1 Accounting for Public Utilities § 4.04

§ 4.04 Items Included in Rate Base

[1] Plant in Service

Plant in service is the most important component of a utility's rate base. This item commonly represents the substantial majority of the total rate base amount, after a deduction for related accumulated depreciation and amortization. The significance of plant in service is easily understood in light of the tremendous amount of capital invested in the construction of utility facilities. Major expenditures are required for land acquired for construction sites, construction material and supplies, operation of construction-related equipment, and construction-related labor activities. In addition, overhead allocations are required for those general expenses incurred which are, at least in part, due to utility construction (administrative payroll, engineering design, employee pension expense, sales tax, etc.). Furthermore, financing costs are generally capitalized as a component of plant cost during the construction period. In the case of electric power generation from nuclear fuels, the extensive costs of procurement, refinement, enrichment, and fabrication of the fuel are also capitalized as a separate component of the utility plant. Despite being the largest component of the rate base, utility plant is generally one of the less controversial areas in a rate proceeding. However, the prudency of expenditures or the usefulness of plant if large amounts of excess capacity exist is sometimes challenged. The amount expended during construction also may be challenged.

[2] Acquisition Adjustments

The general rule related to the acquisition of utility plant previously used in the utility function is that the rate base component for the plant includes only the original cost, net of accumulated depreciation, of the property to the first owner devoting the property to public service. Therefore, if a utility acquires major fixed assets (i.e., an operating unit or system) from another utility by purchase, merger, consolidation, liquidation, or otherwise at a price in excess of the seller's original cost (net of accumulated depreciation), the addition to the acquiring utility's rate base reflecting the acquired assets may be limited to the undepreciated original purchase price. If an amount paid for utility plant exceeds its original cost depreciated, and that amount is recoverable through future rates, the fair value of the plant has been increased and an acquisition adjustment should be recorded as a component of utility plant. With a business combination, if the excess payment is not included in future rates, that amount typically represents goodwill or an intangible asset rather than a plant acquisition adjustment.

The FERC's accounting policy staff issued 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 (Electric/Gas Plant Acquisition Adjustments) 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." In such situations the acquisition adjustment would be amortized to the income statement consistent with the recovery through rates and the goodwill would not be amortized." See *Chapter 11* for a detailed discussion of the Uniform System of Accounts, including discussion of recently proposed rules to update the Uniform System of Accounts to reflect rapid growth of renewable energy sources.

The necessity of this separate accounting treatment is largely a consequence of certain abuses in the utility industry during the acquisition and merger period of the 1920s and 1930s. (See *Chapter 2* for a detailed discussion.) Through the process of acquiring utility assets or entire utility companies at prices in excess of depreciated cost, purchasing utilities were able to write up their basis in plant assets. If these purchase prices were in excess of the "value" of the property, the utility was able to inflate its rate base artificially. This situation often occurred if the purchase was from an affiliated company under the ownership of a common utility holding company. By effectively trading properties, commonly owned utilities were able to inflate their rate bases through transactions that lacked any economic substance.

The outgrowth of this situation was a general consensus among regulators that utility customers should not pay on an amount in excess of the cost when property was originally devoted to public service, since any excess represented only a change in ownership without any increase in the service function to utility ratepayers. By accounting for acquisition adjustments separately from plant in service, these excess costs could be better controlled by regulatory authorities as to their ultimate disposition.

Two basic questions surround the ratemaking treatment referred to above of the various amounts included in the acquisition adjustments account:

(1) should any of the amounts be accorded rate base treatment; and

(2) should the amortization of any of these balances be considered in cost of service?

Rate base and cost of service treatment are often inconsistent when commissions deal with the acquisition adjustments issue.

Rate base treatment and/or cost of service treatment has been allowed by various regulatory commissions under a variety of circumstances. The reasons most commonly cited for allowing rate base and/or cost of service treatment of acquisition adjustments are as follows:

(1) when acquisitions represent an essential or desirable part of an integration of facilities program devoted to serving the public better;

(2) when acquisitions are clearly in the public interest, because operating efficiencies offset the excess price over net original cost; and

(3) when acquisitions are determined to involve arm's-length bargaining.

A substantial number of cases exist where rate base and/or cost of service treatment has been allowed as a result of satisfying one or more of the criteria listed above. For example, in 2010, the Colorado Public Utility Commission allowed both rate base and cost of service treatment for the acquisition adjustments related to Public Service Company of Colorado's (PSCo's) purchase of certain Calpine generating facilities where the acquisitions were deemed to be the least cost option for satisfying PSCo's resource needs.

In the 1955 case of *Arlington County v. Virginia Electric Power Co.,*[4] the Virginia Supreme Court of Appeals ruled that the Virginia State Corporation Commission had properly allowed both rate base and cost of service treatment for an amount paid at arm's-length bargaining in excess of original cost when first devoted to public use. When the Louisiana Public Service Commission allowed Louisiana Power and Light Company rate base and cost of service treatment for certain acquisition adjustments, the Louisiana Commission relied upon several of the criteria previously discussed. To quote from the Louisiana Commission's 1946 decision:

> "The owners of a public utility are entitled to earn and receive a fair rate of return upon the money prudently invested in property used and useful in rendering public service. Money is prudently invested, even though it is in excess of the original cost of the property purchased, if the excess of purchase price over original cost was paid as the result of arm's-length bargaining between nonassociated buyer and seller, if the excess was necessary for the integration of the property into a larger and more efficient system, and if the purchase necessitating the excess did or reasonably should have resulted in public benefit by improvement of service to customers or in lowered rates or both better service and lowered rates. This integration cost or excess of purchase price over original cost termed in prescribed system of accounts as 'Utility Plant Acquisition Adjustments' should remain a part of the prudent investment during the life of the physical property to which it was applied, and its extinguishment from the investment when and if required by the Commission, should be accomplished by amortization through annual charges to

[4] 196 Va 1102 (Va 1955).

> Operating Revenue Deductions during the life of the property remaining after the date of the purchase which created the excess."[5]

Although the FERC generally excludes acquisition adjustments from rate base treatment, it will permit the inclusion of these balances in the rate base for allocation purposes only (that is, allocating utility assets between jurisdictional and nonjurisdictional rate base) if the related state regulatory commission allows rate base treatment of the adjustments.

The FERC reiterated its position in excluding acquisition adjustments from rate base treatment in an order dated June 25, 1998.[6] In this case, Duke Energy requested rate base treatment of the acquisition adjustments resulting from its purchase of two California "reliability must-run" (RMR) generating facilities from Pacific Gas & Electric Company. The FERC summarily denied recovery of the acquisition adjustments indicating that the traditional criteria for recovery of acquisition adjustments do not apply in today's competitive energy marketplace. The FERC further indicated that Duke Energy's intent in purchasing the RMR generating facilities was to sell power in a competitive power market and, accordingly, Duke will have the opportunity to recover the acquisition adjustments through market-based rates when the facilities are not operating in a must-run status.

In another case, the FERC allowed an acquisition adjustment to be included in the distribution rate it allowed one utility to charge another when it found that there were material benefits to ratepayers. In this case, the acquisition adjustment was part of the cost of the Long Island Power Authority's (Authority) acquisition of the Long Island Lighting Company (LILCO). The Authority is a municipal subdivision of New York State that was created to acquire LILCO's securities and assets. The utility acquiring the power and challenging the inclusion of the adjustment acquisition in the distribution rate was Suffolk County Electrical Agency, a municipal power agency. The need for an adjustment was created because the Authority acquired nonproductive assets from LILCO, particularly the never-opened and very expensive Shoreham nuclear power plant. The FERC held that the acquisition adjustment was properly allocable to the Authority's distribution rate because almost the entire benefit of the Authority's acquisition of LILCO flowed to Long Island's retail customers and was related to the lower cost of financing for plant assets and debt.[7]

As a general rule, when acquisition adjustments are allowed in the rate base, amortization to cost of service is also allowed, and, if a return is not allowed, amortization is required below-the-line. Some regulatory commissions, however, have allowed inconsistent treatment principally as a means of sharing the costs associated with acquisition adjustments between investors and ratepayers. For example, the North Carolina Utilities Commission allowed Duke Power Company to amortize certain acquisition adjustment balances to cost of service but disallowed rate base treatment.[8]

On occasion, a utility may purchase used plant at a price lower than the net book value in the hands of the selling utility, thus creating a negative acquisition adjustment. These transactions are generally accounted for by a debit to plant in service for the net original cost with a credit to the acquisition adjustment account for the deficiency. In these cases, a similar question arises regarding the handling of the credit acquisition adjustments for ratemaking purposes. The regulatory commissions and courts have varied in their opinions as to the appropriate treatment of these balances and have not necessarily followed the same reasoning as followed regarding ratemaking treatment for debit adjustments. In general, credit balances are used to reduce the rate base and are also amortized above-the-line (as a reduction of operating expenses) with what appears to be greater frequency than corresponding treatment for debit adjustments. However, the FERC currently treats a negative acquisition adjustment as a credit to accumulated depreciation. Consistent reasoning regarding the treatment of debit and credit adjustments, however, does exist and is exemplified in a 1973 order of the Vermont Public Service Board in a rate proceeding involving Vermont Gas Systems, Incorporated:

---

[5] *Re* Louisiana Power and Light, 65 PUR (NS) 23 (La 1946).

[6] Dkt ER-98-2668-000.

[7] [102 FERC ¶ 63,037 (March 12, 2003)].

[8] *Re* Duke Power Co, 26 PUR4th 241 (NC 1978).

