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Prudence Issues Affecting the U.S. Electric Utility Industry

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PRUDENCE ISSUES AFFECTING THE U.S. ELECTRIC UTILITY INDUSTRY

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ABSTRACT

The cost impact to private utilities resulting from prudence hearings before State Public Utility (Service) Commissions is currently a matter of considerable concern to investors and the nation. Cost disallowances for many utilities threaten the economic health of the companies. The disallowances, which deny full construction cost recovery to utilities, have had a negative effect on the ordering of any new base load power plants, either nuclear or coal. They have contributed to the fact that no nuclear plants have been ordered since 1978, and none are currently being planned in the U.S. This situation has led to a major national concern that adequate, reliable and economic electric power may not be available to fully meet future needs of the country.

The U.S. Department of Energy is addressing the institutional, financial and regulatory problems of the nuclear power industry. This report addresses the prudence issues aspect of this program. This includes the development of a body of data depicting the causes of electric power plant cost disallowances, analysis of the causes and their impact, and the development of recommended actions that may eliminate or alleviate the negative conditions found.

TABLE OF CONTENTS

LIST OF TABLES

PRUDENCE ISSUES AFFECTING THE U.S. ELECTRIC UTILITY INDUSTRY

EXECUTIVE SUMMARY

ELECTRIC UTILITIES PERSPECTIVE AND RATES

Under a regime of regulation, electric utilities undertake an obligation to serve all customers within a specified service area with reliable electric service at fair and non-discriminatory rates. Rates are regulated because large electric utilities are viewed as natural monopolies. The utility is provided an opportunity to earn a fair return on the investment it has made in facilities to provide such electric service. Because the utility is provided some measure of protection against the risks assumed by competitive businesses in unregulated markets, the return on utility investment generally is less than that available for investments made in unregulated businesses.

A key element of regulation is the method used to set rates. Rates are designed to recover the revenue requirement from the various classes of customers. The revenue requirement is computed by determining various production costs (including fuel and operation and maintenance costs needed to provide reliable electric service), and adding to those costs a fair return on the investment in assets (rate base) used to provide the electric service.

PRUDENCE

It has long been recognized that not every capital expenditure made by a utility should necessarily be included as part of the rate base. Rather, only "prudent" expenditures should be included in the rate base. The classic definition of such expenditures was provided by Justice Brandeis in his separate opinion in <u>Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission</u>, 262 U.S. 276 (1923). In his opinion, Brandeis states (<u>id.</u> at 289):

> "The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgement, unless the contrary is shown."(1)

The significant aspect of the Brandeis definition is how narrow it is. Imprudent expenditures are linked with those that are "dishonest" or "obviously wasteful". Moreover, Brandeis is clear to state that "[e]very" investment is assumed to be reasonable, and imprudence must be demonstrated. This narrow view of imprudent expenditures has continued until the very recent time.

Beginning in the late 1970's, the propriety of utility investments began to be challenged. This change in regulator approach primarily arose because of two factors. First, beginning in the late 1970's and continuing through the mid-1980's, a significant number of nuclear power plant construction projects were cancelled in mid-stream. Second, beginning in the early 1980's and continuing to the present, the costs associated with a significant number of completed nuclear power plants rose very dramatically. In both cases, public utility commissions (PUC's) relied primarily on legal principles developed for rate base valuation to mitigate the impacts on customers.

In most cancelled nuclear plant cases, PUC's followed traditional principles and did provide some protection for the utility investor. However, in some states no amortization was permitted and the investor was denied both a return on the use of his money and return of the investment itself.

While the cancellation cases set the stage, most recent regulatory activity addressing the prudence of power plant construction costs has been aimed at the set of completed nuclear power plants coming on-line in the 1980's. These plants typically have been characterized by substantial increases in cost over initial budget and substantial increases in schedule over initial projections. These two factors provide both a reason for investigating the costs incurred (to minimize the rate impact to the customer) and a basis for disallowing some of the costs (treating the initial cost estimate and schedule projection like a fixed price contract).

DISALLOWANCES

The disallowance of construction costs by a PUC occur for a multitude of reasons that reflect the particular situation of the plant under construction, the approaches and decisions of the electric utility system building or owning the plant, and the PUC approach to rate regulation. The disallowances, however, can be broadly classified into the following five categories:

Imprudence

This category includes disallowances as a result of certain utility decisions judged to be imprudent or unreasonable.

Excess Capacity

A facility should be used and be useful to the public, for inclusion in the rate base. If a utility has excess generating capacity, the new facility may not be deemed useful to the public. Thus, the PUC may disallow part of the investment representing excess capacity from inclusion in the rate base. This disallowance is not permanent and can be included in the rate base as the utility's load requirements grow, eliminating excess capacity.

Cost Caps

This is basically a new idea not encountered frequently in utility rate cases. When a generating facility is under construction, the PUC may specify a cap on the amount of investment that will be allowed in the rate base. If the facility is completed for a higher amount, the excess investment will be disallowed from inclusion in the rate base. Recently, utilities have accepted cost caps as a means for settling contested rate cases, in some instances.

Economic Value

The PUC may decide that the actual cost of a facility is above the economic value of that facility. For example, economic value may be estimated by comparison or inference with alternate sources of generation. The amount in excess of economic value may be disallowed from inclusion in the rate base.

Other

This category includes disallowances that do not fall under the other four categories.

The total disallowances for nuclear plant construction costs in the United States from 1980-1986 are currently estimated to be $6,592 million. The following list indicates how much of these disallowances was attributable to each of the five categories.

TYPE OF DISALLOWANCES	AMOUNT OF DISALLOWANCE $ x 10^6	PERCENT
Imprudence	3,421	51.9
Excess Capacity	2,185	33.2
Economic Value	371	5.6
Cost Caps	237	3.6
Other	378	5.7
Total	6,592*	100.

The total disallowances for coal-fired and other plants is $127 million which is quite small compared to the $6,592 million for nuclear plants. The total disallowances, as a percent of investment costs going into the rate base over seven years from 1980 to 1986, is 9.6% for nuclear plants and 0.3% for coal-fired and other plants.

CONSEQUENCES OF DISALLOWANCES

Currently, six plus billion dollars have been excluded from the rate base of utilities for various reasons during the period 1980 to 1986. Although this is small compared to total investment in assets by utilities (the current investment by utilities for large central station nuclear and coal fired power plants, 1980 to 1986, is in excess of 100 billion dollars), any individual utility can be harmed badly by disallowance decisions focused on their plant(s).

The disallowances of capital costs is already having a chilling effect on investment in nuclear and coal-fired plants. Virtually all nuclear plants currently commencing commercial operation are facing possible disallowances. Investors are not willing to commit funds to situations where risk indicates a certain loss despite a high return. Many other adverse consequences are possible. Some of these adverse consequences are discussed below:

* Since the $6,592 billion represents a snapshot in time (thru 1986), the disallowances will change as decisions are appealed, court settlements occur, or new disallowances are considered in current and future rate cases.

Utility Investment Policy

In order to build a power plant with a 10 to 15 year leadtime being typical, a utility must forecast demand 10 to 15 years into the future. If economic conditions change during this period from what was forecasted (as they almost certainly will), demand will be higher or lower than forecasted. In such circumstances, the application of ex-post prudent investment rules can have perverse unintended effects on the investment policies of regulated utilities. These effects create disincentives for long-leadtime construction projects, which could increase chances of underinvestment. Insufficient power at high cost may thus be the result of misguided efforts to protect ratepayers from costs that currently appear high.

Utility Bankruptcy

Utility bankruptcy also is a possible consequence of improperly applying the prudent investment test so as either to disallow from the rate base all or a part of a utility's investment in a completed electric utility plant or to disallow cost recovery for an abandoned plant in which a large investment has been made.

Bankruptcy in itself could result in an increase in the cost of capital that could very well lead to larger increases in utility rates. Also, other utilities (particularly those in financial difficulty) could see their costs of capital rise to offset the higher risks perceived by investors. This too could eventually lead to higher rates.

Utility Relationships

The relationships among the parties with an interest in utility construction could change as they adjust to a possible new regulatory environment. The consequence of these shifting relationships is usually to increase costs in ways that ultimately are borne by utility customers. For example, bidding policies could change to fixed-price, lump sum bids that may require the contractor to include large provisions for contingencies. There could be increased litigation and record keeping requirements, leading to a deterioration in utility-contractor relationships and eventually to adverse effects on ratepayers.

FRAMEWORK FOR CHANGE

Disallowances are due to factors that can be classified as Technical and Regulatory as follows:

Technical

Energy and economic changes of the last fifteen years, have led to two significant events. The first of these is the sudden decline in electricity demand growth, creating large amounts of unused (and, hence, to some "nonuseful") capacity for which regulators are reluctant to charge customers. The second change is the large increase in cost and schedule from early estimates, particularly for nuclear plant construction projects.

Regulatory

The changing approach to regulation also has contributed to the disallowance problem. The recent use of the prudence test to exclude billions of dollars of construction costs actually incurred is more than a mere application of a long-established doctrine. Rather, it represents regulators' discovery of an apparently respectable way of keeping rates from piercing some perceived politically acceptable level. Furthermore, ex-post regulatory findings that portions of new capacity are not "used and useful," even if prudent, represent an added attempt to penalize investors for unavoidable changes in demand that could not be reasonably projected.

Utilities and investors understand quite well that risks previously borne by consumers have been shifted to utilities. As long as there is excess capacity, this realization may matter little. However when new or replacement capacity is required, sooner or later, someone (most probably the ratepayer) will have to bear the increased costs associated with this shift in risk from the customer to the utility.

Consequently, unless some new regulatory framework is developed, one which provides investors with new assurance that capital prudently committed to the business will be fairly compensated, the United States will find itself with a costlier, operating-expense-intensive, capital-starved power system. This will be to the disadvantage of the consumers, whom regulations are designed to protect. Regulators can determine what returns to allow on sunk capital; they cannot conscript new funds.

RECOMMENDATIONS

Reasons for disallowances of certain construction costs in utility rate bases are varied and reflect not only technical and prudence factors but also political, regulatory, and public relation factors. As such, the problems need to be addressed on many fronts. The recommendations address those situations where the prudence process appears to be abused as compared to fair, unbiased treatment for both ratepayers and investors. The following recommendations reflect these considerations.

Improved Management Techniques

Clearly where there has been a significant cost increase from the original planning estimate for a nuclear plant, a PUC may have legitimate concerns about such an increase. What the utility must demonstrate is that the cost of the plant was controlled, to the extent that it is reasonably controllable, by management. For future construction of a power plant, the company should identify the management control techniques to be used, as well as the actions to be taken by management in order to control the engineering and construction process. These could be supplemented by statements in response to potential management audit questions, which support the company's position that it, in fact, controlled the costs to the extent that they were controllable.

Stable Regulatory Environment For Design and Construction

A major reason for cost increases, schedule delays, engineering design changes and construction rework has been the very large increase in the volume of and changes to regulatory requirements, codes and standards, which govern the design, construction and operation of nuclear and coal-fired plants. It is important that DOE work toward the objective of providing a much more stable regulatory environment for guiding the design and construction of these plants. This would significantly reduce schedule delays, design changes and construction rework, which would result in lower overall project costs. As a result, disallowances of power plant construction costs would be minimized.

Standard Plant Design and Construction

A large number of nuclear plants and many large coal-fired plants built over the last fifteen years have basically been custom designed and constructed. As such they have experienced "first-of-a-kind" problems that have led to numerous design changes, construction rework and extended schedules. Development of prelicensed standard plant designs would certainly reduce these factors and minimize disallowances relating to these factors.

Small and Intermediate Size Nuclear Plants

Over the last two decades, the size of nuclear plants has increased sharply to large 1000 to 1300 MWe units. Large plants are more complex in design and require more sophisticated construction approaches. This tends to lead to more redesign and construction rework, which eventually could be disallowed by a PUC. Smaller nuclear plants have the potential to minimize these problems through simplified design and innovative construction techniques that are not necessarily applicable to larger plants.

Smaller plants can have shorter schedules and may be less prone to schedule delays. Bringing capacity on line in smaller increments will also reduce the possibility of excess capacity minimizing disallowances due to imprudent schedule delays and excess capacity. Innovative smaller plants are, however, needed to offset the disadvantage associated with these plants due to the principle of economy of scale.

Preapproval Incentive Standards

Under this approach, a PUC and utility might consider the following regulatory bargain:

- o Establish an expected total cost of a plant having a PUC-specified capacity (and, perhaps, other operating characteristics). This base should be established (most likely through PUC-utility negotiations) in light of best available forecasts and agreed upon capacity needs.

- o Establish (i.e., negotiate) a preapproved minimum recovery level equal to a percentage of the expected total cost of the plant. The minimum recovery amount should be subject to only the most narrowly defined prudence challenges. Such a minimum recovery level could also be set for a situation in which the plant may be cancelled.

- o For actual costs above the minimum recovery level and up to the originally expected cost, allow a rate base equal to actual cost plus a fixed percentage, of the difference between expected and actual costs.

- For actual costs that are higher than the originally expected cost, restrict recovery to no more than originally expected cost plus a certain percent of the cost over the originally expected level.

- Allow the foregoing caps to be indexed by the economy's general rate of inflation (including an inflation premium in the interest rate that constitutes the utility's cost of capital); and allow automatic adjustment of the caps for regulatory delays and mandated mid-stream equipment and design changes.

Public and PUC Awareness

While it may be politically expedient for a PUC to disallow certain construction costs from inclusion in the rate base, the public and the PUC should be made aware by DOE and the utility industry,as to the long range adverse implications of such disallowances on the cost to the utility and its ratepayers for the generation of electricity.

The Prudence Review Process: Retrospective and Commentary

In a report by R.J. Rudden Associates entitled "Nuclear Prudence Reviews: Retrospective and Commentary" several recommendations were identical to this study and the following additional recommendations were made.

More balance between short-term and long-term costs and benefits should be achieved. We do not agree with some observers' views that prudence cases represent a one-time aberration in regulatory trends that will not adversely affect investors' expectations of future treatment. The effects on ratepayers, investors, and utility managers extend well beyond near-term rate and capital loss issues. However, regulators correctly perceive, and utilities need to recognize, that public and political response to these cases will largely be based upon immediate impacts.

The problem of spiralling interest costs ("AFUDC") during unavoidable delays and while the ratemaking treatment of the plant is being considered should be mitigated by interim rate relief for project costs, granted subject to refund upon the final determination of prudence. The problems of rate shock should not be made worse by delaying the recovery of prudent costs any longer than is necessary.

All parties need to clearly distinguish between the issues of rate shock and managerial prudence and deal with them separately. The fact that management's actions have led to a situation which will have a major impact on rates does not mean that those actions are imprudent. The prudent investment test should not be viewed as the solution to the problem of rate shock associated with most nuclear plants. It is equally unreasonable for utility managers to believe that their responsibilities in prudence cases end with a convincing defence of management's actions. In order for any solution to these problems to be complete, it must adequately consider both the immediate and longer term impacts on ratepayers, including the price, availability, and reliability of electric service.

All parties should recognize the political realities of regulation and that prudence cases are expensive and imperfect means to the end of reasonable rates. A greater recognition of the inexactitude of the ratemaking process and long-term need for reliable power sources should lead to a greater willingness by the parties in prudence cases to explore settlements and compromises. In the end, mountains of documents and armies of attorneys and expert witnesses cannot achieve perfection in a process as inherently judgemental as the determination of reasonable rates.

PRUDENCE ISSUES AFFECTING THE U.S. ELECTRIC UTILITY INDUSTRY

INTRODUCTION

The cost impact to private utilities resulting from prudence hearings before State Public Utility (Service) Commissions is currently a matter of considerable concern to investors and the nation. Cost disallowances for many utilities threaten the economic health of the companies. The disallowances and denial of full construction cost recovery, in some cases, have had a negative effect on the ordering of any new base load power plants, either nuclear or coal. This has contributed to the fact that no nuclear plants have been ordered since 1978 and no new orders are currently being planned in the U.S. This situation has led to a major national concern that adequate, reliable and economic electric power may not be available to fully meet future needs of the country.

The U.S. Department of Energy (DOE) has a responsibility to assure that adequate, reliable and economic electric power is made available to meet the future needs of the U.S. As a part of that responsibility, the Office of the Deputy Assistant Secretary for Reactor Deployment, through the Office of Nuclear Plant Performance, is addressing the institutional, financial and regulatory problems of the nuclear power industry.

The overall scope of work for this study includes the development of a body of data to depict the causes of electric power plant cost recovery disallowances, analysis of the causes and their impacts, and the development of recommended actions that may eliminate or alleviate the negative conditions found. This effort is set forth in the following three tasks, which were performed:

1. Develop and organize a body of data that depicts rate disallowances relative to nuclear and coal electric power generating plants. The reported causes for the disallowances and the impacts of the disallowances are to be included.

2. Analyze the reported causes and impacts of rate disallowances for power plant cost recovery, and determine if they represent what is really occurring in the industry.

3. Develop recommended actions that would eliminate or alleviate the conditions leading to negative prudency decisions and cost recovery disallowances.

It was recognized at the outset of this project that there would be a need to have the participation of specialists in the several areas of expertise relating to the questions of prudence in the electric utility industry. The following list of areas were identified in which expert assistance would be needed from key firms:

1. Engineering/Design/Construction
2. Data Acquisition
3. Legal
4. Accounting
5. Financial

The team of United Engineers & Constructors, in association with Utility Data Institute; Shaw, Pittman, Potts and Trowbridge; Arthur Andersen and Company; and Duff and Phelps, was formed to address the respective areas.

Data for this analysis was assembled by Utility Data Institute with the help of the other team members and the Edison Electric Institute. The analysis and recommendations were performed by the engineers, lawyers, accountants and financial analysts of the above firms, all of whom are involved with the electric utility industry.

Currently, six plus billion dollars have been excluded from the rate base of utilities for various reasons during the period 1980 to 1986. Although this is small compared to total investment in assets by utilities (the current investment by utilities for large central station nuclear and coal fired power plants, 1980 to 1986, is in excess of 100 billion dollars), any individual utility can be badly harmed by disallowance decisions focused on their plant(s). To analyze and understand the underlying reasons for these disallowances is urgent, and makes this study particularly appropriate at this time.

Since this entire area of disallowance and imprudence is currently in a state of flux, a monitoring of the situation by DOE is recommended for the future.

I. ELECTRIC UTILITY HISTORICAL PERSPECTIVE

In the United States, rates charged by electric utilities for retail service generally are set and regulated by public utility commissions (PUC's). This rate regulation typically occurs at the state level and by FERC when interstate sales are involved. Rates are regulated because large electric utilities are viewed as natural monopolies. It is assumed that, in the absence of such regulation, electric utilities would exercise their market power and extract monopoly profits through excessive and unwarranted charges. It is sometimes said that regulation is a substitute for competition, and that the objective of regulation is to produce results which would occur if competition among electric utilities were feasible.

Under a regime of regulation, electric utilities undertake an obligation to serve all customers within a specified service area with reliable electric service at fair and non-discriminatory rates. In return, the utility is provided an opportunity to earn a fair return on the investment it has made in facilities to provide such electric service. Because the utility is provided some measure of protection against the risks assumed by competitive businesses in unregulated markets, the return on utility investment generally is less than that available for investments made in unregulated businesses.

This relationship between the protection against certain business risks and a willingness to forego a market-justified return on investment, is sometimes referred to as the regulatory compact or bargain. The United States Court of Appeals for the District of Columbia Circuit recently described such a regulatory compact in the following terms:

> The Utility business represents a compact of sorts; a monopoly on service in a particular geographic area (coupled with state-conferred rights of eminent domain or condemnation) is granted to the utility in exchange for a regime of intensive regulation, quite alien to the free market. ... Each party to the compact gets something in the bargain. As a general rule, utility investors are provided a level of stability in earnings and value less likely to be attained in the unregulated or moderately regulated sector; in turn, ratepayers are afforded universal, non-discriminatory service and protection from monopolistic profits through political control over economic enterprise.(2)

II. RATES

A key element of regulation is the method used to set rates. Traditionally, this has been accomplished through investigation of a "test year". For that test year, a fair and reasonable revenue requirement is established. Rates are then designed to recover that revenue requirement from the various classes of customers. The revenue requirement is computed by determining the annual costs (including allowances for fuel, operation and maintenance, depreciation and income taxes) to provide the electric service. To this is added a fair return on the investment in facilities used to provide the electric service. This fair return on investment usually is expressed as a rate of return times the value of assets (often called the rate base) used to provide the electric service. Thus, the revenue requirement (RR) is equal to the cost of providing service (C) plus a return (R) on rate base (RB):

$$RR = C + (R \times RB)$$

Over the years, there has been much dispute over how the rate base should be valued. Two basic approaches, referred to as the "cost" measure and the "replacement" measure, have been used.

Under the cost measure, the rate base is the value in dollars of all property, used and useful, at the time when first devoted to service for public utility purposes.

By contrast, the replacement measure is a judgmental estimate of what it would cost to reproduce the utility's property at present-day costs, regardless of whether such reproduction costs might be higher or lower than the original cost.

Though once in vogue, the replacement measure for valuing the rate base is not often used today. In Smyth v. Ames, 169 U.S. 466 (1898), the Supreme Court explicitly included the reproduction cost of property as one of the factors by which to measure "fair value". The importance of the replacement measure increased during the next thirty years to the point where it was considered an indispensable measure of the rate base. See McCardle v. Indianapolis Water Co., 272 U.S. 400 (1926). However, in subsequent decisions the Supreme Court moved away from prescribing how the rate base was to be valued. This trend culminated in the leading case of Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944), where the Supreme Court refused to endorse or consider any formula or method of rate base approach as binding, as long as the "end result" of the rate order cannot be shown to be confiscatory. Freed from the use of the replacement measure, most PUC's adopted original cost as the proper measure for the rate base.

III. PRUDENCE

It has long been recognized that not necessarily every capital expenditure made by a utility should be included as part of the rate base. Customarily, property has been excluded from the rate base if it is not "used or useful" in the utility business. This might include non-utility property; unworkable, obsolete or abandoned property; contributed or donated property; and property held for future use. Another class of expenditures not to be included in the rate base would include imprudent investments. The classic definition of such expenditures was provided by Justice Brandeis in his separate opinion in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission, 262 U.S. 276 (1923). In his opinion, Brandeis states (id. at 289):(3)

> The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgement, unless the contrary is shown.

The significant aspect of the Brandeis definition is how narrow it is. Imprudent expenditures are linked with those that are "dishonest" or "obviously wasteful". Moreover, Brandeis is clear to state that "[e]very" investment is assumed to be reasonable, and imprudence must be demonstrated. This narrow view of imprudent expenditures continued until the very recent time. For example, a leading text on rate cases published in 1954 describes the prudent investment test in the following terms:

> Prudent Investment (or Investment) closely approximates original cost for all practical purposes. The only qualification is that the measure be keyed to "prudent" cost rather than actual cost of properties. This results in a theoretical reservation of regulatory judgement as to need, usefulness, or propriety of the properties actually bought or constructed by the utility for serving the public.(4)

Indeed, as late as 1973, commentary appearing in the Columbia Law Review stated that: "Normally, little controversy surrounds the amount of the utility's investment. ... The recorded investment in utility facilities is rarely challenged. While an investment could be disallowed as imprudent, the possibility is more theoretical than real."(5) In a footnote, it is observed that the New York Public Service Commission "has rejected claims that nuclear plants of several New York utilities were unnecessarily expensive."(6)

However, beginning, in the late 1970's the propriety of utility investment began to be challenged. This change in approach primarily arose because of two factors. First, beginning in the late 1970's and continuing through the mid 1980's, a significant number of nuclear power plant construction projects were cancelled in mid-stream. As a result, it became necessary for PUC's to determine what portion (if any) of the money expended on a cancelled nuclear plant should be recovered from customers and how such recovery should be effected (see Appendix, Table 5). Second, beginning in the early 1980's and continuing to the present, the costs associated with significant numbers of completed nuclear power plants rose very dramatically. PUC's were then asked to pass on these very large costs to customers in the form of significant rate increases. Again, the PUC's had to determine what portion of the money expended on a completed nuclear power plant should be recovered from customers and how such recovery should be effected. In both cases, commissions relied primarily on legal principles developed for rate base valuation to mitigate the impacts on customers.

