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NATIONAL UTILITY FINANCIAL STATEMENT MODEL (NUFS)

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Volume I of III:
Model Overview and Description

FINAL REPORT

Submitted to:
Division of Coal and Electric Power
Energy Information Administration
U.S. Department of Energy

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October 29, 1981

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AND DESCRIPTION

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Submitted to:

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by

ICF Incorporated

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I. EXECUTIVE SUMMARY

The National Utility Financial Statement (NUFS) model takes the output for the electric utility sector from the Midterm Energy Forecasting System (MEFS) model and forecasts electric utility financial statements. NUFs forecasts, separately for public and investor owned utilities, the following tables for each region on an annual basis:

- Income Statement
- Balance Sheet
- Sources and Uses of Funds
- Development of Revenue Requirement on an Annual Basis
- Reconciliation of Tax Expenses, Current Taxes and Income Taxes at a 46 Percent Statutory Rate
- Interest Coverage
- External Financing as a Percent of Total Uses of Funds
- AFUDC as a Percentage of Total Uses of Funds
- Book Value and Market to Book Rate
- Dividends per Share
- Actual Return on Equity

In addition, NUFs has been designed to supply inputs to the MEFS iterative solution process. The first such input is the fixed charge rates for each plant type. This quantity is used to form the objective function for the MEFS electric utility model. The second set of inputs are for the existing MEFS electricity price forecasting module. These inputs are referred to as pricing coefficients and old money revenue requirements.

The model requires data inputs including the following by region and by year:

- Capacity additions by plant type
- Fuel and other operation and maintenance costs per kwh
- Generation and sales of electricity
- Tax rates
- Regulatory treatment of construction work in progress (CWIP)
- Cost of equity capital, new debt, and preferred stock
- Capital structure
- Transmission and distribution costs
- Flow of expenditures on new units
- AFUDC capitalization rate
- Allowed rate of return on common equity capital
- Regulatory treatment of tax savings

- Regulatory lags
- Dividend payout ratios
- Base year income statements and balance sheets by region.

Each of these data inputs is user supplied either from MEFS or NUFS data files and is capable of being varied in a sensitivity analysis.

Capacity additions, fuel costs, operation and maintenance costs, and transmission and distribution investments are taken from MEFS solutions. MEFS solves for cumulative capacity additions and fuel costs for the years 1985, 1990 and 1995. NUFS requires yearly capacity additions and capital expenditures. Capacity additions by plant are allocated to individual years. Annual capital expenditures are estimated by the model "looking ahead" to see what plants are scheduled to enter service "n" years later and then multiplying the cost of the plant by the percent of expenditures which are made "n" years before a plant enters service. This is done for each plant type, each year for all "n". The model consists of a series of accounting equations which define income statement and balance sheet relationships.

In each year the capital expenditures made are added to the Construction Work in Progress Account. When plants enter service, the cost of the plant is transferred from the CWIP account to the plant in service account. Revenue requirements are calculated each year using regulatory accounting rules based on 1978 practice for the Public Utility Commissions in the region, or by using user supplied assumptions. Revenues are calculated based on revenue requirements and regulatory lag. Income taxes, other balance sheet and income statement accounts and financial ratios are calculated using standard accounting definitions.

The purpose of NUFS is to forecast the financial position of electric utilities. The MEFS utility sector output forecasts capacity additions assuming that utilities choose plant additions based on the criterion of minimizing the present value of revenue requirements. These capacity addition plans may or may not be financially feasible in the sense that the resulting financial ratios, such as interest coverages and external financial requirements, may be so adverse that the utility is unable to raise enough capital to build these economically efficient additions.

Financial parameters such as external financial requirements and interest coverage are affected by regulatory accounting conventions and allowed rates of return mandated by the regulatory commission. Policies such as normalization versus flow-through accounting for tax savings from accelerated depreciation, the investment tax credit and the debt portion of the Allowance for Funds Used During Construction (AFUDC), the regulatory treatment of Construction Work in Progress (CWIP), the depreciation rates (for regulatory, not tax purposes) on existing plant, and various other items all affect the utility's cash flow and external financial requirements. Any regulatory policy which affects the utility's financial position will also affect the level and/or time pattern of electric rates. In most, but not all cases, public utility commission policies on these regulatory accounting issues and

allowed rates of return are not rigidly determined by statute or precedent, but rather, are set judgmentally after reviewing the company's cash flow and other financial indicators.

NUFS is designed so that the user can input the alternative regulatory policies to evaluate the joint effect of regulatory policies and capacity additions.

The remainder of this report is organized into three volumes. Volume I is a general overview and description of the model. It contains a discussion of the relevant financial and rate issues as well as a description of the solution algorithms used within NUFs. In addition, a sample NUFs run for the nation is included. Volume II is the Users Guide. This contains a complete description of the data base as well as all of the information necessary to run NUFs. Finally, Volume III contains the listings and descriptions of the NUFs computer code.

The remainder of Volume I is organized as follows. Chapter II discusses the key financial issues that are addressed in NUFs. Chapter III discusses the solution algorithms used in NUFs. Appendix 1 is a copy of a NUFs model run for the nation as a whole. Other appendices are also included.

II. FINANCIAL AND RATE ISSUES ASSOCIATED WITH CAPACITY ADDITIONS

The NUFIS model examines the financial and electric rate impacts of differing capacity expansion plans under alternative treatments of CWIP, tax benefits resulting from accelerated depreciation, investment tax credits and the debt portion of AFUDC, regulatory lags and allowed rates of return on equity.

A. ALTERNATIVE REGULATORY POLICIES

The regulatory policies adopted by Public Utility Commissions (PUCs) directly affect electric prices and utility financial indicators. For example, a utility that does not have CWIP in rate base and/or is not allowed to normalize tax benefits from accelerated depreciation and investment tax credits and is in apparently poor financial condition relative to the funds it must raise externally could have its financial picture changed substantially if the PUC altered the allowed rate of return on equity or regulatory treatment of CWIP, the treatment of AFUDC or tax savings and deferrals or substantially reduced regulatory lag.

Three major revenue requirement issues a commission must address include: 1) the treatment of CWIP; 2) the treatment of tax savings from accelerated depreciation, the investment tax credit and the debt portion of AFUDC; and 3) the allowed return on common equity. In addition, the PUC can change the length of regulatory lags.

There are basically three regulatory treatments of construction work in progress. The first, permitting CWIP in rate base with a full cash return, allows the utility to earn a current cash return on all construction expenditures. The second, not allowing CWIP in rate base and capitalizing AFUDC, delays the cash return until the plant comes in-service.* When the plant is placed in-service, its value includes the AFUDC that has been capitalized during construction, thus allowing the utility to earn a cash return on a comparatively larger rate base. The third alternative, referred to as the AFUDC offset method, is a combination of the first two policies and is an alternative method of not allowing a full cash return on CWIP. CWIP is allowed in rate base, but there is a corresponding offset to the income requirement which must be raised via current rates equal to the amount of

* The utility does however record AFUDC as income on its financial statements.

AFUDC capitalized. If the AFUDC rate is less than the rate of return and if the utility is required to use simple interest to calculate AFUDC, this method has the effect of allowing some immediate return on construction. If the AFUDC rate is equal to the incremental cost of capital and if AFUDC is compounded, the offset method is basically equivalent to completely excluding CWIP from rate base.

The two alternative methods of treating the tax savings from accelerated depreciation, the investment tax credit, and the tax savings due to the debt portion of AFUDC are normalization and flow-through. Normalization recognizes the "deferred account" concept by building up a deferred account while the tax savings are generated and then amortizing the account once the asset is placed in-service (generally over the life of the asset). Current rates to ratepayers are based on the sum of current taxes and the amortization of deferred taxes. Flow-through accounting does not provide for any deferred accounts but rather requires the tax savings to reduce rates in the year they are generated.

The PUC sets the return on common equity the utility is allowed to earn. Clearly, the higher the allowed return on equity, the higher the return on rate base and consequently, the higher the revenues and cash flow. An additional method PUC's could use to provide greater cash flow is to allow the accelerated depreciation of existing production plant for regulatory and financial purposes. This increases internally generated funds during the depreciation period.

Regulatory lag refers to the problem that electric utility rates are based on historic test year expenses and rate base instead of the period during which rates are in effect. In an increasing cost environment, a substantial regulatory lag will decrease current rates relative to what they would have been in a no lag scenario.

There are important differences between policies such as allowing CWIP in rate base, higher depreciation rates, and normalization. These differences affect the timing and level of rates. Placing CWIP in rate base or allowing normalization raises rates (relative to what they would have been) in the near term and reduces rates (relative to what they would have been) later on. Increasing the allowed rate of return raises rates in all years for which the rate of return is higher than it otherwise would be. Thus, raising the rate of return affects the level, but not the timing, of revenues and cash flow.

B. FINANCIAL PARAMETERS

There are two types of parameters used to measure the effects of alternative capacity expansion scenarios. The first measure is forecasts of electricity prices in order to estimate the impact of alternative capacity expansion plans on consumers. The second set of parameters are financial ratios. Financial indicators, such as interest coverage, external financing

requirements, etc., provide some information on the financial viability or health of the utility. There are, of course, strong interrelationships between electric rates and financial parameters. For example, low interest coverages or high external funding requirements may raise the cost of new capital (or even prohibit the utility's entering into the bond markets if indenture requirements are violated) and thus would directly influence rates. NUFs assumes the utilities can always raise enough debt and equity to meet their financing requirements in any given year. This is due to the fact that the model is not designed to determine whether or not the utilities could raise the required capital in an absolute sense, but rather is intended to determine the impacts of alternative capacity expansion plans and regulatory treatment on the financial outlook of the utilities.

The following financial parameters -- interest coverage, AFUDC as a percent of earnings, and external financing requirements -- are all used to evaluate the financial health of a utility. Interest coverage is a measure of the earnings or income available to meet interest obligations relative to the magnitude of those obligations. NUFs calculates interest coverage using the SEC method.* Interest coverage is important because most utilities are required by existing bond indentures to have coverage of at least 2.0 before they can issue new debt.** It is important to note that the indenture requirement of coverage equal to at least 2.0 is a minimum legal requirement for the utility to be able to issue any new debt. Given that the utility's coverage exceeds 2.0, the lower the utility's coverage, all other factors held constant, the greater the probability of a lower bond rating and higher interest costs.

The external funds requirement measures the degree to which the utility must enter the capital markets to raise funds needed for capital spending. External funds are provided by issuing new debt and equity. Internal funds are generally provided from net income, depreciation, and deferred taxes.

AFUDC as a percentage of earnings available for common equity measures the degree to which earnings available for common stockholders are due to AFUDC as opposed to current, cash returns raised via current rates. Many security analysts consider AFUDC lower quality earnings and attach a premium, or higher cost of equity capital, to utilities with a high ratio of AFUDC to earnings.

* Interest coverage = (Electric Operating Income Before Federal Income Taxes + .10 * Other Income) / Interest on Long-Term Debt.

** The precise bond indenture requirement varies from utility to utility. Some indentures allow the utility to use the best 12 of the last 15 months data. Some indenture requirements pro forma the new issue. Some indentures are calculated on a post-tax basis. There are often indenture requirements on preferred dividends as well. The degree to which AFUDC can be counted as income for coverage varies as well.

Besides these financial parameters, uncertainty regarding future regulatory policies of the commission have an additional effect on the cost and level of capital a utility is able to raise. If investors expect that the regulatory commission will award rate increases such that investors will earn returns equal to or greater than their opportunity cost of capital, then investors will be willing to provide funds to the utility. If investors do not believe regulators will set rates that allow the utility to earn its cost of capital, or if there is substantial uncertainty concerning whether or not the utility will earn its cost of capital, investors will be less willing to provide funds to the utility.

C. FINANCIAL RATIOS AND COSTS OF DEBT

One of the factors which determines bond rating is the utility's financial position. Table 1 lists the average value of select financial indicators, in 1978, for utilities with different bond ratings.

Note that utilities with Baa bond ratings have lower interest coverage, lower rates of return on common equity, higher AFUDC as a percent of earnings and higher external financing requirements as a percent of total sources of funds. As of February 1980, new Aaa rated utility bonds were yielding 13.25 percent. New Baa rated utility bonds were yielding 14.88 percent.

Table 2 is taken from a study by Pinches, Singleton, and Jahankhani using 1975 data. The statistical analysis conducted in the study concluded that earnings before interest and taxes divided by interest is the most important variable, by itself, in predicting Moody's and Standard and Poor's bond ratings. The statistical analysis also concluded that when several variables were included in the analysis, growth in net earnings, a measure of regulatory climate, net income divided by total assets, construction expenditures divided by total assets and total assets were all as important or more important than interest coverage in predicting bond ratings. In July 1975, the yield on utility bonds was 9.44 percent for bonds rated Aa, 10.09 percent for bonds rated A, and 10.96 percent for bonds rated Baa.

A study by Bhandari, Soldofsky and Boe* examined the impacts of utility financial indicators on changes in bond ratings using data from 63 utility companies for the period 1974-1975. Table 3 lists average values for three financial indicators for bonds which were upgraded versus bonds which were not changed and those downgraded.

Based on statistical analysis, the authors concluded that the most recent level and trend in the past five years of three financial ratios -- net income

* Shyam Bhandari, Robert M. Soldofsky, and William J. Boe, "Bond Quality Changes for Electric Utilities: A Multivariate Analysis," Financial Management, Spring, 1979.

TABLE 1

1978 UTILITY FINANCIAL INDICATORS AND BOND RATINGS

	Utilities Rates			
	<u>Aaa</u>	<u>Aa</u>	<u>A</u>	<u>Baa</u>
Interest Coverage*	3.63	3.02	2.55	2.25
AFUDC As a Percent of Earnings for Common Equity	21.95	31.45	32.30	47.5
Rate of Return on Common Equity (Earned)	11.7	11.6	10.9	10.3
External Financing as a Percentage of Total Uses of Funds	34.25	39.55	45.64	46.4

* Interest coverage is defined using the SEC formula as electric operating income before federal income taxes plus 10 percent of AFUDC, all divided by interest on long term debt.

SOURCE: Data in Appendix 2.

TABLE 2

1975 UTILITY FINANCIAL INDICATORS AND BOND RATINGS*

	Utilities Rates			
	<u>Aaa</u>	<u>Aa</u>	<u>A</u>	<u>Baa</u>
Fixed Charge Coverage	4.18	3.76	3.40	2.89
AFUDC As a Percent of Net Income	16%	22%	21%	29%
Net Income Divided by Fixed Charges	5.01	4.42	3.97	3.31
Long Term Debt Divided by Invested Capital	.49	.52	.53	.54

* George E. Pinches, J. Clay Singleton, and Ali Jahankhani, "Fixed Coverages As A Determinant of Electric Utility Bond Ratings," Financial Management, Summer, 1978.

TABLE 3

AVERAGE UTILITY FINANCIAL INDICATORS AND
CHANGES IN BOND RATINGS

	Upgraded Bonds	No Change	Downgraded
Net Income After Taxes Divided by Interest*	2.78	2.41	2.12
Long Term Debt as Percent of Total Capital	49.79%	53.07%	53.68%
Net Income After Taxes Divided by Total Assets	4.63%	3.93%	3.49%

* It is important to note that each of the studies uses a different definition of fixed charge coverage. The Bhandari, et. al., and the Pines et. al. studies include AFUDC in income for coverage. We only include 10 percent of AFUDC in calculating coverages. Bhandari et. al., calculate coverage after tax, we calculate coverage before tax.

after taxes divided by interest, debt to capitalization ratio, and the rate of return on assets -- and a suitable measure of earnings stability were sufficient to predict about 90 percent of the ratings changes for the electric utility bonds in the sample.

In order to provide additional data on utility financial indicators, we gathered 1978 data for the 50 utilities with the largest oil and gas usage in terms of equivalent barrels of oil per day.*

We developed two groupings of utilities for further analysis. They were:

- low coverage and low internal generation or interest coverage less than 2.5 times and an internal generation ratio (internally generated funds as a percentage of total uses of funds) of 50 percent or less (called low group).
- high coverage and high internal generation or coverage greater than three times and internal generation greater than 50 percent (called high group).

