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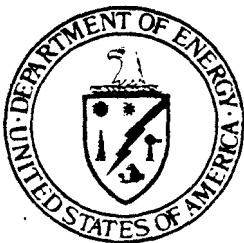
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Validation Report

An Evaluation of the National Utility Financial Statement (NUFS) Model

December 1982

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AN EVALUATION OF THE NATIONAL UTILITY FINANCIAL STATEMENT (NUFS) MODEL

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TABLE OF CONTENTS

<u>Section</u>	<u>Page</u>
ACKNOWLEDGEMENTS	v
EXECUTIVE SUMMARY	vii
ABSTRACT	xvii
1. INTRODUCTION	1
2. REGULATORY THEORY	5
• Economic Regulation	5
• Regulatory Lag	12
• New Construction Expenditures	13
• Accounting for Federal Income Tax Effects	16
3. SPECIFICATION OF THE NUFS MODEL	25
• Information Flow and Implementation of the Code	25
• User-Supplied Inputs	30
• Base Year Financial Information	35
• The MEFS Interface	38
• The NUFS Solution Scheme	45
4. COMPARISON OF FINANCIAL REGULATORY MODELS	75
5. OVER-ALL ASSESSMENT OF THE NUFS MODEL	82
• Model Formulation	82
• NUFS and Economic Considerations	83
6. CONCLUSION	88
• The NUFS Code	89
• An Overall Assessment	90
• NUFS and Model Uses	91
• Recommendations for Improvement	92
FOOTNOTES	94
REFERENCES	97
APPENDIX A: NUFS BASE-CASE SAMPLE PROBLEM	A-1
APPENDIX B: INPUT SOURCES OF NUFS	B-1
APPENDIX C: DISCUSSION OF SENSITIVITY RESULTS	C-1
APPENDIX D: RELATIVE SENSITIVITY RESULTS.	D-1

iii/v

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EXECUTIVE SUMMARY*

In the recent past, there has been a proliferation of capital investment in the electric utility industry which has been associated with the need for ever-increasing infusions of external sources of funds (i.e., debt, preferred and common stock) at interest rates higher than those experienced in the past decade. Although there is a considerable divergence of opinion on the future growth of U.S. electricity consumption, it is generally acknowledged by industry observers that future capital expenditures by electric utilities on new construction programs will continue to increase.

In recognition of the problems that electric utilities face with respect to capital attraction, technical models of the electric utility industry have increasingly relied on explicit specification of the financial regulatory sector in order to determine the financial feasibility of projected capacity expansion programs. To this end, these models have generally attempted to emulate the regulatory environment through specification of systems of financial (accounting) equations that are designed to reflect the electric utility rate-making process.

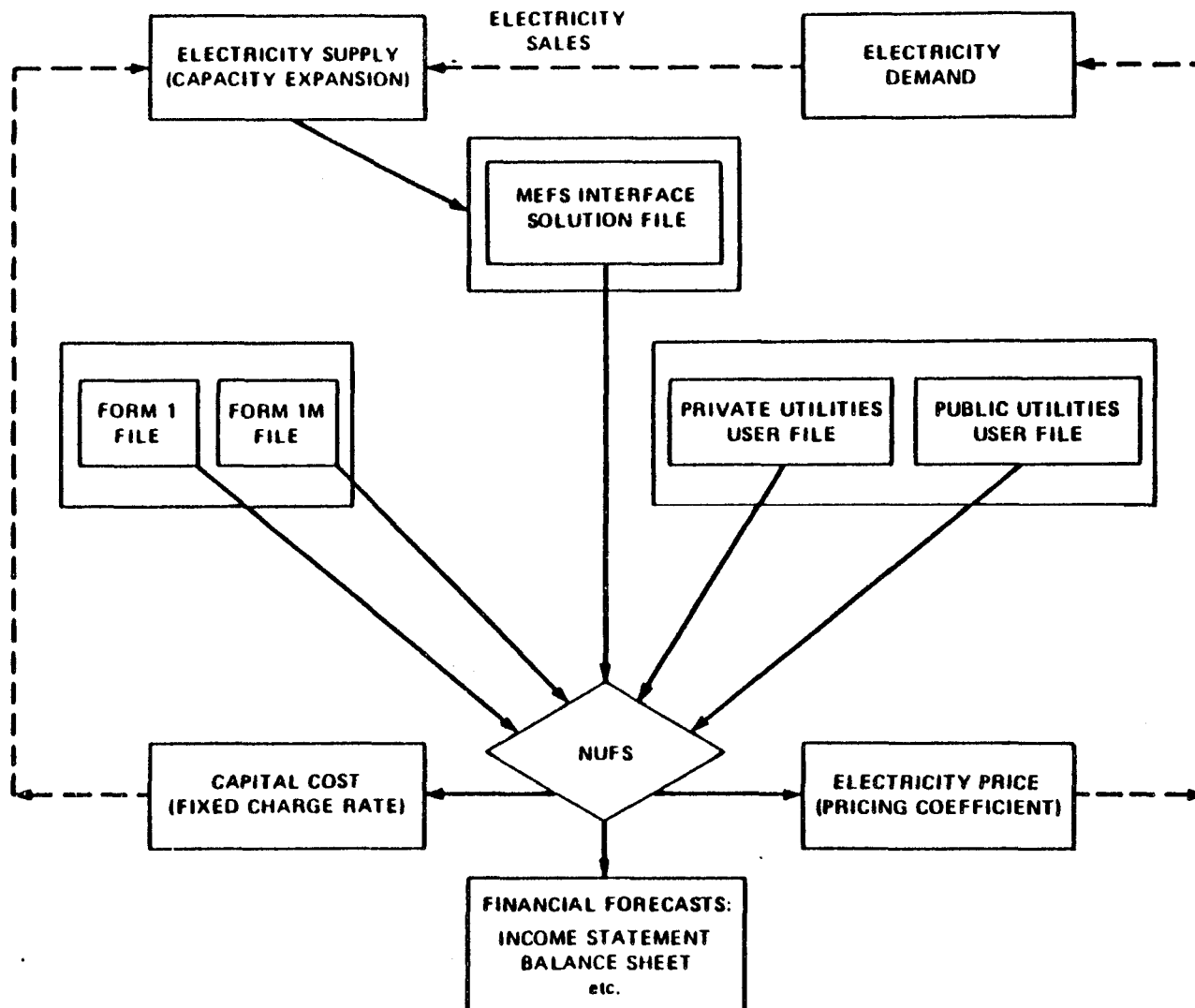
The object of the analysis presented herein is an evaluation of the National Utility Financial Statement (NUFS) Model, a financial regulatory model of the U.S. electric utility industry developed by ICF, Incorporated for the U.S. Department of Energy (DOE), Energy Information Administration (EIA). Although the model is somewhat flexible in terms of prospective applications and level of aggregation, NUFS was originally developed for integration with the Mid-Term Energy Forecasting System (MEFS), a mid-range (to 1995) energy economy forecasting tool used by EIA.

*The work reported here was completed in May 1981 and thus refers to the version of the NUFS code that existed before this date. Revisions to the code after May 1981 have not been considered and thus the text does not necessarily reflect the later versions of the code.

Figure 1 presents a schematic representation of the information flow into NUFS and its relationship to MEFS. The solid lines in Figure 1 represent the actual flow of information into NUFS and the corresponding output that NUFS can provide under alternate options that are embodied in its formulation. The broken lines, on the other hand, represent the optimal "feedback link" from NUFS into the electricity supply and demand specification of MEFS. As will be discussed below, the present evaluation did not encompass this optimal "iterative loop" from NUFS to MEFS.

From Fig. 1, there are three sources of inputs into NUFS: (1) base-year (i.e., the year preceding the first forecast period) financial information for investor-owned utilities (FERC Form 1) and publicly-owned utilities (FERC Form 1M); (2) the projected electric utility capacity expansion profile emanating from the MEFS solution (i.e., the MEFS interface solution file); and (3) a myriad of user-supplied inputs (i.e., user files in Fig. 1) segregated between investor-owned and publicly-owned electric utilities.

Given this array of inputs, one of the fundamental purposes of NUFS is to forecast the primary financial statements of the electric utility industry (i.e., the income statement, balance sheet, and flow-of-funds statement) and financial ratios derived therefrom (e.g., interest coverage, percentage of funds generated internally) for the ten DOE regions and the aggregate U.S., segregated between investor-owned and publicly-owned electric utilities. In this context, the primary role of NUFS is to "assess" the financial feasibility of the projected capacity expansion program emanating from the MEFS' solution.



The capabilities of NUFS, however, are multi-dimensional. Through use of various options that are embodied in the code, it is possible to project the fixed charge rate (i.e., capital cost) and pricing coefficients (i.e., electricity prices) that are implicit in any projection of capacity additions from MEFS under alternate user-provided regulatory assumptions. From Fig. 1, the values of these variables can, in turn, be utilized in an "iterative process" as explanatory variables in the determination of capacity expansion and electricity demand, respectively.

The National Utility Regulatory Model (NUREG), under development by ICF, Incorporated,^{*} is formulated to perform this iterative process for the capacity expansion program emanating from the National Coal Model (NCM) and, alternatively, other electric utility capacity expansion models (including the electric utility sector of MEFS). Unfortunately, NUREG — or, for that matter, any type of formal "feedback link" from NUFS to MEFS — was not available for use in this evaluation.

The users of NUFS at EIA, however, have, in effect, accomplished the task of "closing" the system presented in Fig. 1 by "manually" incorporating the fixed charge rate and pricing coefficients into the supply side and demand side of MEFS, respectively.^{**} That is, given a MEFS

^{*}The documentation for NUREG is provided in Financial Constraints in Capacity Planning: A National Utility Regulatory Model (NUREG), Volume 1: Methodology; Volume 2: Users' Guide; Volume 3: Software Description, ICF, Incorporated, (Washington, D.C.) draft, August 17, 1981.

^{**}This procedure used at EIA was described by Gerald Price, Energy Information Administration, Washington, D.C. in private conversations with the authors of the present evaluation.

solution, the fixed charge rates and pricing coefficients are derived from the execution of NUFS and "manually" incorporated into MEFS, whereupon MEFS is re-executed. This procedure performed at EIA which "closes the loop" between NUFS and MEFS is represented by the broken lines in Fig. 1. The actual procedure utilized by EIA through which the output of NUFS is used in conjunction with MEFS is not addressed in this evaluation and, moreover, to our knowledge, is not documented.

Based on a comprehensive model evaluation methodology developed by a team of multi-disciplined researchers at Oak Ridge National Laboratory,^{*} an overall assessment of NUFS was conducted in the context of a unidirectional flow of information from MEFS (i.e., the projected capacity expansion profile), the base year financial information (i.e., FERC Forms 1 and 1M), and the user-provided inputs into NUFS. Therefore, the analysis of fixed charge rates, pricing coefficients, and their use by EIA as an "iterative loop" back into MEFS is beyond the scope of this evaluation.

With this background on NUFS and its relationship to a larger electric utility supply and demand modeling effort, an evaluation of NUFS was conducted in two distinct stages: (1) an assessment of the NUFS code per se; (i.e., the specification of individual equations and their relationship to each other) and (2) an assessment of NUFS in relationship to the unidirectional flow of information from the MEFS code. The specification of NUFS was analyzed in terms of its underlying assumptions

^{*} C. R. Weisbin, R. W. Peelle and A. S. Loeb1, An Approach to Evaluating Energy-Economy Models, Oak Ridge National Laboratory, ORNL-5742 (1981)

and its consistency with financial regulatory theory. To accommodate the latter assessment stage, a comprehensive sensitivity analysis was performed on NUFS.

With respect to the first stage of evaluation, Section 2 of this report delineates the fundamental features of economic regulation as it is currently administered in the electric utility industry. Section 3, in turn, is focused on the evaluation of NUFS' specification in the context of the theory presented in Section 2. The major issues addressed in Section 2 and their treatment in the NUFS framework are as follows:

- Economic Regulation. In the present institutional arrangement, economic regulation of electric utilities is administered on a state-by-state, utility-specific basis. In the formulation of NUFS, individual utilities are aggregated to the DOE-regional level segregated by investor-owned and publicly-owned utilities. In essence then, NUFS forecasts the financial performance of a "prototype" electric utility for a given region and ownership type.
- Regulatory Lag. Because of the necessity of regulatory body approval of electric utility rate levels and rate structures, a characteristic typical of the electric utility rate-making process is that future rates, derived from a rate hearing, are based on historical or current period costs. Therefore, it is often the case that, in a period of rapidly rising production costs, an individual utility's net revenues or income may be "squeezed" by a rate structure or level determined by costs incurred in the past. The formulation of NUFS affords the user an opportunity to simulate the effect of regulatory lag by provision of four separate, user-supplied lag scenarios: (1) no lag, (2) one year lag, (3) two year lag, and (4) one and one-half year lag.
- New Construction Expenditures. With the proliferation of construction activity in the electric utility industry, an issue of paramount importance in the industry is the compensation to capital contributors for funds expended on construction programs that are not yet completed and, hence, not generating a return through the normal rate-making procedure. In general,

state regulatory commissions allow two methods to compensate capital contributors for their investment: (1) allow the amount of new construction expenditures, termed Construction Work in Progress (CWIP), in the rate base or (2) disallow CWIP in the rate base but "artificially" compute a return to capital invested that is reflected as income on the profit and loss statement. In actuality, an individual regulatory commission may allow a portion of CWIP in the rate base and disallow the remaining amount. Under the formulation of NUFS, the user is allowed to specify the fraction of CWIP allowed in the rate base by DOE region and ownership type. A return is then computed on the amount the user specifies to be excluded from the rate base.

- Federal Income Tax Benefits. Under the provisions of the Internal Revenue Code, a number of federal tax benefits may arise which result in reducing the utility's current period tax liability (e.g., accelerated depreciation, the investment tax credit). Individual regulatory commissions can require that utilities under their jurisdiction "normalize" these tax benefits (thereby allowing larger tax expense for current period rate-making purposes), "flow-through" the benefits (thereby allowing smaller tax expense for rate-making purposes), or require a portion to be "normalized" and a portion to be "flowed-through." In the specification of NUFS, the user is allowed to provide the percentage of federal tax benefits "flowed-through" by DOE region. Since publicly-owned utilities do not pay federal taxes, the procedure is only applicable for investor-owned utilities.

In addition to the treatment of specific regulatory issues in the context of extant regulatory theory, the following assumptions were observed to underlie the specification of NUFS:

- The aggregated, "prototype" electric utility in any region for any ownership type is assumed to maintain positive amounts of working capital based on a presumed 45-day billing cycle.
- All physical assets are assumed to be retired at the termination of a user-specified, useful asset life.
- Individual state regulatory commissions allow determination of rate base value on a historical cost basis only. Reproduction cost or fair value rate base valuation methods are not incorporated into the modeling framework.

- Deferred income taxes (the investment tax credit notwithstanding) arise only as the result of the difference between book depreciation expense and tax depreciation expense.
- The base-year capitalization values (i.e., short- and long-term debt, preferred stock, and common stock and retained earnings), the deferred tax liabilities (deferred income taxes and deferred investment tax credit), working capital, and net income are assumed to be ratably allocated to "electric utility operations", as opposed to the results attributable to natural gas operations, on the basis of an aggregate apportionment scheme.
- The projected amount of electricity generation emanating from the MEFS solution attributable to investor-owned utilities and publicly-owned utilities, respectively, is assumed to be equal to the proportion existing in the base year.
- The general tax rate is assumed to be a constant fraction of the amount of revenues.
- "Old" assets (or, assets that existed prior to the forecast period), categorized by type, are assumed to have the same remaining useful life for any specified region and/or ownership type.
- "Old" assets can only be depreciated utilizing the sum-of-the-years digits method for tax purposes. "New" assets (or, assets that come on line during the forecast period) are allowed to be depreciated by the sum-of-the-years digits method as well as the declining-balance and double declining-balance methods.
- The stock of nuclear fuel in any forecast period is assumed to be equal to twice the amount of nuclear fuel expense.
- The components of capital (i.e., short-term debt, long-term debt, preferred equity, and common equity) are assumed to be available at a constant, user-provided cost (or return) up to a user-provided "critical point" (i.e., the capitalization ratio). Capital supply curves are not embodied in the code.

With respect to the second stage of analysis (i.e., the relationship of NUFS to a larger electric utility supply-demand modeling framework), a sensitivity analysis was performed on all of the Form 1 and

Form 1M base-year financial variables and all of the user-provided inputs. This was accomplished by individually perturbing the relevant inputs and calculating the relative sensitivities based on the resulting changes in output magnitudes. That is, if R represents an output (or response) from NUFS and X an input, the relative sensitivity of R with respect to X is defined as $\frac{X}{R} \frac{dR}{dX}$. The sensitivity studies were conducted without consideration of any "feedback loop" from NUFS to MEFS and thus no conclusions concerning the operation of the system when this feedback is included can be drawn.

ABSTRACT*

The analysis presented herein represents an assessment of the National Utility Financial Statement (NUFS) model, a financial regulatory model of the U.S. electric utilities industry. As presently constituted, NUFS "assesses" the financial feasibility of the electric utilities' capacity expansion program emanating from the Mid-Term Energy Forecasting System (MEFS) through specification of a series of financial accounting relationships that result in the forecast of primary financial statements and other financial information. Since the MEFS code is a forecasting tool that is presently used to project energy-related magnitudes up to 1995, NUFS forecasts financial information in that same time horizon.

The approach to the assessment of NUFS was based on a two-stage level of analysis. First, the individual equations in the code were analyzed in terms of their representation of the underlying institutional character of the electric utility regulatory environment. Second, the over-all performance of NUFS was assessed.

*The work reported here was completed in May 1981 and thus refers to the version of the NUFS code that existed before this date. Revisions to the code after May 1981 have not been considered and thus the text does not necessarily reflect the later versions of the code.

1. INTRODUCTION

In the past decade, increasing consternation has been exhibited by industry leaders, regulators, academicians, and the financial community about the financial plight of the electric utility industry. Until recent years, the investment in new construction by the industry represented a relatively small portion of total capital investment in fixed assets. Therefore, servicing the capital did not represent a significant cash strain on the industry. However, in the immediate past, there has been a proliferation of construction activity in the industry which has been associated with the need for ever-increasing infusions of outside capital at higher rates. This phenomenon, in concert with the vagaries of the regulatory process, has led many industry observers to conclude that the future financial position of the electric utility industry is catastrophic.

There is a considerable divergence of opinion on the future growth of U.S. electricity consumption because of the uncertain impact of conservation measures, the introduction of time-of-day pricing schemes, the proliferation of wheeling arrangements, and the future price path of substitute fuels. Consequently, there is considerable uncertainty with respect to the magnitude of additional generating capacity required by the industry. However, it is generally acknowledged by industry observers that future expenditures by electric utilities on new construction projects will increase. Besides the need for additional capacity, the reasons are manifold.

One of the determinants of projected increases in construction expenditures is rooted in the financial problem that utilities currently face. Because of their bleak financial position and, therefore, lower securities ratings, electric utilities in general pay a premium for capital when they require outside sources of financing. Not unrelated to this phenomenon, is the fact that the incremental cost of capital is higher than the embedded cost of debt. Consequently, when refinancing old debt issues or issuing new ones, the utilities have faced rising capital service costs.

More fundamentally, construction costs are expected to rise because of the need to replace old generating units with more efficient ones and

the need for retro-fitting existing plants to meet new environmental protection and safety standards demanded by the public. This drain on the electric utilities' cash position is exacerbated by the prolific increase in labor and materials cost in conjunction with longer construction periods (and, therefore, higher capital carrying charges) attributable to siting and licensing procedures.

The prognostication for the ability of electric utilities to generate funds for capital expansion internally is bleak. The major sources of internally-generated funds — retained earnings, deferred income taxes, and provisions for depreciation — fall far short of meeting the projected capital expansion commitment. Consequently, utilities must increasingly rely on external sources of funds (i.e., debt, common equity and preferred equity) to finance capital expansion or capital improvement programs.

The constraint imposed on the external attraction and procurement of funds is the weak financial performance exhibited by electric utilities in recent years. This debilitating financial performance is reflected in the deterioration of such financial indicators as interest coverage ratios; construction requirements covered by internally generated funds; debt-to-equity ratios; and, no less, the quality of a utility's reported earnings. Potential investors — interested, of course, in a fair return on their investment — have exhibited concerns over the regulatory institutions' proclivity for allowing electric utilities adequate rate relief and competitive rates of return, and the ability of individual utilities to actually earn their allowed rate of return in a kaleidoscopic economic milieu.

In recognition of the problems that electric utilities face with respect to capital attraction, models of the electric industry have increasingly relied on explicit specification of the financial regulatory sector in order to determine the feasibility of projected capacity expansion programs. To this end, these models have generally attempted to emulate the regulatory environment through systems of financial (accounting) equations that are designed to reflect the electric utility rate-making process.

For example, the Regionalized Electricity Model (REM) developed by Baughman, Joskow, and Kamat,¹ one of the most well-known and oft-cited

models of the electric utility industry, has a financial regulatory sub-model incorporated in it. The entire model, which projects electricity-related activity on both a sub-national and national basis, contains a sophisticated engineering-economic electricity supply side formulation in conjunction with a specification of electricity demand. The link between supply-side activity and demand is the regulatory model wherein the capacity additions projected from the former are, in essence, evaluated in terms of financial feasibility and electricity price effects and "fed back" into the demand for electricity.

Other models have incorporated financial regulatory sectors at a less aggregated level. The Utility Simulation Model, developed by Teknekron Research Inc. for the U.S. Environmental Protection Agency,² projects the annual operations of utilities at the state level. A financial module, incorporated as part of its structure, provides a unifying framework which ensures logical consistency between production and operation costs, investment activity, electricity prices, and regulatory constraints. The Regulatory Analysis Financial Model (RAM)³, on the other hand, was developed specifically to project and assess the financial performance of individual utilities. However, the model does have the capability of forecasting on a regional or national basis. RAM was not developed to be incorporated as part of a larger electric utilities' model but, instead, requires exogenous projections of demand, capital expenditures, and operating costs as part of its input. These latter variables, of course, can be the output from other models.

The object of the analysis presented herein is an assessment of the National Utility Financial Statements (NUFS) Model, a financial regulatory model of the U.S. electric utilities industry developed by ICF, Inc. for the U.S. Department of Energy (DOE)⁴. Although the model is somewhat flexible in terms of application and level of aggregation,⁵ NUFS was originally developed for integration with the Mid-Term Energy Forecasting System (MEFS), a mid-range energy economy forecasting tool used by DOE. In its present application, NUFS forecasts primary financial statements and their derivative financial ratios for the ten DOE regions and the aggregate U.S., segregated between investor-owned electric utilities and

publicly-owned electric utilities. Its primary purpose in that context is to "assess" the financial feasibility of the capacity expansion program emanating from the MEFS' solution.

Another modeling framework, the National Utility Regulatory (NUREG) Model under development by ICF, Incorporated,⁶ is formulated to provide an "iterative loop" from NUFS back to the electric utility capacity expansion portion of the National Coal Model (NCM) or, alternatively, other electric utility capacity expansion models (including the electric utility sub-model in MEFS). Unfortunately, NUREG — or, for that matter, any type of formal "feedback link" from NUFS to MEFS — was not available for use in this evaluation. Consequently, the interaction between the output of NUFS and the corresponding changes induced in MEFS are not addressed in this report.

The approach to the assessment of NUFS is based on a comprehensive model evaluation methodology developed by a team of multi-disciplined researchers at Oak Ridge National Laboratory.⁷ Substantive results of the NUFS assessment are presented in the following four sections. In general terms, those four sections address the following questions:

- Section 2: What theoretical issues must a financial regulatory model of the U.S. electric utility industry encompass?
- Section 3: How is NUFS specified in order to embrace those theoretical issues?
- Section 4: How does the specification of NUFS compare with similar financial regulatory models of the electric utility industry?
- Section 5: How does NUFS perform and what are its limitations?

Section 3 includes a complete description of the model, including data input sources and the specification of individual equations. The comparison of financial regulatory models presented in Section 4 is in general terms and, as such, does not reflect the level of detail that is utilized to evaluate NUFS in Section 3. The overall model assessment is presented in Section 5. The presentation concludes in Section 6 with a summary of the major results of the assessment and recommendations for improvement.

2. REGULATORY THEORY

Economic Regulation

A financial regulatory model, of course, must reflect the prevailing institutional constraints of the regulatory environment. In the electric utility industry, the interstate transmission of electricity was formerly subject to the purview of the Federal Power Commission (FPC). But, with the institution of the Department of Energy in 1977 and concomitant consolidation of regulatory activities, interstate activity is now subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). In general the intrastate operations of privately-owned electric utilities are subject to regulation by individual state Public Utility Commissions (PUCs).

The delineation of electric utility operations on an interstate-intrastate basis is further complicated by the existence of private sector, Investor-Owned Utilities (IOUs) and Publicly-Owned Utilities (POUs). The latter form of organization is comprised of electric utility systems owned and operated by federal agencies, municipal governments, REA cooperatives, power districts, and state agencies. In this formulation, POU's encompass government-owned or government-financed electric utilities. Therefore, even though Rural Electric Cooperatives may operate under a non-government corporate charter, they are financed through a government agency (the Rural Electrification Administration) and, similar to other POU's, do not pay federal corporate income taxes, state corporate income taxes, or property taxes. However, some POU's make voluntary payments to state and local governments in lieu of taxes.

In general, the operation of electric utilities is subject to rate-of-return regulation, wherein an individual utility's pricing structure and, concomitantly, its revenue generation are subject to review and approval by a regulatory body in the jurisdiction in which it operates. A financial regulatory model, therefore, must reflect the institutional character of regulated financial and accounting activities and their attendant effects.

In a broad sense, there are two aspects to rate-of-return regulation. First, an individual utility — in concert with the Public Utility Commission (PUC) in its state of operation — must determine the level of revenues requisite to maintain the financial viability of its operation. From an accounting and financial standpoint in the electric utility industry, this activity encompasses determination of the cost of providing the electric service and a rate of return that is sufficient to compensate contributors of capital (i.e., owners and lenders) for their investment and, moreover, a return large enough to attract new capital. The second aspect of economic regulation involves determination of the structure of rates charged to individual classes of consumers, given the over-all level of allowable revenues. For electric utilities, this aspect of regulation encompasses issues such as price discrimination, time-of-day pricing, and block rates.

In a very simplistic form, the basic rate-making scheme is derived from the determination of Required Revenues (RR):

$$RR = OE + D + T + (RB) (ROR),$$

where OE = Operating Expenses, D = Depreciation, T = Taxes, RB = Rate Base, and ROR = Rate of Return. In this formulation, a utility is allowed to generate revenues (or, alternatively, to price its electrical services) such that it recovers all expenses (OE, D, and T) plus a return on investment in plant that is utilized for producing, transmitting, and distributing the electrical service (RB X ROR). The segregation of revenue requirements, as depicted above, is somewhat arbitrary because depreciation and taxes are technically operating expenses. However, they are segregated in the present context because of their importance and differential treatment in the regulatory process.

Operating expenses, OE, allowed to be recouped from electric utility customers are those "just and reasonable" expenses incurred in the process of providing the electrical service. Those expenses incurred but not applicable to the electrical service function or those deemed "unreasonable" or "unjust" are considered "below-the-line" other deductions.

Hence, they are not allowed to be recouped from rate-payers and, therefore, are charged directly to the utility's owners.

Categorically, operating expenses include maintenance expenditures, commodity fuel costs, wages and salaries, pensions, advertising and publicity costs, contributions to charitable organizations, legal fees, and the like. It must be emphasized that the determination of allowable expenses for rate-making is controversial and, for certain specific items of expense, is determined on a PUC-by-PUC basis. For example, advertising expenditures and political lobbying expenses are closely scrutinized and the amount included or excluded from allowable expenses varies from jurisdiction to jurisdiction.

The amount expended on taxes (T) is also considered an allowable expense for determination of revenues required by an electric utility if the tax is a direct result of providing the electrical service. All privately-owned electric utilities are subject to many different types of taxation. The type of tax and the amount may vary depending upon the utility's location. Included among the taxes levied against IOUs are federal and state income taxes, property taxes, gross revenue taxes, and franchise taxes assessed against utilities in return for their right to operate. As noted, publicly-owned utilities are exempt from federal and state income taxes and, in general, local property taxes.

Although the inclusion of various types of taxes in the determination of revenue requirements poses no conceptual problems, the federal tax effects of a number of items are more complex and require a detailed examination. Those issues will be examined below.

Although depreciation expenses (D) do not reflect a direct cash outlay by a utility, they are nevertheless included as a cost of providing the electrical service because it reimburses the owners for the (estimated) amount of equipment used in the process of producing, transmitting, or distributing electricity. The amount of depreciation expense charged to operations for any period is a function of the asset's original cost, its estimated salvage value, its useful life, and the method used to distribute the cost over its useful life. For financial accounting or book purposes, the latter determination is usually made through the straight-line method

wherein the depreciation charge for any asset or class of property is allocated evenly over the asset's useful life. However, in some jurisdictions the sinking fund method is utilized. Under this scheme, a depreciation reserve is established and equal charges are made to it each period. The period-to-period charges are less than under the straight-line method because it is assumed that the charges are invested and, therefore, interest is earned. For any piece of equipment with a given cost (including salvage) and service life, the two methods result in the same amount of income charges over the depreciable life of the asset.

A complicating issue in book depreciation accounting is the distinction between physical depreciation and functional depreciation. The former has been discussed above in the context of compensating owners for "using up" assets, while the latter involves economic obsolescence. Indeed, in a climate of rapidly changing technology, obsolescence may be a more significant item in dollar terms than physical depreciation. The treatment of obsolescence by regulatory bodies is far from consistent. Some PUCs have defined obsolete equipment as "stand-by" assets, allowing it in the rate base. Others have allowed rapid amortization of the equipment at the same time that replacement equipment is depreciated on a straight-line basis. There is no universally consistent approach to dealing with functional depreciation.

The most difficult and controversial aspect of determining an electric utility's allowable revenues is the derivation of a return to the utility's contributors of capital, reflected as $RB \times ROR$ above. There is no difference between the capital charges and other operating costs (OE, D, and T). Each represents a portion of the cost of providing the electric service. It is necessary that a utility earn an equitable return on its invested capital, not only to compensate the contributors for their investment, but to maintain a sound credit rating and attract new capital. The classes of capital employed by utilities may include long term debt, floating (short term) debt, preferred stock, and common stock.

The determination of an equitable return to a utility's capital contributors involves three components. First, with respect to the rate

base, the assets that are used in providing the electrical service must be determined. Second, a value must be placed on those assets. And, finally, a fair rate of return must be established.

The inclusion of specific assets in the rate base depends, to an extent, on the policies established by individual PUCs. While certain assets are easily determinable and always included, others are less certain and subject to a considerable amount of controversy. Included in the latter category are obsolete assets (discussed above) and the amount expended on new facilities that are not yet providing the electrical service (discussed below).

In general, electrical utilities are allowed to include any tangible assets that currently contribute to the production of electricity. That includes land, buildings, and equipment. Property that is used to produce a parallel utility service (e.g., natural gas facilities), unowned property, and non-electricity producing assets are not included. Currently-used property includes overhead construction costs, such as legal fees, insurance, and taxes. Additionally, working capital and intangibles (e.g., water rights, leaseholds) are generally considered to be a part of the rate base.

Once the individual items of property are determined, their value must be established. In general, individual PUCs allow rate base valuation on the basis of depreciated original cost, fair value, or some measure of reproduction cost. Depreciated original cost is simply the actual or historical cost of assets net of the accumulated depreciation reserve. Reproduction cost, on the other hand, poses other problems. If it is used, a proper measure must be established. General price indices, and construction cost indices may be used to inflate the historical cost of the property.

Technically, the rate of return compensates capital contributors of an electric utility for their investment and, as such, represents the amount of money earned by the company, over and above operating costs, expressed as a percentage of the rate base. In general, the allowable return must be fair and, therefore, cannot be so restrictive so as to represent a confiscation of property. Furthermore, the allowable rate

is a function of time and geography and varies with alternate investment opportunities and the general economic climate. The latter condition highlights the fact that, under the regulatory process, a regulated electric utility is not guaranteed a fair return on its investment, but simply protected from arbitrary action of the regulatory bodies. They are not protected from normal business hazards.

In actuality, the allowed rate of return is meaningless as a single percentage. The percentage is only meaningful when evaluated in the context of the rate base valuation method utilized. A ten percent allowed return on an original cost rate base of \$500 million, for example, is much different than that same ten percent return on a reproduction cost rate base of \$750 million. Three studies of the rate base-rate of return relationship in the electric utility industry illustrate this point. In a study published by Stuart in 1962,⁸ it was concluded that the PUCs that utilize reproduction cost rate bases partially offset the effect of a larger rate base by allowing lower rates of return. The interactive effect of larger rate base and lower return, however, was to permit higher revenue levels in reproduction cost and fair value jurisdictions. Pike corroborated Stuart's findings with a study published in 1967.⁹ In a more recent study by Primeaux, published in 1978,¹⁰ the conclusion was that "... there is no difference in (actual) earnings according to method of rate base determination." A partial explanation provided was that "any downward bias in profits injected because of a particular rate base method must (in practice) be partially offset by regulators allowing larger rates of return." Primeaux's study reflected a comparative examination of electric utilities in states that utilized original cost, fair value, and reproduction cost valuation methods for the years 1967 and 1973.

In general, PUCs take into account the cost of capital and earnings of other industries with commensurate risks in their determination of the allowable rate of return for an electric utility company. The former standard, as used in practice, is simply the weighted average cost of the classes of capital used by a utility — long-term debt, short-term debt, and common and preferred stock. The latter criterion, related

to the cost of capital, deals with alternate investment opportunities of the equity owners in enterprises with similar risks.

Under the cost of capital standard, the appropriate components of the capital structure and their corresponding costs must be determined. Since the interest rate on debt is generally lower than the cost of (return to) equity capital, the overall cost of capital is generally higher for utilities with a low debt-to-equity ratio than for firms with a high debt-to-equity ratio. The problem for PUCs in the rate-making process is to determine an appropriate capital structure on which the cost of capital is to be based: the existing structure, a typical structure, or an ideal one.

In actuality, there is no consensus among PUCs as to which structure is optimal. Some commissions adopt the actual capitalization existing during the rate determination, while others propose and utilize an ideal or hypothetical one.

Once the structure is determined, however, the problem of assigning costs to the various components arises. For debt capital, state commissions generally use the imbedded cost of debt (i.e., the actual fixed charges on existing obligations), or the imbedded cost in concert with current costs for new or contemplated issues. The cost of preferred stock is determined simply by its annual dividend requirements. The cost of equity capital, however, poses more severe problems.

The cost of equity capital does not reduce to any standard mathematical formula. If one assumes that investors purchase utility equity securities on the basis of utility earnings, then the earnings-price ratio of common securities (i.e., earnings per share of stock divided by average market price of stock) is a fair measure of cost. Moreover, if it is assumed that investors purchase the securities on the basis of dividend yields, then the dividend-price ratio (i.e., ratio of annual dividends per share to average market value per share) is an appropriate gauge. The potential for growth of earnings and dividends is reflected in the pay-out ratio, or the ratio of dividends-per-share and earnings-per-share. The difference between the earnings rate and dividend rate is the amount available to the utility for reinvestment.

In practice, PUCs rely to varying degrees on all three measures of a utility's financial performance, since all of them are inter-related. Consequently, the estimates of an individual utility's cost of equity capital can vary significantly and the final determination is a function of the interaction between a number of forces, including the position of the PUC, the financial condition of the individual utility, and the prevailing economic climate.

This rather simplistic framework of the factors involved in the economic regulation of the electric utility industry is complicated by a number of other issues. Foremost among them are the presence of a lag or time-adjustment factor in the regulatory process; the myriad theoretical and pragmatic problems that arise in accounting for new construction expenditures; and, finally, the federal income tax effects of financial accounting-to-tax accounting "timing differences" and other differences between book and tax income. These three issues will be examined in turn.

Regulatory Lag

Regulatory lag is the term associated with a phenomenon that typically occurs in the rate-making process wherein future rates, derived from a rate hearing, are based on current period costs, i.e., regulatory lag is the time between filing for a rate increase and the final action of the regulatory authority. In a period of rapidly rising production costs associated with providing the electrical service and the presence of regulatory lag, the utilities' income is "squeezed" by a rate structure that is determined on the basis of costs incurred in the past. Industry observers have interpreted the phenomenon in a number of ways. Some say that it promotes efficiency because the utility will constantly attempt to utilize resources efficiently in the face of a fixed rate schedule and rising costs. On the other hand, others have opined that it not only distorts the efficient functioning of an individual utility, but it promotes inefficient use of scarce resources. As for the former argument, a utility may delay the introduction of a technological improvement until after the next rate hearing out of fear that the attendant lower costs will depress allowable revenues. Inefficient use of resources is promoted because market prices

do not reflect the true cost of producing the service and, under the market price's allocation function, too much electricity will be consumed.