With respect to cancelled plants, the principle of including in the rate base only utility property that is "used and useful" was relied upon to disallow significant parts (if not all) of investments made. Prior to such decisions, application of the regulatory compact would have argued that, if the decision to initiate the nuclear project was reasonable when made, and if the decision to cancel the nuclear project was reasonable when made, then the investor should receive some protection and should get some return of his investment. In essence, this approach would have protected the utility investor against some of the risk arising from unforeseeable changed circumstances by allowing some return of the reasonable and prudent investment made in the cancelled plant. While an investor in an unregulated, competitive business may not have expected or been entitled to such protection, the utility investor should expect such protection because (1) In principle, his allowed return on investment is lower than the normal return in an unregulated, competitive business; in reality, this may not be true at all times because of factors such as depressed reutrn on investment for industrial companies due to recessionary periods or foreign competition and unusually high returns for utilities due to regulatory lag in rate adjustment in a period of falling costs; and (2) unlike the unregulated company, the utility is obligated under the franchise to serve the electric load in the territory. A utility simply is not entitled to decline plant expansion as being too risky.

In most cancelled nuclear plant cases, PUC's followed traditional principles and did provide some protection for the utility investor. This was accomplished by allowing the utility to amortize over a specified period the money invested in the cancelled plant. This allows the utility to recover the investment as part of its annual expenses. Generally, however, no return was allowed on the unamortized balance of the investment. While this denied the investor a return on the use of his money, it was justified as a reasonable compromise and sharing of the risk between investor and customer. However, in some states no amortization was permitted and the investor was denied both a return on the use of his money and return of the investment itself. While such a result may be appropriate in an unregulated business, the harsh effect of this result for a prudently made investment in a cancelled power plant cannot be reconciled with traditional rate base valuation principles.

In a few cancelled plant cases, PUC's sought to justify the result of disallowing either a return on investment or recovery of that investment by investigating the reasonableness of the investment in the cancelled plant. In theory, the initial decision to begin the power plant construction project could be held to have been unreasonable and all of the investment disallowed. In practice this approach is difficult because in most cases the PUC authorized initiation of the project through some type of certificate of public convenience and necessity. Alternatively, portions of the money spent prior to cancellation could be found to have been unreasonable and therefore disallowed. In practice this approach was not followed in cancellation cases, presumably because the effort needed to identify such imprudent expenditures was not deemed worthwhile. Lastly, some of the investment could be disallowed upon a finding that it was imprudent not to have cancelled the construction project sooner. This approach challenges the reasonableness of the cancellation decision. Such an approach argues that a prudent utility would have evaluated the desirability of continuing with the construction project earlier and would have determined that the reasonable course would have been to cancel the project earlier. In a few cancellation projects, this theory has been adopted. Accordingly, all expenses incurred after the date on which the PUC determined that the project should have been cancelled have been disallowed.

While the cancellation cases set the stage, most recent regulatory activity addressing the prudence of power plant construction costs has been aimed at the set of completed nuclear power plants coming on-line in the 1980's. These plants typically have been characterized by substantial increases in cost over initial budget and substantial increases in schedule over initial projections. These two factors provide both a reason for investigating the costs incurred (to minimize the rate impact to the customer) and a basis for disallowing some of the costs (treating the initial cost estimate and schedule projection like a fixed price contract).

During the current Supreme Court term just recently completed on June 30, 1987, two significant cases bearing on the prudence issue were presented to the Court.

In Kansas Gas & Electric Co. v. State Corporation Commission of Kansas (No. 86-781) and Kansas City Power & Light Co. v. State Corporation Commission of Kansas (No. 86-793) the utilities challenged that part of a state public service commission decision which valued the Wolf Creek Nuclear Generating Station as if it were a coal plant -- a ruling which in the utilities' view disallows 78 percent of the prudent and useful investment in Wolf Creek. The utilities' argument is that the decision confiscates their property in violation of the Fifth and Fourteenth Amendments to the Constitution, and violates their rights to equal protection and due process. The case is significant because it raises constitutional issues about how prudent and useful investments in large, central station, base load power plants should be valued.

On February 23, 1987, the Supreme Court noted probable jurisdiction and agreed to hear the cases. 107 S Ct. 1281 (1987). However, Kansas Gas & Electric had proposed, and on March 11, 1987, the Kansas Corporation Commission adopted, a settlement agreement resolving most of the issues between the parties.

Accordingly, on May 18, 1987, the Supreme Court dismissed the Kansas Gas & Electric appeal. See 107 S. Ct. 2171 (1987). The Kansas City Power & Light case is still pending, but a proposed utility settlement in that case is now before the Kansas Corporation Commission. It is thus likely that this case too may be settled and the Supreme Court appeal dismissed.

The Edison Electric Institute has filed an amicus brief with the Supreme Court that makes many of the broad arguments that are of concern to the Department of Energy. Thus, while this case is potentially important, given its procedural posture and the positions currently being presented to the Court by the parties and the amicus, there is little reason for the Department of Energy to participate directly.

The second important case presented to the Supreme Court involves the Grand Gulf nuclear plant. The legal proceedings involving this plant are especially complex and convoluted, have involved proceedings before the U.S. Courts of Appeals for the District of Columbia and the Fifth and Eighth Circuits. Involved parties include the four operating utilities that are part of the Middle South system, the public service commissions in Mississippi, Arkansas, Missouri and Louisiana, the Federal Energy Regulatory Commission ("FERC"), and others. In Mississippi Power & Light Co. v. State of Mississippi (No. 86-) the utility has challenged a decision by the Mississippi Supreme court which it is alleged nullifies a FERC wholesale rate decision that allocates the wholesale costs of generating electricity among affiliated electric utilities that serve different states. The Supreme Court has not yet ruled whether it will take the case, though the Court has issued two stay orders to preserve the status quo pending its decision on whether to accept the case.

The proceeding is potentially important because it raises constitutional issues relating to the extent a FERC decision preempts the rights of state public service commissions to enter contrary orders. The basic policy issue is whether states may seek to limit rate increases to their citizens while imposing even higher costs to citizens in other states. As may be expected, when such decisions are made at a state level rather than at the federal level, the parochial interests of each state tend to take precedence over national interests.

It is our understanding that FERC has been in contact with the Solicitor General and it is likely that the United States will file an amicus brief. We therefore recommend that the Department of Energy continue to monitor the progress of this case.

The electric utility industry has been undergoing a dramatic upheaval since its entry into the nuclear age. A significant part of this change has been the substantial increase in the cost and time necessary to engineer and construct power plant projects, especially nuclear powered generating facilities. This change has had a pronounced effect on the manner in which PUC's conduct prudence reviews of such projects. In order to provide a perspective on this change, the cost trends and cost drivers underlying the change are discussed in the following section.

IV. INDUSTRY DEVELOPMENTS

The spiraling increase in U.S. coal and nuclear plant costs and schedule projections during the last decade can be shown to have resulted from increasing and changing criteria relative to environmental and safety issues. During that period U.S. nuclear and coal plant capital costs have experienced compound annual growth rates of approximately 20 percent and 15 percent per year, respectively. The problem is particularly serious for nuclear power plants. Owner preferences and the regulatory related increases in the quantities of construction materials, labor content, engineering manhours and schedules of U.S. nuclear plants has resulted in each plant being fundamentally a first-of-a-kind unit with minimum learning feedback to facilitate effective cost reduction. The pursuit of the unattainable goals of zero risk to man and the environment and complete documentation to legally prove its achievement, has driven the cost of nuclear electric generation relentlessly upward over the last 15 years. This is in contrast to Canada, Japan, Korea and France, for example, where costs have risen at a much lower rate.

The Department of Energy (DOE) and its predecessor agencies have been involved in energy economics since 1949. In the late Fifties and the Decade of the Sixties, the Federal efforts were geared to develop rigorous, complete and comparable methods of economic analysis for the nuclear and coal options. During the mid-Sixties the effort was expanded to develop construction cost estimates for nuclear and coal plants as a function of the current regulatory, economic and construction conditions. These Federal agencies have been preparing coal and nuclear cost estimates, with the assistance of United Engineers & Constructors Inc. (UE&C), for almost 20 years. This effort has resulted in the evolution of an engineered approach to cost estimating, and the development of a large, historical data base of nuclear and coal power plant economic models.

The latest series of cost studies (which commenced in 1978), form the historical basis for the current nuclear and coal plant economic models, which comprise the U.S. DOE Energy Economic Data Base (EEDB). The information in the EEDB is used by utilities, contractors, consultants and government agencies throughout the United States. This data base includes capital cost data for several different types of nuclear and coal power plants.

The U.S. DOE historical data base of comparably normalized power plant models identifies trends in design and construction costs of nuclear and coal plants. The consistent application of this approach in the development of these cost estimates permits a historical analysis of the changes in the construction material and labor requirements during the 1970's and 1980's. Such an analysis reveals that the dramatically rising cost of nuclear plants derives from the regulatory changes, which cause manpower and non-NSSS commodities to dominate the total nuclear power plant base construction cost. The problem is further compounded by the impact of extended schedules on the time related cost of money.

Generally speaking the factors driving the capital cost of U.S. nuclear plants are:

- increased construction material requirements
- increased craft labor content,
- increased engineering manhours, and
- lengthened project and construction schedules

The construction material or "commodities" for both nuclear and coal plants have increased substantially in the last decade.

The increases for nuclear power plants are associated mainly with evolving safety requirements. More stringent seismic design requirements have increased the amount of concrete, reinforcing steel and structural steel. Similarly, the more stringent tornado design regulations have increased shielding and missile protection design requirements, resulting in the use of more materials.

The implementation of redundancy and physical separation requirements for the mechanical and electrical systems associated with safety functions have increased the quantities of piping, electrical cable and electrical conduit. It should be noted that most of these increases involve facilities and systems not supplied by the nuclear steam supply system (NSSS) vendor. Rather, they are associated with the envelope that surrounds and integrates the NSSS with the surrounding environment.

The increased construction material requirements for coal plants are associated with implementation of evolving environmental requirements. The increases are not as large for coal plants as for nuclear plants because the environmental regulations are usually met by the addition of more equipment as opposed to construction materials. For fossil plants, the increased material requirements reflect the additional materials associated with the installation of scrubber, waste and water treatment equipment.

The manhours required to engineer and construct a nuclear power plant also have increased dramatically during the last decade. The compound annual growth rate of manual and non-manual labor requirements for U.S. nuclear and coal power plants, as taken from the EEDB, are as follows:

LABOR CATEGORY	NUCLEAR UNIT 1,2	COAL UNIT 1,2
PERIOD:	1971 - 1984	1971 - 1981
CRAFT LABOR:	+ 13%	+ 8%
ENGINEERING & FIELD SERVICE LABOR:	+ 24%	+ 8%

The increase in craft labor manhours for a U.S. nuclear plant has been driven by several factors. The rising quantities of construction materials to be installed has increased the craft manhours. In addition, schedule slippages for financial or licensing reasons have caused increased craft manhour requirements because of associated inefficiencies. The most significant factor, however, has been the decline in overall labor productivity. This decline has been caused by the increased congestion of safety related areas of the plant; increased waiting time for quality assurance inspection of completed work; and significant increases in the amount of rework because of failure to meet the interpretation of stringent standards in the quality assurance program. Regulatory induced increases are not always caused by changes in regulations. Rather, they often result from the interaction of U.S. Nuclear Regulatory Commission (NRC) and industry staffs in an effort to obtain the goals of "zero risk" and "zero defects" in an adversarial and legalistic regulatory environment.

The time required to plan, license, engineer, construct and startup a nuclear or coal-fired power plant increased sharply as the 1970's proceeded into the 1980's.

The increased material and labor requirements associated with the U.S. power plant construction climate during the decade of the Seventies and early Eighties resulted in increased direct and indirect costs. The schedule extensions increased the cost of interest and escalation during construction. This effect was compounded by the rising inflation rate experienced in the U.S. during the same period because it drove up the escalation and interest rates.

A review of the capital cost estimates for nuclear and coal power plants indicates that the compound escalation rate for the capital cost of a U.S. nuclear plant during the period from 1967 to 1984 approximates 20 percent and 15 percent for a coal unit. Inherent in these current dollar escalation rates is a real escalation rate that is in the order of 10 percentage points over the general inflation rate prevailing in the United States during the same period.

An analysis of the trends in nuclear power plant capital costs vividly highlights the shift in importance among the elements which make up the capital cost. The shift is from hardware costs to schedule dependent costs, namely escalation and interest during construction.

DISCUSSION OF CAUSES

The previous section cited the trends in U.S. nuclear and coal power plant construction in terms of materials, labor, schedule and ultimately cost, and commented on the immediate causes of these increases. This section focuses on the factors influencing the deterioration in U.S. engineering and construction performance for nuclear plants.

UE&C has identified the following causes:

- Unstable U.S. Regulatory Environment
- Number and Application of Consensus Standards
- Emphasis on Seismology and Seismic Analytics
- Overly Conservative Interpretation of Standards and Regulations
- Extensive Interface Conflicts
- Quality Assurance Programs

Generally speaking the power plant construction performance deterioration results from the current U.S. nuclear regulatory structure and environment, which has created an unworkable situation in which NRC and industry staffs interact in an effort to obtain the goals of "zero risk" and "zero defects" within an adversarial and legalistic regulatory environment.

Unstable U.S. Regulatory Environment

The U.S. regulatory environment has been unstable during the last decade and a half with respect to both legislation and safety requirements promulgation. The history of U.S. Congressional legislation has impacted to some degree nuclear power plant construction. In addition, the regulatory environment associated with achieving nuclear safety has been very unstable. Unlike some nations, the U.S. nuclear regulatory system does not "grandfather" the regulatory criteria to be satisfied as a function of some pre-construction licensing date. Consequently the design is subject to change during the entire engineering, construction and startup process. The current nuclear safety regulatory structure has numerous ways of imposing requirements. These include:

- Regulations (Title 10 Code of Fed. Reg.)
- Regulatory Guides
- Branch Technical Positions
- Standard Review Plans
- NUREG Reports
- Orders
- I/E Bulletins (Notices & Circulars)
- Generic Letters
- Regulatory Position Statements
- Proposed Rulemakings
- Inspector Preferences

Number and Application of Consensus Standards

The nuclear power industry tried to develop guidance and consistent interpretation of the federal requirements through the consensus standards organizations. In some cases these organizations had NRC representation on the code committees. The result was a rapid and significant increase in the number of applicable consensus standards. Originally most of the consensus standards were viewed as intended to provide flexible guidance to the engineers. However, the NRC views any standards called out in the Preliminary Safety Analysis Report (PSAR) or quality assurance control documents as part of the licensing commitments made by the utility. Therefore, any standard involved in this context takes on the character of a mandatory commitment. As a result, implementation, and particularly modification of the use of these standards has become more of a legal or procedural process rather than a technical process where engineering judgment can be utilized as the basis for action. During the 1970's and the early 1980's the U.S. nuclear engineering and construction process has evolved in a manner that discourages the use of engineering judgment.

Emphasis on Seismology and Seismic Analytics

The U.S. nuclear regulatory climate during the 1970's and 1980's has been characterized by a focus on low probability events. Principal among these has been the evolution in the requirements, sophistication and complexity associated with seismic events and seismic analysis. During the 1960's the principal focus of seismic analysis was only on the major structures that house and support the mechanical, electrical and other equipment associated with operating the plant.

During the 1970's the scope was broadened significantly to include the mechanical equipment, piping, electrical and instrumentation systems.

In addition the sophistication and complexity of the analyses used have increased significantly. The emphasis on dynamic analysis has resulted in a seemingly endless reanalysis and rework as each change, perhaps caused by a field interference, affects the dynamic characteristics of the system and therefore requires reanalysis to verify the seismic acceptability of the design. More importantly, the regulators and the industry have come to view complex analytics as a replacement for "engineering judgment" and "good engineering and construction practice".

For example, in an independent audit of the Perry Nuclear Power Plant the consulting firm of Pickard, Lowe and Garrick found that cost increases due to seismic analysis, pipe rupture/jet impingement impacts analysis, piping code changes and related IE notices and bulletins requirements amounted to more than 11% of the total increase in project costs, not counting allowance for funds used during construction (AFUDC). The total increase for the above changes exceeded $306 million of a total variance (without AFUDC) of $2.689 billion.

Overly Conservative Interpretation of Standards & Regulations

U.S. utilities have for a number of reasons been extremely conservative in the interpretations of U.S. nuclear regulations and associated consensus standards. The reasons include a desire to convince the NRC that the project is being prosecuted in good faith, the fear of being denied an operating license because designs defined in an early part of the project might not meet new requirements issued later during the construction process, and the fear of losing a decision in a regulatory or judicial hearing which would cause financial damage by extending schedules. There has been a tendency to overcommit during the licensing and design process, to accept requirements even though their financial consequences have been severe, and in general to seek levels of perfection and documentation which have been unrealistic in terms of the normal field construction environment.

Extensive Interface Conflicts

The result of all these cross currents within the engineering and construction organizations has been an extensive amount of interface conflicts. For example the complex analytics used to support the licensability of the plant call for installation precision and procedures that are extremely difficult to implement, in terms of the normal field construction environment, resulting in seemingly endless reanalysis and increased rework.

Quality Assurance Programs

In the late 1960's and early 1970's the NRC began to emphasize quality assurance programs throughout the industry. The result has been a continual decline in engineering and construction productivity as more and more manhours have been expended in documenting all the engineering and construction activities required by the NRC to demonstrate that they have been properly planned, executed and documented. These new requirements to document apply to changes that occur during the normal engineering and construction process, including problem resolution, as well as to chances that result from changes in regulatory requirements.

The difficulty in explaining to PUC's the various types of changes incurred in power plant projects, and the incredulity of the PUC's that such an environment could exist, has allowed such commissions to disallow substantial investments. This has occurred because of the utilities' inability to precisely identify changes with specific dollar amounts, and to provide a totally documented justification for these changes. Disallowances have been incurred by utilities in a variety of ways as explained in the next section.

V. TYPES OF DISALLOWANCES

The Appendix includes a summary of capital cost disallowances for nuclear and other power plants. The category of other power plants primarily includes coal-fired plants.

It should be recognized that the disallowances shown in the Appendix are changing and will continue to change over time. For example, appeals currently are in progress for certain nuclear units, and the magnitude of disallowances should be evaluated in that perspective.

The disallowances of construction costs by PUC's occur for a multitude of reasons reflecting the particular situation of the plant under construction, the approaches and decisions of the electric utility system building or owning the plant, and the PUC approach to rate regulation. The disallowances, however, can be broadly classified into the following five categories:

Imprudence

This category includes disallowances as a result of certain utility decisions being judged as imprudent or unreasonable. A reasonable man standard is applied: that is, would a reasonably knowledgeable and trained manager have taken the actions and made the decisions under review, based on circumstances that were known or should have been known at the time. Extra expenses incurred from a failure to meet that standard are disallowed from the rate base. This disallowance is permanent.

Excess Capacity

It is generally construed that a facility should be used and be useful to the public, for inclusion in the rate base. If a utility has excess generating capacity, the facility may not be useful to the public. Therefore, the PUC may disallow part of the investment representing excess capacity from inclusion in the rate base. This disallowance is not permanent and can be included in the rate base as the utility's load requirements grow, eliminating excess capacity.

Cost Caps

This is basically a new idea not encountered frequently in utility rate cases. When a generating facility is under construction, the PUC may specify a cap on the amount of investment that will be allowed in the rate base. If the facility is completed for a higher amount, the excess investment may be disallowed from inclusion in the rate base. This disallowance is permanent. In some cases, utilities have accepted cost caps as a means for settling contested rate cases.

Economic Value

The PUC may decide that the actual cost of a facility is above the economic value of that facility. For example, economic value may be estimated by comparison or inference with alternate sources of generation. The amount in excess of economic value may be disallowed from inclusion in the rate base.

Other

This category includes disallowances that do not fall under the other four categories.

The above five categories represent a set of classifications based on PUC orders.

Table V-1 gives a summary of nuclear plant cost disallowances by unit and type of disallowance over the period 1980-1986. This table gives information on 13 nuclear units with disallowances classified under imprudence, excess capacity, economic value, cost cap and other. The total disallowances add up to $6,592 million. It can be seen that the disallowances under imprudence are most common followed by those under excess capacity. It should be noted that the total disallowance amounts are certain to change over time for nuclear units completed in the 1980 to 1990 time frame where appeals are in progress.

Table V-2 gives a summary of coal and other plant cost disallowances by unit and type of disallowance. The total disallowances for coal-fired and other plants are estimated at $127 million over the period 1980-1986. This is very small compared to the $6,592 millions for nuclear plants.

For comparison, the current investment by utilities for large central station nuclear and coal-fired power plants, 1980 to 1986, is in excess of 100 billion dollars on the order of Nuclear $70 billion, coal approximately $40 billion (See Table VIII-1).

Reasons for Disallowances

The disallowance by regulators of plant-related costs has become common place to an alarming degree in recent years. It appears that the regulatory contract is being violated, to varying degrees, by many state regulators. In the view of investors, the concept of reasonableness or prudence is being abused for political expediency, at the expense of perceived integrity.

Many plant cost disallowances can be hidden under transparent attempts to suppress rates. There are two principal reasons for these rate suppression problems for newly completed plants. The first reason is the result of anti-nuclear sentiment. The economics of electric utility service are a means to an end in this scenario. Construction delays can be achieved through intervention before regulatory bodies, and/or support of anti-nuclear politicians. The accrual of an accounting return on the delayed plant, plus additional hard dollar costs of newly required modifications and enhancements, reduce the economic benefit of the nuclear plant. This technique was successful in bringing about the cancellation and abandonment of many plants and the near-ruin of companies who completed other plants. The success of this strategy in opposing nuclear power is particularly apparent regarding future construction. It is hard to believe any funding could be obtained at a reasonable cost for a new nuclear power plant in the foreseeable future.

The second reason for rate suppression disallowance results from rate shock. The perception of rate shock can result from economic hard times in the service area, which cause consumers to view <u>any</u> cost increases as traumatic. The sources of rate shock include rate suppression <u>during</u> construction.

TABLE V-1

DISALLOWANCES FOR INDIVIDUAL NUCLEAR UNITS
(MILLIONS OF DOLLARS)
(1980-1986)

	DISALLOWANCE					
UNIT	IMPRUDENCE	EXCESS CAPACITY	ECONOMIC VALUE	COST CAP	OTHER	TOTAL
Byron 1	101.5	-----	-----	-----	-----	101.5
Callaway 1	421.7	-----	-----	-----	-----	421.7
Fermi 2	397.0	283.0	-----	-----	-----	680.0
Grand Gulf 1	Most Disallowances not quantified				49.0	49.0
Limerick 1	368.9	-----	-----	-----	-----	368.9
Millstone 3	-----	-----	109.0	237.0	7.0	353.0
San Onofre 2 & 3	328.0	-----	-----	-----	-----	328.0
Shoreham 1	1,395.0	-----	-----	-----	-----	1,395.0
Susquehanna 1	-----	287.0	-----	-----	-----	287.0
Susquehanna 2	-----	522.0	-----	-----	38.0	560.0
Summer 1	-----	123.0	-----	-----	-----	123.0
Waterford 3	-----	-----	-----	284.0	-----	284.0
Wolf Creek 1	409.0	970.0	262.0	-----	-----	1,641.0
	3,421.0	2,185.0	371.0	237.0	378.0	6,592.0*

* Since the $6/592 billion represents a snapshot in time (thru 1986), the disallowances will change as decisions are appealed, court settlements occur, or new disallowances are considered in current and future rate cases.