Table 4 lists the utilities in each group. Table 5 compares the low and high groups on three other measures -- the percent with bond ratings of Aa and above, the percent with AFUDC greater than 50 percent of earnings and the percent with earned rates of return on common equity less than 11 percent.

As Table 5 indicates, the utilities in the low group, based on 1978 data, are less likely to have Aa bond ratings, are more likely to have lower than average rates of return on common equity, and are more likely to have a high ratio of AFUDC to earnings.

It is important to note that many factors affect bond ratings and the cost of new debt. However, in general, utilities with poorer financial indicators have lower bond ratings.** Table 6 lists the yields on utility bonds by rating group for recent years. The spreads between rating groups provide some estimates of the higher interest costs, which on average, might be associated with lower bond ratings.

* The data are reported in Appendix 3. Utilities which had low coverage and high internal generation and utilities which had high coverage and low internal generation are not on either list. Thus, the number of utilities in Table 4 is less than the 50 utilities listed in Appendix 3.

** For a statement by an official of a bond rating firm concerning how Standard and Poor's develops bond ratings, see Thomas G. Fendrich "Utility Rating Criteria, Financial Outlook, and Observations on Regulation," Public Utilities Fortnightly, January 4, 1979.

TABLE 4

UTILITIES SELECTED FOR FURTHER COMPARISON

<u>Low Group</u>	<u>High Group</u>
Arizona Public Service	Baltimore Gas and Electric Company
Central Louisiana Electric Companies	Central Power and Light
Commonwealth Edison	Consolidated Edison
Consumers' Power	Florida Power Corp.
Long Island Lighting	Florida Power & Light
Louisiana Power and Light	Jersey Central Power and Light
Pacific Gas and Electric	New Orleans Public Service
Pennsylvania Power and Light	Oklahoma Gas and Electric
South Carolina Electric and Gas	Orange and Rockland Utilities
Virginia Electric Power	Potomac Electric Power Company
United Illuminating	Public Service Electric & Gas
	Southwestern Electric Power Company
	Southwestern Public Service
	Texas Electric Service
	Texas Power and Light
	West Texas Utilities

TABLE 5

COMPARISON OF LOW AND HIGH GROUPS ON OTHER MEASURES
(percent)

	<u>Low Group</u>	<u>High Group</u>
Percent with Aa (or better) Bond Ratings	27.3	56.3
Percent with AFUDC Greater than 50% of Earnings	63.6	12.5
Percent with Common Equity Return in 1978 Less than 11.0%	54.5	37.5

TABLE 6

ANNUAL AVERAGE YIELDS ON UTILITY BONDS BY RATING

<u>Year</u>	<u>Aaa</u>	<u>Aa</u>	<u>A</u>	<u>Baa</u>
August 1979	9.46	9.75	10.14	10.50
1978	8.87	9.10	9.29	9.62
1977	8.19	8.43	8.61	9.06
1976	8.63	8.92	9.29	9.82
1975	9.03	9.44	10.09	10.96
1974	8.71	9.04	9.50	9.84
1973	7.60	7.72	7.84	8.17
1972	7.46	7.60	7.72	8.17
1971	7.72	8.00	8.10	8.63

D. FINANCIAL INDICATORS, EQUITY COSTS AND THE VALUATION OF UTILITY EQUITIES

To the extent that investors use current financial indicators and information on regulatory policies to estimate future earnings and the risk associated with investing in the utility, one might expect that changes in financial indicators would influence the utility's stock price and the cost of equity capital to the utility. This section reviews three statistical studies of the cost of equity capital which might be used to forecast the impacts of policies on the cost of equity capital.

In testimony before the North Carolina Utilities Commission, John Wilson of Wilson Associates presented the following regression equation, estimated from 1977 and 1978 electric utility data:

$$YLD = 9.535 - .1117 (WAGDE) - .2850 (COVR)$$

where:

YLD = dividend yield
WAGDE = weighted average growth rate in earnings per share
COVR = interest coverage

One method of estimating the cost of equity capital to a utility is the Discounted Cash Flow (DCF) method in which the cost of equity capital is estimated by summing the current dividend yield of the utility and the expected growth rate in dividends per share. The equation estimated by Wilson Associates indicates that increasing the utility's coverage reduces the market dividend yield (or increases the price investors are willing to pay for a given stream of dividends). The estimated reduction in the cost of equity capital due to increasing coverage is the coefficient .2850 multiplied by the

increase in coverage. Using this equation, an increase in interest coverage from 2.25 to 2.75 would reduce the utility's cost of equity capital by .14 percentage points. In other words, if the cost of equity capital was 13.5 percent when interest coverage was 2.25, increasing coverage to 2.75 would reduce the cost of equity capital to 13.36 percent.*

The second approach to estimating the effects of alternative policies and financial indicators utilizes equations estimated by National Economic Research Associates (NERA).** In testimony before the California PUC, Herman G. Roseman presented the following regression equation (estimated using 1973 and 1974 data):

$$\frac{P}{B} = .222751 + .0255174 (X_1) + .000982554 (X_2) + .00232095 (X_3) - .134129 (X_4) \\ - .00086935 (X_5) - .00268022 (X_6) + .554664 (X_7)$$

where:

X_1 = rate of return on common equity, 1974

X_2 = square of the rate of return on common equity, 1973

X_3 = square of rate of return on common equity, value line estimate for 1975

X_4 = accounting method: 1 if flowthrough, 0 if not flowthrough

X_5 = oil as percent of all fuels used in generation, 1974

X_6 = AFUDC as percent of net income for common, 1974

* Several points should be noted. Precise estimates of the cost of equity capital are beyond the scope of this report. ICF has not reviewed the data base or the estimating equation developed by Wilson Associates. Finally, we are not attempting to estimate a cost of equity capital using someone else's methodology. The analysis simply uses equations estimated by others to discuss the effects of alternative policies and financial indicators on the cost of equity capital, assuming such a relationship exists.

** Again, we should point out that ICF has not verified the NERA data base or estimating equation. We are not attempting to duplicate a NERA procedure for estimating the cost of equity capital. We are only attempting to estimate potential effects of alternative policies on the cost of equity capital.

x_7 = ratio of dividends to cash flow, 1974

$\frac{P}{B}$ = the ratio of the price of the utility's stock to book value

Using the result that the utility's stock will trade at book value when the earned rate of return is equal to the cost of capital, Table 7 uses this equation to estimate the impacts of various policies on the cost of equity capital to the utility. This equation also predicts that for each percentage point increase in the rate of return on common equity, the market price to book ratio rises by .10.

TABLE 7

EFFECT OF VARIOUS POLICIES AND FINANCIAL INDICATORS
ON COST OF EQUITY CAPITAL

<u>Policy</u>	<u>Reduction in Cost of Equity Capital</u>
Reduction of AFUDC as Percent of Earnings from 50% to 0%	1.39 percentage points
Substitution of Normalized Accounting for Flow-Through	1.39 percentage points
Reduction in Oil as a Percent of Generation from 50% to 20%	.27 percentage points

A study by Robert Trout estimated an equation (using 1977 data) similar to the NERA equation presented above.* Table 8 lists the variables used in the regression study. Table 9 shows the results of the regression study. This equation indicates that a reduction in AFUDC as a percent of earnings from 50 percent to 0 percent reduces the cost of equity capital by 1.02 percentage points. The equation also indicates that reductions in leverage and increases in dividend payout ratios reduce the cost of equity capital. Each one percentage point increase in the rate of return on equity earned increases the utility's market to book ratio by .073.

* Robert Trout, "The Regulatory Factor and Electric Utility Common Investment Values," Public Utilities Fortnightly, November 22, 1979.

It is important to note that the regression studies discussed in this section are statistical relationships between various financial indicators and market to book ratios and dividend yields. Studies such as these are helpful in indicating the general relationships between financial indicators and the cost of equity capital. They are not used here as precise forecasts of the costs of equity capital. The regression studies summarized here were conducted at different points in time, using different data. Statistical relationships can and do change over time.

TABLE 8

REGRESSION VARIABLES USED IN TROUT STUDY

ROE =	Expected return on equity for the next year.
ROAE =	Return on average equity the past year.
LEV =	Ratio of debt to total capital.
PAY =	Ratio of common dividends to income available for common.
PCTEL =	Ratio of electric revenues to total revenues.
SALC =	Cost of power sold, mills per kilowatt-hour.
WTDGRW =	A composite future growth rate, based on Value Line estimates of company growth in cash flow, book value, dividends, and earnings, all on a per share basis.
AFCNI =	Ratio of the allowance for funds used during construction to net income.
DTCF =	Ratio of deferred taxes to total cash flow, where cash flow is the sum of net income, less AFUDC, plus depreciation and plus deferred taxes.
REGP =	An indicator variable which takes on a value of one if a firm is located in a state with an above average regulatory attitude on the part of the commission, and zero otherwise.
REGN =	An indicator variable which takes on a value of one if a utility is located in a state with a below average regulatory attitude on the part of the commission, and zero otherwise.

TABLE 9

REGRESSION OF MARKET-BOOK RATIOS ON SELECTED
REGULATORY AND ACCOUNTING VARIABLES: TROUT STUDY

Variable	Mean	Model A			Model B			Model C		
		Regression Coefficient	t-stat	Level of Signif.	Regression Coefficient	t-stat	Level of Signif.	Regression Coefficient	t-stat	Level of Signif.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
ROE77	11.6	.0166	1.74	8.5%	.0119	1.34	18.0%	.0202	2.84	0.6%
ROAE76	12.0	.0563	6.84	0.1	.0550	7.14	0.1	.0549	7.22	0.1
LEV	51.8	-.0092	2.77	0.7	-.0065	2.02	4.8	-.0052	1.66	10.0
PAY	66.9	.0118	5.26	0.1	.0106	4.94	0.1	.0087	10.28	0.1
PCTEL	85.4	.0029	4.27	0.1	.0017	2.66	1.0	.0221	3.23	0.2
SALC	16.7	-.0066	3.76	0.1	-.0053	3.18	0.1	-.0058	3.67	0.1
WTDGRW	4.6	.0330	1.59	12.0	.0227	1.14	26.0	--	--	--
REGP	0.21	--	--	--	.0853	3.36	0.1	.0634	2.26	2.7
REGN	0.31	--	--	--	-.0463	2.06	4.3	-.0591	2.69	0.9
AFCNI	30.2	-.0015	2.55	1.3	--	--	--	-.0014	2.49	1.5
STCF	21.6	.0019	2.00	5.0	--	--	--	.0013	1.28	23.0
Intercept	--	-.4312	1.57	12.0	-.3054	1.18	24.0	-.2380	1.11	27.0
R Squared	--	.760	--	--	-.785	--	--	.799	--	--
Std. Error of Est.	--	.088	--	--	.084	--	--	.081	--	--
Mean Value of M/B	--	1.024	--	--	1.024	--	--	1.024	--	--
Sample Size	--	86.0	--	--	86.0	--	--	86.0	--	--
F Value	--	26.9	--	0.1%	30.8	--	0.1%	29.9	--	0.1%

III. NUFS SOLUTION ALGORITHM

A. OVERVIEW

The purpose of this chapter is to describe the solution algorithms used within NUFS. The discussion is organized into two sections. The aim of the first section is to completely describe the method used to forecast annual revenue requirements. In order to forecast the revenue requirement, one must first forecast the components of the rate base and the expenses. This section will describe the many algorithms used to forecast these items. With all of these items forecast, one has nearly all the components of the financial statements and ratios. The second shorter section describes the process of using these items to yield forecasts of electric revenues, prices, taxes (both actual and for financial purposes), financial ratios, and other miscellaneous items (including those for feedback into the MEFS solution process).

B. FORECASTING REVENUE REQUIREMENTS

Our method of forecasting revenue requirements is an attempt to duplicate the regulatory process. That is, our forecast of revenue requirements in any given year is that which allows the utilities to earn a fair rate of return on their investments plus recover their operating costs. Formally, the forecast for revenue requirements in any given year is :*

$$\begin{aligned} \text{REVREQ}_t = & (\text{RB}_t * \text{RR}_t) + \text{FUEL}_t + \text{OM}_t + \text{BDE}_t + \text{GENREG}_t + \text{STAREG}_t \\ & + \text{FEDREG}_t - \text{XITCF}_t - \text{AITC}_t - \text{XAFDCF}_t - \text{AAFDC}_t - \text{OFFSET}_t \end{aligned}$$

* This model involves numerous simplifying assumptions. It is not a precise replication of all the subtleties of the regulatory accounting process. Rather, it is intended to capture enough of the cost factors that determine revenue requirements so that we can forecast the overall trends in the level of revenue requirements and in addition determine the approximate effect of various policies on this level.

where:*

$REVREQ_t$ = revenue requirement, year t,**

RB_t = rate base, year t,

RR_t = rate of return, year t,

$FUEL_t$ = fuel costs, year t,

OM_t = operation and maintenance expenses, excluding fuel, year t,

BDE_t = booked depreciation expense, year t,

$GENREG_t$ = general taxes (gross receipts, property, sales) for regulatory purposes, year t,

$STAREG_t$ = state income taxes for regulatory purposes, year t,

$FEDREG_t$ = federal income taxes for regulatory purposes (net of investment tax credit (ITC)), year t,

$XITCF_t$ = generated ITC which is flowed through, year t,

$AITC_t$ = amortization of deferred ITC, year t,

$XAFDCF_t$ = generated tax savings from the debt portion of AFUDC which is flowed through, year t,

$AAFDC_t$ = amortization of deferred tax savings from the debt portion of AFUDC, year t,

$OFFSET_t$ = AFUDC offset, year t.

Each of the thirteen variables on the right hand side of the revenue requirement equation are discussed in separate sections, labeled B-1 through B-13. Many somewhat involved arguments are needed to fully describe the solution algorithms. To aid in the continuity of this presentation, these arguments are separated into their own sections and are labeled B-14 through B-17. The discussions in sections B-1 through B-13 thus sometimes refer to these later sections. Sections B1 through B-17 now follow.

* The variables names used are the same as those found in the computer code of NUFS.

** For accounts which describe 'flows' (e.g., fuel expense, depreciation expense, etc.), year t refers to the period January 1 to December 31 of year t. For accounts which describe 'stocks' (e.g., rate base, utility plant, etc.), year t refers to the end of year t value, i.e., value on December 31 of year t.

B-1 Calculation of Rate Base (RB)

The rate base formula is:

$$RB_t = UP_t + RBCWIP_t + WC_t + XNUCFL_t - ABDE_t - PRODEF_t$$

where:

RB_t = rate base, year t,

UP_t = gross utility plant in service, year t,

$RBCWIP_t$ = CWIP allowed in rate base, year t,

WC_t = working capital, year t,

$XNUCFL_t$ = nuclear fuel stock, year t,

$ABDE_t$ = accumulated book depreciation, year t,

$PRODEF_t$ = provision for deferred income taxes due to accelerated depreciation, year t.

As calculated above, RB_t is the rate base at the end of year t. Another option in NUFS is to calculate revenue requirements using the average value of the rate base over the year. The analyst may choose either option. The average year rate base is calculated as the simple average of the beginning and end of year rate base. The beginning of year rate base is calculated as the rate base at the end of the previous year plus the book value of any new plants which come on line in the given year. (The calculation of the book value of new assets is described in section B-15-a.)

RBCWIP is discussed in section B-15. ABDE and PRODEF are discussed in section B-16. Each of the remaining components of the rate base equation are discussed below:

B-1-a. Gross Utility Plant in Service (UP)

Utility plant in year t (UP_t) is calculated as:*

$$UP_t = \sum_{\text{all } k} (BA1_k) + \sum_{\text{all } s \leq t} \sum_{\text{all } j} (BA2_j^s) - BRTIRE_t$$

* Assets are divided into two categories; assets existing in the base year or old assets (variables ending in "1") and assets acquired during the forecast period or new assets (variables ending in "2").

where:

$BA1_k$ = book value of assets existing in the base year (old assets)
of type k (for example, nuclear, coal, transmission, etc.)

