units, but it should provide data by which the cost of the retirement unit can be determined. For example, poles are generally maintained in a mass property account (i.e., property consisting of a large number of homogenous items), and costs are maintained by groups and vintages rather than by individual poles. Even so, the records should provide sufficient data for estimating the costs related to individual poles being retired from service.

Construction costs (which include asset retirement costs as a component) and costs of retirement work are accumulated by work orders that serve as subsidiary records of the construction work-in-progress and retirement work-in-progress accounts. Work orders may also be used for certain expense charges. For example, continuing and recurring expense functions, such as meter repairs, or such large special requirements as a generator overhaul may be controlled through work orders. The work-order file generally includes a description of the project, authorization to undertake it, an estimate of its costs, a cost analysis showing estimated costs and variations therefrom, and a completion report.

When depreciable property is retired, the book cost, less salvage, is charged in its entirety to the Accumulated Provision for Depreciation. Except in extraordinary circumstances, any difference between the original cost and the amount of accumulated depreciation is not recognized. Cost of removal that does constitute a legal obligation should be charged to the liability account for assets retirement obligations.

Original cost. The USOA for electric and gas companies prescribed by the FERC requires that the plant accounts "be stated on the basis of cost to the utility of plant constructed by it and the original cost, estimated if not known, of plant acquired as an operating unit or system." The USOA service defines original cost as "the cost incurred by the person who first devoted the property to utility."

In the case of new plant, original cost and historical cost are the same, but they differ in the case of plant acquired as an operating unit or system. The latter must be recorded at original cost, together with the related Accumulated Provision for Depreciation. Any difference between the composite book value of the items transferred and the amount paid is considered to be an acquisition adjustment or goodwill.

Acquisition adjustments and goodwill. For utility plant subject to traditional cost-of-service regulation and Statement No. 71, depreciated original cost is typically equal to its fair value. If an amount paid for utility plant exceeds its original cost depreciated, and that amount is recoverable through future rates, the fair value has been increased and an acquisition adjustment should be recorded as a component of utility plant. If the excess payment is not included in future rates, the amount typically represents goodwill. Because the FERC's USOA does not have an account for goodwill, many utilities have recorded goodwill in the acquisition adjustment account for regulatory reporting. An appropriate reclassification is necessary for GAAP-based financial statements. The FERC's accounting policy staff issued new related guidance in July 2003, which states that "amounts so allocated to utility plant in excess of depreciated original cost at the date of acquisition should be an acquisition adjustment in Account 114 and the excess of the cost of the acquired company over the sum of the amounts assigned to all identifiable assets acquired and liabilities assumed should be recorded as goodwill in Account 186, "Miscellaneous Deferred Debits."

Contributions in aid of construction. Utility customers frequently require services that create unusual and excessive installation costs due to service location, relocations, or facility requirements. For example, a customer may be located in a remote spot and require costly line extensions to connect it to the system. Another example is the recent trend toward installing facilities underground for aesthetic purposes. When such circumstances impose added costs on the construction projects, the utility frequently obtains contributions from customers to offset the excess costs.

Previously, under the requirements of various uniform system of accounts, these contributions, if permanent, were usually accounted for as a separate line item on the liability side of the balance sheet, identified as Contribution in Aid of Construction (CIAC). Amounts that are subject to refund are carried as Customer's Advances for Construction, a liability account, until refunded. Historically, amounts representing CIAC were maintained as deferred credits without any specific provision for the removal or amortization of the CIAC balances. However, most regulators have changed this practice and have required the elimination of this account by offsetting the balances against the related plant accounts. Water and sewerage utilities continue to maintain CIAC balances.

The handling of CIAC can have a significant effect on depreciation. If the contributions are used to reduce plant, the depreciation expense is correspondingly reduced. Historically, most electric, gas, and water utilities depreciated gross plant and maintained the contributions account at the original level. Thus, in effect, they treated the contribution as permanent capital contributed by customers. In almost all cases, the rate base is reduced by the balance in the CIAC account, since that part of plant cost is not provided by investors.

Under present tax law, CIACs are generally taxed as ordinary income in the year that they are received. However, property purchased with these funds can be depreciated for tax purposes.

Allowances for funds used during construction. The FERC's USOA specifies that: "The cost of construction ... shall include, where applicable" allowances for funds used during construction. Such amounts include the "net cost ... of borrowed funds ... and a reasonable rate on other funds" used for construction purposes. The practice of capitalizing the cost of funds used during the construction period accomplishes a number of objectives, including these:

1. The cost of the plant, including the construction financing cost, is fully recognized.
2. The utility operation is shielded from costs associated with construction activity.
3. The present customer is not burdened with supporting an investment designed for future needs.
4. The utility, by capitalizing the financing cost, is afforded an opportunity to recover these costs whenever the plant is placed in service (through depreciation of the costs and a return thereon until they are fully depreciated).
5. The customers of the future will pay the full cost of the facility constructed for their use.

Although the concept has long been recognized as appropriate for the utility industry (which is generally the same as for capitalizing interest under Statement No. 34 for enterprises in general), many aspects of AFUDC have been sources of vexation for both regulators and the industry. In earlier years the difficulties were largely academic because the amounts involved were small and had little impact on the financial statements of utilities. In the 1970s and 1980s, however, a surge in construction expenditures increased the AFUDC amounts to the point where their impact on financial statements was substantial.

Financing for construction may come from external sources (such as bank loans, long-term debt, preferred stock or common stock sales) or from internal sources (such as retained earnings). Over any given period, financing may come from any one or all of these sources. Debt, bank loans, and preferred stock reflect stated cost rates, and the costs for these sources are subject to fairly precise determination when they are adjusted to recognize related premium, discount, and cost of issuance.