The interpretation placed on the economic effects of regulatory lag notwithstanding, a number of fragmented and inconsistently applied attempts to ameliorate the problem have been promulgated. A simple approach is simply to adjust the allowed return on invested capital upward in recognition of the time lag in the rate-making process. The proliferation of fuel adjustment clauses in the past decade has also contributed to partially offsetting the effects of the time lag. In this setting, increases in fuel costs have been passed immediately to consumers in the billing process. Since fuel costs are the largest single item of operating costs for many utilities, the effect is to significantly reduce regulatory lag.

An expansion of the fuel adjustment clause in the form of cost-of-service indexing has been utilized in isolated cases. Under this procedure, electricity rates are adjusted periodically without a formal hearing in order to incorporate the impact of rising costs. Similarly, the use of projected costs — rather than historical or "test year" data — has been utilized to determine future allowable revenues and, consequently, rate levels.

New Construction Expenditures

As the introduction to this report noted, there has been a prolific increase in electric utility expenditures for capital projects in recent years due to the volume of new capacity additions in concert with a pronounced increase in construction costs. Electric utilities can generate the funds for these expenditures either externally or internally. External sources of funds include sales of additional debt and sales of additional equity (both common and preferred stock). The constraints to external financing include the conditions of the capital markets at the time of financing, the cost of alternative forms of financing, and the need to maintain an adequate debt-to-equity ratio. Internal sources of funds, on the other hand, are generated principally through savings (retained earnings), depreciation, and deferred income taxes (to be discussed below).

Assuming for the moment that an individual utility can generate the capital for a new construction program either internally or externally, a

problem of critical importance arises with respect to the accounting for, and timing of, compensation for capital expended on new plant and facilities. The discussion of economic regulation in the electric utility industry presented above established that revenue generation and, therefore, rate-making in the industry is based on the recovery of costs incurred in providing the utility service. One of the distinguishing characteristics of new construction activities, however, is the ever-increasing lead times between the initiation of construction activity and the time when the new facilities contribute to provision of the electrical service. The problem in rate-making, therefore, is the determination of the time period when an electric utility is allowed to recover the cost of on-going, unfinished construction activities.

In general, a new construction program generates costs related to labor, material, and overhead construction items (e.g., legal fees, insurance, taxes). Under generally-accepted financial accounting standards, these construction costs are capitalized during the construction period in a Construction Work in Progress (CWIP) account and the cumulative amount of expenditures on an incomplete construction activity is carried on the balance sheet as an asset. When the facility is completed, the accumulated CWIP for the project is transferred to an appropriate property account and depreciated over its (estimated) useful life.

An additional cost incurred in an on-going construction activity is the capital charges associated with financing the new construction program. If the issuance of debt is the financing method chosen, the cost of capital is simply the service charge on the bonds. If the construction program is financed out of the stockholders' equity — retained earnings, for example — the cost of capital is reflected in the opportunity cost of utilizing the funds in an alternate endeavor.

While the financial accounting treatment of "out-of-pocket" expenditures on labor, materials, and overhead construction costs for new construction activities is universally accepted by PUCs, the accounting treatment of compensation for capital service charges is much more controversial, and, consequently, has resulted in diverse approaches. Basically, there are two approaches to compensating utilities for capital service charges:

(1) Allowing CWIP in the rate base, or (2) Disallowing CWIP in the rate base, but imputing a return (cost) to the capital utilized.¹¹

Under the first approach, the entirety of CWIP for a given accounting period is included in the rate base. As a result, the utility is allowed to earn a current return on the funds expended for new construction activity. Theoretically, at least, the inclusion of CWIP in the rate base affords a utility the opportunity to generate a cash flow currently, and the cost of capital is recovered in the present period. Current rate-payers, then, bear the financing of a not-yet -complete construction program.

Under the second method, disallowing CWIP in the rate base, a return for the cost of capital — called the Allowance for Funds Used During Construction (AFUDC) — is artificially constructed. For the debt portion, the actual cost of the service charge is utilized; while, for the equity portion, the opportunity cost is imputed utilizing a methodology similar to the one used in determining the equity portion of the rate of return. In the current period, the total financing cost is charged to CWIP and credited to income (under current accounting practice the debt portion reduces current interest expense, while the equity portion is reflected as Other Income). From a financial standpoint, AFUDC does not generate a current cash flow for the utility. Cash is generated when the construction activity is completed and the asset (formerly CWIP) is depreciated. The total amount of AFUDC, however, is reflected as income in the current period's operational results.

In actual practice, an individual PUC may allow a portion of construction expenditures (CWIP) in the current period's rate base and disallow the remaining amount. Under these circumstances, AFUDC is computed on the fraction not allowed in the current period's rate base.

A number of issues arise when discussing the alternative treatment of construction expenditures, not the least of which are questions of equity. By allowing CWIP in the rate base, a PUC permits an individual utility to

generate a current cash return on the construction program, but effectively makes current electricity consumers bear the burden of financing costs associated with plants that contribute to providing the electrical service in the future. On the other hand, by disallowing CWIP in the rate base, the costs of financing new construction activities are deferred to years when the facilities are actually used, but the utility must then generate the ever-increasing capital service charges out of the current period's operations.

Disallowing CWIP in the rate base poses significant problems for a utility attempting to utilize the capital markets for new sources of funds. Although AFUDC represents current period income for financial accounting purposes, it does not generate a current cash flow and, therefore, is generally viewed as "soft earnings" by the investment community.

Accounting for Federal Income Tax Effects

The complications of accounting for construction expenditures in a financial regulatory framework are exacerbated by the treatment of the federal income tax effects for privately-owned utilities. (Publicly-owned utilities are not subject to federal income taxes.) In addition to the federal income tax effects of construction-related items, the federal tax effects are complicated by depreciation accounting, the investment tax credit, and other "timing differences" and "permanent differences" between financial accounting and tax accounting. Financial (book) accounting is required by the Federal Energy Regulatory Commission, but may or may not be the method used to develop records for the financial community to evaluate the worthiness of a utility for investment purposes.

"Timing differences" between financial (book) accounting and tax accounting arise when expenses are recorded for tax purposes in one year and for book purposes in another year or, alternatively, revenues are reported for tax purposes in one year and for book purposes in another. Over a sufficient number of years, the applicable items of revenue and/or expense have the same net effect on both financial and tax accounting. However, in the short term differences arise.

One of the primary timing differences for electric utilities — and, indeed, for all business entities — is depreciation of physical assets. With passage of the amended Internal Revenue Code in 1954, business firms were allowed to utilize accelerated depreciation rates (e.g., sum-of-the-years digits method; declining balance method) for the purpose of computing their current federal income tax liability. Both of these methods weight the early years of an asset's life with a larger depreciation charge than the straight-line method (i.e., equal charges over the asset's useful life) under the assumption that an asset makes a larger contribution to revenues during the earlier portion of its useful life than in later years. Since the Federal Energy Regulatory Commission requires straight-line depreciation methods for financial (book) accounting purposes, a difference arises between book depreciation expense and tax depreciation expense. During the early years of an asset's life, tax depreciation is greater than book depreciation and consequently, the current federal tax liability is less than that reflected as "Federal Income Tax Expense" in the financial records. On the other hand, during the later years of an asset's life, book depreciation expense is larger than tax depreciation expense and the actual federal tax liability is greater than that reflected on the books.

Besides depreciation accounting, a number of other items of revenue and expense lead to timing differences between book accounting and tax accounting. The debt portion of AFUDC, mentioned above in connection with accounting for new construction expenditures, while capitalized in the years of incursion and "written off" as depreciation expense over the useful life of the asset once it comes "on line", is deductible for tax purposes in the year in which it was incurred. Consequently, the deduction for tax purposes "turns around" (i.e., is added back to book income) over the useful life of the asset.

Similarly, certain portions of an asset's cost that are capitalized for book purposes during the construction phase and depreciated over the asset's (estimated) useful life once the asset comes "on line" are allowed to be deducted for tax purposes in the year in which they are incurred. Pension costs and payroll taxes are examples of this type of deduction. These expenditures represent a "timing difference" between the period

when they are deducted for tax purposes and charged to income for financial accounting purposes. Again, in nominal terms, the allowable deduction nets to zero over the asset's useful life.

Another related timing difference concerns assets that have different useful lives for book and tax (shorter) accounting. Here again, depreciation for tax purposes is larger than book depreciation in the asset's early life but "turns around" over the useful life of the asset. Other timing differences that have the same effect as the asset-related ones include the differential treatment of sales or exchanges of property and damage from natural disasters. Finally, timing differences can arise because of the difference between accrual and cash accounting. For example, a utility may accrue payroll liabilities on a uniform basis for book purposes. For federal tax purposes, however, only the actual amount of salaries paid is an allowable deduction. Consequently, a timing difference arises between book and tax accounting.

Contrasted with timing differences between book and tax accounting are "permanent differences." Permanent differences arise when items of income or expense are includable or deductible for tax purposes but never impact the books, or vice versa. For example, the interest income generated from a utility's investment in tax-free municipal securities is reflected in financial income, but is never a part of its income for tax purposes. Similar to a timing difference, there is a disparity between income for book and tax purposes; however, in this case, the difference is permanent because interest on municipal bonds will never be incorporated as part of taxable income for purposes of determining a utility's federal tax liability.

Similarly, the imputed return to (cost of) the equity portion of AFUDC is a permanent difference between financial accounting income and the taxable income utilized for computation of a utility's current federal income tax liability. Unlike the debt portion of AFUDC which is a legitimate "out-of-pocket" cost to the utility and deductible currently for federal tax purposes, the portion of AFUDC attributable to equity financing does not impact the computation of the federal tax liability or, consequently, the computation of federal income tax expense for financial reporting purposes. This is true in the year that the imputation

originates and in the year in which the asset comes "on line" and is reflected as depreciation expense for financial accounting purposes. In the accounting sense, therefore, AFUDC-Equity represents a permanent book-to-tax difference.

A question of paramount significance for rate-making purposes in an expanding electric utility industry is the treatment of the current federal tax benefits resulting from asset-related timing differences (e.g., tax depreciation greater than book depreciation). In utilities that are expanding via the construction of new facilities, the tax benefits may be substantial. Indeed, it can be argued that in utilities where constant growth is the norm, the allowable deduction for tax purposes will always be larger than depreciation expenses for financial accounting purposes.

Two methods of treating the federal tax benefits are generally used by PUCs. The first method allows the utility to defer the tax benefits and amortize the amount over the useful life of the asset. Or, accounting-wise, a charge is made to current operations ("Provision for Deferred Taxes") and a corresponding credit is made to a deferred liability ("Reserve for Deferred Taxes"). When the timing difference "turns around", the reverse entry is made (i.e., income is credited and the reserve charged). Under the second method, termed flow-through accounting, no deferred reserve is established. The current tax benefits are not amortized, but impact the financial accounts and, therefore, rate-making in the current period.

A similar option for PUCs exists with respect to the Investment Tax Credit (ITC). The ITC, first enacted in 1962, has a storied history. It was suspended in 1966, reinstated in 1967, terminated in 1969, reinstated in 1971, and amended in 1975. Through all of its terminations and revisions, its primary purpose was to be an incentive for corporate taxpayers to replace, modernize, and expand productive facilities. To this end, its provisions specify that taxpayers are allowed a dollar-for-dollar credit against their current federal income tax liability for a specified percent of the amount of investment in qualified plant. For electric utilities, the applicable percentage was originally limited to three percent but increased to four percent in 1971. With the amendments enacted in 1975,

however, the credit was increased to ten percent of the investment in qualified property.

From an accounting standpoint, the ITC represents a permanent savings in taxes rather than a deferral. The pertinent rate-making question concerns the year in which tax expense should be reduced for financial accounting purposes and, hence, rate-making purposes.

There are two accounting methods utilized to reflect the impact of the ITC on financial accounting records. The first method requires a deferral of the credit in the year it is realized. The amount of the credit is then amortized over the useful life of the property. The rationale behind this approach is that the ITC represents a reduction in the cost of property and, therefore, should impact financial income as the asset in question is depreciated. The second method allows the totality of the credit to impact book income the year in which the asset is placed in service on the assumption that the credit reduces the effective income tax rate in the current year and should be reflected as such in the current financial tax expense.

Table 1 presents a representative example of the federal tax-related issues discussed above. The first subsection of the table, called "Results of Operation" is, in essence, a condensed income statement. The second section of the table, termed "Tax Adjustments", details the adjustments made to book and tax income that are attributable to permanent and tax timing differences. The last section presents the actual tax calculation. The column headings detail the applicable tax expense accounts for book and tax accounting in a utility that normalizes the impact of all timing differences and the investment tax credit.

For the sake of simplicity, it is assumed in Table 1 that the utility brought one asset "on line" in the current period and that asset is the only one presently utilized (and depreciated). The asset was constructed in prior years at a total cost of \$100,000 and, since it is further assumed that CWIP is not allowed in the rate base, the value of the asset includes AFUDC. The amount of capitalized AFUDC is assumed to be \$10,000: \$4,000 attributable to debt financing and \$6,000 related to equity financing. It has an estimated useful life of 10 years with no salvage

value and, utilizing a straight-line depreciation rate, annual depreciation expense for book purposes is \$10,000. The sum-of-the-years digits method is utilized for tax depreciation. Furthermore, with an ITC rate of 10%, it is assumed that a \$9,000 deferred ITC liability was established in prior years and will be amortized in equal amounts over the life of the asset. The deferred accumulated deferred ITC liability is calculated on the basis of the cost of the asset less AFUDC; i.e., $(\$100,000 - \$10,000) \times 10\%$.

Moreover, it is assumed that the utility initiated construction on another qualified asset with a \$200,000 "out-of-pocket" expenditure in the current period. Of this \$200,000 capitalized expense, \$10,000 is attributable to expenditures that are deductible currently for tax purposes (e.g., payroll, pensions). Also, \$20,000 of capitalized interest (AFUDC) was calculated on the new construction activity (AFUDC - Debt = \$8,000 and AFUDC - Equity = \$12,000).

The first portion of Table 1 details the pre-tax results of operations for the utility as they would appear on the income statement. The first item appearing as a "Tax Adjustment" in the second section represents a "turn around" of a timing difference attributable to the debt portion of AFUDC calculated on the asset presently in service. Since AFUDC was capitalized (and depreciated currently) and becomes part of the asset's depreciable value and, furthermore, the debt portion is deducted for tax purposes in the year it is capitalized, the \$400 adjustment reflects one-tenth of total AFUDC - Debt that was capitalized and deducted for tax purposes in prior years. Analogously, the \$8,000 of AFUDC - Debt deducted for tax purposes in the current period reflects the amount of debt service charge attributable to the on-going construction activity. Once the new asset comes "on line," the cumulative amount of AFUDC - Debt will "turn around" over the life of the asset.

AFUDC - Equity is similarly segregated into two parts. However, since the equity portion of AFUDC represents a permanent book-to-tax difference, no deferred liability was established in prior years and, of course, none is established in the current period.

The fifth item appearing as a "Tax Adjustment" deals with accelerated depreciation for tax purposes. Note that for financial statement purposes a \$10,000 straight line depreciation charge has been incorporated. Since the sum-of-the-years digits method is utilized for tax purposes, the depreciation charge for federal income tax purposes is \$18,182. Consequently, an additional \$8,182 of depreciation expense is deducted for tax purposes. This incremental amount is deferred in the current period and will begin to "turn around" as the depreciation for tax purposes becomes less than \$10,000.

The sixth adjustment originates with the accounting treatment of construction activity. Payroll expenses are capitalized as part of the asset's cost. However, these expenditures are deductible currently for tax purposes. Consequently, for book purposes, the tax effect is deferred until the asset comes "on line" and is depreciated. These adjustments then "turn around" over the useful life of the asset.

Income from Municipal Bonds is a permanent difference also and, similar to the tax treatment of AFUDC — Equity, is incorporated as part of financial income but no tax affect is calculated for book or tax purposes.

The third section of Table 1 details the actual tax calculation for book and tax purposes and the consequent impact on the deferred accounts. The ITC generated in the current period represents application of the ITC rate against the cost of construction activity net of AFUDC (i.e., $10\% \times \$200,000$). Since it is assumed that the utility operates under tax normalization, the credit is applied to the current "tax" calculation, but deferred for book purposes until the asset is actually placed in service. The amount of ITC generated in past years for the asset that is presently in use (i.e., \$9,000) is now amortized over its service life (10 years). Therefore, book income tax is reduced by one-tenth of the deferral.

Based on the principles of tax normalization, the accounting entry that reflects the results in Table 1 would be to charge income for the current income tax expense (\$1,996), deferred income tax expense (\$11,860), and the deferred ITC (\$19,100) with offsetting entries to current taxes payable, deferred income taxes, and the deferred investment tax credit,

respectively. Under this scenario, the amount of federal taxes allowable for rate-making purposes and, therefore, for the determination of revenues, would be the total book amount reflected in Table 1, or \$32,956. Since the actual current federal tax liability is only \$1,996, current rate-payers are, in essence, providing the utility with an interest-free loan of \$30,960 (the sum of the deferred components) to be "paid back" when the timing differences turn around and the deferred investment tax credit is amortized.

Although the results presented in Table 1 reflect the tax effects under normalized accounting, the financial accounting tax effect under the flow-through method is easily determined from the results of Table 1. If the utility represented in Table 1 was not allowed to defer income taxes or the investment tax credit but was required to "flow-through" all current tax benefits, the amount of income tax expense for financial accounting purposes would be \$1,996 as reflected in the "Tax" Column in Table 1. Under this circumstance, the amount allowable for rate-making purposes would be lower than under the normalization method and, consequently, current rate-payers would reap the entire benefit of the favorable federal tax effects.

Clearly, if only a portion of the federal tax benefits were allowed to be "flowed-through", the impact on current rate-payers would be somewhere between the two extremes that were delineated above.

Table 1. Computation of federal income tax expense;
deferral basis; representative example

	Book	Tax	Deferred Inc. Taxes	Deferred ITC
Results of Operation:				
Operating Revenues	\$1,000,000	\$1,000,000		
Depreciation Expenses	(10,000)	(10,000)		
AFUDC - Debt	8,000	8,000		
- Equity	12,000	12,000		
Income from Municipal Bonds	15,000	15,000		
Other Expenses (Net)	(925,000)	(925,000)		
Income Before Taxes	100,000	100,000		
Tax Adjustments:				
1. Prior Years' AFUDC - Debt		400	\$ (400)	
2. - Equity	600	600		
3. Current Year's AFUDC - Debt		(8,000)	8,000	
4. - Equity	(12,000)	(12,000)		
5. Depreciation		(8,182)	8,182	
6. Payroll Expenditures - New Asset		(10,000)	10,000	
7. Municipal Bonds	(15,000)	(15,000)		
Taxable Income	73,600	47,818	25,782	
Tax Calculation:				
Tax @ Statutory Rate (46%)	33,856	21,996	11,860	
ITC-Generated (New Construction)		(20,000)		\$ 20,000
ITC-Amortized (From Prior Years)	(900)			(900)
Total Tax Expense	\$ 32,956	\$ 1,996	\$ 11,860	\$ 19,100

3. SPECIFICATION OF THE NUFS MODEL

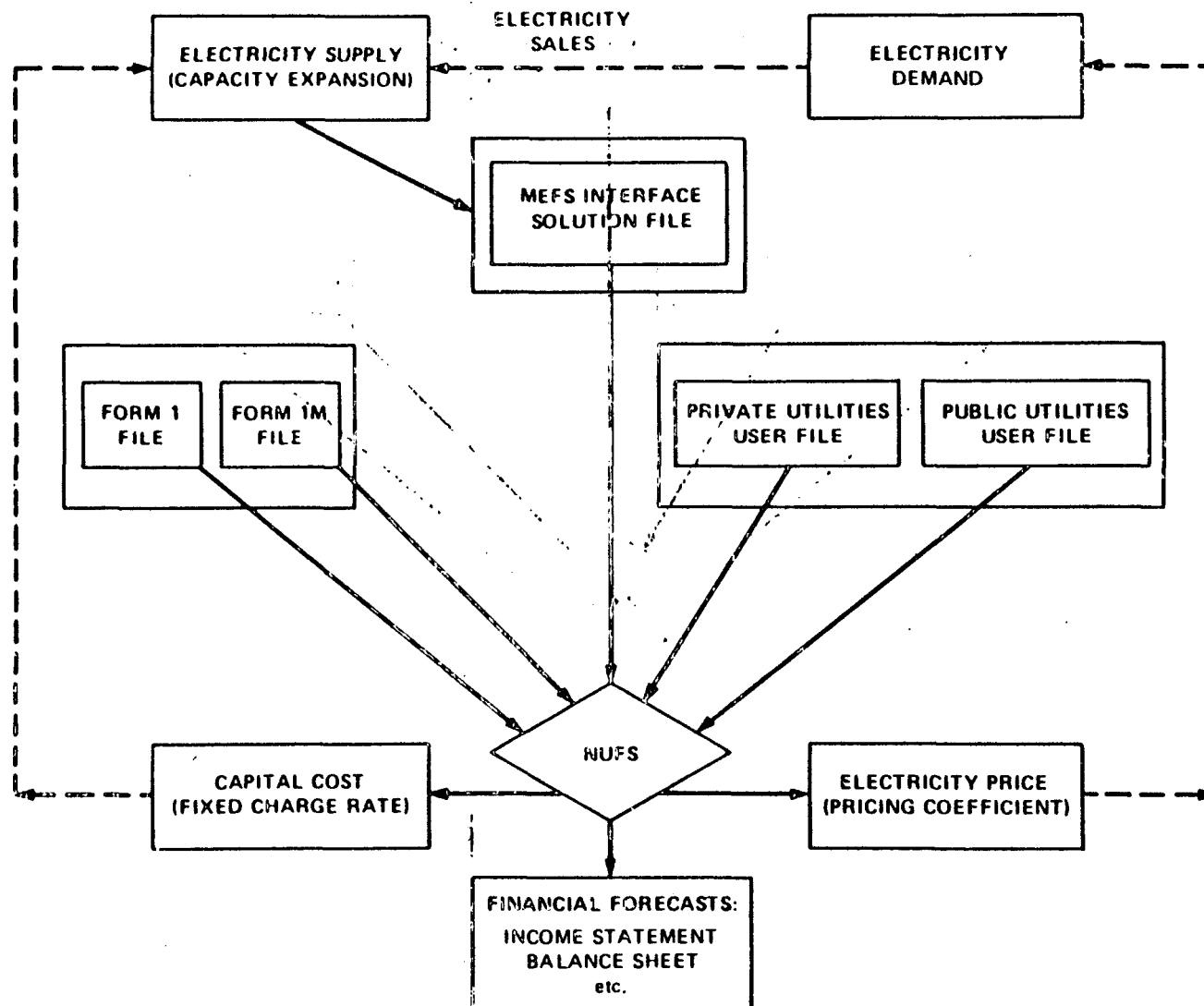
Information Flow and Implementation of the Code

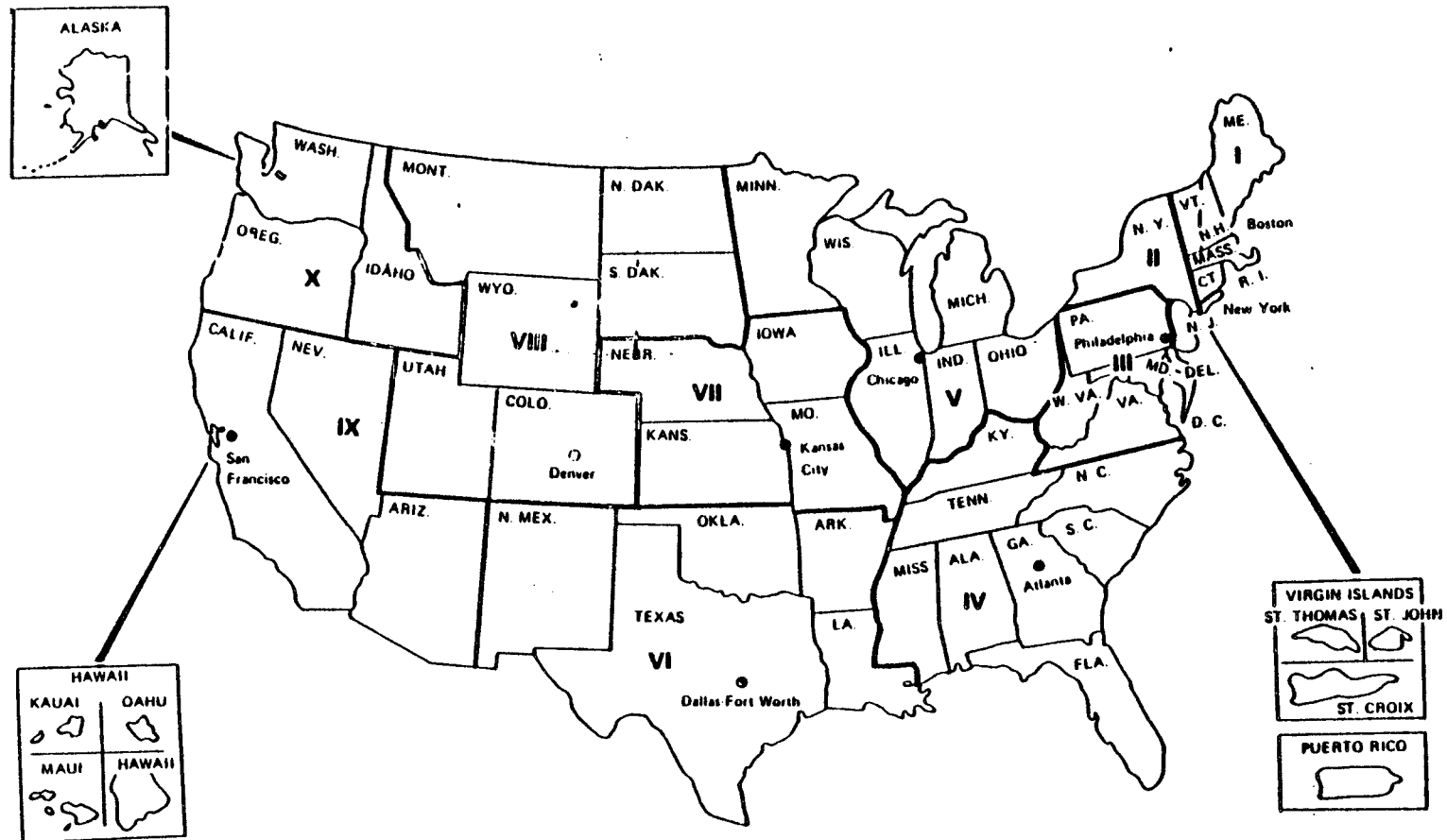
The NUFS code is an amalgamation of sub-models that was constructed for the purpose of forecasting the financial viability of the electric utility industry. Figure 1 presents a schematic representation of the flow of information in the NUFS system. The NUFS code, represented as a diamond in Fig. 1, derives inputs from the Mid-Term Energy Forecasting System (MEFS), a large scale, medium-term energy forecasting model; the Federal Power Commission (now the Federal Energy Regulatory Commission) public- and privately-owned computer tapes of financial information on individual companies in the electric utility industry (Form 1 File and Form 1M File in Fig. 1); and a significant amount of user-supplied financial regulatory information, noted as the Private Utilities and Public Utilities User Files in Fig. 1.

A detailed background on each of these three sources of data inputs is provided in the following three sections. A detailed description of the NUFS solution scheme follows the discussion of data sources.

In its entirety, the NUFS code is presently integrated as one component of the MEFS' system. As part of its output, MEFS provides a forecast of the electric utility industry's investment in generation, transmission, and distribution facilities; the forecasted operation, maintenance, and fuel costs for the industry; and, finally, the forecasted amount of electricity generation. Given the MEFS' solution, the NUFS code projects the financial position of electric utilities for eleven aggregated geographical areas: the ten DOE regions and the aggregate U.S. Figure 2 delineates the level of aggregation involved in the NUFS specification. In addition, for each of the eleven regions, NUFS output is segregated between IOUs, POUs, and the sum of the two.

It must be noted, however, that the NUFS code has the capability of forecasting the financial performance of any individual utility. A detailed assessment of that capability is beyond the scope of the present analysis and, therefore, will not be incorporated as part of this report. Furthermore, with minor modification, the NUFS system can aggregate the





financial performance of electric utilities to sub-DOE region levels (e.g., individual state levels). Again, this capability will not be analyzed.¹² The present study only encompasses execution of the NUFS code for the ten DOE regions and their aggregate as part of the interface with MEFS.

Appendix A contains the results of an execution of a sample problem utilizing the NUFS code. The results in Appendix A reflect model output for the ten DOE regions and their aggregation. As the information presented in Appendix A details, the forecasted financial performance derived from the execution of the NUFS code is reflected in three primary financial statements, their derivative financial ratios, and miscellaneous notes to the financial statements. The NUFS output includes an income statement, a balance sheet, and a flow-of-funds statement for investor-owned electric utilities (IOUs), publicly-owned electric utilities (POUs) and their total for each of the ten DOE regions and the aggregate U.S. The financial indicators derived from the basic financial statements include interest coverage (i.e., the ratio of financial income to the interest on debt); AFUDC as a percent of net income; and external financing requirements. Additionally, NUFS provides revenue generation under four user-supplied lag scenarios (no lag, one-year lag, one and one-half year lag, and two year lag options); a reconciliation of financial (book) accounting to tax accounting; the average price of electricity; and an analysis of the rate base, rate of return, and revenue requirements.

Under this formulation, the primary purpose of NUFS is to "assess" the electric utility capacity expansion profile derived from the MEFS solution. The capabilities of NUFS, however, are multi-dimensional. Through use of various options that are embodied in the code, it is possible to project the fixed charge rate (i.e., capital cost) and pricing coefficients (i.e., electricity prices) that are implicit in any projection of capacity additions from MEFS under alternate user-provided regulatory assumptions. From the broken lines in Fig. 1, the values of these variables can, in turn, be utilized in an "iterative process" as explanatory variables in the determination of capacity expansion and electricity demand, respectively.

The National Utility Regulatory Model (NUREG), under development by ICF, Incorporated, is formulated to perform this iterative process for the capacity expansion program emanating from the National Coal Model (NCM) and, alternatively, other electric utility capacity expansion models (including the electric utility sub-model in MEFS). Unfortunately, NUREG — or, for that matter, any type of formal "feedback link" from NUFS to MEFS — was not available for use in this evaluation.

The users of NUFS at EIA, however, have, in effect, accomplished the task of "closing" the system presented in Fig. 1 by "manually" incorporating the fixed charge rate and pricing coefficients into the supply side and demand side of MEFS, respectively.¹³ That is, given a MEFS solution, the fixed charge rates and pricing coefficient are derived from the execution of NUFS and "manually" incorporated into MEFS, whereupon MEFS is re-executed. This procedure performed at EIA which "closes the loop" between NUFS and MEFS is represented by the broken lines in Fig. 1. The actual procedure by which the output of NUFS is used in conjunction with MEFS by EIA is not addressed in this evaluation and, moreover, to our knowledge, the procedure is not documented.

Instructions for implementation of the code and a discussion of the various options for regional and national financial analysis in the NUFS system are contained in the documentation accompanying the model.¹⁴ Execution of the code requires user-supplied inputs for each region under analysis, segregated by IOUs and POUs. And, since the MEFS output and base-year financial information (Form 1/Form 1M tapes) can be aggregated to any of the eleven regions (ten DOE regions and the aggregate U.S.) by ownership type (IOUs and POUs), it is possible for the user to generate financial outputs separately for any of the eleven regions differentiated between publicly-owned and privately-owned electric utilities.

The three-volume documentation accompanying the NUFS code contains a detailed background on financial regulatory issues; discussion of the most important equations implemented in the code and some of the assumptions

underlying their derivation; software/hardware information; a user guide; discussion of information flows; and, finally, a sample problem. Although the documentation does not specify every equation in detail, the information provided is sufficient to understand the underpinnings of the modeling framework. The information contained in the users' guide is sufficiently detailed for a prospective user to understand the JCL and, consequently, to execute the code. In totality, therefore, it is the evaluators' opinion that the documentation is adequate for understanding and implementing the NUFS model.

The calculation procedure in NUFS is performed separately for each region segregated between private utilities and public utilities. Since NUFS is comprised of a series of financial accounting relationships applicable to each region and ownership type, and no numerical solution techniques are used, questions regarding uniqueness of solution, degree of solution convergence, and the behavior of successive iterations in a solution algorithm are not relevant for the purposes of this report.

After a considerable amount of experience with execution of the code, it is concluded that approximately ten days are required for an experienced IBM programmer to become familiar with the NUFS code in its relationship to the MEFS interface (i.e., multi-utility analysis). Since analysis of individual electric utilities or sub-DOE region aggregations were beyond the scope of this report, no conclusion can be stated with respect to familiarization time for those types of analyses.

Finally, the estimated computer running time for a complete one-region analysis (POUs, IOUs, and their total) is approximately three seconds CPU time on an IBM 360/91 computer. Since the calculation procedure in NUFS is performed separately for each region, an execution time of $3n$ seconds is required for an n -region problem (where $n \leq 11$).

User-Supplied Inputs

Table B.1 in Appendix B presents in detail the variables that must be assigned values by the user for execution of the NUFS code. In addition, the table presents the value of the variables for the base case problem (aggregate U.S. only) and the notation assigned by the NUFS code. Some of the variables are not required for publicly-owned utilities, and that information is explicitly noted with the designation "NA" in Table B.1.

The user-supplied variables in Table B.1 have been categorized as those pertaining to New Construction Expenditures; Tax-Related Issues; Depreciation Variables; the cost of capital and its structure; the discount and inflation rates; the base year; and five financial options. Additional variables need to be specified if the user wishes to use NUFs for analysis other than aggregation to the DOE region level. The exact nature of those variables, which include information on electricity customers and transmission and distribution costs is detailed in the documentation of the model.

Some of the most important variables in NUFs for the analysis of financial regulatory policies are contained under the heading of New Construction Expenditures in Table B.1. The first two variables relate to the asset types that emanate from MEFS (16 different assets, 12 production plants), while the third variable, J1, is an assumption relating to the month a new asset begins operation. As footnote one points out, the variable CONPER, percentage of construction completed each year, details the user's assumption regarding the fraction of a plant under construction that is completed each year.

The last three variables dealing with new construction, AFUDCR, CWPPER, and OFFSET, are particularly important since they reflect the user's assumptions regarding the accounting treatment of new construction activity. OFFSET is a binary choice variable that determines whether the user has specified the OFFSET method of accounting or not.¹⁵ The variable AFUDCR represents the user's assumption with respect to the capital return a utility is allowed to generate on new construction expenditures, while CWPPER represents the percentage of CWIP allowed in the rate base. AFUDCR and CWPPER play a prominent role in the determination of the book value of new assets. For example, if the total amount of CWIP generated by a utility is allowed in the rate base currently, the value of new assets should not reflect any capitalized interest. In this case, the return on capital used for new construction is generated currently. At the other extreme, if no current-year CWIP is allowed in the rate base, new construction expenditures should include the entirety of capitalized interest. The particular values of 8.23% and 14.2% for AFUDCR and CWPPER, respectively, were based on the individual 1978 annual 10-K filings of the privately-owned electric utilities.

The second section of Table B.1 reflects the user's assumptions regarding individual tax rates and the treatment of federal tax benefits emanating from book-to-tax accounting differences. Of particular importance is the specification of the latter two variables, FLPR1 and FLPR2, which, respectively, pertain to the percentage of tax benefits of accelerated depreciation and the I.T.C., and the debt portion of AFUDC which is flowed-through to current consumers rather than deferred and amortized later.

The user-supplied variables in the third category of Table B.1, depreciation-related variables, deal primarily with the book and tax rate of use of both old and new assets. The variable T1, years of service, is especially important since it defines the age of old assets. The specification of T1 is necessary because old assets are not delineated by specific asset type but, instead, book value is provided *in toto* for each asset type. Rather than arbitrarily specifying the years of service for any asset type, it is possible to obtain some information from published sources. For example, an estimate of the average years of service life can be obtained for any asset class by dividing accumulated depreciation for that asset by the amount of depreciation expense for the current period.