$BA2_j^s$ = book value of new assets of type j coming on line in year s,

$BRTIRE_t$ = book value of all assets which have been retired during the
forecast period before or during year t.

The book value of existing assets is an input which comes from the Form 1 or Form 1M. The calculation of BA2 and BRTIRE are discussed in sections B-15 and B-16 respectively.

B-1-b. Working Capital (WC)

For our analysis we use the FPC method (commonly called the "1/8 method") to calculate working capital for regulatory rate setting purposes. In general, this method arrives at working capital by summing the following: materials and supplies including fuel stocks; a percentage of operating and maintenance expenses, usually 1/8, representing a 45 day net lag in revenues and expenses; and other adjustments unique to a jurisdiction. The "1/8 method" is based on the assumption that an average monthly billing utility has a net lag of 45 days between the payment of expenses and collection of revenues. This method of estimating working capital does have some drawbacks. The implicit assumption behind the "1/8 method" is that there is a positive working capital need. The "1/8 method" does not give any recognition to the availability of working capital resulting from the accrual of interest or tax expenses prior to the time of their payment. Items such as these constitute sources of working capital that are not considered using the "1/8 method." In addition, under circumstances of unusually fast receipt of customer payments and extended delay in paying suppliers, there can actually be a negative working capital requirement for a utility. The "1/8 method" also assumes that all utilities have the same experience with regard to receipt of payment from customers and employ the same payment policies.

Our calculation for working capital is:

$$WC_t = .125 * (OM_t + FUEL_t)$$

OM_t = operation and maintenance costs, excluding fuel, year t,

$FUEL_t$ = fuel costs, year t.

The calculation of OM is discussed in Section B-4. FUEL is discussed in section B-3.

B-1-c: NUCLEAR FUEL STOCK (XNUCFL)

The nuclear fuel stock in any given year is assumed to equal twice the nuclear fuel expense for that year. The reasoning for this is that nuclear fuel is loaded in batches. If one batch is loaded every year, and a batch has a three year life, on average, the amount of fuel in the reactor is equal to two years burnup. The nuclear fuel expense is the value of the nuclear fuel burned.

The calculation for nuclear fuel stock is:

$$XNUCFL_t = 2 * XNUCEX_t$$

$$XNUCEX_t = GWHNUC_t * FCNUC_t$$

where:

$XNUCEX_t$ = nuclear fuel expense, year t,

$GWHNUC_t$ = nuclear generation, year t (comes from MEFS),

$FCNUC_t$ = cost of nuclear fuel (mills/kwh) (comes from MEFS).

B-2 Rate of Return (RR)

The rate of return is calculated as a weighted average of the cost of long term debt, short term debt, common equity, and preferred stock. The equation is:

$$RR_t = PERLT_t * EMDT_t + PERST_t * RTST_t + PERCE_t * RTCEQ_t + PERPS_t * EMPS_t$$

where:

$PERLT_t$ = capital structure weight for long term debt, year t,

$PERST_t$ = " " " " short term debt, year t,

$PERCE_t$ = " " " " common equity, year t,

$PERPS_t$ = " " " " preferred stock, year t,

$EMDT_t$ = embedded cost of long term debt, year t,

$RTST_t$ = cost of short term debt, year t,

$RTCEQ_t$ = cost of common equity, year t,

$EMPS_t$ = embedded cost of preferred stock, year t.

With the exception of EMDT and EMPS, all of the above values are user inputs.

B-2-a. Embedded Cost of Long Term Debt (EMDT)

The embedded cost of long term debt in any year is a function of several quantities including the cost of new debt, the cost of past debt, and the timing and quantity of retirements and issues of debt. Doing this calculation exactly requires a data base presently outside the scope of NUFS. The algorithm used in NUFS attempts to approximate the embedded cost as follows:

$$\text{BONDS}_t = \text{AMD}_t * \text{PERLT}_t$$

$$\text{RETIRE}_t = \text{maximum of: } \begin{cases} \text{PERLT}_t * \text{BDE}_t \\ \text{OB}_{t-1} \end{cases} ;$$

$$\text{OB}_t = \text{OB}_{t-1} - \text{RETIRE}_t$$

$$\begin{aligned} \text{EMDT}_t = & (\text{EMDT}_{t-1} * \text{BOND}_{t-1} - \text{EMDT}_{\text{BYR}} * \text{RETIRE}_t \\ & + \text{RTNWL}_t * (\text{BONDS}_t - \text{BONDS}_{t-1} + \text{RETIRE}_t)) / \text{BONDS}_t \end{aligned}$$

where:

BONDS_t = total amount of long term debt outstanding, year t ,

OB_t = amount of long term debt outstanding, year t , which was issued before year $\text{BYR}+1$,

RETIRE_t = amount of OB_{BYR} which is retired (and refinanced) in year t ,

RTNWL_t = cost of long term debt issued in year t ,

AMD_t = assets minus deferrals, year t ,

PERLT_t = capital structure weight for long term debt, year t ,

BDE_t = booked depreciation expense, year t ,

BYR = base year (ie. year before forecast period begins).

The algorithm calculates the embedded cost of debt as a weighted average of: i) the embedded cost in the previous year (EMDT_{t-1}); ii) the embedded cost in the base year (EMDT_{BYR}); and iii) the cost of long term debt issued

in the current year ($RTNWB_N_t$). Only debt issued before the forecast period is assumed to be refinanced. This is appropriate given the midrange forecast period over which NUFS forecasts. OB_{BYR} , EMD_{BYR} , $PERLT$, and $RTNWB_N$ are user inputs in this algorithm. AMD and BDE are discussed in Sections B-7-b and B-16, respectively.

B-2-b. Embedded Cost of Preferred Stock (EMPS)

The embedded cost of preferred stock is calculated in a similar way to the algorithm used for the embedded cost of long term debt above.

$$PREFER_t = AMD_t * PERPS_t$$

$$RETIRE_t = \text{maximum of } \begin{cases} PERPS_t * BDE_t; \\ OLDPS_{t-1} \end{cases}$$

$$OLDPS_t = OLDPS_{t-1} - RETIRE_t$$

$$EMPS_t = (EMPS_{t-1} * PREFER_{t-1} - EMPS_{BYR} * RETIRE_t + RTNWPS_t * (PREFER_t - PREFER_{t-1} + RETIRE_t)) / PREFER_t$$

where:

$PREFER_t$ = total amount of preferred stock, year t,

AMD_t = assets minus deferrals, year t (see Section B-7-b),

$PERPS_t$ = capital structure weight for preferred stock, year t (user input),

$RETIRE_t$ = amount of $OLDPS_{BYR}$ which is refinanced, year t,

BDE_t = booked depreciation expense, year t,

$OLDPS_t$ = amount of preferred stock outstanding, in year t, which was issued before year $BYR + 1$,

$RTNWPS_t$ = cost of preferred stock issued in year t,

BYR = base year (i.e., year before forecast period begins).

The values of $OLDPS_{BYR}$ and $EMPS_{BYR}$ are input into NUFS. These values come from the Form 1.

B-3. Fuel Costs (FUEL)

Fuel costs are input to NUFS from the results of the MEFS run which is under analysis. Since MEFS works in real dollars, fuel costs are inflated each year by a user defined inflation rate.

B-4. Operation and Maintenance, excluding fuel (OM)

As with fuel costs, operation and maintenance costs are input to NUFS from the results of the MEFS run which is under analysis. Again, these costs are inflated each year by a user defined inflation rate.

B-5. Depreciation (BDE)

Discussion of the depreciation expense may be found in section B-16.

B-6. General Taxes for Regulatory Purposes (GENREG)

General taxes encompass all taxes except state and federal income taxes. Among these taxes are: gross receipts, FICA, capitalized payroll, property and sales.

The assumption is made that these taxes each year will be a constant percentage of revenue requirements.

$$\text{GENREG}_t = \text{GTXRT} * \text{REVREQ}_t$$

where:

GTXRT = gross receipts tax rate,

REVREQ_t = revenue requirements, year t.

The gross receipts tax rate is an input which is calculated from base year data (Form 1/Form 1M). Including REVREQ on the right hand side of the equation appears to make this discussion circular. (i.e., REVREQ is a function of GENREG and GENREG is a function of REVREQ). This is resolved in section B-14.

B-7 State Income Taxes for Regulatory Purposes (STAREG)

STAREG is equal to regulatory state taxable income multiplied by the tax rate:

$$\text{STAREG}_t = (\text{REVREQ}_t - \text{FUEL}_t - \text{OM}_t - \text{TDEWOA}_t - \text{XINEX}_t) * \text{STXRT}$$

where:

REVREQ_t = revenue requirement, year t,

$FUEL_t$ = fuel expense, year t ,
 OM_t = operation and maintenance expense, excluding fuel, year t ,
 $TDEWOA_t$ = tax depreciation expense (calculated on asset book values net of AFUDC), year t ,
 $XINEX_t$ = interest expense, year t ,
 $STXRT$ = state income tax rate.

REVREQ on the right hand side of this equation is discussed in B-14. FUEL and OM were discussed in sections B-3 and B-4, respectively. TDEWOA is discussed in section B-16. STXRT is a user input. XINEX is now discussed.

B-7-a: Interest Expenses (XINEX)

The total interest expenses depend on the cost of debt and on the average amount of debt outstanding during the year.

$$XSINEX_t = RTST_t * PERST_t * \frac{AMD_t + AMD_{t-1}}{2}$$

$$XLINEX_t = EMDT_t * PERLT_t * \frac{AMD_t + AMD_{t-1}}{2}$$

$$XINEX_t = XSINEX_t + XLINEX_t$$

where:

$XSINEX_t$ = short-term interest expense, year t ,
 $XLINEX_t$ = long-term interest expense, year t ,
 $RTST_t$ = cost of short term debt, year t ,
 $EMDT_t$ = embedded cost of long term debt, year t ,
 $PERST_t$ = capital structure weight for short term debt, year t ,
 $PERLT_t$ = capital structure weight for long term debt, year t ,
 AMD_t = assets minus deferrals (equals amount which must be financed through debt or equity), end of year t .

RTST, PERST, and PERLT are user inputs. EMDT was discussed in section B-2-a. AMD is discussed below.

B-7-b. Assets minus Deferrals (AMD)

$$AMD_t = UP_t + BCWIP_t + WC_t + XNUCFL_t - ABDE_t - PRODEF_t - DITC_t$$

where:

UP_t = gross utility plant in service, year t (see B-1-a),

$BCWIP_t$ = booked construction work in progress, year t (see B-15),

WC_t = working capital, year t (see B-1-b),

$XNUCFL_t$ = nuclear fuel stock, year t (see B-1-c),

$ABDE_t$ = accumulated book depreciation, year t (see B-16),

$PRODEF_t$ = provision for deferred income taxes, year t (see B-16),

$DITC_t$ = deferred investment tax credit, year t (see B-17).

B-8. Federal Income Taxes for Regulatory Purposes (FEDREG)

FEDREG is equal to federal taxable income (for regulatory purposes) multiplied by the federal tax rate:

$$FEDREG_t = (REVREQ_t - FUEL_t - OM_t - GENREG_t - STAREG_t - TDEREG_t - XINEX_t + AFUDCD_t) * TXRT$$

where:

$REVREQ_t$ = revenue requirement, year t ,

$FUEL_t$ = fuel expenses, year t (see B-3),

OM_t = operation and maintenance expense, excluding fuel, year t
(see B-4),

$GENREG_t$ = general taxes for regulatory purposes, year t (see B-6),

$STAREG_t$ = state income taxes for regulatory purposes, year t (see B-7),

$TDEREG_t$ = tax depreciation expense for regulatory purposes, year t
(see B-16),

$XINEX_t$ = interest expenses, year t (see B-7a),

$AFUDCD_t$ = debt portion of AFUDC, year t (see B-15),

$TXRT$ = federal income tax rate.

REVREQ on the right side of the equation is discussed in B-14. TXRT is a user supplied input. FEDREG does not include the effects of the ITC or the tax savings due to the debt portion of AFUDC. These effects are captured with the variables XITCF, AITC, XAFDCF, and AAFDC.

B-9. Generated ITC which is Flowed Through (XITCF)

See Section B-17

B-10. Amortization of Deferred ITC (AITC)

See Section B-17

B-11. GENERATED Tax Savings from AFUDC, Flowed Through (XAFDCF)

See Section B-15

B-12. Amortization of Deferred Tax-Savings from AFUDC (AAFDC)

See section B-15

B-13. AFUDC Offset (OFFSET)

See Section B-15

B-14. Resolution of REVREQ 'Circular' Argument

The following four equations have been presented:

$$(i) \quad \text{REVREQ}_t = \dots + \text{GENREG}_t + \text{STAREG}_t + \text{FEDREG}_t - \dots$$

$$(ii) \quad \text{GENREG}_t = \text{GTXT} * \text{REVREQ}_t$$

$$(iii) \quad \text{STAREG}_T = (\text{REVREQ}_t - \dots) * \text{STXT}$$

$$(iv) \quad \text{FEDREG}_t = (\text{REVREQ}_t - \dots) * \text{TXRT}$$

In the somewhat linear presentation of sections B-1 through B-13, the above equations seem to present a circular argument. (REVREQ is a function of GENREG, STAREG, and FEDREG but also the later variables depend on REVREQ.) This, of course, is not really a problem. The above is just a system of four equations with four unknowns. NUFs solves the above equations simultaneously and always yields a unique result.

B-15. Construction Work in Progress (CWIP)

For regulatory purposes, NUFs is able to analyze three alternative treatments of construction work in progress: 1) CWIP in rate base; 2) CWIP not in rate base; and 3) offset method. When CWIP is allowed in rate base for ratemaking purposes, the utility is allowed to earn a current return on all construction outlays. If CWIP is not allowed in rate base (i.e., AFUDC is capitalized) the utility is allowed to include an annual estimate of the net

cost, for the period of construction, of borrowed funds used for construction purposes and a reasonable rate on other funds. These "allowances" are accumulated over the life of the project and are brought into the rate base as an addition to the value of the completed investment once the investment becomes operational. The third alternative of dealing with construction work in progress is the capitalized AFUDC offset method. For this procedure, CWIP is allowed in rate base and AFUDC is capitalized, but there is a corresponding offset to the revenue requirement equal to the amount of the capitalized AFUDC. If the AFUDC rate is equal to the allowed rate of return on rate base and if the utility is allowed to compound the effects of AFUDC then this method is essentially equivalent to not allowing CWIP in rate base.

The regulatory treatment of CWIP varies from utility to utility, sometimes even between utilities within the same state. In general, at the multi-utility aggregation level at which NUFSS is run, all of the treatments are used to some degree. To account for this, NUFSS requires a user input CWPPER, which is the percentage of CWIP which is allowed in rate base. The remainder of the CWIP is then assumed either not to be in rate base or to be handled under the offset method (depending on the value of RBAFDC, another user input).

The treatment of CWIP affects quite a few variables. These effects will now be discussed. All of the discussions will assume only one plant is being built. This is for ease in presentation only and going to the "n" plant builds case presents no conceptual problems. For the presented algorithms, the following values are input to NUFSS:

<u>Variable</u>	<u>Description</u>	<u>Source</u>
PLTCAP	Capacity of Build	MEFS
CAPCST	Cost of capacity (\$/capacity), including AFUDC	MEFS
JYR	Year plant comes on line	MEFS
CONPER _j	Percent of construction completed during year j, j = JYR - 14, JYR	USER
CWPPER	Percentage of CWIP allowed in rate base	USER
RBAFDC	0 remainder (i.e., 1-CWPPER percent) of CWIP not in rate base 1 remainder of CWIP is handled under offset	USER

B-15-a. Book Value of New Plants (BA2)

The cost of the new plant is:

$$\text{COST} = \text{PLTCAP} * \text{CAPCST}$$

where:

COST = total cost of plant,

PLTCAP = capacity of plant,

CAPCST = cost of capacity, including AFUDC, (\$/capacity).