FERC Order No. 561 provides a uniform method of determining the annual maximum allowable AFUDC rate. The computation of the maximum allowable rate assumes that short-term debt is the first source of funds used for construction, with the remainder assumed to be financed out of long-term debt, preferred stock, and common equity on the basis of the ratio of such funds that existed at the end of the prior year.

The order also provides that the AFUDC is to be segregated into two component parts - borrowed funds and other funds. The borrowed funds are located in the interest-charges section of the income statement, while the other-funds component is reflected in the other-income-and-deductions section.

Depreciation. Although the USOA does not specify a method of depreciation to be used, the straight-line method is applied almost universally for both accounting and ratemaking (although units-of-production and accelerated/decelerated methods of depreciation have been utilized in certain cases). Straight-line depreciation is generally considered reasonable and systematic in spreading investment cost over the life of the plant. It is also common practice to include in depreciation a provision for the estimated cost of removing plant from service, less the estimated salvage. The cost of plant removal has become a more significant factor in the past decade, due to the increasing cost of removals, inability to retire many plant items in place without removal, and the recent focus on environmental restoration.

Revenue accounting

Because utilities have large numbers of relatively small accounts, these accounts are generally grouped by routes or districts. It is generally not practical to bill all customers at the end of each month, and cycle billing (billing some accounts each working day of the month) is common.

Traditionally, most utilities did not accrue unbilled revenue related to usage from the ending date of the cycle to the end of the month. However, due to the increased significance of unbilled revenue, and because the 1986 Tax Reform Act requires the identification of these amounts for inclusion in taxable income, most utilities now accrue the estimated amount of unbilled revenues. For a company on a monthly billing cycle, as much as a half month's revenues may be unbilled at the end of each month.

Volatility in the prices of fuel can significantly affect the operations of utilities. The magnitude of and rapid changes in fuel costs lead many regulatory bodies to provide for automatic adjustment clauses in order to reflect these cost changes quickly in the rates charged to customers. In addition, volatility in fuel prices has caused many utilities to establish an accounting policy of deferring fuel costs that will be recovered in subsequent periods or accruing the related unbilled revenues in order to properly match costs and revenues.

Inventory accounting

Inventories of utilities generally include fuel for electric companies, gas in underground storage for natural gas distribution companies, and materials and supplies. Materials and supplies inventories may be used for operations, maintenance, or construction. Because of a need to distinguish usage in the accounting records, an issue ticket is generally used to identify the proper charge as items are removed from inventory. Inventories of fuel and materials and supplies are generally classified as current assets. Nuclear fuel costs are classified within the utility plant accounts, because the life of a nuclear fuel core extends over several years, and are amortized to expense as fuel is consumed. Unique and large emergency spare parts maintained for generating plant replacements are generally included in the utility plant accounts and are depreciated.

Inventories of coal are generally kept on a perpetual basis. Aerial or ground surveys and density tests of coal piles are made periodically to confirm the reasonableness of perpetual records. Natural gas is often stored in underground caverns where tests of quantities are difficult. Through pressure meters and other techniques it is usually possible to determine the reasonableness of perpetual records. A considerable portion of the gas underground is "cushion gas," which is necessary to maintain pressure and is not recoverable. This gas is generally capitalized and depreciated as part of the cost of the cavern. In addition, a portion of the gas may be classified as a noncurrent asset because it exceeds the quantity that will be withdrawn within a year.

Income tax accounting

Income taxes, a potentially significant factor in financial reporting for any company, have special significance for the regulated utility. As a component of its cost of service, the income taxes recorded for a reporting period will have a direct impact on the rates the utility requires for its services. Because of this impact, regulators often require the use of income tax accounting practices that differ from those employed under similar circumstances by nonregulated companies.

The USOA generally provides that income taxes are to include the amount of state and federal taxes on income properly accrued during the period to meet the actual liability of such taxes. The systems further require that the accrual be apportioned among utility departments (e.g., electric and gas departments in a combined electric and gas company) and nonutility operations, so that the expenses are related to the operations that gave rise to the taxes (or tax savings). Proper allocation among utility departments and nonutility operations is necessary in order to properly establish the total costs to be recovered for each type of utility service through the rates established for it. However, in many jurisdictions "negative tax" may not be allocated to a department operating at a loss, particularly to an unregulated department. Similar problems often occur in the allocation for accounting purposes of tax in a consolidated return, and this is an unsettled area with many jurisdictional variations (the allocation may be Subject to SEC jurisdiction under the PUHCA).

The difficulty in determining the tax expense for the period stems largely from differences between tax accounting and financial accounting. Revenues and expenses are often reported for tax purposes in periods other than those for which they are reported on the books. Consequently, taxable income is generally different from book income. The AFUDC, for example, does not result in income for tax purposes but does for book purposes. In addition, it is quite common for tax depreciation to be greater than book depreciation during the early years of an asset's life because of differences in the estimated life or deprecation method used. If the tax effects of transactions are realized in periods other than those in which the transactions are recorded on the books, "timing" or "temporary differences" occur between book and tax accounting.

In 1967, the AICPA issued APB Opinion No. 11, *Accounting for Income Taxes*, which in essence required comprehensive interperiod tax allocations for all timing differences between book and tax income. The Opinion observed that "interperiod tax allocation is an integral part of the determination of income tax expense, and income tax expense should include the tax effects of revenue and expense transactions included in the determination of pretax accounting income." The concept of providing deferred income taxes on timing or temporary differences between book and taxable income is frequently referred to as income tax "normalization."