> " 'Original cost' relates to the cost incurred by the utility purchasing the facility, not the original cost of a prior owner. Assuming prudent investment, the stockholders should be allowed to earn a return on their actual 'out-of-pocket' investment; the fact that the marketplace may place a higher *or lower* valuation on the property does not affect the amount of the actual price paid by petitioner."[9] (Emphasis added.)

The basis for disallowing rate base treatment of acquisition adjustments is the assumption that the rate base should include only the net original cost to the utility first devoting the property to public use. In GAAP based financial statements the excess of fair value of acquired net assets over cost should be accounted for in accordance with ASC 805-30-10 and 11.

In cases where used property is purchased from nonutility sellers, there generally is no acquisition adjustment, since the property has not previously been utilized in providing utility services. In these cases, net original cost is the purchase price paid by the acquiring utility. However, we are aware of recent transactions in which the FERC staff required a purchaser to record the amount paid over net original cost as a plant acquisition adjustment. A question that has occasionally been raised concerns the purchase of used property from another utility (rate regulated enterprise) not involved in the same utility operation and therefore subject to a different scheme of regulation. While this issue has not been raised often, it appears that in most cases the general rule is interpreted broadly to encompass the first regulated enterprise of any type devoting plant to public service. A court case related to this matter involved the purchase of electric transmission lines by Montana Power Company from Chicago, Milwaukee, St. Paul & Pacific Railroad. In this 1979 case, the U.S. Court of Appeals ruled that the property had previously been devoted to public use by a regulated enterprise and that only the original cost to the original user should therefore be allowed in rate base.[10]

[3] Accumulated Depreciation and Amortization

Recovery of the dollars invested in plant in service is permitted over the plant's estimated useful life by a systematic depreciation charge to cost of service, normally on a straight-line basis with an equal portion of the original cost investment (net of estimated salvage less removal costs) recovered in each period over the estimated service life of the related fixed assets. The subject of utility depreciation accounting is examined in detail in *Chapter 6*.

Deduction of the reserves accumulated for annual depreciation and amortization charges from a utility's rate base is an accepted principle of rate base development, with the reserve balances generally calculated on the same basis as that used for determining rate base plant in service (13-month average, year-end, etc.). Theoretically, the accumulated reserves have already been collected from utility customers through the cost of service treatment for depreciation and the resulting revenue requirements generated. Deducting accumulated reserves from the rate base prohibits the utility from earning a further return on costs that have been recovered and also avoids the confusion of attempting to equate net plant in service (unamortized cost investment) with any measure of current "value" of the property. It does not matter if net plant in service is not an accurate measure of the property's current value (and it most likely is not). Accumulated depreciation in investment cost jurisdictions is not designed to force net plant to equal current value but instead is simply used to reduce the rate base for that portion of plant investment and net salvage already recouped through rates.

For regulatory jurisdictions following the fair value approach to rate base development, determination of the appropriate accumulated depreciation balance is the subject of considerable controversy, with the specific techniques employed varying widely among the different regulatory commissions. With this approach, accumulated depreciation is more closely associated with an attempt to measure the "current value" of utility plant, with a corresponding recognition of the value that has been "used" since the plant was placed in service. Examples of the methods employed for determining depreciation reserves under the fair value concept include:

(1) determining the fair value of gross plant and then attempting to calculate the necessary depreciation reserve to reflect the cumulative loss in value in current dollars; and

---

[9] *Re* Vermont Gas Sys, 100 PUR3d 209 (Vt 1973).

[10] *Montana Power Co v Federal Energy Regulatory Commn, 31 PUR4th 191 (9th Cir 1979)*.

(2) determining the fair value of gross plant and then calculating the related depreciation reserve by multiplying gross plant by the same percentage as the ratio of original cost accumulated depreciation to gross original cost plant.

Concepts for estimating fair value depreciation are discussed in more detail in *Chapter 6*.

Sometimes, depreciation reserves are determined to be either too small or too large, usually as a result of either the experience being different than what was expected or the modification of future expectations. In those cases where the reserves are found to be too small, the reserve difference is commonly the result of two possible factors. Earlier estimates of service lives may have been too long as a result of changing circumstances, such as current technological advances and/or changes in regulatory operating requirements, or increases in the current estimates of removal costs when the associated plant will be retired.

The ratemaking treatment of reserve differences varies from one regulatory commission to another, especially in cases where the differences are significant. Usually, the difference is recovered or credited through the use of "remaining life" depreciation rates, in which the total unrecovered investment and net salvage is depreciated over its estimated remaining life. Occasionally, for regulatory purposes, accumulated depreciation is adjusted upward to eliminate the deficiency, and the rate base is reduced for the entire accumulated reserve. When the accumulated reserve is adjusted, the debit side of the adjustment is either amortized to cost of service or eliminated against retained earnings. Amortization to cost of service is generally allowed where the utility can demonstrate that it was not negligent in failing to adjust depreciation rates at an earlier time, since the circumstances leading to the deficiency were largely unforeseen. In rare cases, commissions have not required rate base reduction for differences and still allowed amortization of the debit adjustment to cost of service. For instance, the New York Public Service Commission allowed such treatment to the Iroquois Gas Corporation in 1970 where it was determined that factors unforeseen to the utility resulted in shorter lives and sharp increases in negative salvage and that the utility would be unduly penalized "for encountering the vicissitudes of conducting a business enterprise."[11]

In those situations where the reserve is determined to be too high, the reserve difference usually results from an upward adjustment in current estimated service lives beyond the estimates previously utilized. Regulatory treatment of these reserve differences also vary among regulatory jurisdictions. Most commonly, the entire reserve is deducted from the rate base under the premise that any downward adjustment to the reserve will result in ratepayers paying again in the future for depreciation already recouped through previous cost of service deductions. Thus, adjustment of the reserve excess is generally prospective through revised future depreciation provisions with no penalty imposed for the excess past charges.

[4] Construction Work in Progress (CWIP)

Historically, CWIP was not included in the rate base under the theory that rate base treatment violates two interrelated principles of utility ratemaking—only property that is used and useful should earn a rate of return, and interperiod equity requires an allocation of costs (and the rates they generate) to those specific periods when the costs actually provide service to ratepayers. In other words, present customers should be required to pay only for construction costs directly incurred in providing their specific service.

When utilities are not allowed to earn a return to cover their construction financing costs during the construction period, they are allowed to capitalize the financing costs for future recovery through an allowance for funds used during construction (AFUDC). This capitalized cost, which is added to the basis of utility plant under construction, will ultimately be included in the rate base as a component of plant in service, thereby earning a return and being recovered through depreciation allowances. Although the actual mechanics of computing AFUDC may be challenged, there is little debate over the propriety of including AFUDC as a component of construction costs along with materials, labor, overhead, and the like. The actual mechanics of computing AFUDC are discussed in greater detail in *§ 4.04[5][b]*, below.

While rate base treatment of CWIP has historically been denied, inclusion in the rate base is often allowed where a significant amount of plant will be in service in the immediately foreseeable future, even in those cases

[11] *Re* Iroquois Gas Corp, 85 PUR3d 359 (NY 1970).

where a future test period is not employed. This is especially true if the plant is actually in service after the test period but before the rate order, or if the plant is anticipated to be in service in the near future and is expected to affect operations significantly. Often the inclusion of the post-test period CWIP in the rate base necessitates other rate case adjustments to reflect properly anticipated operating changes resulting from this new plant addition. Some of these operating changes that may require other rate case adjustments include the retirement of other utility plant, lower cost of service due to greater operating efficiency of new plant, changes in fuel cost mixtures, and changes in depreciation expense (usually higher due to new plant being costed at more current dollars). In addition to the above circumstances, commissions often allow CWIP in the rate base where the plant additions possess one or more of the following characteristics:

(1) Additions are basically minor replacements and therefore are neither revenue-producing nor expense-reducing assets.

(2) Additions do not affect the overall level of operations.

(3) Additions are specifically being made to improve the environment or improve the quality of utility service.

Further, a tendency developed in the late 1970s, primarily in the electric industry, to include portions of CWIP as a rate base component and to discontinue the capitalization of AFUDC. This trend largely resulted from conditions then faced by a substantial portion of this industry. Very long-term construction projects with high financing costs resulted in amounts of capitalized AFUDC that produced disproportionate contributions to reported net income. In some cases, AFUDC earnings actually exceeded reported net income. This AFUDC income did not supply cash funds for the payment of interest costs and dividends; therefore, utilities with extensive construction programs often found themselves in an extremely tight cash flow situation. This in turn led investors to discount AFUDC earnings, which in turn resulted in relatively higher costs associated with future financings—a product of the perceived higher risk. Recognition by some commissions of the second-class status being assigned to AFUDC earnings is exemplified in this quotation from the New Jersey Board of Public Utilities:

> "The investment community is no longer enamoured with AFUDC earnings. They have been discounted. Investors look to the quality of earnings in real dollars and see through more nonconservative accounting principles. Replacing AFUDC earnings with real earnings is the most significant step this Board can take to increase investor confidence in this utility so that debt and equity can be sold at reasonable levels."[12]

When consideration is given to the time value of money (with all other matters held constant), either the inclusion of CWIP in the rate base or the accrual of AFUDC results in the same overall charges to ratepayers. Because of the lower capitalized costs, the inclusion of CWIP in the rate base actually reduces the total cost to the utility and its customers over the life of the plant. In addition, increased cash flows associated with CWIP in the rate base avoids a certain amount of outside financing, which is advantageous whenever incremental borrowing costs exceed embedded costs. Further, the improved quality of actual cash earnings may allow required financings at relatively lower costs. Because of these factors, many now believe that ratepayers are better off financing construction costs currently (with the resulting increased service rates) rather than paying for even higher financing costs over the service lives of the assets.