COST is the total cost of the plant, including AFUDC. The book value of the new plant may or may not include some or all of the AFUDC, depending on the regulatory treatment which is input. The cost of the new plant net of AFUDC is:

$$\text{A2} = \text{COST} / \text{CWPFAC}$$

where:

A2 = cost of new plant, net of AFUDC,

COST = cost of new plant, including AFUDC,

CWPFAC = ratio of COST to A2.

The equation for CWPFAC is:

$$\text{CWPFAC} = \sum_{i=1}^{15} \text{CONPER}_{\text{JYR} - i + 1} * (1 + \text{AFUDCR}) ** (i - .5)$$

where:

CONPER_j = Percent of construction completed during year j,
for j = JYR-14, JYR,

JYR = year plant comes on line,

AFUDCR = compound AFUDC rate,

Finally, the book value of plant depends on the regulatory treatment of CWIP:

$$BA2 = A2 * CWPPER + COST * (1 - CWPPER)$$

where:

BA2 = book value of new asset,

CWPPER = percentage of CWIP allowed in rate base.

B-15-b. Construction Work in Progress accounts

There are several values related to CWIP which are calculated.

$$FCWIP_j = CONPER_j * A2 \quad \text{for} \quad j = JYR-14, JYR$$

$$CWIP_j = \sum_{i = JYR-14}^j FCWIP_i \quad \text{for} \quad j = JYR-14, JYR$$

where:

FCWIP_j = construction expenses, net of AFUDC, year j,

CWIP_j = cumulative construction expenses, net of AFUDC, year j,

CONPER = percent of construction completed during year j,

A2 = cost of new plant, net of AFUDC (see B-15a),

JYR = year plant comes on line.

FCWIP and CWIP should be thought of as the actual construction expenses, net of any interest expenses. The CWIP actually booked depends on the regulatory treatment:

$$BCWIP_j = \sum_{i = JYR-14}^j (FCWIP_i) * (1 + AFUDCR) ** (j-i + .5) * (1 - CWPPER) + CWIP_j * CWPPER \quad \text{for} \quad j = JYR-14, JYR$$

where:

BCWIP_j = booked (cumulative) construction work in progress, year j
(ie. amount which appears on balance sheet).

Still different from the above quantities is the CWIP allowed in rate base. Again, it depends on the regulatory treatment. If RBAFDC = 0 (i.e., no offset), then:

$$RBCWIP_j = CWIP_j * CWPPER \quad \text{for } j = JYR-14, JYR$$

where:

$$RBCWIP_j = \text{CWIP allowed in rate base, year } j.$$

If RBAFDC = 1 (i.e., offset AFUDC), then:

$$RBCWIP_j = BCWIP_j \quad \text{for } j = JYR - 14, JYR.$$

B-15-c. Allowance for Funds Used During Construction

As with CWIP, there are several accounts relating to AFUDC which need to be calculated.

$$AFUDC_j = (BCWIP_j - BCWIP_{j-1}) - FCWIP_j \quad \text{for } j = JYR-14, JYR$$

where:

$$AFUDC_j = \text{AFUDC, year } j,$$

$$BCWIP_j = \text{booked CWIP (includes AFUDC), year } j,$$

$$FCWIP_j = \text{construction expenses, year } j.$$

The revenue requirement may or may not be offset by AFUDC:

$$OFFSET_j = AFUDC_j * RBAFDC \quad \text{for } j = JYR-14, JYR$$

$$= \begin{cases} AFUDC_j & \text{if } RBAFDC = 1 \quad (\text{offset}) \\ 0 & \text{if } RBAFDC = 0 \quad (\text{no offset}) \end{cases}$$

where:

$$OFFSET_j = \text{AFUDC offset, year } j.$$

It is important (see section B-15-d) to separate AFUDC into that financed by debt and that financed by equity:

$$AFUDCD_j = WACD_j * AFUDC_j$$

$$AFUDCE_j = WACE_j * AFUDC_j \quad \text{for } j = JYR-14, JYR$$

where:

AFUDCD_j = debt financed portion of AFUDC, year j,

AFUDCE_j = equity financed portion of AFUDC, year j,

WACD_j = portion of AFUDC paid for by debt, year j (see below),

WACE_j = " " " " " " equity, year j (see below).

$$WACD_t = \frac{(PERLT_t * RTNWL_t + PERST_t * RTST_t)}{(PERLT_t * RTNWL_t + PERST_t * RTST_t + PERCE_t * RTCEQ_t + PERPS_t * RTNWPS_t)}$$

$$WACE_t = \frac{(PERCE_t * RTCEQ_t + PERPS_t * RTNWPS_t)}{(PERLT_t * RTNWL_t + PERST_t * RTST_t + PERCE_t * RTCEQ_t + PERPS_t * RTNWPS_t)}$$

All of the right hand terms were defined and discussed in Section B-2.

B-15-d. Tax Savings Due to Debt Portion of AFUDC

While a plant is being built, various interest expenses associated with construction of the plant accrue. This interest expense provides a tax savings to the utility because interest is a deductible expense. The regulatory process attempts to capture this savings and either flow it through or defer it for ratemaking purposes. This is done using the concept of the tax savings due to the debt portion of AFUDC.

$$XAFDCF_j = AFUDCD_j * TXRT * FLPR2$$

$$XAFDCD_j = AFUDCD_j * TXRT * (1 - FLPR2)$$

$$DAFDC_j = \sum_{i = JYR-14}^j XAFDCD_i \quad \text{for } j = JYR-14, JYR$$

where:

XAFDCF_j = generated tax savings from the debt portion of AFUDC
which is flowed through, year j,

XAFDCD_j = generated tax savings from the debt portion of AFUDC
which is deferred (normalized) year j,

DAFDC_j = deferred tax savings from the debt portion of AFUDC,
year j,

AFUDCD_j = debt financed portion of AFUDC, year j, (see section
B-17-c),

TXRT = federal tax rate (user input),

FLPR2 = flow through percentage for AFUDC tax savings,

JYR = year plant comes on line.

FLPR2 reflects the regulatory policy towards the tax savings and is a user input. The tax savings is generated while the plant is being constructed. When the plant begins service, the deferred taxes, if any, are amortized over the service life of the plant.

$$AAFDC_j = (BA2 - A2) * WACD_{JYR} * TXRT * (1 - FLPR2) / SY2$$

$$DAFDC_j = DAFDC_{j-1} - AAFDC_j$$

$$\text{for } j = JYR, JYR + SY2 - 1$$

where:

AAFDC_j = amortization of deferred savings from the debt portion of
AFUDC, year j,

DAFDC_j = deferred tax savings from the debt portion of AFUDC,
year j,

WACD_j = portion of AFUDC financed by debt, year j,

BA2 = book value of plant (includes AFUDC),

A2 = cost of plant, excluding AFUDC,

SY2 = book life of plant.

B-16: Depreciation

Depreciation expenses are calculated separately for financial and for tax purposes. The major difference occurs because for tax purposes capitalized AFUDC may not be depreciated. In addition, depreciation for tax purposes is complicated by the fact that deferred tax effects may arise from accelerated tax depreciation. The following discussion applies to a new plant with the following input characteristics:

JYR = year plant comes on line;

SY2 = book life of plant;

DR2 = depreciation rate for financial purposes (usually $1/SY2$); and

TXSY2 = tax life of plant.

The ideas presented here are easily expanded to the n-plant build case and to existing plants.

B-16-a. Depreciation for Financial Purposes (Book Depreciation)

Book depreciation is calculated using the straight line method:

$$BDE_j = BA2 * DR2 \quad \text{for} \quad j = JYR, JYR + SY2 - 1$$

and

$$ABDE_j = \sum_{i=JYR}^j BDE_i$$

where:

BDE_j = book depreciation, year j,

$ABDE_j$ = accumulated book depreciation, year j,

BA2 = book value of plant (includes any AFUDC).

The derivation of BA2 is discussed in section B-15-a. When the plant retires (year $JYR + SY2$), its book value is added to account BRTIRE and subtracted from ABDE. This has the effect of removing the plant from the books. (See section B-1-a.)

B-16-b. Depreciation for Tax Purposes

For tax purposes, depreciation is accelerated (ie., allowed to be greater in early life of plant and less in later life) by two forces. First, utilities may depreciate the plant over a shorter period of time than the service life used for financial purposes. Second, an accelerated depreciation rate is used instead of a straight-line constant rate. The effect of this is to lower tax liability in the earlier years of the plant life and raise them in the later years compared to the non-accelerated alternative. For further discussion, see chapter 2.

The accelerated tax depreciation rate may be calculated using the sum of the years digits method or the declining balance method. For discussion purposes, the former is presented.

$$TDRATE_j = \begin{cases} (TXSY2 - (j - JYR)) / (TXSY2 * (TXSY2 + 1) / 2) & \text{for } j = JYR, JYR + TXSY2 - 1; \text{ and} \\ 0 & \text{for } j = JYR + TXSY2, JYR + SY2 - 1 \end{cases}$$

where:

$TDRATE_j$ = depreciation rate for accelerated tax, year j .

Then,

$$TDE_j = TDRATE_j * A2 \quad \text{for } j = JYR, JYR + SY2 - 1$$

where:

TDE_j = depreciation expense for tax purposes, year j ,

$A2$ = value of plant, excluding capitalized AFUDC.

Note that $A2$, not $BA2$, is used. Capitalized AFUDC is not depreciated for tax purposes. $A2$ is discussed in section B-15-a.

Now, absent any accelerated depreciation, tax depreciation would be:

$$TDEWOA_j = DR2 * A2 \quad \text{for } j = JYR, JYR + SY2 - 1$$

where:

$TDEWOA_j$ = depreciation for tax purposes, without acceleration, year j .

The difference between $TDEWOA_j$ and TDE_j is a tax savings in the early years of service followed by increased taxes in the later years. The regulatory authority determines the treatment of this difference.

$$TDEREG_j = TDEWOA_j * (1 - FLPR1) + TDE * (FLPR1) \\ \text{for } j = JYR, JYR + SY2 - 1$$

where:

$TDEREG_j$ = tax depreciation expense for regulatory purposes, year j ,

$FLPR1$ = percentage of tax savings due to accelerated depreciation which are flowed through.

When the tax effects of accelerated depreciation are flowed through for regulatory purposes ($FLPR1 = 1.0$), $TDEREG$ is equal to TDE . In this case, revenue requirements directly show the effects of the acceleration. However, when the tax effects are totally deferred ($FLPR1 = 0.0$), then $TDEREG$ is equal to $TDEWOA$ and thus the revenue requirements show no effects of the acceleration. Thus, in a flow through scenario revenue requirements are lower in the early years of the plants service and higher in the later years compared to revenue requirements in a normalized scenario (all else equal). This effect comes about because $TDEREG$ affects federal income taxes for regulatory purposes, which in turn affects revenue requirements.

Other useful quantities relating to this tax effect are:

$$EXTBF_j = TXRT * (TDE_j - TDEWOA_j) * FLPR1$$

$$EXTBD_j = TXRT * (TDE_j - TDEWOA_j) * (1 - FLPR1)$$

$$DAD_j = \sum_{i=1}^j EXTBD_i \quad \text{for } j = JYR, JYR + SY2 - 1$$

where:

$EXTBF_j$ = tax savings resulting from accelerated depreciation which are flowed through, year j ,

$EXTBD_j$ = tax savings resulting from accelerated depreciation which are deferred, year j ,

DAD_j = deferred taxes due to accelerated tax depreciation, year j ,

$TXRT$ = federal income tax rate.

B-16-c. Provision for Deferred Income Taxes (PRODEF)

The provision for deferred income taxes is the sum of the values of all deferred income taxes or deferred tax savings (excluding ITC). For purposes of NUFS, this includes the deferred taxes from accelerated depreciation and the deferred tax savings from the debt portion of AFUDC.

$$PRODEF_t = DAD_t + DAFDC_t$$

where:

$PRODEF_t$ = provision for deferred income taxes, year t ,

DAD_t = deferred income taxes due to accelerated depreciation,
year t (see Section B-16-b)

$DAFDC_t$ = deferred tax savings from the debt portion of AFUDC,
year t (see Section B-15-d).

B-17. Investment Tax Credit

The investment tax credit was established by Congress to encourage certain kinds of investments. The effect of the investment credit is to reduce the federal tax liability by the amount of the credit. The credit is generated during each year of the construction period for the plant. The value of the credit each year is a percentage of construction expenses (excluding AFUDC) for that year. The regulatory treatment of this tax savings is decided by the commission. The credit can be flowed through to lower the revenue requirement in the year it was generated or deferred totally and then amortized over the life of the plant. NUFS handles any combination of these two extremes.

$$XITCF_j = FCWIP_j * RITC * FLPR1$$

$$XITCD_j = FCWIP_j * RITC * (1 - FLPR1)$$

$$DITC_j = \sum_{i=1}^j XITCD_i \quad \text{for} \quad j = JYR - 14, JYR$$

where:

$XITCF_j$ = generated ITC which is flowed through, year j ,

$XITCD_j$ = " " " " deferred, year j ,

$DITC_j$ = deferred ITC, year j ,

$FCWIP_t$ = construction expenses, net of AFUDC, year j (see B-15-b),

$RITC$ = investment tax credit rate,

$FLPR1$ = percentage of tax savings flowed through.

When the plant begins service, any deferred ITC is amortized over the life of the plant.

$$\text{AITC}_j = A2 * \text{RITC}/\text{SY2}$$

$$\text{DITC}_j = \text{DITC}_{j-1} - \text{AITC} \quad \text{for} \quad j = \text{JYR}, \text{JYR} + \text{SY2} - 1$$

where:

AITC_j = amortization of deferred investment tax credit, year j ,

$A2$ = value of plant, excluding AFUDC (see B-15-a),

SY2 = service life of plant (user input).

RITC is a user input and is currently ten percent. Note that the investment tax credit is generated only on the construction expense, not on capitalized AFUDC.

C. REMAINING ALGORITHMS

Section B describes the NUFs algorithm to forecast revenue requirements. There are many components to the revenue requirement, each of which must in turn be forecast. The algorithms to forecast each component were discussed. This section describes the remaining algorithms which are used to yield forecasts of electric revenues, the price of electricity, taxes (both current and for financial purposes), financial ratios, and other miscellaneous items. In addition, the algorithms used for the results which feedback to the MEFS process are discussed.

C-1. Electric Revenues

Electric revenues are a function of revenue requirements and the regulatory lag. Regulatory lag refers to the problem that electric utility rates (and thus revenues) are based on historic test year expenses and rate base instead of the period during which the rates are in effect. NUFs calculates electric revenues under four different assumptions: i) no lag, ii) one year lag, iii) one and one half year lag, and iv) two year lag. The user must specify which lag scenario is to be used.

In a no lag scenario, rates are based on current year expenses and rate base so electric revenues are equal to the revenue requirement calculated in section B:

$$\text{REVLAG}_t = \text{REVREQ}_t$$

where:

REVLAG_t = electric revenues, year t ,

REVREQ_t = revenue requirements, year t .

In a one year lag scenario, electric revenues are calculated as follows:

$$\text{REVLAG}_t = \text{TOTSAL}_t * \frac{(\text{REVREQ}_{t-1} - \text{TXFUEL}_{t-1})}{\text{TOTSAL}_{t-1}} + \text{TXFUEL}_t$$

where:

TOTSAL_t = sales of electricity (kwh), year t (see below),

TXFUEL_t = total fuel costs adjusted for taxes, year t (see below).

This approach is equivalent to stating that the price of electricity is comprised of two parts -- a fuel cost (recovered through an instantaneously adjusting fuel adjustment clause) and base rates set in rate hearings. In the two year lag scenario, revenues are calculated in a similar manner. The average of the revenues under the one and two year lag case is used in the one and half year lag scenario.