TABLE V-2

DISALLOWANCES FOR INDIVIDUAL COAL-FIRED AND OTHER UNITS
(MILLIONS OF DOLLARS)
(1980-1986)

	DISALLOWANCES					
UNIT	IMPRUDENCE	EXCESS CAPACITY	ECONOMIC VALUE	COST CAP	OTHER	TOTAL
Belle River 1 & 2	96.9	-----	-----	-----	-----	96.9
Big Bend 4	3.7	-----	-----	-----	-----	3.7
Holcomb 1	0.5	-----	-----	-----	-----	0.5
Reid Gardner 4	4.4	-----	-----	-----	-----	4.4
Helms 1-3	22.0	-----	-----	-----	-----	22.0
	127.5	-----	-----	-----	-----	127.5

The rate shock listed above is a matter of regulatory policy. During construction, plant costs can be reflected in rates as they accumulate, resulting in a truthful price signal to the consumer and a lower final plant cost, which is not burdened with capitalized interest and equity return. Also, capital costs, both interest and equity return, are minimized since credit quality is greatly enhanced. Typically, plant costs during construction can be reflected in rates as those costs accumulate by allowing Construction Work in Progress (CWIP). However, in some jurisdictions political decisions have been made which preclude the use of CWIP.

The antithesis of the practice of including plant costs in rates during construction is the accrual of Allowance for Funds Used During Construction (AFUDC). This alternative practice suppresses utility rates during construction, increases capital costs to the cash-poor utility through diminished credit quality, and bloats the final cost of the plant. Furthermore, companies who must live on AFUDC rather than cash earnings during a major construction project are sometimes forced to slow down, or periodically stop, the pace of construction, thereby adding further to the cost of the plant.

VI. DISCUSSION OF SPECIFIC DISALLOWANCES

Nuclear Units

Table 6 in the Appendix gives capital cost disallowances for nuclear plants. This table gives the name of the nuclear unit, the electric utility and its area of jurisdiction, the type of disallowance, amount of disallowance and comments relating to the disallowance. In certain cases the amount of disallowance is not given because of difficulties in quantifying the disallowances or some other reason. For cases where the amounts are available, the total disallowances add up to 6,592 million dollars over the period 1980-1986.
Of this total, approximately $3,421 million or 51.9% is due to imprudence, $2,185 million or 33.2% is due to excess capacity, $371 million or 5.6% is due to economic value, $237 million or 3.6% is due to cost caps and $378 million or 5.7% falls in the category of other. The overall disallowances are summarized below:

TYPE OF DISALLOWANCES	AMOUNT OF DISALLOWANCE $\$ \times 10^6$	PERCENT
Imprudence	3,421	51.9
Excess Capacity	2,185	33.2
Economic Value	371	5.6
Cost Cap	237	3.6
Other	378	5.7
Total	6,592*	100.0

The disallowances for selected individual nuclear units are discussed below:

Callaway 1

On March 29, 1985 the Missouri Commission ordered a 6-year phase-in of $455 million of rate relief in response to Union Electric's request for $474 million of additional revenues. The principal reason for the difference between the amount requested by the Company and that allowed by the Commission was the disallowance from the rate base of $384 million of Callaway expenditures. The Missouri Commission concluded that "although Union Electric did a credible job of managing many aspects of the Callaway project, there are exceptions which require significant disallowances in order to establish 'just and reasonable' rates". The Company appealed the imprudence decision, but later dropped its appeal. As indicated in their press release, Union Electric maintains its position that the Callaway disallowance was unfounded, but dropped the appeal due to the legal expense and lack of encouragement in the legal process.

The Illinois and Iowa Commissions based Callaway-related rate increases on plant disallowances and phase-ins similar to that allowed by the Missouri Commission. In aggregate the three state regulators disallowed $422 million of Callaway costs from rate base.

* Since the $6.592 billion represents a snapshot in time (thru 1986), the disallowances will change as decisioins are appealed, court settlements occur, or new disallownces are considered in current and future rate cases.

On July 25, 1984, Union Electric filed a request with FERC for about $37 million of annual rate relief based on a proposed phase-in of Callaway costs. The FERC permitted interim increases of $12 million in January 1985 and $5 million in January 1986. In its initial decision of June 4, 1986, FERC disallowed $18 million of Callaway expenditures and granted a 5-year phase-in of $31 million of rate relief. Based on the $31 million determination of June 1986, the January 1985 and January 1986 rate increases were lowered retroactively, resulting in an approximate $3 million refund to customers.

Fermi 2

The notes on Fermi 2 in the Appendix state the Administrative Law Judge's (ALJ) recommendation in the case, rather than the Michigan PSC's decision of April 1, 1986, which is much more important and differs from the ALJ's recommendation. Furthermore, the notes suggest that the ALJ set a cap on the co-op's investment in Fermi 2.

The co-op's investment in Fermi 2 arises from the Rural Electrification Administration's (REA's) refusal to permit further funding for the co-op. As expenditures continue without further co-op investment, the ownership breakdown has changed to 88/12. Furthermore, the Company and the co-op have agreed that Detroit Edison (DTE) will ultimately purchase the entire co-op's share of Fermi 2.

In the April 1986 rate order, the MPSC agreed with the ALJ, and removed the $283 million Greenwood 1 oil-fired plant from rate base, but required the Company to keep Greenwood 1 available for service. This requirement is central to Detroit Edison's appeal of the order.

Detroit Edison filed for Fermi-related rate relief based on a $3,075 million cost estimate. The Company expects Fermi 2 to commence commercial operation in the fall of 1987 at about a $4,300 million total cost. The $1,225 million ($4,300 minus 3,075) additional investment in Fermi is unaddressed, not denied. The MPSC has agreed that no decisions have yet been made on these expenditures, although in April 1986 the Commission decided that $397 million of the $3,075 million Fermi investment was made imprudently.

Limerick 1

The data reported in the Appendix, Table 6, on Limerick 1, specifically that $369 million of expenditures were excluded from the rate base as imprudently incurred, is correct. To this fact, it should be added that $632 million of common plant was disallowed from the rate base as being attributed to unit 2. The accrual of AFUDC on these expenditures was allowed through commercial start-up, which is expected in 1991.

San Onofre 2 and 3

The $344.6 million of disallowed expenditures are for the entire unit 2 and 3 construction costs. Southern California Edison's 75% share of the $344.6 million aggregate disallowance equaled $258.6 million ($161.9 million due to 358 days of construction delay plus $74.0 million of indirect costs plus $22.7 million of quality assurance and quality control expenditures). The $284.4 million of disallowance being appealed by Southern California Edison also represents the total project share. The Company's 75% share of the amount being appealed equals $213.4 million ($139.4 million of scheduling delays plus $74.0 million of indirect costs). The California Commission has agreed to re-consider one-third of the disallowance and has not denied a rehearing on the remaining two-thirds.

Shoreham 1

The New York Public Service Commission (NYPSC) adopted a plan calling for a 15-year phase-in of all prudently incurred Shoreham costs. However, the 4.5% to 5% allowed annual rate increases includes the costs of Nine Mile Point 2 and many other operating and maintenance expense items.

Wolf Creek 1

The information on Wolf Creek in the Kansas City Power and Light (KCPL) rate decisions in Kansas and Missouri and the Kansas Gas and Electric decision in Kansas is essentially correct. However, in the Kansas City Power and Light case in its Kansas jurisdiction, the story should be updated for the "rate reduction, equalization and stabilization plan" filed April 6, 1987.

In this rather complicated filing, KCPL asks that the Commission approve the entire plan without modification. The plan would have the net effect of reducing retail electric rates in the Company's Kansas jurisdiction. The Company proposes a 2% rate reduction on May 5, 1987 and a 3% rate reduction one year later. The two rate adjustments total $10.3 million, which equals the Company's estimated cost savings under the Tax Reform Act of 1986.

In its filing, KCPL proposes to revalue its Wolf Creek investment at the full $2,300/kW rather than at the $1,290/kW valuation established by the Kansas Commission. The Company would be required not to seek inclusion in the rate base of any of its 314 MW of excess capacity until at least January 1, 1990, at which time KCPL would file for rate increases to reflect Wolf Creek in the rate base at $2,300/kW effective January 1, 1991. Furthermore, KCPL proposes to accrue carrying costs on excess capacity at $2,300/kW instead of at the $1,290/kW level approved in 1985. The Company also seeks a 30-year rather than 40-year depreciation life for Wolf Creek, would reduce its authorized return on equity to 12% from 15.8%, and would recover some higher-than-expected Wolf Creek operating expenses.

Finally, as part of this plan, KCPL would withdraw its pending appeal before the United States Supreme Court of the Commission's 1985 Wolf Creek decision. The Kansas Commission expects to issue a decision on the Company's proposed plan in the summer of 1987.

Kansas Gas & Electric (KG&E) the other investor-owned utility participating in Wolf Creek already has obtained Commission approval of its plan to pay for Wolf Creek. In December 1986, KG&E filed an application with the Kansas Corporation Commission (KCC) proposing to resolve outstanding issues relating to the rate treatment of Wolf Creek. Essenetial points of the KG&E application are:

- o KG&E would purchase substantial amounts of Key Man Life Insurance on its personnel with an actuarial value of $800 million over the 40 year life of the plant.

- o KG&E would credit any proceeds received from such insurance against its cost of service revenue requirement -- in effect, offsetting electric rate revenues with insurance proceeds.

- The KCC would value the prudent and useful portion of Wolf Creek at actual cost rather than the cost of a hypothetical coal plant. On March 11, 1987, the KCC issued an order substantially granting the KG&E application.

Coal Units

Table 7 in the Appendix gives capital cost disallowances for coal-fired and other plants. This table gives the name of the unit, the electric utility and its area of jurisdiction, the type of disallowance, amount of disallowance and comments relating to the disallowance. These disallowances add up to a total of 127 million dollars.

The disallowances for certain coal-fired units are discussed below:

Belle River 1 and 2

In July 1985, the MPSC disallowed $97 million of Belle River investment from the rate base. Some $36 million of the total amount was for certain coal handling facilities deemed by the MPSC to be not yet used and useful. However, the rate order allowed recovery of all but $3 million of the coal handling equipment investment through depreciation. Furthermore, the Commission disallowed the coal handling facilities until the Company could demonstrate, in a future rate case, that it is used and useful.

The remaining $61 million of Belle River plant disallowed from the rate base was due to an "imprudent" 18 month delay of the project beginning in 1974. The Company claimed, and the Commission agreed, that the 1974 shutdown of constuction at Belle River resulted from a lack of funds due to an adverse capital market, a state regulation prohibiting the sale of common stock below par, and insufficient internally generated cash. Using the low Belle River CWIP levels and AFUDC rate applicable during the construction delay period in question, Detroit Edison calculated an approximate $2 million increment to the final Belle River plant costs using the Commission's rationale.

The Company appealed the July 16, 1985 order to the Ingham County Circuit Court, which, on September 17, 1985, issued an injunction which allowed the Company to collect, subject to refund, $12.1 million in annual revenues related to the $61 million rate base disallowance. The UDI note number 1 to Table 2 in Appendix concerning Belle River 1 and 2 refers to a December 16, 1986 court decision which found that the MPSC had not met the substantial evidence standard for the $61 million Belle River costs disallowed due to imprudent delay.

Holcomb 1

In the Appendix, Table 2, Note 4, the less-than-requested phase-in could definitely be considered an excess capacity penalty. Upon completion of Holcomb 1, the Co-op had a 75% reserve margin. This was due in part to the Co-op's failure to give sufficient (4 year lead-time) notice to KP&L to cancel a firm purchased power contract.

Reid Gardner 4

Less than 100% of the plant was allowed in the rate base. A total of approximately $4.37 million of Nevada Powers' $115 million share of the unit cost was disallowed (somewhat over three percent). Nevada Power is the minority owner with a 32% share.

VII. IMPRUDENCE TEST AND CLASSIFICATIONS

There have been many state commission applications of the prudence test in recent years. In this chapter, information for successful applications of the prudent investment test are offered.

The principal factors for a successful utility prudence inquiry are: (1) reliance on the rebuttable presumption of prudence, (2) a rule of reasonableness under the circumstances, (3) a proscription against hindsight, and (4) a retrospective, factual inquiry. Following these guidelines is likely to be useful, perhaps necessary, for having a court sustain commission findings. However, because prudence is an evolving regulatory tool, following these guidelines may not be sufficient to guarantee that plant capital costs will be recovered from ratepayers. This is because regulatory tests other than prudence must also be considered.

The Presumption of Prudence

When applying the prudent investment test, state commissions should take seriously Justice Brandeis' admonition regarding prudent investments: "Every investment may be assumed to have been made in the exercise of reasonable judgement, unless the contrary is shown."[7] It has been held that without "affirmative evidence showing mismanagement, inefficiency, or bad faith,"[8] an investment decision is presumed to be prudent. In the absence of such an affirmative showing, at least one court had stated that a commission cannot disallow a utility's expenses.[9] Thus, for example, unless a particular management decision associated with the planning or construction of a power plant is challenged, the full original cost of the investment in the power plant is presumed to be prudent and includable in the rate base. Of course, in fair value States, the investment is included in the rate base at its fair value, which may or may not be its original cost.

Reasonableness under the Circumstances

When the rate base treatment of an investment is challenged on the basis of prudence, the test applied to determine if the investment decision is prudent becomes critical. Most commissions applying the prudent investment test use the standard developed in the Brandeis opinion of the Southwestern Bell case; namely, the prudence of a decision is based on its reasonableness under the circumstances. From this starting point, state commissions have developed the prudent investment test as it is currently applied to public utilities. This test requires a standard of care owed by the utility to its customers. The standard of care is one of "reasonableness under the circumstances, which was known at the time."

Proscription Against Hindsight

A proscription against the use of hindsight in applying the prudence standard is a corollary to the "reasonableness under the circumstances" test. Decisions are to be judged in light of the conditions and circumstances that were or should have been known to the utility at the time of its decision.

If a state commission engages in hindsight, any finding of imprudence is subject to reversal.

Retrospective, Factual Inquiry

Once the presumption of prudence is overcome, there is a need to develop evidence about whether the investment decision was prudent or imprudent. To accomplish this, state commissions engage in retrospective, factual inquiries.

Evidence for prudence or imprudence needs to be retrospective, or backward looking, in that it must be concerned with the time at which the decision was made. It must present facts, not merely opinion. These facts should cover all the elements that did or could have entered into the decision, including all relevant data, information, decision-making tools, and the circumstances at the time. For example, it would be improper to use past data in a current computer model to review a past decision if this type of model were not available in the past or if use of such a model could not reasonably be expected of the decision maker.

Areas of Recent State Application

We have reviewed recent state commission prudence inquiries involving electric and gas utilities. The two principal areas of application involving electric utilities were construction cost overruns and plant abandonments.

Few of these cases rely solely on the prudence test for reaching a judgement. In most, the commission references the "used-and-useful" test or a "balancing of interests" test (that is, balancing the legitimate interests of customers and investors) to decide if certain costs should be included in rates.

The prudence inquiries that rely most heavily on staff investigations are those involving generating plant construction cost overruns. This is so because the purpose is not simply to decide whether or not imprudent decisions were made, but also to determine the consequences of any imprudent decisions in terms of additional costs.

Because construction cost overruns rarely occurred before the 1970's, and when they did occur the overruns were of small magnitude, there were few cases explicitly applying the prudence test to construction cost overruns before the 1970's. Rather, the presumption of prudence applied. However, since the 1970's, state commissions have been more active in challenging the value of investments about to go into rate base on the basis of prudence. Such a challenge usually must be preceded by a staff prudence investigation to develop evidence of imprudence.

Some key areas into which a staff investigation of cost overruns is likely to inquire are: (1) whether decisions relating to costs were made at the appropriate levels within the corporate hierarchy and whether the senior officers received adequate information to allow them to make responsible decisions; (2) whether the utility was adequately involved in the planning of the project; (3) whether the utility selected an architect/engineer who could handle the project in a cost-effective manner; (4) whether the utility monitored the engineering effort; (5) whether procurement was based on competitive bids; (6) whether the contracts were all cost-plus, or whether there were incentive mechanisms included; (7) whether the utility monitored the work force utilization; (8) whether time schedules were established for construction tasks and whether there were adequate reporting systems in place to identify deviations from the schedule; (9) whether the scheduling was realistic and whether management used the reporting systems as a tool to prevent future delays; (10) whether delivery of materials and equipment were effectively scheduled, controlled, and monitored; (11) whether the construction manager was effectively monitored; (12) whether the utility took steps (especially in nuclear construction) to improve the interaction between construction and engineering; (13) whether there was adequate monitoring of the project budget and whether variances from the budget were brought to the attention of project management; and (14) whether the utility arranged its financial planning so that financing would not adversely affect scheduling, and hence cost. In addition, key technical issues that deal with the competence of the design, engineering, and construction of the plant are usually investigated.

In general, the disallowances under prudence can be classified into the following categories:

1. Imprudent Schedule Delays

This category includes construction costs disallowed due to delay in project schedule deemed to be imprudent. It can include allowance for funds used during construction (AFUDC) due to the schedule delay. Other examples of disallowances under this category are indirect and overhead costs attributed to schedule slippage believed to be controllable.

2. Imprudent Engineering

This category includes cost disallowances due to design and engineering practices that are believed to be imprudent. For example, expenditures directly associated with imprudent engineering can be disallowed. Modifications resulting from imprudent engineering can also be disallowed.

The establishment of a certain engineering approach as imprudent is difficult. For large nuclear or coal-fired construction projects, it is certain that engineering approaches will be modified as the project progresses. These modifications/changes may reflect regulatory changes, interfacing considerations or further optimization of design.

3. Imprudent Construction Practices

This category includes cost disallowances due to construction practices believed to be imprudent. This category includes the maximum amount of disallowances as compared to other categories under imprudence. It can include disallowances for direct manhours, modifications of certain equipment and/or systems, and construction management. In addition, delay in the project can cause the above categories to become more costly.

Table VII-1 gives a summary of disallowances for nuclear plants due to imprudence. These disallowances are categorized under imprudent schedule delays, imprudent engineering and construction, and other disallowances due to imprudence. The disallowances under engineering and construction are given combined values due to the difficulty of separating them in many cases.

Table VII-2 gives a summary of disallowances for coal-fired and other units due to imprudence. These disallowances are categorized under imprudent schedule delays, imprudent engineering and construction, and other disallowances due to imprudence.

TABLE VII-1

DISALLOWANCES DUE TO IMPRUDENCE FOR NUCLEAR UNITS
MILLIONS OF DOLLARS
(1980-1986)

UNIT	IMPRUDENT SCHEDULE DELAYS	IMPRUDENT ENGINEERING & CONSTRUCTION	OTHER DISALLOWANCES DUE TO IMPRUDENCE	TOTAL
Byron 1	-----	101.5	-----	101.5
Callaway 1	88.8	177.2	155.7	421.7
Fermi 2	96.3	274.5	26.1	396.9
Limerick 1	368.9	-----	-----	368.9
San Onofre 2 & 3	-----	328.0	-----	328.0
Shoreham 1	305.0	894.6	195.4	1395.0
Wolf Creek 1	244.6	38.4	126.0	409.0
	1103.6	1814.2	503.2	3,421.0

TABLE VII-2

DISALLOWANCES DUE TO IMPRUDENCE FOR COAL-FIRED AND OTHER UNITS
(MILLIONS OF DOLLARS)
(1980-1986)

UNIT	IMPRUDENT SCHEDULE DELAYS	IMPRUDENT ENGINEERING & CONSTRUCTION	OTHER DISALLOWANCES DUE TO IMPRUDENCE	TOTAL
Belle River 1&2	60.9	36.0	-----	96.9
Big Bend 4	-----	3.7	-----	3.7
Holcomb 1	-----	0.5	-----	0.5
Reid Gardner 4	-----	4.4	-----	4.4
Helms 1-3	-----	22.0	-----	22.0
	60.9	66.6	-----	127.5

VIII. ANALYSIS OF IMPRUDENCE DISALLOWANCES

GENERAL DISCUSSION

Excess Capacity

An electric utility has to plan its generating capacity to meet the demands placed on its system with adequate reliability. The lead times associated with base load generating capacity options are significant, on the order of ten years. Thus, a utility has to predict the demand for electricity over say the next ten years and then build the generating facilities to meet the predicted demand.

Any predictions for the future have inherent uncertainties associated with them. Predicting the demand for electricity is no exception. In fact, predicting the demand for electricity is dependent upon many factors that are themselves highly uncertain. For example, the growth rate of the economy, the growth rate of energy consuming industries, and similar macro-economic developments are difficult to predict but have considerable effect on the predictions for growth in demand for electricity.

A utility can plan its generating capacity in such a way so as to err on the side of excess capacity or not enough capacity. Under normal conditions, a utility management may decide to err on the side of excess capacity because the cost of some excess capacity may be much less than the cost of not having enough capacity leading to brown-outs or worse and possible interruption of industrial or other production.

If the cost of excess capacity is to be borne by the utility itself, management may plan so as to err on the side of not having enough capacity. This may actually be much more adverse to the customers of the utility than having to pay for some excess capacity.

Another possible effect of disallowing costs associated with excess capacity is for the utility to select generating options with shorter lead times. Large base load coal-fired and nuclear plants have long lead times. Since longer term forecasts have generally more uncertainty associated with them, the possibility of disallowances increases with the selection of such base load options with long lead times. It should be realized that such base load options are generally the most economic. Thus, selecting short lead time options to minimize excess capacity disallowances will only hurt the utility customers by increasing their bills for electricity.

Cost Caps

Cost caps are generally specified while a facility is under construction. For projects with longer lead times, there is a higher possibility of the construction cost exceeding the cost cap. In addition there is a higher possibility of regulatory change while the plant is under construction. Both coal and nuclear plants tend to fall under this category. Thus, the cost caps tend to provide encouragement to a utility to select options with short lead time and/or low possibility of regulatory changes (such as gas turbines), and stay away from large central station coal and nuclear plants. These large central station plants, however, have the best chance of providing low cost reliable electricity in the long term.

Economic Value

A utility selects generation options to meet the long range electricity needs of its customers so as to minimize the present value of total revenue requirements from its customers over a planning period of twenty to thirty years. This approach considers factors such as the rate of inflation that can be expected with various fuels (coal, nuclear, oil, gas) over the twenty to thirty year period.

The options that are most economical over the twenty to thirty year period generally gain increasing economic advantage with time. For example, a nuclear plant may have very little economic advantages over an oil-fired plant in its initial years of operation. As time goes on, the price of electricity from oil-fired plants will tend to rise faster than that from a nuclear plant, because the fuel cost for oil is a large component of total generating cost. For nuclear plants, the cost of electricity will increase slowly with time because a large part of the cost of electricity is the capital component, which remains fixed with time. Thus, the nuclear plant will tend to gain economic advantage over the oil-fired plant, with time.