Of the more than 50 regulatory bodies in the United States, all have adopted the principles of income tax normalization for accounting and rate purposes on book/tax timing differences relating to property depreciation lives and methods. However, the comprehensive approach adopted by APB Opinion No. 11 has not been implemented in other areas by many commissions. For example, regulators generally permit recovery of the difference between accelerated tax depreciation and straight-line tax depreciation as a deferred income tax expense. Some commissions, however, have rejected the normalization approach for other timing differences and have maintained a "flow-through" policy, whereby only actual taxes paid are allowed as part of operating expenses for ratemaking purposes and the tax reductions from these timing differences are required to flow through to income. The initial effect of the flow-through practice has been to reduce cost of service, giving the current customer the benefit of accelerated tax deductions. Once the timing or temporary difference turns around, cost of service increases as the then-current customer gives back the benefit.

The FERC has issued Orders No. 144 and 144-A (Docket Nos. RM80-42, R-424, R-446), which require full tax normalization of all timing differences in any rate filing before that Commission. Several state commissions have also adopted full normalization.

The Economic Recovery Tax Act of 1981 (ERTA) extended previous restrictions on the regulatory treatment of accelerated depreciation tax benefits. Under ERTA, a utility is not eligible for the accelerated cost recovery system (ACRS) unless the ACRS benefits are normalized. Such benefits result from the use of accelerated depreciation methods and shorter lives for tax purposes as compared with that used for ratemaking. Failure to comply with these requirements would restrict the utility to use of straight-line tax depreciation (based on book lives) for tax-return purposes.

In 1992, the FASB issued Statement No. 109, *Accounting for Income Taxes*, which superseded APB No. 11. Statement No. 109, which is effective for years beginning after December 15, 1992, utilizes a balance sheet approach to recognizing deferred income taxes (in contrast to APB No. 11, which utilized an income-statement approach) based upon the expected future tax consequences of events that have been recognized in an enterprise's financial statements and tax returns. Deferred tax liabilities and assets are recognized for temporary differences and carryforwards that have accumulated as of a point in time, using tax rates under enacted tax laws that would apply when the future tax effects attributable to temporary differences and carryforwards are realized. A temporary difference is a difference between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable or deductible amounts in future years when the reported amount of the asset or liability is recovered or settled, respectively.

Under APB Opinion No. 11, deferred income taxes were provided to the extent that timing differences originating or reversing in the current period increased or decreased current income taxes. However, Statement No. 71 did not require that regulated enterprises provide deferred income taxes for the effects of timing differences that were afforded flow-through treatment in ratemaking if it was probable that income taxes payable in future years when the timing differences reversed would be recovered through rates based on taxes payable at that time. Under Statement No. 109, regulated enterprises that meet the criteria for application of Statement No. 71 are required to provide deferred income taxes for all temporary differences and are:

1. Prohibited from using net-of-tax accounting and reporting. This provision requires, for example, the tax effects of the debt component of AFUDC to be recorded as a deferred tax liability rather than as a reduction of plant in service and CWIP (a practice previously followed by many regulated enterprises).
2. Required to recognize a deferred tax liability (a) for tax benefits that are flowed through to customers when temporary differences originate and (b) for the equity component of AFUDC.
3. Required to adjust a deferred tax liability or asset for an enacted change in tax laws or rates.

An exception was provided for amounts of plant in service at the beginning of the year the Statement was first applied that have been reported on a net-of-tax or after-tax basis. However, any difference between the reported amount and the tax basis of that plant in service was a temporary difference for which a deferred tax liability was recognized.

If, as a result of rate actions by a regulator, it was probable that future increase or decrease in deferred income tax liabilities because of items 2 and 3 above, or for the exception discussed in the preceding paragraph, were to be recovered from or returned to customers through future rates, a regulatory asset or regulatory liability under Statement No. 71 was recognized for that probable future revenue or revenue reduction. That asset or liability was also a temporary difference for which a deferred tax asset or liability was recognized.

For many regulated enterprises that apply Statement No. 71, the impact of implementing Statement No. 109 was to increase regulatory assets and deferred tax liabilities in comparison with amounts reported under APB No. 11.

Regulatory cost deferrals

The treatment of large, infrequently occurring costs is typical of the differences in the time when an expense is recognized by utilities, on the one hand, and by business generally, on the other. A utility is entitled, under traditional ratemaking concepts, to rates that are adequate to recover all amounts reasonably expended in rendering service. The rates are designed to cover the usual and recurring costs of providing service, but certain items are neither usual nor expected to be routinely recurring. Such events do occur, nevertheless, and recovery is not possible unless the costs are allowed for ratemaking purposes. If the entire cost were charged in full to a single year, it would necessarily be omitted for rate-design purposes. A common solution is to defer the item’s cost when incurred, and then to amortize them over a period that, in the commission’s opinion, will result in a fair annual charge to income. For financial reporting purposes, the regulator’s action creates a regulated asset under Statement No. 71, which should be recorded on the balance sheet. Typical regulatory assets deferred and amortized with commission approval include:

1. Uninsured storm losses
2. Losses from early retirement of major plant assets (not provided for in depreciation)
3. Expenses of a rate case
4. Costs of an abandoned construction project
5. Infrequent maintenance expenditures
6. Environmental cleanup costs.