In addition, many advocates of CWIP in the rate base are challenging the validity of the used and useful and interperiod equity arguments. They contend that the used and useful concept fails to address the realities of the economic environment in which utilities presently operate, because funds invested in CWIP represent an investment necessary to provide continuing service and CWIP is therefore currently used and useful. They believe that CWIP investment is no different from material and supplies, prepayments, and PHFU, all of which are allowed in the rate base by the majority of the regulatory commissions. As for the interperiod equity argument, CWIP advocates believe that the economic environment in which utilities operate negates the protective intent of a principle developed in an entirely different technological and economic era. In other words, the premise that present customers should pay only for costs incurred in providing their direct service while recognition of costs benefiting future customers should be deferred is no longer viable in the case of modern utility operations.

---

[12] *Re* Public Serv Elec and Gas, Docket No 744-335 (NJ 1975).

This change in economic conditions from the time when the "used and useful" and AFUDC concepts were first adopted is highlighted by a brief review of the economic developments of the electric industry. During its development stage, the industry was building new plants and facilities to provide the convenience of electricity to a larger proportion of the U.S. population. In its adolescent years, the electric industry continued to build additional capacity to provide energy for industrial development.

In the early 1950s, the electric industry reached maturity. That is, low-cost electric energy generally was available to the entire population of the United States. For the next 15 to 20 years, the industry continued to build largely to meet the increasing demands of current customers and the increasing size of the U.S. population.

Throughout this period of development, the industry was able to construct new facilities that had a lower cost per kilowatt than the facilities then in service. This was largely a consequence of economies of scale, few environmental restrictions, and relatively low capital costs. These conditions provided regulators with a basis for deferring the financing costs of new construction for ratemaking purposes through the AFUDC mechanism. They recognized that the power generated and delivered through these new facilities would be cheaper than power generated by existing plants upon which current customer rates were based. Therefore, to balance the interest of present customers with those of future customers, a case could be made for deferring the financing costs of new construction. Even though the deferral of financing costs was contrary to generally accepted accounting doctrine for industry in general at the time, the accounting profession accepted this treatment for the utility industry, since such deferral accounting was the basis for establishing rates and a matching of revenues and expenses would be achieved. The investment community accepted the deferral treatment, because the electric industry was healthy. That is, more efficient plants were being built, construction periods were relatively short, and the industry had sufficient cash flow to meet its capital cost requirements until the new plants went into service.

The electric industry has experienced significant changes in economic conditions affecting the costs of delivering energy. While the costs of new facilities were historically less per kilowatt than existing facilities on a routine basis, the current economic trend is not as clear. In certain situations, the cost of new facilities may exceed the costs of existing facilities due to the impact of new environmental requirements, the cumulative impact of inflation, or other reasons. In other situations, new facilities may result in a lower cost than existing facilities due to benefits associated with enhanced efficiency or utilization of a lower cost fuel source or renewable technologies.

As a result of these changed conditions, today's customers are using the economic value of facilities that will cost a great deal more to replace per unit of capacity.

The decision by some regulators to allow CWIP in rate base, in whole or in part, is thus based on a broader understanding of the "used and useful" concept and on a recognition that different conditions exist today than when the "used and useful" position was employed by regulators to balance the interests of current and future ratepayers.

A quotation from the Florida Public Service Commission is a good example of the philosophy adopted by some regulatory bodies currently allowing CWIP in rate base:

> "The electric utilities in this state are currently undertaking massive construction programs. Included in these programs are additional nuclear generating facilities, which require construction lead times in the area of ten years. It is common knowledge that one electric utility in the state has had to delay the completion of a large nuclear facility due to cash-flow problems. This type of delay is very costly due to the fact that substantial amounts of carrying costs (AFDC) are being added to the cost of the facility, even though physical construction has slowed to a minimal pace."
>
> "Faced with the problems of extremely long lead times in the construction of nuclear units, and the possibility that huge sums of money would be tied up in construction from which there would be no cash flow whatsoever, we are aware that many utilities are canceling plans for nuclear units. This is taking place irrespective of engineering economics, since the utilities are going to fossil units in an effort to obtain as much capacity for their dollars as possible. In such cases, it is obvious that the fuel cost savings associated with nuclear fuel will not be achieved."

> "After considering these factors, as well as the fact that the inclusion of CWIP in rate base with a concurrent cessation of AFDC charges cannot produce a double return to the company, we conclude that the company's proposal should be accepted. An increase in the amount of internally generated funds will enable the company to reduce the amount of external financing that would otherwise be required, thereby alleviating to some extent the debt coverage problem that the utilities are currently encountering. We would also expect that the adoption of such regulatory philosophy would enable utilities to reconsider the feasibility of constructing additional nuclear generating facilities if the engineering economics should dictate such a decision. Therefore, in an effort to improve the quality of the earnings of the company, we are accepting its proposal to include an additional $200 million of CWIP, in the rate base, on which no AFDC will be capitalized in the future and find the same to be reasonable and proper, and in the public interest."[13]

Other commissions, while still adhering to the general policy of excluding CWIP from the rate base, have allowed rate base treatment for certain portions of CWIP as a means of aiding a particular utility's general cash flow situation or as a means of alleviating cash flow problems associated with a particular construction project. An example of this philosophy toward CWIP in the rate base is the present FERC policy for the electric industry. The FERC currently follows Order No. 474-B, which permits electric utilities generally to include up to 50 percent of their FERC jurisdictional CWIP in rate base. Order No. 474-B also allows rate base treatment of CWIP related to the construction of pollution control facilities or the conversion of existing plants to conserve oil and natural gas, without reference to the 50-percent limitation. (Rate base treatment here is justified as being consistent with national goals.)

The inclusion of CWIP in the rate base requires the discontinuance of AFUDC capitalization at the appropriate time in order to avoid a double return on plant investment. Once CWIP is in the rate base and actually earning a return designed to cover construction-related financing costs, to continue AFUDC capitalization (which would later earn a return and be depreciated to cost of service) results in consumers paying twice for the same capital costs. The various commissions allowing CWIP in the rate base have generally developed accounting procedures designed to cut off AFUDC at the appropriate time (when rates based on including CWIP in the rate base become effective), thereby avoiding a double return problem.

On the other hand, some commissions have effectively allowed a partial return on CWIP investment through a procedure whereby CWIP is allowed in the rate base, while the capitalization of AFUDC continues with the AFUDC earnings included above-the-line in operating income. To the extent that the overall allowed return exceeds the AFUDC capitalization rate, the utility is currently earning a return on a portion of its construction investment.

In May 1983, the FERC issued Order No. 298.[14] This order provided for CWIP rate base treatment of pollution control and fuel conversion facilities and also allowed inclusion in rate base for not more than 50 percent of all remaining CWIP applicable to the wholesale rate base. Order No. 298 limited the effect of the rate increase associated with CWIP in rate base to no more than 6 percent in the first year and an additional 6 percent in the second year. A utility filing for CWIP in rate base was required to show that wholesale customers would not be charged for both capitalized AFUDC and a return on CWIP in rate base. If CWIP fell below the amount included in rate base, a utility was required to record negative AFUDC. Subsequently, the Commission also issued Order No. 298A[15] that includes a provision to permit wholesale customers to escape rates associated with CWIP in rate base if they prove that they bear no responsibility for the decision to build a new plant and will, in fact, not purchase full or partial requirements which involve the plant.

In September 1985, the Court of Appeals for the District of Columbia Circuit remanded these orders to the Commission for reconsideration.[16] The court found that the Commission's consideration of the potential "price squeeze" and "double whammy" effects of the rule was inconsistent and inadequate.

---

[13] *Re Florida Power and Light, 9 PUR4th 156 (Fla 1975)*.

[14] Dkt No RM81-38 (May 16, 1983), effective July 1, 1983.

[15] Dkt Nos RM81-38-001 and RM83-38-012 (Oct 4, 1983).

[16] *Mid-Tex Elec Coop, Inc, et al v FERC, 773 F2d 327 (1985)*.

"Price squeeze" is alleged to occur when a utility's rates for wholesale service are higher in relation to the costs of providing the wholesale service than are the utility's rates for retail service in relation to the costs of providing retail service. This disparity of utility rules theoretically may result in an inability of the wholesale customer to compete with the utility for retail customers. Because retail rates are set by state commissions, price squeeze may be caused by the ratemaking policy differences between state commissions and the FERC.

"Double whammy" is alleged to arise when a wholesale customer is constructing its own generation facilities in order to supply itself with all or part of its future power requirements but, in the interim, must pay rates to the utility supplying its current needs that are based on certain CWIP in rate base.

In February 1986, the FERC issued Order No. 448,[17] which sets forth interim regulations reinstating its previous policy with certain modifications concerning the inclusion of CWIP in rate base.

In June 1987, the FERC issued a final rule regarding the inclusion of CWIP in rate base.[18] Order No. 474 addresses the concerns raised by the U.S. Appeals Court about possible anticompetitive implications. The provisions of this rule are substantially different from those presented in Order No. 298, but are similar to those put into effect on an interim basis in Order No. 448, with certain modifications intended to more thoroughly address the U.S. Appeals Court decision.

In October 1989, the FERC issued a modified CWIP order[19] in response to the U.S. Circuit Court of Appeals for the District of Columbia ruling that vacated part of the FERC's Order No. 474.