The variable DEPFAC is simply a binary variable that takes on the value 1 or 2 in the calculation of the declining balance accelerated depreciation rate. Two represents the calculation of double declining balance accelerated depreciation.

The information presented under Depreciation-Related Variables in Table B.1 is sufficient to derive the accelerated depreciation rates that are used for the calculation of tax depreciation in NUFS. For "old assets" (i.e., assets that were utilized before the first forecast period), it is assumed that only the sum-of-years digits (SYD) method can be utilized. For "new assets" (i.e., assets that come "on line" in the forecast period), either the sum-of-the-years digits or a declining balance (DB) depreciation method can be used for tax purposes. Furthermore, with use of the variable DEPFAC in Table B.1, the user can specify a single or double declining balance method.

The SYD tax depreciation rate, $TDRATE_t$ is computed as follows for a new asset coming on line in the forecast period:

$$TDRATE_t = \begin{cases} \frac{[TXSY2-(t-JYR)]}{\frac{[TXSY2(TXSY2+1)]}{2}}, & t = JYR, JYR + TXSY2 - 1 \\ 0 & t = (JYR+TXSY2), (JYR+SY2-1) \end{cases} \quad (1)$$

where $TXSY2$ and $SY2$ are the user-specified tax life and book life, respectively, and JYR represents the year that the plant comes into service. The calculation of SYD for old assets is similar. The only difference is that $(T1-1)$ is substituted for $(t-JYR)$ in the numerator of Eq. (1), where, from Table B.1, $T1$ is the years of service for old assets.

The computation of the declining balance depreciation rate (DEPRAT) in NUFS is as follows:

$$DEPRAT = \frac{DEPFAC}{TXSY2} \quad (2)$$

If $DEPFAC$ is specified as two by the user, then double declining balance is utilized. Otherwise, the depreciation rate is equal over the tax life of the asset.

The reason that $DEPRAT$ produces an accelerated rate of depreciation (over the straight-line method) is that the factor $DEPRAT$ is applied against the undepreciated portion of the asset's value, $A2$:

$$TXDEP_t = DEPRAT (A2 - AD2_t), \quad (3)$$

where $TXDEP_t$ = the amount of accelerated depreciation, and $AD2_t$ is the accumulated amount of depreciation for the asset in year t . Thus, in contrast to the SYD method, the base upon which the depreciation rate is applied becomes smaller as the asset ages under the DB method rather than a depreciation rate that decreases over the asset's useful life.

The fourth category in Table B.1, Capital-Related Variables, defines the user's assumptions regarding the use of four types of capital and their cost. The percentage use of the four components of capital structure — PERLT, PERST, PERCE, and PERPS — and their related return or cost — RTNWB, RTST, RTCEQ, and RTPEQ — are time dependent in NUFS and, hence, can be specified to vary over the forecast horizon. For the purposes of base case analysis, however, the values noted in Table B.1 were specified as constants over the forecast horizon. The last three capital-related variables are applicable to common equity — the amount (XNSHRS), price (P), and pay-out ratio (DIVRAT).

The discount rate, DISCR, is used to determine the present value of revenue requirements. The latter magnitudes are part of the NUFS output as presented in Appendix A. As will be discussed in Section 5 of this report, the user-supplied inflation rate (GINF in Table B.1) has a significant impact on the values of many forecasted variables in NUFS. The rate is used primarily in the derivation of inputs emanating from MEFS.

Finally, the various options presented in Table B.1 define the user's assumptions with regard to the accounting treatment of the capital structure, CWIP, regulatory lag and tax depreciation. Option 5 allows either a multi-utility or single utility scenario. Options 3 and 4 allow the user to specify lag structures with respect to revenue generation (i.e., regulatory lag) and the type of accelerated depreciation rate to be utilized for new assets, respectively. Option 1 concerns the specification of the capital structure. Generally, Option 2 takes on the value of 2 because, if 1 is specified, additional information on each asset is required.

All of the options with the exception of Option 2 = 1 and Option 5 = 1 were executed during the analysis and found to be operational. Option 2 was executed only for the case where CWIP is treated uniformly because, otherwise, additional data would be required. Option 5 was executed only for a multi-utility case because the present analysis deals only with NUFS as part of the MEFS model.

Base Year Financial Information

Table B.2 in Appendix B presents the base year financial variables that are utilized in the execution of NUFS. The values of the variables for both privately- and publicly-owned utilities are based on individual utility submissions to the Federal Energy Regulatory Commission (formerly the Federal Power Commission). The Department of Energy computerizes the annual submissions of individual utilities and the data contained in those two tapes -- termed the Form 1 (Private) and Form 1M (Public) tapes -- are the source of base year financial information for the NUFS code.

Two pieces of software, described in detail elsewhere,¹⁶ have been developed to aggregate the data for individual utilities to the regional and aggregate U.S. totals requisite for use in NUFS. Although the values of the 1978 base-case variables in Table B.2 represent national aggregates for the private and public electric utilities, the NUFS program affords geographical aggregation to any of the ten DOE Regions, segregated by ownership type.

The data provided by the FERC (FPC) tapes and utilized by NUFS has been segregated into year-end stock (balance sheet) and annual flow (income statement) information for the calendar year 1978 in Table B.2. All of the information aggregated from individual utility company submissions and presented in Table B.2 as base-year data has been verified with two DOE publications: (1) *Statistics of Privately-Owned Electric Utilities in the United States: Classes A and B Companies, 1978*,¹⁷ and (2) *Statistics of Publicly-Owned Electric Utility Companies in the United States, 1978*.¹⁸

For privately-owned utilities, all of the asset totals (with the exception of the amount of Working Capital) presented in Table B.2 represent a simple aggregation of individual company reports of their electric utility plant. The amount of Working Capital represents the amount of aggregate net current assets (i.e., Current and Accrued Assets less Current and Accrued Liabilities) that is apportioned to the electrical service function. An apportionment routine is necessitated by the inclusion of the results of gas utility operations in the accounts reported to FERC for utilities that provide both the gas and electric

service. For purposes of segregating the effect of electric activity from gas activity, it is assumed that the amount attributable to the electricity function can be estimated as the ratio of total electric utility plant to total utility assets.

Besides its use in determining the amount of electricity-related Working Capital, the apportionment factor is utilized to estimate the year-end values for all of the variables listed under Liabilities and Stockholders' Equity in Table B.2. Again those totals are the simple aggregation of individual privately-owned electric utility company submissions; and it is assumed that the amounts attributable to electricity operations can be segregated using the apportionment equation.

The aggregate amounts listed in Table B.2 as Income Statement items for Generation, Sales to Ultimate Customers, and Revenues represent a simple summation of individual company submissions because those items are segregated for electricity operations on the FERC tapes. Fuel Adjusted for Taxes, TXFUEL, is simple the aggregate electric utility expenditures for operation and maintenance purposes (including fuel costs) adjusted for taxes utilizing the General Tax Rate (GTXRT) in Table B.2. The latter rate is calculated from the FERC tapes as the ratio of all taxes — other than federal income taxes — to Electric Operating Revenues. General taxes reflect all tax payments except state and federal income taxes. The rate is intended to encompass gross receipts, FICA, payroll, property, and sales taxes.

In contrast to the calculation of TXFUEL for base-year financial information in Table B.2, the computation of that same variable for forecasting purposes is:

$$\text{TXFUEL}_t = \frac{\text{FUEL}_t}{(1 - \text{GTXRT}_t)}, \quad (4)$$

where FUEL_t = total fuel expenses in year t (provided from MEFS) and GTXRT is the rate carried forward from the base year solution. Note that the only expense reflected in the forecasting algorithm is for fuel and that operation-maintenance costs are not included.

Since the aggregate Net Income amount of \$8,717 million reported in Table B.2 includes income from both electric and gas operations, it is assumed that the fraction attributable to electric operations is simply the portion of Net Electric Operating Income to Total All Utility Operating Income (94.45% in 1978). Finally, the Cost of Embedded Debt calculated for privately-owned utilities in Table B.2 is simply the ratio of Interest on Long Term Debt to the book value of Outstanding Bonds. Again, this formulation is in contrast to the method used in NUFs' forecasting scheme, where the embedded cost of debt in year t , $EMDT_t$, is calculated as the weighted average of the cost of old debt, new debt, and debt retirements:

$$EMDT_t = \frac{[(EMDT_{t-1})(BONDS_{t-1})] - [(EMDT_{BYR})(RETIRE)]}{BONDS_t} + \frac{[RTNWB_t(BONDS_t - BONDS_{t-1} + RETIRE)]}{BONDS_t} \quad (5)$$

where, without subscripts,

BONDS = Total amount of outstanding long-term debt

RETIRE = Amount of debt issued prior to first forecast period which is retired and refinanced

RTNWB = Return (cost) to newly-issued long-term debt (user-supplied)

BYR = Base year.

RTNWB is a user-supplied input (see Table B.1), while the variables BOND and RETIRE require further explanation. The amount of outstanding debt (BONDS) is assumed to be the product of the user-supplied percent of capital structure, PERLT (see Table B.1), and the product of assets that need to be financed, AMD, (i.e., utility plant, construction expenditures, working capital, and the nuclear fuel stock net of deferrals). Retirements of debt issued prior to the forecast period (RETIRE), on the other hand, are assumed to be the maximum of (a) the product of the percent of capital attributable to long term debt (PERLT) and the amount of depreciation expenditures, or (b) OB_{t-1} , the amount of long-term debt outstanding in the prior period which was issued prior to the base year, where $OB_t = OB_{t-1} - RETIRE_t$.

The derivation of base-year financial information for publicly-owned utilities is similar to that of the privately-owned. From Table B.2, the asset values are the simple summation of individual submissions for federal and municipal utilities, as are the amounts for electricity generation, sales, revenues, and net income. The amounts reflected for Working Capital, Outstanding Bonds, Common Stock, and Retained Earnings are apportioned to electricity operations in the same manner as that of privately-owned utilities. The General Tax Rate and the Cost of Embedded Debt are also derived similarly.

One of the most important variables derived from the base-year financial information is the book value of "old assets", BAl, or assets in existence prior to the forecast period for both IOUs and POUs. Since the financial information presented on the FPC tapes does not detail specific assets but only provides the total book value for ten (old) asset types (e.g., steam production or nuclear production in Table B.2), an assumption must be made concerning the length of time that old assets have been in existence. In NUFS, that determination is made through use of the user-supplied variable, T1 (Table B.1), or the year of service for each class of old assets. Therefore, NUFS implicitly assumes that the aggregation of individual utility company asset accounts in any region (e.g., DOE Region 1, the U.S. aggregate) represents a generic plant type and, as will be shown later, is depreciated accordingly.

Although ascertaining the validity of base-year financial information can be construed as data analysis, it by no means represents a comprehensive evaluation of input data. In the present context, that activity would involve an audit trail encompassing verification of the legitimacy of each individual utility's submission of financial information to the FERC. That process, however, is well beyond the scope of the present analysis.

The MEFS Interface

The National Utility Financial Statements Model (NUFS) was developed primarily for the purpose of integration with DOE's Mid-Term Energy Forecasting System (MEFS). The latter model is a system of integrated energy supply and demand sub-models used for mid-range forecasting (up to 1995)

by the Department of Energy. MEFS is specified in a forecasting framework and, as such, is not an optimizing model.¹⁹

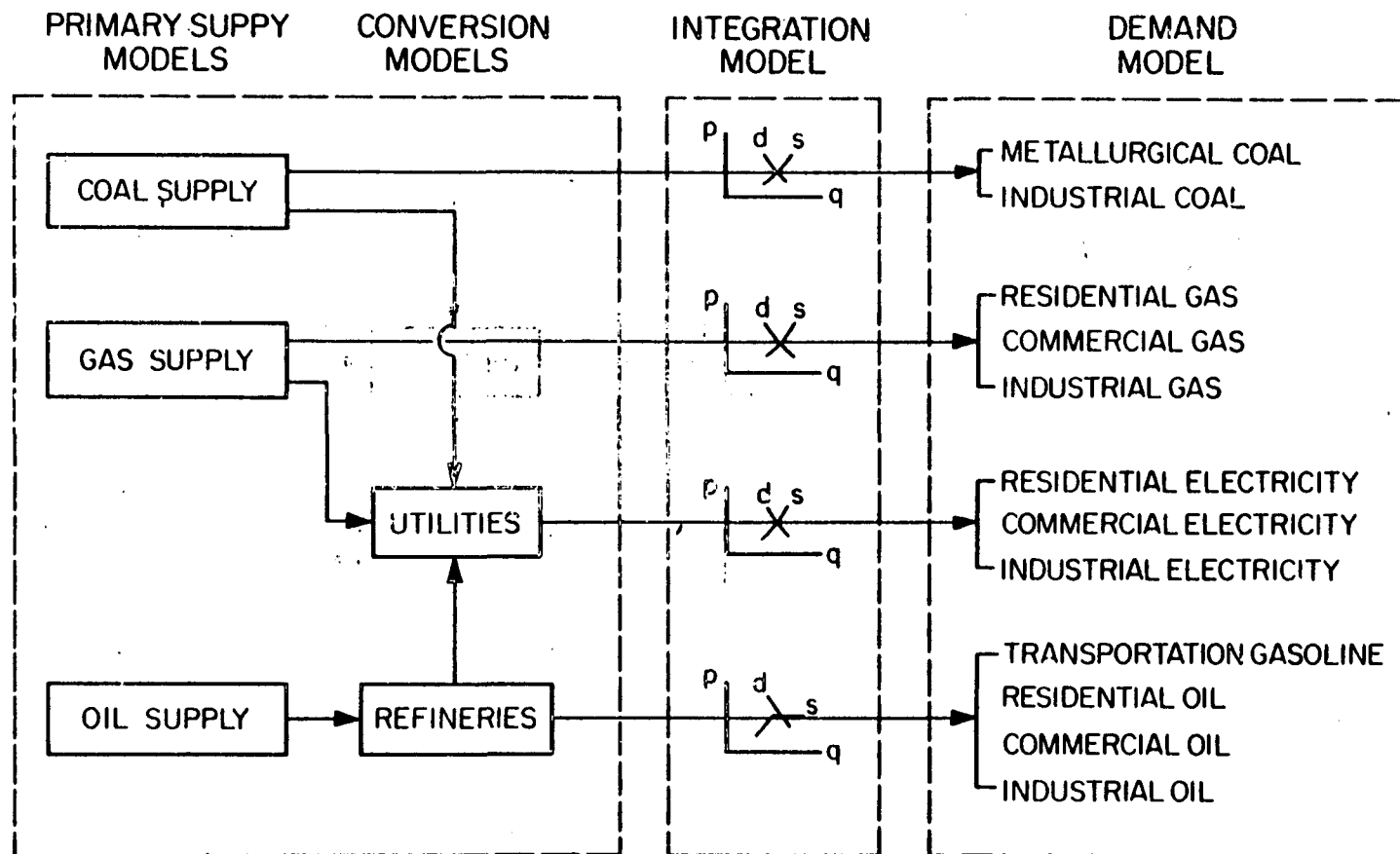
In its simplest form, MEFS can be characterized as a system consisting of four broad components: (1) energy supply models; (2) energy conversion models; (3) energy demand models; and (4) an integrating model that takes as its input the outputs of the other three components and solves for equilibrium prices and quantities, domestic production of energy, and foreign imports. A characteristic representation of the four components of MEFS and their relationship in the MEFS System is presented in Figure 3.

The supply side of MEFS consists of crude petroleum, natural gas, coal, and uranium supply sub-models. There are two energy conversion sub-models. The refinery model selects crude supplies and refinery methods that satisfy a given demand at minimum cost. The Electric Utilities Conversion Model estimates the optimal generating capacity required to meet a demand profile partitioned into three segments: base, intermediate, and peak. The model determines the plants (both new and old) that will be required to satisfy demand by minimizing the cost of meeting that demand.

The demand side of MEFS is represented by demand curves for eight fuels: gasoline, distillates, residual fuel oil, other refined petroleum products, steam coal, metallurgical coal, natural gas, and electricity. Finally, the integrating model, termed the Mid-Term Energy Market Module (MEMM), represents the balancing portion of the model. It takes as its input the demand and supply curves of the other sub-models and, through the iterative use of a large scale optimization program, provides equilibrium prices and quantities through the least cost method of supplying the quantity demanded.

Tables B.3 through B.6 in Appendix B detail the information that is provided to NUFS from the MEFS solution files. The specific software utilized and the techniques used to "strip" the applicable NUFS' variables from the MEFS output file are described thoroughly in the documentation accompanying NUFS.

From Table B.3, an individual MEFS solution provides the total amount of electricity generated and the portion of that provided by nuclear generation. The loss factor (XLF) in Table B.3 is simply the



MEFS estimate of the amount of generation that is used in the power production process. Table B.4 provides MEFS' results with respect to fuel, operation, and maintenance costs. The information in Tables B.5 and B.6 details the book value of capacity additions for 16 different plant types segregated by investor-owned and publicly-owned utilities, respectively.

All of the numerical values presented in Tables B.3 through B.6 are those used in the base case problem for sensitivity analysis and, therefore, represent aggregate U.S. amounts for publicly-owned and privately-owned utilities. Under the various options available in NUFS, however, it is possible to generate the results contained in Tables B.3 through B.6 for any of the individual ten DOE regions, or alternatively, for any combination of those regions.

It must be emphasized at this point that the MEFS code was treated as a "black box" for purposes of the present study. The input into MEFS, the sub-models that characterize the energy economy representation, and the resulting MEFS forecasts were not scrutinized. The variables and quantities provided in Tables B.3 through B.6 are the results provided from a given MEFS solution file for the U.S. in total and no attempt was made to document their accuracy.

Since the current version of MEFS provides cumulative electric utility capacity additions, capacity costs, generation, fuel costs, and operation-maintenance costs in five year increments for 1985, 1990, and 1995, annual allocating schemes have been devised to apportion the five-year cumulative MEFS totals into annual amounts because NUFS requires the aforementioned variables on a yearly basis. A description of the allocation routine and a comprehensive listing of the code are provided in the documentation accompanying NUFS.

Similarly, MEFS forecasts five-year cumulative capacity additions based on minimizing the present value of revenue requirements. In NUFS, the year in which capacity additions come "on line" are allocated to individual years on the basis of an exponential trend factor derived from the forecast of annual electricity generation. The latter amounts, in turn, were themselves based on exponential trending. The percentage of new construction activity completed in any year is calculated on the basis of percentage completion factors provided by the model user (CONPER in Table B.1). Annual fuel, operation, and maintenance costs are also allocated on the basis of growth rates.

For the purposes of financial statement preparation in NUFS, the latter variables derived from MEFS (fuel, operation, and maintenance expenses) are used directly in the preparation of the income statement. With reference to Appendix A, the Operation and Maintenance expenditures (OM) from MEFS are IS-2 and the fuel costs (FUEL) are IS-3.

Besides the actual values of FUEL and OM and the variables related to capacity additions, their costs, and total electricity generation, a number of variables used in the NUFS' solution algorithm are directly calculable from the MEFS solution files. Total sales for any pre-specified region in any year t , $TOTSAL_t$, a function of the loss factor (XLF) and total electricity generation (GWHTOT), is computed as:

$$TOTSAL_t = (1 - XLF_t) GWHTOT_t, \quad (6)$$

or, in words, the amount sold in a year equals the amount generated less the fraction of generation lost through use. Equation (6) is applicable to any of the ten DOE regions and the aggregate U.S.

The amount of working capital that appears on the balance sheet at any point in time, WC_t , (BS-11 in Appendix A) for any region and ownership type is assumed to be equal to one-eighth of the Operation and Maintenance expenses (OM) and fuel costs (FUEL) for the period; or, formally,

$$WC_t = (OM_t + FUEL_t) .125, \quad (7) \quad [BS-11]$$

The implicit assumption behind this specification is that an average monthly billing utility has 45 days (one-eighth of a year) between payment of expenses and receipt of revenues and, furthermore, that utilities always generate a positive amount of working capital. This calculation utilized in NUFS is called the FPC method because of its use by rate-making authorities for the purpose of setting rates.

The amount of nuclear fuel represented as an asset on the balance sheet for any period, $XNUCFL_t$, (BS-9 in Appendix A) is assumed to be equal to twice the amount of nuclear fuel expense, $XNUCEX_t$, that originates from the MEFS solution. Specifically,

$$XNUCFL_t = 2 XNUCEX_t \quad (8) \quad [BS-9]$$

The rationale for this computation in NUFS is that a batch of fuel is loaded every year and each batch has a three-year life. Consequently, the amount of "unspent" fuel in any year is equal to twice the amount of "spent" fuel.

The most important output of the MEFS solution file that is utilized by NUFS is related to capacity additions and their cost. Tables B.5 and B.6 present that information for publicly-owned utilities, respectively. Since the cost of plant in Tables B.5 and B.6 is presented on a dollars per unit of capacity basis, the total cost of a plant, COST, is calculated in NUFS by:

$$\text{COST} = (\text{PLTCAP})(\text{CAPCST}) , \quad (9)$$

where

PLTCAP = Plant Capacity and CAPCST = Capacity Cost.

If the asset has a construction period of less than one year (e.g., transmission and distribution facilities), then the value of the asset for balance sheet purposes is the amount reflected in Eq. (9). However, if the asset's construction period is longer than one year, the derivation is more complex. Recalling the discussion earlier, if CWIP — or a portion thereof — is not allowed in the rate base, then the book value of an asset includes capitalized interest (AFUDC). In NUFS, the AFUDC rate is incorporated via the user-supplied variable, AFUDCR (see Table B.1).

Therefore, in order to determine the cost of an asset without AFUDC, A2, the total cost of the plant must be factored as follows:

$$A2 = \frac{\text{COST}}{\text{CWPFAC}} , \quad (10)$$

where CWPFAC is derived as follows:

$$\text{CWPFAC} = \sum_{i=1}^{15} \left[\left(\text{CONPER}_{\text{JYR}-i+1} \right) (1 + \text{AFUDCR}) \right]^{(i-.5)} \quad (11)$$

and CONPER and AFUDCR were discussed in context of user-supplied inputs (Table B.1).

The book value of new assets, BA2, follows from the percentage of CWIP that the user specifies to be allowed in the rate base (CWPPER):

$$BA2 = (A2)(CWPPER) + COST (1 - CWPPER) . \quad (12)$$

Now, the gross value of utility plant in service and, therefore, the amount of utility plant in the rate base is simply the sum over all asset types of the book value of "old assets," BA1 (discussed in the previous section), and the book value of "new assets," (BA2), net of retirements:

$$UP_t = \sum_{J=1}^{10} BA1_J + \sum_{K=1}^{16} BA2_K - BRTIRE_t, \quad (13)$$

where, deleting the temporal subscript,

UP = Gross Utility Plant

BRTIRE = book value of all assets which have retired during the period before or during year t. (A plant retires after SY1 or SY2 years of operation).

-
- J = 1. Intangible
 2. Steam Production
 3. Nuclear Production
 4. Hydraulic Production — Conventional
 5. Hydraulic Production — Pumped Storage
 6. Other Production
 7. Transmission
 8. Distribution
 9. General
 10. Common — Electric

- K = 1. Gas Steam
 2. Oil Steam
 3. Coal Type 1
 4. Coal Type 2 (Different from Type 1 because of construction profile)
 5. Pumped Storage
 6. Hydro
 7. Nuclear
 8. Combined Cycle
-

9. Turbine
10. Retrofits W/ 3 Year Construction Schedule (Cremod)
11. Conversions and Retrofits W/ 1 Year Construction Schedule
12. Other Technologies (Solar, Geothermal, etc.)
13. Transmission
14. Distribution
15. Meters
16. Other

The ten existing plant types, BA1, and sixteen asset types that come "on line" in the forecast period, BA2, reflected in Eq. (13), are aggregated as follows for balance sheet presentation in any region by ownership type:

- Production Assets = (J1 through J6; K1 through K12) [BS-1]
- Transmission Assets = (J7; K13) [BS-2]
- Distribution Assets = (J8; K14) [BS-3]
- Other Assets = (J9 and J10; K15 and K16) [BS-4]

The NUFs Solution Scheme

NUFS is a series of accounting relationships that together with the aforementioned data inputs, produces forecasted financial statements and derivative financial ratios for the electric utility industry. Since the same accounting (forecasting) scheme is utilized for any region under analysis — and, indeed, for any ownership type being evaluated — the discussion in this section is generic; that is, the equations are applicable to any region and ownership type that the user specifies for analysis. Aggregates for regions or ownership types are derived by simple summation.

The basic regulatory equation in the model is the computation of required revenues for ratemaking. In NUFs, it consists of the following components:

$$\begin{aligned} \text{REVREQ}_t = & \left[\text{UP}_t + \text{RBCWIP}_t + \text{WC}_t + \text{XNUCFL}_t - \text{ABDE}_t - \text{PRODEF}_t \right] * \text{RR}_t \\ & + \text{FUEL}_t + \text{OM}_t + \text{BDE}_t + \text{TAXES}_t - \text{OFFSET}_t, \end{aligned} \quad (14)$$

where t refers to the forecasted period under consideration, and without subscripts,

REVREQ = The revenue requirement,
 UP = Gross utility plant in service [Eq. (13)],
 RBCWIP = CWIP allowed in the rate base [Calculated in Eq. (29)],
 WC = Working Capital [Eq. (7)],
 XNUCFL = Nuclear Fuel Stock [Eq. (8)],
 ABDE = Accumulated Book Depreciation [Calculated in Eq. (21)],
 PRODEF = Provision for Deferred Taxes Due to Accelerated Depreciation
 [Calculated in Eq. (39)],
 RR = Allowable Rate of Return [Calculated in Eq. (15)],
 FUEL = Fuel Costs (From MEFS),
 OM = Operation and Maintenance Expenses (From MEFS),
 BDE = Book Depreciation Expense [Calculated in Eq. (20)],
 TAXES = General, State and Federal Tax Items (Including the amortiza-
 tion and deferral of federal tax effects) [Calculated in
 Eq. (30)],
 OFFSET = AFUDC Offset.

The derivation of Gross Utility Plant in Service (UP), Working Capital (WC), and the Nuclear Fuel Stock (XNUCFL) were presented above in Eqs. (13), (7), and (8), respectively. The amount expended on fuel (FUEL) and operation and maintenance activities (OM) are directly attributable to the MEFS solution file and, accordingly, were discussed above in that context. The amount presented in brackets in Eq. (14) is simply the rate base upon which the utility is allowed to earn a fair return. The remaining items in Eq. (14) will be derived and discussed in the following sections.

Equation (14) is intended to reflect the rule of rate-making wherein an individual utility is allowed to generate revenues sufficient to cover all operating expenses (the variables FUEL, OM, BDE, and TAXES) plus a fair return on its invested capital (RR times the rate base). The rate base, in turn, is comprised of net physical plant (UP less ABDE), the user-specified amount of construction expenditures allowed to be incorporated as part of the rate base (RBCWIP), Working Capital (WC), the amount of un-spent nuclear fuel (XNUCFL), and a reduction due to deferred taxes (PRODEF).

The inclusion of (net) Physical Plant and the stock of nuclear fuel in the rate base are self-evident since they represent property that is used in providing the electrical service. The amount of CWIP included in the rate base (RBCWIP) is contingent upon individual PUC's accounting treatment of the construction activity. Working Capital, which

theoretically represents the utility's investment in materials and supplies and the cash required to meet current obligations, is included in the rate base in order that investors are compensated for capital they have contributed to the company. The Provision for Deferred Taxes is subtracted from the rate base because, in a sense, it is similar to the reserve for depreciation. If one assumes that an asset has two characteristics — a service-producing capacity (and, therefore, revenue-generating function), and tax-reducing capacity (through depreciation charges) — then the depreciation reserve reflects the amount of the former characteristic "used up", while the deferred tax liability represents the amount of the latter function that has been used to date. Therefore, both ABDE and PRODEF are subtracted from the rate base in order to derive the net value of utility plant.

Although Eq. (14) reflects revenue determination on the basis of current-period costs, provision is made in the NUFS framework to determine current-period revenues under different lag scenarios. That process will be discussed in a later section.

An implicit assumption in Eq. (14) is that rate-making is always based on a historical-cost rate base. Specifically, no provision is made in the NUFS framework for use of a "fair value" or reproduction cost rate base or, as discussed in Section 2, an allowance for the interaction of the rate base valuation method and the allowable rate of return.

The rate of return

The problems of accuracy associated with the assumption of a historical cost rate base are partially ameliorated because the rate of return in NUFS is essentially user-specified. The astute user, therefore, may recognize the contributions of recent research on the rate base valuation — rate of return relationship and select capital return variables that reflect that interaction. However, in reality, the allowable rate of return is also a function of the interaction between an individual utility and its governing PUC. Indeed, different utilities within the jurisdiction of a single PUC may be allowed to generate revenues and, therefore, set rates on the basis of varying rates of return contingent on their individual operating

characteristics and the general economic climate. As NUFS is presently formulated for multi-utility analysis, however, the user is only allowed to specify a rate of return for the aggregation of individual states and utilities within a DOE Region by ownership type (i.e., IOUs and POUs).

The problems associated with aggregation notwithstanding, NUFS does attempt to reflect the actual rate-making process in the determination of the allowable rate of return. Formally, the rate of return, RR , is calculated as a function of the weighted average of capital costs:

$$RR_t = (PERLT_t)(EMDT_t) + (PERST_t)(RTST_t) + (PERCE_t)(RTCEQ_t) + (PERPS_t)(RTPEQ_t), \quad (15)$$

where, dropping the subscripts,

PERLT = Percent of Capital, Long-Term Debt (User-Supplied),
 EMDT = Embedded Cost of Debt [Calculated in Eq. (5)],
 PERST = Percent of Capital, Short-Term Debt (User-Supplied),
 RTST = Return to (Cost of) Short Term Debt (User-Supplied),
 PERCE = Percent of Capital, Common Equity (User-Supplied),
 RTCEQ = Return to (Cost of) Common Equity (User-Supplied),
 PERPS = Percent of Capital, Preferred Stock (User-Supplied),
 RTPEQ = Return to (Cost of) Preferred Stock (User-Supplied).

All of the determinants of the rate of return in Eq. (15) are user-supplied inputs (see Table B.1) with the exception of EMDT, the embedded cost of debt. That variable, calculated as a function of the weighted average cost of old debt, currently-issued debt, and debt retirements, was discussed and derived above in the context of Eq. (5).

Again, the computation of the rate of return in Eq. (15) relies, to a large extent, on user judgment. Furthermore, since the inputs must be aggregated to at least a regional level, the capital weights (PERLT, PERST, PERCE, and PERPS) and return to capital (RTST, RTCEQ, and RTPEQ) must necessarily reflect an average across the region.

Depreciation

Under existing tax laws, utilities (and, indeed, all corporations) are allowed to utilize the provisions of the 1954 Tax Act for determination

of the amount of depreciation allowed for tax purposes. The provisions of the IRS code with respect to tax depreciation differ from the amount allowed for book purposes under generally accepted accounting principles. While the latter determination provides for straight-line depreciation (e.g., an asset with a useful life of ten years is depreciated one-tenth in each year of its useful life), the provisions of the tax code allow an accelerated amount of depreciation in an asset's early life in comparison with the straight line method, while the reverse is true in later years of the asset's (estimated) useful life.

Furthermore, for financial accounting purposes, the depreciable value of the asset includes the capitalized interest (AFUDC) associated with the financing costs of new construction expenditures. Under this approach, the book value of an asset includes the AFUDC applicable to any amount of construction expenditures that were not included in the rate base. In the years during which construction was in progress, the costs of debt and equity capital were capitalized and, hence, no return was allowed from rate-payers during that period. The return for the cost of capital is deferred until the asset comes "on line" and is reflected in the form of allowable depreciation expense for rate-making purposes.

Under current tax laws, however, the value of the asset for tax depreciation purposes cannot include capitalized interest costs. The value of an asset is simply the total of labor, material, and overhead construction costs.

Besides distinguishing between book and tax on a cost basis, the NUFs' framework differentiates between book depreciation accounting and tax depreciation accounting by allowing specification of different depreciation rates for the two methods. Furthermore, in addition to the different nominal amounts of depreciation calculated for both book and tax purposes, there are related federal tax effects applicable to the difference between the two magnitudes. The amount and treatment of that difference will be discussed below in the context of the federal tax determination.

For financial accounting (book) purposes, depreciation expense for the current period is simply the product of the book value of a plant and

a straight-line depreciation rate. The latter percentage is simply the inverse of an asset's useful life. Under the NUFs' framework, assets are differentiated between those existing in the base year ("old assets") and those coming on line in the forecast period ("new assets"). For old assets, book depreciation expense, BDE1, is the sum of depreciation over all old asset types:

$$BDE1_t = \sum_{i=1}^{10} (BA2_t \times DR1_t)_i, \quad (16)$$

where, BA1 is the book value of old assets (from Form 1/Form 1M base year financial information); and DR1 is a user-supplied depreciation rate: the inverse of SY1, the useful asset life.

A complexity introduced when determining the accumulated amount of depreciation at any point in time is the derivation of that total as of the base year. As noted above, the user specifies the years of service of base year assets through specification of the variable T1 for each of 10 asset types. The amount of accumulated depreciation, ABDE1, prior to the forecast period, therefore, can be expressed as follows:

$$ABDE1_{BYR} = \sum_{i=1}^{10} (T1 \times DR1 \times BA1)_i, \quad (17)$$

where BA1 = the book value of assets in the base year.

The amount of accumulated depreciation for old assets in any forecast period, t, is simply the sum of the prior period amount and the depreciation expense in the current period:

$$ABDE1_t = ABDE1_{t-1} + BDE1_t. \quad (18)$$

The calculation of book depreciation accounts for new assets, BDE2, is similar with the exception that sixteen different plant types are considered rather than ten:

$$BDE2_t = \sum_{i=1}^{16} (BA2_t \times DR2)_i . \quad (19)$$

Trivially, the total amount of depreciation expense reflected in the income statement for any period, t (IS-4 in Appendix A) is simply the sum of the depreciation amounts for old and new assets:

$$BDE_t = BDE1_t + BDE2_t . \quad (20) \quad [IS-4]$$

Similarly, the total amount of accumulated book depreciation reflected in the rate base Eq. (14) and on the balance sheet (BS-7 in Appendix A) is comprised of the total for old and new assets:

$$ABDE_t = ABDE1_t + ABDE2_t , \quad (21) \quad [BS-7]$$

where $ABDE2$ is calculated in the same manner as Eq. (17).

An implicit assumption made in the context of NUFS' treatment of depreciation accounting is that an asset is used and useful over its entire, user-specified life (i.e., SY1 for "old" assets and SY2 for "new" assets). When an asset is fully depreciated, its book value is added to the retirement account (BRTIRE) and subtracted from the accumulated amount of depreciation. Although this treatment fully accounts for physical depreciation, it entirely ignores the issue of functional depreciation or obsolescence. An oil-fired generating plant, for example, may have an (estimated) useful life of 30 years and be depreciated accordingly for financial accounting purposes. However, the plant may become economically obsolete and retired from the rate base well before the expiration of the 30-year period.

In a study published in 1975,²⁰ for example, Egg found that the more rapidly the load on an electrical system grows, the more rapidly economic obsolescence for power generating units (i.e., functional depreciation) occurs. Furthermore, the economic life span of a power production unit is not the average service life of the asset (i.e., SY1 and SY2 in NUFS),

but service life is a function of the economic life span, interim replacements of units, and interim retirements. The economic life span, in turn, is inversely related to the growth in load and, of course, any factor that affects load (e.g., birth rates, changes in the relative prices of substitute energy sources).

The calculation of tax depreciation expense, TDE, in NUFS is similar to the financial accounting (book) method with two exceptions: (1) capitalized AFUDC cannot be depreciated for tax purposes, and (2) a depreciation rate other than the straight-line rate must be used. The first difference leads to a calculation of tax depreciation on the basis of $A1$ ($A2$), the value of old (new) plant excluding AFUDC, rather than $BA1$ (or $BA2$), the book value of old (new) plant, which includes AFUDC. The second difference is accounted for by the use of accelerated tax depreciation rates. In NUFS, the user is allowed to specify the use of either the sum-of-the-years digits (SYD) method or the declining balance (DB) method for new assets, while old assets must be depreciated on the basis of the SYD method for tax purposes. Those two depreciation rates were discussed and derived above in the context of Eqs. (1), (2), and (3). Furthermore, for new assets of a given ownership type within any region under analysis, the selection of an accelerated tax depreciation rate is an "either-or" decision. The specification of an accelerated depreciation rate type cannot be altered within a region.