In the case of losses that can be reasonably anticipated, even though the amounts cannot be known, some commissions have allowed annual provisions to a reserve for future losses. For financial reporting purposes, the regulator’s action creates a regulatory liability under Statement No. 71, which should be recorded on the balance sheet. When such losses are experienced, the regulatory liability is reversed to operating income. However, many commissions do not make allowances for indeterminate future losses. When it is probable that the cost will be recoverable out of future revenues, deferral under Statement No. 71 is in conformity with the principle of matching costs with revenues.

Form of financial statements

Financial statements. Published reports do not usually follow the exact wording of the accounts, for example, in the FERC's USOA. However, they are generally quite close to the prescribed form, and the captions are usually similar. As might be expected, the financial statements of individual utilities show variations of form. However, they resemble each other more than they resemble the statements of industries that are not regulated.

At the end of this section is an example balance sheet, income statement, statement of cash flows, and statement of capitalization and shareholder's equity for a combination electric and gas investor-owned utility. They are intended to give an idea of the form of utility financial statements and the relationships between amounts, but not necessarily to supply a recommended form for use in a specific situation.

The Statement of Cash flows is similar to nonregulated companies. A variety of other statements may also be presented: Statement of Changes in Stockholders Equity, Statement of Capitalization, and Statement of Comprehensive Income.

To an accountant accustomed to commercial financial statements, the difference in presentation is apparent immediately. Utility plant is the first major caption on the asset side of the balance sheet, and capitalization is first on the liability side. Current assets and current liabilities are relegated to a comparatively unimportant position in the center of the balance sheet, rather than being placed prominently as in statements for commercial and industrial companies. This form of presentation is intended to reflect the relative importance to a utility of the various accounts.

The form of income statement reflects the classification of expenses in ratemaking. Operating income (subject to regulation) is shown as the result of deducting total operating expenses (generally allowable as operating revenues deduction in ratemaking) from total operating revenues. Other income and deductions (generally not considered in ratemaking) and interest expense (considered only in determining the allowed rate of return) are then applied to arrive at net income.

Operating expenses are referred to as "above the line" because they are allowable in ratemaking and are deducted in arriving at operating income. Interest expense (which is recovered through the allowed rate of return) and other income and deductions are referred to as "below the line" because they are applied after operating income and are not allowable as operating expenses in ratemaking. The concept of above-the-line expenses being allowable in ratemaking affects the form of income statement, the classification of expenses, and, in fact, decisions of management in incurring expenses.

In the income statement, fixed expenses are relatively high. Depreciation and taxes other than income are high in relation to those of other businesses because of the relatively high proportion of fixed assets. Income taxes may be low or high as a percentage of pretax income because of differences between book and tax accounting and the related regulatory treatment.

Notes to financial statements

Notes to financial statements for utilities follow the same basic format and the related regulatory environment as that generally found in the financial statements of nonregulated companies. The notes differ primarily in the content detail. The significant factors affecting the content of the notes for regulated utilities are:

1. **Investment in plant.** The significant plant investment requires adequate disclosure of capitalizations policies; depreciation, amortization, and retirement methods and principles; and for nuclear-related investments, detail on nuclear decommissioning.
2. **Capitalization.** The large commitments for financing long-term construction investments require disclosure of the interest rates, voting rights, preferences, "call" provisions and amounts, redemption requirements, convertibility options, mortgage restrictions, related property liens, and other relevant detail.
3. **Regulation.** Regulation impacts the accounting and the economics of transactions. The disclosures should include the impact on current financial statements and future operations where alternative accounting exists and for specific regulatory action exists, like rate refunds.
4. **Conflicts with Generally Accepted Accounting Principles.** Where conflicts exist between regulatory requirements (and FASB Statement No. 71) and other GAAP, disclosure should be detailed enough to avoid misleading information in the financial statements.

Specific notes that differ from non-utility disclosures include:

1. **Accounting policies.** This note should include detailed description of the uniform system of accounts used, consolidation methods, revenue recognition policies, depreciation and amortization policies, methodology for accounting for income taxes, justification of rate related accruals and deferrals, and justification for various reserves and other significant judgments and estimates.
2. **Regulatory assets and liabilities.** Details of the nature of regulatory deferrals should be provided, including whether they earn a return, are being currently recovered and the recovery period.
3. **Rate matters.** Disclosures in this note, not previously included in accounting policies, include rate cases and the effect on operations, the effect of adjustments related to prior accounting treatment determined to be in conflict with rate-making, regulatory contingencies, and conflicts between various jurisdictional bodies.
4. **Retained earnings.** Disclosure is required for any debt-related restrictions on Retained Earnings or changes in dividend policy.
5. **Commitments.** Future construction obligations are disclosed to the degree that they can be estimated.
6. **Contingencies.** Often combined with "Commitments" to present regulatory matters that are pending, such as incomplete or canceled plants, refunds or recoveries collected that are still subject to refund, pending liabilities, including environmental related costs.
7. **Jointly owned electric utility plants.** Disclosure of the share of construction and ownership and the energy entitlement are necessary. The SEC also requires specific disclosure requirements for jointly owned plant.
8. **Long-term contracts for the purchase of electric power.** Specific disclosure of the long-term contracts and the related derivative and risk management disclosure detail are required. The contract terms and conditions, and any debt service costs. Specific detail of all derivative transactions and valuation of the transaction is requires along with the associated exposure to risk.
9. **Business segments.** Business segments should be represented in the way in which management organizes its operations and evaluates performance.