The disallowance of a certain part of construction costs based on the principle of economic value may overlook these intricate economic factors and can unduly penalize a utility. The disallowances also encourage the utility to select options with short lead times because the chances of changes in relative economics over short time frames are smaller. To pursue short term options, acts to the detriment of the utility's customers over the long term.

FINDINGS

Table VIII-1 gives an overall summary of disallowances for nuclear and other units. The key findings are summarized below:

a) Disallowances due to imprudence constitute a majority of total disallowances.

b) Disallowances for nuclear plants constitute approximately 98 percent of total disallowances. Disallowances for coal-fired and other units constitute the remaining 2 percent.

c) The disallowances for nuclear plants constitute almost 10 percent of the total investment cost of nuclear plants going into the rate base over a seven year period from 1980 to 1986. The similar percentage for coal-fired and other plants is well below one percent.

CONSEQUENCES

The disallowances of capital costs is already having a chilling effect on investment in nuclear and coal-fired plants. Many other adverse consequences are possible. Some of these adverse consequences are discussed below:

TABLE VIII-1

OVERALL SUMMARY OF DISALLOWANCES FOR NUCLEAR AND OTHER UNITS
MILLIONS OF DOLLARS
(1980-1986)

TYPE OF UNITS	TOTAL DISALLOWANCES DUE TO IMPRUDENCE	ALL OTHER DISALLOWANCES	TOTAL DISALLOWANCES	CAPITAL INVESTMENTS	TOTAL DISALLOWANCES AS PERCENT OF INVESTMENT COSTS GOING INTO RATE BASE OVER 7 YEARS FROM 1980-1986
NUCLEAR	3421	3171	6592	70,000	9.6%
COAL-FIRED AND OTHER UNITS	127	----	127	43,000	0.3%
ALL UNITS	3548	3171	6719	113,000	5.9%

Utility Investment Policy

In order to build a power plant with 10 to 15 year leadtime, a utility must forecast demand 10 to 15 years into the future. If economic conditions change during these intervening 10 to 15 years, demand will probably turn out to be higher or lower than forecasted. Commissions may deny rate base treatment to utilities on the basis of prudence when demand turns out to be lower than forecasted by asserting that the plant, even though it was prudent ex-ante, is not prudent ex-post. The application of ex-post prudent investment rule can have perverse unintended effects on the investment policies of regulated utilities, and chances of under investment will increase. The result of an effort to protect ratepayers so that they have sufficient power at lowest possible cost may be insufficient power at high cost.

Utility Bankruptcy

Utility bankruptcy is a possible consequence of improperly applying the prudent investment test so as either to disallow from the rate base all or a part of a utility's investment in a completed electric utility plant or to disallow cost recovery for an abandoned plant in which a large investment has been made. Indeed major brokerage firms, such as Standard & Poor's, have openly discussed the possibility of utility bankruptcy. In the 1984 Standard & Poor's/Applied Economic Research Company Industry Survey (Utilities - Electric), the following appraisal was given about whether bankruptcy is possible in the electric utility industry:

> At least for the half of the industry currently involved in nuclear construction, the answer to this question is really who is going to bear the cost of the industry's nuclear nightmares: ratepayers or stockholders. How regulators will decide this issue realistically will be a matter of balancing ratepayer hostility against their judgment of utility management. Because the consequences of the regulator's decisions are more profound than any in current regulator's experience--the outcome could be anything from utility bankruptcies to electric rate increases markedly higher than even those during the energy crisis years--it is impossible to foretell how the nuclear dilemma will be resolved. [Emphasis added.](10)

The Consequences of Utility Bankruptcy for Investors and Customers

One 1984 study completed by the Congressional Research Service addresses the potential effects on rates of an electric utility bankruptcy.

The results of their hypothetical example are sensitive to changes in the assumed interest rate and the debt load, and the hypothetical example is simplistic in that most state commissions amortize the construction cost of abandoned plants over a period of years. Also, there are tax effects that have not been incorporated, and a portion of debt is likely to be written off or restructured in bankruptcy. Yet, the point made is that bankruptcy may result in an increase in the cost of capital that could well require a larger increase in utility rates than that required without bankruptcy. Also other utilities (particularly those utilities in financial difficulties in the same jurisdiction as the candidate bankrupt utility) might see their costs of capital rise to offset the higher risks perceived by investors. This might eventually lead to higher rates.

Utility Relationships

Between the extreme consequences of a utility risking bankruptcy by undertaking construction and a utility refusing to undertake construction for fear of bankruptcy are many other, less severe, possible consequences of frequent, misapplications of the prudence standard. These represent shifting relationships among the parties with an interest in utility construction as they adjust to a possibly new regulatory environment.

The consequence of these shifting relationships is usually to increase costs in ways that ultimately are borne by utility customers. While these cost increases are important, they are all difficult to quantify. Hence, it is not possible to forecast the net effect on rates of moves made ostensibly to protect customers by disallowance of costs in the hopes of forcing managers and other parties to be more efficient, as the moves may actually increase costs because of shifting relationships.

Capital Costs

Frequent and severe application of the prudent investment test would affect utility relationships with the financial community and--even without a bankruptcy--would result in higher costs of capital. Bond rating agencies and the stock market take account of a utility's ability to have all of its capital expenditures recognized by its regulatory authorities and included in the rate base. If exclusion becomes common, a certain consequence is to increase the cost of raising capital, both debt and equity, in the financial markets. As the cost of money increases, so does the cost of financing construction and the cost to the ratepayer of providing a return on investments that enter the rate base.

Utility-Contractor Relations

To date, most relationships between utility officials and equipment vendors, architect-engineers, and construction firms have been one of partnership in construction. A possible consequence of regular prudence investigations may be to move utilities into a more "arm's length" relationship with contractors, possibly one characterized by mutual mistrust and suspicion. If heavy pressure on utilities to question every activity of a contractor becomes the norm, the mutual trust and confidence between the parties and their treatment of each other as partners in a construction endeavor may be impaired, if not lost.

Bidding Policies

Until now, many major contractors have bid on utility projects on the basis of cost plus a reasonable fee. It was argued that this resulted in the utility obtaining the lowest cost. The alternative of a "fixed price," lump sum bid might require the contractor to include a large provision for contingencies.

Under the cost-plus contract, however, contractors are unable to make provisions for the possibly large costs of their involvement in a prudence investigation, or resulting litigation, following construction. To protect themselves, contractors on relatively small utility undertakings will build into their bid proposals adequate protection against the potential liabilities they could incur if utilities seek compensation from their contractors for costs that have been disallowed on the basis of a prudence inquiry.

Lump sum bidding may then become the norm, possibly resulting in higher costs for the same services and equipment. For large contracts involving millions or even billions of dollars, the only contractors who might risk lump sum bids are those with only limited assets to protect. Their solution to a major repayment obligation might be to declare bankruptcy. The large established architect-engineering firms could well withdraw from bidding--to no one's long term advantage.

Moreover, insurance rates are reported to have risen very sharply for such firms, and other firms are reportedly experiencing difficulty in obtaining insurance because of concern over prudence questions. Rising insurance rates can add to the cost the ratepayer must bear.

Increased Litigation

If state commissions disallow certain expenses on grounds that utility management or its contractors did not act prudently, increased litigation is a probable consequence. Indeed, a commission might require a utility to recover all possible costs by litigation before deciding how the residual costs are to be treated. Where utility management has been found by the state commission to have been imprudent, stockholder derivative suits will almost certainly result.

Record Keeping

Another possible consequence of frequent and strict prudence investigations is an increase in the expenses associated with the records that the various parties must keep. All business activities ought to be reasonably well documented, especially those dealing with major and complex contracts. If, however, the prudence test is applied with increasing strictness by state commissions, the consequence may be far greater and more detailed record keeping by both utilities and contractors. Much of this will be unnecessary for engineering purposes and will add to the cost of any facility being constructed. Insofar as nuclear facilities are concerned, the NRC already requires extensive and expensive record keeping.

This could increase to a level where, as in the field of medicine, contractors, like doctors practice "defensive medicine." This means that they routinely order all sorts of tests, many of which may be irrelevant and expensive, just to have a battery of results available for possible malpractice suits. The doctors, of course, do not pay for them--the patients or their insurance companies do, increasing the cost of medical care.

Architect-engineers and equipment manufacturers have played major roles in putting and keeping the United States in the forefront of technological development in the design and construction of electric power generating plants. A possibly stifling effect on new designs could result if they had to defend all efforts at improving equipment, systems, and construction technology to regulatory agencies, and perhaps the courts.

Accounting Aspects

Generally accepted accounting principles applied during the course of past disallowances may have invited such disallowances. Under generally accepted accounting principles, prior to Financial Accounting Standards Board (FASB) Opinion No. 90, disallowances generally went unreflected in current financial statements. There would simply be a footnote disclosure of the disallowance. The reason this occurred is that the recoverability test, under generally accepted accounting principles, usually required that future revenues be sufficient to offset the cost of the plant.

Under the accounting recoverability test, one could have a substantial disallowance, and yet because of future earnings on the allowed portion of the plant that could be used to offset depreciation on the unallowed portion, there would be no current accounting write-off. Therefore, regulators could order a substantial disallowance and not have any immediate adverse impact on the reported financial condition of the utility. There would, of course, be future adverse impacts, but that was viewed as a future problem by some regulators.

FASB Opinion No. 90 will change this practice completely. Under FASB Opinion No. 90, any disallowance of cost of a recently completed plant will require an immediate write-off in the income statement of the utility. Thus, a "free ride", that some regulators may have believed was temporarily possible, no longer exists. In any event, the adverse actions of regulators will be immediately reflected in the financial statements.

Framework For Change

If the goal of regulation is to produce an efficient electric supply system in the United States--one that produces adequate supplies of electrical energy efficiently and at prices deemed fair by consumers and remunerative by investors--regulation as now practiced leaves much to be desired. Consumers feel ripped off and investors betrayed, despite regulators' ad hoc efforts to cope with problems created for them by the inflation of the 1970's, OPEC, and the increased unpredictability of costs and demand.

These problems have arisen due to many factors that can be classified into two major categories:

Technical

Part of the problems are a result of the energy and economic changes of the last fifteen years, leading to two major forces. The first of these is the sudden decline in demand growth, creating large amounts of unused (and, hence, to some "unuseful") capacity for which regulators are reluctant to charge customers. The second is the large cost overruns associated with nuclear plant construction.

Regulatory

A part of the problem also lies with the changing approach to regulation. The recent use of the prudence test to exclude billions of dollars of construction costs actually incurred, is more than a mere application of a long-established doctrine. Rather, it represents regulators' discovery of an apparently respectable way of keeping rates from piercing some perceived politically acceptable ceiling. Furthermore, ex post regulatory findings that portions of new capacity are not "used and useful," even if prudent, represent an added attempt to penalize investors for unavoidable errors in projecting demand.

The fact is that utility managements and investors feel -- and will act on the feeling -- that the traditional regulatory bargain has collapsed. The financial markets now distinguish sharply between companies with construction programs and those committing no new capital to the electric business. Boards of directors might agree to small additions to capacity, and then only reluctantly, when demonstrable needs emerge. But they have had billions of dollars of their investment wiped from the books. They fear, too, that the hostility to nuclear power in the 1980's may become pollution-induced hostility to coal plants in the 1990's, forcing regulators to renew ex post consideration of those investments, in the manner of recent years.

In short, utilities and investors understand quite well that risks previously borne by consumers have been shifted to utilities. As long as there is excess capacity, this realization may matter little. But new and/or replacement capacity will be required, sooner or later. By that time any one of three things will have to happen:

(1) The increase in the perception that investors now run a larger risk of having their investment expropriated, will have to be compensated for by higher allowed rates of return on their capital, or

(2) Greater reliance will have to be placed on power from unregulated suppliers, either independent producers or restructured utilities; or

(3) A new regulatory framework, somehow reducing the risk of ex post regulatory disallowance of investments in the industry, will have to be developed.

The first of these alternatives is, in our view, unlikely to suffice. Utility managers now know that, absent some reform of the current regulatory system, a promised level of reward can be withdrawn by successors to the regulators making those promises. Investors agree: regulators' IOU's, which take the form of allowances for funds used during construction, are discounted to 70 percent of face value -- about the rate applied to Latin American debt.

The second of the above-listed alternatives will, in almost any event, be explored by utilities and their emerging competitors. But we doubt -- further empirical work would be required to raise this doubt to a certainty -- that sufficient capacity will materialize in unregulated markets to meet the nation's need for a maximally efficient, integrated power supply system.

Consequently, unless some new regulatory framework is developed, one which provides investors with new assurance that capital prudently committed to the business will be fairly compensated, the United States will find itself with a costlier, operating-expense-intensive, capital-starved power system, to the disadvantage of the consumers whom regulation is designed to protect. Regulators can determine what returns to allow on sunk capital; they cannot conscript new funds.

IX. RECOMMENDATIONS

Reasons for disallowances of certain constructor costs in utility rate bases are varied and reflect not only technical/prudence factors but also political, regulatory, and public relation factors. As such, the problems need to be tackled on many fronts. The following recommendations reflect these considerations.

Improved Management Techniques

Clearly where there has been a significant cost increase from the original planning estimate for a nuclear plant, a PUC may have legitimate concerns about such an increase. What the utility must demonstrate is that the cost of the plant was controlled, to the extent that it is reasonably controllable, by management. For future construction of a power plant, the company should identify the management control techniques to be used, as well as the actions to be taken by management in order to control the engineering and construction process. These could be supplemented by statements in response to potential management audit questions, which support the company's position that it, in fact, controlled the costs to the extent that they were controllable.

Effective control must be exercised "on the line" at the project site by the project management group. A clear and convincing statement by appropriate personnel of the methods used by management to control the scheduling and costs of construction projects, will go a long way to winning the point if made with sufficient conviction and specificity, based on personal firsthand knowledge.

In addition, there should be a clear statement of top management's role in assuring itself that there were appropriate construction management and cost control techniques. This statement could include participation in progress meetings, budget reviews, etc., and the more first-hand involvement, the better.

Below are suggestions with respect to how the effectiveness of management's effort of controlling the construction schedule and cost might be stated. We have presumed certain facts in formulating these suggestions, which are grouped in terms of Project Management, Schedule, Cost, Quality and Productivity.

Project management organization should be laid out clearly and communicated to all key personnel. Such personnel should be in a position to state convincingly the degree of personal involvement in project decisions and the control over those decisions. With respect to overall control of the project through the project management organization, company personnel should be in a position to state the frequency of the reporting of the project activities, schedule and cost matters, and the assessment of the project by company management.

Any reports from consultants should be reviewed for findings or recommendations, which might raise questions about the project organization or other aspects of the company's management of the project. In addition, reports and recommendations from the company's independent CPA's and internal auditors should be considered. Company personnel should be prepared to show the action taken on valid recommendations, or reasons why those considered invalid were rejected.

In addition, company personnel should be able to state, given the contractual terms with its Architect/Engineer (A/E), that either there was some incentive for the A/E to perform efficiently and to make engineerig decisions on the basis of economy and efficiency, or that company management controlled the activities of the A/E so that decisions were made in this manner. Further, if the A/E charges constitute a substantial portion of the total project cost, then company personnel should be able to state how the A/E's activities were controlled. For example, a simple basic verification of labor and other charges to the project by the A/E is not a sufficient basis to assert that their activities were controlled. What needs to be stated is that the company controlled both the direction of the A/E's work effort and the productivity of that work effort, in addition to validating the dollars of charges to the project.

Clearly, the schedule of the project is critical to cost containment given the thousands of project activities. Company personnel should be able to state how management had visibility over the progress of the project given the level of detail and numerous simultaneous activities. In other words, were there "rollups" by responsibility area/or some ranking of critical priority for management's review? Such reporting should be contained in a top summary schedule which is useful and manageable to top project management. Company personnel should also be able to state how the performance monitoring of the planned construction activities was accomplished.

Frequently, those responsible for construction management attempt to control the cost of a project through use of a "current approved budget" together with periodic cost and schedule status reports. In order for such budget and actual cost data to be effective as a control technique, the top budget amounts should be broken down on the basis of some work breakdown structure and along responsibility lines, which match the project organization. Further, some method of early warning of adverse trends should be included if it is to be useful as a management tool. In addition, such reports should account for commitments as well as project scope changes, which occur for a variety of reasons as the project progresses.

Quality assurance programs are also an effective means to ensure an efficient level of construction efforts. These include checking on compliance with NRC requirements and other technical requirements. Company personnel should be able to explain how this was done in an efficient manner to prevent rework, which would occur if subsequent failures were detected.

Finally, the productivity monitoring and tracking systems should be mentioned. In other words, how did project management track productivity of various work efforts or crafts, such as electrical wiring, concrete pouring, steel erection, plumbing, etc.? Productivity reports should be reviewed to ascertain that company personnel are in a position to show that proper actions were taken when adverse trends appeared.

Stable Regulatory Environment For Design and Construction

As discussed in Section IV, the current nuclear safety regulatory structure has numerous ways of imposing requirements on the planning, design, construction, and operation of nuclear power plants. These include:

- o Regulations (Title 10 Code of Fed. Reg.)
- o Regulatory Guides
- o Branch Technical Position
- o Standard Review Plan
- o NUREG Reports
- o Orders
- o I/E Bulletins (Notices & Circulars)
- o Generic Letters
- o Regulatory Position Statements
- o Proposed Rulemakings
- o Inspector Preferences

Thus, a major reason for schedule delays, engineering design changes and construction rework has been the tremendous expansion in the number and volume of regulatory guides governing the design, construction and operation of nuclear. It is important that DOE work towards the objective of providing a much more stable regulatory environment guiding the design and construction of these plants. This will significantly reduce schedule delays, design changes and construction rework thus minimizing disallowances relating to these factors.

Standard Plant Design and Construction

A large number of nuclear plants and many large coal-fired plants built over the last fifteen years have basically been custom designed and constructed. To some extent, this is necessary because a plant has to be designed for the geographical and site conditions of the particular utility. Still, custom design and construction have had the effect of prolonging schedules, and have led to many design changes and construction rework. Development of prelicensed standard plant designs will certainly reduce these factors and minimize disallowances relating to these factors.

It should be noted that a wide range of costs exist for nuclear plants in the U.S. Successful projects (i.e. based on multiple unit designs) in the U.S. derive from plant standardization and the continuity of management, design, and construction personnel. These same factors are at work in the nuclear programs of other countries such as Canada, France, Japan, and Korea.

The concept of standardization will probably require institutional changes in the current structure of the nuclear power industry. This can include using a single NSSS design and a broadly standardized plant design that is consistent with this NSSS design. Such an approach will require restructuring the current set of multiple NSSS manufacturers and many A/E firms into a much smaller number of entities.

Small and Intermediate Size Nuclear Plants

Over the last two decades, the size of nuclear plants has increased sharply to large 1000 to 1300 MWe units. These large plants have more complex design and construction approaches that have led to redesign and construction reworks, some eventually disallowed by the PUC. Smaller nuclear plants have potential to reduce these problems, through simplified design and innovative construction techniques.

Additionally there is a growing and global view that, in the face of reduced or uncertain load growth and economic growth, smaller reactor plants should be the focus for this current decade. The International Atomic Energy Agency in Vienna has sponsored a series of meetings with suppliers and users to determine the availability of technology and user interest. These meetings have been well attended and considerable interest has been exhibited.

The DOE and the Electric Power Research Institute in the U.S. are sponsoring the development of smaller reactors. A high interest is exhibited in standardized and manufactured modules, to eliminate the inefficiencies of first of a kind design and to improve on low field labor productivity. Hopefully, this approach can lead to a product, which will facilitate a more stable regulatory environment. This approach should also be of great interest to developing countries where the national grid requires a smaller unit.

Smaller plants can have shorter schedules and may be less prone to schedule delays. Bringing capacity on line in smaller increments will also reduce the possibility of excess capacity minimizing disallowances due to imprudent schedule delays and excess capacity. Innovative smaller plants are, however, needed to offset the disadvantage associated with these plants due to the principle of economy of scale.

Preapproval Incentive Standards

Ideally, the regulation of cost recovery by electric utilities would duplicate the market-value tests that a competitive, unregulated marketplace produces. There are two general ways in which this might be done. One possible approach lies in the application of avoided cost standards that are symmetric with respect to both a) extraordinarily good (e.g., low cost) and poor investments and b) new and old installations of capital. The political roadblocks to particularly the latter treatment of rate bases are unlikely to be eliminated in the short-run.

A second approach to market-value criteria of cost recovery would lie in competitive bidding processes. Under this approach, PUC's could award the rights to build capacity (or otherwise supply power) under specified terms of rate design and cost recovery, with prospective power suppliers competing to offer the package specified at the most favorable terms. Under this approach, successful bidders will not offer to supply capacity under terms that do not offer expected returns in excess of expected costs; and, in theory, consumers and regulators will not end up paying for more than efficient, competitive levels of power supply. Despite their appeal, however, competitive bidding systems for supplying electric power capacity are still some way off in the future. Even if they can be made politically acceptable, they must await institutional changes such as removal of barriers to entry in the operation of transmission grids and the modification of many states' franchise monopoly standards (under which the rights to build capacity are exclusively awarded to already authorized utilities). Even more fundamentally, an effective competitive bidding system will require credible commitments by both PUC's and power suppliers to their respective sides of any resulting bargains; the same problems of opportunistic breach of contract that we currently face are likely to confront successful bidding systems.

Progress on the central problem of binding (particularly) regulators to their before-the-fact commitments on the rules of the investment game may be possible through less radical approaches than full market-value and/or competitive bidding systems. Specifically, preapproval minimum recovery standards hold some hope of providing insurance against opportunism risk (assuming they can ultimately be enforced). Moreover, when coupled with marginal prospects of profit and loss, these standards can motivate efficiency. These two principles -- precommitment and marginal incentives -- provide a framework for an approach to electric utility cost recovery. The following proposal attempts to embody both principles. In our discussion, we have in mind a prototypical generating plant that is being considered for construction. The PUC in question might consider the following regulatory bargain:

- Establish an expected total cost of a plant having a PUC-specified capacity (and, perhaps, other operating characteristics). This base should be established (most likely through PUC-utility negotiations) in light of best available forecasts and agreed upon capacity needs.

- Establish (i.e., negotiate) a preapproved minimum recovery level equal to a percentage of the expected total cost of the plant. The minimum recovery amount should be subject to only the most narrowly defined prudence challenges. Such a minimum recovery level could also be set for a situation in which the plant may be cancelled.

- For actual costs above the minimum recovery level and up to the originally expected cost, allow a rate base equal to actual cost plus a fixed percentage of the difference between expected and actual costs.

- For actual costs that are higher than the originally expected cost, restrict recovery to no more than original cost plus a percent of cost above the original cost.

- Allow the foregoing caps to be indexed by the economy's general rate of inflation (including an inflation premium in the interest rate that constitutes the utility's cost of capital); and allow automatic adjustment of the caps for regulatory delays and mandated mid-stream equipment and design changes.

The obvious, overriding intent of this proposal is to provide incentives for utilities to minimize the costs provision of any given level of capacity. This is done by allowing profits to rise as costs fall below the negotiated expected cost, and by allowing profits to diminish as cost overruns accumulate.

Public and PUC Awareness

While it is politically expedient for a PUC to disallow certain construction costs from inclusion in the rate base, the public and the PUC should be made aware, by DOE and the utility industry, as to the long range implications of such disallowances. It should be recognized that a utility management can be expected to change its mode of decision making to minimize future disallowances. This means that a utility will lean towards low capital cost and short schedule options to meet the demands of the utility customers. Such options will generally have higher fuel costs and are normally less economical over their life cycle as compared to central station coal and nuclear plants. The higher fuel costs of these plants can, however, be passed along to the utility customers on an as incurred basis, reducing the risk to the utility shareholders. Thus the public and the PUC's should be made to understand the effect of the disallowances on utility management decision making and electricity rates in the long term.