In April 1990, the FERC issued Opinion No. 284-A in which it clarified certain price squeeze policies adopted in Opinion No. 284.

The trend toward increased rate base treatment of CWIP was influenced by the high cost of new plant investment, which produced more conditions in which rates had to be increased dramatically (rate shock) at the time that the plants went into service. It is hoped that acknowledgment of these conditions will continue to foster gradual recognition of construction financing costs during the construction period of the facility, as opposed to deferral of all costs to the future.

A step in this direction is the allowance of CWIP in rate base during the construction period of the plant and then, after the plant goes into service, capitalization of the return on the investment in plant for an arbitrary period of two to five years. This capitalization is limited to an amount equal to the AFUDC that would have been capitalized during the construction period. After the capitalization period (phase-in), the capitalized returns are recovered over the remaining life of the plant. An alternative to this approach is the application of "mirror-CWIP," which allows certain CWIP in rate base and the continued capitalization of AFUDC with the associated income being deferred. Following construction of the plant, the AFUDC deferrals are amortized on an accelerated basis in order to lower the cost of service impact of the new plant.

By having increased rates (thereby sending early price signals to consumers) because of the inclusion of CWIP in rate base and by reversing that procedure in the early commercial life of the plant, a significant part of the peak in rates associated with new plants is smoothed out. This procedure was used a number of times in the 1980s and 1990s with respect to nuclear power plant construction and more recently with respect to certain significant new transmission line construction. In GAAP based financial statements "mirror-CWIP" should be accounted for in accordance with ASC 980-340-55-4 through 8.

[5] Allowance for Funds Used During Construction (AFUDC)

As discussed in the previous section, so long as CWIP is not included in the rate base, capitalization of the cost of funds during construction is proper. In January 1968, the FERC issued Accounting Release Number AR-5 (Revised). In AR-5, the FERC states that the proper period for capitalization of interest during construction begins with the date that construction costs are continuously incurred on a planned progressive basis. Capitalization of interest stops when the facilities have been tested and are placed in, or

---

[17] Dkt No RM86-6 (Feb 27, 1986).

[18] Order No 474, Dkt No RM86-6-000 (June 18, 1987).

[19] Order No. 474-B, Dkt No RM86-6, *modified by* Order No 626, Dkt No RM02-9-000.

are ready for, service. A company should cease the capitalization of interest for portions of construction projects completed and put into service although the entire project is not yet fully completed. The FERC further states that no interest should be accrued during a period of interrupted construction unless the company can justify the interruption as being reasonable under the circumstances.

The practice of capitalizing construction period carrying charges accomplishes a number of general objectives:

(1) The total costs of construction activities, including financing costs, are fully recognized.

(2) The utility operation is effectively shielded from costs associated with construction activities.

(3) The utility, by capitalizing the financing costs, is afforded an opportunity to recover the costs when the plant is placed in service.

Although the concept of AFUDC has long been recognized and followed in the utility industry, many aspects of AFUDC have been a source of vexation for both regulators and utilities. The controversy surrounding the computation of AFUDC and the proper treatment for ratemaking and financial reporting purposes has received considerable attention. This is especially true when conditions produce a surge in both financing costs and construction expenditures and the resulting increase in the amount of AFUDC, to a point where the effect of these non-cash “earnings” on financial statements is substantial.

[a] Two Components of AFUDC “Earnings”

The financing required for plant construction comes from external sources (such as bank loans, long-term debt, and preferred and common stock sales) and from internal sources (such as earnings retained by the utility). Over a given period, financing may come from any one or all of these categories. Bank loans, debt, 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 premiums, discounts, and costs of issuance.

Common equity funds (common stock and retained earnings), however, have no such convenient reference point, and, while these funds obviously do have an economic cost, the difficulties inherent in measuring their cost create considerable controversy. (See *Chapter 9* for a detailed discussion.) In addition, the AFUDC income credit related to the use of either preferred stock or common equity has the appearance of creating income, since the costs related to these capital components are not reflected in the income statement—the income credit has no counterbalancing expense to offset its effect. In contrast, debt financing involves interest costs which are shown as an expense and offset by the debt portion of the AFUDC credit, with no net effect being seen in net income. Under GAAP, it is appropriate to recognize the equity portion of the AFUDC credit in the income statement to recognize that the regulator is providing for the costs of preferred and common equity used in construction, as long as the recovery in future rates of the capitalized AFUDC is probable.

[b] Mechanics of Computation

The mechanics of computing AFUDC may vary significantly among regulatory jurisdictions and even among individual utilities within the same jurisdiction. These variations sometimes involve the methods used in determining the AFUDC capitalization (accrual) rate and in many cases involve the specific capitalization policies followed by the individual utilities. For instance, capitalization policies commonly vary as to the dollar limits and length of construction periods required before AFUDC is capitalized and also differ in the mechanics of actual capitalization (simple annual interest, interest compounded monthly, semiannually, etc.). Regulatory commissions generally must approve the specific AFUDC accrual rates and capitalization policies and also require prior approval before utilities implement any changes that have the potential to alter significantly the amount of AFUDC capitalized.

By developing a standard method for determining the maximum allowable accrual rate, the FERC has lent a certain degree of uniformity to the AFUDC capitalization process. The formula, which the FERC provided for in its Order No. 561, is as follows (see *§ 4.05*, below) for the actual wording of the formula and the accompanying instructions under FERC Uniform System of Accounts for Class A and B Electric Utilities):

A_i	=	s(S/W) + d(D/D + P + C) (1 − S/W)
A_e	=	[1 − S/W] [p(P/D + P + C) + c(C/D + P + C)]
A_i	=	gross allowance for borrowed funds used during construction rate
A_e	=	allowance for other funds used during construction rate
S	=	average short-term debt
s	=	short-term debt interest rate
D	=	long-term debt
d	=	long-term debt interest rate
P	=	preferred stock
p	=	preferred stock cost rate
C	=	common equity
c	=	common equity cost rate
W	=	average balance in CWIP plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication

FERC Order No. 561 (and the FERC Uniform System of Accounts) expands upon the mechanics of applying the formula with the following additional instructions:

(1) Balances for long-term debt, preferred stock, and common equity shall be actual book balances as of the end of the prior year.

(2) Cost rates for long-term debt and preferred stock shall be weighted average cost.

(3) The cost rate for common equity shall be the rate granted on common equity in the last rate proceeding before the ratemaking body having primary rate jurisdiction. If such cost is not available, the average rate actually earned in the preceding three years shall be used.

(4) Short-term debt balances, short-term debt costs, and average CWIP shall be estimated for the current year and adjusted as actual data become available. No adjustment is necessary if the actual cost rate does not exceed the estimated rate by more than a fourth of one percent.

(5) Rates under the formula shall be determined annually and reported to the FERC.

A brief analysis of the FERC formula and its instructions reveals several important points. First, the formula assumes that a utility's short-term debt is the first source of funds used for financing construction. The remainder of the construction is assumed to be financed out of long-term debt, preferred stock, and common stock equity on the basis of these funds as they existed at the end of the prior year. Second, the formula provides for a precise segregation of AFUDC into its two component parts—borrowed funds and equity funds. For financial reporting purposes, the borrowed funds (debt) portion is commonly treated as a negative component of interest expense and located in the interest charges section of the income statement. The other funds portion (common equity and preferred stock) is treated as non-operating income and located in the other income and deductions section of the income statement.

In response to a request filed with FERC by EEI, AGA, and INGAA, on June 30, 2020 FERC granted a 12-month waiver request to modify the Short-term debt component of the FERC's prescribed AFUDC calculation. This allowed companies to use a simple average of prior year short-term debt balances in the calculation of the short-term debt component of AFUDC, instead of the current short-term debt balances required by the rules, while leaving all other aspects of the AFUDC rate formula unchanged (including current period short-term debt cost rates). This also allowed companies to obtain the needed liquidity to respond to the COVID 19 pandemic without an unduly adverse impact on its AFUDC rate. This waiver was available to all jurisdictional entities subject to the FERC's accounting regulations for the period March 1, 2020 through February 28, 2021. On February 23, 2021, FERC issued an order extending its June 2020 AFUDC rate waiver for an additional seven months. The extension allows companies the option to modify their AFUDC rate calculation through September 30, 2021, to mitigate the impact of short-term debt issued during the COVID-19 pandemic. The extension allows continued use of this methodology for up to an additional seven months. On September 21, 2021, FERC approved to extend the currently approved waiver through March 31, 2022.

Before the Tax Reform Act of 1986 and the accompanying changes in the tax deductibility of CWIP-related interest, three basic alternatives were commonly utilized for recognizing the income tax effects of capitalized debt costs. The first two methods described below provided for the normalization of the benefits of deferred taxes, while the third approach provided for a direct flow-through of the tax benefits to the utility ratepayers.

(1) *Gross rate with normalization*. Under this alternative, the utility employed the gross rate during the computation of the debt portion of AFUDC and then provided deferred taxes on the book/tax timing difference resulting from the AFUDC credit by charging deferred income tax expense on the income statement (above-the-line) and crediting accumulated deferred income taxes on the balance sheet.

(2) *Net rate with tax allocation*. With this method, the utility initially computed a net of tax AFUDC accrual rate for use in the capitalization calculations. In this case, it was necessary to allocate properly the income tax benefit associated with AFUDC below-the-line. The net effect of this approach is similar to the gross rate approach except that the tax effect related to AFUDC is netted against the property accounts on the balance sheet. With the adoption of ASC 740, the net-of-tax approach is no longer permitted in GAAP based financial statements.