Example financial statements – electric and gas utility

Balance sheet - December 31, 200X	Amount ($000)	Percent of total
Assets		
Utility plant:		
Utility plant, at original cost	$346,566	
Construction work in progress	84,576	
Total	**431,142**	**82.5 %**
Less accumulated depreciation and amortization	97,360	
Total utility plant-net	**333,782**	
Other property and investments:		
Nonutility property (less accumulated depreciation and amortization)	581	
Investment in associated and subsidiary companies	8,391	
Other investments and special funds	3,136	
Total other property and investments	**12,108**	**3.0**
Current assets:		
Cash and temporary cash investments	7,857	
Accounts receivable, including unbilled (less allowance for uncollectables)	14,544	
Materials, supplies and coal	5,496	
Gas inventory	7,870	
Deferred fuel costs	1,597	
Prepayments and other	2,065	
Total current assets	**39,429**	**9.7**
Deferred debits:		
Other regulatory assets	15,828	
Unamortized debt expense	878	
Under/(over) recovered fuel costs	2,691	
Total deferred debits	**19,397**	**4.8**
Total assets	**$ 404,716**	**100.0%**

Balance sheet - December 31, 200X	Amount ($000)	Percent of total
Capitalization and liabilities		
Capitalization:		
Common stock	687	
Additional paid in capital	87,546	
Retained earnings	43,218	
Accumulated other comprehensive income	10	
Total common shareholders' equity	**131,461**	32.5%
Preferred stocks	30,020	7.4
Long-term debt	152,661	37.7
Total capitalization	**314,142**	
Current liabilities:		
Notes payable and current portion of long-term debt	9,421	
Accounts payable	10,346	
Taxes accrued	5,162	
Interest and dividends accrued	5,469	
Customer deposits	1,587	
Total current liabilities	**31,985**	7.9
Deferred credits:		
Accumulated deferred income taxes	41,693	
Accumulated deferred investment tax credits	16,177	
Advances for construction	719	
Total deferred credits	**58,589**	14.5
Total capitalization and liabilities	$ 404,716	100.0%

Statement of income ______________________ For the year ended December 31, 200x	Amount ($000, except per share amounts)
Operating revenues:	
Electric	$ 135,268
Gas	18,653
Other	878
Total operating revenues	**$ 154,799**
Operating expenses:	
Fuel used in electric generation	46,124
Purchased power	31,826
Gas purchased for resale	8,787
Operations and maintenance	9,633
Depreciation and amortization	10,911
Taxes other than income taxes	9,838
Income taxes	12,362
Gains from disposition of utility plant	(10)
Total operating expenses	**129,471**
Operating income	25,328
Other income (expense):	
Allowance for other funds used during construction	2,200
Other income	5,087
Other expense	(2,300)
Income taxes applicable to other income and expense	(2,092)
Total other income	**2,895**
Interest charges:	
Long-term debt	10,686
Amortization of debt premium, discount and expense	134
Other	35
Allowance for borrowed funds used during construction	(2,989)
Net interest charges	7,866
Income before extraordinary items	20,357
Extraordinary items net of related income taxes	(702)
Net income	19,665
Preferred stock dividend requirement	950
Earnings for common stock	18,705
Average common shares outstanding	68,650
Earnings per common share	0.27
Earnings per common share – assuming dilution	0.26

Statement of cash flows for the year ended December 31, 200x	Amount ($000)
Operating activities:	
Net income (applicable to common stock)	$ 18,705
Adjustments to reconcile net income to net cash provided by operating activities:	
Depreciation and amortization	10,911
Deferred income taxes	5,612
Amortization of investment tax credits	(967)
Amortization of debt premium, discount and expense, and gains or loss on acquisition	1,101
Allowance for equity funds used during construction	(2,200)
Other noncash items	(799)
Changes in current assets and current liabilities:	
Accounts receivable, including unbilled	12,500
Inventories	570
Accounts payable	(1,525)
Customer deposits	700
Accrued taxes	150
Other assets	(200)
Other liabilities	(550)
Net cash provided by operating activities	44,008
Financing activities:	
Common stock issued	5,000
Long-term debt issued	110,000
Long-term debt retired	(90,050)
Debt issuance costs	100
Notes payable	(19,050)
Dividends on common stock	(5,000)
Dividends on preferred stock	(950)
Other financing activities	(600)
Net cash used in financing activities	(550)
Investing activities:	
Capital expenditures (less allowance for equity funds used during construction)	50,600
Net proceeds from sales of other non-utility assets	125
Other investing activities	625
Net cash used in investing activities	(49,850)
Net decrease in cash and cash equivalents:	**(5,425)**
Cash and cash equivalents at beginning of year	13,282
Cash and cash equivalents at end of year	$ 7,857

Statement of capitalization and common shareholders' equity for the year ended December 31, 200x	Amount ($000)
Common shareholders' equity:	
Common stock, $.01 Par value	
120,000,000 Shares authorized, 68,650,890 shares issued paid-in capital	$687
Paid-in capital	87,546
Retained earnings	43,218
Accumulated other comprehensive income	10
Total common shareholders' equity	131,461
Preferred stocks, which are redeemable	
Solely at option of issuer:	
Cumulative preferred stock, without par value, 1,000,000 shares authorized, issued, and outstanding: $3.75 Series, 250,000 shares	9,375
$3.35 Series, 250,000 shares	8,370
$3.05 Series, 250,000 shares	7,625
$1.86 Series, 250,000 shares	4,650
Total preferred stock	30,020
Long term debt:	
First mortgage bonds:	
6.90% Series due October 1, 2006	5,000
7.45% Series due January 1, 2007	10,000
6.64% Series due July 1, 2011	15,000
5.17% Series due October 1, 2014	17,000
6.95% Series due April 1, 2024	25,000
6.15% Series due January 1, 2026	35,000
7.50% Series due July 1, 2030	45,000
Total first mortgage bonds	152,000
Other long-term debt	661
Total long-term debt	152,661
Total capitalization	$ 314,142

IV. Utility finance

Historically, utility plant construction expenditures have been substantial and have been financed largely from external sources. During periods of heavy expenditures for construction, bank loans or commercial paper were used for interim financing, and bonds, debentures, and preferred and common stocks were the principal external source for long-term financing. Utilities have also employed leasing and other nontraditional forms of financing to some extent.