For old assets, then, the amount of tax depreciation expense, $TDE1$, is calculated as:

$$TDE1_t = \sum_{i=1}^{10} (TD1 \times A1)_i, \quad (22)$$

where,

$TD1$ = SYD accelerated depreciation rate [Eq. (1)],

$A1$ = value of old assets without AFUDC.

The computation of tax depreciation expense for new assets, $TDE2$, utilizing the SYD method is analogous to that of Eq. (22). Use of the declining balance method of accelerated depreciation for new assets was discussed

in the context of Eqs. (2) and (3) above. Again, Total Tax Depreciation Expense, TDE, for any period t , reflects the amounts for old and new assets:

$$TDE_t = TDE1_t + TDE2_t . \quad (23)$$

Construction expenditures

As Section 1 of this paper delineated, new construction activity has played an increasingly prominent role in the electric utility industry's financial position and is expected to do so in the future. Consequently, the specification of equations dealing with the financial regulatory treatment of new construction expenditures is important in a financial regulatory model of the electric utility industry. The problems with modeling new construction activity are exacerbated by the diverse treatments afforded different utilities by various state-level utility commissions. Individual PUCs may allow CWIP — or a portion of it — in the rate base but let utilities calculate a return (i.e., AFUDC) on the portion excluded from the rate base; or they may allow a combination of those two methods, termed the AFUDC offset method, wherein CWIP is allowed in the rate base with a corresponding offset to the revenue requirement.

In the NUFs framework, the crucial variables pertinent to accounting for construction expenditures are the user-supplied inputs CWPPER, the percentage of CWIP allowed in the rate base; AFUDCR, the compounded AFUDC rate; and, to a lesser extent, CONPER, the percentage of construction completed annually on new plants (see Table B.1). These three user-supplied variables are of critical importance in the determination of various income statement and balance sheet entries and the financial ratios derived from them. Additionally, as will be shown in the next section, their importance is compounded by their federal tax treatment.

Consider first the calculation of $FCWIP_t$, the actual amount (flow) of new construction expenditures in year t ;

$$FCWIP_t = \sum_{i=1}^{NPLTS} (CONPER_t \times A2)_i , \quad (24)$$

where, deleting subscripts,

A2 = cost of new plant net of AFUDC (From MEFS),
 CONPER = percent of construction completed in year t (User-supplied),
 NPLTS = number of plants (From MEFS).

The actual construction expenditures, therefore, are simply the user-supplied fraction of work completed on new plants, summed over all of the plants that have completion time horizons of more than one year. The cumulative amount of construction expenditures, $CWIP_t$, is the sum of the yearly amounts completed over the time horizon of the construction activity until JYR, the year the plant begins operation (i.e., 15 years is the time horizon allowed in NUFS, from Table B.1):

$$CWIP_t = \sum_{t=JYR-14}^{JYR} FCWIP_t, \quad (25)$$

In essence, at any point in time, the NUFS code "looks ahead" to see what plants are coming on line in the next 15 years and, through user specification of CONPER, calculates the amount of CWIP as the applicable fraction of the asset cost that emanates from MEFS.

Now, the actual amount of in-process, construction expenditures capitalized and, therefore, reflected as plant in construction on the balance sheet (BS-5 in Appendix A), depends on the assumed rate-making treatment of CWIP expenditures. Recalling from Section 2, if CWIP — or any portion of it — is not allowed in the rate base, the utility is allowed to artificially compute a return to those expenditures and that amount, in turn, is reflected as part of the cost of plants and incorporated into ongoing construction activity on the balance sheet. In NUFS, that process is user-determined since the amount of construction expenditures reflected on the balance sheet, BCWIP, is a function of the user-supplied AFUDC rate, AFUDCR, and the user-provided portion of CWIP allowed in the rate base, CWPPER:

$$BCWIP_t = \sum_{t=JYR-14}^{JYR} \left[(FCWIP_t)(1+AFUDCR)^{(t-1+.5)} \right] \left[(1-CWPPER) + (FCWIP_t)(CWPPER) \right], \quad (26) \quad [BS-5]$$

or, in words, booked construction expenditures represent the sum (over applicable years) of the annual amount of construction expenditures, including capitalized AFUDC, that are not included in the rate base for regulatory purposes and the amount of the annual flow that is included in the rate base but for which no AFUDC is capitalized, because the utility is allowed to earn a current return on that portion. When an asset comes on line, its cost (including any AFUDC) is charged to a property account and the CWIP accounts are correspondingly credited.

One of the primary problems with this accounting treatment of new construction activity in NUFS is that there is no correspondence or reconciliation between the actual amount of CWIP reflected on the balance sheet in the base year (from Form 1/Form 1M tapes) and the amount of CWIP calculated in NUFS over the forecast horizon for those assets. Clearly, a relationship exists because the amount of CWIP reflected on the balance sheet in the base year is applicable to some of the assets that come on line during the forecast period. The calculation of BCWIP in NUFS Eq. (26) takes no account of that relationship.

Since AFUDC was incorporated in the derivation of "booked" CWIP, BCWIP, the amount of AFUDC in any year can be expressed in terms of these amounts:

$$AFUDC_t = (BCWIP_t - BCWIP_{t-1}) - FCWIP_t; \quad t = JYR - 14, JYR. \quad (27)$$

In this formulation, AFUDC for any period t is simply the increase in balance sheet CWIP (which, of course, includes capitalized interest, AFUDC) less the amount of construction expenditures for the year net of any AFUDC, FCWIP.

For purposes of formal presentation in the income statement and accounting for federal income taxes, it is necessary to segregate the capitalized interest into the amounts attributable to both debt and equity financing. This is accomplished by multiplying the calculated amount of AFUDC in Eq. (27) by both the weighted average cost of debt (WACD) and the weighted average cost of equity (WACE):

$$AFUDCD_t = WACD_t * AFUDC_t , \quad (28) \quad [IS-14]$$

$$AFUDCE_t = WACE_t * AFUDC_t , \quad (29) \quad [IS-9]$$

where AFUDCD and AFUDCE are the respective amounts of capitalized interest due to debt and equity financing that appear as a source of income on the income statement. The cost of debt, WACD, includes both short and long-term debt, while WACE incorporates the cost of common and preferred stock. The weights are simply ratios of their respective components to the total cost of capital.

Equations (26), (28), and (29) provide the balance sheet and income statement effects for new construction activity in NUFS. A further consideration is the effect that these expenditures have on the rate base. Depending on the value assigned CWPPER, a portion of construction work in progress is included in the rate base, RBCWIP. The rate base value further depends on whether the OFFSET technique is utilized.

From Table B.1, if the variable RBAFDC = 0, no offset included, then the variable OFFSET equals 0 in the determination of revenue requirements. Under this scenario, the amount of CWIP included in the rate base is simply given by;

$$RBCWIP_t = (CWIP_t)(CWPPER) , \quad (30)$$

or, simply, the amount incorporated in the rate base is the fraction of cumulative construction expenditures net of AFUDC, CWIP, that the user pre-specifies as a part of the rate base.

On the other hand, if RBAFDC = 1 (i.e., from Table B.1, the offset method is utilized), then the variable OFFSET in the revenue requirements determination [Eq. (14)] is the amount of AFUDC calculated in Eq. (27). The corresponding amount of RBCWIP_t (using the offset method) is then equal to the booked construction expenditures, BCWIP, calculated in Eq. (26) and appearing on the balance sheet. The latter total, of course, includes the amount of capitalized interest.

From Eq. (14), note that the effect of the OFFSET method in NUFS is to allow some current-period return on new construction expenditures if the rate of return (RR) is greater than the AFUDC rate. However, if the AFUDC rate is equal to the rate of return, then the OFFSET option effectively reduces to disallowing CWIP in the rate base. Or, technically, the return on rate base construction expenditures in Eq. (14) is exactly negated by the variable OFFSET under this circumstance.

Tax variables

A financial regulatory model must make explicit the complex treatment of all tax effects. Besides addressing the specific taxes applicable to utilities — gross receipts, FICA, payroll, property, sales, and state and federal income taxes — the model must be capable of treating the substantial effect of "timing differences" and "permanent differences" in the reconciliation of financial accounting and tax accounting. In addition, the model must be capable of addressing the issue of flow-through versus normalization in treating the federal income tax benefits resulting from accelerated depreciation, the investment tax credit, and other current period book-to-tax differences.

The treatment of taxes in NUFS is, in essence, a two-part process. First, taxes for regulatory purposes are calculated in conjunction with Eq. (14). Under this formulation, the calculated totals for general taxes (i.e., all taxes except income taxes) and state and federal income taxes are based on current period revenues and expenses. However, since NUFS has a provision for various lag scenarios wherein the actual electric revenues for income statement purposes are based on a user-supplied lag structure, the actual tax magnitudes are calculated on the basis of the user-specified lag scenario in the second part of the solution scheme. Thus, the actual amount of current taxes payable and the amount appearing on the income statement as expense is derived in the second portion of the process. The first part of the process is explained in the present section, while the second part is dealt with in the context of regulatory lag in the next section.

In Eq. (14), the determination of revenue requirements in NUFS, the variable TAXES represents the total allowable tax expense for regulatory purposes. That variable, comprised of all tax effects, including general

taxes (property, sales, payroll, etc.), state and federal income taxes, and their related federal tax effects, is expressed as follows:

$$\text{TAXES}_t = \text{GENREG}_t + \text{STAREG}_t + (\text{FEDREG}_t - \text{XITCF}_t - \text{AITC}_t - \text{XAFDCT}_t - \text{AAFDC}_t) \quad (31)$$

where, without subscripts,

- GENREG = General Taxes for Regulatory Purposes [calculated in Eq. (32)],
- STAREG = State Taxes for Regulatory Purposes [calculated in Eq. (33)],
- FEDREG = Federal Taxes for Regulatory Purposes [calculated in Eq. (36)],
- XITCF = The Amount of Current Period ITC Flowed Through [calculated in Eq. (41)],
- AITC = The Amount of Prior Years' ITC that is amortized in the current year [calculated in Eq. (43)],
- XAFDCF = The Amount of Current Period Tax Savings due to AFUDC - Debt that is Flowed Through [calculated in Eq. (45)],
- AAFDC = The Amount of Prior Years' AFUDC - Debt that is amortized in the Current Year [calculated in Eq. (47)].

The variables in parentheses in Eq. (31) represent the effects of federal income tax items and, as such, incorporate the amortization of prior periods' deferred taxes, (AITC, AAFDC); and the flow-through of the current period's federal tax benefits due to accelerated depreciation (included in FEDREG), the investment tax credit (XITCF), and the debt portion of AFUDC (XAFDCF).

General taxes for regulatory purposes, GENREG, are assumed to be a constant fraction of revenue requirements, REVREQ. The tax rate, GTXRT, is provided from the Form 1/Form 1M base year financial information (Table B.2). Therefore, the determination of General Taxes in NUFS is simply,

$$\text{GENREG} = (\text{GTXRT})(\text{REVREQ}) . \quad (32)$$

Similarly, the state tax amount for regulatory purposes, STAREG, is calculated as the product of a user-supplied state tax rate, STXRT, (Table B.1), and revenue requirements less allowable expenses. Specifically, we have:

$$\text{STAREG}_t = (\text{REVREQ}_t - \text{FUEL}_t - \text{OM}_t - \text{TDEWOA}_t - \text{XINEX}_t) \text{STXRT}, \quad (33)$$

where, without subscripts,

FUEL = Total Fuel Costs (from MEFS),

OM = Total Operation and Maintenance Expenses (from MEFS),

TDEWOA = Tax Depreciation Expense without Acceleration,

XINEX = Interest Expense.

Therefore, the NUFS code incorporates state taxes as a user-specified tax rate times the income base for state tax determination purposes. The FUEL and OM variables are allowable deductions, representing costs of operation. The variables related to depreciation (TDEWOA) and interest expense (XINEX) warrant further explanation.

TDEWOA is simply the product of a straight-line depreciation rate, (1/SY1 for old assets, 1/SY2 for new assets), and the value of plant, excluding capitalized AFUDC (i.e., A1 for "old" assets and A2 for "new" assets). In this form, it is an analogue of Eq. (23), which captured the accelerated amount of depreciation. The variable TDEWOA is used in the state tax determination because it is assumed that state tax jurisdictions do not allow accelerated depreciation. It is also used below in the calculation of federal income taxes. Note that TDEWOA and Book Depreciation Expense, BDE, of Eq. (20) are similar except that depreciation for book purposes allows the depreciation of capitalized AFUDC (contained in the book value of the asset), whereas, for tax purposes, the capitalized AFUDC represents a difference between book and tax accounting.

The calculation of total interest expense that appears on the income statement, XINEX, which is the sum of the short-term interest expense, XSINEX, and long-term interest, XLINEX, is reflected in the following equations:

$$\text{XSINEX}_t = (\text{RTST}_t)(\text{PERST}_t) \left(\frac{\text{AMD}_t + \text{AMD}_{t-1}}{2} \right), \quad (34) \quad [\text{IS-13}]$$

$$\text{XLINEX}_t = (\text{EMDT}_t)(\text{PERLT}_t) \left(\frac{\text{AMD}_t + \text{AMD}_{t-1}}{2} \right), \quad (35) \quad [\text{IS-12}]$$

where, deleting subscripts,

RTST = Return to (Cost of) Short Term Debt (User-Supplied),
 PERST = Percent of Capital, Short-Term Debt (User-Supplied),
 EMDT = Embedded Cost of Debt [Eq. (5)],
 PERLT = Percent of Capital, Long-Term Debt (User-Supplied),
 AMD = Assets Minus Deferrals.

Interest expense in NUFS, therefore, is simply the weighted average cost of short and long term interest cost times the net assets that need to be financed, AMD. The variable AMD is computed in NUFS as total assets less deferrals.²⁰

The computation of federal income tax effects for regulatory purposes is much more complex than either of the two other tax variables. Although the computation of FEDREG in Eq. (31) is comparable to the state tax computation, consideration must be given to the investment tax credit, the debt portion of AFUDC, and other timing differences. The basic equation for calculation of federal taxes for regulatory purposes, FEDREG, in NUFS is:

$$\begin{aligned} \text{FEDREG}_t = & (\text{REVREQ}_t - \text{FUEL}_t - \text{OM}_t - \text{GENREG}_t - \text{STAREG}_t - \text{TDEREG}_t \\ & - \text{XINEX}_t + \text{AFUDCD}_t) \text{TXRT} , \end{aligned} \quad (36)$$

where, ignoring subscripts,

TDEREG = Tax Depreciation Expense for Regulatory Purposes,
 TXRT = Federal Tax Rate (User-Supplied),

and REVREQ, FUEL, OM, GENREG, STAREG, XINEX, and AFUDCD are as defined above.

Equation (36) attempts to capture the allowable federal income taxes for regulatory and, therefore, rate-making purposes. In the context of Table 1 that was incorporated in the second part of this paper, the computation of FEDREG in Eq. (36) attempts to reflect the tax results in the first column ("Book" taxes) of Table 2. To this end, a taxable base is computed in NUFS and the applicable federal tax rate is applied against that base. The taxable base reflects the revenues (REVREQ) net of allowable deductions generated by the private utilities in a given region. The computation of allowable deductions for fuel, operation

and maintenance costs, general and state taxes, and interest expenses were discussed above. The debt portion of AFUDCD is added in because for financial accounting purposes and, therefore, the determination of allowable income tax expense, debt portion of AFUDC is a legitimate item of income and, therefore, taxes are calculated on it (note the computation in Table 1). However, as detailed in Eq. (31), the federal tax benefit to rate-payers in the current period due to AFUDCD depends on the regulatory treatment of that tax benefit.

Tax depreciation expense for regulatory purposes, TDEREG in Eq. (36) is a direct function of the amount of the income tax benefit due to accelerated depreciation that PUCs allow to be flowed through in the current period. The representation in NUFS is as follows:

$$\begin{aligned} \text{TDEREG}_t &= (\text{TDEWOA}_t)(1 - \text{FLPR1}) + (\text{TDE} * \text{FLPR1}); \\ t &= \text{JYR}, \text{JYR} + \text{SY2} - 1, \end{aligned} \quad (37)$$

where, without subscripts,

TDEWOA = Tax Depreciation Expense Without Acceleration,
 JYR = Year Plant Comes on Line (from MEFS),
 TDE = Tax Depreciation Expense [Eq. (19)],
 SY2 = Service Life of the Plant (User-Supplied),
 FLPR1 = the Percentage of the Tax Benefit Allowed to be Flowed-Through in the Current Year (User-Supplied).

Clearly, from Eq. (37), as FLPR1 approaches one (i.e., all of the federal tax benefits are realized in the current period), the depreciation expense allowed for computation of taxes for regulatory purposes approaches the accelerated tax depreciation expense, TDE. On the other hand, as FLPR1 approaches zero (i.e., "normalization" of the federal tax benefit), the federal tax benefits of accelerated tax depreciation are not allowed to be utilized in the current period and, therefore, taxes are higher and revenue requirements are higher. In this case, the tax benefits of accelerated depreciation are deferred and "turn around" in later years of the asset's useful life.

In NUFS, the amount of taxes deferred due to accelerated depreciation, PRODEF, and reflected in the rate base in Eq. (14), can be derived directly

from Eq. (37). In Eq. (37), the gross amount of depreciation for tax purposes is computed on the basis of the regulatory treatment of the tax benefit through the variable, FLPR1. The tax effect is realized upon incorporation in Eq. (36). The excess of tax over book depreciation that is both flowed-through (EXTBF) and deferred (EXTBD), therefore, is computed as follows:

$$\text{EXTBF}_t = (\text{TXRT})(\text{TDE}_t - \text{TDEWOA}_t)(\text{FLPR1}) , \quad (38)$$

$$\text{EXTBD}_t = (\text{TXRT})(\text{TDE}_t - \text{TDEWOA}_t)(1 - \text{FLPR1}) . \quad (39)$$

The amount deferred in any year is simply added to the prior year's total and reflected in the balance sheet as a deferred liability (BS-21 in Appendix A):

$$\text{PRODEF}_t = \text{PRODEF}_{t-1} + \text{EXTBD}_t . \quad (40) \quad [\text{BS-21}]$$

The determination of the deferred tax liability in Eq. (40) misrepresents reality. The only "timing difference" reflected as a deferred liability is attributable to the difference between book and tax depreciation. In reality, as pointed out in Section 2 above, there are a number of such differences that arise in the operation of a utility. Indeed, the portion of capitalized interest attributable to debt financing (AFUDCD) is an example of a timing difference that NUFs accounts for, but is not reflected in the deferred tax liability.

The equation for FEDREG captures one of the three federal tax timing differences between financial and tax accounting that are incorporated in NUFs. Consideration must also be given to the investment tax credit and the debt portion of AFUDC.

The investment tax credit was instituted by Congress to encourage capital investment. As such, a specified percentage of expenditures for new investment in qualified property is applied as a direct credit against the federal income taxes of a utility in any given year. PUCs, on the other hand, have the option of allowing an individual utility to flow

through all or a portion of the credit to current consumers. The effect of flowing through the investment tax credit is to reduce the permissible amount of taxes used in calculating revenue requirements in any year and, hence, to reduce rates for current consumers. The portion of the credit that is not flowed through in the current period is deferred and the credit is amortized over the useful life of the asset. The specification of NUFs accounts for both treatments.

Consider Eq. (41) which provides the computation of XITCF, the amount of the investment tax credit that is generated in the current period and allowed to be flowed through:

$$XITCF_t = (FCWIP_t)(RITC)(FLPR1) , \quad (41)$$

where, without subscripts,

FCWIP = Annual Construction Expenses, net of AFUDC, [Eq. (24)],
 RITC = Investment Tax Credit Rate (User-Supplied),
 FLPR1 = Percentage of Tax Savings Flowed Through (User-Supplied).

The amount of investment tax credit flowed through, therefore, is simply the actual amount of construction expenses in the current period times the tax rate, factored by the amount the PUC allows to be flowed through, FLPR1. The amount of current period construction expenses deferred and amortized over the useful life of the asset (XITCD) is simply the amount not flowed-through:

$$XITCD_t = (FCWIP_t)(RITC)(1 - FLPR1) . \quad (42)$$

Equations (41) and (42) detail the amount of the investment tax credit which is generated in any forecast period. The amount that is reflected on the balance sheet as a deferral in a forecast period (BS-20 in Appendix A) and the amount that is amortized in any forecasted year depends on the amount of the deferral attributable to base year assets. The base year deferral (see Table B-2) is comprised of amounts attributable to (a) assets which are still under construction in the forecast period and to (b) base-year assets which are "on line" in the forecast period. The NUFs code segregates these two components. The

deferral attributable to the former amount is not amortized until the asset comes "on line", while the amount attributable to the latter is amortized immediately.

In general, then, the amount of the deferral amortized for any asset in a period represents equal amounts of the total deferral taken over the asset's useful life:

$$AITC_t = \left[\frac{(RITC)(A2)}{SY2} \right] (1 - FLPR1) . \quad (43)$$

The amount reflected as a deferral on the balance sheet (BS-20 in Appendix A) is simply the difference between current period ITC generated and deferred, XITCD, and the amount amortized in the current period:

$$DITC_t = (XITCD_t - AITC_t) + DITC_{t-1} . \quad (44) \quad [BS-20]$$

The treatment of the tax savings due to the debt portion of capitalized interest is similar to the treatment of the investment tax credit in NUFs. As was previously noted, one of the methods used by PUCs to allow utilities a return on construction expenditures is to capitalize interest expenses attributable to both debt and equity financing. The capitalization of interest expense is, of course, reflected as income on the current period income statement. The equity portion is an imputed amount based on the utility's return to equity financing and, as such, has no tax effect. Consequently, the equity portion of AFUDC is not considered in the tax calculation in the period when it is capitalized, nor should it be considered as depreciation expense for book purposes when the asset comes into service and the AFUDC is depreciated (see Table 1).

On the other hand, the debt portion of AFUDC, although capitalized and reflected as income on the current year's profit and loss statement (in reality, it is formally reported as a reduction in interest expense), is a legitimate deduction for tax accounting purposes in the year that it is capitalized. Since AFUDC-Debt is treated as income for book purposes, a tax-to-book timing difference arises. The current period

effect on book federal income taxes and, consequently, revenue requirements and electricity prices depends on the amount of the tax benefit - if any - the PUC allows to be flowed through.

Similar to the treatment of the investment tax credit, the amount of the federal tax benefit attributable to the debt portion of AFUDC allowed to be flowed through in a forecast period t , $XAFDCF_t$, is calculated as follows:

$$XAFDCF_t = (AFUDCD_t)(TXRT)(FLPR2) , \quad (45)$$

where, without subscripts,

AFUDCD = Amount of AFUDC Attributable to Debt Financing [Eq. (28)],

TXRT = Federal Tax Rate (User-Supplied),

FLPR2 = Percentage Flow Through of AFUDCD (User-Supplied);

and, consequently, the amount deferred, $XAFDCD$, is:

$$XAFDCD_t = (AFUDCD_t)(TXRT)(1 - FLPR2) . \quad (46)$$

The total amount deferred and amortized in future years is not reflected in the balance sheet along with accelerated depreciation as "Deferred Federal Income Taxes".

When an amount of capitalized debt is deferred, the deferral is amortized over the service life of the asset once it commences useful service. The calculation of $AAFDC_t$; the amortization of the deferral is:

$$AAFDC_t = \frac{(BA2-A2)(1-FLPR2)WACD_{JYR}}{SY2} ; t = JYR, (JYR+SY2-1) , \quad (47)$$

where, deleting subscripts,

JYR = Year Asset Begins Operation,

BA2 = Book Value of the Assets (including AFUDC),

A2 = Value of asset without AFUDC,

FLPR2 = Flow-Through Percentage (User-Supplied),

SY2 = Service Life (User-Supplied).

Regulatory lag and its effects

The determination of the components of revenue requirements and their (net) total in Eq. (14) is the first step in calculation of the actual revenues generated in NUFS. All of the determining factors of REVREQ for any period t in Eq. (14) are themselves current period magnitudes. It has been observed, however, that revenue determination for an individual utility is oftentimes not based on current or projected future expenses; but, instead, are based on some historical "test period" operating results. Consequently, a financial regulatory model of the electric utility industry must attempt to capture this delayed effect in its specification.

In the construction of the NUFS code, the modelers built four, user-supplied lag scenarios into the model:

1. no lag,
2. one-year lag,
3. one-and-one-half year lag,
4. two year lag.

In the no-lag scenario, revenues generated in any specified year, REVLAG, and reflected as IS-1 in Appendix A, are simply equal to the computed revenue requirements, REVREQ, for that year. In a one-year lag scenario, revenues are calculated as follows:

$$\text{REVLAG}_t = \text{TOTSAL}_t \left[\frac{\text{REVREQ}_{t-1} - \text{TXFUEL}_{t-1}}{\text{TOTSAL}_{t-1}} \right] + \text{TXFUEL}_t, \quad (48) \quad [\text{IS-1}]$$

where, deleting subscripts,

TOTSAL = Sales of Electricity (in gwh) [Eq. (6)],

REVREQ = Revenue Requirements [Eq. (14)],

TXFUEL = Fuel Costs Adjusted for Taxes [Eq. (4)].

In the specification of Eq. (48), lagged revenues and, therefore, current electricity prices, are a function of current period fuel costs (through fuel adjustment clauses) and rates based on some pre-specified historic test period. For the two-year lag case, the fraction in Eq. (48) is lagged two years. In the one-and-one-half year case, the average of one- and two-year lags is calculated.

The calculation of average price of electricity, PRICE, follows once a lag scenario is established. The calculation is simply:

$$PRICE_t = \frac{REVLAG_t}{TOTSAL_t}, \quad (49)$$

where TOTSAL was derived in Eq. (6).

In the previous section, taxes for regulatory purposes were calculated on the basis of current period revenue generation. If a user specifies the no-lag scenario, REVLAG = REVREG and, therefore, all taxes would be based on the revenues calculated in Eq. (14). However, if one of the other lag scenarios is specified, all taxes must be based on the revenues calculated from that particular scenario.

For income statement purposes in NUFS, the actual tax expenses are divided into two categories: General Taxes (IS-5 in Appendix A) and Income Taxes (IS-6 in Appendix A). The former variable includes all taxes except (state and federal) income taxes, while the latter amount is the total of federal and state income taxes. The categories applicable to taxes on the balance sheet only include the amounts attributable to the Deferred Investment Tax Credit (BS-20 in Appendix A) and to the excess of tax over book depreciation that is not flowed through in the current period, PRODEF, calculated in Eq. (40) and reflected as BS-21 in Appendix A. The current tax liability is presumably reflected in Working Capital, which was calculated as one-eighth the amount of operation and maintenance expenses in Eq. (7). The amount of General Taxes reflected as expense on the income statements, GENTX, is computed as follows in NUFS:

$$GENTX_t = (GTXRT)(REVLAG_t) + PROPTX_t + SALETX_t, \quad (50) \quad [IS-5]$$

- GTXRT = General Tax Rate (From Form/Form 3),

- PROPTX = Property Taxes,

- SALETX = Sales Taxes,

- REVLAG = Actual Revenues [Eq. (48)].

The specification of Eq. (50) originates from the manner in which the General Tax Rate, GTXRT, is calculated in NUFS. Recalling the discussion of base year financial information above, the general tax rate is computed as the ratio of all non-income taxes to operating revenues in the base year (i.e., 1978). Since the rate does not incorporate "new" assets and is carried over into the forecast period, the variables PROPTX and SALETX presumably reflect property and sales taxes that emanate from new assets, respectively. They are calculated in NUFS as follows:

$$\text{PROPTX}_t = (\text{BA2}_t)(\text{PRTXRT}) , \quad (50A)$$

$$\text{SALETX}_t = (\text{FCWIP}_t)(\text{SATXRT}) , \quad (50B)$$

where,

BA2 = Book Value of "New" Assets,
 FCWIP = Annual Amount of New Construction [Eq. (24)],
 PRTXRT = Property Tax Rate (User-Supplied),
 SATXRT = Sales Tax Rate (User-Supplied).

The amount of current state taxes, net of federal income tax benefits (since state taxes are an allowable deduction for federal tax purposes), STATET, is computed the same as in Eq. (33) with the exception that the current revenues, as determined by REVLAGE, is substituted for REVREQ. Additionally, because of the particular method used in the NUFS' solution scheme, STATET is calculated net of the federal tax benefit. The calculation is:

$$\begin{aligned} \text{STATET}_t &= (\text{REVLAGE}_t - \text{FUEL}_t - \text{OM}_t - \text{TDEWOA}_t - \text{XINEX}_t) \\ &\quad \text{STXRT} (1 - \text{TXRT}) , \end{aligned} \quad (51)$$

where TXRT = Federal Tax Rate, and FUEL, OM, TDEWOA, XINEX, and STXRT are defined in the context of Eq. (33).

Consider Table 1 in Section 2. As noted in that section, the actual federal income tax expense that is reflected on the income statement for

financial reporting purposes is the sum of the current tax provision (second column) and the deferred tax provisions (third and fourth columns). The second or "Tax" Accounting column mirrors the computation of the actual tax liability for the accounting period. The computation of federal income taxes in NUFS is patterned along the same general framework. First, a current tax provision is calculated and, then, the deferred totals are added on to derive the total income tax expense.

The calculation of Current Income Taxes for any forecast period, t , is as follows:

$$\begin{aligned} \text{CIT}_t = & (\text{REVLAG}_t - \text{FUEL}_t - \text{OM}_t - \text{TDEWOA}_t - \text{GENTX}_t - \text{XINEX}_t) \text{TXRT} + \\ & \text{STATET}_t - [\text{XITCF}_t + \text{XITCD}_t] - [\text{EXTBF}_t + \text{EXTBD}_t], \end{aligned} \quad (52)$$

where, deleting subscripts, REVLAG, FUEL, OM, TDEWOA, GENTX, XINEX, TXRT, and STATET were defined previously, and the amounts in brackets reflect the total amount of investment tax credit and excess of tax over book depreciation generated in the forecast period t , respectively.

The computation in Eq. (52) attempts to parallel the actual federal income tax calculation. The variable STATET is included because, in the NUFS framework, CIT reflects both federal and state income taxes. The total appearing in the first set of parentheses reflects taxable income with the exception that the tax depreciation amount, as reflected in TDEWOA, is a straight-line amount. The net effect of the excess of tax over book depreciation is contained in the total $[\text{EXTBF} + \text{EXTBD}]$. The derivation of these latter variables are discussed and derived in the context of Eqs. (38) and (39). Finally, the total amount of the investment tax credit and tax-over-book depreciation generated in the current period is subtracted — even if PUCs allow the credits to be flowed-through to current consumers — because, for federal tax purposes, they are allowable deductions in the current period.

Given the computation of the current tax liability in Eq. (52), the amount of Total Income Tax Expense, TTXEX, that is incorporated into the

income statement for financial reporting purposes is:

$$TTXEX_t = CIT_t + (XITCD_t - AITC_t) + EXTBD_t, \quad (53) \quad [IS-6]$$

where, CIT is the amount computed in Eq. (52) and,

XITCD = The Amount of ITC Generated in the Current Period and Deferred [Eq. (42)],

AITC = Amortization of ITC Deferred in Prior Periods [Eq. (43)],

EXTBD = Excess of Tax-Over-Book Depreciation Generated in the Current Period and Deferred [Eq. (39)].

The total (XITCD - AITC) in Eq. (53) is the charge to current operations for the deferred investment tax credit, while EXTBD represents the charge for deferred taxes. The segregation of federal tax effects between current taxes, deferred taxes, and the deferred ITC is summarized as part of one of the output tables in NUFS. That information is contained in the "Income Tax Expense" table on pages and of Appendix A.

Capitalization and financial ratios

The most important forecasted variables that emanate from NUFS are related to capitalization and its structure. The total amount of long-term and short-term debt outstanding (BS-17 and BS-18 in Appendix A, respectively) and the amount of preferred stock (BS-14) and common stock (BS-13) are crucial variables for analysis of a utility's financial position. In addition, the amount of corporate savings or retained earnings (BS-15) also plays a pivotal role in financial analysis.

The NUFS solution scheme has a provision for two methods through which the determination of capitalization is derived. The selection of either method is made through use of Option 1 in the user-supplied inputs (see Table B.1). When the user specifies Option 1 to be 1, capitalization is calculated on the assumption that the amount of Common Equity and Preferred Stock will not be decreased from the prior period. If the user specifies Option 1 = 2, the capital structure is simply calculated on the basis of the user's specification of the capitalization percentages (i.e., PERLT, PERST, PERPS, and PERCE). Since Option 1 = 2 for the base case analysis, the discussion will begin with a description of that option.

Since by the definition of double-entry accounting, assets must equal liabilities and equity, the basis for computation of the

capitalization components in NUFS is the variable AMD, Assets Minus Deferrals, which is computed as follows:

$$\text{AMD}_t = (\text{ASSETS}_t + \text{BCWIP}_t - \text{ABDE}_t + \text{XNUCFL}_t + \text{WC}_t) - (\text{DITC}_t + \text{PRODEF}_t), \quad (53)$$

where, deleting subscripts,

ASSETS = The Book Value of Assets [BS-1 through BS-4 in Appendix A],
 BCWIP = Construction Work in Progress, Book Value [BS-5],
 ABDE = Total Accumulated Book Depreciation Expense [BS-7],
 XNUCFL = Net Nuclear Fuel [BS-9],
 WC = Working Capital [BS-11],
 DITC = Deferred Investment Tax Credit [BS-20],
 PRODEF = Provision for Deferred Taxes [BS-21].

The total contained in the first set of parentheses is simply the "Total Assets and Other Debits" from the balance sheet (see Appendix A), while the amount in the second set of parentheses is the total deferrals calculated in NUFS. Thus, in essence, AMD in NUFS represents the (Net) assets that need to be financed and, as such, is the basis for computation of the capital structure.

First, the amount of Preferred Stock, PS, (BS-14 in Appendix A), Long-Term Debt, LTD, (BS-17), and Short-Term Debt, STD, (BS-18) are calculated as follows:

$$\text{PS}_t = (\text{PERPS})(\text{AMD}_t), \quad (55) \quad [\text{BS-14}]$$

$$\text{LTD}_t = (\text{PERLT}_t)(\text{AMD}_t), \quad (56) \quad [\text{BS-17}]$$

$$\text{STD}_t = (\text{PERST}_t)(\text{AMD}_t), \quad (57) \quad [\text{BS-18}]$$

where PERPS, PERLT, and PERST are user-supplied inputs for the percentage of capitalization attributable to preferred stock, long-term debt, and short-term debt, respectively.

Preferred Dividends are then calculated on the basis of the user-supplied return to (cost of) preferred stock, RTPEQ:

$$\text{PREDIV}_t = (\text{RTPEQ}_t)(\text{PS}_t), \quad (58) \quad [\text{IS-17}]$$

and common stock dividends, COMDIV, are computed as a user-supplied fraction, DIVRAT, of the amount of Earnings for Common Stock:

$$\text{COMDIV}_t = (\text{DIVRAT}_t)(\text{ECS}_t), \quad (59)$$

where ECS is simply Net Income less preferred dividends (see the Income Statement in Appendix A).

Quite trivially, the amount of Retained Earnings, RE, (BS-15) is reflected as last year's balance, RE_{t-1} , plus the incremental contribution this year:

$$\text{RE}_t = (\text{ECS} - \text{COMDIV}) + \text{RE}_{t-1}, \quad (60) \quad [\text{BS-15}]$$

while the book value of common stock, CS, is reflected as follows:

$$\text{CS}_t = (\text{PERCE}_t)(\text{AMD}_t) - \text{RE}_t, \quad (61) \quad [\text{BS-13}]$$

where PERCE is the user-supplied percentage of common equity (see Table B-1).

Under this formulation, forecasted capitalization is, in essence, user-supplied. The asset and liability/equity portions of the balance sheet are equated through use of the variable AMD as the basis of the capitalization computation.

Under the alternate treatment of capitalization, (Option 1 = 1 in Table B-1), the amount of Assets Minus Deferrals; Preferred Stock; Long-Term Debt; and Short-Term Debt are calculated as in Eqs. (54), (55), (56), and (57), respectively. However, if the amount of Preferred Stock calculated in Equation (55) is less than the amount in the prior period, the prior period's value is used and the deficiency (i.e., $\text{PS}_{t-1} > \text{PS}_t$) is "forced" into the computation of Long-Term Debt, LTD*:

$$LTD^* = LTD + (PS_t - PS_{t-1}), \quad (56A)$$

where LTD is the amount computed in Eq. (56). Therefore, the amount of Preferred Stock cannot be reduced from the prior period. The total amount of Preferred Dividends, Common Dividends, Retained Earnings, and Common Stock are then computed as in Eqs. (58), (59), (60), and (61), respectively.