Sales of electricity are calculated as:

$$\text{TOTSAL}_t = (1 - \text{XLF}_t) \text{GWHTOT}_t$$

where:

XLF_t = loss factor, year t (input from MEFS),

GWHTOT_t = generation of electricity, year t (input from MEFS).

Fuel costs adjusted for taxes is calculated as:

$$\text{TXFUEL}_t = \text{FUEL}_t / (1 - \text{GTXRT})$$

where:

FUEL_t = fuel expenses, year t,

GTXRT_t = general tax rate.

FUEL_t is discussed in section B-3. GTXRT is a user input.

C-2. Price of Electricity

With electric revenues forecast, the price of electricity forecast is straightforward:

$$\text{PRICE}_t = \text{REVLAG}_t / \text{TOTSAL}_t$$

where:

$PRICE_t$ = price of electricity, year t,

$REVLAG_t$ = electric revenues, year t (see section C-1)

$TOTSAL_t$ = sales of electricity, year t (see section C-1).

C-3. Taxes

NUFS calculates two categories of taxes; general taxes and income taxes.

C-3-a. General Taxes

General taxes encompass all taxes except the state and federal income taxes. Among these taxes are: gross receipts, FICA, capitalized payroll, property and sales.

The assumption is made that these taxes each year will be a constant percentage of revenues.

$$GENTX_t = GTXRT * REVLAG_t$$

where:

$GENTX_t$ = actual general taxes, year t,

$GTXRT_t$ = general tax rate, year t (user input),

$REVLAG_t$ = electric revenues, year t (see section C-1).

C-3-b. Income Taxes

Current income taxes are those which are actually paid by the utility in a given year. Because of the regulatory treatment of certain tax issues (investment tax credits, accelerated depreciation), this is not, in general, what is booked on the income statement as income tax expense.

$$\begin{aligned} CIT_t = & (REVLAG_t - FUEL_t - OM_t - TDEWOA_t - GENTX_t \\ & - XINEX_t) * TXRT \\ & + STATET_t - (XITCF_t + XITCD_t) - (EXTBF_t + EXTBD_t) \end{aligned}$$

where:

CIT_t = current income taxes, year t,

$REVLAG_t$ = electric revenues, year t (see section C-),

$FUEL_t$ = fuel costs, year t (see section B-3),

OM_t = operation and maintenance expenses, excluding fuel,
year t (see section B-4),

$TDEWOA_t$ = depreciation for tax purposes, without acceleration,
year t (see section B-16-b),

$GENTX_t$ = actual general taxes, year t (see section C-3-a),

$XINEX_t$ = interest expenses, year t (see section B-7-a),

$TXRT$ = federal income tax rate (user input),

$STATET_t$ = state income taxes, including federal income tax benefits,
year t (see below),

$XITCF_t$ = generated ITC which is flowed through, year t (see
section B-17),

$XITCD_t$ = generated ITC which is deferred, year t, (see section
B-17),

$EXTBF_t$ = tax savings from accelerated depreciation which is flowed
through, year t (see section B-16-b),

$EXTBD_t$ = tax savings from accelerated depreciation which is
deferred, year t (see section B-16-b).

Now, booked income tax expense is current taxes, plus deferrals, minus
amortizations:

$$TTXEX_t = CIT_t + (XITCD_t - AITC_t) + (XAFDCD_t - AAFDC_t) \\ + EXTBD_t$$

where:

$TTXEX_t$ = booked income tax expense, year t,

$AITC_t$ = amortization of deferred ITC, year t (see section B-17),

$XAFDCD_t$ = generated tax savings from debt portion of AFUDC which is
deferred, year t (see Section B-15-d),

$AAFDC_t$ = amortization of deferred tax savings from the debt portion
of AFUDC, year t (see Section B-15-d).

The only remaining tax variable to be explained is STATEX (state income taxes including federal income tax benefits):

$$\text{STATEX}_t = (\text{REVLAG}_t - \text{FUEL}_t - \text{OM}_t - \text{TDEWOA}_t - \text{XINEX}_t) \\ * \text{STXRT} * (1 - \text{TXRT})$$

where:

STXRT = state income tax rate (user input).

The state income taxes are deductible in calculating federally taxable income so the net effect of state income taxes on total income taxes is STATEX.

C-4. Financial Ratios

The output of NUFS includes the forecasted values of four financial ratios. These ratios are standard indicators of a utility company's financial health. However, financial analysts disagree over the exact formula to be used in some cases. For NUFS, the following definitions are used:

- i) Interest Coverage. Interest coverage for a given year is calculated as Electric Operating Income, plus Income Taxes, plus 10% of AFUDC, all divided by the interest expense on long term debt.
- ii) Actual Return on Common Equity. This ratio is calculated as Earnings Available for Common divided by the year average of the Book Value of Common Equity (Common Stock plus Retained Earnings).
- iii) AFUDC as a Percentage of Income. This ratio is calculated AFUDC divided by income available for common equity.
- iv) External Financing as a Percent of Total Applications. This ratio is forecast as Total Internal Funds divided by Total Applications.

C-5. Book Value Per Share, Shares of Stock and Market to Book Ratio

In order to determine whether dividends forecast from payout ratios are reasonable, NUFS forecasts dividends and earnings per share. This requires a forecast of the stock market to book value ratio. Of course, this section applies only for the privately-owned sector.

The market value to book ratio (m) is based on the formula

$$m = \frac{g - r}{g - k}$$

The actual equations used are

$$g = \frac{2 (B_t - B_{t-1})}{B_t + B_{t-1}}$$

where

B_t = Book value in year t .

$$M_t = M_0 + \frac{r_t - r_0}{k-g}$$

where

r_t = return on equity in year t

r_0 = return on equity in base year

M_0 = market to book value ratio in base year

The change in the number of shares outstanding (ΔN_t) is

$$\Delta N_t = M_t \left(g - \frac{(E_t - D_t)}{2 (B_t + B_{t-1})} \right)$$

where

E_t = earnings available for common equity in year t

D_t = dividends paid in year t

From these equations one can also calculate earnings per share.

C-6: Special Ratios Calculated for MEFS

NUFS has been designed to produce pricing and capital investment information which can be fed into the existing version of MEFS. There are two types of data which NUFs is able to provide:

- o Real Fixed Charge Rate. This rate is also referred to as a real capital recovery rate. It is used to calculate the levelized annual costs associated with a given type of capacity. This quantity forms an important part of the objective function in the MEFS electric utility sector. It is calculated for each plant type. The fixed charge rate is a fraction which, when multiplied by the real total cost of a new plant, yields the annual levelized

revenue required to cover the financial fixed charges over the life of the plant. The fraction captures the effects of financial assumptions related to the region and the specific plant type. The present value of this levelized stream over the life of the plant is equal to the present value of the actual revenue requirements associated with the plant over its life.

- o Electricity Prices. There are two quantities which NUFS can provide the current MEFS electricity price forecasting structure with. The first is referred to as the old money revenue requirements. These are calculated for each year of the forecast period. Old money revenue requirements are the dollar amount of revenue requirements in a given year which is associated with assets existing in the base year. The second quantity is referred to as the pricing coefficients. These are calculated for each MEFS solution year (1985, 1990, and 1995) and plant type. The pricing coefficient is equal to the dollar amount of revenue requirements in the given year associated with the capacity additions of the plant type, divided by the total cost of the capital additions for the plant type. Given these values, and MEFS forecasts of operation costs and capacity additions, MEFS calculates total revenue requirements, and thus prices, for a given year. The above process is redundant since NUFS is designed to forecast electricity prices internally. The present version of MEFS is not designed to accept pricing information in other than the form described above. The MEFS pricing algorithm will be replaced by NUFS in the future. This will end the need for these values to be calculated.

The calculation of each of these quantities is now described.

C-6-a. Fixed Charge Rates

NUFS has a special option to calculate the fixed charge rate for any plant type. (This is fully described in the user's guide, volume two.) The first step is to calculate the revenue requirement stream associated with the plant. This is done by using the same equations described in this text, but zeroing out all existing assets, operating cost, and other new capacity additions. Then the following equations are used:

$$CUMPRV = \sum_{t=1}^{SY2} \frac{RR_t}{(1+DISCR)^t}$$

$$RCRF = \sum_{t=1}^{SY2} \left(\frac{1 + GINF_t}{1 + DISCR} \right)^t$$

$$RFCR = \frac{RCRF * CUMPVR}{COST}$$

where: RR_t = revenue requirement associated with plant, year t,
 DISCR = discount rate (user input),
 SYR = book life of plant,
 CUMPVR = cumulative present value of revenue requirements,
 $GINF_t$ = general inflation, year t,
 RCRF = real capital recovery factor,
 COST = total cost of plant,
 RFCR = real fixed charge rate.

C-6-b. Old Money Revenue Requirements

NUFS has a special option to calculate the old money revenue requirements. (This is fully described in the user's guide, volume two.) The revenue requirements are calculated by zeroing operating costs and new capital additions and using the same equations described in this text. The revenue requirements passed to MEFS are in real dollars.

C-6-c. Pricing Coefficients

NUFS has a special option to calculate pricing coefficients. The first step is to calculate revenue requirements associated with the plant type and year of interest. This is done in a similar way as described in the fixed charge rate calculations. Finally, the pricing coefficients are calculated as:

$$PC = \frac{RR_t}{BLDTOT_t}$$

where: PC_t = pricing coefficient, year t (where t = 1985, 1990, or 1995),
 RR_t = revenue requirements associated with plant type capital additions, year t,
 $BLDTOT_t$ = the total cost of plant type additions occurring in, or previous to, year t.

APPENDIX 1

SAMPLE NUFS OUTPUT

This appendix contains examples of the output of NUFS. Four different examples are given:

- i) Standard NUFS Analysis (Option 8=1). NUFS will produce separate regional reports for the private sector, public sector, or the entire industry. This output shows the report for the entire industry. The national results are shown.
- ii) Fixed Charge Rate Analysis (Option 8=2). When calculating fixed charge rates, NUFS will output a summary report containing the key parameters of the calculations. This output shows this report for each of the ten regions.
- iii) Pricing Coefficient Analysis (Option 8=3). When calculating pricing coefficients, NUFS will output a summary report containing the key parameters of the calculations. This output shows this report for each of the ten regions.
- iv) Old Money Revenue Requirements (Option 8=4). When calculating old money revenue requirements, NUFS will output a summary report containing the revenue requirements. This output shows this report for each of the ten regions.

i) Standard Analysis Output

***** PRO FORMA STATEMENT OF EARNINGS *****

YEAR ENDED DECEMBER 31

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 71728.	\$ 90333.	\$ 100459.	\$ 110509.	\$ 121994.	\$ 133476.	\$ 145946.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	3820.	4237.	4701.	5217.	5790.	6428.	7138.
FUEL	41992.	46578.	51677.	57346.	63650.	70663.	78465.
DEPRECIATION	6833.	7324.	8005.	8665.	9409.	10054.	10689.
GENERAL TAXES	5093.	6428.	7147.	7855.	8667.	9475.	10353.
INCOME TAXES	1767.	5959.	6827.	7389.	8225.	8732.	9004.
TOTAL ELECTRIC EXPENSES	59504.	70526.	78357.	86472.	95742.	105352.	115649.
ELECTRIC OPERATING INCOME	12223.	19807.	22102.	24036.	26252.	28124.	30297.
OTHER INCOME							
AFUDC-EQUITY FUNDS	2484.	2502.	2631.	2742.	2988.	3284.	3526.
TOTAL OTHER INCOME	2484.	2502.	2631.	2742.	2988.	3284.	3526.
INCOME BEFORE INTEREST DEDUCTIONS	14707.	22308.	24733.	26778.	29241.	31408.	33824.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	7994.	9075.	10023.	11050.	12087.	13173.	14533.
INTEREST ON SHORT-TERM DEBT	370.	402.	426.	452.	478.	505.	540.
AFUDC-BORROWED FUNDS	(2041.)	(2056.)	(2163.)	(2254.)	(2456.)	(2699.)	(2898.)
TOTAL INTEREST DEDUCTIONS	6323.	7420.	8286.	9248.	10108.	10980.	12175.
NET INCOME	8384.	14888.	16447.	17530.	19132.	20428.	21648.
DIVIDENDS ON PREFERRED STOCKS	1639.	1842.	2026.	2225.	2425.	2636.	2901.
EARNINGS FOR COMMON STOCK	\$ 6745.	\$ 13046.	\$ 14421.	\$ 15305.	\$ 16707.	\$ 17792.	\$ 18747.

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

	1986	1987	1988	1989	1990	1991	1992
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 161136.	\$ 180060.	\$ 199252.	\$ 220306.	\$ 243852.	\$ 274956.	\$ 307776.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	8514.	10152.	12112.	14446.	17235.	20450.	24277.
FUEL	86950.	96354.	106783.	118350.	131173.	143158.	156268.
DEPRECIATION	11594.	12783.	13780.	14674.	15549.	17477.	19697.
GENERAL TAXES	11425.	12763.	14113.	15594.	17251.	19465.	21793.
INCOME TAXES	9376.	10452.	10958.	11402.	11713.	14489.	16874.
TOTAL ELECTRIC EXPENSES	127858.	142505.	157746.	174466.	192921.	215039.	238908.
ELECTRIC OPERATING INCOME	33278.	37555.	41506.	45840.	50932.	59917.	68868.
OTHER INCOME							
AFUDC-EQUITY FUNDS	3735.	4579.	5942.	7713.	8574.	9534.	10594.
TOTAL OTHER INCOME	3735.	4579.	5942.	7713.	8574.	9534.	10594.
INCOME BEFORE INTEREST DEDUCTIONS	37013.	42135.	47448.	53553.	59506.	69451.	79462.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	16395.	18805.	21742.	25202.	29117.	33469.	38308.
INTEREST ON SHORT-TERM DEBT	590.	657.	741.	841.	955.	1081.	1222.
AFUDC-BORROWED FUNDS	(3070.)	(3764.)	(4884.)	(6340.)	(7047.)	(7837.)	(8707.)
TOTAL INTEREST DEDUCTIONS	13915.	15698.	17599.	19703.	23024.	26714.	30822.
NET INCOME	23098.	26436.	29849.	33850.	36482.	42738.	48640.
DIVIDENDS ON PREFERRED STOCKS	3266.	3740.	4320.	5005.	5781.	6643.	7601.
EARNINGS FOR COMMON STOCK	\$ 19831.	\$ 22696.	\$ 25528.	\$ 28844.	\$ 30701.	\$ 36095.	\$ 41039.

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

	1993	1994	1995	0	0	0	0
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 344129.	\$ 384495.	\$ 428882.	\$ 0.	\$ 0.	\$ 0.	\$ 0.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	28316.	34228.	40647.	0.	0.	0.	0.
FUEL	170623.	186336.	203554.	0.	0.	0.	0.
DEPRECIATION	22157.	24885.	27912.	0.	0.	0.	0.
GENERAL TAXES	24371.	27233.	30378.	0.	0.	0.	0.
INCOME TAXES	19443.	22337.	25324.	0.	0.	0.	0.
TOTAL ELECTRIC EXPENSES	265410.	295019.	327814.	0.	0.	0.	0.
ELECTRIC OPERATING INCOME	78719.	89476.	101069.	0.	0.	0.	0.
OTHER INCOME							
AFUDC-EQUITY FUNDS	11807.	13203.	14826.	0.	0.	0.	0.
TOTAL OTHER INCOME	11807.	13203.	14826.	0.	0.	0.	0.
INCOME BEFORE INTEREST DEDUCTIONS	90526.	102680.	115895.	0.	0.	0.	0.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	43699.	49422.	55618.	0.	0.	0.	0.
INTEREST ON SHORT-TERM DEBT	1378.	1553.	1747.	0.	0.	0.	0.
AFUDC-BORROWED FUNDS	(9704.)	(10852.)	(12186.)	(0.)	(0.)	(0.)	(0.)
TOTAL INTEREST DEDUCTIONS	35373.	40123.	45179.	0.	0.	0.	0.
NET INCOME	55153.	62557.	70716.	0.	0.	0.	0.
DIVIDENDS ON PREFERRED STOCKS	8668.	9794.	11020.	0.	0.	0.	0.
EARNINGS FOR COMMON STOCK	\$ 46485.	\$ 52763.	\$ 59696.	\$ 0.	\$ 0.	\$ 0.	\$ 0.