Since the early 1980s, construction activities have sharply declined (due to completion of large construction projects begun in the 1970s and because of declining load growth, producing adequate, sometimes excessive, existing plant capability). With the decline in the need for construction funds, internally generated funds have become available for other uses, and many utilities have embarked on an investment-diversification policy, investing substantial amounts of capital in nonutility companies, particularly energy trading and marketing and nonutility generation plants.

Long-term securities are marketed by competitive bidding, negotiation with underwriters, private placement, and subscription offerings to stockholders; competitive bidding is most common for bonds. Utility bonds are purchased principally by institutional investors such as pension funds and insurance companies. Substantial amounts of preferred stock have been purchased by large life insurance companies; the dividends-received credit has made preferred stocks attractive at yields almost as low as bonds. Utility common stocks are owned by many investment trusts and other institutions, but there are also millions of individual investors.

Bonds are generally offered with interest rates in multiples of 1/8 percent and ordinarily at a price between 98 and 102 (although a number of regulatory commissions or bond indentures prevent prices below par).

Bond ratings

Bonds are rated for investment merit by Moody's Investor Service, Standard & Poor's Corporation, Fitch IBCA, Duff & Phelps, and others; the ratings in many instances constitute the standard by which bonds are acquired. Bond ratings are based on many tangible and intangible elements, including debt ratio, interest coverage, consistency and stability of earnings, size of company, growth trends, character of territory, management, and attitude of regulatory commissions. Moody's debt ratings are, in descending order, Aaa-Aa-A-Baa, etc.; the other agencies use similar symbols.

Capitalization ratios

Utilities rely more on investment-grade, debt financing than do most other businesses. This is possible because of the use of mortgage bonds and a large plant investment (bond base), and relative stability in earnings. In recent years, the ratio of debt to total capitalization of investor-owned electric companies has averaged approximately 49 percent. The average debt ratio for gas distribution companies and pipelines is nearer 44 percent.

Bond terms and covenants

Most electric and gas company debt issues are first mortgage bonds on which interest is paid semiannually. Electric mortgage bonds most often are issued for 30 years. Bonds generally may be called for redemption on short notice, except that refunding may be restricted for a period of years. The call price reduces gradually to par over the life of the issue.

First mortgage bonds of electric and gas distribution companies sometimes have a sinking-fund requirement of perhaps 1 to 1 1/2 percent annually of maximum outstanding bonds; generally it may be satisfied by cash, delivery of bonds, or, for electric companies, certification of bondable property additions.

Most mortgages are open-end; additional bonds may be issued as property is constructed (as long as bondable additions are available in excess of those necessary to satisfy sinking-fund or maintenance requirements). The new issue may amount to 60 percent, or sometimes more, of available bondable property. New bond issues must generally satisfy a requirement that bond interest, including the new issue, shall be covered by income (either before or after income taxes) by not less than a 2 to 1 ratio.

Bond indentures frequently include protective covenants. Clauses restricting the availability of retained earnings for dividends are common. Another clause in many mortgages is a requirement that maintenance plus either replacements or depreciation shall equal some minimum, commonly a percentage (frequently 15 percent) of gross revenues or a percentage of gross plant.

Preferred stocks

Preferred shares usually have a par value of $100, although some have a smaller par. They pay a fixed-or variable-rate dividend, generally quarterly, and in most instances are cumulative. They may or may not have regular voting privileges, but usually have special voting rights, such as the right to elect a minimum majority of the directors in the event of dividend default for a year.

Frequently, preferred stockholders are accorded other protection, such as restrictions on common dividends if common equity falls below a stated percentage of capitalization. Generally, additional preferred stock may not be issued unless certain charter provisions are met (e.g., combined interest and preferred dividends are earned at least 1 to 1 1/2 times). Many of the present restrictions stem in part from the numerous dividend arrearages and defaults in the 1930s.

Preferred stocks are almost always callable. Call prices on most present issues are set on a basis somewhat similar to that for bonds. Preferreds do not have a maturity date, but many have sinking fund provisions that bring about their retirement over a period of years.

Dividend policy

Common stock dividends of utilities have traditionally been very high; often representing dividend payout ratios of 70 to 90% of net income. Policy varies considerably between companies and several utilities have reduced dividend payout ratios in order to retain cash for construction or investment needs.

Because of differences between tax and book, earnings, many utility dividends in the past have been partly nontaxable. After retained earnings for tax purposes are exhausted by dividends, any excess of dividends over income on the tax basis is a return of capital to the investor for tax purposes. This condition existed in several of the larger electric companies during the 1970s and early 1980s when earnings, exclusive of AFUDC provisions, were depressed. With improved earning levels in recent years, it has largely disappeared.

With the transition to competition during the 1 990s, many utilities lowered the dividend payouts and funnel earnings into the competitive growth businesses. This trend could reverse with the transformation, during the year 2000, by "energy" companies back to being traditional regulated utilities as a result of the California energy crisis, the marketplace collapse for energy trading, and the 2003 favorable federal income tax legislation for dividends.

Appendices

Glossary

Acquisition adjustment. The difference between the fair value of an acquired **operating unit or system** and the depreciated original cost of the acquired property. (Note: Any existing **contributions in aid of construction** are also carried with the property transfer and reinstated by the new owner, thus affecting the amount of recorded acquisition adjustment.)