Since by definition of the option, the book value of common stock cannot be lower than the prior period's value, the algorithm "compares" the calculation of common stock in Eq. (61) with the previous year's balance. In the event that the latter value is higher, the value of common stock in the current period is simply the prior period's amount. Again, this "deficiency" (i.e., $CS_{t-1} > CS_t$) is incorporated into the computation of Long-Term Debt^{**}:

$$LTD^{**} = LTD^* + (CS_t - CS_{t-1}), \quad (56B)$$

where LTD^* is calculated in Eq. (56A).

In essence, the derivation of total capitalization under this method arbitrarily "attributes" any current-period deficiency in common and preferred stock from the prior period to Long-Term Debt. Furthermore, this method relies solely on user-supplied inputs that may not reflect prevailing conditions in the capital markets. The economic consequences for the specification of capitalization under either of the two options will be discussed more thoroughly in Section 5.

The primary financial ratios emanating from NUFS are derived from the three basic forecasted financial statements presented in Appendix A. Capitalized interest (AFUDC) as a percent of earnings is simply the ratio of total AFUDC and earnings available for common stock on the income statement. External financing requirements represent the ratio of total external funds to total application of funds on the "Sources and Uses of Funds" statement. Interest coverage, COVRAT, calculated in NUFS under the SEC formula, is derived as follows:

$$\text{COVRAT}_t = \frac{(\text{OI}_t + \text{TTXEX}_t + .10 \text{ AFUDC}_t)}{\text{XLINEX}_t}, \quad (62)$$

where, deleting subscripts,

OI = Operating Income (From the Income Statement),
TTXEX = Total Income Tax Expense [Eq. (53)],
AFUDC = Allowance for Funds Used During Construction [Eq. (27)],
XLINEX = Long-Term Interest Expense [Eq. (35)].

4. COMPARISON OF FINANCIAL REGULATORY MODELS

As the financing problems of electric utilities have intensified, financial regulatory models have increasingly been utilized to evaluate the financial implications of electric utilities' projected capital expansion programs. While the focal point of all such models is financial statement projections accomplished through specification of a series of accounting relationships, significant differences have been observed with respect to their formulation. Included among these differences is the purpose for which the model is intended. For example, some models were developed for incorporation into a larger modelling system embracing the totality of the electric utility industry and, consequently, involve various levels of aggregation across individual utilities. Others, on the other hand, were constructed for the primary purpose of forecasting the financial performance of individual utilities.

NUFS, of course, is an example of the former wherein the specification of the model involves a considerable amount of aggregation. The financial regulatory model incorporated within the Regionalized Electricity Model (REM)²¹ is another example of a financial model incorporated within a larger system. The financial regulatory model in REM provides a link between the specification of supply-side and demand-side activity. The financial regulatory model incorporated in the Utility Simulation Model (USM),²² developed by Teknekron Research, Inc. for the U.S. Environmental Protection Agency, is another example of a financial model that is incorporated as part of a larger system. The focal point of analysis in USM is state-level activity wherein the financial module simulates the regulatory performance of firms within the state under scrutiny.

Although some financial regulatory models were developed with the primary intent of evaluating the financial character of individual utilities, they can be used for state, regional, or national analysis. In this context, the inputs to the code need only be aggregated to the level that the user specifies. The Regulatory Analysis Model (RAM),²³ for example, developed primarily for use with individual utility data, can easily accommodate aggregation to any level by altering the structure of inputs.

The purpose of this section is to compare the specification of NUFS with other models that characterize electric utility financial regulatory activity. The emphasis is on specification of the financial regulatory sector and, therefore, no attempt will be made to compare the capacity expansion plans that are an integral input into any financial model. The capacity expansion program emanating from MEFS, for example, will not be assessed relative to similar supply-side models utilized in other financial regulatory models.

Two models have been selected for detailed comparison with NUFS: (1) the financial regulatory model in REM and (2) the Regulatory Analysis Model (RAM). The former representation has been selected because, like NUFS, the financial regulatory sector represents aggregation across individual utilities on a regional basis and is incorporated as part of a larger system. RAM, on the other hand, was developed for the primary purpose of simulating the financial performance of an individual utility under alternate capacity expansion and regulatory scenarios and, as such, represents the formulation of financial regulatory activity outside of a larger modelling effort.

REM represents a dynamic characterization of the electricity market in the U.S. It consists of a supply-side specification and a demand component that interact through the price of electricity. The supply side of REM utilizes investment decision rules to determine the production profile of electricity from five generation types and the user-supplied portion of hydro-electric power. The demand side in REM is characterized in two steps. First, the overall level of energy use is determined for the residential-commercial and industrial sectors. Then, using a multinomial logit framework, the relative use of different types of fuels is derived.

The link between the supply and demand specification in REM is provided by a financial regulatory submodel wherein the average price of electricity is computed and utilized in the specification of demand. Additionally, the capital charge rate is computed and incorporated in the electricity supply submodel.

Since REM is aggregated to the nine-census region level, the characterization of economic regulation for electric utilities is, in essence, on an industry basis rather than an individual utility basis. Therefore, similar to NUFS, the representation of the financial regulatory sector necessarily involves aggregation across utilities and the projected financial position of electric utilities represents an average across utilities of varying financial "health" within a region.

RAM, on the other hand, was developed primarily for use in the projection of financial variables for an individual utility. In this formulation, it does not represent a link between supply-side and demand-side modelling efforts. The input into RAM consists of historical financial information (i.e., structure of capital, assets, depreciation, operating costs, and maintenance data) and a user-provided capital budget. The latter variable, of course, could be provided from a separate electric utility capacity expansion model. Similar to NUFS and the financial regulatory submodel in REM, the output of RAM consists of projected financial statements and financial ratios derived therefrom.

Table 2 presents a comparative description of NUFS, RAM, and REM with respect to specification and underlying assumptions present in the respective models. The modelling areas compared in Table 2 are not intended to be all-encompassing, but, instead, represent select issues relating to specification and alternative treatments of characteristics in the various regulatory models represented.

At the outset, it must be emphasized that the comparative criteria detailed in Table 2 are related to financial regulatory models, per se, and not the models as part of a larger system. Thus, the comparison is not on the basis of the methodology used for determination of input magnitudes. Indeed, the capacity expansion programs for both NUFS and REM emanate from electric utility supply models, while those same variables are user-supplied in RAM (although they can be based on a capacity planning model).

From Table 2, although NUFS and the financial regulatory model in REM perform essentially the same function in their respective systems, NUFS has a greater degree of flexibility built into it. NUFS affords the

Table 2. Comparison of financial regulatory models

	NUFS	REM	RAM
Working Capital	• FPC Method	• FPC Method	• Calculated
Plant Retirement	• User-Supplied	• User-Supplied	• User-Supplied
Rate Base Valuation	• Original Cost	• Original Cost	• Original Cost
Revenues	• 4 Lag Scenarios	• One Year Lag	• Current
Deferred Inc. Taxes	• Tax-Over-Book Dep.	• Tax-Over-Book Dep.	• Tax-Over-Book Dep.
% CWIP in Rate Base	• User-Supplied	• Not Allowed	• User-Supplied
Electricity Price	• Average	• Average	• NA
Tax Deprec. Rate ¹	• DB, 2DB, SYD	• SYD	• 2DB
AFUDC Rate	• User-Supplied	• User-Supplied	• User-Supplied
Solution Criteria	• Revenue Reqmts.	• Revenue Reqmts.	• Revenue Reqmts. • Return on Equity • Return on Rate Base
Capital Structure	• 2 Scenarios	• Hierarchy of Sources	• Hierarchy of Sources

¹ DB = Declining Balance Method
 2DB = Double Declining Method
 SYD = Sum-of-Years Digits Method

user the use of no-lag, one-year lag, two-year lag, and one and one-half year lag scenarios, while REM essentially computes revenues on a one-year lag basis. Curiously, REM does not allow the incorporation of CWIP in the rate base. In NUFS, the user specifies the percentage of CWIP allowed. The NUFS framework also allows three different accelerated depreciation rates and REM incorporates only one.

The major similarities between the two codes generally relates to the assumptions incorporated in the financial accounting framework. Thus, the rate base valuation method, the computation of working capital, and the plant retirement assumptions are treated in the same way in the two codes.

As the last section of this report delineated, the capital structure in NUFS is determined on the basis of one of two user-supplied options. Either the structure is based exactly on the weights that the user assigns to the various components or the structure is based on those same weights with the additional stipulation that preferred and common equity cannot be reduced. Capital markets are not modelled.

In the financial regulatory model of REM, capital markets are not specified, but a "hierarchy" of capital components is formulated. Internal financing is the first priority. If the amount of required financing exceeds the internal generation of funds, the code assumes that utilities attract external capital from among debt, preferred stock, and common stock sources - in that order - up to the user-specified limit placed on their use. In the event that utilities cannot generate the requisite capital from among the aforementioned internal and external sources, the model assumes a fictitious "State Power Authority" that will act as a "lender of last resort". Moreover, similar to the NUFS' framework, the cost of the various components of capital in REM is user-specified since capital supply curves are not incorporated into the system.

Similar to the results of the procedure performed at EIA wherein fixed charge rates and pricing coefficients are "manually" incorporated into the MEFS modeling framework (see Fig. 1, Section 3), the capital service charge and average price of electricity computed in the financial regulatory model of REM are, in turn, formally linked to the electricity supply and demand sectors of REM, respectively. Since, to our knowledge,

the procedure utilized at EIA is undocumented, any substantive similarities or differences between the interaction of the financial regulatory sub-models of REM and NUFS and electricity supply and demand sub-models are unknown.

RAM fundamentally differs from NUFS and REM because the model was not constructed for incorporation into a larger electric utility modelling system. The primary inputs into NUFS and REM (e.g., capital costs, capital investment profile, fuel costs, operation-maintenance costs, and the generation of electricity) are attributable to the representation of an electric utility supply model. Although RAM requires values for variables of a similar nature, they are based on a combination of user-provided data and econometric relationships.

The execution of RAM is accomplished through the interaction of four modules: (1) a Plant Module, (2) a Performance Module, (3) a Fixed Obligations Module, and (4) a Finance Module. The first three modules require historical data relative to plant/depreciation, operation-maintenance expenses, and debt/preferred stock balances, respectively. Additionally, the Plant Module requires an assumed capital budget profile.

The output of these three modules is utilized by the Finance Module to forecast the primary financial statements and other financial information. A comparison of the specification of the Finance Module with REM and NUFS is provided in Table 2.

The most salient feature of RAM in comparison to the other two codes listed in Table 2 is the level of input detail required for the operation of RAM. For example, the Fixed Obligations Module affords the treatment of individual debt and preferred stock issues. Thus, data are specified relative to the year and date of issue, retirement date, interest or dividend rate, and sinking fund payment for each individual issue of debt and preferred stock. Moreover, in concert with the Finance Module, estimates of interest and dividend payments are made for each of these issues and a calculation of requisite new debt and stock is made.

The forecasted capital structure in RAM is based on a "hierarchy" of external sources. In the event that the internal generation of funds is not sufficient to finance the capital program, short-term debt is utilized up to a user-provided maximum, followed by a user-supplied mix of long-term-debt, preferred stock, and common stock.

As Table 2 notes, RAM also differs from the other two codes on the basis of solution criteria. In NUFS, for example, the solution is based on the attainment of required revenues in conjunction with a pre-specified lag scenario. RAM affords solution of the code on the basis of attainment of a user-provided return on equity and return on rate base, in addition to attainment of the operating revenue goal.

Instead of relying on the FPC formula for computation of working capital, RAM specifies the calculation of working capital. In essence, the value of working capital represents a "balancing item" for financial statement preparation. For example, if the amount of internally-generated funds is greater than the amount of expenditures, the excess is used to reduce short-term-debt to a user-specified minimum and any remaining amount is incorporated into the computation of working capital.

5. OVER-ALL ASSESSMENT OF THE NUFS MODEL

Model Formulation

The NUFS code attempts to emulate the electric utility rate-making process through specification of a series of financial accounting relationships. These financial accounting equations are intended to "evaluate" the feasibility of the capacity expansion programs emanating from MEFS as a portion of its output. Thus, MEFS' regional forecasts of new capital additions and associated operating costs, in concert with aggregate electric utility base-year financial information and myriad user-provided assumptions, are assimilated in NUFS for the purpose of deriving the "financial condition" of electric utilities. The resulting output is used to "assess", in some sense, the growth of the industry and, more importantly, the ability of the industry to acquire the capital financing (both internally and externally) that new investment requires.

Not unlike most models, the formulation of NUFS abstracts from many of the subtleties inherent in the process that is being modeled. While the derivation of the three primary financial statements in NUFS (i.e., the income statement, balance sheet, and flow-of-funds statement) represents an attempt to mirror the real-world financial environment, many of the details inherent in that financial representation are assumed away. For example, the numerous entries that comprise Current Assets and Liabilities in a firm (e.g., cash, materials, supplies, current taxes payable, accounts payable) are "lumped" together as Working Capital in NUFS and further assumed to be equal to one-eighth of FUEL and OM costs. Consequently, the current cash position of utilities is unidentified in NUFS on the balance sheet. The Sources and Uses of Funds Statement, incorporated as part of NUFS output, however, identifies the amount of funds generated internally.

Even more importantly, the NUFS code models the actual rate-making process through a series of user-supplied assumptions with respect to the treatment of CWIP; the rate at which AFUDC is capitalized; the treatment of federal tax benefits; the allowed capital structure; and the rate of return that can be earned. Dismissing the problem of aggregation for the moment, all of the determinants of the rate-making procedure in NUFS are financial or economic. In reality, that process encompasses significant political aspects wherein the determination of allowable revenues, the rate

structure, and their concomitant details (e.g., rate base valuation, rate of return) represents the complex political interaction of an individual utility, an individual PUC, and an assortment of adversary groups.

In a similar vein, aggregation at the (DOE) regional level in the NUFS-MEFS interface misrepresents the electric utility rate-making process. The NUFS user must specify financial regulatory information and other important inputs aggregated to the regional level. In practice, this procedure necessitates some type of "averaging" process across all of the utilities and states within a region. Since economic regulation in the electric utility industry is on an individual-firm basis, the aggregation procedure in NUFS distorts the institutional character of the industry.

What is implicitly modeled in NUFS, however, is economic regulation on an industry (or regional) basis. In actuality, NUFS forecasts the financial performance of a "prototype" electric utility for a pre-specified region and ownership type. Thus, revenue generation and rates are assumed to be set for a "class" of utilities and, furthermore, inclusion in a specific "class" is defined only on the basis of geography and ownership type.

NUFS and Economic Considerations

Section 3 of this report presented in considerable detail the information flow into NUFS; the specification of individual equations in the code and their underlying assumptions; and the corresponding output of the model. As such, that section was primarily concerned with the financial and accounting aspects of economic regulation as formulated in NUFS. Presently, the discussion will be oriented to the economic considerations involved in the NUFS-MEFS interface.

At a maximum, a financial regulatory model of the electric utility industry should be able to address - and simulate the effects of - various policy alternatives and institutional changes in the industry. Presently, a number of issues have been raised with respect to the current operation of electric utilities that has led to a proliferation of research into the industry and proposals for reform of the future course of the industry. Included among those issues are power pooling and wheeling arrangements, various time-of-day pricing schemes, and deregulation of the industry in order to promote competition and a more efficient use of resources.

The remainder of this section will be devoted to the capability of NUFS to simulate these various policy alternatives and to some deficiencies in the economic formulation of NUFS.

Interaction of demand and supply

As Section 3 of this report delineated, NUFS is presently utilized in conjunction with the electric utility sector of MEFS. The ultimate goal is for NUFS to "assess" the financial feasibility of MEFS' capacity expansion plan through a projection of primary financial statements and financial ratios, given a specific capacity expansion program from MEFS. Included among the variables projected from NUFS are implicit financing sources, capital service charges, and the average price of electricity. Conceptually, a supply-side financial constraint from NUFS to MEFS could link the former two variables to MEFS.

However, every proposed increment to capacity or substitution among alternate forms of producing electricity also has implications for the price of electricity and its concomitant impact on demand. One of the variables forecasted in NUFS is the average price of electricity implicit in the MEFS' forecast of capacity expansion and its accompanying cost. Theoretically, the impact of higher electricity prices on demand should pose as much of a constraint on a capacity expansion program as the inability of the industry to generate the funds required for financing the program. Pragmatically, however, the impact of changing electricity prices on demand and, therefore, the capacity expansion plan emanating from MEFS depends on the price elasticity of demand incorporated as part of MEFS' specification of the demand for electricity.

As the broken lines in Fig. 1 (Section 3) indicate, the users of NUFS at EIA have apparently attempted to emulate a formal supply- and demand-side constraint by "manually" incorporating both the fixed charge rate and pricing coefficients into MEFS. However, as we pointed out earlier, the results of that procedure are not addressed in this report, and, to our knowledge, the procedure is not documented.

Innovative pricing schemes

In recent years, a large amount of research on the electric utility industry has been oriented to the determination of the economic impact of alternative pricing schemes in the industry. Included among those proposals has been the elimination of declining block rates and the introduction of time-of-day (TOD) pricing of the electrical service. In essence, TOD pricing would encourage use of electricity during off-peak hours — when demand on an electrical system is relatively low — by structuring rates to more accurately reflect the marginal cost of providing the electrical service. Thus, during periods of relatively high demand when higher-cost production "peaking units" are utilized, rates would reflect that higher cost.

Unfortunately, under the present specification of NUFS, the impact of introducing alternative pricing schemes on demand and its effect on capacity expansion cannot be analyzed. It may be possible, however, to reflect a TOD pricing structure by arbitrarily changing the representation of the load duration curve in the formulation of MEFS' electric utility conversion process to reflect the proposed impact of TOD pricing. The problems and procedures associated with that possibility are beyond the scope of the present analysis.

Inter-regional effects

The actual fuel and operation and maintenance costs associated with operating an electrical system are derived from the MEFS system. Those outputs are aggregated into regional totals — by ownership type — for use in NUFS. NUFS, in turn, is regionally a "closed system." The modeling framework in NUFS does not have cost curves associated with it and, even if it did, could not reflect economies across regional boundaries. Any efficiencies associated with the operation of an electric system, therefore, must emanate from the specification of MEFS' modeling framework.

With passage of the Public Utility Regulatory Policies Act (PURPA) in 1978, the Federal Energy Regulatory Commission was granted broader authority

with respect to ordering "wheeling" arrangements in the industry. In its broadest sense, "wheeling" refers to the use of the electric transmission facilities of one utility to transmit power of and for another utility. It is an integral part of an electrical system which is not geographically contiguous to sources of power, or may be mandatory for utilities with remote generating sources or geographically disparate service areas.

The economic advantages associated with wheeling revolve around efficiency arguments. If electric utilities are to increase the efficiency of their operations through power pooling, for example, wheeling arrangements may proliferate.

Unfortunately, the NUFs' code is not specified in a way to handle the financial ramifications of inter-regional activity in general, or wheeling arrangements in particular. Therefore, at present, there is no way to simulate the financial implications of increased wheeling activity. It may be argued, however, that wheeling solutions are implicit in the MEFS' results or that the inputs to MEFS could be altered so as to reflect wheeling arrangements. Under these arguments then, NUFs merely projects the financial ramifications of the MEFS' solution. The capability of MEFS to include the cost effects of increased wheeling activity is beyond the scope of the present research effort.

Capitalization

Perhaps the most troubling aspect of NUFs' specification is related to the determination of capitalization. The most important assumption in NUFs is that utilities can always generate enough external funding — through both debt and equity issues — to meet their capacity addition commitments. As the last portion of Section 3 made explicit, the structure and cost of capitalization in NUFs is essentially user-provided. Under one scenario, utilizing Option 1 in Table B.1, the capital structure is determined solely on the basis of the weights assigned by the user; while, under the alternate treatment, user-supplied weights determine the structure with the added constraint that equity cannot be reduced from the prior period's value. Any reduction in equity is "forced" into the long-term debt component under the latter option.

From an economic standpoint, the relationship between the components of capital and their cost are not modeled in NUFS. Or, in other words, there are no supply curves for the sources of external funding in NUFS. Thus, given a particular capitalization constraint [e.g., the percentage of long-term debt (PERLT) = 49.26% for the private sector in Table B.1] and its associated cost (e.g., the cost of new debt = 10% for private utilities in Table B.1), it is implicitly assumed that debt is available at a constant price up until a debt:capitalization ratio of 49.26% and, furthermore, no incremental amount is available beyond that pre-specified percentage. Or, in more precise terms, the supply of debt is perfectly elastic to the point where it satisfies the pre-specified constraint (49.26% in this example) and perfectly inelastic for larger percentages. The same argument, of course, holds for the other components of capital (i.e., short-term debt, preferred equity, and common equity). The absence of explicitly formulated capital markets in NUFS represents a serious theoretical misrepresentation of economic relationships.

6. CONCLUSION^{*}

Models in general are necessarily abstractions of perceived or actual real world processes. Viewed in this way, there may be any number of approaches to modelling the same economic phenomena. Indeed, models of the same economic process may vary with respect to the degree of exogeneity, the level of aggregation, and the technique used for representation (e.g., engineering process model vs. econometric model), among an assortment of other criteria. Oftentimes, specific modelling approaches are elected simply on the basis of the modeler's expertise or to accommodate the use for which the model is intended.

The process of determining whether a model is "good" or "bad" - in some sense of those words - is, therefore, more than a trivial matter. Is an economic model that is replete with theoretical deficiencies "better" than a competing model which is conceptually sound because the former one forecasts more accurately? Or, is a model that simulates "better" over a historical period better than one that performs relatively "poorly" over historical periods, but can identify "turning points" more accurately? Although there is no generally-accepted body of evaluative criteria, to a limited extent the aforementioned questions must be answered in the context of the purpose for which the model was constructed.

Evaluative criteria notwithstanding, the problems with drawing conclusions on NUFS are exacerbated by the position NUFS occupies as part of a larger system. The NUFS code does not "stand alone". It is presently used as one component of a larger system that encompasses the entire energy economy. As such, it is but one of a multitude of submodels that comprise the MEFS forecasting system. Since interaction is characteristic of the energy economy, the various models that comprise MEFS represent a network of complex interaction of supply sources and demand availability. NUFS is presently utilized to complement the specification of the electric utility sector in that larger modelling framework.

In this context, it is feasible to evaluate NUFS at two different levels. First, one can view NUFS as a self-contained code. That is, the specification of individual financial accounting relationships can be

^{*}The work reported here was completed in May 1981 and thus refers to the version of the NUFS code that existed before this date. Revisions to the code after May 1981 have not been considered and thus the text does not necessarily reflect the later versions of the code.

examined and evaluated in light of the existing regulatory environment. In the present report, that task was accomplished in Section 3 wherein the major equations were examined and their underlying assumptions explained. Second, NUFS can be evaluated in the context of its overall performance, including its relationship to MEFS; its uses for policy analysis; and its performance. Questions relating to this issue were addressed in Section 5 of this report.

The remainder of this section will be devoted to a summarization of the evaluative results found at these two levels of analysis. It will conclude with a discussion of the uses to which NUFS can be used and recommendations for improvement of the code, per se, and its relationship to a larger modelling framework.

The NUFS Code

In general, the NUFS' financial accounting framework is an attempt to represent current electric utility industry practices with respect to the flow of financial information. The code does not, however, capture a number of intricacies associated with the financial accounting process. With respect to the process modelled, the major assumptions in the specification of the code include:

- Electric utilities in any region are assumed to maintain positive amounts of working capital based on a presumed 45-day billing cycle.
- Assets are assumed to be retired at the end of a user-specified, "useful asset life".
- Public Utility Commissions allow determination of rate base value on a historical cost basis only.
- Deferred income taxes (the investment tax credit notwithstanding) arise only as a result of the difference between book depreciation expense and tax depreciation expense.
- The base-year capitalization values (i.e., short- and long-term debt, preferred stock, common stock, and retained earnings), the deferred liabilities (deferred income taxes and deferred ITC), working capital, and net income, are assumed to be ratably allocated to "electric utility operations" on the basis of an aggregate apportionment scheme.

- The amount of electricity generation emanating from the MEFS solution attributable to private and public utilities, respectively, is assumed to be equal to the proportion existing in the base year.
- The general tax rate is assumed to be a constant fraction of the amount of revenues.
- "Old" assets (or, assets that existed prior to the forecast period), categorized by type, are assumed to have the same remaining useful life for any specified region and/or ownership type.
- "Old" assets can only be depreciated utilizing the sum-of-the-years digits method for tax purposes.
- The stock of nuclear fuel in any forecast period is assumed to be twice the amount of nuclear fuel expense.
- The components of capital are assumed to be available at a constant, user-supplied cost up to a user-supplied "critical point" (i.e., the capitalization ratio). Capital supply curves are not embodied in the model.

An Overall Assessment

Apart from the specification of individual equations and their relationship to each other, a number of NUFS' characteristics and potential applications were noted in Section 5 and Appendix C of this report. They include:

- The NUFS code treats the regulatory process on an industry basis rather than an individual utility basis. Thus, for any specified region and/or ownership type, use of NUFS necessarily involves an "averaging" process across utilities for important model inputs.
- Since the "iterative loop" between NUFS and MEFS as implemented by EIA and prospectively manifested in NUREG (both described at the outset of Section 3) was not incorporated as part of this evaluation, it is difficult to draw conclusions about the relationship of NUFS to a larger electricity supply and demand modeling framework. Thus, for the most part, the relative sensitivity results presented in Appendix C — and the conclusions derived therefrom — should be interpreted as those that would be obtained if the outputs of NUFS were not, in turn, "fed back" into capacity expansion and electricity demand sub-models.
- The code relies to an inordinate extent on user-supplied data. It is, of course, not possible to completely eliminate all exogeneous parameters. To "endogenize" the amount of CWIP that PUCs allow in the rate base, for example, would require consideration of political, as well as economic, aspects of the regulatory environment. However, it is possible to "model" many of the inputs into the code that are presently user-supplied.

- The NUFS code, as presently constituted, does not afford examination and/or simulation of many of the policy options promulgated for the industry. Thus, the impact of time-of-day pricing schemes and increased coordination of the industry through wheeling arrangements can not be analyzed within the current framework unless the specification of MEFS can be altered.

NUFS and Model Uses

In a very broad sense, models can be used to forecast, test a theoretical hypothesis, or simulate the impact of a change in an institutional stimulus that the model encompasses (e.g., a proposed policy change). In the words of the developers of NUFS, "... (the model) is intended to determine the impacts of alternative capacity expansion plans and regulatory treatment on the financial outlook of the utilities." Therefore, the model was presumably developed for purposes of both forecasting and simulation. Or, in the context of MEFS' overall framework, given a capacity expansion program emanating from MEFS, what are the implications of that program for the financial position of electric utilities and how does their financial condition change under alternative regulatory treatment?

Under the present constitution of NUFS and its relationship to MEFS — as that relationship was considered for the present evaluation — it is concluded that (1) NUFS fails to adequately forecast the ability of utilities to attract external capital, and (2) it is difficult to determine NUFS capability to simulate alternate regulatory scenarios.

First, the problems of regional aggregation in NUFS notwithstanding, it is a spurious effort to forecast the financial position of the electric utility industry when the focal point of concern in the industry and the area with the widest-reaching impact is assumed away. That is, on the one hand, NUFS forecasts financial and accounting variables that supposedly reflect the impact of financing huge construction increments on the structure of capital and the utilities' ability to attract it, but, on the other hand, assumes that utilities can always attract a user-supplied

capital structure. The results are vacuous. In essence, for forecasting purposes, a model user provides the results for the most important variables reflected in the primary financial statements (i.e., the capital structure) and, of course, that structure is reflected in the financial ratios derived from those statements (e.g., interest coverage).

Second, since the iterative feedback from NUFS to MEFS as implemented at EIA or as embodied in NUREG was not a part of the present evaluation effort, it is difficult to draw conclusions on the ability of NUFS to simulate alternate policy scenarios. What is clear from the sensitivity results provided in Appendix C, however, is that failure to incorporate an "iterative loop" from NUFS to MEFS will lead to simulation results that are contrary to economic theory.

Recommendations for Improvement

Although the conclusions reached in the present evaluation effort are mixed, the concept of a financial regulatory model is not without merit. It can be argued, moreover, that any representation of supply and demand activities in the electric utility sector must explicate the institutional constraints imposed by economic regulation.

Toward this end, the primary recommendation posited for improvement of the modeling effort under review is total integration of the NUFS code into a larger system. To the extent that this is already accomplished at EIA by "manual" incorporation of the NUFS output into the supply side and demand side of the electric utility sector of MEFS, that procedure should be documented and the totality of the system should undergo a comprehensive sensitivity analysis. It is only through the latter activity that the ability of NUFS to simulate alternate policy scenarios can be evaluated.

The first recommendation necessitates the incorporation of capital supply curves in the modeling framework of NUFS. In this way, the model will more adequately reflect prevailing conditions in the capital market and eliminate the need for "user judgment" with respect to the composition and cost of the various components of capital.

In the same vein, an effort should be made to "endogenize" some of the other user-supplied parameters that comprise a large portion of the input sources for NUFS. The rate at which interest is capitalized in NUFS (AFUDCR), for example, can be reflected endogeneously as a direct manifestation of the inclusion of capital supply curves. The retirement of physical assets is another area in which endogeneity can be improved. At present, assets are assumed to be retired at the end of some pre-determined useful life. However, as has been noted, a relationship exists between the life of an asset and the growth in load on a generating system, among other factors.

FOOTNOTES

1. A thorough description of the Regionalized Electricity Model can be found in [2], while a comprehensive background of the financial regulatory sector in REM is provided in [12].
2. A description of the Utility Simulation Model is provided in [23].
3. A description of the Regulatory Analysis Financial Model can be found in [14].
4. The documentation for the National Utility Financial Statement model is provided in [9], [10], and [11].
5. NUFS can be used for various levels of aggregation. A description of the procedures for its use in a context other than the MEFS interface can be found in Part I of its documentation [9].
6. Reference [28].
7. The approach is provided in [27].
8. Reference [21].
9. Reference [18].
10. Reference [20].
11. A third approach, incorporated in the specification of NUFS, is the "AFUDC offset method." Under this scheme, CWIP is included in the rate base, but that same amount is offset against the determination of revenues. If the rate of return allowed on the rate base is greater than the rate at which AFUDC is calculated, some current-period return will result.
12. A description of the aggregative capabilities of NUFS can be found in Part I of its documentation [9].
13. The procedure used at EIA was described in private conversations with Gerald Price, Energy Information Administration, Washington, D.C.
14. The documentation for the NUFS code can be found in [9], [10], and [11]. The equations presented in [9] have been compared to the NUFS fortran listing. In general, the equations are consistent with the code except for two cases: (1) the equation for the amortization of the deferred investment tax credit (p. III-20), $AITC = A2 \cdot RITC / SY2$, has to be corrected to $AITC = A2 \cdot RITC / SY2 \cdot (1 - FLPR1)$; and (2) the equation for the determination of general taxes (p. III-23), $GENTX = RTXRT \cdot REVLAGE$, has to be corrected to $GENTX = GTXRT \cdot REVLAGE + PROPTX + SALETX$.

Footnotes (Cont'd)

15. See Footnote 10.
16. Reference [11].
17. Reference [26].
18. Reference [25].
19. A comprehensive background, formulation, and ostensible drawbacks of MEFS, originally formulated as the Project/Independence Evaluation System (PIES), is provided in [5] and [8].
20. Reference [6].
21. References [2] and [12].
22. Reference [23].
23. Reference [14].
24. For a background on sensitivity theory and its application to economic models, consult References [15] and [16].
25. A number of studies have corroborated this point. See, for example, W. S. Chern et al., The ORNL State-Level Electricity Demand Forecasting Model, Oak Ridge National Laboratory, ORNL/NUREG-63; and W. S. Chern et al., A Varying Elasticity Model of Electricity Demand, Oak Ridge National Laboratory, awaiting publication.

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APPENDIX A

NUFS BASE-CASE SAMPLE PROBLEM

- A.I: INCOME STATEMENT AND BALANCE SHEET
VARIABLES: CROSS-REFERENCE LISTING
FOR COMPUTATION
- A.II: NUFF SAMPLE PROBLEM OUTPUT¹

¹The inputs into the NUFF code are described in Section 3. The values of the input variables for the sample problem are provided in Appendix B.

Table A.1a. Income Statement Variables

	Internal Code ¹	Equation Number ²
Electric Revenues	[IS-1]	(48)
Electric Expenses:		
Operation & Maintenance	[IS-2]	MEFS
Fuel	[IS-3]	MEFS
Depreciation	[IS-4]	(20)
General Taxes	[IS-5]	(50)
Income Taxes	[IS-6]	(53)
Total Electric Expenses		
Electric Operating Income		
Other Income		
AFUCD-Equity Funds	[IS-9]	(29)
Total Other Income		
Income Before Interest Deductions		
Interest Deductions:		
Interest on Long-Term Debt	[IS-12]	(35)
Interest on Short-Term Debt	[IS-13]	(34)
AFUDC-Borrowed Funds	[IS-14]	(28)
Total Interest Deductions		
Net Income		
Dividends on Preferred Stocks	[IS-17]	(58)
Earnings for Common Stock		

¹Represents a cross-reference listing of income statement variables that are calculated in Section 3. For example, the equation that specifies the calculation of "Interest on Long-Term Debt" in Section 3 is noted as "IS-12."

²Represents the equation in which the various income statement variables were derived in Section 3.

Table A.Ib. Balance Sheet Variables

	Internal Code ¹	Equation Number ²
<u>Assets & Other Debits:</u>		
Utility Plant:		
Production	[BS-1]	-
Transmission	[BS-2]	-
Distribution	[BS-3]	-
Other	[BS-4]	-
Construction Work in Progress	[BS-5]	(26)
Total Utility Plant		
Accumulated Depreciation	[BS-7]	(21)
Net Utility Plant, Less Nuclear Fuel		
Net Nuclear Fuel	[BS-9]	(8)
Working Capital	[BS-11]	(7)
Total Assets & Other Debits		
<u>Liabilities & Other Credits:</u>		
Proprietary Capital:		
Common Stock	[BS-13]	(61)
Preferred Stock	[BS-14]	(55)
Retained Earnings	[BS-15]	(60)
Total Proprietary Capital		
Long-Term Debt	[BS-17]	(56)
Short-Term Debt	[BS-18]	(57)
Total Debt		
Deferred Credits:		
Accumulated Deferred ITC	[BS-20]	(44)
Accumulated Deferred Income Taxes	[BS-21]	(40)
Total Deferred Credits		
Total Liabilities & Other Credits		

¹ Represents a cross-reference listing of balance sheet variables that are calculated in Section 3. For example, the equation that specifies the calculation of "Construction Work in Progress" in Section 3 is noted as "BS-5."

² Represents the equation in which the various balance sheet items were derived in Section 3.

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

YEAR ENDED DECEMBER 31

ONE REGION 11
PRIVATE SECTOR
231111- TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 54657.	\$ 66485.	\$ 80846.	\$ 89426.	\$ 98674.	\$ 107914.	\$ 117027.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	3106.	3452.	3837.	4265.	4743.	5274.	5867.
DEPRECIATION	29250.	32503.	36126.	40160.	44654.	49662.	55242.
GENERAL TAXES	6053.	6671.	7232.	8003.	8403.	8921.	9704.
INCOME TAXES	4750.	6067.	7572.	8723.	9691.	10741.	11970.
	3543.	6469.	10075.	10761.	11802.	12492.	12623.
TOTAL ELECTRIC EXPENSES	46702.	55161.	64842.	71912.	79294.	87091.	95407.
ELECTRIC OPERATING INCOME	7955.	11324.	16005.	17514.	19380.	20823.	21621.
OTHER INCOME							
AFUDC-ELIGIBLE FUNDS	2165.	2165.	2276.	2194.	2551.	2785.	2789.
TOTAL OTHER INCOME	2165.	2165.	2276.	2194.	2551.	2785.	2789.
INCOME BEFORE INTEREST DEDUCTIONS	10120.	13488.	18281.	19707.	21931.	23609.	24410.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	7108.	7512.	8182.	8879.	9563.	10257.	11085.
INTEREST ON SHORT-TERM DEBT	362.	11.	12.	12.	12.	12.	16.
AFUDC-APPROVED FUNDS	(1747.)	(1747.)	(1837.)	(1770.)	(2058.)	(2248.)	(2251.)
TOTAL INTEREST DEDUCTIONS	5723.	5776.	6358.	7121.	7516.	8022.	8851.
NET INCOME	4397.	7712.	11923.	12587.	14415.	15587.	15559.
DIVIDENDS ON PREFERRED STOCKS	2179.	2310.	2460.	2603.	2743.	2888.	3063.
EARNINGS FOR COMMON STOCK	\$ 2218.	\$ 5402.	\$ 9463.	\$ 9983.	\$ 11672.	\$ 12699.	\$ 12496.