***** PRO FORMA BALANCE SHEET *****

DECEMBER 31

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

1979	1980	1981	1982	1983	1984	1985
(DOLLARS IN MILLIONS)						
117071.	137217.	156685.	178622.	197527.	216099.	240869.
35018.	35340.	35698.	36100.	36548.	37049.	39457.
58502.	58502.	58502.	58502.	58502.	58502.	58502.
9153.	9153.	9153.	9153.	9153.	9153.	9153.
75191.	76472.	81306.	84758.	91126.	99752.	108408.
294935.	316683.	341344.	367134.	392856.	420556.	456389.
68330.	75654.	83659.	92325.	101734.	111788.	122476.
226605.	241029.	257685.	274810.	291122.	308768.	333913.
4610.	5278.	6032.	6883.	7843.	8926.	10147.
231216.	246307.	263717.	281693.	298965.	317694.	344059.
5726.	7707.	9822.	12188.	15037.	18108.	20767.
236942.	254014.	273539.	293880.	314002.	335802.	364827.
58797.	59840.	61257.	62675.	63660.	64881.	68006.
21209.	22398.	23800.	25256.	26662.	28212.	30441.
27494.	33020.	39116.	45614.	52727.	60322.	68315.
107500.	115258.	124174.	133545.	143048.	153414.	166763.
109752.	116307.	123977.	131936.	139625.	148066.	160086.
3523.	3721.	3953.	4195.	4429.	4686.	5057.
113275.	120027.	127930.	136132.	144053.	152752.	165143.
5722.	6707.	7828.	8971.	10049.	11186.	12765.
10445.	12021.	13606.	15232.	16951.	18450.	20156.
16167.	18728.	21434.	24203.	26900.	29636.	32921.
236942.	254013.	273538.	293880.	314002.	335802.	364826.

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

	1986	1987	1988	1989	1990	1991	1992
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	273959.	300950.	324498.	347114.	401619.	463072.	531191.
TRANSMISSION	42083.	45023.	48314.	51997.	55385.	60583.	66343.
DISTRIBUTION	58502.	58502.	58502.	58502.	58502.	58502.	58502.
OTHER	9153.	9153.	9153.	9153.	9153.	9153.	9153.
CONSTRUCTION WORK IN PROGRESS	119631.	147037.	187723.	238522.	265427.	294487.	327524.
	-----	-----	-----	-----	-----	-----	-----
TOTAL UTILITY PLANT	503328.	560664.	628188.	705288.	790085.	885797.	992713.
	-----	-----	-----	-----	-----	-----	-----
ACCUMULATED DEPRECIATION	134070.	146853.	160633.	175307.	190856.	208333.	228030.
	-----	-----	-----	-----	-----	-----	-----
NET UTILITY PLANT, LESS NUCLEAR FUEL	369257.	413811.	467555.	529981.	599229.	677464.	764683.
	-----	-----	-----	-----	-----	-----	-----
NET NUCLEAR FUEL	12205.	14644.	17532.	20948.	24986.	28529.	32218.
	-----	-----	-----	-----	-----	-----	-----
NET UTILITY PLANT	381462.	428455.	485088.	550930.	624215.	705992.	796901.
	-----	-----	-----	-----	-----	-----	-----
WORKING CAPITAL	22739.	24570.	26297.	28084.	29804.	31798.	34220.
	-----	-----	-----	-----	-----	-----	-----
TOTAL ASSETS & OTHER DEBITS	404201.	453024.	511384.	579014.	654019.	737790.	831121.
	-----	-----	-----	-----	-----	-----	-----
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	73920.	81971.	92240.	104547.	118491.	133528.	150036.
PREFERRED STOCK	33648.	37734.	42721.	48584.	55095.	62319.	70342.
RETAINED EARNINGS	76731.	86350.	97181.	109427.	122476.	137749.	155108.
	-----	-----	-----	-----	-----	-----	-----
TOTAL PROPRIETARY CAPITAL	184298.	206055.	232142.	262558.	296062.	333596.	375486.
	-----	-----	-----	-----	-----	-----	-----
LONG-TERM DEBT	177259.	199039.	225518.	256549.	291024.	329286.	371782.
SHORT-TERM DEBT	5580.	6268.	7096.	8070.	9152.	10352.	11684.
	-----	-----	-----	-----	-----	-----	-----
TOTAL DEBT	182848.	205307.	232614.	264619.	300176.	339638.	383467.
	-----	-----	-----	-----	-----	-----	-----
DEFERRED CREDITS							
ACCUMULATED DEFERRED ITC	14966.	17678.	20833.	24345.	28150.	32428.	37172.
ACCUMULATED DEFERRED INCOME TAXES	22089.	23984.	25795.	27491.	29631.	32128.	34996.
	-----	-----	-----	-----	-----	-----	-----
TOTAL DEFERRED CREDITS	37055.	41662.	46628.	51837.	57781.	64556.	72168.
	-----	-----	-----	-----	-----	-----	-----
TOTAL LIABILITIES & OTHER CREDITS	404200.	453024.	511384.	579013.	654018.	737790.	831121.
	-----	-----	-----	-----	-----	-----	-----

(DOLLARS IN MILLIONS)

(DOLLARS IN MILLIONS)

506733.	690546.	782935.	0.	0.	0.	0.
72731.	79817.	87206.	0.	0.	0.	0.
58502.	58502.	58502.	0.	0.	0.	0.
9153.	9153.	9153.	0.	0.	0.	0.
365408.	408941.	459383.	0.	0.	0.	0.
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1112526.	1246958.	1397178.	0.	0.	0.	0.
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250186.	275071.	302983.	0.	0.	0.	0.
-----	-----	-----	-----	-----	-----	-----
862340.	971888.	1094195.	0.	0.	0.	0.
-----	-----	-----	-----	-----	-----	-----
36018.	39871.	43699.	0.	0.	0.	0.
-----	-----	-----	-----	-----	-----	-----
898358.	1011758.	1137894.	0.	0.	0.	0.
-----	-----	-----	-----	-----	-----	-----
37069.	40421.	44416.	0.	0.	0.	0.
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935427.	1052179.	1182310.	0.	0.	0.	0.
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[illegible]

168299.	188529.	210763.	0.	0.	0.	0.
79291.	89288.	100385.	0.	0.	0.	0.
174760.	197053.	222290.	0.	0.	0.	0.
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422349.	474869.	533438.	0.	0.	0.	0.
-----	-----	-----	-----	-----	-----	-----
419176.	472121.	530911.	0.	0.	0.	0.
13171.	14831.	16675.	0.	0.	0.	0.
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432347.	486952.	547586.	0.	0.	0.	0.
-----	-----	-----	-----	-----	-----	-----
42457.	48356.	54903.	0.	0.	0.	0.
38274.	42002.	46384.	0.	0.	0.	0.
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80731.	90358.	101287.	0.	0.	0.	0.
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935427.	1052179.	1182310.	0.	0.	0.	0.
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***** PFO FORMA SOURCES AND USES OF FUNDS *****

DECEMBER 31

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

1979	1980	1981	1982	1983	1984	1985
(DOLLARS IN MILLIONS)						

SOURCES OF FUNDS:

NET INCOME	8384.	14888.	16447.	17530.	19132.	20428.	21648.
DEPRECIATION	6833.	7324.	8005.	8665.	9409.	10354.	10689.
DEFERRED ITC-NET	1013.	985.	1121.	1143.	1078.	1137.	1579.
DEFERRED INCOME TAXES	1510.	1576.	1585.	1626.	1619.	1599.	1706.
AFUDC	(4525.)(	4558.)(	4794.)(	4995.)(	5445.)(	5983.)(	6425.)(
TOTAL INTERNAL FUNDS	13215.	20215.	22365.	23968.	25794.	27235.	29198.
INCREASE IN SHORT-TERM DEBT	353.	198.	233.	242.	233.	257.	370.
INCREASE IN LONG-TERM DEBT	11925.	6555.	7670.	7960.	7688.	8441.	12020.
ISSUANCE OF COMMON STOCK	6749.	1043.	1418.	1417.	985.	1221.	3126.
ISSUANCE OF PREFERRED STOCK	2127.	1189.	1402.	1456.	1405.	1550.	2230.
TOTAL EXTERNAL FUNDS	21154.	8985.	10722.	11075.	10312.	11470.	17746.
TOTAL SOURCES	34368.	29199.	33087.	35043.	36106.	38705.	46944.

APPLICATION OF FUNDS:

CONSTRUCTION EXPENDITURES (EXCLUDING AFUDC)	19989.	17189.	19867.	20795.	20277.	21717.	29409.
COMMON STOCK DIVIDENDS	3976.	7520.	8325.	8807.	9594.	10198.	10754.
PREFERRED STOCK DIVIDENDS	1639.	1842.	2026.	2225.	2425.	2636.	2901.
CHANGE IN WORKING CAPITAL	4312.	1980.	2115.	2366.	2849.	3071.	2659.
CHANGE IN NUCLEAR FUEL STOCK	0.	667.	754.	851.	960.	1083.	1220.
TOTAL APPLICATIONS	29917.	29199.	33087.	35043.	36106.	38705.	46944.

EXTERNAL FINANCING AS A PERCENT
OF TOTAL APPLICATIONS

75.71.	30.77	32.41	31.67	28.56	29.63	37.80
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DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

1986	1987	1988	1989	1990	1991	1992
(DOLLARS IN MILLIONS)						
23098.	26436.	29849.	33850.	36482.	42738.	48640.
11594.	12783.	13780.	14674.	15549.	17477.	19697.
2201.	2712.	3155.	3512.	3805.	4279.	4743.
1933.	1895.	1811.	1697.	2140.	2497.	2869.
(6805.)(	(8343.)(	(10825.)(	(14052.)(	(15622.)(	(17371.)(	(19301.)(
32020.	35483.	37769.	39680.	42354.	49619.	56647.
533.	679.	828.	974.	1082.	1200.	1333.
17172.	21780.	26479.	31031.	34475.	38262.	42497.
5913.	8052.	10268.	12307.	13944.	15037.	16507.
3206.	4087.	4987.	5862.	6511.	7224.	8023.
26825.	34597.	42563.	50175.	56012.	61723.	68360.
58845.	70081.	80332.	89854.	98365.	111342.	125007.
40133.	48993.	56699.	63047.	69175.	78341.	87614.
11416.	13077.	14698.	16598.	17652.	20822.	23680.
3266.	3740.	4320.	5005.	5781.	6643.	7601.
1971.	1831.	1727.	1787.	1720.	1994.	2422.
2058.	2439.	2888.	3416.	4037.	3543.	3689.
58845.	70080.	80332.	89854.	98365.	111342.	125006.
45.58	49.37	52.98	55.84	56.94	55.44	54.69

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

1993	1994	1995	0	0	0	0
(DOLLARS IN MILLIONS)						

SOURCES OF FUNDS:

NET INCOME	55153.	62557.	70716.	0.	0.	0.	0.
DEPRECIATION	22157.	24885.	27912.	0.	0.	0.	0.
DEFERRED ITC-NET	5285.	5899.	6547.	0.	0.	0.	0.
DEFERRED INCOME TAXES	3278.	3728.	4382.	0.	0.	0.	0.
AFUDC	(21511.)(	24056.)(	27012.)(	0.)(	0.)(	0.)(	0.)(
TOTAL INTERNAL FUNDS	64361.	73013.	92545.	0.	0.	0.	0.
INCREASE IN SHORT-TERM DEBT	1486.	1661.	1843.	0.	0.	0.	0.
INCREASE IN LONG-TERM DEBT	47394.	52945.	58790.	0.	0.	0.	0.
ISSUANCE OF COMMON STOCK	18263.	20230.	22234.	0.	0.	0.	0.
ISSUANCE OF PREFERRED STOCK	8948.	9997.	11097.	0.	0.	0.	0.
TOTAL EXTERNAL FUNDS	76091.	84833.	93964.	0.	0.	0.	0.
TOTAL SOURCES	140452.	157846.	176509.	0.	0.	0.	0.

APPLICATION OF FUNDS:

CONSTRUCTION EXPENDITURES (EXCLUDING AFUDC)	98303.	110376.	123208.	0.	0.	0.	0.
COMMON STOCK DIVIDENDS	26832.	30478.	34458.	0.	0.	0.	0.
PREFERRED STOCK DIVIDENDS	8668.	9794.	11020.	0.	0.	0.	0.
CHANGE IN WORKING CAPITAL	2849.	3352.	3995.	0.	0.	0.	0.
CHANGE IN NUCLEAR FUEL STOCK	3800.	3853.	3829.	0.	0.	0.	0.
TOTAL APPLICATIONS	140452.	157846.	176510.	0.	0.	0.	0.

EXTERNAL FINANCING AS A PERCENT
OF TOTAL APPLICATIONS

54.18	53.74	53.23	0.0	0.0	0.0	0.0
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***** PRO FORMA REVENUE REQUIREMENT *****

YEAR ENDED DECEMBER 31

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST).

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	219744.	240211.	260038.	282376.	301730.	320804.	347981.
ADDITIONS:							
CONSTRUCTION WORK IN PROGRESS	75191.	76472.	81306.	84758.	91126.	99752.	108408.
NUCLEAR FUEL	4610.	5278.	6032.	6883.	7843.	8926.	10147.
WORKING CAPITAL	5726.	6352.	7047.	7820.	8680.	9636.	10703.
DEDUCTIONS:							
ACCUMULATED DEPRECIATION	(68330.)(	75654.)(	83659.)(	92325.)(	101734.)(	111788.)(	122476.)(
ACCUMULATED DEFERRED TAXES	(10445.)(	12021.)(	13606.)(	15232.)(	16851.)(	18450.)(	20156.)(
YEAR END RATE BASE	226497.	240637.	257158.	274281.	290794.	308881.	334604.
REVENUE REQUIREMENT							
AVERAGE RATE BASE	225064.	243800.	258811.	276888.	292214.	309374.	335331.
RATE OF RETURN ON RATE BASE	0.106	0.108	0.110	0.112	0.113	0.115	0.116
RETURN ON RATE BASE	23861.	26302.	28409.	30879.	33053.	35468.	38995.
EXPENSES:							
OPERATION & MAINTENANCE	3820.	4237.	4701.	5217.	5790.	6428.	7138.
FUEL	41992.	46578.	51677.	57346.	63650.	70663.	78465.
DEPRECIATION	6833.	7324.	8005.	8665.	9409.	10054.	10689.
GENERAL TAXES	6081.	6671.	7328.	8081.	8827.	9636.	10630.
STATE TAXES	0.	0.	0.	0.	0.	0.	0.
FEDERAL INCOME TAXES (NET OF ITC)	7432.	8339.	9002.	9882.	10484.	11141.	12247.
ITC-FLOWED THROUGH	(297.)(	298.)(	345.)(	361.)(	352.)(	377.)(	510.)(
ITC-AMORTIZED	(71.)(	105.)(	138.)(	175.)(	207.)(	239.)(	284.)(
TAX SAVINGS FROM AFUDCD-FLOWED THROUGH	(761.)(	767.)(	806.)(	840.)(	916.)(	1006.)(	1081.)(
TAX SAVINGS FROM AFUDCD-AMORTIZED	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
AFUDC OFFSET	(4525.)(	4558.)(	4794.)(	4995.)(	5445.)(	5983.)(	6425.)(
TOTAL EXPENSES	60424.	67421.	74630.	82819.	91241.	100317.	110869.
REVENUE REQUIREMENTS	84285.	93723.	103039.	113697.	124293.	135785.	149864.