The Prudence Review Process: Retrospective and Commentary

In a report by R.J. Rudden Associates entitled "Nuclear Prudence Reviews: Retrospective and Commentary" several recommendations were identical to this study and the following additional recommendations were made.

More balance between short-term and long-term costs and benefits should be achieved. We do not agree with some observers' views that prudence cases represent a one-time aberration in regulatory trends that will not adversely affect investors' expectations of future treatment. The effects on ratepayers, investors, and utility managers extend well beyond near-term rate and capital loss issues. However, regulators correctly perceive, and utilities need to recognize, that public and political response to these cases will largely be based upon immediate impacts.

The problem of spiraling interest costs ("AFUDC") during unavoidable delays and while the ratemaking treatment of the plant is being considered should be mitigated by interim rate relief for project costs, granted subject to refund upon the final determination of prudence. The problems of rate shock should not be made worse by delaying the recovery of prudent costs any longer than is necessary.

All parties need to clearly distinguish between the issues of rate shock and managerial prudence and deal with them separately. The fact that management's actions have led to a situation which will have a major impact on rates does not mean that those actions are imprudent. The prudent investment test should not be viewed as the solution to the problem of rate shock associated with most nuclear plants. It is equally unreasonable for utility managers to believe that their responsibilities in prudence cases end with a convincing defense of management's actions. In order for any solution to these problems to be complete, it must adequately consider both the immediate and longer term impacts on ratepayers, including the price, availability, and reliability of electric service.

All parties should recognize the political realities of regulation and that prudence cases are expensive and imperfect means to the end of reasonable rates. A greater recognition of the inexactitude of the ratemaking process and long-term need for reliable power sources should lead to a greater willingness by the parties in prudence cases to explore settlements and compromises. In the end, mountains of documents and armies of attorneys and expert witnesses cannot achieve perfection in a process as inherently judgmental as the determination of reasonable rates.

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APPENDIX

RATE BASE DECISIONS FOR NUCLEAR AND COAL POWER PLANTS

PREPARED BY UTILITY DATA INSTITUTE

INTRODUCTION

Utility Data Institute has prepared seven data tables with information regarding regulatory treatment of the capital costs of utility-owned power plants. The time period covered is generally 1982-present for plants in operation or under construction and 1980-present for cancelled nuclear units.

Data were obtained from a variety of sources, including rate orders and decisions, utility Annual Reports, SEC Form 10Ks, press releases and miscellaneous filings, information compiled by trade associations and consultants, and personal contacts with utilities. While coverage is not yet entirely complete, a significant amount of new information has been added since UDI's first report on the subject in June 1986.

Many of the cases recorded herein have involved lengthy and extremely complicated proceedings. Some utilities have rate cases in more than one state, and many newer plants have numerous joint owners. UDI has attempted to get data for the various combinations of states, owners and plants where appropriate.

The intent of this research has been to provide representative, if not definitive, data. Virtually all current cases are likely to continue for some time and their final outcome is difficult to predict.

Throughout the tables, "--" is used to signify either missing or unknown data or "not applicable". Capacities are generally gross values.

Table 1

Summary of Power Plant Rate Base Decisions
Nuclear Plants

Utility Data Institute
March 31, 1987

Plant/Unit	MW	Utility	% Own	Jurisdiction	Facility Location	Init. Dec./ Order Date	Current Decision/ Order Date	Appeal (Y/N)	Rate Base %	Phase-In (Y/N)	Excess Cap. Adj. (Y/N)	Notes
Byron 1	1175	Commonwealth Edison	100	IL	IL	--	4/29/86	Y	< 100	N	N	1/
Callaway 1	1192	Union Electric Co.	100	MO	MO	--	4/85	Y	< 100	10 year	N	2/
Catawba 1	1205	Duke Power Co.	25	NC	SC	--	9/17/85	Y	100	N	N	3/
Catawba 1	1205	Duke Power Co.	25	SC	SC	--	10/8/85	Y	100	N	N	3/
Catawba 2	1205	Duke Power Co.	0	SC	SC	--	11/5/86	N	100	N	N	4/
Catawba 2	1205	Duke Power Co.	0	NC	SC	--	10/31/86	N	100	N	N	5/
Fermi 2	1203	Detroit Edison Co.	93	MI	MI	6/5/85	4/86	Y	< 100	5 year	Y	6/
Grand Gulf 1	1306	Mississippi Power & Light	--	MS	MS	9/85	9/16/86	Y	100	8 year	N	7/
Grand Gulf 1	1306	Arkansas Power & Light	--	AR	MS	--	--	Y	100	Y	N	7/

Table 1 (Cont'd)

Summary of Power Plant Rate Base Decisions
Nuclear Plants

Plant/Unit	MW	Utility	% Own	Jurisdiction	Facility Location	Init. Dec./ Order Date	Current Decision/ Order Date	Appeal (Y/N)	Rate Base %	Phase-In (Y/N)	Excess Cap. Adj. (Y/N)	Notes
Grand Gulf 1	1306	New Orleans Public Service	--	LA	MS	3/86	9/2/86	N	< 100	13 year	--	8/
Harris 1	955	Carolina Power & Light Co.	83.83	NC	NC	--	7/24/86	--	--	--	Y	9/
LaSalle 1	1132	Commonwealth Edison Co.	100	IL	IL	--	7/12/84	N	100	N	N	
LaSalle 2	1132	Commonwealth Edison Co.	100	IL	IL	--	7/12/84	N	100	N	N	
Limerick 1	1100	Philadelphia Elec. Co.	100	PA	PA	--	6/26/86	--	--	3 year	N	10/
McGuire 2	1220	Duke Power Co.	100	SC	NC	--	2/22/84	N	100	N	N	
McGuire 2	1220	Duke Power Co.	100	NC	NC	--	6/13/84	N	100	N	N	11/
Millstone 3	1209	Central Maine Power Co.	2.5	ME	CT	--	7/86	N	85	N	N	12/
Millstone 3	1209	Central VT Pub. Ser. Corp.	1.88	VT	CT	--	1/2/87	N	100	N	N	13/
Millstone 3	1209	Connecticut Lt. & Power	52.6	CT	CT	--	4/1/86	N	89	5 year	N	14/
Millstone 3	1209	Public Service New Hampshire	2.5	NH	CT	--	--	--	--	--	--	15/
Millstone 3	1209	United Illuminating Co.	3.685	CT	CT	5/6/86	11/25/86	N	< 100	N	N	16/
Millstone 3	1209	Western Mass. Elec. Co.	13.35	MA	CT	--	6/30/86	--	76	5 year	Y	17/
Nine Mile Point 2	1100	Central Hudson Gas & Elec.	9	NY	NY	--	7/25/86	--	70	7 year	N	18/

Table 1 (Cont'd)

Summary of Power Plant Rate Base Decisions
Nuclear Plants

Plant/Unit	MW	Utility	% Own	Jurisdiction	Facility Location	Init. Dec./ Order Date	Current Decision/ Order Date	Appeal (Y/N)	Rate Base %	Phase-In (Y/N)	Excess Cap. Adj. (Y/N)	Notes
Nine Mile Point 2	1100	Niagara Mohawk Power Corp.	41	NY	NY	--	12/12/86	--	60	5 year	N	19/
Nine Mile Point 2	1100	Rochester Gas & Elec.	14	NY	NY	--	7/20/86	--	71	7 year	N	20/
San Onofre 2&3	2254	Southern California Edison Co.	80	CA	CA	--	10/29/86	Y	92	N	N	21/
Seabrook 1	1200	Maine Public Service	1.5	ME	NH	--	--	N	100	3/5 year	--	22/
Shoreham 1	849	Long Island Lighting	100	NY	NY	12/16/85	--	--	< 100	15 year	N	23/
St. Lucie 2	850	Florida Power & Light Co.	85.11	FL	FL	--	8/9/83	--	100	N	N	24/
Summer 1	950	South Carolina Electric & Gas	67	SC	SC	--	3/2/84	--	100	N	Y	25/
Susquehanna 1	1152	Pennsylvania Power & Light	90	PA	PA	--	8/19/83	--	100	N	Y	26/
Susquehanna 2	1152	Pennsylvania Power & Light	90	PA	PA	--	4/25/85	--	100	N	Y	27/
Wolf Creek 1	1188	Kansas City Power & Light	47	KS	KS	9/27/85	11/15/85	Y	< 100	3 year	Y	28/
Wolf Creek 1	1188	Kansas City Power & Light	47	MO	KS	4/23/86	2/4/87	--	< 100	7 year	Y	29/
Wolf Creek 1	1188	Kansas Gas & Elec.	47	KS	KS	12/9/86	3/11/87	Y	< 100	8 year	N	30/

Table 1

Nuclear Plant Notes

1/	Byron 1	Initial order recommended disallowance of approximately $100 million. Circuit Court Judge reversed order (4/29/86) and excluded Byron 1 costs (approx. $2.22 billion) from rate base pending additional Commerce Commission work.
2/	Callaway 1	FERC Initial Decision 6/4/86 reversed some disallowances and changed phase-in period.
3/	Catawba 1	Extensive discussion in order regarding Duke Power's actual vs. jurisdictional ownership. Question arises due to complicated sales agreements with several public power agencies for Catawba 1&2. Duke Power has title to 25% of Unit 1, but was only granted increase on 12.5%. This order has been appealed to the NC State Supreme Court.
4/	Catawba 2	SCPSC rejected "economic benefits" analysis and included full allocated investment in rate base. No prudence review.
5/	Catawba 2	NCUC allowed entire invest. in rate base; rejected state Att. Gen. claims that all but 300 MW was excess capacity. No prudence review.
6/	Fermi 2	ALJ ruled that Greenwood 1 (oil-fired, 850 MW) should be mothballed when Fermi 2 enters operation. Greenwood 1 is valued at $282.9 million. Cost of cooperative co-owner capped.
7/	Grand Gulf 1	FERC Opinion No. 234 allocates one-third of Grand Gulf 1 to MS P&L and 36% to Arkansas Power & Light. This is one of many issues still in dispute. Costs of Grand Gulf 1 provisionally accepted in both cases. On 9/16/86, MSPSC froze MS P&L rates and ordered a prudency audit.
8/	Grand Gulf 1	In February 1987, U.S. Circuit Court of Appeals reversed its earlier (2/86) decision and gave New Orleans City Council (rather than FERC) authority to determine prudence and ratepayer liability of costs. By prior agreement between NOPSI and the city, NOPSI would absorb $51 million of cost and phase remainder in over 13 years. Prudence audit initiated.

9/ Harris	CP&L has $692.6 million in CWIP presently. Prudence review will be conducted.
10/ Limerick 1	Case filed 9/85 to recover costs of Limerick 1 and 100% of common plant. 28.2% increase to be phased in over 3 years, PA PUC ordered full public hearings. As a result of construction deferrals in 1976 and 1978, PUC recommend disallowance of $1.1 billion, OCA recommends disallowance of $654 million. The $681.8 million rate increase was reduced to $350.8 million (9.4% annually), to be recovered over 3 years.
11/ McGuire 2	Some adjustments to CWIP amount in North Carolina.
12/ Millstone 3	CMP can recover 85% of $114.9 million investment. $11 million after-tax charge against 1986 earnings.
13/ Millstone 3	VPSB allowed inclusion in rate base of entire investment. Saw no imprudence by NE Util.
14/ Millstone 3	By terms of a Settlement Agreement, CL&P is allowed to recover and earn a return on pro rata share of $3.4 billion of Millstone 3 construction cost (incl. AFUDC). Total costs estimated at $3.8 billion. As of 6/30/86, CL&P reclassified about $186 million of Millstone 3 costs (which represents CL&P's unrecoverable costs) to Other Property for depreciation over the plant's useful life. The prudence proceedings were terminated without findings.
15/ Millstone 3	PSNH implemented $58.9 million (14%) interim rate hike applied for on 5/29/86. About 1/2 related to comm. op. of Unit 3.
16/ Millstone 3	DPUC approved inclusion in rate base of $130.3 million of UI's $148 million investment. UI has to recognize loss of $12 million by 1988. Decision terminated pending prudence investigation.
17/ Millstone 3	MA DPU analyzed economic value of Millstone 3 and determined that 76% ($353 million) of WMECO's $462 million investment would be "useful". This amount will be phased into rates over 5 years with WMECO allowed to earn a return on this portion. DPU further found that Millstone 3 had been a prudently managed project and that WMECO should be entitled to recover most of the remaining $109 million cost from ratepayers. Therefore, DPU directed that $95.5 million be recovered over 10 years without earning a return with the final $13.5 million (the equity portion of AFUDC for the unuseful section) disallowed. On 7/25/86, WMECO filed for a recalculation of the DPU analysis to demonstrate that 82.4% of its investment was both "used and useful."

18/ Nine Mile Point 2	Effective 7/25/86, CHG&E had $222.4 million CWIP in rate base. Disallowance over $4.16 billion CAP in proportion to ownership interest unless "extraordinary event" occurs. CHG&E disallowances will be approximately $155 million of total investment of $507 million (based on $5.878 billion costs estimate, since increased). On 7/17/86, PSC stipulated 7-year phase-in for prudently incurred NMP2 costs. CHG&E has requested 3-year phase in. State Consumer Protection Board has initiated a judicial procedure challenging the 7-year phase in.
19/ Nine Mile Point 2	On October 3, 1986 NY PSC issued an order approving a cost cap settlement affecting all joint owners. According to the settlement, the maximum cost that can be included in the cotenants' rate base is $4.16 billion with disallowed expenditures allocated according to ownership interests. The cap amount would only be charged to reflect an "extraordinary event"; cotenants stipulated at the end of the agreement that they were not aware of any basis for such a claim. NMP entered into an agreement with the cotenants on 7/15/86 whereby the other cotenants would be reimbursed by NMP for their portion of the difference between the first proposed cost cap (9/85: $4.45 billion) and $4.16 billion figure. 12/12/86 -- PSC ALJ issued recommended decision: 1) electric revenue increase of $130.8 million, including $114.8 million for first year of 5-year phase in for NMP2. Total of $.4 billion NMP2 costs included in rate base for first year. Final decision expected 3/87.
20/ Nine Mile Point 2	PSC adopted a 7-year phase-in plan for RG&E costs up to the cost cap. RG&E share of estimated costs of NMP2 of $6.151 billion would be $882 million with disallowed costs of approximately $259 million.
21/ San Onofre 2&3	CPUC disallowed as imprudently incurred $344.6 million of Unit 2&3 $4.5 billion construction cost even though the CPUC ALJ recommended that none of the Unit 2&3 investment be disallowed. SCE filed appeal 12/8/86 for rehearing on $284.4 million of disallowance. Prudency hearings were completed 5/23/86 (started 1983). (CPUC has also approved a stipulation that for every disallowed dollar of SONGS investment by SCE 19.3¢ of SCE's investment in Palo Verde should be disallowed.)
22/ Seabrook 1	ME PSC will allow complete recovery of costs with or without sale to EUA. 3-year phase-in if sale is consummated, 5-year phase-in w/no sale.
23/ Shoreham 1	PUC gave LILCo a $1.4 billion imprudence disallowance in 12/86. NYPSC adopted plan calling for 15-year phase in of all prudent costs. Annual rate increases of 4.5-5%.

24/ St. Lucie 2	Decision incorporates an incentive/penalty plan referring to operation of the unit. Plan in effect for the first 12 months of service.
25/ Summer 1	While 100% of SCE&G Summer capital costs was included in rate base, the PSC excluded $123.2 million of net plant in service which in effect recovers 400-MW of "average production plant" (slice of the system) from the rate base. This was attributed to "excess generation reserves". Carrying costs for plant to be phased in are deferred and are to be recovered over some future period.
26/ Susquehanna 1	PP&L not allowed to earn a return on the net plant investment in a 945 MW slice of the system, PP&L can recover depreciation and other operating costs associated with the excess capacity.
27/ Susquehanna 2	(PA) Capacity equivalent to PP&L share of Susquehanna was determined to be excess. ALJ recommended disallowance of the total return on a 945 MW slice of the system. PUC reduced PP&L's annual revenue requirement "by the dollar value, adjusted for taxes, of the equity return on 945 MW valued at the specific depreciated original cost per MW of SSES 2 . . ." This adjustment to continue until PP&L makes a showing that 1) the net benefits to ratepayers exceed the net costs; or 2) the that capacity is necessary for system reliability. Total annual base rate revenue requirement is reduced $161,417,000.
28/ Wolf Creek 1	KCC order held that: 1) KCP&L jurisdictional investment in Wolf Creek should be reduced by $40.3 million (excess manhours and construction costs) and denied return and depreciation on that amount; and 2) for rate of return purposes, Kansas jurisdictional investment was further reduced by $288.7 million for economic revaluation and alleged excess capacity of 314 MW (KCC allowed depreciation on this amount). Economic revaluation based on costs ($1290/kw) of hypothetical coal plant and KCP&L filed an appeal with U.S. Supreme Court 11/14/86 seeking a review of this adjustment.
29/ Wolf Creek 1	Latest stipulation and agreement finalizes several arrangements including: 1) no further attempt to rate base $92 million of Wolf Creek investment specifically disallowed by MPSC; 2) makes KCP&L share financial burden of MPSC-assumed 395 MW excess capacity on system in 1990 by allowing only one-half of the common equity return on 75% of the allowed jurisdictional rate base; 3) reduced jurisdictional rate base by $103 million for unexplained cost overruns, mismanagement, and investment in common facilities; and 4) allows recovery of costs for $74 million of plant additions from 3/85-9/85 and $89 million of deferred costs from 9/85-5/86 (latter costs to be amortized over 10 years).

30/ Wolf Creek 1

On 3/11/87, KCC ruled that: 1) KG&E will delay several rate increases ordered earlier; 2) KG&E will phase out WC excess capacity by 53.8 MW/year from 1/1/88-1/1/92; 3) KG&E will be allowed to value the plant at $2376/kw rather than $1290 as in the original order; 4) KG&E will include in cost of service undepreciated costs of WC found to be imprudent ($128 million). Chronology of KG&E case follows. Originally sought a $370.9 million increase, to be phased in over 5 years. The commission allowed the company a $169.6 million increase, to be phased in over three years. The company was allowed a $135 million increase the first year (Oct. 3, 1985, to Sept. 27, 1986), $20 million the second year (which began Sept. 27, 1986), and $14.6 million the third year (scheduled to be effective Sept. 27, 1987). A fourth-year $15.6 million increase, scheduled to be effective Sept. 27, 1988, was authorized to remain in effect in years 4, 5, 6, 7 and 8. In year 9, rates were to be reduced by $15.6 million, and $169.6 million was to be the permanent increase.

KCC reduced KG&E's request by 54 percent because of construction imprudence, excess physical capacity (the commission found that 327 megawatts of KG&E's share of Wolf Creek was excess capacity -- not currently required to be used) and excess economic capacity. (In comparing Wolf Creek's cost to that of a coal-fired plant, the commission found that Wolf Creek should be valued at $1,290 per installed kilowatt of capacity, rather than the approximately $2,600 that that the companies had spent.).

Table 2

Summary of Power Plant Rate Base Decisions
Coal-Fired Plants

Utility Data Institute
March 31, 1987

Plant/Unit	MW	Utility	% Own	Jurisdiction	Facility Location	Init. Dec./ Order Date	Final Dec./ Order Date	Appeal (Y/N)	Rate Base %	Phase-In (Y/N)	Excess Cap. Adj. (Y/N)	Notes
AB Brown 2	265	Southern Indiana Gas & Elec.	100	IN	IN	--	2/5/86	--	100	2 year	N	
Belle River 1&2	1398	Detroit Edison Co.	81	MI	MI	--	7/16/85	Y	< 100	N	N	1/
Big Cajun Two 3	565	Gulf States Utilities Co.	42	LA	LA	--	12/12/83	Y	100	N	N	
Big Bend 4	455	Tampa Electric Co.	100	FL	FL	--	12/13/85	--	< 100	N	N	
Brandon Shores 1	685	Baltimore Gas & Elec. Co.	100	MD	MD	--	5/29/84	--	100	N	N	
Colstrip 3	778	Montana Power Co.	30	MT	MT	--	8/28/85	Y	100	4 year	N	
Colstrip 4	778	Pacific Power & Light	10	OR	MT	--	1/8/87	--	< 100	--	--	2/
Crystal River 5	739	Florida Power Corp.	100	FL	FL	--	10/12/84	--	100	N	N	
Dolet Hills 1	720	Central Louisiana Elec. Co.	50	LA	LA	--	7/14/86	Y	100	N	N	3/

Table 2 (Cont'd)

Summary of Power Plant Rate Base Decisions
Coal-Fired Plants

Plant/Unit	MW	Utility	% Own	Jurisdiction	Facility Location	Init. Dec./ Order Date	Final Dec./ Order Date	Appeal (Y/N)	Rate Base %	Phase-In (Y/N)	Excess Cap. Adj. (Y/N)	Notes
Edgewater 5	380	Wisconsin Elec. Power Co.	25	WI	WI	--	1/3/85	--	100	N	N	
Gibson 5	668	Public Service Indiana	50.05	IN	IN	--	1/20/83	--	100	N	N	
Holcomb 1	348	Sunflower Elec. Coop.	100	KS	KS	--	4/2/85	--	< 100	6 year	Y	4/
Hunter 3	430	Utah Power & Light Co.	100	UT	UT				100	Y	N	
Hunter 3	430	Utah Power & Light	100	WY	UT	--	3/1/85	--	100	Y	N	5/
Independence 1	800	Arkansas Power & Light	31.5	AR	AR	--	--	--	100	N	N	
Independence 2	800	Arkansas Power & Light	31.5	AR	AR	--	--	--	100	N	N	
Jeffrey 3	720	Kansas Power & Light	64	KS	KS	5/26/83	1/17/85	--	100	N	N	
Limestone 1	809	Houston Lighting & Power	100	TX	TX	11/7/86	--	--	100	N	Y	6/
Killen 2	666	Dayton Power & Light	67	OH	OH	--	4/83	--	100	N	N	
Louisa 1	685	Iowa Power & Light Co.	30.5	IA	IA	--	9/8/83	--	100	Y	Y	7/
Mayo 1	749	Carolina Power & Light	83.83	NC	NC	--	9/19/85	--	100	N	N	
Muskogee 6	572	Oklahoma Gas & Elec. Co.	100	OK	OK	--	12/20/85	--	100	Y	N	8/
North Valmy 2	290	Sierra Pacific Power Co.	50	NV	NV	--	10/28/85	--	100	N	N	9/

Table 2 (Cont'd)

Summary of Power Plant Rate Base Decisions
Coal-Fired Plants

Plant/Unit	MW	Utility	% Own	Jurisdiction	Facility Location	Init. Dec./ Order Date	Final Dec./ Order Date	Appeal (Y/N)	Rate Base %	Phase-In (Y/N)	Excess Cap. Adj. (Y/N)	Notes
North Valmy 2	290	Idaho Power Co.	50	ID	NV	--	10/28/85	N	100	2 year	N	10/
Petersburg 4	552	Indianapolis Power & Light	100	IN	IN	--	7/86	N	100	2 year	N	
Pirkey 1	720	Southwestern Elec. Power	85.94	LA	TX	--	2/21/85	--	100	N	N	
Plains 1	233	Plains Elec. G&T Coop.	100	NM	NM	12/21/84	2/4/85	--	100	N	N	11/
Pleasant Prairie 2	617	Wisconsin Elec. Power Co.	100	WI	WI	--	1/3/85	--	100	N	N	
Reid Gardner 4	295	Nevada Power Co.	32.2	NV	NV	--	12/20/83	Y	< 100	N	N	
RM Schahfer 17	393	No. Indiana Public Service	100	IN	IN	--	8/9/84	--	100	N	N	12/
Rockport 1	1300	Indiana & Michigan Electric	50	IN	IN	--	12/3/84	--	100	2 year	N	13/
Rodemacher 2	552	Central Louisiana Elec. Co.	30	LA	LA	--	10/17/83	--	100	N	N	
San Juan 4	550	Public Service New Mexico	62.7	NM	NM	--	--	--	--	Y	Y	14/
Somerset 1	710	New York St. Electric & Gas	100	NY	NY	--	4/18/84	--	100	3 year	N	
Tolk 1	565	Southwestern Pub. Serv.	100	TX	TX	--	6/23/82	--	100	N	N	
Tolk 2	565	Southwestern Pub. Serv.	100	TX	TX	--	6/30/86	--	100	N	N	15/
WA Parish 8	615	Houston Lighting & Power	100	TX	TX	--		--	100	N	N	

Table 2

Coal-Fired Plant Notes

1/	Belle River 1&2	On 12/16/86, Ingham County Cir. Court remanded some issues from rate case to MIPSC. Essentially requires PSC to reverse a $12.1 million disallowance from 7/16/85 case.
2/	Colstrip 4	PUC allowed $22.6 million (4%) permanent rate hike. Company had requested $22.6 million hike on 6/16/86 for rate base inclusion of Unit 4 and pollution control costs for Jim Bridger. PUC allowance also includes other projects, so request not fully granted.
3/	Dolet Hills 1	CLECO obtained "excess revenues" during test period. Led to refusal of rate increase on 5/1/86. Overturned by State District Court on 7/14.
4/	Holcomb 1	Utility proposed to place 60% of unit cost in rate base first year with 10% to be included each of the next 5 years. At 4/2/85, 57% was authorized for inclusion. This could be considered an excess capacity adjustment.
5/	Hunter 3	One-third of unit's costs allowed in rate base with "a "carrying charge" of the overall rate of return on rate base granted in this case to be applied on that part of Hunter 3 Unit and the other power plants not allowed in rate base." Treatment of this portion to be determined in future case.
6/	Limestone 1	First HL&P unit to be examined under revised PUC by-laws. Prudence review expected to end 9/86. Rate case filed 3/19/86. Approximately $593 million of Unit 1 costs already in rate base. Unit 1 classified as plant-in-service; allowed $677 million CWIP in rate base.
7/	Louisa 1	An order setting interim rate levels incorporates an excess capacity provision that eliminates the return associated with common equity on a 267 MW "slice of the system".
8/	Muskogee 6	AFUDC amortized over 10-year period.
9/	North Valmy 2	$74,000 removed from rate base for certain equipment declared surplus after construction completed.