DEL REGION II
PRIVATE SECTOR
ASTORIA TEST 2/4/81

	1986	1987	1988	1989	1990	1991	1992
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 130256.	\$ 146605.	\$ 165041.	\$ 184879.	\$ 206570.	\$ 225732.	\$ 249061.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	6919.	8160.	9622.	11347.	13383.	15746.	1851.
DEPRECIATION	62963.	71806.	81871.	93353.	106445.	115835.	1260.
GENERAL TAXES	10659.	11495.	12222.	12893.	14198.	15709.	17.
PROPERTY TAXES	13621.	15440.	17345.	19313.	21806.	24244.	27.
	14064.	14260.	15596.	16653.	16976.	17556.	191.
TOTAL ELECTRIC EXPENSES	107266.	121161.	136657.	153560.	172807.	189090.	2082.
ELECTRIC OPERATING INCOME	22990.	25444.	28385.	31320.	33762.	36642.	408.
OTHER INCOME							
AFUDC-QUALITY FUNDS	2862.	3327.	4180.	5354.	6024.	6629.	7304.
TOTAL OTHER INCOME	2862.	3327.	4180.	5354.	6024.	6629.	7304.
INCOME BEFORE INTEREST DEDUCTIONS	25852.	28771.	32565.	36674.	39786.	43271.	48147.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	12180.	13574.	15269.	17270.	19519.	21968.	24655.
INTEREST ON SHORT-TERM DEBT	2.	28.	34.	40.	44.	47.	52.
AFUDC-QUALITY FUNDS	2310.	2635.	3373.	4321.	4861.	5349.	5894.
TOTAL INTEREST DEDUCTIONS	9892.	10917.	11930.	12989.	14702.	16666.	18612.
NET INCOME	15960.	17853.	20635.	23685.	25084.	26605.	29534.
DIVIDENDS ON PREFERRED STOCKS	3352.	3690.	4100.	4584.	5109.	5680.	6311.
EARNINGS FOR COMMON STOCK	\$ 12608.	\$ 14163.	\$ 16535.	\$ 19101.	\$ 19975.	\$ 20925.	\$ 23023.

DOE REGION 11
PRIVATE SECTOR
A3T1114 TEST 2/4/81

	1993	1994	1995	0	0	0	0
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 275415.	\$ 304510.	\$ 336533.	\$ 0.	\$ 0.	\$ 0.	\$ 0.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	21810.	25677.	30227.	0.	0.	0.	0.
FUEL	137215.	149368.	162619.	0.	0.	0.	0.
DEPRECIATION	19278.	21342.	23587.	0.	0.	0.	0.
GENERAL TAXES	30327.	33677.	37764.	0.	0.	0.	0.
INCOME TAXES	21092.	23308.	25661.	0.	0.	0.	0.
TOTAL ELECTRIC EXPENSES	229722.	253572.	279857.	0.	0.	0.	0.
ELECTRIC OPERATING INCOME	45693.	50938.	56676.	0.	0.	0.	0.
OTHER INCOME							
AFUDC-EQUITY FUNDS	8068.	8938.	9965.	0.	0.	0.	0.
TOTAL OTHER INCOME	8068.	8938.	9965.	0.	0.	0.	0.
INCOME BEFORE INTEREST DEDUCTIONS	53762.	59876.	66641.	0.	0.	0.	0.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	27527.	30581.	33964.	0.	0.	0.	0.
INTEREST ON SHORT-TERM DEBT	58.	65.	71.	0.	0.	0.	0.
AFUDC-DEBT FUNDS	(6511.)	(7212.)	(8041.)	(0.)	(0.)	(0.)	(0.)
TOTAL INTEREST DEDUCTIONS	21074.	23434.	25994.	0.	0.	0.	0.
NET INCOME	32687.	36442.	40646.	0.	0.	0.	0.
DIVIDENDS ON PREFERRED STOCKS	7011.	7789.	8648.	0.	0.	0.	0.
EARNINGS FOR COMMON STOCK	\$ 25676.	\$ 28653.	\$ 31998.	\$ 0.	\$ 0.	\$ 0.	\$ 0.

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

DECEMBER 31

DOE REGION II
PRIVATE SECTOR
ASSET TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	95311.	113213.	129893.	152825.	164608.	179907.	203127.
TRANSMISSION	29139.	29329.	29540.	29775.	30036.	30326.	32707.
DISTRIBUTION	53341.	53341.	53341.	53341.	53341.	53341.	53341.
OTHER	4473.	4473.	4473.	4473.	4473.	4473.	4473.
CONSTRUCTION WORK IN PROGRESS	65216.	65773.	69835.	67946.	77075.	83482.	85356.
TOTAL UTILITY PLANT	247481.	266129.	287082.	308360.	329533.	351529.	379004.
ACCUMULATED DEPRECIATION	50981.	63651.	70804.	78487.	87290.	96211.	105916.
NET UTILITY PLANT, LESS NUCLEAR FUEL	196500.	202477.	216198.	229873.	242243.	255318.	273088.
NET NUCLEAR FUEL	3712.	4244.	4846.	5525.	6291.	7156.	8130.
NET UTILITY PLANT	194212.	206722.	221044.	234998.	248534.	262474.	281219.
WORKING CAPITAL	4045.	4494.	4995.	5553.	6175.	6867.	7639.
TOTAL ASSETS & OTHER DEBITS	198257.	211216.	226039.	240551.	254709.	269341.	288857.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	49406.	52110.	54289.	56135.	57434.	58615.	61417.
PAID-UP STOCK	21791.	23100.	24599.	26034.	27433.	28881.	30834.
RETAINED EARNINGS	17881.	19282.	21736.	24324.	27351.	30644.	33979.
TOTAL PROPRIETARY CAPITAL	89078.	94491.	100624.	106493.	112218.	118139.	126130.
LONG-TERM DEBT	90652.	95450.	101656.	107585.	113369.	119350.	127423.
SHORT-TERM DEBT	3620.	3637.	4086.	4324.	4557.	4797.	5122.
TOTAL DEBT	94272.	99087.	105742.	111909.	117926.	124147.	132545.
DEFERRED CREDITS							
ACCUMULATED DEFERRED ITC	5757.	6620.	8013.	9196.	10296.	11394.	12869.
ACCUMULATED DEFERRED INCOME TAXES	9691.	10607.	11660.	12952.	14269.	15660.	17314.
TOTAL DEFERRED CREDITS	15448.	17227.	19673.	22148.	24565.	27054.	30183.
TOTAL LIABILITIES & OTHER CREDITS	198257.	211216.	226039.	240551.	254709.	269340.	288857.

LOS ANGELES
PRIVATE SECTOR
ASSETS LIST 2/4/91

	1986	1987	1988	1989	1990	1991	1992
	(DOLLARS IN MILLIONS)						
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	229404.	252063.	271102.	288118.	323778.	366599.	413802.
TRANSMISSION	35174.	37954.	41088.	44618.	47193.	50944.	55099.
DISTRIBUTION	53341.	53341.	53341.	53341.	53341.	53341.	53341.
OTHER	4473.	4473.	4473.	4473.	4473.	4473.	4473.
CONSTRUCTION WORK IN PROGRESS	90862.	106436.	131917.	165385.	185525.	204254.	225279.
TOTAL UTILITY PLANT	413254.	454267.	501921.	555935.	614310.	679612.	751995.
ACCUMULATED DEPRECIATION	116574.	128069.	140291.	153184.	167381.	183091.	200497.
NET UTILITY PLANT, LESS NUCLEAR FUEL	296680.	326198.	361630.	402752.	446929.	496521.	551498.
NET NUCLEAR FUEL	9788.	11783.	14177.	17050.	20490.	23457.	26620.
NET UTILITY PLANT	306468.	337981.	375808.	419802.	467419.	519979.	578118.
WORKING CAPITAL	8738.	9496.	11437.	13088.	14979.	16448.	18075.
TOTAL ASSETS & OTHER DEBITS	315206.	347977.	387244.	432889.	482397.	536426.	596193.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	66434.	73211.	81617.	91610.	102668.	114886.	128412.
PREFERRED STOCK	33515.	36896.	41003.	45839.	51093.	56802.	63110.
RETAINED EARNINGS	37148.	40821.	45108.	50061.	55240.	60666.	66536.
TOTAL PROPRIETARY CAPITAL	137097.	150927.	167728.	187510.	209002.	232353.	258058.
LONG-TERM DEBT	136503.	152475.	169448.	189433.	211145.	234736.	260806.
SHORT-TERM DEBT	5567.	6129.	6811.	7614.	8487.	9435.	10483.
TOTAL DEBT	142070.	158604.	176259.	197047.	219632.	244171.	271289.
DEFERRED CREDITS							
ACCUMULATED DEFERRED LTC	14807.	17157.	19860.	22853.	26014.	29540.	33419.
ACCUMULATED DEFERRED INCOME TAXES	19233.	21288.	23346.	25479.	27749.	30361.	33326.
TOTAL DEFERRED CREDITS	34039.	38445.	43206.	48332.	53763.	59901.	66746.
TOTAL LIABILITIES & OTHER CREDITS	315206.	347977.	387244.	432889.	482397.	536426.	596193.

JOL REGION 11
PRIVATE SECTOR
ASTORIA TEST 2/4/81

	1993	1994	1995	0	0	0	0
				(DOLLARS IN	MILLIONS)		
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	485849.	523233.	585552.	0.	0.	0.	0.
TRANSMISSION	59705.	64604.	70126.	0.	0.	0.	0.
DISTRIBUTION	53361.	53341.	53341.	0.	0.	0.	0.
OTHER	4473.	4473.	4473.	0.	0.	0.	0.
CONSTRUCTION WORK IN PROGRESS	249120.	276202.	307784.	0.	0.	0.	0.
TOTAL UTILITY PLANT	832406.	922074.	1021275.	0.	0.	0.	0.
ACCUMULATED DEPRECIATION	219774.	241117.	264704.	0.	0.	0.	0.
NET UTILITY PLANT, LESS NUCLEAR FUEL	612712.	680958.	756572.	0.	0.	0.	0.
NET NUCLEAR FUEL	29985.	33489.	37161.	0.	0.	0.	0.
NET UTILITY PLANT	642678.	714447.	793733.	0.	0.	0.	0.
WORKING CAPITAL	19478.	21841.	24106.	0.	0.	0.	0.
TOTAL ASSETS & OTHER DEBITS	662556.	736327.	817838.	0.	0.	0.	0.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	143391.	160010.	178268.	0.	0.	0.	0.
PREFERRED STOCK	70111.	77892.	86484.	0.	0.	0.	0.
RETAINED EARNINGS	73294.	80724.	89021.	0.	0.	0.	0.
TOTAL PROPRIETARY CAPITAL	286796.	318625.	353772.	0.	0.	0.	0.
LONG-TERM DEBT	289737.	321892.	357400.	0.	0.	0.	0.
SHORT-TERM DEBT	11646.	12938.	14366.	0.	0.	0.	0.
TOTAL DEBT	301383.	334831.	371766.	0.	0.	0.	0.
DEFERRED CREDITS							
ACCUMULATED DEFERRED TTL	37711.	42464.	47684.	0.	0.	0.	0.
ACCUMULATED DEFERRED INCOME TAXES	36565.	40407.	44612.	0.	0.	0.	0.
TOTAL DEFERRED CREDITS	74377.	82871.	92300.	0.	0.	0.	0.
TOTAL LIABILITIES & OTHER CREDITS	662556.	736327.	817838.	0.	0.	0.	0.

**** DOD FORM 1000 NOTES TO FINANCIAL STATEMENTS ****

INCOME TAX EXPENSE

INCOME TAX EXPENSE OF COMPRISED OF THE FOLLOWING COMPONENTS:

YEAR ENDED DECEMBER 31

DOE REGION 11
PRIVATE SECTOR
ARTICLE 101 274781

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
CURRENT INCOME TAXES	1740.	4490.	7829.	8285.	9386.	10003.	9495.
DEFERRED TAXES (NET) (TIMING DIFFERENCES)							
EXCESS TAX OVER BOOK DEPRECIATION	756.	916.	1053.	1292.	1317.	1391.	1654.
INVESTMENT TAX CREDIT GENERATED (AND DEFERRED)	1105.	1158.	1323.	1360.	1301.	1332.	1762.
AMORTIZATION OF DEFERMENTS (CREDIT)	(58.)	(95.)	(129.)	(177.)	(202.)	(234.)	(287.)
	1047.	1063.	1193.	1183.	1099.	1098.	1475.
TOTAL INCOME TAX EXPENSE	3543.	6469.	10075.	10761.	11802.	12492.	12623.

DOE REGION 11
PRIVATE SECTOR
ARTICLE 101 274781

	1986	1987	1988	1989	1990	1991	1992
	(DOLLARS IN MILLIONS)						
CURRENT INCOME TAXES	9227.	9854.	10785.	11578.	11549.	11418.	12255.
DEFERRED TAXES (NET) (TIMING DIFFERENCES)							
EXCESS TAX OVER BOOK DEPRECIATION	1919.	2056.	2108.	2083.	2270.	2612.	2965.
INVESTMENT TAX CREDIT GENERATED (AND DEFERRED)	2284.	2749.	3150.	3482.	3730.	4191.	4111.
AMORTIZATION OF DEFERMENTS (CREDIT)	(346.)	(399.)	(446.)	(490.)	(569.)	(665.)	(711.)
	1938.	2350.	2704.	2992.	3161.	3526.	3400.
TOTAL INCOME TAX EXPENSE	13084.	14260.	15596.	16653.	16976.	17556.	18615.

COMPANION 11
PRIVATE SECTOR
A31111H TLST 2/4/81

	1993	1994	1995	0	0	0	0
	-----	-----	-----	-----	-----	-----	-----
				(DOLLARS IN MILLIONS)			
CURRENT INCOME TAXES	13461.	14814.	16232.	0.	0.	0.	0.
	-----	-----	-----	-----	-----	-----	-----
DEFERRED TAXES NET (TIMING DIFFERENCES)							
EXCESS TAX OVER BOOK DEPRECIATION	3340.	3741.	4205.	0.	0.	0.	0.
	-----	-----	-----	-----	-----	-----	-----
INVESTMENT TAX CREDIT							
GENERATED (AND DEFERRED)	5160.	5771.	6381.	0.	0.	0.	0.
AMORTIZATION OF DEFERMENTS (CREDIT)	(888.)	(1018.)	(1157.)	(0.)	(0.)	(0.)	(0.)
	-----	-----	-----	-----	-----	-----	-----
	4291.	4754.	5223.	0.	0.	0.	0.
	-----	-----	-----	-----	-----	-----	-----
TOTAL INCOME TAX EXPENSE	21092.	23308.	25661.	0.	0.	0.	0.
	-----	-----	-----	-----	-----	-----	-----

***** PRG FORMA NOTES TO FINANCIAL STATEMENTS: CONT *****

INCOME TAXES DIFFER FROM AMOUNTS COMPUTED BY APPLYING THE STATUTORY
TAX RATE TO PRE-TAX INCOME AS FOLLOWS:

YEAR ENDED DECEMBER 31

DOE REGION 11
PRIVATE SECTOR
AS11111 TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
INCOME TAXES ON PRE-TAX INCOME AT THE STATUTORY FEDERAL RATE OF 46%	3652.	6523.	10119.	10740.	12060.	12916.	12964.
ADJUSTMENTS TO ABOVE AT 46%							
DIFFERENCE BETWEEN BOOK ASSET BASE AND TAX ASSET BASE AFUDC	(1553. 1799.))	(1612. 1799.))	(1668. 1892.))	(1745. 1824.))	(1784. 2120.))	(1835. 2315.))	(1917. 2318.))
OTHER ADJUSTMENTS							
AMORTIZATION OF ITC DEFERRALS	(58.))	(95.))	(129.))	(177.))	(202.))	(234.))	(287.))
ITC NOT DEFERRED	(303.))	(317.))	(362.))	(372.))	(356.))	(365.))	(482.))
TAX SAVINGS FROM EXCESS TAX OVER BOOK DEPRECIATION-NOT DEFERRED	(207.))	(251.))	(288.))	(354.))	(361.))	(381.))	(453.))
STATE INCOME TAXES NET OF FEDERAL INCOME TAX BENEFIT	98.	161.	236.	258.	285.	306.	318.
TOTAL INCOME TAX EXPENSE	3543.	6469.	10075.	10761.	11802.	12492.	12623.

DOE REGION 11
PRIVATE SECTOR
AS11111 TEST 2/4/81

	1986	1987	1988	1989	1990	1991	1992
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
INCOME TAXES ON PRE-TAX INCOME AT THE STATUTORY FEDERAL RATE OF 46%	13360.	14772.	16666.	18555.	19348.	20314.	22280.
ADJUSTMENTS TO ABOVE AT 46%							
DIFFERENCE BETWEEN BOOK ASSET BASE AND TAX ASSET BASE AFUDC	(2010. 2379.))	(2089. 2765.))	(2154. 3475.))	(2211. 4451.))	(2334. 5007.))	(2484. 5510.))	(2649. 6071.))
OTHER ADJUSTMENTS							
AMORTIZATION OF ITC DEFERRALS	(346.))	(399.))	(446.))	(490.))	(569.))	(665.))	(771.))
ITC NOT DEFERRED	(626.))	(753.))	(863.))	(954.))	(1022.))	(1148.))	(1274.))
TAX SAVINGS FROM EXCESS TAX OVER BOOK DEPRECIATION-NOT DEFERRED	(525.))	(563.))	(577.))	(570.))	(622.))	(715.))	(812.))

TAX SAVINGS FROM EXCESS TAX OVER
BOOK DEPRECIATION-NOT DEFERRED

(525.)(563.)(577.)(570.)(622.)(715.)(812.)

STATE INCOME TAXES, NET OF FEDERAL
INCOME TAX BENEFIT

339.	373.	411.	444.	470.	501.	552.
13084.	14260.	15596.	16653.	16976.	17556.	19100.

TOTAL INCOME TAX EXPENSE

REGION II
PRIVATE SECTOR
ADDITION TEST 2/4/81

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

INCOME TAXES ON PRE-TAX INCOME AT THE
STATUTORY FEDERAL RATE OF 46%

24738.	27485.	30501.	0.	0.	0.	0.
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ADJUSTMENTS TO ABOVE AT 46%
DIFFERENCE BETWEEN BOOK ASSET
BASE AND TAX ASSET BASE
AFORD

2832.	3032.	3250.	0.	0.	0.	0.
(6706.)(	7429.)(	8263.)(	0.)(	0.)(	0.)(	0.)(

OTHER ADJUSTMENTS
EXPORTATION OF ITC DEFERRALS
ITC NOT DEFERRED
TAX SAVINGS FROM EXCESS TAX OVER
BOOK DEPRECIATION-NOT DEFERRED

(889.)(	1018.)(	1157.)(	0.)(	0.)(	0.)(	0.)(
(1419.)(	1581.)(	1748.)(	0.)(	0.)(	0.)(	0.)(
(915.)(	1024.)(	1152.)(	0.)(	0.)(	0.)(	0.)(

STATE INCOME TAXES, NET OF FEDERAL
INCOME TAX BENEFIT

613.	601.	754.	0.	0.	0.	0.
21092.	23368.	25651.	0.	0.	0.	0.

TOTAL INCOME TAX EXPENSE

*** PRIFORMA SOURCES AND USES OF FUNDS ***

DECEMBER 31

SECRET REGION II
PRIVATE SECTOR
311117 TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
SOURCES OF FUNDS:							
NET INCOME	4397.	7712.	11923.	12587.	14415.	15587.	15559.
DEPRECIATION	6053.	6671.	7232.	8003.	8403.	8921.	9704.
DEFERRED TIC-NET	1047.	1063.	1193.	1183.	1099.	1098.	1475.
TIER 20 INCOME TAXES	756.	916.	1053.	1292.	1317.	1391.	1654.
ADDC	(3911.)	(3911.)	(4113.)	(3964.)	(4609.)	(5033.)	(5040.)
TOTAL INTERNAL FUNDS	8341.	12451.	17288.	19101.	20626.	21964.	23352.
INCREASE IN SHORT-TERM DEBT	450.	217.	249.	238.	232.	240.	324.
INCREASE IN LONG-TERM DEBT	11221.	5409.	6195.	5929.	5784.	5982.	8073.
ISSUANCE OF COMMON STOCK	7823.	2644.	2179.	1846.	1299.	1181.	2802.
ISSUANCE OF PREFERRED STOCK	2708.	1309.	1499.	1435.	1400.	1447.	1953.
TOTAL EXTERNAL FUNDS	22202.	8579.	10123.	9448.	8715.	8850.	13153.
TOTAL SOURCES	30543.	22030.	27411.	28549.	29341.	30814.	36505.
APPLICATION OF FUNDS:							
CONSTRUCTION EXPENDITURES (EXCLUDING ADDC)	16551.	14736.	16840.	17314.	16565.	16963.	22435.
CHANGE STOCK DIVIDENDS	1643.	4001.	7009.	7395.	8645.	9406.	9241.
PREFERRED STOCK DIVIDENDS	2179.	2310.	2460.	2603.	2743.	2888.	3083.
CHANGE IN WORKING CAPITAL	3507.	450.	501.	558.	621.	692.	772.
CHANGE IN NUCLEAR FUEL STOCK	0.	532.	601.	679.	766.	864.	975.
TOTAL APPLICATIONS	23879.	22030.	27411.	28549.	29341.	30814.	36505.
EXTERNAL FINANCING AS A PERCENT OF TOTAL APPLICATIONS							
	92.98	43.48	36.93	33.09	29.70	28.72	36.03

A-14

DOE REGION II
PRIVATE SECTOR
ANNUAL TEST 224281

	1986	1987	1988	1989	1990	1991	1992
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	(DOLLARS IN MILLIONS)						
SOURCES OF FUNDS:							
NET INCOME	15960.	17853.	20635.	23685.	25084.	26605.	29334.
DEPRECIATION	10659.	11495.	12222.	12893.	14198.	15709.	17406.
DEFERRED INCOME	1938.	2550.	2704.	2992.	3161.	3526.	3860.
DEFERRED INCOME TAXES	1919.	2056.	2109.	2083.	2270.	2612.	2964.
STOCK	(5172.)	(6012.)	(7554.)	(9673.)	(10885.)	(11970.)	(13199.)
TOTAL INTERNAL FUNDS	25303.	27742.	30115.	31978.	33828.	36474.	40386.
INCREASE IN SHORT-TERM DEBT	445.	562.	682.	803.	873.	948.	1049.
INCREASE IN LONG-TERM DEBT	11040.	13973.	16973.	19985.	21712.	23591.	26070.
ISSUANCE OF COMMON STOCK	5017.	4777.	8405.	8903.	11058.	12217.	15527.
ISSUANCE OF PREFERRED STOCK	2601.	3581.	4107.	4836.	5254.	5709.	6308.
TOTAL EXTERNAL FUNDS	19223.	24672.	30169.	35617.	38897.	42465.	48953.
TOTAL SOURCES	44526.	52435.	60283.	67595.	72725.	78939.	87339.
APPLICATION OF FUNDS:							
CONSTRUCTION EXPENDITURES (EXCLUDING AFFILIATES)	29078.	35002.	40100.	44339.	47490.	53324.	59184.
COMMON STOCK DIVIDENDS	9339.	10491.	12247.	14148.	14795.	15499.	17053.
PREFERRED STOCK DIVIDENDS	3352.	3690.	4100.	4584.	5109.	5680.	6311.
CHANGE IN WORKING CAPITAL	1039.	1258.	1441.	1651.	1891.	1469.	1628.
CHANGE IN NUCLEAR FUEL STOCK	1538.	1995.	2394.	2873.	3440.	2967.	3163.
TOTAL APPLICATIONS	44526.	52435.	60283.	67595.	72726.	78939.	87339.
EXTERNAL FINANCING AS A PERCENT							
OF TOTAL APPLICATIONS	43.17	47.09	50.04	52.69	53.48	53.79	50.78

DOE REGION 11
PRIVATE SECTOR
A31111M TEST 2/4/81

	1993	1994	1995	0	0	0	0
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	(DOLLARS IN MILLIONS)						
SOURCES OF FUNDS:							
NET INCOME	32687.	36442.	40646.	0.	0.	0.	0.
DEPRECIATION	19278.	21342.	23587.	0.	0.	0.	0.
DEFERRED INCOME TAXES	4291.	4754.	5223.	0.	0.	0.	0.
DEFERRED INCOME TAXES	3340.	3741.	4205.	0.	0.	0.	0.
ADJUD	(14579.)(	(16150.)(	(18006.)(	(0.)(	(0.)(	(0.)(	(0.)(
TOTAL INTERNAL FUNDS	45017.	50129.	55656.	0.	0.	0.	0.
INCREASE IN SHORT-TERM DEBT	1163.	1292.	1427.	0.	0.	0.	0.
INCREASE IN LONG-TERM DEBT	28931.	32156.	35508.	0.	0.	0.	0.
ISSUANCE OF COMMON STOCK	14779.	15619.	18258.	0.	0.	0.	0.
ISSUANCE OF PREFERRED STOCK	7001.	7741.	8592.	0.	0.	0.	0.
TOTAL EXTERNAL FUNDS	52073.	57648.	63785.	0.	0.	0.	0.
TOTAL SOURCES	97091.	107977.	119441.	0.	0.	0.	0.
APPLICATION OF FUNDS:							
CONSTRUCTION EXPENDITURES (EXCLUDING ADJUD)	65912.	73439.	81195.	0.	0.	0.	0.
COMMON STOCK DIVIDENDS	19018.	21223.	23701.	0.	0.	0.	0.
PREFERRED STOCK DIVIDENDS	7011.	7789.	8648.	0.	0.	0.	0.
CHANGE IN WORKING CAPITAL	1803.	2002.	2225.	0.	0.	0.	0.
CHANGE IN UNCOLLECTIBLE STOCK	3346.	3523.	3672.	0.	0.	0.	0.
TOTAL APPLICATIONS	97091.	107976.	119441.	0.	0.	0.	0.
EXTERNAL FINANCING AS A PERCENT							
NET TOTAL APPLICATIONS	53.63	53.57	53.40	0.0	0.0	0.0	0.0

YEAR ENDED DECEMBER 31

ONE REGION 11
PRIVATE SECTOR
A3111111 TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	182265.	200356.	217247.	240413.	252454.	268048.	293648.
CONSTRUCTION WORK IN PROGRESS	65216.	65773.	69835.	67946.	77075.	83482.	85356.
NUCLEAR FUEL	3712.	4244.	4846.	5525.	6291.	7156.	8130.
WORKING CAPITAL	4045.	4494.	4995.	5553.	6175.	6867.	7639.
ACCUMULATED DEPRECIATION	56481.11	63651.11	70884.11	78887.11	87290.11	96211.11	105916.11
ACCUMULATED DEFERRED TAXES	9691.11	10607.11	11660.11	12952.11	14269.11	15660.11	17314.11
RATE BASE	188556.	200609.	214379.	227599.	240440.	253681.	271543.
REVENUE REQUIREMENT							
RATE OF RETURN ON RATE BASE	0.104	0.105	0.106	0.107	0.108	0.109	0.110
RETURN ON RATE BASE	19678.	21138.	22804.	24418.	25995.	27626.	29797.
EXPENSES:							
OPERATION & MAINTENANCE	3106.	3452.	3837.	4265.	4743.	5274.	5867.
DEPRECIATION	29250.	32503.	36126.	40160.	44654.	49662.	55242.
NUCLEAR FUEL	6053.	6671.	7232.	8003.	8403.	8921.	9704.
NUCLEAR WASTE	5932.	6931.	7894.	9082.	9903.	10912.	12326.
NUCLEAR TAXES	404.	459.	496.	546.	567.	599.	656.
FEDERAL INCOME TAXES (NET OF ITC)	10058.	11241.	11921.	12771.	13168.	13714.	14723.
ITC-FLAGGED THROUGH	303.11	317.11	362.11	372.11	356.11	365.11	482.11
ITC-AMORTIZED	58.11	95.11	129.11	177.11	202.11	234.11	287.11
TAX SAVINGS FROM AFUDOC-FLAGGED THROUGH	804.11	803.11	845.11	814.11	947.11	1034.11	1035.11
TAX SAVINGS FROM AFUDOC-AMORTIZED	0.11	0.11	0.11	0.11	0.11	0.11	0.11
AFUDOC OFFSET	3911.11	3911.11	4113.11	3964.11	4609.11	5033.11	5040.11
TOTAL EXPENSES	49726.	56130.	62056.	69499.	75325.	82416.	91674.
REVENUE REQUIREMENTS	69405.	77268.	84860.	93917.	101320.	110042.	121471.

DOE REGION 11
PRIVATE SECTOR
ASR111111 TEST 2/4/81

	1986	1987	1988	1989	1990	1991	1992
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	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	322392.	347631.	370004.	390550.	428785.	475358.	526719.
ADDITIONS:							
CONSTRUCTION WORK IN PROGRESS	90802.	106436.	131917.	165385.	185525.	204254.	225279.
NUCLEAR FUEL	9788.	11783.	14177.	17050.	20490.	23457.	26620.
WORKING CAPITAL	8738.	9996.	11437.	13088.	14979.	16448.	18075.
DEDUCTIONS:							
ACCUMULATED DEPRECIATION	(116574.)(	128059.)(	140291.)(	153184.)(	167381.)(	183091.)(	200497.)(
ACCUMULATED DEFERRED TAXES	(19233.)(	21288.)(	23396.)(	25479.)(	27749.)(	30361.)(	33326.)(
RATE BASE	295973.	326648.	363844.	407411.	454648.	506065.	562867.
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REVENUE REQUIREMENT							
RATE BASE	295973.	326648.	363844.	407411.	454648.	506065.	562867.
RATE OF RETURN ON RATE BASE	0.111	0.111	0.112	0.113	0.113	0.114	0.114
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RETURN ON RATE BASE	32734.	36405.	40825.	45990.	51595.	57699.	64444.
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EXPENSES:							
OPERATION & MAINTENANCE	6919.	8160.	9622.	11347.	13383.	15746.	18536.
FUEL	62983.	71800.	81071.	93353.	106445.	115835.	126066.
DEPRECIATION	10659.	11495.	12222.	12893.	14198.	15709.	17405.
GENERAL TAXES	14165.	16005.	17664.	19820.	22610.	25356.	28400.
STATE TAXES	730.	797.	858.	917.	1021.	1136.	1263.
FEDERAL INCOME TAXES (NET OF ITC)	16069.	17383.	18664.	19986.	22067.	24385.	26978.
ITC-ALLOWED THROUGH	(626.)(	753.)(	863.)(	954.)(	1022.)(	1148.)(	1274.)(
ITC-DEFERRED	(346.)(	399.)(	446.)(	490.)(	569.)(	665.)(	771.)(
TAX SAVINGS FROM DEFERRED-ALLOWED THROUGH	(1062.)(	1235.)(	1552.)(	1988.)(	2236.)(	2461.)(	2711.)(
TAX SAVINGS FROM DEFERRED-DEFERRED	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
NET OFFSET	(5172.)(	6012.)(	7554.)(	9675.)(	10885.)(	11978.)(	13199.)(
TOTAL EXPENSES	104319.	117247.	130686.	145208.	165012.	181915.	200692.
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REVENUE REQUIREMENTS	137054.	153652.	171512.	191199.	216607.	239613.	265136.
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000 REGION 11
PRIVATE SECTOR
ABIIIIIN TEST 2/4/81

	1993	1994	1995	0	0	0	0
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	(DOLLARS IN MYLLIONS)						
UTILITY PLANT IN SERVICE	583365.	645872.	713492.	0.	0.	0.	0.
ADDITIONS							
CONSTRUCTION WORK IN PROGRESS	249120.	276202.	307784.	0.	0.	0.	0.
NUCLEAR FUEL	29966.	33449.	37161.	0.	0.	0.	0.
STARTING CAPITAL	19878.	21681.	24106.	0.	0.	0.	0.
DEDUCTIONS							
ACCUMULATED DEPRECIATION	(219774.)(	241117.)(	264704.)(	0.)(	0.)(	0.)(	0.)(
ACCUMULATED DEFERRED TAXES	(36666.)(	40407.)(	44512.)(	0.)(	0.)(	0.)(	0.)(
RATE BASE	625889.	695920.	773225.	0.	0.	0.	0.
REVENUE REQUIREMENT							
RATE BASE	625889.	695920.	773225.	0.	0.	0.	0.
RATE OF RETURN ON RATE BASE	0.115	0.115	0.115	0.0	0.0	0.0	0.0
RETURN ON RATE BASE	71812.	79847.	88716.	0.	0.	0.	0.
EXPENSES							
OPERATION & MAINTENANCE	21910.	25677.	30227.	0.	0.	0.	0.
FUEL	137215.	149368.	162619.	0.	0.	0.	0.
GOODWILL	19278.	21342.	23587.	0.	0.	0.	0.
GENERAL TAXES	31758.	35450.	39492.	0.	0.	0.	0.
STATE TAXES	1402.	1556.	1720.	0.	0.	0.	0.
FEDERAL INCOME TAXES (NET OF ITC)	29834.	32977.	36351.	0.	0.	0.	0.
ITC-EXPANDED THROUGH	(1419.)(	1581.)(	1748.)(	0.)(	0.)(	0.)(	0.)(
ITC-AMORTIZED	(858.)(	1018.)(	1157.)(	0.)(	0.)(	0.)(	0.)(
TAX SAVINGS FROM AFUSCO-EXPANDED THROUGH	(2995.)(	3318.)(	3699.)(	0.)(	0.)(	0.)(	0.)(
TAX SAVINGS FROM AFUSCO-AMORTIZED	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
TOTAL EXPENSES	221412.	244304.	269385.	0.	0.	0.	0.
REVENUE REQUIREMENTS	293224.	324151.	358102.	0.	0.	0.	0.

ONE REGION 11
PRIVATE SECTOR
A311111 TEST 2/4/81

YEAR	ELEC REVS NDV	ELEC REVS PV	ELEC REVS CUMPV	DISCOUNT RATE USED=0.1250
1979	54657.	54657.	54657.	
1980	66485.	59098.	113755.	
1981	80846.	63679.	177633.	
1982	87426.	62807.	240440.	
1983	94674.	61602.	302042.	
1984	107315.	59655.	361697.	
1985	117027.	57726.	419652.	
1986	130256.	57112.	476765.	
1987	145005.	57138.	533903.	
1988	165041.	57177.	591080.	
1989	184673.	56933.	648013.	
1990	200570.	56514.	704557.	
1991	220732.	54924.	759481.	
1992	243041.	53857.	813348.	
1993	275415.	52948.	866296.	
1994	304510.	52037.	918334.	
1995	336535.	51120.	969453.	