(3) *Gross rate with flow-through*. In this case, the utility used a gross accrual rate for the computation of the debt portion of AFUDC, and tax benefits were flowed through currently.

Failure to properly consider and classify the tax effects of the borrowed funds portion of AFUDC has been a major problem in accounting for capitalized financing costs. It must be remembered that the purpose of capitalizing AFUDC is not only to record the total costs of construction accurately but also to shield the utility operations (above-the-line) from the impact of these costs. In order to isolate utility operations successfully, all items related to construction must be segregated, so that utility operations can be reported as though the construction activities do not exist.

Many utilities and regulators have not been completely successful in isolating the costs of operations from the costs of construction, since they have failed to allocate properly the income tax savings from AFUDC that arise from construction activities. A failure to understand the implications of these book/tax timing differences may result in the recording of tax savings in a manner that reduces the taxes on operating income and thus affects the rate of return reported on utility operations. The income tax implications of AFUDC accounting are dealt with in greater detail in *Chapter 17*.

A special situation arises in cases where restricted-use debt is issued by a utility to finance the construction of facilities that are generally non-income-producing and are often associated with environmental requirements (e.g., industrial development bonds and pollution control bonds). Three characteristics distinguish these financings from capital traditionally raised by a utility to finance its construction:

(1) Use of the funds borrowed is restricted to the costs of the specific project, and any excess proceeds from the debt issuance are used to satisfy the related debt service requirements.

(2) Interest paid on the borrowings is tax exempt, which generally allows the utility to borrow the funds at a lower cost than the current rate for long-term debt.

(3) The proceeds of the borrowings are held in trust or special funds until needed, and unexpended funds are invested to earn interest income.

The central issue arising when restricted-use debt is issued is how to account for the interest earned on the unexpended funds because it affects the capitalization of AFUDC. A variety of approaches were being followed, including:

(1) reflecting the earnings in the calculation of the AFUDC rate;

(2) crediting the earnings against the CWIP financed by the restricted-use debt;

(3) lowering the cost of the long-term debt in the capital structure to reflect a “net” interest expense (i.e., the rate of return is affected, but not AFUDC); and

(4) recognizing the earnings currently in the income statement.

As a result of the divergent practices, the FERC, in 1983, issued Accounting Release AR-13 to provide for consistent treatment. Generally, AR-13 requires that restricted-use debt be included with other debt and that the average balance of the unexpended funds held in trust (or other special funds) be included in the computation of average CWIP when calculating AFUDC rates. Also, AFUDC should be capitalized on a CWIP balance that includes the unused funds balance. All earnings on the unused funds during construction are then credited to the cost of constructing the related facilities. (See *§ 4.06*, below, for the complete text of Accounting Release AR-13.)

[6] Plant Held for Future Use (PHFU)

As distinguished from CWIP, PHFU either represents plant acquired and basically ready for use in the utility function under a definite plan or land and land rights owned and held for future use. With the exception of land and land rights, PHFU is similar to the category of fixed assets known as “completed construction not classified,” and no AFUDC is normally capitalized on PHFU. For this reason, assets falling in the PHFU category are generally segregated and accounted for separately. For instance, the FERC requires electric utilities to account for these assets in Account 105—Electric Plant Held for Future Use.

Considerable disagreement exists over the proper treatment of PHFU for ratemaking purposes. On one hand, it appears appropriate to include PHFU in the rate base and to permit the utility to earn a return on property that has been prudently acquired and set aside for future operations (particularly since AFUDC is normally not allowed). On the other hand, ratepayers do not relish the idea of paying the carrying costs for assets that are not presently providing any service. The most common argument offered by commissions rejecting rate base treatment for PHFU is that only plant presently used and useful in providing service should be allowed in the rate base.

A number of regulatory commissions have, however, from time to time allowed portions of PHFU in the rate base for a variety of reasons. The two general criteria for allowing rate base treatment are the following:

(1) *Imminent use*. The utility is able to demonstrate that certain PHFU will be used and useful within a short period of time.

(2) *Definite plan for use*. The utility is able to demonstrate that the purchase of certain PHFU is associated with a definite plan for use in the foreseeable future and will result in benefits to ratepayers.

The “imminent use” criterion is most clearly demonstrated where the subject PHFU is actually in service before the rate order or will be in the immediate future. On the other hand, the “definite plan for use” criterion is usually more difficult to prove, since the time frame generally extends further into the future. An important question raised in this respect is what period into the future constitutes a definite plan. While there is no clear-cut trend in this area, several commissions allowing PHFU in the rate base under the definite plan criterion have used three years as an upper limit for a definite plan.[20]

In addition to the general criteria described above, some regulatory authorities consider other factors before allowing PHFU in the rate base. The various circumstances sometimes resulting in rate base treatment include:

(1) *Environmental factors*. Environmental restrictions (safety, aesthetics, etc.) on site locations for new construction have sometimes required utilities to purchase several potential land sites well in advance. The extended time frame is necessary in order to perform required environmental studies and to obtain the required regulatory approvals, with the purchase of several potential sites considered necessary to reduce the possibility that no site will be available due to a failure to pass environmental tests. In these situations, commissions sometimes extend the time frame of the definite plan and allow the various land purchases in the rate base as prudent purchases under the circumstances. When allowed in the

20 Re Northwestern Bell Tel Co, 3 PUR 4th 486 (SD 1974); Re Florida Power and Light, 9 PUR 4th 146 (Fla 1975); Re Pacific Tel and Tel Co, 58 PUR3d 229 (Cal 1965).

rate base, any gains on the subsequent sales of alternative sites may be passed on to the ratepayers, while any transfers to nonutility operations are closely scrutinized as to their ultimate disposition.

(2) *Economic factors*. Overall economic conditions or specific conditions in the area where a utility operates may make it prudent to invest in land in order to secure future plant sites. This may well be the case where land is extremely scarce (especially for urban utilities) and/or when the price of real estate is steadily increasing. Under these situations, some commissions deem these land purchases as good management decisions for the benefit of ratepayers and thus allow rate base treatment. Again, the treatment of gain or loss from any subsequent sale or transfer of the property may take into consideration whether ratepayers have previously paid a return on these investments.

Many state commissions as well as FERC have policies allowing certain portions of PHFU in the rate base under various circumstances.

[7] Customer Advances for Construction/Contributions in Aid of Construction

Customer advances for construction are distinguished from contributions in aid of construction in that the former involves a recorded liability representing the obligation to eventually return the funds advanced. Little controversy exists over the fact that the liability associated with customer advances should be deducted from the rate base. The utility plant constructed with these funds is not financed with debt or equity; ratepayers should not, therefore, be obligated to pay a return on these plant investments.

A question does arise regarding appropriate ratemaking treatment if the utility pays interest on customer advances. Two basic options are available, both of which provide for appropriate consideration of the interest costs. First, customer advances can be treated similar to any other form of debt financing. In this case, the liability associated with these advances is included in the capital structure for purposes of computing the rate of return allowed on the rate base, and no reduction from the rate base is made for the customer advances liability balance. The other option is to continue to reduce the rate base for customer advances while treating the interest expense associated with these borrowings as a component of cost of service.

Ratemaking treatment for contributions in aid of construction is a different situation, because no obligation exists for the utility either to repay any funds received or to reimburse parties donating physical property. The general rule is that any such contributions should be excluded from the rate base, since the related plant investment has not been financed by the utility, and customers should not therefore be required to pay a return on the plant. The actual process of reducing the rate base for these contributions varies from one regulatory jurisdiction to another. The FERC and most state commissions now require utilities to reduce initially the plant account balances to which contributions from customers relate by the actual amount of the contribution. On the other hand, many water and wastewater utilities follow the practice (formerly followed by most utilities) of recording a contribution in aid of construction “liability” when the contribution is first received. In this case, all plant (including that constructed with contributions) is included in the rate base which in turn is generally reduced by the contribution’s “liability.”

Where utilities still record a contribution’s liability, the question is raised regarding ratemaking treatment of depreciation expense associated with plant supported by contributions. In these situations, the ruling factor appears to be the regulatory commission’s view as to the appropriate role of depreciation accounting in utility ratemaking—whether the purpose of depreciation is to provide funds for the eventual replacement of plant used by customers or whether depreciation is designed simply to enable a utility to recoup its investment in plant over the period in which it provides customers with service. Those jurisdictions that take the former view are much more likely to allow depreciation on contributed plant as an operating expense. Here, the fact that the utility did not make an investment in the plant is basically viewed as irrelevant. The utility must eventually replace this plant which customers are using, and the ratepayers are therefore obligated to provide funds for this replacement. Those jurisdictions taking the latter view clearly see no reason to allow depreciation as a component of cost of service, since the utility has no investment to recoup for plant contributed by others.

If cost of service treatment is allowed for depreciation of contributed plant, it is generally accomplished by depreciating gross plant with no amortization of the contribution-related liability. In effect, contributions are treated as permanent capital contributed by customers. Where cost of service treatment is not allowed for this depreciation, the accounting generally involves depreciation of gross plant with an offsetting amortization of the contribution's liability to operating revenues.

[8] Operating Reserves

In some situations, regulatory commissions allow annual operating expense provisions for the purpose of creating "reserves" for either future extraordinary loss contingencies or significant future expenditures that can be anticipated to occur but for which actual future amounts can only be estimated. When actual losses or expenditures are experienced, they are applied against available reserves to the extent possible. The purpose of creating these reserves is basically twofold:

(1) In the case of extraordinary loss contingencies, operating reserves avoid placing the entire burden of the loss on rate payers at the time of occurrence (or placing the burden on future ratepayers).