Average load. The total production for the period divided by the hours in the period.

Capital-intensive. A term used to designate a condition in which a relatively large dollar investment is required to produce a dollar of revenue. The electric industry, for example, has an investment of about $2.60 for each dollar of revenue generated annually.

Contributions in aid of construction. Nonrefundable donations or contributions in cash or properties from individuals, governmental agencies, or others for construction or property-addition purposes.

Cost of capital. The composite rate of cost for debt interest, preferred stock dividends and common stockholder earnings requirements. It is the composite of the cost of the various capital sources used to provide the facilities used in supplying utility service.

Cost of service. The total cost of providing utility service to the system or to a group therein (the latter is commonly referred to as an allocated cost of service). The cost components include operating expenses, depreciation, taxes, and capital costs (determined by the **rate of return** adequate to service investment capital). Cost of service is synonymous with the **revenue requirements** of the system (or segment thereof).

Cycle billing. The process of reading a segment of the systems meters and billing that portion of the system's customers each day of a billing period. By the end of the cycle, the complete system is read and billed, and a new cycle begins. The customer reading on each day of the cycle will reflect the use for a full period so that the only customers up to date at the end of the accounting period are those read and billed as of the last day of the cycle. All other customers will have unread and unbilled consumption of from one to thirty days, assuming a one-month cycle. This produces an unbilled revenue at the end of each accounting period.

Deferred fuel costs. The amount of fuel costs applicable to service rendered in one accounting period that will not be reflected in billings to customers until a subsequent accounting period. Balance-sheet deferral may be required to match these costs properly with related revenue.

Embedded costs. Those costs that are in existence at any point in time, regardless of the date originally incurred, and that affect current operations on a continuing basis.

Extraordinary losses. The uniform system of accounts provide that, in normal circumstances, property retirements be made through the accumulated depreciation accounts without recognition of gains and losses. Where such retirements are unusual, unexpected, and "could not reasonably have been foreseen and provided for," losses normally result and are treated as extraordinary and set up in Account 182, Extraordinary Property Losses. The resultant charge to Account 182 is most often amortized over a five to ten-year period and is quite often allowed "above the line" for rate purposes as a means of allowing the full recovery of the investment originally committed to public service.

Fair market value. Generally the term applies to the amount that a willing buyer will pay a willing seller in an arm's-length transaction. Because of the predominant use of **original cost** in the **rate base** and the constraints that original-cost factors place on the rates that may be charged, the depreciated book cost of utility plant may be a prominent factor in establishing fair market value for a utility system.

Fair value. A term normally used in those jurisdictions that, by statute or regulatory precedent, allow the **rate base** to be expressed at a level other than the recorded **original cost** amounts. The most common measure of fair value is reflected in a composite of original cost and **trended original cost** factors. In practice the fair-value figure has often been closer to the original cost level than the trended original cost level.

Firm power. Power that is intended to have assured availability to the customer to meet all or any agreed-on portion of the customer's load requirements.

Heat rate. A measure of generating-station thermal efficiency, generally expressed as BTU per net kwh. is computed by dividing the total BTU content of fuel burned by the resulting net kwh generated.

Historic cost. The initial cost to the entity that holds the property. **Original cost** and historic cost are the same where property has not changed ownership. When utility property of an **operating unit or system** nature changes ownership, the original cost carries forward and is maintained by the new owner, although the purchase price (i.e., historic cost to the new owner) may be something different.

Interchange energy. Electric energy received from or delivered to another electric utility system under an interconnection or power pool agreement. Interchange energy may be settled in cash or by future exchange of energy.

Load factor. The average load of a customer, a group of customers, or the system, divided by the maximum load. For example, assuming 48 kwh of usage for the day, the average load is 48/24 or 2 kW. If the maximum capacity available is 4 kw, the load factor is 2/4= 50 percent.

Market-Based rates. Competition, beginning with PURPA and moving forward with the Energy Policy Act of 1992 and the implementation of FERC Orders 888, 889, and 2000, initiated price development for generation where no market power exists and buyers and sellers come together and the forces of supply and demand affect prices. For transmission, the transmission owner or operator lacks market power in transmission or has mitigated its transmission market power by using other suppliers.

Net operating income. The amount of revenues from utility operations that remains after the deduction of the operating and maintenance expenses, depreciation expenses, and taxes (income, property, etc.) attributable to the utility's operation. The revenues and expenses that are measured to produce net operating revenues are commonly referred to as "above-the-line" items. The revenues and expenses measured apart from net operating income are referred to as "below-the-line" items. The net-operating-income line on the income statement is the dividing point.

Net original cost. Original cost less accumulated depreciation.

Nonoperating items. Although sometimes used interchangeably with **nonutility items,** this term may more properly be used to describe items such as construction work-in-progress, which is not currently used in providing utility service. It has also been applied traditionally to financial items (e.g., interest expense).

Nonutility items. All items of revenue, expense, and investment not associated, either by direct assignment or by allocation, with providing service to the utility customer.

Operating unit or system. Although not clearly defined by the various uniform systems of accounts, this term generally relates to a complete and self-sustaining facility or to a group of facilities acquired and operated intact as a segment of a complete system.

Original cost. Cost of property to the entity that first developed it for public use.

Peak demand. The maximum level of operating requirements (i.e., production) placed on the system by customer usage during a specified period of time (e.g., instantaneous peak, 30 minute peak, one-hour peak, and one-day peak outputs are common points of reference). It may be measured by an operating segment of the company, such as a customer class, or for the entire company, depending on intended use of the data.