	1986	1987	1988	1989	1990	1991	1992
	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	383696.	413627.	440466.	466766.	524659.	591310.	665189.
ADDITIONS:							
CONSTRUCTION WORK IN PROGRESS	119631.	147037.	187723.	238522.	265427.	294487.	327524.
NUCLEAR FUEL	12205.	14644.	17532.	20948.	24986.	28529.	32218.
WORKING CAPITAL	11933.	13313.	14862.	16600.	18551.	20451.	22568.
DEDUCTIONS:							
ACCUMULATED DEPRECIATION	(134070.)	(146853.)	(160633.)	(175307.)	(190856.)	(208333.)	(228030.)
ACCUMULATED DEFERRED TAXES	(22089.)	(23984.)	(25795.)	(27491.)	(29631.)	(32128.)	(34996.)
YEAR END RATE BASE	371306.	417784.	474154.	540038.	613134.	694315.	784472.
REVENUE REQUIREMENT							
AVERAGE RATE BASE	370813.	409510.	459388.	520246.	605532.	687050.	776333.
RATE OF RETURN ON RATE BASE	0.118	0.120	0.121	0.122	0.123	0.124	0.125
RETURN ON RATE BASE	43758.	48996.	55642.	63677.	74762.	85466.	97207.
EXPENSES:							
OPERATION & MAINTENANCE	8514.	10152.	12112.	14446.	17235.	20450.	24277.
FUEL	86950.	96354.	106783.	118350.	131173.	143158.	156268.
DEPRECIATION	11594.	12783.	13780.	14674.	15549.	17477.	19697.
GENERAL TAXES	11877.	13132.	14506.	16046.	18288.	20482.	22516.
STATE TAXES	0.	0.	0.	0.	0.	0.	0.
FEDERAL INCOME TAXES (NET OF ITC)	13796.	14902.	16123.	17557.	21289.	24509.	28025.
ITC-FLOWED THROUGH	(697.)	(850.)	(984.)	(1094.)	(1201.)	(1361.)	(1522.)
ITC-AMORTIZED	(343.)	(393.)	(438.)	(483.)	(579.)	(690.)	(813.)
TAX SAVINGS FROM AFUDCD-FLOWED THROUGH	(1145.)	(1403.)	(1821.)	(2363.)	(2627.)	(2922.)	(3246.)
TAX SAVINGS FROM AFUDCD-AMORTIZED	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)
AFUDC OFFSET	(6805.)	(8343.)	(10825.)	(14053.)	(15622.)	(17371.)	(19301.)
TOTAL EXPENSES	123741.	136333.	149236.	163079.	183505.	203732.	226299.
REVENUE REQUIREMENTS	167499.	185329.	204878.	226756.	258267.	289198.	323506.

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DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

YEAR	ELEC REVS NOM	ELEC REVS PV	ELEC REVS CUMPV	DISCOUNT RATE USED=0.1250
1979	71728.	71728.	71728.	
1980	90333.	80296.	152023.	
1981	100459.	79375.	231399.	
1982	110509.	77614.	309012.	
1983	121994.	76160.	385173.	
1984	133476.	74070.	459242.	
1985	145946.	71991.	531233.	
1986	161136.	70652.	601885.	
1987	180060.	70177.	672062.	
1988	199252.	69029.	741091.	
1989	220306.	67842.	808933.	
1990	243852.	66750.	875683.	
1991	274956.	66951.	942584.	
1992	307776.	66566.	1009150.	
1993	344129.	66159.	1075308.	
1994	384495.	65706.	1141013.	
1995	428882.	65148.	1206160.	

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

INTEREST COVERAGE CALCULATIONS

YEAR	SEC FORMULA
1979	1.8066
1980	2.8854
1981	2.9340
1982	2.8891
1983	2.8976
1984	2.8432
1985	2.7485
1986	2.6431
1987	2.5973
1988	2.4628
1989	2.3271
1990	2.2051
1991	2.2750
1992	2.2886
1993	2.2955
1994	2.3111
1995	2.3211

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

YEAR	ELEC REVS (\$1 **6)	TOTAL SALES (GWH)	AVERAGE PRICE OF ELECTRICITY (MILLS/KWH)
1979	71727.50	2017.	35.56711
1980	90332.75	2074.	43.55179
1981	100455.437	2134.	47.08248
1982	110508.687	2195.	50.33609
1983	121994.125	2259.	53.99385
1984	133475.875	2326.	57.39008
1985	145946.00	2395.	60.94807
1986	151135.625	2473.	65.15538
1987	180067.125	2555.	70.47726
1988	199252.125	2639.	75.48926
1989	220305.812	2727.	80.78607
1990	243852.437	2818.	86.54535
1991	274955.750	2909.	94.51991
1992	307775.687	3005.	102.41130
1993	344129.062	3106.	110.81259
1994	384495.375	3210.	119.78854
1995	423882.437	3318.	125.24734

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

AFUDC AS A % OF EARNINGS AVAILABLE FOR COMMON

YEAR	AFUDC	AVAILABLE EARNINGS	%
1979	4525.	6745.	67.09
1980	4558.	13046.	34.94
1981	4794.	14421.	33.24
1982	4995.	15305.	32.64
1983	5445.	16707.	32.59
1984	5983.	17792.	33.63
1985	6425.	18747.	34.27
1986	6805.	19831.	34.32
1987	8343.	22696.	36.76
1988	10825.	25528.	42.40
1989	14052.	28844.	48.72
1990	15622.	30701.	50.88
1991	17371.	36095.	48.13
1992	19301.	41039.	47.03
1993	21511.	46485.	46.28
1994	24056.	52763.	45.59
1995	27012.	59696.	45.25

DOE REGION 11
PUBLIC & PRIVATE
NUFS NATIONAL (TEST)

REGULATORY LAG INFORMATION

YEAR	NO LAG	1 YEAR LAG	1 & 1/2 YEARS LAG	TWO YEARS LAG
1979	84285.	71728.	71728.	71728.
1980	93723.	90333.	83875.	77418.
1981	103039.	110459.	98716.	96972.
1982	113697.	110509.	109182.	107855.
1983	124294.	121994.	120353.	118713.
1984	135785.	133476.	132292.	131109.
1985	149864.	145946.	144757.	143569.
1986	167590.	161136.	159113.	157090.
1987	185330.	180060.	176773.	173486.
1988	204879.	199252.	196530.	193808.
1989	226756.	220306.	217399.	214493.
1990	258267.	243852.	240520.	237188.
1991	289198.	274956.	267515.	260074.
1992	32356.	307776.	300419.	293062.
1993	361614.	344129.	336002.	327874.
1994	403498.	384495.	375459.	366423.
1995	449554.	428882.	419060.	409237.

SUMMARY REPORT

YEAR	INTEREST COVERAGE	AFUDC AS A PERCENTAGE OF EARNINGS	EARNED RETURN ON EQUITY	EXTERNAL FINANCING PERCENTAGE
1979	1.8066	67.09	0.08623	70.71
1980	2.3894	34.94	0.15065	30.77
1981	2.9342	33.24	0.15744	32.41
1982	2.8851	32.64	0.15685	31.68
1983	2.3976	32.59	0.16145	28.56
1984	2.9432	33.63	0.16236	29.63
1985	2.7485	34.27	0.16018	37.80
1986	2.5431	34.32	0.15562	45.58
1987	2.5973	36.76	0.16015	49.37
1988	2.4628	42.40	0.15950	52.98
1989	2.3271	48.72	0.15832	55.84
1990	2.2051	50.88	0.14875	56.94
1991	2.2750	48.13	0.15433	55.44
1992	2.2886	47.03	0.15535	54.69
1993	2.2955	46.28	0.15657	54.18
1994	2.3111	45.59	0.15791	53.74
1995	2.3211	45.25	0.15872	53.23

ii) Fixed Charge Rate Analysis Report

DOE REGION 1
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1579091.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 94804.94
NOMINAL ANNUITY: 203324.25
COST OF PLANT: 993605.

***REAL FIXED CHARGE RATE:0.09542
***NOMINAL FIXED CHARGE RATE:0.20463

DOE REGION 2
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1867413.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 112115.12
NOMINAL ANNUITY: 240448.69
COST OF PLANT: 971402.

***REAL FIXED CHARGE RATE:0.11542
***NOMINAL FIXED CHARGE RATE:0.24753

DOE REGION 3
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1799452.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 108034.87
NOMINAL ANNUITY: 231698.00
COST OF PLANT: 997211.

***REAL FIXED CHARGE RATE:0.10834
***NOMINAL FIXED CHARGE RATE:0.23235

DOE REGION 4
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1392732.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 83616.37
NOMINAL ANNUITY: 179328.62
COST OF PLANT: 773842.

***REAL FIXED CHARGE RATE:0.10805
***NOMINAL FIXED CHARGE RATE:0.23174

DOE REGION 5
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1825761.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 109614.44
NOMINAL ANNUITY: 235085.56
COST OF PLANT: 1000000.

***REAL FIXED CHARGE RATE:0.10961
***NOMINAL FIXED CHARGE RATE:0.23509

DOE REGION 6
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1801115.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 108134.75
NOMINAL ANNUITY: 231912.12
COST OF PLANT: 990934.

***REAL FIXED CHARGE RATE:0.10912
***NOMINAL FIXED CHARGE RATE:0.23403

DOE REGION 7
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1830274.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 109885.37
NOMINAL ANNUITY: 235666.69
COST OF PLANT: 1000000.

***REAL FIXED CHARGE RATE:0.10989

***NOMINAL FIXED CHARGE RATE:0.23567

DOE REGION 8
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1120752.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 67287.31
NOMINAL ANNUITY: 144308.37
COST OF PLANT: 652815.

***REAL FIXED CHARGE RATE:0.10307

***NOMINAL FIXED CHARGE RATE:0.22106

DOE REGION 9
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE:1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 1429893.
REAL CAPITAL RECOVERY FACTOR:0.0600
NOMINAL CAPITAL RECOVERY FACTOR:0.1288
REAL ANNUITY: 85847.44
NOMINAL ANNUITY: 184113.50
COST OF PLANT: 850934.

***REAL FIXED CHARGE RATE:0.10089

***NOMINAL FIXED CHARGE RATE:0.21637

DOE REGION 10
PRIVATE SECTOR
NUFS FCF FOR PLANT TYPE

*****FIXED CHARGE RATE CALCULATIONS*****

PLANT TYPE: 7 PLANT LIFE: 30.
YEAR PLANT COMES ON LINE: 1987
PV OF REV REQS DISCOUNTED TO 1987 DOLLARS: 529873.
REAL CAPITAL RECOVERY FACTOR: 0.0600
NOMINAL CAPITAL RECOVERY FACTOR: 0.1288
REAL ANNUITY: 31812.34
NOMINAL ANNUITY: 68226.56
COST OF PLANT: 305096.

***REAL FIXED CHARGE RATE: 0.10427
***NOMINAL FIXED CHARGE RATE: 0.22362

iii) Pricing Coefficient Analysis Report

DOE REGION 1
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	360.	1117.	0.3219
1990	631.	3324.	0.1897
1995	788.	4791.	0.1646

DOE REGION 2
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	519.	1990.	0.2610
1990	1016.	5467.	0.1859
1995	846.	5467.	0.1548

DOE REGION 3
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	785.	2854.	0.2749
1990	1223.	6911.	0.1770
1995	980.	6911.	0.1419

DOE REGION 4
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	2169.	10176.	0.2131
1990	2624.	16291.	0.1611
1995	2437.	20301.	0.1200

DOE REGION 5
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	2312.	8970.	0.2578
1990	2523.	13369.	0.1887
1995	2374.	15723.	0.1510

DOE REGION 6
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	928.	3901.	0.2379
1990	1117.	5411.	0.2064
1995	1537.	10084.	0.1524

DOE REGION 7
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	544.	2487.	0.2189
1990	464.	2487.	0.1867
1995	620.	3902.	0.1590

DOE REGION 8
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	72.	457.	0.1584
1990	60.	457.	0.1310
1995	50.	457.	0.1086

DOE REGION 9
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	1108.	5689.	0.1947
1990	1294.	7686.	0.1684
1995	1185.	7686.	0.1541

DOE REGION 10
PUBLIC & PRIVATE
PRICING COEFF 10 REG.

****PRICING COEFFICIENT CALCULATIONS FOR PLANT TYPE: 7****

YEAR	REVENUES	TOTAL VALUE OF BUILDS	PRICING COEFFICIENT
1985	670.	2516.	0.2664
1990	834.	5024.	0.1660
1995	708.	5024.	0.1410

iv) Old Money Revenue Requirement Report

DOE REGION 1
PUBLIC & PRIVATE
NUFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	1415.
1980	1189.
1981	1061.
1982	948.
1983	846.
1984	755.
1985	674.
1986	602.
1987	538.
1988	478.
1989	425.
1990	378.
1991	336.
1992	298.
1993	265.
1994	235.
1995	205.

DOE REGION 2
PUBLIC & PRIVATE
NUFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	3372.
1980	2787.
1981	2484.
1982	2214.
1983	1973.
1984	1758.
1985	1566.
1986	1395.
1987	1244.
1988	1106.
1989	984.
1990	875.
1991	778.
1992	691.
1993	615.
1994	547.
95	478.

DOE REGION 3
PUBLIC & PRIVATE
NUFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	3818.
1980	3119.
1981	2765.
1982	2451.
1983	2173.
1984	1926.
1985	1708.
1986	1515.
1987	1344.
1988	1190.
1989	1054.
1990	933.
1991	826.
1992	731.
1993	647.
1994	569.
1995	489.

DOE REGION 4
PUBLIC & PRIVATE
NUFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	4810.
1980	4030.
1981	3557.
1982	3137.
1983	2764.
1984	2435.
1985	2143.
1986	1886.
1987	1658.
1988	1457.
1989	1279.
1990	1122.
1991	984.
1992	861.
1993	754.
1994	659.
1995	575.

DOE REGION 5
PUBLIC & PRIVATE
UFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	6350.
1980	5223.
1981	4599.
1982	4047.
1983	3559.
1984	3129.
1985	2751.
1986	2417.
1987	2125.
1988	1867.
1989	1640.
1990	1440.
1991	1264.
1992	1110.
1993	976.
1994	858.
1995	753.

DOE REGION 6
PUBLIC & PRIVATE
NUFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	2691.
1980	2287.
1981	2015.
1982	1773.
1983	1560.
1984	1371.
1985	1205.
1986	1057.
1987	928.
1988	814.
1989	713.
1990	625.
1991	548.
1992	480.
1993	421.
1994	369.
1995	323.

DOE REGION 7
PUBLIC & PRIVATE
UFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	1507.
1980	1243.
1981	1098.
1982	969.
1983	854.
1984	753.
1985	664.
1986	584.
1987	515.
1988	453.
1989	399.
1990	351.
1991	308.
1992	271.
1993	239.
1994	210.
1995	185.

DOE REGION 8
PUBLIC & PRIVATE
NUFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	791.
1980	684.
1981	608.
1982	540.
1983	479.
1984	424.
1985	375.
1986	332.
1987	293.
1988	258.
1989	227.
1990	200.
1991	175.
1992	153.
1993	134.
1994	117.
1995	101.

DOE REGION 9
PUBLIC & PRIVATE
NUFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	3020.
1980	2547.
1981	2302.
1982	2081.
1983	1879.
1984	1696.
1985	1530.
1986	1380.
1987	1243.
1988	1119.
1989	1006.
1990	904.
1991	812.
1992	729.
1993	653.
1994	585.
1995	510.

DOE REGION 10
PUBLIC & PRIVATE
NUFS OLD MONEY 10 REG.

****CONSTANT BASE YEAR DOLLAR REVENUE REQUIREMENTS FOR EXISTING ASSETS****
(OLD MONEY)

YEAR	REVENUE REQUIREMENTS
1979	1817.
1980	1583.
1981	1414.
1982	1263.
1983	1127.
1984	1004.
1985	894.
1986	795.
1987	707.
1988	627.
1989	555.
1990	491.
1991	434.
1992	382.
1993	336.
1994	296.
1995	256.