(2) In the case of significant known future expenditures, reserves represent an attempt to require customers to pay all costs associated with providing their current service, a portion of which will not actually be incurred by the utility until sometime in the future.

An example of operating reserves for use against significant future expenditures relates to two interrelated types of future expenditures—nuclear plant decommissioning costs and the costs of handling and storing spent nuclear fuel. In the case of future costs for decommissioning nuclear power plants, the current expense provisions in some instances have been included as a component of depreciation expense, and the reserve has been included as a part of the accumulated depreciation reserve for regulatory reporting while these reserves are classified as asset retirement obligations or regulatory liabilities under GAAP, depending on whether they represent a legal obligation. In these instances, decommissioning costs have been treated in the same manner as traditional costs of removal. On the other hand, extremely large reserves have sometimes been associated with the current provisions for future costs of handling and storing spent nuclear fuel. As nuclear fuel is amortized, its net cost balance may, in fact, become a credit balance. For this reason, the provisions and related reserves for spent fuel often have been segregated from the nuclear fuel and the accumulated amortization accounts.

While these types of operating reserves in rate base were more prevalent in the past for a variety of future costs, today it is quite common to obtain regulatory commission approval to establish a cost tracker mechanism whereby the collection of a specific surcharge included in rates from customers is used to offset defined costs incurred, or to be incurred. To the extent that surcharges collected are greater/less than the defined costs incurred, a regulatory liability/asset will be recorded in accordance with U.S. GAAP. This type of mechanism is frequently used for energy efficiency initiatives, fuel costs, storm damage costs, among others.

When expense provisions required to create reserves are allowed in cost of service, the ratepayer is supplying funds to the utility in advance of actual need. The funds so supplied are generally available to the utility for supporting its rate base investment. Thus, the accumulated reserves are deducted from the rate base to avoid customers paying a return on funds they have supplied. In a few cases, the reserves may be funded by the utility with the money set aside for payment of the future expenditures. Under these circumstances, the utility does not have access to the funds for general operating purposes, and earnings on the funds are considered in establishing the required provision. Therefore, funded reserves do not require rate base exclusion.

[9] Deferred Income Tax Liabilities

Differences in accounting and taxable income occur for a variety of reasons, some of which involve permanent differences and some of which involve temporary differences that will reverse in subsequent years. In the case of utilities, the major component of annual temporary differences generally involves liberalized depreciation and accelerated amortization for income tax purposes. While GAAP (primarily under ASC 740) call for deferred income tax accounting for these and other temporary differences, utilities follow deferral accounting for income statement purposes only to the extent that the effects of deferred income taxes are considered as a component of cost of service for ratemaking purposes (i.e., the accounting treatment tracks the ratemaking treatment and, if tax benefits flow through to rates, financial reporting reflects this). In this respect, deferred income tax accounting (tax normalization) for utilities generally results in a larger initial book income tax provision than actual taxes payable largely as a result of items such as accelerated tax depreciation. The book provision for income taxes that exceed the amounts currently due and payable permits the utility to collect rates from its customers in the early years of a plant's life that provide more cash than is required to pay current taxes. This condition will reverse in later years when book deductions exceed tax deductions.

Considerable controversy exists over the notion of deferred income tax accounting, since it does, in fact, enable utilities to collect more from ratepayers than is currently owed to the U.S. Treasury in the form of taxes in the earlier years of a facility. If it is assumed that construction programs will increase indefinitely, the result will be a continuous net tax return deduction for depreciation and amortization in excess of related current book deductions (even though the depreciation expense on significant amounts of older property has actually reversed). This continuous situation of book tax expense in excess of taxes payable has led many consumer advocates to label deferred income taxes as "phantom" taxes that the utility will never pay.

On the other hand, the benefits of individual accelerated tax deductions do turn around, and utilities find themselves paying more tax dollars on specific items than they are collecting from their customers in rates. Thus, deferred income tax liability balances represent a genuine obligation to pay taxes at some point in the future. If customers are to shoulder the total expenses incurred in rendering their specific service, they have an obligation to pay for the income tax expenses when the liability initially arises.

The general trend has been for commissions to recognize deferred income tax accounting for more and more specific book/tax timing differences. This trend is to a large degree a consequence of the Internal Revenue Code requirement of tax normalization for ratemaking and financial reporting with respect to accelerated depreciation and investment tax credits (discussed in *§ 4.04[10]*, below). Failure to follow the normalization as prescribed by the Code results in the possible loss of eligibility to utilize the tax benefits.

The subject of deferred income taxes and related Internal Revenue Code requirements is dealt with in much greater detail in *Chapter 17*. The concern here relates to the appropriate treatment of deferred tax liabilities for rate base purposes. The general view in this respect is that these liabilities represent a source of interest-free funds supplied by the U.S. Treasury that the utility is free to use in support of rate base investment. Therefore, the rate base must be reduced by accumulated deferred income tax ("ADIT") liabilities balance to avoid paying a return on funds that are cost free.

An optional method of recognizing the cost-free nature of the ADIT liabilities balance is to treat the liabilities as an element of the capital structure with a zero capital cost rate for purposes of determining the overall allowed rate of return on the rate base. If this method is utilized, there is no rate base reduction for the ADIT liabilities balance. Either this method or direct rate base reduction normally produces similar revenue requirements. While rate base reduction results in a higher rate of return on a lower rate base, the zero capital cost method produces a larger rate base balance with a lower rate of return requirement, with the changes in the amounts of these two elements being approximately directly proportional. A good example of this relationship is presented in Chapter 3.

A problem that sometimes occurs involves changes in the statutory tax rates. This occurred, for example, in 1978 when the federal corporate rate decreased from 48 percent to 46 percent effective January 1, 1979. As a result, deferred income taxes that were accumulated in the past on the assumption that tax rates would remain at 48 percent will actually turn around and be paid at the lower rate. It is argued that customers have, in effect, paid more for future tax liabilities than what the actual liability will be, or, to put it another way, deferred income tax liabilities set up at 48 percent will never completely reverse.

Faced with this situation, regulatory commissions basically followed one of two alternatives. First, some believe that consumers have the right to a return of the excess funds immediately. In this case, many commissions required the amortization of the additional 2-percent tax reserve over a relatively short period of time—normally one to ten years. It was argued that the short amortization period came closer to ensuring that those ratepayers originally funding the excess liabilities would be the ones receiving the "refunds." The alternative was to amortize the excess income tax liabilities over the remaining life of the assets initially generating the reserves. In this case, the return of the over collections was accomplished by turning the timing differences around at the original 48-percent rate at which the deferred taxes were accumulated. Those defending this alternative have cited two basic points in favor of ratable amortization over the remaining asset life:

(1) *Treasury regulations*. The Internal Revenue Code requires the amortization of deferred income tax liabilities over the lives of the related assets. A shorter amortization period, regardless of the reasons, may result in the loss of eligibility to utilize accelerated tax depreciation and amortization. (See *Chapter 17* for a detailed discussion.)

(2) *Generally accepted accounting principles*. In recognition of changes over time in effective tax rates, GAAP, as stated prior to ASC 740 in Accounting Principles Board Opinion No. 11, called for the amortization of tax "reserves" over the lives of the assets creating the "reserves" at the rates utilized when the "reserves" were originally created. For further discussion of the changes in accounting standards for income taxes and the related ratemaking impacts, please refer to Chapter 17, Accounting for Income Taxes.

The FERC's general position on this controversial issue was initially stated by the Federal Power Commission (FPC) in 1965 with the issuance of Accounting Release No. AR-2. The FPC's response to the question regarding the appropriate treatment was as follows:

> "Amounts accumulated in Account 281, Accumulated Deferred Income Taxes—Accelerated Amortization, shall be credited to Account 411, Income Taxes Deferred In Prior Years—Credit, at the same rate that was originally used to defer the amounts in Account 281. Therefore, the amounts previously deferred will be fully restored to income over the appropriate estimated remaining useful life allowable for tax purposes of the related property."

The FERC readdressed this issue in an indirect manner in 1981 with the issuance of its Order No. 144, which requires tax normalization for the tax effects of certain timing differences in rate proceedings before the Commission. Here, the FERC's primary concern related to excessive or deficient tax reserves that were largely the result of prior flow-through treatment of tax benefits that would now turn around and be accounted for under tax normalization. While recognizing that amortization of excess reserves over the service lives of the assets was an appropriate method, the FERC stated that the most appropriate method of dealing with the 2-percent reserve excess was the subject of case-by-case determination, since other factors may also have contributed to an excessive or deficient reserve.

The Tax Reform Act of 1986 reduced the federal corporate tax rate from 46 percent to 34 percent effective July 1, 1987. In contrast to the previous 2-percent reduction, the 1986 Act specifically addressed regulatory accounting treatment of the so-called "excess" deferred income tax liabilities created by the tax rate reduction. Generally, the 1986 Act specifies that deferred income tax reserves associated with timing differences between book and tax depreciation that result from different depreciation methods and lives are "protected" deferred income tax liabilities. The identified protected liabilities must be reversed using an average tax rate assumption that effectively results in a reversal at the average tax rate at which the deferred income taxes were previously provided. (See *Chapter 17* for a more detailed discussion of the 1986 Act and the regulatory implications of the corporate tax rate reduction.)