ONE REGION 11
PRIVATE SECTOR
A311111 TEST 2/4/81

INTEREST COVERAGE CALCULATIONS

YEAR	SEC FD 400A
1979	1.6727
1980	2.4207
1981	3.2376
1982	3.2289
1983	3.3091
1984	3.7470
1985	3.7315
1986	3.6015
1987	2.9642
1988	2.9219
1989	2.8339
1990	2.6551
1991	2.5217
1992	2.4848
1993	2.4791
1994	2.4806
1995	2.4772

DOE REGION 11
PRIVATE SECTOR
ANNUAL TEST 2/4/81

YEAR	ELEC REVS (\$100000)	TOTAL SALES (GWH)	AVERAGE PRICE OF ELECT. (MILLS/KWH)
1979	92550.715	1641.	56.30298
1980	87835.187	1691.	51.91606
1981	89849.312	1743.	51.51994
1982	89225.387	1796.	49.70346
1983	97774.437	1852.	53.28105
1984	107714.312	1910.	56.50870
1985	117027.187	1970.	59.41460
1986	130655.675	2041.	63.80736
1987	145504.312	2116.	69.27499
1988	155731.250	2122.	75.22446
1989	16473.312	2275.	81.27804
1990	205567.312	2356.	87.59113
1991	227731.312	2420.	92.97807
1992	247061.375	2500.	99.62056
1993	275415.312	2575.	106.96315
1994	304509.312	2652.	114.81598
1995	332533.125	2732.	123.17873
1996	358747.187	28045	0.1307
STOCK CHECK	2.13.	0 1643.	0 0.1330 GE-0.0087
STOCK CHECK	5.00.	0 4001.	0 0.0543 GE-0.0020
STOCK CHECK	9.00.	0 7000.	0 0.0629 GE-0.0023
STOCK CHECK	13.00.	0 7305.	0 0.0567 GE-0.0018
STOCK CHECK	17.00.	0 2645.	0 0.0524 GE-0.0012
STOCK CHECK	21.00.	0 9456.	0 0.0514 GE-0.0011
STOCK CHECK	25.00.	0 9241.	0 0.0654 GE-0.0023
STOCK CHECK	29.00.	0 9330.	0 0.0613 GE-0.0034
STOCK CHECK	33.00.	0 10441.	0 0.0540 GE-0.0048
STOCK CHECK	37.00.	0 12247.	0 0.1054 GE-0.0054
STOCK CHECK	41.00.	0 11145.	0 0.1114 GE-0.0059
STOCK CHECK	45.00.	0 13795.	0 0.1084 GE-0.0057
STOCK CHECK	49.00.	0 15499.	0 0.1058 GE-0.0055
STOCK CHECK	53.00.	0 17053.	0 0.1052 GE-0.0055
STOCK CHECK	57.00.	0 19018.	0 0.1051 GE-0.0055
STOCK CHECK	61.00.	0 21223.	0 0.1051 GE-0.0055
STOCK CHECK	65.00.	0 23701.	0 0.1045 GE-0.0054

DOE REGION 11
PRIVATE SECTOR
A3T111- TEST 2/4/81

COMMON STOCK INFORMATION

YEAR	# OF SHARES	DIV/SHARE	M/H RATIO	BOOK VALUE		STOCK PRICE		ROE
				END YEAR	AVER	END YEAR	AVER	
1979	3032.	0.54	*****	22.21	20.74	*****	*****	0.033
1980	3024.	1.32	*****	23.61	22.91	*****	*****	0.076
1981	3017.	2.32	*****	25.20	24.40	*****	*****	0.124
1982	3011.	2.36	*****	26.72	25.96	*****	*****	0.124
1983	3008.	2.87	*****	28.19	27.45	*****	*****	0.138
1984	3005.	3.13	*****	29.71	28.95	*****	*****	0.142
1985	2993.	3.08	*****	31.79	30.75	*****	*****	0.131
1986	2986.	3.13	*****	34.69	33.24	*****	*****	0.122
1987	2972.	3.53	*****	38.37	36.52	*****	*****	0.124
1988	2956.	4.14	*****	42.87	40.61	*****	*****	0.130
1989	2939.	4.81	*****	48.21	45.53	*****	*****	0.135
1990	2922.	5.06	*****	54.04	51.11	*****	*****	0.126
1991	2906.	5.33	*****	60.41	57.21	*****	*****	0.119
1992	2890.	5.40	*****	67.49	63.94	*****	*****	0.118
1993	2874.	6.62	*****	75.39	71.43	*****	*****	0.118
1994	2859.	7.42	*****	83.21	79.79	*****	*****	0.119
1995	2843.	8.34	*****	94.01	89.10	*****	*****	0.120

DOE REGION 11
PRIVATE SECTOR
A3T111- TEST 2/4/81

AFUDC AS A % OF EARNINGS AVAILABLE FOR COMMON

YEAR	AFUDC	AVAILABLE EARNINGS	%
1979	3911.	2218.	1.7637
1980	3911.	5402.	0.7240
1981	4113.	9463.	0.4347
1982	3954.	9453.	0.3971
1983	4619.	11672.	0.3949
1984	5033.	12693.	0.3963
1985	5040.	12473.	0.4040
1986	5172.	12506.	0.4102
1987	6012.	14163.	0.4245
1988	7554.	16535.	0.4568
1989	8873.	19101.	0.5065
1990	10013.	19673.	0.5049
1991	11973.	26425.	0.5724
1992	13193.	23023.	0.5733
1993	13573.	26575.	0.5678
1994	15153.	26853.	0.5636
1995	16006.	31992.	0.5627

*** PRO FORMA STATEMENT OF EARNINGS ***

YEAR ENDED DECEMBER 31

ONE REGION 11
PUBLIC SECTOR
ADDITIONAL TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 11118.	\$ 13016.	\$ 15374.	\$ 17170.	\$ 19168.	\$ 21206.	\$ 23272.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	743.	826.	918.	1020.	1135.	1262.	1404.
DEPRECIATION	8997.	7776.	8642.	9607.	10583.	11680.	13215.
GENERAL TAXES	1269.	1416.	1551.	1735.	1831.	1955.	2142.
INCOME TAXES	385.	524.	671.	830.	938.	1066.	1240.
	19.	31.	47.	53.	61.	66.	69.
TOTAL ELECTRIC EXPENSES	9413.	10573.	11830.	13246.	14646.	16230.	18071.
ELECTRIC OPERATING INCOME	1705.	2443.	3544.	3924.	4522.	4977.	5202.
OTHER INCOME							
STOCK-OWNERS FUNDS	531.	531.	559.	538.	626.	684.	685.
TOTAL OTHER INCOME	531.	531.	559.	538.	626.	684.	685.
INCOME BEFORE INTEREST DEDUCTIONS	2236.	2974.	4103.	4463.	5148.	5660.	5886.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	1447.	1586.	1796.	2016.	2235.	2458.	2721.
INTEREST ON SHORT-TERM DEBT	44.	2.	2.	2.	2.	2.	2.
STOCK-BORROWED FUNDS	404.	404.	425.	410.	477.	520.	521.
TOTAL INTEREST DEDUCTIONS	1067.	1183.	1373.	1608.	1760.	1939.	2202.
NET INCOME	1150.	1791.	2730.	2855.	3388.	3721.	3684.
DIVIDENDS ON PREFERRED STOCKS	0.	0.	0.	0.	0.	0.	0.
EARNINGS FOR COMMON STOCK	\$ 1150.	\$ 1791.	\$ 2730.	\$ 2855.	\$ 3388.	\$ 3721.	\$ 3684.

A-23

DOE REGION 11
PUBLIC SECTOR
ADJILIN TEST 2/4/81

	1986	1987	1988	1989	1990	1991	1992
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	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 26167.	\$ 29738.	\$ 33707.	\$ 38166.	\$ 43021.	\$ 47227.	\$ 52229.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	1655.	1952.	2302.	2715.	3202.	3767.	4434.
FUEL	15067.	17178.	19586.	22333.	25465.	27711.	30158.
DEPRECIATION	2370.	2571.	2744.	2905.	3217.	3579.	3985.
GENERAL TAXES	1459.	1676.	1886.	2093.	2403.	2731.	3103.
INCOME TAXES	73.	82.	91.	99.	108.	110.	122.
TOTAL ELECTRIC EXPENSES	20626.	23459.	26609.	30145.	34391.	37898.	41803.
ELECTRIC OPERATING INCOME	5561.	6280.	7156.	8021.	8630.	9329.	10427.
OTHER INCOME							
PRODUCIBILITY FUNDS	703.	817.	1026.	1314.	1478.	1627.	1793.
TOTAL OTHER INCOME	703.	817.	1026.	1314.	1478.	1627.	1793.
INCOME BEFORE INTEREST DEDUCTIONS	6264.	7096.	8184.	9335.	10108.	10956.	12219.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	3060.	3481.	3983.	4565.	5214.	5921.	6699.
INTEREST ON SHORT-TERM DEBT	3.	4.	5.	6.	6.	7.	7.
PRODUCIBILITY FUNDS	(535.)	(622.)	(781.)	(1000.)	(1125.)	(1239.)	(1365.)
TOTAL INTEREST DEDUCTIONS	2529.	2864.	3207.	3570.	4095.	4690.	5342.
NET INCOME	3735.	4232.	4977.	5765.	6014.	6267.	6877.
DIVIDENDS ON PREFERRED STOCKS	0.	0.	0.	0.	0.	0.	0.
EARNINGS FOR COMMON STOCK	\$ 3735.	\$ 4232.	\$ 4977.	\$ 5765.	\$ 6014.	\$ 6267.	\$ 6877.

DOE REGION 11
PUBLIC SECTION
A311111* TEST 2/4/81

	1993	1994	1995	0	0	0	0
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	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 57867.	\$ 64101.	\$ 70946.	\$ 0.	\$ 0.	\$ 0.	\$ 0.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	5218.	6143.	7231.	0.	0.	0.	0.
FUEL	32826.	35733.	38903.	0.	0.	0.	0.
DEPRECIATION	4432.	4926.	5463.	0.	0.	0.	0.
GENERAL TAXES	3518.	3975.	4474.	0.	0.	0.	0.
INCOME TAXES	137.	154.	172.	0.	0.	0.	0.
TOTAL ELECTRIC EXPENSES	46130.	50931.	56243.	0.	0.	0.	0.
ELECTRIC OPERATING INCOME	11737.	13170.	14703.	0.	0.	0.	0.
OTHER INCOME							
PRODUCIBILITY FUNDS	1460.	2194.	2446.	0.	0.	0.	0.
TOTAL OTHER INCOME	1460.	2194.	2446.	0.	0.	0.	0.
INCOME BEFORE INTEREST DEDUCTIONS	13717.	15365.	17149.	0.	0.	0.	0.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	7558.	8415.	9304.	0.	0.	0.	0.
INTEREST ON SHORT-TERM DEBT	0.	9.	10.	0.	0.	0.	0.
PRODUCIBILITY FUNDS	(3507.)	(1670.)	(1862.)	(0.)	(0.)	(0.)	(0.)
TOTAL INTEREST DEDUCTIONS	6059.	6754.	7512.	0.	0.	0.	0.
NET INCOME	7659.	8609.	9637.	0.	0.	0.	0.
DIVIDENDS ON PREFERRED STOCKS	0.	0.	0.	0.	0.	0.	0.
EARNINGS FOR COMMON STOCK	\$ 7659.	\$ 8609.	\$ 9637.	\$ 0.	\$ 0.	\$ 0.	\$ 0.

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

DECEMBER 31

LOS ANGELES
PUBLIC UTILITY
ADDITIONAL (22428)

	1979	1980	1981	1982	1983	1984	1985
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(DOLLARS IN MILLIONS)							
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	22784.	27067.	31057.	36543.	39362.	43022.	48576.
TRANSMISSION	5598.	5643.	5693.	5750.	5812.	5882.	6451.
DISTRIBUTION	5161.	5161.	5161.	5161.	5161.	5161.	5161.
OTHER	4680.	4680.	4680.	4680.	4680.	4680.	4680.
CONSTRUCTION WORK IN PROGRESS	15602.	15735.	16706.	16255.	18439.	19971.	20420.
TOTAL UTILITY PLANT	53824.	58285.	63297.	68388.	73453.	78715.	85288.
ACCUMULATED DEPRECIATION	11838.	13254.	14805.	16541.	18372.	20326.	22469.
NET UTILITY PLANT, LESS NUCLEAR FUEL	41986.	45030.	48492.	51847.	55081.	58389.	62819.
NET NUCLEAR FUEL	868.	1015.	1159.	1322.	1505.	1712.	1925.
NET UTILITY PLANT	42854.	46045.	49651.	53169.	56587.	60101.	64744.
WORKING CAPITAL	968.	1075.	1195.	1328.	1477.	1643.	1827.
TOTAL ASSETS & OTHER DEBITS	43842.	47121.	50846.	54497.	58064.	61743.	66591.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	12655.	12452.	11526.	10438.	8777.	6837.	5500.
PAID-UP STOCK	0.	0.	0.	0.	0.	0.	0.
RETAINED EARNINGS	8568.	10359.	13089.	15944.	19332.	23053.	26737.
TOTAL PROPRIETARY CAPITAL	21223.	22811.	24615.	26382.	28109.	29890.	32237.
LONG-TERM DEBT	22179.	23639.	25723.	27570.	29374.	31236.	33689.
SHORT-TERM DEBT	430.	471.	508.	545.	581.	617.	666.
TOTAL DEBT	22618.	24110.	26232.	28115.	29955.	31853.	34355.
DEFERRED CREDITS							
ACCUMULATED DEFERRED ITC	0.	0.	0.	0.	0.	0.	0.
ACCUMULATED DEFERRED INCOME TAXES	0.	0.	0.	0.	0.	0.	0.
TOTAL DEFERRED CREDITS	0.	0.	0.	0.	0.	0.	0.
TOTAL LIABILITIES & OTHER CREDITS	43842.	47121.	50846.	54497.	58064.	61743.	66591.

DOF REGION 11
PUBLIC SECTION
471111N TLST 2/4/P1

	1986	1987	1988	1989	1990	1991	1992
	(DOLLARS IN MILLIONS)						
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	54863.	60283.	64838.	68908.	77439.	87683.	98975.
TRANSMISSION	7041.	7706.	8456.	9301.	9917.	10814.	11808.
DISTRIBUTION	5161.	5161.	5161.	5161.	5161.	5161.	5161.
OTHER	4680.	4680.	4680.	4680.	4680.	4680.	4680.
CONSTRUCTION WORK IN PROGRESS	21737.	25463.	31558.	39565.	44383.	48853.	53493.
TOTAL UTILITY PLANT	93481.	103293.	114693.	127614.	141579.	157201.	174017.
ACCUMULATED DEPRECIATION	24039.	27410.	30154.	33059.	36276.	39855.	43111.
NET UTILITY PLANT, LESS NUCLEAR FUEL	68642.	75883.	84539.	94555.	105303.	117346.	130906.
NET NUCLEAR FUEL	2342.	2819.	3392.	4079.	4902.	5612.	6400.
NET UTILITY PLANT	70984.	78702.	87930.	98634.	110204.	122957.	137306.
WORKING CAPITAL	2090.	2391.	2736.	3131.	3583.	3935.	4311.
TOTAL ASSETS & OTHER DEBITS	73074.	81093.	90666.	101765.	113788.	126892.	141369.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	4903.	4553.	4210.	3818.	3624.	3701.	3832.
DEFERRED STOCK	0.	0.	0.	0.	0.	0.	0.
RETAINED EARNINGS	30472.	34704.	39682.	45447.	51461.	57727.	64604.
TOTAL PROPRIETARY CAPITAL	35375.	39257.	43891.	49264.	55085.	61428.	68437.
DEBT							
LONG-TERM DEBT	36960.	41025.	45868.	51483.	57565.	64195.	71519.
SHORT-TERM DEBT	731.	811.	907.	1018.	1138.	1269.	1414.
TOTAL DEBT	37691.	41836.	46775.	52500.	58703.	65464.	72932.
DEFERRED CREDITS							
ACCUMULATED DEFERRED TTC	0.	0.	0.	0.	0.	0.	0.
ACCUMULATED DEFERRED INCOME TAXES	0.	0.	0.	0.	0.	0.	0.
TOTAL DEFERRED CREDITS	0.	0.	0.	0.	0.	0.	0.
TOTAL LIABILITIES & OTHER CREDITS	73074.	81093.	90666.	101765.	113788.	126892.	141369.

4-21

DOE REGION 11
PUBLIC SECTION
ASTORIA TEST 2/4/81

	1993	1994	1995	0	0	0	0
				(DOLLARS IN	MILLIONS)		
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	111426.	125159.	140063.	0.	0.	0.	0.
TRANSMISSION	12909.	14130.	15403.	0.	0.	0.	0.
DISTRIBUTION	5161.	5161.	5161.	0.	0.	0.	0.
OTHER	4680.	4680.	4680.	0.	0.	0.	0.
CONSTRUCTION WORK IN PROGRESS	59596.	66075.	73530.	0.	0.	0.	0.
TOTAL UTILITY PLANT	193772.	215204.	238236.	0.	0.	0.	0.
ACCUMULATED DEPRECIATION	48272.	53199.	58662.	0.	0.	0.	0.
NET UTILITY PLANT, LESS NUCLEAR FUEL	145500.	162006.	180274.	0.	0.	0.	0.
NET NUCLEAR FUEL	7169.	9012.	8890.	0.	0.	0.	0.
NET UTILITY PLANT	152669.	170017.	189163.	0.	0.	0.	0.
WORKING CAPITAL	4755.	5234.	5767.	0.	0.	0.	0.
TOTAL ASSETS & OTHER DEBITS	157424.	175251.	194930.	0.	0.	0.	0.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	3946.	3967.	3857.	0.	0.	0.	0.
PREFERRED STOCK	0.	0.	0.	0.	0.	0.	0.
RETAINED EARNINGS	72253.	80872.	90509.	0.	0.	0.	0.
TOTAL PROPRIETARY CAPITAL	76209.	84839.	94366.	0.	0.	0.	0.
DEBT							
LONG-TERM DEBT	79641.	88660.	98615.	0.	0.	0.	0.
SHORT-TERM DEBT	1574.	1753.	1949.	0.	0.	0.	0.
TOTAL DEBT	81215.	90412.	100564.	0.	0.	0.	0.
DEFERRED CREDITS							
ACCUMULATED DEFERRED LTC	0.	0.	0.	0.	0.	0.	0.
ACCUMULATED DEFERRED INCOME TAXES	0.	0.	0.	0.	0.	0.	0.
TOTAL DEFERRED CREDITS	0.	0.	0.	0.	0.	0.	0.
TOTAL LIABILITIES & OTHER CREDITS	157424.	175251.	194930.	0.	0.	0.	0.

***** PRO FORMA SOURCES AND USES OF FUNDS *****

DECEMBER 31

USE REGION II
PUBLIC SECTOR
ADDITION TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
SOURCES OF FUNDS							
NET INCOME	1150.	1791.	2730.	2855.	3388.	3721.	3684.
DEPRECIATION	1269.	1416.	1551.	1735.	1831.	1955.	2142.
DEFERRED LTC-NET	0.	0.	0.	0.	0.	0.	0.
DEFERRED INCOME TAXES	0.	0.	0.	0.	0.	0.	0.
ADJOC	(936.)	(936.)	(984.)	(948.)	(1103.)	(1204.)	(1206.)
TOTAL INTERNAL FUNDS	1482.	2272.	3297.	3642.	4116.	4472.	4620.
INCREASE IN SHORT-TERM DEBT	438.	33.	37.	37.	36.	37.	48.
INCREASE IN LONG-TERM DEBT	3184.	1659.	1885.	1847.	1804.	1862.	2453.
ISSUANCE OF COMMON STOCK	2250.	-203.	-946.	-1087.	-1661.	-1940.	-1337.
ISSUANCE OF PREFERRED STOCK	0.	0.	0.	0.	0.	0.	0.
TOTAL EXTERNAL FUNDS	5472.	1488.	996.	796.	178.	-42.	1164.
TOTAL SOURCES	7355.	3760.	4292.	4438.	4295.	4430.	5785.
APPLICATION OF FUNDS							
CONSTRUCTION EXPENDITURES (EXCLUDING STOCK)	3959.	3525.	4029.	4142.	3963.	4058.	5367.
COMMON STOCK DIVIDENDS	0.	0.	0.	0.	0.	0.	0.
PREFERRED STOCK DIVIDENDS	0.	0.	0.	0.	0.	0.	0.
CHANGE IN WORKING CAPITAL	91.	108.	120.	133.	149.	166.	185.
CHANGE IN NUCLEAR FUEL STOCK	0.	127.	144.	162.	183.	207.	233.
TOTAL APPLICATIONS	4051.	3760.	4292.	4438.	4295.	4430.	5785.
EXTERNAL FINANCING AS A PERCENT OF TOTAL APPLICATIONS							
	146.97	39.68	23.20	17.94	4.15	-0.94	20.13

110

DOE REGION 11
PUBLIC SECTION
A3T111M TEST 2/4/81

	1986	1987	1988	1989	1990	1991	1992
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	(DOLLARS IN MILLIONS)						
SOURCES OF FUNDS:							
NET INCOME	3735.	4232.	4977.	5765.	6014.	6267.	6877.
DEPRECIATION	2370.	2571.	2744.	2905.	3217.	3579.	3985.
DEFERRED LTC-NET	0.	0.	0.	0.	0.	0.	0.
DEFERRED INCOME TAXES	0.	0.	0.	0.	0.	0.	0.
AFUDC	(1237.)	(1438.)	(1807.)	(2315.)	(2604.)	(2866.)	(3158.)
TOTAL INTERNAL FUNDS	4868.	5365.	5915.	6356.	6627.	6980.	7705.
INCREASE IN SHORT-TERM DEBT	65.	80.	96.	111.	120.	131.	145.
INCREASE IN LONG-TERM DEBT	3279.	4057.	4843.	5615.	6082.	6630.	7324.
ISSUANCE OF COMMON STOCK	-597.	-350.	-343.	-392.	-193.	77.	131.
ISSUANCE OF PREFERRED STOCK	0.	0.	0.	0.	0.	0.	0.
TOTAL EXTERNAL FUNDS	2747.	3786.	4596.	5334.	6009.	6838.	7600.
TOTAL SOURCES	7616.	9151.	10511.	11689.	12636.	13818.	15304.
APPLICATION OF FUNDS:							
CONSTRUCTION EXPENDITURES	6956.	8373.	9593.	10607.	11361.	12756.	14158.
(EXCLUDING AFUDC)	0.	0.	0.	0.	0.	0.	0.
COMMON STOCK DIVIDENDS	0.	0.	0.	0.	0.	0.	0.
PREFERRED STOCK DIVIDENDS	0.	0.	0.	0.	0.	0.	0.
CHANGE IN WORKING CAPITAL	263.	301.	345.	395.	452.	351.	389.
CHANGE IN NUCLEAR FUEL STOCK	397.	477.	573.	687.	823.	710.	757.
TOTAL APPLICATIONS	7616.	9151.	10511.	11689.	12636.	13818.	15304.
EXTERNAL FINANCING AS A PERCENT							
OF TOTAL APPLICATIONS	36.08	41.38	43.73	45.63	47.55	49.49	49.66

002 REGION 11
PUBLIC SECTOR
A31110 TEST 2/4/81

	1993	1994	1995	0	0	0	0
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	(DOLLARS IN MILLIONS)						
SOURCES OF FUNDS:							
NET INCOME	7659.	8609.	9637.	0.	0.	0.	0.
DEPRECIATION	4432.	4926.	5463.	0.	0.	0.	0.
PREFERRED TTC-NET	0.	0.	0.	0.	0.	0.	0.
DEFERRED INCOME TAXES	0.	0.	0.	0.	0.	0.	0.
AFUDC	(3480.)	(3854.)	(4308.)	(0.)	(0.)	(0.)	(0.)
TOTAL INTERNAL FUNDS	8603.	9672.	10793.	0.	0.	0.	0.
INCREASE IN SHORT-TERM DEBT	161.	178.	197.	0.	0.	0.	0.
INCREASE IN LONG-TERM DEBT	8122.	9019.	9955.	0.	0.	0.	0.
ISSUANCE OF COMMON STOCK	114.	21.	-110.	0.	0.	0.	0.
ISSUANCE OF PREFERRED STOCK	0.	0.	0.	0.	0.	0.	0.
TOTAL EXTERNAL FUNDS	8396.	9218.	10042.	0.	0.	0.	0.
TOTAL SOURCES	17000.	18890.	20835.	0.	0.	0.	0.
APPLICATION OF FUNDS:							
CONSTRUCTION EXPENDITURES (EXCLUDING AFUDC)	15768.	17568.	19424.	0.	0.	0.	0.
COMMON STOCK DIVIDENDS	0.	0.	0.	0.	0.	0.	0.
PREFERRED STOCK DIVIDENDS	0.	0.	0.	0.	0.	0.	0.
CHANGE IN WORKING CAPITAL	431.	479.	532.	0.	0.	0.	0.
CHANGE IN RECEIVABLES/STOCK	800.	843.	878.	0.	0.	0.	0.
TOTAL APPLICATIONS	17000.	18890.	20834.	0.	0.	0.	0.
EXTERNAL FINANCING AS A PERCENT							
OF TOTAL APPLICATIONS	49.39	48.80	48.20	0.0	0.0	0.0	0.0

***** PRO FORMA REVENUE REQUIREMENT *****

YEAR ENDED DECEMBER 31

SECTION 11
DOMESTIC SECTOR
A3T1114 TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	38222.	42550.	46591.	52133.	55015.	58744.	64868.
CONSTRUCTION WORK IN PROGRESS	15602.	15735.	16706.	16255.	18439.	19971.	20420.
NUCLEAR FUEL	888.	1015.	1159.	1322.	1505.	1712.	1945.
WORKING CAPITAL	968.	1075.	1195.	1328.	1477.	1643.	1827.
DEDUCTIONS:							
ACCUMULATED DEPRECIATION	(11838.)	(13254.)	(14805.)	(16541.)	(18372.)	(20326.)	(22469.)
ACCUMULATED DEFERRED TAXES	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)
RATE BASE	43842.	47121.	50846.	54497.	58064.	61743.	66591.
REVENUE REQUIREMENT							
RATE BASE	43842.	47121.	50846.	54497.	58064.	61743.	66591.
RATE OF RETURN ON RATE BASE	0.102	0.104	0.105	0.107	0.108	0.110	0.111
RETURN ON RATE BASE	4462.	4894.	5361.	5834.	6299.	6779.	7404.
EXPENSES:							
OPERATION & MAINTENANCE	743.	826.	918.	1020.	1135.	1262.	1404.
DEPRECIATION	6997.	7775.	8542.	9607.	10683.	11880.	13215.
PROPERTY TAXES	1209.	1416.	1551.	1735.	1831.	1955.	2142.
SALES TAXES	435.	566.	595.	857.	957.	1083.	1268.
FEDERAL INCOME TAXES (NET OF ITC)	47.	55.	60.	68.	71.	76.	85.
ITC-FLOWED THROUGH	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)
ITC-AMORTIZED	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)
TAX SAVINGS FROM AFUDCO-FLOWED THROUGH	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)
TAX SAVINGS FROM AFUDCO-AMORTIZED	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)
AFUDCO OFFSET	(936.)	(936.)	(984.)	(948.)	(1103.)	(1204.)	(1327.)
TOTAL EXPENSES	8556.	9702.	10882.	12339.	13573.	15052.	16723.
REVENUE REQUIREMENTS	13018.	14586.	16243.	18173.	19872.	21831.	24115.

DOE REGION 11
PUBLIC SECTOR
431111M TEST 2/4/81

	1986	1987	1988	1989	1990	1991	1992
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	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	71744.	77830.	83135.	88050.	97196.	108338.	120624.
ADDITIONS:							
CONSTRUCTION WORK IN PROGRESS	21737.	25463.	31558.	39565.	44383.	48863.	53893.
NUCLEAR FUEL	2342.	2619.	3392.	4079.	4902.	5612.	6368.
WORKING CAPITAL	2090.	2391.	2736.	3131.	3583.	3935.	4324.
DEDUCTIONS:							
ACCUMULATED DEPRECIATION	(24839.))	(27410.))	(30154.))	(33059.))	(36276.))	(39855.))	(43840.))
ACCUMULATED DEFERRED TAXES	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))
RATE BASE	73074.	81093.	90666.	101765.	113788.	126892.	141369.
REVENUE REQUIREMENT							
RATE BASE	73074.	81093.	90666.	101765.	113788.	126892.	141369.
RATE OF RETURN ON RATE BASE	0.113	0.114	0.115	0.116	0.117	0.118	0.119
RETURN ON RATE BASE	8224.	9240.	10441.	11827.	13331.	14971.	16783.
EXPENSES:							
OPERATION & MAINTENANCE	1655.	1952.	2302.	2715.	3202.	3767.	4434.
FUEL	15067.	17174.	19586.	22333.	25465.	27711.	30156.
DEPRECIATION	2370.	2571.	2744.	2905.	3217.	3579.	3985.
GENERAL TAXES	1499.	1718.	1927.	2135.	2461.	2808.	3192.
STATE TAXES	96.	106.	114.	123.	137.	154.	172.
FEDERAL INCOME TAXES (NET OF ITC)	0.	0.	0.	0.	0.	0.	0.
ITC-ALLOWED THROUGH	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))
ITC-DEFERRED	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))
TAX SAVINGS FROM DEFUCO-ALLOWED THROUGH	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))
TAX SAVINGS FROM DEFUCO-DEFERRED	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))
DEFUCO OFFSET	(1237.))	(1436.))	(1807.))	(2315.))	(2604.))	(2866.))	(3158.))
TOTAL EXPENSES	19451.	22086.	24866.	27895.	31878.	35153.	38784.
REVENUE REQUIREMENTS	27679.	31326.	35307.	39722.	45208.	50124.	55568.

DOE REGION 11
PUBLIC SECTOR
4311114 TEST 2/4/81

	1993	1994	1995	0	0	0	0
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	134176.	149129.	165306.	0.	0.	0.	0.
ADDITIONS							
CONSTRUCTION WORK IN PROGRESS	59596.	66075.	73630.	0.	0.	0.	0.
NUCLEAR FUEL	7169.	8012.	8890.	0.	0.	0.	0.
WORKING CAPITAL	4755.	5234.	5767.	0.	0.	0.	0.
DEBT							
ACCUMULATED DEPRECIATION	(48272.)(	53199.)(	58662.)(	0.)(	0.)(	0.)(	0.)(
ACCUMULATED DEFERRED TAXES	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
RATE BASE	157424.	175251.	194930.	0.	0.	0.	0.
REVENUE REQUIREMENT							
RATE BASE	157424.	175251.	194930.	0.	0.	0.	0.
RATE OF RETURN ON RATE BASE	0.119	0.119	0.119	0.0	0.0	0.0	0.0
RETURN ON RATE BASE	18791.	20919.	23268.	0.	0.	0.	0.
EXPENSES							
OPERATION & MAINTENANCE	5218.	6143.	7231.	0.	0.	0.	0.
DEPRECIATION	32826.	35733.	38903.	0.	0.	0.	0.
GENERAL TAXES	4432.	4926.	5463.	0.	0.	0.	0.
STATE TAXES	3517.	4083.	4592.	0.	0.	0.	0.
FEDERAL INCOME TAXES (NET OF ITC)	193.	215.	239.	0.	0.	0.	0.
DEFERRED THROUGH	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
DEFERRED THROUGH	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
TAX SAVINGS FROM AFUDCO-FLOWED THROUGH	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
TAX SAVINGS FROM AFUDCO-AMORTIZED	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
AFUDCO OFFSET	(3488.)(	3864.)(	4308.)(	0.)(	0.)(	0.)(	0.)(
TOTAL EXPENSES	42797.	47237.	52121.	0.	0.	0.	0.
REVENUE REQUIREMENTS	61588.	68155.	75388.	0.	0.	0.	0.

REGION II
 PUBLIC SECTOR
 A31111M TEST 2/4/81

YR	ELEC REVS NOM	ELEC REVS PV	ELEC REVS CUMPV	DISCOUNT RATE USED=0.1250
1979	11118.	11118.	11118.	
1980	13018.	11570.	22687.	
1981	15374.	12147.	34834.	
1982	17170.	12059.	46893.	
1983	19139.	11757.	58650.	
1984	21288.	11768.	70624.	
1985	23272.	11480.	82107.	
1986	26107.	11482.	93589.	
1987	29738.	11590.	105180.	
1988	33767.	11699.	116878.	
1989	38158.	11753.	128631.	
1990	42911.	11755.	140407.	
1991	47827.	11491.	151898.	
1992	52823.	11285.	163194.	
1993	57857.	11125.	174319.	
1994	64101.	10954.	185273.	
1995	70540.	10777.	196050.	

REGION II
 PUBLIC SECTOR
 A31111M TEST 2/4/81

INTEREST COVERAGE CALCULATIONS

YR	SEC FORMULA
1979	1.2157
1980	1.0139
1981	2.0041
1982	2.0196
1983	2.0099
1984	2.1010
1985	1.9813
1986	1.3517
1987	1.3536
1988	1.3634
1989	1.6295
1990	1.7200
1991	1.6425
1992	1.6217
1993	1.6172
1994	1.6272
1995	1.6356

DOE REGION 11
PUBLIC SECTOR
431111M TEST 2/4/81

YEAR	ELEC REVS (\$10**6)	TOTAL SALES (GWH)	AVERAGE PRICE OF ELECT (MILLS/KWH)
1979	11117.510	393.	28.31633
1980	13015.591	405.	32.17442
1981	15073.570	417.	36.87527
1982	17170.262	430.	39.95670
1983	19166.103	443.	43.26572
1984	21206.344	457.	46.41859
1985	23272.258	471.	49.38951
1986	26147.168	486.	53.62308
1987	29730.262	506.	58.73397
1988	33757.359	525.	64.33592
1989	38155.062	544.	70.13434
1990	43020.556	564.	76.25345
1991	47227.031	581.	81.31509
1992	52237.434	598.	87.32684
1993	57860.824	610.	93.94325
1994	64100.773	634.	101.03068
1995	70945.937	654.	108.54886

DOE REGION 11
PUBLIC SECTOR
431111M TEST 2/4/81

AFUDC AS A % OF EARNINGS AVAILABLE FOR COMMON			
YEAR	AFUDC	AVAILABLE EARNINGS	%
1979	930.	1150.	0.8140
1980	936.	1791.	0.5224
1981	944.	2730.	0.3605
1982	945.	2855.	0.3322
1983	1103.	3380.	0.3254
1984	1204.	3721.	0.3236
1985	1206.	3584.	0.3273
1986	1237.	3735.	0.3313
1987	1435.	4232.	0.3398
1988	1607.	4977.	0.3630
1989	2315.	5765.	0.4015
1990	2604.	6014.	0.4330
1991	2616.	6267.	0.4573
1992	3155.	6877.	0.4591
1993	3400.	7650.	0.4554
1994	3600.	8603.	0.4368
1995	4300.	9637.	0.4470

ODE REGION 11
 PUBLIC SECTION
 ASSESSMENT TEST 2/4/81

REGULATORY LAG INFORMATION				
YEAR	NO LAG	1 YEAR LAG	1 & 1/2 YEARS LAG	TWO YEARS LAG
1970	15018.	11118.	11118.	11118.
1969	14506.	13395.	13016.	12036.
1968	14243.	15078.	15374.	15069.
1967	16173.	17451.	17170.	16879.
1966	19672.	19545.	19168.	18801.
1965	21831.	21340.	21208.	21033.
1964	24012.	23593.	23272.	23040.
1963	27073.	26695.	26167.	25769.
1962	31325.	30295.	29738.	29182.
1961	35307.	34302.	33767.	33233.
1960	39722.	38687.	38166.	37645.
1959	45206.	43587.	43021.	42484.
1958	51124.	49077.	47827.	46377.
1957	56805.	53283.	52129.	51175.
1956	61503.	58043.	57067.	56090.
1955	66105.	62411.	61101.	60290.
1954	70308.	67359.	65946.	64533.

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

YEAR ENDED DECEMBER 31

DCE REGION II
PUBLIC & PRIVATE
ASSET MANAGEMENT TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 65774.	\$ 79501.	\$ 96220.	\$ 106596.	\$ 117843.	\$ 129121.	\$ 140299.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	3850.	4278.	4755.	5286.	5877.	6536.	7271.
DEPRECIATION	36247.	40279.	44768.	49768.	55337.	61542.	68458.
GENERAL TAXES	7321.	8087.	8783.	9738.	10234.	10876.	11846.
LOCAL TAXES	5135.	6591.	8243.	9553.	10629.	11807.	13210.
	3562.	6500.	10122.	10814.	11863.	12559.	12692.
TOTAL ELECTRIC EXPENSES	56114.	65734.	76671.	85158.	93940.	103321.	113477.
ELECTRIC OPERATING INCOME	9660.	13767.	19548.	21438.	23902.	25800.	26822.
OTHER INCOME							
APPOC-OWNED FUNDS	2596.	2636.	2835.	2732.	3177.	3469.	3474.
TOTAL OTHER INCOME	2596.	2636.	2835.	2732.	3177.	3469.	3474.
INCOME BEFORE INTEREST DEDUCTIONS	12356.	16462.	22383.	24170.	27079.	29269.	30296.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	8555.	9098.	9979.	10896.	11797.	12715.	13806.
INTEREST ON SHORT-TERM DEBT	406.	13.	14.	14.	13.	14.	19.
APPOC-OWNED FUNDS	(2151.)	(2151.)	(2262.)	(2180.)	(2535.)	(2768.)	(2772.)
TOTAL INTEREST DEDUCTIONS	6809.	6959.	7731.	8729.	9276.	9961.	11053.
NET INCOME	5546.	9503.	14653.	15441.	17803.	19308.	19243.
DIVIDENDS ON PREFERRED STOCKS	2179.	2310.	2460.	2603.	2743.	2888.	3083.
EARNINGS FOR COMMON STOCK	\$ 3367.	\$ 7193.	\$ 12193.	\$ 12838.	\$ 15060.	\$ 16420.	\$ 16159.