10/ North Valmy 2	PUC rehearing refused return on equity -- based on "used and useful". Rehearing 10/86. Granted only $980,000 of $84 million (1.16%) requested rate increase.
11/ Plains 1	To reduce rate impacts of new plant, PSC adopts decelerated ("Sinking Fund") depreciation for plant costs. Utility is directed to keep PSC apprised of results of aggressive marketing scheme to utilize excess capacity.
12/ RM Schahfer 17	After a series of hearings and rehearings, the costs of RM Schahfer 17 were placed in the rate base. The order contained a cap on RM Schahfer 18 costs that could be included in rate base.
13/ Rockport 1	PSCI approved a two-step rate increase of $48,500,000 and $23,000,000, respectively for I&M. The first step, effective December 10, 1984, concurrent with the commercial operating date of Rockport 1 and the second step, effective one year later, excluded from rate base $315,153,000 and $245,000,000, respectively, of construction costs associated with Rockport 1 but allowed I&M to accrue a deferred return based on a rate equal to its AFUDC rate and to defer annual depreciation expense on the amounts excluded from rate base. The second-step rate levels provide for amortization of the first-step deferred return and deferred depreciation to cost of service over a 30-year period. In August, September, and October 1985, FERC issued orders approving settlement agreements providing for a total increase of approximately $47,216,000 in three steps. Step I of approximately $17,446,000 was effective in October 1984; Step II of approximately $17,534,000 was effective in December 1984, and Step III of approximately $12,236,000 was effective in December 1985. As agreed by the parties, the Step II and Step III rates excluded from rate base $170,724,000 and $132,721,000 respectively, of construction costs associated with Rockport 1 but allowed I&M to accrue a deferred return based on a rate equal to its AFUDC rate and to defer annual depreciation expense on the amounts excluded from rate base. The Step III rate levels provide for amortization of the Step II deferred return and deferred depreciation in cost of service over a 30-year period. As a result of the above rate proceedings, I&M had recorded through December 31, 1985, a deferred return of $63,661,000 and deferred depreciation of $16,652,000 on Rockport I.

14/ San Juan 4	As of 1985, 202 MW of San Juan 4 had been "inventoried", the unit having contributed to capacity over PSNM's 20% reserve margin. The inventory process involves cash recovery from customers when plant is needed to meet service requirements. PSNM's total share (390 MW) of Palo Verde will also be inventoried.
15/ Tolk 2	Approximately $2.57 million excluded from plant in service. These are costs associated with certain expenses for Tolk 2 and a transmission line that were incurred prior to the end of the test year but were not closed on the company's books. These costs were determined to be not properly part of the company's test year end plant in service.

Table 3

Summary of Power Plant Rate Base Decisions
Other Plants

Utility Data Institute
March 31, 1987

Plant/Unit	MW	F	Utility	% Own	Jurisdiction	Facility Location	Init. Dec./ Order Date	Final Dec./ Order Date	Appeal (Y/N)	Rate Base %	Phase-In (Y/N)	Excess Cap. Adj. (Y/N)	Notes
Bath County 1-6	2100	PS	Monongahela Power Co.	11	WV	WV	--	6/30/86	--	100	3 year	N	1/
Bath County 1-6	2100	PS	Potomac Edison Co.	11	WV	WV	--	6/30/86	--	100	3 year	N	
Bath County 1-6	2100	PS	West Penn Power Co.	18	PA	PA	--	7/24/86	--	100	--	N	2/
Blundell 1	20	GH	Utah Power & Light	100	ID	UT	--	9/10/84	--	75	N	N	3/
Chalk Point 4	659	O	Potomac Electric Power Co.	100	DC	MD	--	2/28/83	--	100	N	N	4/
Helms 1-3	1053	PS	Pacific Gas & Electric Co.	100	CA	CA	--	8/21/85	--	97	Y	N	5/
Kettle Falls 1	51	W	Washington Water Power Co.	100	ID	WA	--	11/19/84	--	90	N	N	

Table 3

Other Plant Notes

1/	Bath County 1-6	On 11/7/86, WV Sup. Ct. accepted appeal by industrial intervenors of 6/30/86 order. Suspended PSC order but specified that if PSC conducts rate hearing, court may render its instant order moot.
2/	Bath County 1-6	PUC allowed full recovery of company's share. No excess capacity found. ALJ recommended decision that all associated costs and revenues be allocated for and collected through the energy costs rate mechanism. This decision incorporates plant treatment as an energy storage device and removes project costs from current rate proceedings.
3/	Blundell 1	Idaho PUC ruled that 25% of the cost of the unit is related to research and development: these costs are to be amortized as an expense over 5 years with the unamortized portion not included in rate base. Remaining 75% of unit costs allowed in rate base.
4/	Chalk Point 4	Last utility-owned, oil fired, steam electric unit built in U.S.
5/	Helms 1-3	The Helms Final Opinion excludes treatment of an additional $229 million in capital expenditures related to the reconstruction of the Lost Canyon Pipe Crossing.

Table 4

Summary of Power Plant Rate Base Decisions Pending

Utility Data Institute
March 31, 1987

Plant/Unit	MW	F	Utility	% Own	Juris.	Plt. Loc.	Current Decision Date	Prudence Review	Cost Cap	CWIP	Notes
Big Cajun Two 3	565	C	Gulf States Utilities	42	TX	LA	7/13/84	N	N	Y	TX order denied recovery of BCT 3 costs due to CO after test year. Order has been appealed.
Braidwood 1	1175	N	Commonwealth Edison Co.	100	IL	IL	3/28/86	Y	Y	--	Prudence review proposal due before IL Commerce Commission (ICC) 6/9/86. Report due early 1987. Proposed order (still pending ICC action) includes cost cap of $5.05 billion for units 1&2.
Braidwood 1/2 Byron 1/2	4700	N	Commonwealth Edison	100	IL	IL		--	--	--	Agreement between CE, IL Att. Gen., etc. on 12/19/86: 1) CE increase rates 13% on 7/1/87, with 5-year subsequent freeze; 2) CE to establish GENCO to own units, but would keep the $7.1 billion investment out of IL rate base. Needs ICC approval.
Clinton 1	990	N	Illinois Power Co.	80	IL	IL	8/7/85	Y	Y	Y	Illinois Commerce Commission order (8/7/85) set cost cap of $2.698 billion. Two-phase audit being conducted by Touche-Ross and Nielsen-Wurster. Phase I report (filed 1/9/86) covers period from project start to 3/85: consultants contend that between $294 and $464 million in expenditures associated with 1982 stop work order were unreasonable. No decision as of 2/87 by PUC. IPC retained TBA, Ebasco, and Burns & Roe for independent audit. ICC will hold hearings to consider the results of the various audits. Rate hike of $66 million (9%) put into effect 10/4/86, after fuel loading; $352 million CWIP allowed into rate base. At full power license, additional $72 million (9%) rate hike to be effective, along with another $384 million CWIP in rate base.

Table 4 (Cont'd)

Summary of Power Plant Rate Base Decisions Pending

Plant/Unit	MW	F	Utility	% Own	Juris.	Plt. Loc.	Current Decision Date	Prudence Review	Cost Cap	CWIP	Notes
Comanche Peak 1&2	2384	N	Texas Utilities	87.83	TX	TX	--	Y	--	Y	At 4/87, Comanche Peak 1&2 were scheduled for service in 1989 at a total cost excluding AFUDC estimated at $5.27 billion. At 12/31/86, TU had invested about $4.6 million (total) with $1.284 billion CWIP in rate base. TU has stated that it does not plan to include any additional Comanche Peak costs in rate base until CO of Unit 1. Initial rate increase for CP 1 can be held to about 10% according to TU estimate.
Diablo Canyon 1&2	1137	N	Pacific Gas & Elec. Co.	100	CA	CA	12/18/85	Y	N	--	Approximately $3.3 billion transferred to electric plant in service after commercial operation of Unit 1 (5/7/85). In March 1985, PG&E and CPUC public staff stipulation to set up a rate mechanism was approved. Mechanism has two components: 1) an adjustment account (DCAA) recognizes revenues for expenses incurred and a return on nuclear plant in service; and 2) an interim adjustment (DCIA) to accumulate the value of fuel saved. The DCIA was terminated 12/18/85 when PG&E was allowed an annual rate increase of $53.8 million to cover Unit 1 O&M costs. Final recovery of plant capital costs will not be authorized until the completion of a prudency audit, probably in 1988. State Supreme Court in 10/86 refused to review 12/85 PUC decision to grant interim rate relief for Units 1&2.
Hope Creek 1	1117	N	Atlantic Electric	5	NJ	NJ	2/20/87	--	Y	--	BPU disallowed recovery of $22.4 million in const. costs. Also applied provisions of a cost containment agreement to excess costs of $17.1 million - company can recover, but 20% of excess ($3.4 million) excluded from rate base for computing a return. BPU also established performance standard for nuclear units in which AE has interest - incentive if units run at 80% cap factor or better, penalty is at or below 60%. AE thinks cap. fact of 55.5% more appropriate target.
Hope Creek 1	1117	N	Public Service Elec. & Gas	95	NJ	NJ	2/6/87	Y	N	--	NJBPU disallowed $455 million as not prudent. Hearings to be held on treating plant as cogen facility - charge by avoided cost.

Table 4 (Cont'd)

Summary of Power Plant Rate Base Decisions Pending

Plant/Unit	MW	F	Utility	% Own	Juris.	Plt. Loc.	Current Decision Date	Prudence Review	Cost Cap	CWIP	Notes
Louisa 1	685	C	Iowa-Illinois Gas & Elec.	43	IA	IA	4/25/84	N	N	--	Appeal of restrictive excess capacity adjustment in progress. Not resolved as of 1985 Annual Report.
Palo Verde 1	1403	N	Arizona Public Service	29.1	AZ	AZ	12/5/86	N	N		ACC allowed APS to defer capital costs, depreciation, taxes, and O&M expenses to reflect difference between time Unit 1 reached CO and time of final ratemaking order recognizing unit would be decided. Conditions: 1) Cap on O&M expenses; 2) NRC fines not included in O&M. Approximately one half of PV1 costs in AZ PS rate base. In 9/86, 4-state audit voided by agreement w/ ACC for APS ratepayers to pay entire $5.5 million audit cost. 12-14 month audit. ACC issued order providing for rate base inclusion of $210 million (approx. 25% of PV 1 costs) but made inclusion "interim or temporary in nature" pending further ACC order. Order also established 1/1/86 COD rather than 2/13/86 for PV 1 and splits common costs into 3 equal portions for rate base inclusion as Units 1-3 enter operation.
Palo Verde 1-3	4209	N	El Paso Elec. Co.	15.8	TX	AZ	1/86	--	--	--	TX PUC authorized rate base inclusion of 50% of Palo Verde CWIP. Appealed to state district court. Currently, decision is stayed. In 12/86, company filed a request with TX PUC regarding COD for PV 2. New filing for PV inclusion as "plant-in-service" scheduled for spring 1987. El Paso completed sale and leaseback of PV 2 in eight transactions from August-December 1986.
Palo Verde 1	1403	N	El Paso Elec. Co.	15.8	NM	AZ	2/26/86	Y	--	--	PSC allowed #1 in rate base on 3/26/86. Prudence may be issue later. PSC later filed for "rate moderation" for #1. 12/5/86 -- El Paso, PSC, Att. Gen., etc. signed "Agreement in Principle": 1) regulatory disallowance equal to NM share ($100 million); 2) no part of Unit 3 to be allowed in rate base at any time; 3) Unit 2 phased in by 12/31/87. Needs final approval. Pending case regarding #1 costs being appealed. Prudence came up in CWIP issue.

Table 4 (Cont'd)

Summary of Power Plant Rate Base Decisions Pending

Plant/Unit	MW	F	Utility	% Own	Juris.	Plt. Loc.	Current Decision Date	Prudence Review	Cost Cap	CWIP	Notes
Palo Verde 2	1403	N	Arizona Public Service	10.2	AZ	AZ	2/87	Y	N	Y	APS filed revisions to rate case on 12/19/86. Proposed 3-year phase in. No additonal rate hikes before 1/1/91. AZ Corp. Commission recommended APS be given less than 1/3 of $194 milion requested to pay for Unit 2 (would allow hike of $62.2 million, effective 9/1/87). Also advocates reducing APS fuel charges simultaneously and proposed new incentive plan for APS to include all generating units and purchased power. AZPS completed sale/leaseback of 42% of share of PV 2.
Palo Verde 2	1403	N	Public Serv. New Mexico	10.2	NM	AZ	9/86	--	--	--	State Supreme Court upheld 12/84 PSC order adopting PSNM inventorying method -- PV power not in rate base until energy needed -- est. to be year 2000.
Perry 1	1250	N	Cleveland Elec. Ill. Co.	31.1	OH/PA	OH	--	Y	N	--	Rate base CWIP discontinued 3/85. Touche-Ross/Nielsen Wurster prudency audit report expected 7/86. Capital cost treatment will probably be a separate issue in OH, rolled into general case in PA.
Perry 1	1250	N	Cleveland Elec. Ill. Co.	31.1	OH/PA	OH	7/86	Y	--	--	PUC conditionally granted 6% ($76 million) rate increase. $37 million effective 7/86, balance subject to approval when plant at 20% power. Company asked for 11% ($140 million). Plant reached 20% power 2/2/87.
Perry 1	1250	N	Duquesne Light	14.0	PA	OH	3/87	--	--	--	Filed case for $47 million for Unit 1 costs. Plans to abandon interest in Unit 2. PUC authorized "early window" deferral accounting (5/86). PUC denied $58 million annual rate increase to cover Perry costs and ordered $18.6 million annual reduction (3/87).
Perry 1	1250	N	Ohio Edison Co.	30	OH	OH	2/87	--	--	--	OH PUC authorized OH Edison to refinance construction costs by entering into 1 or more sales and leaseback transactions. Sold 30% of its ownership and leased back same. Aggregate amount financed was $509 million.

Table 4 (Cont'd)

Summary of Power Plant Rate Base Decisions Pending

Plant/Unit	MW	F	Utility	% Own	Juris.	Plt. Loc.	Current Decision Date	Prudence Review	Cost Cap	CWIP	Notes
Perry 1	1250	N	Pennsylvania Power Co.	5	PA	OH	6/86	--	--	--	State Consumer Advocate contending excess capacity in rate case filed in June 1986.
River Bend 1	991	N	Gulf States Utilities Co.	70	LA/TX	LA	--	Y	N	Y	Rate case filed 9/30/85 in LA. On 5/27/86, LPSC voted 3-1 to dismiss River Bend portion of current plant-in-service case. GSU is waiting for written order prior to decision on next step. If LPSC action stands, a new filing will be required after COD. OKA initially recommended disallowance of $1.589 billion (incl. $357 AFUDC) in TX case. Draft stipulation distributed in TX case 5/15/85. Declared commercial 7/16/86 by TPUC & LPSC. Requested $202 million (26%) in-service rate increase from LPUC on 7/24/86. Filed with TPUC for $144.1 million (26%) rate increase on 11/18/86. On 1/27/87, TPUC granted $39.9 million emergency rate increase w/stipulations. LPSC denied GSU $100 million interim rate increase on 12/2/86. LPSC suggested sale of assets to raise cash. GSU appealed on 12/5/86. TX prudence audit in progress.
RM Schahfer 18	393	C	No. Indiana Public Service	100	IN	IN	4/22/87		Y		Filed with PSC for rate hike of 3.75% in 1987 and 1988, and 0.91% in 1989; moratorium until 1991 on rate hikes. Unit 18 to be phased in over 5 years. PUC had not resolved case as of 2/87.
Seabrook 1	1200	N	Public Service NH	47.58	NH	NH	--	--	--	--	PSNH will file for $1.57 billion in Unit 1 costs when plant enters service. Condition: will no longer attempt to charge ratepayers for Seabrook #2 or Pilgrim #2. Expect 10% annual increases for 5 years for Unit 1.
Seabrook 1	1200	N	Connecticut Light & Power/ United Illuminating Co.	31.82	CT	NH	--	--	Y	--	Connecticut Dept. of Public Utility Control set cost of cap of $4.7 billion related to ownership of Connecticut Light & Power and United Illuminating Co.
Seabrook 1	1200	N	United Illuminating Co.	17.5	CT	NH	--	--	Y	Y	On 9/27/87, CT DPUC set cost up of $4.7 billion, UIC assumes that it loss of about $125 million will thereby be incurred. Various appeals have been made.

Table 4 (Cont'd)

Summary of Power Plant Rate Base Decisions Pending

Plant/Unit	MW	F	Utility	% Own	Juris.	Plt. Loc.	Current Decision Date	Prudence Review	Cost Cap	CWIP	Notes
South Texas 1&2	2624	N	Houston Lighting & Pwr	30.8	TX	TX	7/86	Y	--	--	PUC-commissioned audit found $1.1-1.3 billion of $5.5 billion const. costs due to mgmt. imprudence. PUC expected to recommend $1.3 billion excl. from rate base when plant begins operation in late 1987. Util. disagrees. Prudence audit in progress.
Vogtle 1&2	2320	N	Georgia Power Co.	45.7	GA	GA	12/16/86	Y	Y	--	Prudence audit in progress for Units 1&2. PSC allowed GA Pwr to defer operating costs, depreciation, and other expenses for #1 from COD to date 1st reflected or partly reflected in company's rates. Cost cap for GA Pwr is $3.56 billion, which is company share of $8.35 billion project cap. 3/87 -- Will take after-tax charge of $226 million against earnings.
Waterford 3	1165	N	Louisiana Power & Light	100	LA	LA	11/14/85	Y	Y	--	Utility proposed to include 90% of construction costs in rate base. Emergency rate relief granted on several conditions including: 1) Grand Gulf 1 treatment be agreed to by all parties; 2) LP&L forego recovery of $284 million of Waterford's costs regardless of prudency outcome (additional investment may be disallowed); 3) LP&L must refund certain billings related to Grand Gulf 1. Prudence audit found only 5% of $2.8 billion to be imprudent (11/86).
WNP 3	1316	N	Washington Water Power	5	WQ	WA	2/87	--	--	--	2/87 -- Proposed settlement: 1) WWP can recover 64.1% ($15.5 million) of its total investment during 1987; 2) WWP will seek no further rate recovery for No. 3 investment; 3) represents recovery over 32.5-year period of $79.6 million of WWP's total $124.2 million investment (WA portion).

Table 5

Rate Base Treatment of
Cancelled Nuclear Plants

Plant/Unit:	Allens Creek 1
Utility:	Houston Lighting & Power
Utility %:	100
Capacity (MWe):	1200
Cancel Date:	8208
Sunk Costs ($MM):	362
Rate Base Treatment:	6/82 -- HLP filed with PUC for general rate increases to recover entire investment over 10-year period using an accelerated amortization method. 12/82 -- PUC order: 1) disallowed recovery of about $166 million incurred after 1/1/80 as imprudent; 2) tax savings associated with unrecoverable portion to be passed through to ratepayers over 10-year period. HLP charged $287 million ($168 million after-tax) against 4th quarter income. PUC allowed recovery of $195 million on straight-line basis over 10-year period; however, due to tax savings treatment, allowed recovery was reduced to $84 million. 6/84 -- Travis County Dist. Ct. ruled that certain punitive measures in 12/82 PUC order had been imposed without legal authority: after costs disallowed, became non-utility matter and flow-through of tax savings should not have been reflected. PUC appealed Dist. Ct. ruling to Austin Ct. of Appeals.

Table 5 (Cont'd)

Plant/Unit:	Barton 1&2
Utility:	Alabama Power Co.
Utility %:	100
Capacity (MW):	2400
Cancel Date:	7711
Sunk Costs (Million $):	34
Rate Base Treatment:	Filed to amortize as an operating expense over 5-year period and to collect in full. Began to amortize in 11/77.

Table 5 (Cont'd)

Plant/Unit:	Bailly 1
Utility:	No. Indiana Public Service
Utility %:	100
Capacity (MWe):	660
Cancel Date:	8108
Sunk Costs ($MM):	190.747
Rate Base Treatment:	11/16/81 -- NIPSCO filed with IN PSC to amortize investment over 5-year period and to recover such amounts through rates. 8/11/82 -- IN PSC provided for amortization and recovery over 15-year period. 10/6/82 -- PSC denied intervenor petition for rehearing that challenged amortization. 9/28/82 -- PSC adopted new rate order (identical to 8/11/82 order) to remedy alleged procedural defects in former. 10/22/82 -- Intervenors appealed 9/28/82 order to IN Court of Appeals. 12/27/84 -- Court of Appeals reversed PSC; found that IN law does not allow the ordered amortization. NIPSCO petitioned for rehearing. 2/7/85 -- Court of Appeals denied NIPSCO rehearing. Company will petition for transfer to IN Sup. Ct. 11/19/85 -- IN Sup. Ct. denied amortization of Bailly. 1/3/86 -- Denied rehearing of 11/19/85 decision. Company will appeal to U.S. Sup. Ct. NIPSCO recorded extraordinary loss of unamortized costs of about $148.4 million ($94.8 million after taxes). 1/7/86 -- Company filed petition with PSC to begin evidentiary proceedings to determine effect of IN Sup. Ct. order upon revenue levels of the company, including NIPSCO obligations (if any) to make refunds to customers. 1/14/87 -- PSC ordered NIPSCO to refund $54.7 million relating to Bailly costs amortized through 12/31/85 and related expenses during 1986. Company requested rehearing; was denied. Will file court appeal of decision.