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the "Act") was signed into law. Among other provisions, the Act decreased the maximum federal corporate income tax rate from 35% to a flat 21% (which resulted in a corresponding reduction of the federal benefit of state income taxes), and modified the tax bonus depreciation allowance amounts for qualified property placed in service after September 21, 2017, and before January 1, 2023. The Act did not address the regulatory accounting treatment of the so-called "excess" or "deficient" accumulated deferred income taxes ("ADIT") created by the tax rate reduction.

During November 2018, the FERC issued a Notice of Proposed Rulemaking, *Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes* and a Policy Statement, *Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset.* A final rule on the Notice of Proposed Rulemaking was issued as Order No. 864 in November 2019.

In order to maintain an accurate cost of service in formula transmission rates after the implementation of the Act, the FERC provided guidance for formula rates with two components: (1) preservation of rate base neutrality through the removal of excess ADIT from or addition of deficient ADIT to rate base; and (2) the return of excess ADIT to or recovery of deficient ADIT from ratepayers. Further, the FERC stated that multiple approaches to modifying rate base and adjusting income tax allowances may be just and reasonable due to the varying formats of transmission rate templates and formulas currently in use. In the final rule, FERC requires public utilities with transmission formula rates to include a mechanism in those transmission formula rates to deduct any excess accumulated deferred income taxes (ADIT) from or add any deficient ADIT to their rate bases. Public utilities with transmission formula rates are also required to incorporate a mechanism to decrease or increase their income tax allowances by any amortized excess or deficient ADIT, respectively. Finally, FERC is requiring public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track information related to excess or deficient ADIT.

As it relates to stated transmission rates, the FERC maintained FERC Order No. 144 already contained a requirement that public utilities provide sufficient support for any related tax changes. Therefore, no further regulations were deemed necessary to address excess or deficient ADIT as a result of the Act. However, the FERC did specify that the excess or deficient ADIT should be calculated using the ADIT approved in the last public utility rate case.

The FERC also ordered public utilities to return excess ADIT using the fastest allowable method under the IRS' normalization requirements. To address the concern regarding whether or not the FERC would have sufficient information to provide transparency with respect to the impacts of the Act on ADIT, the FERC adopted a requirement to disclose the following information in the Notes to the FERC Form Financial Statements on an annual basis: (1) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein; (2) the accounting of any excess or deficient amounts in Accounts 182.3 and 254; (3) whether the excess or deficient ADIT is protected or unprotected; (4) the accounts to which the excess or deficient ADIT are amortized; and (5) the amortization period of the excess or deficient ADIT being returned or recovered through the rates.

The FERC's Policy Statement clarified the following with respect to ADIT associated with a sale or retirement of an asset:

(1) For both accounting purposes and ratemaking purposes, public utilities and natural gas companies should record the amortization of the excess and/or deficient ADIT recorded in Account 254 (Other Regulatory Liabilities) and/or Account 182.3 (Other Regulatory Assets) by recording the offsetting entries to Account 410.1. (Provision for Deferred Income Taxes, Utility Operating Income) or Account 411.1 (Provision for Deferred Income Taxes—Credit, Utility Operating Income), as required by the USofA. Further, for accounting purposes oil pipelines should adjust their ADIT balances to reflect the change in federal income tax rates with offsetting entries to the appropriate income statement account, as required by the USofA. Accordingly, oil pipeline companies will not record excess or deficient ADIT for accounting purposes.

(2) For accounting purposes, public utilities and natural gas pipelines must continue to follow the accounting guidance issued by the Chief Accountant in Docket No. AI93-5-000 with respect to changes in tax law or rates.

(3) For ratemaking purposes, a public utility or natural gas pipeline that continues to have an income tax allowance, any excess or deficient ADIT associated with an asset must continue to be amortized in rates even after the sale or retirement of that asset (unless the ADIT is transferred to the buyer). This excess or deficient ADIT will be recorded as a regulatory asset or liability and continue to be refunded to or recovered from ratepayers based on the schedule that was initially established. Similarly, for ratemaking purposes oil pipelines should keep records of excess and deficient ADIT.

(See *Chapter 17* for a more detailed discussion of the Act and the related regulatory implications.)

[10] Investment Tax Credits

Accounting and ratemaking treatment for investment tax credits (ITC) has largely been dictated by the Internal Revenue Code with a limited number of options available to utilities and their regulatory commissions. In this sense, the Code has generally attempted to require a sharing of the benefits of ITC between utility investors and utility customers. This has basically been accomplished by providing for either rate base reduction for deferred ITC balances or amortization of deferred ITC balances above-the-line as a reduction of income tax expense—both of which reduce revenue requirements to the ratepayers' benefit. Only one or the other of these procedures, however, is generally allowed, thereby allowing the utility to share in the tax savings of investment tax credit. Only in limited circumstances have both procedures been permitted simultaneously and usually most public utilities use the deferral method of accounting for ITC.

The pertinent section of the Code regarding ratemaking treatment of ITC is *IRC Section 46(f)*. Two optional methods are described under this section that are commonly labeled Options 1 and 2. Utilities must follow one of these options to avoid recapture of ITC benefits by the Service.

(1) *Option 1*. Under this option, utilities are permitted to defer the ITC utilized and amortize the deferred balance over the life of the assets giving rise to the credits. This amortization is below-the-line (to nonutility tax expense), thereby having no effect on utility cost of service. The utility, however, may reduce the rate base for the unamortized deferred ITC balance. These rate base reductions are in effect restored over the useful life of the tax credit property as the deferred balance is amortized. Option 1 is generally termed as the “ratable restoration” method, since, in essence, it allows the utility to keep the tax credit savings but does not require that the utility earn a return on those assets effectively financed by the U.S. Treasury.

(2) *Option 2*. Following this option, utilities again defer the ITC utilized. Ratemaking treatment under this option is basically the reverse of Option 1. The deferred ITC balance may be amortized above-the-line, thereby reducing the income tax component of cost of service. No rate base reduction is permitted for the unamortized ITC balance. This option is generally referred to as the “ratable flow-through” method, since it allows the utility to earn a return on the entire cost of assets generating the ITC (with no reduction for the tax savings) but at the same time permits a flow-through of the ITC benefits to customers over the life of the related assets.

At one time, a third option was available. This option provided that no restrictions applied and was commonly labeled the “immediate flow-through” method. The most common treatment under this option was to recognize the utilization of ITC as a current reduction of the income tax element of cost of service. Because there was immediate recognition of the entire benefit, no deferred investment tax credit balance existed for ratemaking or financial accounting purposes. Availability of this option was restricted before 1981 and was effectively eliminated as an option for ratemaking purposes for years after 1980 by the Economic Recovery Tax Act of 1981.

This discussion of investment tax credit has been purposely brief and devoted solely to a general discussion of the available rate base treatments. A detailed discussion of this highly controversial and complex subject is contained in *Chapter 17*, where the implications of the various options are explored in detail.

[11] Other Items

Various other items are from time to time considered by the different regulatory commissions in establishing a utility’s rate base. Both the consideration of these items and the methods of handling will vary from one regulatory commission to another, depending on commission policy and the specific circumstances involved. While these items usually have an insignificant impact on the overall rate base, in some situations their impact clearly warrants appropriate attention. This section’s purpose is not to set forth an all-inclusive list but to briefly discuss the more commonly encountered items.

[a] Standby, Auxiliary, and Reserve Equipment

As discussed briefly in *§ 4.03*, above, standby, auxiliary, and reserve equipment represent reserve capacity used only in cases of emergency or to meet maximum peak service demands. Many commissions permit rate base treatment where it can be demonstrated that this property investment is truly reserve plant for the benefit of utility customers and not simply uncommitted capacity beyond reasonable emergency requirements.

Generally, a good case for inclusion in the rate base is made where the following is demonstrated:

(1) The plant is properly maintained and capable of providing service.

(2) The plant actually contributes to the overall efficiency of operations. For example, reserve utility plant may avoid the necessity of contracting for more expensive electric power from other utilities to meet peak demands.

(3) The plant does not involve uncommitted capacity that resulted from poor management policies or actions.

The specific facts and circumstances of individual situations must be reviewed by the regulatory commissions, and a judgment must be made as to whether the questioned plant is actually used and useful in providing utility service. The appropriateness of treating genuine reserve equipment as used and useful plant was clearly demonstrated by the Indiana Public Service Commission in a 1958 rate proceeding involving the Indianapolis Water Company. In this case, the question centered around the used and useful nature of plant that was not being operated to full capacity but was designed to meet the peak demands of the public. In expressing its view on the concept of used and useful plant, the Indiana Commission stated:

> "All utilities are required, in order to properly serve the public, to provide for peak demands in the design of its utility properties. There is no evidence in this case to indicate that the petitioner has departed from sound engineering practice and has overbuilt its utility properties. A unit of property cannot be partially used and useful. A unit of property is definitely either used and useful or it is not used and useful."[21]

[b] Leasehold Improvements

Leasehold improvements represent capitalized improvements or additions to property leased from other parties. Leasehold improvements are usually considered an intangible asset. Due to the nature of these capital items, they are normally accounted for separately from utility plant owned outright, with the capitalized improvements included in "miscellaneous deferred charges." To the extent related leased properties are used in the rendering of utility service, rent expense is included as a component of cost of service. Since investments in leasehold improvements are merely additions to these leased properties, these improvements are generally afforded rate base treatment in the same manner as any other plant in service. In this respect, the amortization of these improvements is an appropriate element of cost of service, while related accumulated amortization balances must be deducted from the rate base.