APPENDIX 2

SELECTED FINANCIAL INDICATORS AND BOND RATINGS FOR CLASS A AND B ELECTRIC UTILITIES, 1978

This appendix lists selected financial indicators for Class A and B utilities. The data is organized in four tables by Moody's bond rating. The financial data is taken from "Statistics of Privately Owned Electric Utilities in the United States - 1978". All financial indicators are calculated on the basis of electric operations only and exclude non-operating income and gas operations. Interest coverage is calculated using the SEC formula.

TABLE 1

SELECT FINANCIAL INDICATORS FOR
UTILITIES WITH Aaa BOND RATINGS

<u>Utility</u>	<u>Interest Coverage</u>	<u>AFUDC as a Percent of Income</u>	<u>Return on Common Equity</u>	<u>External Financing as a Percent of Total Applications</u>
Louisville Gas & Electric Co.	3.649	0.0%	8.4%	43.4%
Dallas Power & Light Co.	3.105	43.2	10.7	56.1
Texas Electric Service Co.	3.964	27.5	13.0	35.4
Texas Power & Light Co.	3.805	17.1	14.7	2.1
Average of All Aaa Rated Utilities	3.631	21.95	11.7	34.25

TABLE 2
SELECT FINANCIAL INDICATORS
FOR UTILITIES WITH Aa BOND RATINGS

<u>Utility</u>	<u>Interest Coverage</u>	<u>AFUDC as a Percent of Income</u>	<u>Return on Common Equity</u>	<u>External Financing as a Percent of Total Applications</u>
Citizens Utility Company	2.704	3.2%	13.7	8.6%
Pacific Gas & Electric Co.	1.882	43.4	10.7	50.9
Southern California Edison	2.485	39.0	9.8	48.8
Public Service Co. of Colorado	2.462	37.4	8.6	46.8
Tampa Electric Company	4.287	4.2	14.5	6.5
Central Illinois Public Service	2.949	26.8	10.5	41.5
Commonwealth Edison	2.342	62.9	11.0	61.5
Illinois Power Company	2.379	43.4	11.9	48.7
Indianapolis Power & Light	3.313	7.8	10.0	33.2
Northern Indiana Public Service	1.707	55.3	8.1	51.9
Public Service Co. of Indiana	3.513	47.4	11.8	52.2
Southern Indiana Gas & Electric	3.382	46.9	14.4	56.2
Iowa-Illinois Gas & Electric	2.229	44.9	12.1	60.3
Iowa Power & Light Company	3.218	45.6	13.7	44.8
Iowa Public Service Company	2.052	57.9	13.4	55.5
Iowa Southern Utilities	3.065	24.2	12.5	62.2
Kentucky Utilities Company	2.940	1.8	7.5	38.7
Baltimore Gas & Electric	2.965	7.3	11.5	25.5
New Bedford Gas & Electric	2.970	20.1	9.4	0
New England Power	2.905	42.0	11.9	29.5
Northern States Power Co.	4.263	7.7	12.9	6.3
Kansas City Power & Light Co.	2.531	68.8	10.3	56.7
Atlantic City Electric Co.	3.434	23.3	10.3	5.5
Public Service Electric & Gas Co.	3.463	22.5	10.5	24.5
Public Service Co. of New Mexico	2.783	50.3	10.5	80.6
Cincinnati Gas & Electric Co.	2.175	35.8	11.6	53.7
Cleveland Electric Illum. Co.	2.128	53.7	10.8	44.9
Oklahoma Gas & Electric Co.	2.596	56.3	10.7	44.0
Pennsylvania Power & Light Co.	2.386	66.2	10.9	56.3
West Penn Power Co.	3.208	47.6	12.5	37.0
Central Power & Light Co.	3.647	42.5	14.3	39.8
Houston Lighting & Power Co.	3.647	23.5	12.1	56.8
Southwestern Electric Power Co.	4.006	23.5	13.0	39.8
Southwestern Public Serv. Co.	3.173	17.9	16.1	41.2
West Texas Utilities Co.	6.683	1.8	12.3	0.0
Northern States Power Co.* (Wisc.)	.166	12.8	10.2	41.5
Wisconsin Electric Power Co.	4.283	8.2	11.8	54.1
Wisconsin Power & Light Co.	3.045	2.8	11.1	32.1
Wisconsin Public Serv. Corp.	4.592	0.0	13.1	2.5
Average of all Aa-rated utilities	3.02	31.45	11.59	39.55

* Northern States Power Company appears.

TABLE 3

SELECT FINANCIAL INDICATORS FOR
UTILITIES WITH A BOND RATINGS

<u>Utility</u>	<u>Interest Coverage</u>	<u>AFUDC as a Percent of Income</u>	<u>Return on Common Equity</u>	<u>External Financing as a Percent of Total Applications</u>
Arizona Public Service Co.	2.487	43.7%	12.1	65.3%
Tucson Electric Power Co.	2.085	55.9	13.3	66.0
Connecticut Light & Power Co.	1.849	45.1	10.0	29.8
Hartford Electric Light Co.	2.057	28.8	10.5	38.6
United Illuminating Co.	1.913	49.4	9.4	66.6
Delmarva Power & Light Co.	1.909	26.7	11.6	46.2
Potomac Electric Power Co.	3.083	0.0	10.4	27.0
Florida Power Corp.	4.484	1.4	13.2	1.2
Florida Power & Light Co.	3.610	18.9	13.9	24.3
Gulf Power Co.	3.049	30.2	11.3	32.5
Idaho Power Co.	2.556	27.7	9.6	59.1
Central Illinois Light Co.	2.777	9.4	9.9	15.4
Interstate Power Co.	2.335	26.9	12.5	58.2
Iowa Electric Light & Power Co.	3.703	21.1	11.2	50.7
Kansas Gas & Electric Co.	2.504	71.8	9.0	68.8
Central Louisiana Electric Co.	2.385	6.4	14.3	95.1
Gulf States Utilities Co.	2.364	54.9	10.0	46.2
New Orleans Public Service Co.	2.730	1.4	12.2	29.6
Central Maine Power Co.	2.920	47.8	12.3	58.5
Massachusetts Electric Co.	3.948	0.7	15.3	0.0
Consumers Power Co.	1.754	55.1	9.4	53.6
Minnesota Power & Light Co.	3.144	24.6	13.4	78.4
Mississippi Power Co.		5.0	8.0	25.9
Mississippi Power & Light Co.	3.337	4.4	15.6	0.5
Empire District Electric Co.	3.156	20.7	10.2	69.4
Kentucky Power Co.	2.682	26.2	12.1	22.5
Missouri Edison Co.	1.904	4.6	6.9	45.9
Missouri Power & Light Co.	1.927	2.7	7.6	31.6
St. Joseph Light Power Co.	1.663	72.0	10.8	64.2
Union Electric Co.	2.991	32.2	11.6	51.9
Montana Power Co.	2.177	9.2	11.4	37.1
Sierra Pacific Power Co.	2.504	28.4	10.9	52.4
Rockland Electric Co.	3.671	1.5	12.8	0.0
Central Hudson Gas & Electric Co.	2.947	31.2	11.4	58.5
Consolidated Edison Co.	2.949	3.9	10.2	0.0
Long Island Lighting Co.	1.858	59.4	11.3	61.3
New York State Electric & Gas Corp.	2.134	29.0	10.8	47.8
Niagara Mohawk Power Co.	1.852	40.0	10.6	48.3
Orange & Rockland Utilities Co.	2.821	13.3	12.1	24.9

TABLE 3 (Cont'd)
SELECT FINANCIAL INDICATORS FOR
UTILITIES WITH A BOND RATINGS

<u>Utility</u>	<u>Interest Coverage</u>	<u>AFUDC as a Percent of Income</u>	<u>Return on Common Equity</u>	<u>External Financing as a Percent of Total Applications</u>
Rochester Gas & Electric Co.	1.983	39.9	9.7	45.9
Carolina Power & Light Co.	3.100	57.4	11.7	30.0
Duke Power Co.	2.274	66.3	12.0	61.2
Montana-Dakota Utilities Co.	1.790	14.1	11.8	58.6
Otter Tail Power Co.	3.880	21.5	13.4	60.3
Columbus & Southern Ohio Electric Co.	1.741	73.1	6.7	67.8
Dayton Power & Light Co.	1.765	59.0	8.6	66.1
Ohio Edison Co.	1.464	83.3	7.2	60.5
Duquesne Light Co.	2.375	44.6	6.0	55.0
Philadelphia Electric Co.	1.704	64.2	9.6	39.9
Narragansett Electric Co.	3.033	7.5	9.5	0.0
South Carolina Electric & Gas Co.	2.096	58.7	12.0	61.2
El Paso Electric Co.	3.375	55.8	12.0	69.4
Utah Power & Light Co.	2.681	25.6	9.7	59.4
Virginia Electric & Power Co.	2.054	59.1	9.2	55.0
Washington Water Power Co.	2.281	14.9	12.3	66.4
Average of All A-Rated Utilities	2.552	32.30	10.92	45.64

TABLE 4
SELECT FINANCIAL INDICATORS FOR
UTILITIES WITH Baa BOND RATINGS

<u>Utility</u>	<u>Interest Coverage</u>	<u>AFUDC as a Percent of Income</u>	<u>Return on Common Equity</u>	<u>External Financing as a Percent of Total Applications</u>
Alabama Power Co.	1.225	100.0%	4.5%	61.2%
Arkansas Power & Light Co.	2.105	68.3	15.3	73.8
San Diego Gas & Electric Co.	1.572	43.9	10.3	37.3
Savannah Electric & Power Co.	2.025	71.6	15.8	54.6
Georgia Power Co.	2.446	50.6	11.6	42.7
Indiana & Michigan Electric Co.	1.849	30.3	14.5	35.2
Louisiana Power and Light Co.	1.205	68.1	10.9	76.5
Potomac Edison Co.	3.034	43.6	3.4	62.5
Boston Edison Co.	2.588	50.0	7.9	40.3
Brockton Edison Co.	1.177	0.2	10.8	43.2
Fall River Electric Light Co.	3.153	0.8	13.3	5.0
Western Massachusetts Electric Co.	2.339	44.4	9.4	4.7
Detroit Edison Co.	2.106	52.8	8.9	45.3
Nevada Power Co.	3.074	8.4	9.0	38.0
Public Service Co. of New Hampshire	3.170	51.8	13.2	56.7
Jersey Central Power & Light Co.	2.552	56.6	9.8	49.2
Ohio Power Co.	1.567	18.8	9.6	18.3
Toledo Edison Co.	2.299	59.3	10.8	48.3
Pacific Power & Light Co.	2.079	30.6	11.4	67.2
Portland General Electric Co.	1.691	67.3	8.9	60.8
Metropolitan Edison Co.	3.181	72.9	13.0	38.2
Pennsylvania Electric Co.	2.483	48.9	9.9	26.5
Puget Sound Power & Light Co.	2.553	31.0	10.4	60.6
Appalachian Power Co.	1.815	47.3	8.1	66.8
Monongahela Power Co.	3.510	47.3	9.3	38.0
Pennsylvania Power Co.	1.825	71.0	6.8	55.8
Average of All Baa-Rated Utilities	2.25	47.5	10.26	46.41

APPENDIX 3

BOND RATINGS AND SELECT FINANCIAL INDICATORS IN 1978 FOR THE FIFTY CLASS A & B ELECTRIC UTILITIES WITH THE LARGEST OIL AND GAS GENERATION PER DAY

<u>Company</u>	<u>Bond Rating</u>	<u>Interest Coverage</u>	<u>AFUDC As a Percentage of Income</u>	<u>Return on Common Equity</u>	<u>External Financing As a Percent of Total Uses of Funds</u>
Houston Lighting & Power	Aa	3.647	23.5	12.1	56.6
Southern California Edison	Aa	2.485	39.6	9.8	48.8
Pacific Gas & Electric	Aa	1.882	43.4	10.7	50.9
Florida Power & Light	A	3.616	18.9	13.9	24.3
Gulf States Utilities	A	2.364	54.9	10.0	46.2
Consolidated Edison	A	2.949	3.9	10.2	0.0
Louisiana Power & Light	Baa	1.205	68.1	10.9	76.5
Virginia Electric Power	A	2.054	59.1	9.2	55.0
Oklahoma Gas & Electric	Aa	2.596	56.3	10.7	44.0
Texas Power & Light	Aaa	3.805	17.1	14.7	2.1
Public Service Company of Oklahoma	Aa	4.474	28.1	14.9	54.7
Texas Electric Service	Aaa	3.964	27.5	13.0	35.4
Public Service Electric & Gas	Aa	3.463	22.5	10.5	24.5
Florida Power Corporation	A	4.484	1.4	13.2	1.2
Long Island Lighting	A	1.858	59.4	11.3	61.3
New England Electric	A-Aa		Separately Reported		
Central Power & Light	Aa	3.647	42.5	14.3	39.8
Southwestern Public Service	Aa	3.173	17.9	16.1	41.2
Southwestern Electric Power Co.	Aa	4.006	23.5	13.0	39.8
Mississippi Power & Light	A	3.337	4.4	15.6	.5
Boston Edison Co.	Baa	2.588	50.0	7.9	40.3
San Diego Gas & Electric	Baa	1.572	43.9	10.3	37.3
Dallas Power & Light Co.	Aaa	3.105	43.2	10.7	56.1
Detroit Edison	Baa	2.106	52.8	8.9	45.3
Philadelphia Electric	A	1.704	64.2	9.6	39.9
Commonwealth Edison	Aa	2.342	62.9	11.0	61.5
Baltimore Gas & Electric	Aa	2.965	7.3	11.5	25.5
Arkansas Power & Light Co.	Baa	2.165	68.3	15.3	73.8
Central Hudson Gas & Electric	A	2.947	31.2	11.4	58.5
Potomac Electric Power Co.	A	3.083	0.0	10.4	27.0
Orange & Rockland Utilities	A	2.821	13.3	12.1	24.9
New England Gas & Electric	A-Aa		Separately Reported		
Consumers Power	A	1.754	55.1	9.4	53.6
Kansas Gas & Electric	A	2.564	71.8	9.0	68.8
Delmarva Power & Light	A	1.909	26.7	11.6	46.2

APPENDIX 3 (Cont'd)

BOND RATINGS AND SELECT FINANCIAL INDICATORS
IN 1978 FOR THE FIFTY CLASS A & B ELECTRIC UTILITIES
WITH THE LARGEST OIL AND GAS GENERATION PER DAY

<u>Company</u>	<u>Bond Rating</u>	<u>Interest Coverage</u>	<u>AFUDC As a Percentage of Income</u>	<u>Return on Common Equity</u>	<u>External Financing As a Percent of Total Uses of Funds</u>
Niagara Mohawk Power	A	1.352	40.0	10.6	48.3
United Illuminating	A	1.313	49.4	9.4	66.6
Connecticut Light & Power	A	1.349	45.1	10.0	29.8
Central Louisiana Electric Co.	A	2.385	6.4	14.3	95.1
Kansas Power & Light	Aa	2.591	66.1	11.0	55.8
West Texas Utilities	Aa	6.583	1.8	12.3	0.0
Georgia Power Co.	Baa	2.446	50.6	11.6	42.7
Public Service Co. of Colorado	Aa	2.462	37.4	8.6	46.8
Jersey Central Power & Light	Baa	2.552	56.8	9.8	49.2
South Carolina Electric & Gas	A	2.096	58.7	12.0	61.2
Pennsylvania Power & Light	Aa	2.386	66.2	10.9	56.3
New Orleans Public Service	A	2.730	54.9	10.0	46.2
El Paso Electric	A	3.375	55.8	12.0	69.4
Hartford Electric Co.	A	2.057	28.8	10.5	38.6
Arizona Public Service	A	2.487	43.7	12.1	65.3

SOURCE: Appendix 2.