Table 5 (Cont'd)

Plant/Unit:	Black Fox 1&2
Utility:	Public Service Oklahoma
Utility %:	60.9
Capacity (MWe):	2450
Cancel Date:	8202
Sunk Costs ($MM):	260
Rate Base Treatment:	A. Oklahoma

6/82 -- OCC allowed PSO ratable recovery through 10-year amortization plan, with return on unrecovered costs after deduction of related deferred income taxes. Part of recovery to be made through certain revenues realized by PSO ($6.348 million in 1982 and $53.60 prior to 1982).

Appealed by OK Att. Gen. alleging that OCC exceeded statutory and constitutional authority in granting PSO recovery of investment. Another party appealed on procedural grounds.

1984 -- OK Sup. Ct. affirmed OCC decision with respect to procedural matters.

7/85 -- Attn. Gen. appeal dismissed as result of settlement, part of which required PSO to make one-time cash payment to customers of $15 million.

B. FERC

3/82 -- PSO filed rate hike request for $1.9 million with FERC to reflect amortization of plant. Placed rates in effect 10/82, subject to refund.

12/82 -- PSO filed Offer of Settlement with FERC, combining $1.9 million request with previous one for $8.2 million (reduced to $7.2 million).

2/83 -- FERC issued order permitting reduced amount to become effective 1/1/83, subject to refund. Opposed by Att. Gen.

6/83 -- FERC Final Order that provided for recovery, over 10 years, of FERC jurisdictional portion of costs.

Table 5 (Cont'd)

Plant/Unit:	Black Fox 1&2
Utility:	Western Farmers Electric Coop.
Utility %:	17.39
Capacity (MWe):	2450
Cancel Date:	8202
Sunk Costs ($MM):	1.85
Rate Base Treatment:	Recorded investment as a deferred debit.

Table 5 (Cont'd)

Plant/Unit:	Callaway 2
Utility:	Union Electric Co.
Utility %:	100
Capacity (MWe):	1185
Cancel Date:	8110
Sunk Costs ($MM):	70 (after tax)
Rate Base Treatment:	A. Missouri 10/21/83 -- MO PSC ruled that recovery of $37 million cancellation costs in MO jurisdiction barred by state statute prohibiting rate recovery of cost of facility before it is fully operational and used for service. UE appealed. 2/26/85 -- MO Sup. Ct. ruled that statutory ban does not apply to cancelled plants; remanded issue to PSC for further proceedings. B. Other jurisdictions Costs presently being collected through rates or cases under review.

Table 5 (Cont'd)

Plant/Unit:	Cherokee 1
Utility:	Duke Power Co.
Utility %:	100
Capacity (MW):	1343
Cancel Date:	8306
Sunk Costs (Million $):	Included with Units 2&3
Rate Base Treatment:	All jurisdictions (NC, SC, and FERC) permitted recovery of costs incurred through 4/3/83, over a 10-year period. Duke will seek recovery of remaining incurred costs.

Table 5 (Cont'd)

Plant/Unit:	Cherokee 2&3
Utility:	Duke Power Co.
Utility %:	100
Capacity (MWe):	2686
Cancel Date:	8211
Sunk Costs ($MM):	632.127
Rate Base Treatment:	A. North Carolina PUC allowed for amortization recovery of all costs incurred through 4/30/83. 10-year recovery period; began 10/83. B. South Carolina Same treatment. C. FERC Same treatment. Note: Sunk costs listed here also include Unit 1

Table 5 (Cont'd)

Plant/Unit:	Clinton 2
Utility:	Illinois Power Co.
Utility %:	80
Capacity (MWe):	990
Cancel Date:	8310
Sunk Costs ($MM):	34.8
Rate Base Treatment:	Construction and cancellation charges deferred and classified as unamortized deferred abandonment costs. Filed request to recover all costs over 3-year period and to earn a return on the amortized balance during that period. 8/7/85 -- ICC decision given: 1) allowed amortization and recovery through rates of $31.9 million of $34.8 million invested; 2) set 5-year period for recovery; 3) no return on the unamortized balance of the investment during that period; 4) disallowed that portion of AFUDC recorded after construction was halted ($2.9 million), which amount was charged against income in third quarter 1985.

Table 5 (Cont'd)

Plant/Unit:	Forked River 1
Utility:	Jersey Central Power & Light
Utility %:	97
Capacity (MW):	1168
Cancel Date:	8011
Sunk Costs ($MM):	414
Rate Base Treatment:	PSE&G reclassified investment to deferred debits (unamortized property losses). 7/31/81 -- NJ BPU order: 1) allowed for recovery of $225.4 million of $252.3 million net investment (after $142.2 million anticipated tax benefits and $19.2 million anticipated salvage value) over 15-year period through rates; 2) excluded recovery of AFUDC accrued during 4/4/79 through 3/31/80. PSE&G recorded extraordinary charge of $26.9 million relating to disallowed AFUDC.

Table 5 (Cont'd)

Plant/Unit:	Grand Gulf 2
Utility:	Middle South Energy
Utility %:	90
Capacity (MWe):	1373
Cancel Date:	--
Sunk Costs ($MM):	947
Rate Base Treatment:	Suspension of construction activities for up to 3 years (from 1/87). Will not seek rate increase during that period for Unit 2 costs. Note: Facility has not been cancelled as of 4/1/87. Current status is indefinitely deferred.

Table 5 (Cont'd)

Plant/Unit:	Harris 2
Utility:	Carolina Power & Light
Utility %:	83.83
Capacity (MWe):	955
Cancel Date:	8312
Sunk Costs ($MM):	315
Rate Base Treatment:	Filed to write off costs over 10 years and to recover through rates. 9/84 -- Received approval to begin amortization (for retail operations) for 10-year period. Filed with FERC to amortize $40.965 million related to wholesale jurisdiction over 10-year period. Received approval; began amortization in March 1985.

Table 5 (Cont'd)

Plant/Unit:	Harris 3&4
Utility:	Carolina Power & Light
Utility %:	100
Capacity (MWe):	1910
Cancel Date:	8112
Sunk Costs ($MM):	187
Rate Base Treatment:	Requested amortization over period of not more than 10 years. Received approval to begin amortization in July 1982 for 10-year period.

Table 5 (Cont'd)

Plant/Unit:	Hartsville A1&A2 Yellow Creek 1&2
Utility:	Tennessee Valley Authority
Utility %:	100
Capacity (MWe):	2538/2678
Cancel Date:	8408
Sunk Costs ($MM):	2800
Rate Base Treatment:	To be combined with unamortized balance from other 4 units; amortized over 11-year period beginning in FY85. Amortization schedule: limit of 6% applied to the $2.7 billion unamortized balance as of 9/30/84, increased by 1% per year until 5th year, after which it would reach and remain at 10%.

Table 5 (Cont'd)

Plant/Unit:	Hartsville B1&B2 Phipps Bend 1&2
Utility:	Tennessee Valley Authority
Utility %:	100
Capacity (MWe):	2538/2538
Cancel Date:	8208
Sunk Costs ($MM):	1900
Rate Base Treatment:	To be amortized within 10 years of cancel date, and recovered through rates. Reflected as deferred charge on balance sheet.

Table 5 (Cont'd)

Plant/Unit:	Hope Creek 2
Utility:	Public Service Elec. & Gas
Utility %:	95
Capacity (MW):	1117
Cancel Date:	8112
Sunk Costs ($MM):	290.8
Rate Base Treatment:	Charged $290.8 million to Extraordinary Property Losses and associated tax reduction of $126.3 million included in Accumulated Deferred Income Taxes. 3/4/82 -- NJ BPU authorized transfer of $112 million of Unit 2 costs to Unit 1 and recovery of all after-tax abandonment costs for Unit 2 through rates. 15-year amortization period on an accelerated method, beginning 7/1/82.

Table 5 (Cont'd)

Plant/Unit:	Hope Creek 2
Utility:	Atlantic City Electric
Utility %:	5
Capacity (MW):	1117
Cancel Date:	8112
Sunk Costs ($MM):	15.956
Rate Base Treatment:	Transferred investment from CWIP to Property Abandonment Costs. Appropriate amount of deferred federal income taxes provided. 12/6/82 -- NJ BPU granted ACE increase of $73.7 million in base rates. Allowed amortization of Unit 2 costs through rates over a 15-year period; no return on unamortized balance.

Table 5 (Cont'd)

Plant/Unit:	Jamesport 1&2
Utility:	Long Island Lighting Co.
Utility %:	50
Capacity (MW):	2458
Cancel Date:	8009
Sunk Costs ($MM):	53
Rate Base Treatment:	Petitioned NY PSC to amortize investment and to accumulate AFUDC or its equivalent on any unamortized expenditures until full recovery achieved. Not seeking recovery of non-nuclear costs. 1981 -- PSC authorized LILCO to continue accrual of AFUDC on expenditures until matters concerning possibility of using site for coal plant are resolved. 11/83 -- NY Appellate Ct. nullified certificate authorizing coal plant and dismissed LILCO's application. No LILCO appeal.

Table 5 (Cont'd)

Plant/Unit:	Jamesport 1&2
Utility:	New York State Elec. & Gas Co.
Utility %:	50
Capacity (MW):	2458
Cancel Date:	8009
Sunk Costs ($MM):	55.4
Rate Base Treatment:	1980 -- Filed for permission to: 1) continue accumulating AFUDC on nuclear-related costs until amortization commences to be recovered in rates; 2) amortize investment through rates; and 3) include in rates appropriate carrying charges on unamortized balances. Planning to file with FERC for same handling of AFUDC. 1981 -- State offered certificate to NYSE&G and LILCO to build coal plant on site; NYSE&G refused. 3/24/82 -- PSC authorized NYSE&G to continue accrual of AFUDC on nuclear-related costs until decision reached regarding prudence and disposition of such costs. 9/22/82 -- PSC suspended proceedings until possibility of coal plant construction resolved. 11/7/83 -- NY Sup. Ct. annulled Certificate for coal plant. 1/16/84 -- NYSE&G filed petition requesting resumption of amortization proceeding. 6/8/84 -- Proceedings reopened.

Table 5 (Cont'd)

Plant/Unit:	Marble Hill 1&2
Utility:	Public Service Indiana
Utility %:	83
Capacity (MWe):	2344
Cancel Date:	8411
Sunk Costs ($MM):	2288
Rate Base Treatment:	Recorded costs as deferred assets during 1984/1985, pending regulatory decision on recoverability of such costs through rates. Based on Bailly decision (costs not recoverable), PSI wrote off $1.337 billion costs allocable to retail customers. 3/7/86 -- PSC issued order (Settlement Agreement): 1) approved $68.2 million (8.2%) annual rate increase; 2) 5% emergency increase collected as surcharge since 3/84 included in base rates; 3) PSI will not seek recovery of Marble Hill costs in retail rates; 4) PSI will not file rate increase request (except fuel cost) prior to 1/1/89, except for emergency; 5) common dividends suspended 1986-1988; 6) PSI will be allowed to record a regulatory asset of $475 million for accounting to avoid negative common equity from earlier write-off. Decision under appeal by intervenors.

Table 5 (Cont'd)

Plant/Unit:	Marble Hill 1&2
Utility:	Wabash Valley Power Association
Utility %:	17
Capacity (MWe):	2344
Cancel Date:	8411
Sunk Costs ($MM):	466
Rate Base Treatment:	Filed suit against PSI to recover its $466 million+ investment. 1/14/87 -- PSC denied WVPA's request for recovery of Marble Hill costs. Had requested 51% rate hike. PSC rejected intervenor argument that Chapter 11 reorganization proceeding filed by WVPA under Bankruptcy Code precluded the Commission from continuing to regulate the corporation's rates.

Table 5 (Cont'd)

Plant/Unit:	Midland 1&2
Utility:	Consumers Power Co.
Utility %:	100
Capacity (MWe):	1300
Cancel Date:	--
Sunk Costs ($MM):	4200
Rate Base Treatment:	10/22/86 -- PSC approved conversion to gas-fired cogen plant. No more than $50 million addition rate-payer funds to be spent. Consumers will not seek rate hike until electricity produced. 3/11/87 -- FERC decision: 1) CP will sell $1.5 billion worth of assets from nuclear facility to partnership that will own and operate the cogen facility; 2) granted "qualifying facility" status under PURPA. Electricity to be sold to CP at avoided costs. CP seeking rate hike to recover $2.2 billion of its $4.2 billion investment in nuclear plant. Wrote off $500 million in 1985. Hearings in progress on CPC request for recovery of $2.1 billion of Midland assets not usable in the conversion project. <u>Note</u>: CPC abandoned components not needed in conversion 6/86. This may represent "cancellation" of nuclear plant.

Table 5 (Cont'd)

Plant/Unit:	Montague 1&2
Utility:	Northeast Utilities
Utility %:	100
Capacity (MW):	2490
Cancel Date:	8012
Sunk Costs ($MM):	29.5
Rate Base Treatment:	A. Connecticut 11/25/81 -- CT DPUC granted Conn. Light & Power and Hartford Elec. Light Co. annual rate increases totaling about $186 million. Grant was 71.3% of request. Allowed for recovery of $15.8 million of the $23.9 million (CT allocation) investment in Montague, over 3-year period. Disallowed recovery of about $4.6 million incurred after 1977. B. Massachusetts 7/31/81 -- MA DPU approved Western Mass. Elec. Co. rate hike of $25.5 million. Grant was about 60% of request. Allowed for recovery through rates of $4.1 million of WMECO's $5.6 million (MA allocation) investment in Montague, over 4-year period. Disallowed $600,000 relating to equity portion of project's AFUDC.

Table 5 (Cont'd)

Plant/Unit:	North Anna 3
Utility:	Virginia Power
Utility %:	100
Capacity (MWe):	950
Cancel Date:	8211
Sunk Costs ($MM):	469.3
Rate Base Treatment:	Requested rate relief to recover deferred amount ($469.3 million) and any subsequent cancellation costs.

A. North Carolina

9/83 -- Received permission to recover such costs through 10-year amortization.

B. FERC

11/83 -- Received permission to recover such costs through 10-year amortization. Amended to 15-year period.

C. Virginia

2/1/84 -- SCC Hearing Examiner issued report. Recommended: 1) recovery over 15-year amortization period;
2) disallowance of inclusion of unamortized costs in rate base. Final decision pending.

3/27/84 -- SCC issued Final Order upholding initial order.

Table 5 (Cont'd)

Plant/Unit:	North Anna 4
Utility:	Virginia Power
Utility %:	100
Capacity (MWe):	950
Cancel Date:	8011
Sunk Costs ($MM):	154.5
Rate Base Treatment:	Being collected in rate base (total); amortized over 10-year period.

Table 5 (Cont'd)

Plant/Unit:	Pebble Springs 1&2
Utility:	Portland General Electric Co.
Utility %:	47.1
Capacity (MWe):	2628
Cancel Date:	8210
Sunk Costs ($MM):	126.852
Rate Base Treatment:	PGE wrote off entire investment in 1982.

9/23/82 -- PUC granted PGE rate increase of 8.6%, which included funds for Pebble Springs.

A. 10/82 -- Coalition for Safe Power and Forelaws on Board filed suit seeking to set aside PUC order. Challenged findings of fact re: abandonment and write-off, and accounting treatment by PGE.

3/85 -- Judge remanded proceedings to Commissioner.

B. 5/83 -- Coalition for Safe Power and 2 individuals filed class-action suit against PGE, the Commissioner, and another IOU. Alleged that PGE indirectly included in rate base a substantial portion of Pebble Springs via debt/equity exchanges.

10/28/85 -- Settlement Agreement approved by court: 1) dismissed all Pebble Springs and Skagit lawsuits pending; 2) did not address interpretation of Ballot Measure 9; 3) PGE gave up collection of $14 million previously authorized to collect from customers (part to Pebble Springs and part to Skagit).

Table 5 (Cont'd)

Plant/Unit:	Pebble Springs 1&2/WNP5
Utility:	Pacific Power & Light
Utility %:	29.4/10
Capacity (MWe):	2628/1316
Cancel Date:	8210/8201
Sunk Costs ($MM):	174.234
Rate Base Treatment:	A. California

1983 -- PPL request for amortization of Pebble Springs/WNP 5 costs denied. PPL petition for review denied by CA Sup. Ct.

B. Montana

4/83 -- PSC denied any cost recovery. PPL appealed to State Court.

C. Oregon

1982 -- PPL wrote off $32.7 million as unrecoverable OR share of Pebble Springs.

12/83 -- PUC granted increased rates to cover OR share of WNP 5/Skagit over 5-year period. Limited to expenditures prior to 1979. PPL appealed to obtain all expenditures; consumer group appealed to oppose any recovery.

2/85 -- OR Att. Gen. filed brief stating that any amortization contrary to OR law.

D. Washington

1983 -- WA UTC granted recovery of Pebble Springs/WNP-5 costs through specific increment to return on common equity.

1984 -- WA UTC replaced such return by allowing 5-year amortization through rates. Decision was appealed.

8/2/85 -- WA UTC issued order re: 1984 rate case determining that rate of amortization should be lowered because of error in earlier order. PPL appealed.

Table 5 (Cont'd)

E. Wyoming

10/82 -- Recorded $23.3 million provision for unrecoverability.

12/82 -- WY PSC denied any recovery of terminated nuclear project costs.

2/7/84 -- WY Sup. Ct. affirmed PSC decision. PPL filed petition for reconsideration.

U.S. Sup. Ct. let stand WY Sup. Ct. decision without comment.

Table 5 (Cont'd)

Plant/Unit:	Pebble Springs 1&2
Utility:	Puget Sound Power & Light
Utility %:	23.5
Capacity (MWe):	2628
Cancel Date:	8210
Sunk Costs ($MM):	72
Rate Base Treatment:	1983 -- Puget requested amortization of net investment at 6/30/82 ($53.5 million) through rates over 5-year period, with return on unamortized balance. Puget will later request that investment be amortized through rates adjusted to reflect positive or negative salvage, continuing accrual of AFUDC after 6/30/82. 7/25/83 -- WA UTC allowed Puget to recover its net investment over 10 years, with no return on unamortized balance. Appealed by WA Att. Gen. and a ratepayers group. 12/12/85 -- WA Sup. Ct. affirmed WA UTC 7/25/83 order. WA Att. Gen. and ratepayer group filed motion for reconsideration. Motion denied; order became final 2/24/86.

Table 5 (Cont'd)

Plant/Unit:	Perkins 1-3
Utility:	Duke Power Co.
Utility %:	100
Capacity (MWe):	4035
Cancel Date:	8202
Sunk Costs ($MM):	8.927
Rate Base Treatment:	All jurisdictions (NC, SC, FERC) allowed recovery of total costs over 5-year period.

Table 5 (Cont'd)

Plant/Unit:	Pilgrim 2
Utility:	Boston Edison Co.
Utility %:	58.42
Capacity (MWe):	1240
Cancel Date:	8109
Sunk Costs ($MM):	278
Rate Base Treatment:	MA DPU allowed collection of $116.8 million through rates over 13-year period. Additional $110 million recoverable through federal income tax credits. Also, permits recovery of $46 million of money costs over same period. Intervenors appealed to MA Sup. Ct. MA DPU order upheld on 9/23/83.

Table 5 (Cont'd)

Plant/Unit:	Pilgrim 2
Utility:	Public Service New Hampshire
Utility %:	3.47
Capacity (MWe):	1240
Cancel Date:	8109
Sunk Costs ($MM):	15.0
Rate Base Treatment:	6/84 -- NH Sup. Ct. ruled that NH anti-CWIP statute prohibits recovery from ratepayers of #2 investment. Company now in proceedings before NH PUC and will then seek final determination from Sup. Ct. on constitutionality of anti-CWIP statute.

Table 5 (Cont'd)

Plant/Unit:	Pilgrim 2
Utility:	Central Maine Power Co.
Utility %:	2.85
Capacity (MWe):	1240
Cancel Date:	8109
Sunk Costs ($MM):	14.6
Rate Base Treatment:	Requested rate increase to cover investment over 10-year period. 12/15/83 -- PUC deferred decision until future rate increase request. 5/85 -- PUC allowed CMP to recover $43.3 million over 10-year period (included Seabrook 2, Pilgrim 2, and Sears Island coal plant).

Table 5 (Cont'd)

Plant/Unit:	River Bend 2
Utility:	Gulf States Utilities
Utility %:	70
Capacity (MWe):	991
Cancel Date:	8401
Sunk Costs ($MM):	107.722
Rate Base Treatment:	A. Louisiana Will request rate hike for costs allocable to LA portion of unit from LA PSC. B. Texas PUC authorized GSU to recover all allocated costs associated with Unit 2 incurred before 12/31/83 ($41.3 million) through amortization over 15 year period. No return on investment. PUC did not consider recovery of estimated cancellation costs; GSU will request recovery of such later. C. FERC Requested authorization from FERC to amortize Unit 2 costs allocable to wholesale operations over 5-year period with no return on unamortized balance. Began collecting such costs in 9/84, subject to hearing and refund. FERC determined 10-year period.

Table 5 (Cont'd)

Plant/Unit:	Skagit 1&2
Utility:	Puget Sound Power & Light
Utility %:	40
Capacity (MW):	2670
Cancel Date:	8308
Sunk Costs ($MM):	178.758
Rate Base Treatment:	Total investment included in CWIP. Includes AFUDC through 7/25/83, when such accrual was stopped by WA PUC. Filed to allow amortization of about $127.7 million through rates to customers over 10-year period, with a return on unamortized balance. 9/28/84 -- PUC general rate order: 1) allowed recovery of $82 million of $128 million <u>net</u> investment; 2) recovery period of 10 years; 3) no return on unamortized balance. Order appealed by WA Att. Gen. and an intervenor group; alleged that rate recovery for terminated projects was unlawful. Seeking refunds of amounts recovered in rates so far. Final decision not yet in.

Table 5 (Cont'd)

Plant/Unit:	Skagit 1&2
Utility:	Portland General Electric Co.
Utility %:	30
Capacity (MW):	2670
Cancel Date:	8308
Sunk Costs ($MM):	126.39
Rate Base Treatment:	10/83 -- PGE filed request for net 6.1% average rate increase to recover entire investment over 5-year period. 12/83 -- PUC granted net 2.2% average increase to recover portion ($36.263 million net of related income tax reductions of $31.773 million) over 5-year period. Amount not allowed was recorded by PGE as extraordinary loss of $48.598 million net of income tax reductions of $9.756 million. 12/83 -- Coalition for Safe Power filed suit in Circuit Court for Multnomah County to set aside PUC order. 2/84 -- PGE filed suit in same court to allow for collection of remainder of costs, alleging that Ballot Measure 9 not applicable to this case. 2/85 -- Att. Gen. office took position that Ballot Measure 9 precluded all rate recovery for Skagit. 10/28/85 -- Settlement agreement reached under which PGE foregoes collection of $14 million previously authorized to recover in rates.