Rate base. The investor-owned plant facilities and other assets used in supplying utility service to the consumer. This investment base is the amount to which the **rate of return** is applied (i.e., Rate Base x Rate of Return = Net Operating Income).

Rate of return. The realized rate of return is the percentage factor obtained by dividing the **net operating income** from utility operations by the **rate base**. An adequate rate of return is the percentage factor that, when multiplied by the **rate base**, produces earnings that will meet the interest and equity requirements of the capital used to support the rate base. The measure of the adequacy of the rate-of-return factor is usually based on cost-of-capital measurements.

Replacement cost. An estimate of the cost to replace the existing facilities (either as currently structured or as redesigned to embrace new technology) with facilities that will perform the same functions. This method recognizes the benefits of presently available technology in replacing the system. For example, a number of small generating units may be replaced with a single large unit at lower unit costs and greater efficiency.

Reproduction cost. The estimated cost to reproduce existing properties in their current form and capability at current cost levels. The mechanics may involve a trending of the original cost dollars to reflect current costing factors, or they may involve a property appraisal accompanied by estimates of costs to reconstruct the facilities (the former is most often used).

Revenue requirements. The sum total of the revenues required to pay all operating and capital costs of providing service.

Test year. The 12 month operating period selected to evaluate the **cost of service** and the adequacy of the rates in effect or being sought. Frequently the term "test period" is used, and it may refer simply to the test year or expressly to the adjusted test year.

Trended original cost. The result of isolating original-cost plant additions by year of placement and factoring the original amounts upward to recognize subsequent changes in the cost of constructing plant facilities. The object is usually to restate installed cost of facilities at current levels.

Unbilled revenues. The amount of service rendered but not billed at the end of an accounting period. Cycle meter-reading practices result in unbilled consumption between the date of last meter reading and the end of the period. These amounts are typically estimated and recorded as "unbilled" revenues.

Utilization factor. The ratio of the maximum demand of a system to the installed capacity of the system.

Wheeling. An electric operation wherein transmission facilities of one system are used to transmit power of another system.

Working capital. Used broadly, the term refers to those rate-base allowances other than the utility plant in service and may include materials and supplies, fuels, etc. In the narrower use, commonly referred to as cash working capital, it relates to the investor-supplied funds necessary to meet operating expense or going-concern requirements of the business. There is normally a time lag between the point when service is rendered and the related operating costs are incurred and the point when revenues to recover such costs are received. The operating funds to bridge the lag are usually supplied by the investor and become a fixed commitment to the utility.

The 50 largest public and private electric and gas utilities
(Ranked by revenues at December 31, 2002)

Rank	Company Name	Revenues (000)
1	Duke Energy Corporation	$15,663
2	Exelon Corporation	14,955
3	American Electric Power	14,536
4	PG&E Corporation	12,495
5	FirstEnergy Corporation	12,247
6	El Paso Corporation	12,194
7	Cinergy Corporation	11,960
8	Reliant Resources, Inc.	11,558
9	Edison International	11,488
10	The Southern Company	10,549
11	Dominion Resources, Inc.	10,218
12	TXU Corporation	10,034
13	Xcel Energy Inc.	9,524
14	CMS Energy Corporation	8,687
15	The AES Corporation	8,632
16	Consolidated Edison, Inc.	8,482
17	Public Service Enterprise Group Inc.	8,390
18	FPL Group, Inc.	8,311
19	Entergy Corporation	8,305
20	Progress Energy Inc.	7,945
21	CenterPoint Energy, Inc.	7,922
22	Calpine Corporation	7,458
23	DTE Energy Company	6,749
24	Nisource Inc.	6,492
25	Mirant Corporation	6,436

Rank	Company Name	Revenues (000)
26	Sempra Energy	6,020
27	KeySpan Corporation	5,971
28	Williams Companies, Inc.	5,608
29	PPL Corporation	5,429
30	Northeast Utilities System	5,216
31	Constellation Energy Group	4,703
32	Pepco Holdings, Inc.	4,325
33	Energy East Corporation	4,009
34	Ameren Corporation	3,841
35	Wisconsin Energy Corporation	3,736
36	OGE Energy Corp.	3,024
37	Sierra Pacific Resources	2,992
38	Allegheny Energy, Inc.	2,988
39	SCANA Corporation	2,954
40	Edison Mission Energy	2,945
41	NSTAR	2,719
42	TECO Energy, Inc.	2,676
43	WPS Resources Corp.	2,675
44	Pinnacle West Capital	2,637
45	Alliant Energy Corporation	2,609
46	Puget Energy, Inc.	2,392
47	Aquila, Inc.	2,377
48	Salt River Project	2,214
49	New York Power Authority, Inc.	2,034
50	NorthWestern Corporation	1,992

Source: OneSource Information Services, 2003

Deloitte.

Center for Energy Solutions

About the Deloitte Center for Energy Solutions
The Deloitte Center for Energy Solutions provides a forum for innovation, thought leadership, groundbreaking research, and industry collaboration to help companies solve the most complex energy challenges.

Through the Center, Deloitte's Energy & Resources Group leads the debate on critical topics on the minds of executives—from the impact of legislative and regulatory policy, to operational efficiency, to sustainable and profitable growth. We provide comprehensive solutions through a global network of specialists and thought leaders.

With locations in Houston and Washington, D.C., the Deloitte Center for Energy Solutions offers interaction through seminars, roundtables and other forms of engagement, where established and growing companies can come together to learn, discuss and debate.

www.deloitte.com/energysolutions