While rent expense related to leased property is normally included in cost of service, the question arises as to the appropriate accounting treatment for those lease transactions that would be classified as right-of-use (ROU) assets under GAAP. Although regulatory commissions generally have not treated ROU assets related to leases as assets for ratemaking purposes, these leases are required to be accounted for as assets for financial accounting purposes. The issue of lease accounting and the FASB's decision to require capitalization (regardless of ratemaking treatment) is discussed in *Chapter 12*.

[c] Extraordinary Retirements

Extraordinary retirements sometimes occur when a partially depreciated unit of property is retired earlier than anticipated, and the reduction in the depreciation reserve is substantially greater than the amount which has been provided during the in-service years. In these cases, the plant investment has not been adequately recovered through depreciation expense. Furthermore, the depreciation reserve will be excessively depleted if the "loss" on the retirement is immediately charged against the reserve balance. Because utilities employ the group concept of depreciation accounting, the reserve applicable to the particular group is of significance to the test of reserve adequacy. The specific groups utilized are unique to individual utilities, but they often are primary plant accounts or subaccounts. The group concept of depreciation accounting is discussed in *§ 6.04*.

These situations can be caused by several factors. For instance, significant losses in demand for service may occur due to "obsolescence" of the particular service. A good example is the demise of the streetcar system. Early retirement of plant may also be necessitated by unexpected technological advances or changes in government regulations that render portions of utility plant obsolete or totally inefficient. An

21 Re Indianapolis Water Co, 26 PUR3d 276 (Ind 1958).

excellent example of technological "obsolescence" was the movement away from manufactured gas operations to natural gas facilities during the 1950s and 1960s. A final factor that may result in an extraordinary retirement is significant unexpected damage to plant that is not adequately covered by insurance and for which no operating reserve has been provided. The expectation of the replacement of plant components is usually reflected in the determination of depreciation rates, so depreciation accounting practices will be a factor considered in the determination of whether a retirement is ordinary or extraordinary.

When extraordinary losses occur, utilities often request permission to charge the loss to a deferred debit account and either amortize it over future periods or dispose of it as otherwise may be directed by the jurisdictional regulatory commission. For example, the FERC provides Account 182—"Extraordinary Property Losses," which may be used to segregate these items when permission is obtained from the Commission. The disposition of items allowed in Account 182 is up to the discretion of the FERC.

As would be expected, regulatory treatment of deferred extraordinary losses varies among regulatory bodies and is greatly influenced by the specific facts and circumstances involved. On the one hand, the utility has not been allowed to recover its investment through the depreciation process. On the other hand, the property is no longer used and useful in rendering utility service. Regulatory commissions have often excluded these loss deferrals from the rate base under the premise that the utility is not entitled to a return on property no longer in service. Exceptions have been found, however, especially in the situation where gas utilities have converted from manufactured gas to natural gas facilities. For example, in 1949, the District of Columbia Public Utilities Commission allowed Washington Gas Light to include in the rate base deferred extraordinary losses resulting from the changeover to natural gas under the premise that it was not the company's fault that depreciation provisions had been inadequate in the past. It was felt that the exclusion of this item from the rate base would deprive investors of a return on investment that was originally made to furnish utility service.[22] While not allowing Brooklyn Union Gas Company to include the unamortized balance of extraordinary retirement losses in the rate base in 1970, the New York Public Service Commission did allow the utility to earn a 6 percent "carrying charge" on the average balance of these unamortized losses. The 6-percent rate represented the overall rate of return deemed adequate when the facilities (manufactured gas plant) were initially installed. The New York Commission deemed this treatment appropriate, since shareholders should not bear the full cost of carrying the unamortized balance where the original investment was proper.[23]

While rate base treatment many times is not allowed, recovery of extraordinary retirements through a cost of service amortization is more commonplace. Amortization of these balances to utility operations is often allowed where the utility can demonstrate that, through no fault of its own, prior depreciation provisions were inadequate, and the retirement is clearly for the public's benefit. This is often the case where retired plant is replaced with more efficient equipment.

[d] Cancelled Projects

For purposes of this discussion, cancelled projects refer to the cancellation of incomplete construction projects as opposed to the abandonment or retirement of plant that has actually been in service (discussed at *§ 4.04[11][c]*, above). These abandonments can occur for a variety of interrelated reasons including:

(1) decrease in predicted demand for future service (cancellation may be voluntary or commission ordered);

(2) government regulations that render project completion infeasible; and

(3) inability to raise the necessary capital on reasonable terms.

The most prominent example of cancelled projects involves the abandonment of electric generating plant construction, as was the case with a number of nuclear power plants in the 80s and 90s.

22 Re Washington Gas Light Co, 83 PUR (NS) 4 (DC 1949).
23 Re Brooklyn Union Gas Co, 87 PUR3d 119 (NY 1970).

In these situations, rate base treatment is generally denied, since the accumulated construction costs were never used and useful in providing service in the past and will not be utilized in the future. An exception to this policy exists, however. In 1980, the Louisiana Public Service Commission permitted Gulf States Utilities Company to include the unamortized cost of an abandoned nuclear project in its rate base. The Louisiana Commission based its decision on the fact that no evidence existed to show imprudence or negligence on the part of the utility in initiating the particular construction project.[24]

While rate base treatment may be denied, the question remains as to the proper method to eliminate the costs accumulated before the cancellation. Amortization to cost of service is usually allowed where the utility can demonstrate:

(1) The initial decision to develop the project was prudent and in the best interests of its customers.

(2) Factors that could not be initially foreseen have resulted in the necessity to cancel the project.

(3) The utility has taken appropriate steps both to cancel the project as soon as the course of action was found necessary and to minimize additional losses.

The FERC in Opinion No. 295 adopted a 50-50 sharing policy relating to the recovery of the costs of abandoned or cancelled construction projects by electric utilities.[25] The methodology adopted by the FERC provides that 50 percent of the incurred costs of a cancelled plant are to be amortized to cost of service over the expected life of the planned plant. The remaining incurred costs of the plant are to be written off as a loss to the utility. In the past, as specified in Order No. 49, the FERC allowed utilities to pass through abandonment costs but did not permit rate base treatment of the unrecovered investment. Under the new policy, rate base treatment is permitted on the portion of the costs recovered from ratepayers, less related deferred income taxes. According to the FERC, this ruling allows utility shareholders funding major facilities to recover a greater share of abandonment losses and reduces regulatory uncertainty.

By fixing amortization periods equal to the expected plant life—rather than allowing them to vary from case to case—the FERC hopes to avoid rate cases involving plant abandonments.

The FERC's prior policy under Opinion No. 49 permitted utilities to defer and amortize cancelled plant costs in order to recover their total investment in cancelled projects, including accrued AFUDC, up to the time of cancellation. However, utilities were not allowed to include the unamortized deferral in rate base (and thereby earn a return on the unrecovered cost during the recovery period). Electric utilities in the past have requested rate base recognition of unrecovered cancelled plant costs, and the FERC appropriately reexamined this issue.

In GAAP based financial statements, a cancelled plant or a plant that is probable of abandonment is accounted for in accordance with ASC 980-360-35-1 through 4.

[e] Customer Deposits

Customer deposits generally represent funds received from ratepayers as security against potential losses arising from failure to pay for service. These funds are similar in nature to customer advances for construction (see *§ 4.04[7]*, above). Both represent a liability to repay the funds received either after a specified period or upon satisfaction of certain requirements. Like customer advances, the deposits are available to the utility for use in support of its rate base investment.

The alternative methods of treating customer deposits for ratemaking purposes also parallel treatment of customer advances. If no interest accrual is required on the funds, the deposits represent a cost-free source of capital commonly deducted from the rate base. If customer deposits are interest bearing, two options are available. The liability may be deducted from the rate base with the associated interest included as a component of cost of service, or the liability may be included in the capital structure for purposes of calculating the allowed rate of return (in which case there is no rate base reduction).

[f] Merchandising Property

24 Re Gulf States Util Co, 40 PUR 4th 593 (La 1980).
25 New England Power Co, FERC Release No. R-88-03, Dkt Nos ER 85-646 et seq (Jan 15, 1988).

As a general rule, merchandising property is excluded from the rate base, because it is not used and useful in rendering utility service. On rare occasions, however, commissions have made exceptions under the premise that appliance merchandising tends to promote the sale of utility services. In those cases where rate base treatment is allowed, merchandising revenue and expense are included in above-the-line operations. If inclusion in the rate base is permitted, the reasons generally cited for allowing this treatment are the following:

(1) Merchandising activities are directly connected and interrelated with rendering utility services.

(2) Personnel and property utilized in the utility function are also involved in merchandising activities; therefore, the inclusion of these activities under the ratemaking concept avoids a somewhat arbitrary allocation between utility and nonutility operations.

[12] Stranded Costs

The issue of stranded costs became a significant regulatory concern as the electric utility industry moved toward competition and deregulation. Electric utilities and their regulators recognized that costs traditionally included in the rate base were becoming stranded. This occurred because the costs were no longer economically viable due to changes in statutes or regulatory policies that allowed other parties to compete for the utility customers. The FERC has recognized the need for utilities to recover stranded costs through FERC Order No. 636 and FERC Order No. 888. FERC Order No. 636 allowed natural gas pipelines to recover from pipeline customers, prudently incurred costs that otherwise would not have been recovered because of the switch from bundled to unbundled service. FERC Order No. 888 embraces this same concept regarding open access to electric transmission and generation-related stranded costs. (Stranded costs are discussed in greater detail in *§ 20.04*.)

End of Document