Table 5 (Cont'd)

Plant/Unit:	Skagit 1&2
Utility:	Pacific Power & Light Co.
Utility %:	20
Capacity (MW):	2760
Cancel Date:	8308
Sunk Costs ($MM):	88.475
Rate Base Treatment:	A. Wyoming 12/82 -- WY PSC denied recovery of all terminated nuclear plant costs. 2/7/84 -- WY Sup. Ct. affirmed PSC decision. PPL filed petition for reconsideration. U.S. Sup. Ct. let stand without comment. B. Oregon 12/83 -- OR PUC granted increased rates to permit amortization over 5 years of the OR share of the investment ($20 million after-tax) in Skagit prior to 1979. Appealed by PPL to obtain recovery of all expenditures; appealed by consumer group to oppose any recovery. PPL offset $573 million investment in cancelled nuclear plants (Skagit, Pebble Springs, WNP 3&5) during 1982-1983 via allowances for estimated unrecoverability ($284 million) expected tax benefits ($150 million), and asset accounts to be recovered through rate recovery already or expected to be granted ($139 million). Recorded extraordinary loss of $58 million in 1982 from nuclear project abandonment. 12/31/84 -- PPL had on balance sheet $127 million estimated to be recoverable through rates in WA and OR. Authorized to amortize $64 million over 7-year period.

Table 5 (Cont'd)

Plant/Unit:	Skagit 1&2
Utility:	Washington Water Power Co.
Utility %:	10
Capacity (MW):	2670
Cancel Date:	8308
Sunk Costs ($MM):	39.3
Rate Base Treatment:	Investment claimed as federal income tax deduction in 1983. Filed with WA UTC and ID PUC to amortize investment (not deferred tax benefits) over 5-year period. Allocation of sunk costs ($ million) -- WA (23.672), ID (14.096), FERC (1.583).

A. Idaho

1/30/85 -- ID PUC allowed amortization of 50% of ID share of costs incurred through 12/31/81, through rates, over 15-year period. No return on unamortized balance.

B. Washington

1/10/85 -- WA UTC allowed amortization for WA share of project, through rates, over 10-year period. NO return on unamortized balance.

2/5/85 -- WA Public Counsel appealed WA UTC order.

12/12/85 -- WA Sup. Ct. upheld WA UTC order.

Table 5 (Cont'd)

Plant/Unit:	Surry 3&4
Utility:	Virginia Power
Utility %:	100
Capacity (MWe):	1764
Cancel Date:	7703
Sunk Costs ($MM):	98.4
Rate Base Treatment:	Total investment being collected in rate base; amortized over 10-year period.

Table 5 (Cont'd)

Plant/Unit:	WNP 5
Utility:	Pacific Power & Light
Utility %:	10
Capacity (MWe):	1316
Cancel Date:	8201
Sunk Costs ($MM):	150
Rate Base Treatment:	A. Oregon 12/83 -- OR PUC granted rate hike to permit amortization, over 5 years, of the OR portion of the WNP5/Skagit projects, to the extent of expenditures before 1979. PPL appealed to recover all expenses; consumer group appealed to oppose allowance of any recovery. 2/85 -- OR Att. Gen. filed brief asserting that any amortization was contrary to OR law. B. Washington 1983 -- WA UTC granted recovery of WNP5/Pebble Springs costs through a specific increment to return on common equity. 1984 -- WA UTC replaced prior plan by allowing 5-year amortization through rates. 8/2/85 -- WA UTC ordered reduction in allowed level of amortization due to error in earlier orders. PPL appealed. C. Wyoming 12/82 -- WY PSC denied any recovery of terminated nuclear plant costs. 2/7/84 -- WY Sup. Ct. affirmed PSC denial. PPL filed petition for reconsideration. U.S. Sup. Ct., without comment, let stand WY Sup. Ct. decision. D. California 1983 -- Request for amortization of WNP5/Pebble Springs costs denied by CA PUC. Petition for review denied by CA Sup. Ct.

Table 5 (Cont'd)

E. Montana

4/83 -- MT PSC denied recovery of terminated nuclear plant costs. PPL appealed.

Table 5 (Cont'd)

Plant/Unit:	WNP 4&5
Utility:	Wash Public Power Supply
Utility %:	95
Capacity (MWe):	2656
Cancel Date:	8201
Sunk Costs ($MM):	2281.783
Rate Base Treatment:	6/15/83 -- WA Sup. Ct. ruled that Participants' Agreements were invalid as to WA State public bodies. King County Superior Ct. ruled that Agreements were therefore unenforceable against all remaining participants. Appealed by WPPSS and Chemical Bank. 7/22/83 -- WPPSS defaulted on Bond Resolution. Remaining funds transferred to Chemical Bank, which then controlled disbursement of payments for No. 4&5 termination activities. 8/83 -- Chemical Bank filed suit against WPPSS, all No. 4&5 participants, WPPSS member utilities and Directors, BPA, and other individuals. 11/6/84 -- WA Sup. Ct. reaffirmed 6/15/83 decision. WPPSS and Chemical Bank petitioned U.S. Sup. Ct. for grant of a writ of certiorari. 4/29/85 -- U.S. Sup. Ct. denied grant of writ.

Table 5 (Cont'd)

Plant/Unit:	Zimmer 1
Utility:	Cincinnati Gas & Electric
Utility %:	37
Capacity (MWe):	840
Cancel Date:	8401
Sunk Costs ($MM):	716
Rate Base Treatment:	1/27/82 -- PUC granted rate increase of $85.4 million (CG&E requested $135 million) to cover portion of East Bend 2 and Zimmer 1. Allowed 50% of Zimmer investment as of 3/31/81 into rate base. 11/82 -- Ohio Office of Consumers' Counsel requested PUC to reduce by about $30 million rates being charged to reflect exclusion of Zimmer during NRC stop work order. 3/83 -- PUC allowed rate hike of $30.7 million, specifically not recognizing costs of Zimmer. PUC hired private consultant in late 1983 to determine any portion of cost due to mismanagement. 8/84 -- Announced plan for coal conversion. 10/84 -- PUC announced intention to determine what portion of existing facility will be "used and useful" in converted plant; also to determine if any costs to date are attributable to management. Accrual of AFUDC on 55% of CGE's Zimmer share discontinued after 1/20/84, recognizing portion of plant that will not be used in conversion. PUC allowed CG&E to write off $142 million of Zimmer costs after taxes. Other terms: 1) co-owners cannot recover $861 million through rate requests; 2) cap of $3.6 billion recoverable if project completed.

Table 5 (Cont'd)

Plant/Unit:	Zimmer 1
Utility:	Dayton Power & Light Co.
Utility %:	31.5
Capacity (MWe):	840
Cancel Date:	8401
Sunk Costs ($MM):	645
Rate Base Treatment:	See Cincinnati Gas and Electric Co. and Columbus and Southern Ohio Elec. for details of Stipulation. DPL portion of $861 million disallowance was $242 million. DPL share of $3.6 billion cost cap is $1.067 billion.

Table 5 (Cont'd)

Plant/Unit:	Zimmer 1
Utility:	Columbus & Southern Ohio Elec.
Utility %:	28.5
Capacity (MWe):	840
Cancel Date:	8401
Sunk Costs ($MM):	585.598
Rate Base Treatment:	10/23/84 -- OH PUC commenced proceeding to determine portion of plant not "used and useful" after conversion to coal. Will also determine any exclusion for: 1) costs resulting from imprudence or mismanagement in construction, and 2) costs in excess of reasonable cost for like items in plant originally designed for coal. 11/26/85 -- OH PUC approved Stipulation: 1) $861 million and any AFUDC accrued on such after 1/31/84 disallowed for rate-making purposes; 2) terminated consultant's investigation on mismanagement; 3) $3.6 billion maximum that co-owners may request in rate base as gross plant in service value. 12/85 -- Company declared Extraordinary Loss of $66.313 million net of related income taxes of $39.950 million to reflect its portion of disallowance. Balance of disallowed portion classified as deferred debit pending resolution of related lawsuit.

Table 6

Capital Cost Disallowances
Nuclear Plants[1/]

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Byron 1	Commonwealth Edison	IL	Reinspection Costs	101,500	Initial disallowance related to the costs for the reinspection of work and materials of two electrical contractors. Direct costs were estimated at approximately $11.5 million. Half of the AFUDC associated with a nine-month delay in COD were also disallowed ($90 million). This disallowance subsequently remanded to PSC for additional work.
				101,500	

1/ Includes "general" disallowances for cost caps, etc.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Callaway 1	Union Electric	MO	Direct Manhours	66,193	5.521 million manhours disallowed. Based by staff on adjusted D.E., particularly unit rates and unit costs. Major disallowances 2.07 mm civic, 1.67 electrical, 0.79 hangers, 0.62 structural steel, 0.26 miscellaneous outside, 0.17 electric outside.
			Scaffolding	8,344	Disallowance attributed to late design in hanger area.
			Start-up Costs	17,043	Disallowance related to premature mobilization ($16.4 million) and under-utilization of SNUPPS concept ($0.63).
			Schedule	88,778	Adjustment of AFUDC on the duration of construction schedule (80.5 months) related to staff's recommended level of man-hours.
			Overtime	57,438	Disallowance related to "non-productive" overtime and straight time as established by OKA analysis.
			Safety	2,828	Disallowance of safety meeting costs related to reduction in manhours.
			Indirect Costs	25,562	Disallowance of $13.5 million indirect costs and $12.1 million indirect nonmanual labor costs based on staff work with UE matrix relating indirect costs to schedule duration, man-hours, and other construction project variables.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Callaway 1	Union Electric	MO	NPI 1985 Costs	2,310	Disallowance of 1st operating year costs for NPI (contractor).
			AFUDC Non-Labor	54,541	Disallowance of AFUDC associated with adjustments not related to direct man-hours.
			Miscellaneous	60,963	
		IL	Imprudence	30,000	Jurisdictional treatment.
		IA	Imprudence	8,000	Jurisdictional treatment.
				421,730	

Modified per FERC Initial Decision June 4, 1986.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Catawba 1	Duke Power	NC		0	
Catawba 1	Duke Power	SC		0	
Catawba 2	Duke Power	NC		0	
Catawba 2	Duke Power	SC		0	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Fermi 2	Detroit Edison Co.	MI	Nozzle Repair	1,600	Disallowance of direct costs and AFUDC related to repair of five nozzles in reactor pressure vessel.
			T-G Supply	6,820	Disallowance of costs over original contract cost for foreign TG set (English Electric). Utility position that similar problems would have been faced with any supplier was not accepted.
			Turbine Installation	9,160	Disallowance of costs over original contract for T-G erection. Attributed by ALJ to generally poor construction management and poor contractor performance.
			Radwaste Modification	25,800	Disallowance of costs related to extensive modification and rebuilding of original radwaste system.
			Steam System Testing	1,290	Disallowance for system designed to provide clean steam from Fermi 1 to Fermi 2. This procedure was ultimately discarded due to schedule considerations.
			Piping	51,500	Disallowance based on productivity and rework problems. Total disallowance of 15% of contract amount.
			Cooling Towers	14,890	Disallowance related to installation of two natural draft cooling towers and indecisiveness by DECO in original choice of cooling system.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Fermi 2			Reactor Controls	5,530	Disallowance related to poor management of contract for completion of installation of reactor internals and control rod drive system.
			Security System	1,250	Disallowance related to payments to first contractor for security system. Contractor declared bankruptcy after having received advanced payment exceeding value delivered.
			Project Shutdown	16,780	Disallowance of 50% of the overheads and indirect costs associated with complete shutdown of Fermi 2 site from 11/74 - 2/77.
			Refurbishment Program	6,240	Disallowance of costs of 17 items related to project delays, including delivery deferral, equipment storage and lay-up and maintenance.
			Project Engineering	47,800	Disallowance of direct project engineering costs above 10% of total project costs. Actual was 10.3%.
			Project Delays	96,330	Disallowance of project expenditures excepting direct engineering and construction, start-up and testing and property taxes incurred during 6 month fuel load date slip 12/31/83 - 6/30/84.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Fermi 2			AFUDC Adjustment	9,270	Disallowance of increase in dollar values of certain items to reflect 10.53% AFUDC through 1983.
			Other	102,740	
			Excess Capacity	283,000	Investment in other generating plant, which will, pursuant to MI PSC order in Detroit Edison's most recent rate case, be excluded from rate base as excess capacity when Fermi 2 enters commercial operation.
				679,900	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Grand Gulf 1	Arkansas Power & Lt.	AR			It is not possible to quantify the amount of the substantial disallowances agreed to in stipulation agreements between Arkansas Power & Light Co. (AP&L) and the Arkansas PSC, or between Louisiana Power & Light Co. (LP&L) and the Louisiana PSC, because they are disallowances of percentages of total operating expenses incurred pursuant to a Federal Regulatory Commission (FERC) approved wholesale rate. System Energy Resources, a generating subsidiary of the Middle South Utilities (MSU) holding company system, owns 90% of Grand Gulf. The subsidiary will recover its investment in the plant through sales of power to, *inter alia*, AP&L, LP&L, and other MSU operating subsidiaries.
	Arkansas Power & Lt.	MO			Same as above.
	Louisiana Power & Lt.	LA			Same as above.
	Mississippi Pwr & Lt.	MS		0	
	New Orleans Pub. Serv.	LA		49,000	New Orleans Public Service, Inc. (NOPSI) agreed, in a settlement with the New Orleans Council, the body which regulates its rates, to forego recovery from ratepayers of this amount of deferred expense which NOPSI had incurred for puchases of Grand Gulf power.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
LaSalle 1	Commonwealth Edison	IL		0	
LaSalle 2	Commonwealth Edison	IL		0	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Limerick 1	Philadelphia Electric	PA	Construction Delays	368,900	Construction delays in 1978 and 1979. PECO has appealed.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
McGuire 2	Duke Power Co.	NC		0	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Millstone 3	Central Maine Power Co.	ME	Other	7,000	Settlement agreement provides for disallowance of 15% of the investment.
	Central Vermont Public Service	VT		0	
	Connecticut Light & Pwr	CT	Cost cap and other	147,000	Effect of Connecticut statutory cost cap.
				72,000	Incremental disallowance, in addition to disallowance imposed by statutory cost cap, provided for by settlement agreement.
	United Illuminating	CT	Cost cap and other	18,000	Same as above.
	Western Massachusetts Electric Co.	MA	Economic value	109,000	
				353,000	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Nine Mile Point 2	Central Hudson Gas & Electric Co.	NY	Cost cap & other		A stipulation agreement was approved by the New York PSC in August, 1986, ending an investigation into the prudence of the NMP 2 investment. The agreement provides that the amount of the investment to be included in the plant's five co-tenants' rate bases will total $4,160,000,000. The effect of two successive cost caps ordered earlier by the PSC had been to limit the plant's recoverable cost to approximately $5,200,000,000. The incremental disallowances agreed to in the stipulation have not been apportioned among the co-tenants in this table, because substantial problems of interpretation have arisen.
	Long Island Lighting	NY	Cost cap & other		Same as above.
	New York State E&G	NY	Cost cap & other		Same as above.
	Niagara Mohawk Power	NY	Cost cap & other		Same as above.
	Rochester Gas & Elec.	NY	Cost cap & other		Same as above.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Palo Verde 1	Arizona Public Service	AZ	Imprudence		The commission made no disallowance, in this rate case, for imprudence. However, rates attributable to inclusion of $210,000,000 of the Palo Verde No. 1 investment in Arizona Public Service's rate base remain in effect subject to refund, pending completion of the commission's prudence review.
	El Paso Electric Co.	NM		0	
	Southern California Edison Co.	CA	Imprudence		An October, 1986 stipulation agreement provides that disallowances to Southern California Edison Co.'s (SCE) investment in the three Palo Verde units (the third is not yet completed) shall equal 19.33% of disallowances for San Onofre 2&3. On the basis of the California PUC's subsequent final order in the San Onofre prudence investigation, SCE calculated that disallowances for all three Palo Verde units should total $50,000,000. This amount is subject to change if the amount of San Onofre imprudence disallowance changes on rehearing (currently in progress) or appeal. No breakdown by unit is available.
Palo Verde 2	Southern California Edison Co.	CA	Imprudence		Same as above.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
St. Lucie 2	Florida Power & Light Co.	FL		0	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
San Onofre 2&3	**San Diego Gas & Elec.**	CA	Imprudence	69,000	The total cost of these two units, and the total disallowance thereto, have been combined because the California issues only one final order on the prudence of the investment in both units, and did not fully separate the disallowances for each unit. These amounts represent San Diego Gas & Electric Co's. and Southern California Edison Co.'s shares of the entire $344,600,000 disallowance. (The remainder is allocable to non-investor-owned utilities, which are not subject to PUC jurisdiction in California.) Total cost per unit is $2,694,300,000 for Unit 2 and $1,796,200,000 for Unit 3. (Unit 1 was completed in 1968.)
	Southern California Edison Co.	CA	Imprudence	259,000	Same as above.
				328,000	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Shoreham 1	Long Island Lighting	NY	Engineering Manhours	104,829	Reflects disallowance of 2.9 million engineering manhours @ $34.60/hr.
			Construction Manhours	295,800	Reflects disallowance of 7.6 million construction manhours.
			Schedule Delay	305,000	Reflects adoption of ½ of staff's recommended disallowance for schedule delay; includes 7 categories of schedule delay costs.
			Diesel Generator Indirect	399,000	Disallowance of half of indirect, delay-related costs of diesel generator failure.
			Diesel Direct	95,000	Disallowance of $95 million of direct costs of diesel generator failure.
			Other	195,371	
				1,395,000	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Susquehanna 1	Pennsylvania Power & Light Co.	PA	Excess capacity	287,000	This adjustment is a "slice of system" adjustment, i.e., it is applied to equal portions of each of the utility's generating units. It is listed here in total because the high reserve margins which resulted in a finding of excess capacity were precipitated by the addition of the new unit.
Susquehanna 2	Pennsylvania Power & Light Co.	PA	Excess capacity	522,000	In this rate case order, the Pennsylvania PUC disallowed a return on the common equity component of the utility's investment in Susquehanna 2. The disallowance shown has been calculated by multiplying the utility's jurisdictional investment in the unit ($1,494,800,000) by the common equity ratio used in the case (34.9).
			Other	38,000	Disallowance of the cost of a short-term buy-back by Pennsylvania Power & Light Co., of Allegheny Electric Coop's interest in the unit. The buy-back was provided for in the earlier contract for sale of Susquehanna 2 capacity.
				847,000	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Summer 1	South Carolina Electric & Gas	SC	Excess capacity	123,000	This adjustment is a "slice of system" adjustment, i.e., it is applied to equal portions of each of the utility's generating units. It is listed here in toto because the high reserve margins which resulted in a finding of excess capacity were precipitated by the addition of the new unit.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Waterford 3	Louisiana Power & Light	LA	Other	284,000	Per stipulation agreement.

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Wolf Creek 1	Joint Owners		Manpower Cost	37,962	Disallowance of direct and indirect costs of 1.828 million manhours.
			Controllable Slippage	78,372	Disallowance for indirect/overhead costs attributed to 14.5 months controllable slippage.
			AFUDC Slippage	166,189	Disallowance of AFUDC associated with controllable slippage.
			Adj. to Constructor Billing	450	Disallowance of fees paid to constructor for work they did not perform or administer.
			Miscellaneous	103,000	Unexplained cost overruns/project management.
			Miscellaneous	22,000	Costs incurred after audit cutoff date.
			Miscellaneous	1,000	Transfers to materials and supplies.
				408,973	
	KC Power & Light	KS	Excess Capacity	221,000	
			Economic Value	68,000	
				289,000	

Table 6 (continued)

Capital Cost Disallowances
Nuclear Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Wolf Creek 1	KC Power & Light	MO	Excess Capacity	33,000	
	Kansas Gas & Electric	KS	Excess Capacity	716,000	
			Economic Value	194,000	
				910,000	
			Total	1,640,973	

Table 7

Capital Cost Disallowances
Other Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Belle River 1&2	Detroit Edison Co.	MI	Coal Handling System & Misc.	35,993	Disallowance of approximately $25 million in direct and overhead costs for modification of coal handling system, $2 million for miscellaneous items, and the remainder in AFUDC.
			Cost of Delay	60,875	Disallowance of one year's worth of AFUDC for cost of imprudent delay.
				96,868	

Table 7 (continued)

Capital Cost Disallowances
Other Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Big Bend 4	Tampa Elec. Co.	FL	FGD Test Materials	72	Costs of limerock used for testing FGD scrubber were excluded. Net loss of $49,000 to be amortized over 5 years (material sold for $23,000).
			Survey Variance	214	Costs of correcting differences in survey work were excluded ($214,000).
			Vendor Back Charges	1,600	Costs of a settlement with supplier of steel and fabrication services excluded from plant in service. Settlement cost of $1.6 million to be amortized over 5 years.
			Original Cooling System	1,713	Original design included cooling pond which was subsequently used as an ash pond. Net difference (cooling pond costs vs. ash pond costs) of $1.713 million to be amortized over 5 years.
			Transformer Purchase	82	Difference in cost between competitively bid transformer and more reliable transformer actually purchased excluded from plant in service. $82,000 to be amortized over 5 years.
				3,681	

Table 7 (continued)

Capital Cost Disallowances
Other Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Holcomb 1	Sunflower Electric Power Coop.	KS	Common Plant	500	Disallowance of investment in common plant for future unit.
				500	

Table 7 (continued)

Capital Cost Disallowances
Other Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Reid Gardner 4	Nevada Power	NV	A/E Selection	95	Adjustment for unit-related contract cost difference between A/E selected and lower cost proposal submitted. Reasoning that a formal study should have been done before acceptance of $9 million contract.
		NV	Change Orders	597	Adjustment for 6 of 68 change orders to A/E contract. Disallowance justified on basis that in traditional engineering concept, change orders would have been responsible for the work, not the contractors. Actual A/E engineering concept apparently considered non-traditional.
		NV	Second A/E Firm	718	Adjustment for 50% of conrtractor-furnished engineering furnished by another A/E. Lack of change order documentation and fact that prime A/E billing was not reduced by equipment amount (as might be expected in a traditional firm price engineering contract) supports PSC ruling.
		NV	NV Power AFUDC	397	Adjustment for Nevada Power AFUDC on 32.2% of disallowances.
		NV	Coal Handling Equipment	723	Reduction for coal slurry handling equipment installed but not currently used. Cost removed from plant-in-service and transferred to plant held for future use.

Table 7 (continued)

Capital Cost Disallowances
Other Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Reid Gardner 4		NV	Acceleration Incentives	1,843	50% reduction in monies paid as acceleration incentives. Adjustment related to utility's responsibilities for delays from work stoppages, fuel gas problems, late engineering, and underestimate of materials.
				4,373	

Table 7 (continued)

Capital Cost Disallowances
Other Plants

Unit	Utility	State	Disallowance	Amount ($1000)	Comment
Helms 1-3	Pacific Gas & Electric	CA	Avoidable Costs	21,171	Disallowance based on staff consultants' analysis of the difference between "good" and "adequate" construction performance standards. Consultants conclude that "good" performance would have saved 3.5 months and direct and indirect expenditures with a total value of $21.2 million.
			Drilling Machine Decision	822	Disallowance based on consultants' contention that expenditures associated with 41 days delay related to the design of the inclined shaft shashing jumbo could been avoided. The disallowance takes into account delays caused by difficult geologic conditions.
					Note: The Helms Final Opinion excludes treatment of an additional $240 million in capital expenditures related to the reconstruction of the Lost Canyon Pipe Crossing.
				21,993	

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