SEE REGION 11
PUBLIC & PRIVATE
ASSET TEST 2/4/81

	1986	1987	1988	1989	1990	1991	1992
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 156443.	\$ 176343.	\$ 190809.	\$ 223045.	\$ 249590.	\$ 272959.	\$ 301291.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	8475.	10112.	11924.	14062.	16584.	19512.	22970.
FUEL	78051.	88984.	101457.	115686.	131910.	143546.	156224.
DEPRECIATION	13029.	14066.	14966.	15798.	17415.	19288.	21391.
GENERAL TAXES	15060.	17116.	19231.	21407.	24209.	26975.	30215.
INCOME TAXES	13154.	14342.	15648.	16752.	17080.	17667.	19223.
TOTAL ELECTRIC EXPENSES	127892.	144620.	163266.	183705.	207198.	226988.	250022.
ELECTRIC OPERATING INCOME	28551.	31723.	35543.	39341.	42392.	45971.	51269.
OTHER INCOME							
AFRICO-BURUNDI FUNDS	3565.	4144.	5206.	6669.	7502.	8256.	9097.
TOTAL OTHER INCOME	3565.	4144.	5206.	6669.	7502.	8256.	9097.
INCOME BEFORE INTEREST DEDUCTIONS	32115.	35867.	40749.	46009.	49894.	54227.	60366.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	15240.	17056.	19252.	21835.	24734.	27889.	31354.
INTEREST ON SHORT-TERM DEBT	28.	32.	39.	46.	50.	54.	61.
AFRICO-BURUNDI FUNDS	(2845.)	(3300.)	(4154.)	(5321.)	(5986.)	(6588.)	(7259.)
TOTAL INTEREST DEDUCTIONS	12421.	13781.	15137.	16559.	18797.	21355.	24154.
TAXY INCOME	19595.	22086.	25613.	29450.	31098.	32871.	36212.
DIVIDENDS ON PREFERRED STOCKS	3352.	3690.	4100.	4584.	5109.	5640.	6311.
EARNINGS FOR COMMON STOCK	\$ 16343.	\$ 18396.	\$ 21512.	\$ 24866.	\$ 25988.	\$ 27191.	\$ 29901.

DOE REGION 11
PUBLIC & PRIVATE
ASTORIA TEST 2/4/81

	1993	1994	1995	0	0	0	0
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
ELECTRIC REVENUES	\$ 333282.	\$ 368611.	\$ 407479.	\$ 0.	\$ 0.	\$ 0.	\$ 0.
ELECTRIC EXPENSES							
OPERATION & MAINTENANCE	27028.	31819.	37458.	0.	0.	0.	0.
DEPRECIATION	170041.	185101.	201522.	0.	0.	0.	0.
GENERAL TAXES	23710.	26269.	29050.	0.	0.	0.	0.
INCOME TAXES	33845.	37852.	42237.	0.	0.	0.	0.
	21229.	23462.	25834.	0.	0.	0.	0.
TOTAL ELECTRIC EXPENSES	275852.	304503.	336100.	0.	0.	0.	0.
ELECTRIC OPERATING INCOME	57430.	64108.	71379.	0.	0.	0.	0.
OTHER INCOME							
AFUDC-DEBT FUND	10048.	11131.	12411.	0.	0.	0.	0.
TOTAL OTHER INCOME	10048.	11131.	12411.	0.	0.	0.	0.
INCOME BEFORE INTEREST DEDUCTIONS	67479.	75239.	83789.	0.	0.	0.	0.
INTEREST DEDUCTIONS							
INTEREST ON LONG-TERM DEBT	35085.	38996.	43328.	0.	0.	0.	0.
INTEREST ON SHORT-TERM DEBT	86.	74.	81.	0.	0.	0.	0.
AFUDC-DEBT FUND	(8018.)	(8082.)	(9903.)	(0.)	(0.)	(0.)	(0.)
TOTAL INTEREST DEDUCTIONS	27133.	30188.	33506.	0.	0.	0.	0.
NET INCOME	40346.	45051.	50283.	0.	0.	0.	0.
DIVIDENDS ON PREFERRED STOCKS	7011.	7789.	8648.	0.	0.	0.	0.
EARNINGS FOR COMMON STOCK	\$ 33335.	\$ 37262.	\$ 41635.	\$ 0.	\$ 0.	\$ 0.	\$ 0.

PRO FORMA BALANCE SHEET

DECEMBER 31

DOE REGION II
PUBLIC & PRIVATE
ASSET TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	118096.	140240.	160949.	189367.	203970.	222929.	251703.
TRANSMISSION	34737.	34972.	35233.	35524.	35848.	36208.	39154.
DISTRIBUTION	58502.	58502.	58502.	58502.	58502.	58502.	58502.
OTHER	9153.	9153.	9153.	9153.	9153.	9153.	9153.
CONSTRUCTION WORK IN PROGRESS	80818.	81507.	86541.	84201.	95514.	103453.	105776.
TOTAL UTILITY PLANT	301305.	324413.	350379.	376747.	402986.	430244.	464292.
ACCUMULATED DEPRECIATION	68819.	76906.	85689.	95427.	105661.	116530.	126384.
NET UTILITY PLANT, LESS NUCLEAR FUEL	232486.	247508.	264690.	281320.	297325.	313707.	335908.
NET NUCLEAR FUEL	4600.	5260.	6005.	6847.	7796.	8867.	10075.
NET UTILITY PLANT	237086.	252767.	270695.	288167.	305121.	322574.	345983.
WORKING CAPITAL	5012.	5570.	6190.	6882.	7652.	8510.	9465.
TOTAL ASSETS & OTHER DEBITS	242098.	258337.	276885.	295048.	312772.	331084.	355449.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	62121.	64562.	65815.	66573.	66211.	65451.	60917.
PREFERRED STOCK	21791.	21100.	24590.	26034.	27433.	28881.	30833.
RETAINED EARNINGS	26450.	29641.	34825.	40268.	46683.	53697.	60615.
TOTAL PROPRIETARY CAPITAL	110361.	117303.	125239.	132875.	140327.	148029.	158365.
LONG-TERM DEBT	112231.	119299.	127379.	135155.	142743.	150586.	151112.
SHORT-TERM DEBT	4058.	4308.	4595.	4869.	5137.	5415.	5788.
TOTAL DEBT	116289.	123607.	131973.	140025.	147881.	156001.	156900.
DEFERRED CREDITS							
ACCUMULATED DEFERRED LTC	5757.	6820.	8013.	9196.	10296.	11394.	12869.
ACCUMULATED DEFERRED INCOME TAXES	9691.	10607.	11660.	12952.	14269.	15660.	17314.
TOTAL DEFERRED CREDITS	15448.	17427.	19673.	22148.	24565.	27054.	30183.
TOTAL LIABILITIES & OTHER CREDITS	242098.	258337.	276885.	295048.	312772.	331083.	355449.

COE REGION II
PUBLIC & PRIVATE
ASSETS & LIABILITIES 2/4/81

ASSET ITEM (SEE 27475)	1986	1987	1988	1989	1990	1991	1992
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	284267.	312346.	335940.	357026.	401217.	454283.	512777.
TRANSMISSION	42215.	45660.	49544.	53919.	57110.	61758.	66907.
DISTRIBUTION	56502.	58502.	58502.	58502.	58502.	58502.	58502.
OTHER	9153.	9153.	9153.	9153.	9153.	9153.	9153.
CONSTRUCTION WORK IN PROGRESS	112599.	131699.	163476.	204950.	229907.	253117.	279172.
TOTAL UTILITY PLANT	506735.	557560.	616614.	603550.	755869.	836813.	926512.
ACCUMULATED DEPRECIATION	141413.	155479.	170445.	186243.	203658.	222946.	244337.
NET UTILITY PLANT, LESS NUCLEAR FUEL	365322.	402081.	446169.	417307.	552211.	613867.	682175.
NET NUCLEAR FUEL	12140.	14602.	17569.	21129.	25392.	29069.	32948.
NET UTILITY PLANT	377462.	416683.	463738.	438436.	577603.	642936.	715123.
WORKING CAPITAL	10828.	12387.	14173.	16218.	18562.	20382.	22399.
TOTAL ASSETS & OTHER DEBITS	388280.	429070.	477910.	534654.	596185.	663318.	737562.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	71337.	77764.	85827.	95428.	106293.	119587.	132245.
PREFERRED STOCK	33515.	35896.	41003.	45839.	51093.	56802.	63110.
RETAINED EARNINGS	67620.	75525.	84790.	95508.	106701.	119393.	131240.
TOTAL PROPRIETARY CAPITAL	172472.	190185.	211620.	236775.	264087.	293782.	326595.
LONG-TERM DEBT	175471.	193500.	215316.	240916.	266710.	296931.	332325.
SHORT-TERM DEBT	6298.	6940.	7718.	8632.	9625.	10704.	11897.
TOTAL DEBT	181769.	200440.	223034.	249548.	278335.	309635.	344221.
DEFERRED CREDITS							
ACCUMULATED DEFERRED LTC	14807.	17157.	19860.	22853.	26014.	29540.	33419.
ACCUMULATED DEFERRED INCOME TAXES	19233.	21258.	23396.	25479.	27749.	30361.	33326.
TOTAL DEFERRED CREDITS	34039.	38415.	43256.	48332.	53763.	59901.	66746.
TOTAL LIABILITIES & OTHER CREDITS	388280.	429069.	477910.	534654.	596185.	663318.	737562.

DOE REGION 11
PUBLIC & PRIVATE
ASSETS & LIABILITIES 2/4/81

	1993	1994	1995	0	0	0	0
				(DOLLARS IN	MILLIONS)		
ASSETS & OTHER DEBITS							
UTILITY PLANT							
PRODUCTION	577275.	648413.	725614.	0.	0.	0.	0.
TRANSMISSION	72612.	78934.	85528.	0.	0.	0.	0.
DISTRIBUTION	58502.	58502.	58502.	0.	0.	0.	0.
OTHER	9153.	9153.	9153.	0.	0.	0.	0.
CONSTRUCTION WORK IN PROGRESS	304717.	342277.	381413.	0.	0.	0.	0.
TOTAL UTILITY PLANT	1026256.	1137278.	1260210.	0.	0.	0.	0.
ACCUMULATED DEPRECIATION	268047.	294315.	323366.	0.	0.	0.	0.
NET UTILITY PLANTS, LESS NUCLEAR FUEL	758212.	842963.	936845.	0.	0.	0.	0.
NET NUCLEAR FUEL	37135.	41501.	46051.	0.	0.	0.	0.
NET UTILITY PLANT	795346.	884464.	982896.	0.	0.	0.	0.
WORKING CAPITAL	24634.	27115.	29872.	0.	0.	0.	0.
TOTAL ASSETS & OTHER DEBITS	819980.	911579.	1012768.	0.	0.	0.	0.
LIABILITIES & OTHER CREDITS							
PROPRIETARY CAPITAL							
COMMON STOCK	147337.	163977.	182124.	0.	0.	0.	0.
PREFERRED STOCK	70111.	77492.	86484.	0.	0.	0.	0.
RETAINED EARNINGS	145557.	161506.	179530.	0.	0.	0.	0.
TOTAL PROPRIETARY CAPITAL	363005.	402975.	448138.	0.	0.	0.	0.
DEBT							
LONG-TERM DEBT	369378.	410552.	456015.	0.	0.	0.	0.
SHORT-TERM DEBT	13220.	14691.	16315.	0.	0.	0.	0.
TOTAL DEBT	382598.	425243.	472330.	0.	0.	0.	0.
DEFERRED CREDITS							
ACCUMULATED DEFERRED LTC	37711.	42464.	47608.	0.	0.	0.	0.
ACCUMULATED DEFERRED INCOME TAXES	36666.	40407.	44512.	0.	0.	0.	0.
TOTAL DEFERRED CREDITS	74377.	82871.	92120.	0.	0.	0.	0.
TOTAL LIABILITIES & OTHER CREDITS	819980.	911578.	1012768.	0.	0.	0.	0.

*** PRO FORMA SOURCES AND USES OF FUNDS ***

DECEMBER 31

EDITION 11
PUBLIC & PRIVATE
AST11114 TEST 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
SOURCES OF FUNDS:							
NET INCOME	5546.	9503.	14653.	15441.	17803.	19308.	19243.
DEPRECIATION	7321.	8087.	8783.	9738.	10234.	10876.	11846.
DEFERRED LTC-NET	1047.	1063.	1193.	1183.	1099.	1098.	1475.
INCREASE IN INCOME TAXES	735.	316.	1053.	1292.	1317.	1391.	1554.
NET	(4947.)	(4847.)	(5097.)	(4913.)	(5711.)	(6237.)	(6246.)
TOTAL INTERNAL FUNDS	9424.	14722.	20585.	22742.	24742.	26436.	27972.
INCREASE IN SHORT-TERM DEBT	888.	250.	286.	275.	268.	277.	373.
INCREASE IN LONG-TERM DEBT	14405.	7068.	8080.	7776.	7588.	7843.	10525.
ISSUANCE OF COMMON STOCK	10073.	2441.	1253.	758.	-362.	-759.	1466.
ISSUANCE OF PREFERRED STOCK	2708.	1309.	1499.	1435.	1400.	1447.	1953.
TOTAL EXTERNAL FUNDS	28074.	11068.	11119.	10244.	8893.	8808.	14317.
TOTAL SOURCES	37898.	25790.	31704.	32987.	33636.	35245.	42290.
APPLICATION OF FUNDS:							
CONSTRUCTION EXPENDITURES (EXCLUDING FUEL)	20510.	18261.	20868.	21456.	20527.	21021.	27802.
COMMON STOCK DIVIDENDS	1643.	4001.	7009.	7395.	8645.	9406.	9241.
PREFERRED STOCK DIVIDENDS	2179.	2310.	2460.	2603.	2743.	2888.	3063.
CHANGE IN WORKING CAPITAL	3598.	558.	621.	691.	770.	858.	956.
CHANGE IN NUCLEAR FUEL STOCK	0.	660.	745.	842.	950.	1071.	1208.
TOTAL APPLICATIONS	27930.	25790.	31704.	32987.	33636.	35245.	42290.
EXTERNAL FINANCING AS A PERCENT OF TOTAL APPLICATIONS	100.52	42.91	35.07	31.06	26.44	24.99	33.86

DOE REGION II
PUBLIC & PRIVATE
UTILITIES (P2428)

	1986	1987	1988	1989	1990	1991	1992
	(DOLLARS IN MILLIONS)						
SOURCES OF FUNDS							
NET INCOME	19695.	22086.	25613.	29450.	31098.	32871.	36212.
DEPRECIATION	13029.	14066.	14966.	15748.	17415.	19288.	21391.
DEFERRED INCOME TAX	1938.	2350.	2704.	2992.	3161.	3526.	3880.
DEFERRED INCOME TAXES	1919.	2056.	2108.	2083.	2270.	2612.	2965.
INCREASE IN CURRENT TAXES	(6409.)	(7450.)	(9361.)	(11990.)	(13449.)	(14844.)	(16355.)
TOTAL INTERNAL FUNDS	30171.	33107.	36030.	38333.	40455.	43454.	48091.
INCREASE IN SHORT-TERM DEBT	510.	642.	778.	914.	993.	1079.	1193.
INCREASE IN LONG-TERM DEBT	14359.	18029.	21816.	25600.	27794.	30220.	33394.
ISSUANCE OF COMMON STOCK	4420.	6426.	8963.	9601.	10865.	12295.	13651.
ISSUANCE OF PREFERRED STOCK	2661.	3381.	4107.	4836.	5254.	5709.	6300.
TOTAL EXTERNAL FUNDS	21970.	28479.	34765.	40951.	44906.	49303.	54552.
TOTAL SOURCES	52141.	61586.	70794.	79284.	85362.	92757.	102643.
APPLICATION OF FUNDS							
CONSTRUCTION EXPENSE OTHERS	36034.	43375.	49693.	54946.	58851.	66080.	73342.
CONSTRUCTION EXPENSE	9339.	10491.	12247.	14148.	14795.	15499.	17053.
COMMON STOCK DIVIDENDS	3352.	3690.	4100.	4584.	5109.	5680.	6311.
PREFERRED STOCK DIVIDENDS	1362.	1559.	1786.	2046.	2343.	1820.	2017.
CHANGE IN WORKING CAPITAL	2055.	2472.	2967.	3560.	4263.	3677.	3919.
CHANGE IN OTHER FULL STOCK	---	---	---	---	---	---	---
TOTAL APPLICATIONS	52142.	61586.	70794.	79284.	85362.	92757.	102643.
EXTERNAL FINANCING AS A PERCENT							
OF TOTAL APPLICATIONS	42.14	46.24	49.11	51.65	52.61	53.15	53.15

DOE MEMO 11
PUBLIC & PRIVATE
AS11114 TEST 2/4/91

	1993	1994	1995	0	0	0	0
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
SOURCE OF FUNDS:							
NET INCOME	40346.	45051.	50283.	0.	0.	0.	0.
DEPRECIATION	23710.	26269.	29050.	0.	0.	0.	0.
DEFERRED LTC-NET	4291.	4754.	5223.	0.	0.	0.	0.
DEFERRED INCOME TAXES	3340.	3741.	4205.	0.	0.	0.	0.
AFUD.	(18067.)	(20013.)	(22314.)	(0.)	(0.)	(0.)	(0.)
TOTAL INTERNAL FUNDS	53621.	59801.	66448.	0.	0.	0.	0.
INCREASE IN SHORT-TERM DEBT	1323.	1471.	1624.	0.	0.	0.	0.
INCREASE IN LONG-TERM DEBT	37053.	41175.	45463.	0.	0.	0.	0.
ISSUANCE OF COMMON STOCK	15092.	16640.	18149.	0.	0.	0.	0.
ISSUANCE OF PREFERRED STOCK	7001.	7781.	8592.	0.	0.	0.	0.
TOTAL EXTERNAL FUNDS	60470.	67066.	73827.	0.	0.	0.	0.
TOTAL SOURCES	114090.	125867.	140275.	0.	0.	0.	0.
APPLICATION OF FUNDS:							
CONSTRUCTION EXPENDITURES (EXCLUDING AFUDC)	81560.	91007.	100618.	0.	0.	0.	0.
COMMON STOCK DIVIDENDS	19018.	21223.	23701.	0.	0.	0.	0.
PREFERRED STOCK DIVIDENDS	7011.	7769.	8648.	0.	0.	0.	0.
CHANGE IN WORKING CAPITAL	2234.	2482.	2757.	0.	0.	0.	0.
CHANGE IN NUCLEAR FUEL STOCK	4147.	4356.	4550.	0.	0.	0.	0.
TOTAL APPLICATIONS	114090.	125867.	140275.	0.	0.	0.	0.
EXTERNAL FINANCING AS A PERCENT							
OF TOTAL APPLICATIONS	53.00	52.86	52.63	0.0	0.0	0.0	0.0

**** FNU FURIA REVENUE REQUIREMENT ****

YEAR ENDED DECEMBER 31

SEE REGION 11
 110100 PRIVATE
 131111 1251 2/4/81

	1979	1980	1981	1982	1983	1984	1985
	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	220487.	242906.	263838.	292546.	307472.	326792.	358516.
CONSTRUCTION WORK IN PROGRESS	80818.	81507.	86541.	84201.	95514.	103453.	105776.
NUCLEAR FUEL	4600.	5260.	6005.	6847.	7796.	8867.	10075.
WORKING CAPITAL	5012.	5570.	6190.	6882.	7652.	8510.	9466.
DEDUCTIONS							
ACCUMULATED DEPRECIATION	(68219.))	(75906.))	(85689.))	(95427.))	(105661.))	(116538.))	(126384.))
ACCUMULATED DEFERRED TAXES	(4691.))	(10607.))	(11660.))	(12952.))	(14269.))	(15660.))	(17314.))
RATE BASE	232400.	247730.	265226.	282096.	298503.	315424.	338135.
REVENUE REQUIREMENT							
RATE BASE	232400.	247730.	265226.	282096.	298503.	315424.	338135.
RATE OF RETURN ON RATE BASE	0.104	0.105	0.106	0.107	0.108	0.109	0.110
RETENTION RATE BASE	24140.	26022.	28165.	30252.	32294.	34405.	37201.
EXPENSES							
OPERATION & MAINTENANCE	3850.	4278.	4755.	5286.	5877.	6536.	7271.
FUEL	36247.	40279.	44768.	49768.	55337.	61542.	68458.
DEPRECIATION	7321.	8087.	8783.	9738.	10234.	10876.	11446.
NUCLEAR FUEL	6367.	7447.	8568.	9539.	10860.	11995.	13594.
WATER FUEL	451.	514.	557.	614.	638.	674.	741.
FEDERAL INCOME TAXES (NET OF ITC)	10058.	11241.	11921.	12771.	13168.	13714.	14723.
IFC-FLUOR THROUGH	(303.))	(317.))	(362.))	(372.))	(356.))	(365.))	(482.))
IFC-FLUORIZED	(58.))	(95.))	(129.))	(177.))	(202.))	(234.))	(267.))
TAX SAVINGS FROM AFUDCO-FLUOR THROUGH	(804.))	(803.))	(845.))	(814.))	(947.))	(1034.))	(1035.))
TAX SAVINGS FROM AFUDCO-FLUORIZED	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))	(0.))
AFUDCO OFFSET	(4947.))	(4847.))	(5047.))	(4913.))	(5711.))	(6237.))	(6246.))
TOTAL EXPENSES	58263.	65633.	72934.	81839.	88898.	97468.	108582.
REVENUE REQUIREMENTS	82423.	91854.	101103.	112090.	121192.	131873.	145783.

ONE REGION II
PUBLIC & PRIVATE
ASSETS LIST 2/4/81

	1986	1987	1988	1989	1990	1991	1992
	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	394136.	425661.	453138.	478600.	525982.	583695.	647339.
ADDITIONS:							
CONSTRUCTION WORK IN PROGRESS	112599.	131699.	163476.	204950.	229907.	253117.	279172.
NUCLEAR FUEL	12130.	14602.	17569.	21129.	25392.	29069.	32988.
ACQUIRING CAPITAL	10528.	12387.	14173.	16218.	18562.	20382.	22399.
DEDUCTIONS:							
ACCUMULATED DEPRECIATION	(141413.)(	155479.)(	170445.)(	186243.)(	203658.)(	222946.)(	244337.)(
ACCUMULATED DEFERRED TAXES	(19233.)(	21288.)(	23325.)(	25479.)(	27749.)(	30361.)(	33326.)(
RATE BASE	369047.	407781.	454514.	509175.	568436.	632957.	704236.
REVENUE REQUIREMENT							
RATE OF RETURN ON RATE BASE	0.111	0.112	0.113	0.114	0.114	0.115	0.115
RETURN ON RATE BASE	40962.	45644.	51266.	57817.	64925.	72670.	81227.
EXPENSES:							
OPERATION & MAINTENANCE	8575.	10112.	11924.	14062.	16584.	19512.	22970.
DEPRECIATION	78051.	86984.	101457.	115686.	131910.	143546.	156224.
GENERAL TAXES	13029.	14056.	14906.	15798.	17415.	19288.	21391.
STATE TAXES	15665.	17723.	19730.	21955.	25071.	28165.	31592.
FEDERAL INCOME TAXES (NET OF ITC)	826.	903.	972.	1039.	1159.	1289.	1435.
ITC-FLOWED THROUGH	16009.	17383.	18664.	19986.	22067.	24385.	26478.
ITC-AMORTIZED	(625.)(	753.)(	863.)(	954.)(	1022.)(	1148.)(	1274.)(
TAX SAVINGS FROM AMORTIZED	(346.)(	379.)(	446.)(	490.)(	569.)(	665.)(	771.)(
TAX SAVINGS FROM AMORTIZED THROUGH	(1062.)(	1235.)(	1552.)(	1988.)(	2236.)(	2461.)(	2711.)(
TAX SAVINGS FROM AMORTIZED	(0.)(	0.)(	0.)(	0.)(	0.)(	0.)(	0.)(
AMORT. OFFSET	(6402.)(	7450.)(	9361.)(	11990.)(	13489.)(	14844.)(	16356.)(
TOTAL EXPENSES	123770.	139333.	155553.	173103.	196890.	217068.	239477.
REVENUE REQUIREMENTS	164732.	184978.	206918.	230921.	261816.	289737.	320704.

DOE REGION 11
PUBLIC & PRIVATE
ACTIVITY TEST: 2/4/81

	1993	1994	1995	0	0	0	0
	-----	-----	-----	-----	-----	-----	-----
	(DOLLARS IN MILLIONS)						
UTILITY PLANT IN SERVICE	717542.	795001.	878797.	0.	0.	0.	0.
ADDITIONS:							
CONSTRUCTION WORK IN PROGRESS	308717.	342277.	351413.	0.	0.	0.	0.
NUCLEAR FUEL	37135.	41501.	46051.	0.	0.	0.	0.
WORKING CAPITAL	24634.	27115.	29872.	0.	0.	0.	0.
DEDUCTIONS:							
ACCUMULATED DEPRECIATION	(268747.)	(294315.)	(323356.)	(0.)	(0.)	(0.)	(0.)
ACCUMULATED DEFERRED TAXES	(36606.)	(40407.)	(44612.)	(0.)	(0.)	(0.)	(0.)
RATE BASE	783313.	871172.	964155.	0.	0.	0.	0.
REVENUE REQUIREMENT							
RATE BASE	783313.	871172.	964155.	0.	0.	0.	0.
RATE OF RETURN ON RATE BASE	0.116	0.116	0.116	0.0	0.0	0.0	0.
RETURN ON RATE BASE	90603.	100766.	111984.	0.	0.	0.	0.
EXPENSES:							
OPERATION & MAINTENANCE	27028.	31819.	37458.	0.	0.	0.	0.
FUEL	170041.	185101.	201522.	0.	0.	0.	0.
DEPRECIATION	23710.	26289.	21930.	0.	0.	0.	0.
GENERAL TAXES	35371.	31533.	44084.	0.	0.	0.	0.
STATE TAXES	1595.	1771.	1959.	0.	0.	0.	0.
FEDERAL INCOME TAXES (NET OF ITC)	29834.	32977.	36351.	0.	0.	0.	0.
ITC-ELIGIBLE THROUGH	(1419.)	(1501.)	(1748.)	(0.)	(0.)	(0.)	(0.)
ITC-AMORTIZED	(888.)	(1018.)	(1157.)	(0.)	(0.)	(0.)	(0.)
TAX SAVINGS FROM AMTDCU-ELIGIBLE THROUGH	(2995.)	(3318.)	(3699.)	(0.)	(0.)	(0.)	(0.)
TAX SAVINGS FROM AMTDCU-AMORTIZED	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)	(0.)
GOOD OFFSET	(18067.)	(20013.)	(22314.)	(0.)	(0.)	(0.)	(0.)
TOTAL EXPENSES	264210.	291541.	321506.	0.	0.	0.	0.
REVENUE REQUIREMENTS	354812.	342306.	433490.	0.	0.	0.	0.

DOE REGION 11
PUBLIC & PRIVATE
A311114 TEST 2/4/81

YEAR	ELEC REVS TOT	ELEC REVS PV	ELEC REVS CUMPV	DISCOUNT RATE USED=0.1250
1979	65774.	65774.	65774.	
1980	73591.	70657.	136442.	
1981	95220.	76076.	212457.	
1982	105576.	74356.	287333.	
1983	117513.	73556.	360901.	
1984	129121.	71653.	432554.	
1985	140295.	69206.	501760.	
1986	150443.	66594.	570354.	
1987	175343.	63729.	639083.	
1988	198509.	60675.	707958.	
1989	223045.	56656.	776644.	
1990	241590.	51390.	844964.	
1991	272559.	46415.	911379.	
1992	301291.	40153.	976542.	
1993	333252.	31973.	1040816.	
1994	368611.	22991.	1103606.	
1995	407479.	16896.	1165502.	

DOE REGION 11
PUBLIC & PRIVATE
A311114 TEST 2/4/81

INTEREST COVERAGE CALCULATIONS

YEAR	SEC FORMULA
1979	1.6622
1980	2.2809
1981	3.0215
1982	3.0052
1983	3.0601
1984	3.0656
1985	2.9973
1986	2.7758
1987	2.7445
1988	2.7007
1989	2.6259
1990	2.4571
1991	2.3350
1992	2.3094
1993	2.2935
1994	2.2959
1995	2.2951

DOE REGION II
PUBLIC & PRIVATE
UTILITY TEST 2/4/81

YEAR	ELEC REVS (1000000)	TOTAL SALES (GWH)	AVERAGE PRICE OF ELECT (MILLS/KWH)
1979	55724.107	2034.	32.34030
1980	78307.075	2006.	37.03405
1981	98114.375	2180.	44.55495
1982	108700.337	2226.	47.84644
1983	117746.370	2293.	51.34827
1984	129120.075	2367.	54.56364
1985	140299.437	2441.	57.47429
1986	156440.000	2530.	61.84131
1987	176343.002	2623.	67.24126
1988	186100.372	2719.	73.12245
1989	200443.375	2819.	74.12805
1990	249250.375	2923.	85.40242
1991	272380.312	3009.	90.72707
1992	301249.750	3096.	97.24730
1993	333252.125	3191.	104.44972
1994	368010.502	3287.	112.15483
1995	407473.002	3386.	120.35451

DOE REGION II
PUBLIC & PRIVATE
UTILITY TEST 2/4/81

AFUDC AS A % OF EARNINGS AVAILABLE FOR COMMON

YEAR	AFUDC	AVAILABLE EARNINGS	%
1979	4847.	3367.	1.4395
1980	4847.	7193.	0.6738
1981	5037.	12193.	0.4180
1982	4373.	12538.	0.3327
1983	5711.	15000.	0.3792
1984	6207.	15120.	0.3799
1985	7205.	16150.	0.3865
1986	7450.	18343.	0.3922
1987	7450.	18396.	0.4050
1988	9361.	21512.	0.4351
1989	11900.	24855.	0.4422
1990	13400.	25937.	0.5130
1991	14900.	27171.	0.5459
1992	17300.	29901.	0.5470
1993	17900.	33355.	0.5420
1994	22010.	37207.	0.5371
1995	22314.	41035.	0.5359

DIST. REGION 11
 PUBLIC & PRIVATE
 4311114 TEST 2/4/81

REGULATORY LAG INFORMATION				
YEAR	NO LAG	1 YEAR LAG	1 & 1/2 YEARS LAG	TWO YEARS LAG
1979	82423.	65774.	65774.	65774.
1980	91854.	68076.	79501.	70924.
1981	101163.	75163.	96220.	94274.
1982	112391.	105110.	106596.	105042.
1983	121193.	110494.	117843.	115791.
1984	131473.	129750.	129121.	126452.
1985	143753.	141374.	140299.	139225.
1986	154752.	155720.	156443.	154158.
1987	164976.	179453.	176343.	173231.
1988	205519.	201671.	198809.	195546.
1989	236721.	225714.	223645.	220377.
1990	261419.	228250.	249530.	246691.
1991	279757.	277562.	272459.	268056.
1992	320754.	307465.	301291.	295170.
1993	304412.	340130.	335252.	326434.
1994	342355.	376172.	366611.	361049.
1995	433490.	415769.	407479.	399169.

APPENDIX B

INPUT SOURCES OF NUFIS:

- Table B.1: User-Supplied Inputs¹
- Table B.2: Base-Year Financial Data²
- Tables B.3-B.6: Inputs from MEFS

¹ The values of the user-provided variables in Table B.1 reflect the magnitudes that were utilized in the base-case sample problem for sensitivity analysis purposes. For purposes of execution of the code, all of the variables expressed in percentage terms in Table B.1 must be expressed in decimal places (e.g., 3.3% = .0333). Furthermore, four variables for both public and private utilities that were not assigned values in the sample problem accompanying the documentation were assigned values for the base case problem in order to more accurately reflect real-world circumstances. Those variables (and the value assigned them) are: the state tax rate (1.5%); the property tax rate (2.0%); the sales tax rate (1.0%); and the salvage percentage (1.0%). Additionally, the percentage of short-term debt for the public sector was provided a value of 1.0% and the long-term debt percentage was correspondingly reduced from 51.59% to 50.59%.

² The values of the base year financial data were arbitrarily rounded to the nearest hundred-thousand dollar.

Table B.1. User-Supplied Inputs Into NUFS

	NUFS Code	Base Case Values	
		Private	Public
New Construction Expenditures:			
Number of New Plant Types		16	16
Number of New Production Plant Types		12	12
Month New Plant Comes On Line		1	1
% of Construction Completed Each Year	CONPER	1	1
AFUDC Rate	AFUDCR	8.23%	8.23%
CWIP Rate	CWPPER	14.2%	14.2%
AFUDC Offset	OFFSET	1 ²	1 ²
Tax-Related Variables:			
Federal Tax Rate	TXRT	46.0%	NA
State Tax Rate	STXRT	1.5%	1.5%
Property Tax Rate	PRTXRT	2.0%	2.0%
Sales Tax Rate	SATXRT	1.0%	1.0%
Investment Tax Credit Rate	RITC	10.0%	NA
Flow-Through % of - Accl. Deprec.	FLPR1	21.5%	NA
- AFUDC-Debt	FLPR2	100%	NA
- Investment T.C.	FLPR1	21.5%	NA
Depreciation-Related Variables:			
Book Depreciation Rate - Old Assets ³	DR1	3.33%	3.33%
- New Assets ⁴	DR2	3.33%	3.33%
Book Life - Old Assets ³	SY1	30	30
- New Assets ⁴	SY2	30	30
Tax Life - Old Assets ³	TXSY1	23	23
- New Assets ⁴	TXSY2	23	23
Years of Service (Old Assets Only) ³	T1	9	9
Salvage Value % - Old Assets ³	SALPR1	1.0%	1.0%
- New Assets ⁴	SALPR2	1.0%	1.0%
Declining Balance Depreciation Factor ^{4,5} (New Assets Only)	DEPFAC	2	2
Capital-Related Variables:			
Capital Ratio - % Long-Term Debt	PERLT*	49.26%	50.59%
- % Short-Term Debt	PERST*	1.98%	1.0%
- % Common Equity	PERCE*	36.84%	48.41%
- % Preferred Stock	PERPS*	11.92%	NA
Return to - New Bonds	RTNWB*	10.0%	10.0%
- Short Term Debt	RTST*	10.0%	10.0%
- Common Equity	RTCEQ*	14.0%	14.0%
- Preferred Stock	RTPEQ*	10.0%	NA
Price of Common Stock	P	\$19.36	NA
Shares of Common Stock	XNSHRS	3,058.7	NA
Common Dividend Payout Ratio	DIVRAT*	74.07%	NA

Table B.1 (Cont'd)

	NUFS Code	Base Case Values	
		Private	Public
Discount Rate	DISCR	12.5%	12.5%
Inflation Rate	GINF*	7.85%	7.85%
Base Year	BYR	1979	1979
Options			
1. Capital Structure Constraint ⁶		2	2
2. CWIP for New Construction ⁷		2	2
3. Regulatory Lag ⁸		3	3
4. Tax Depreciation Method ⁹		1	1
5. MEFS vs. NCM Link ¹⁰		2	2

* Variables with an asterisk represent inputs that can be varied yearly over the forecast horizon.

¹ The NUFS framework allows user specification of a fifteen-year time profile for completion of each of twelve types of new production capacity expansions. The yearly percentages for each of the twelve production plant types utilized in the base case for both private and public utilities are as follows:

Production Plant Type	Annual Percentage Completed, By Year											
	1	2	3	4	5	6	7	8	9	10	11	12
1. Gas Steam	0.0	2.1	8.8	25.5	40.3	18.8	4.5	0.0	0.0	0.0	0.0	0.0
2. Oil Steam	0.0	2.1	8.8	25.5	40.3	18.8	4.5	0.0	0.0	0.0	0.0	0.0
3. Coal-Type I	0.0	1.2	7.1	20.9	37.8	24.4	10.6	0.0	0.0	0.0	0.0	0.0
4. Coal-Type II	0.0	2.1	8.8	25.5	40.3	18.8	4.5	0.0	0.0	0.0	0.0	0.0
5. Pumped Storage	0.0	18.0	40.0	30.0	9.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0
6. Hydropower	0.0	18.0	40.0	30.0	9.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0
7. Nuclear	0.0	3.3	5.7	16.2	26.1	28.4	12.9	3.4	1.6	1.1	1.3	0.0
8. Combined Cycle	0.0	22.6	25.5	10.7	16.9	15.2	9.1	0.0	0.0	0.0	0.0	0.0
9. Turbine	0.0	75.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. Retrofits (3-year)	0.0	33.3	33.3	33.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. Retrofits (1-year)	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. Other (Solar, Etc.)	0.0	25.0	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

² The variable OFFSET can be specified as either zero or one. A value of one means that the offset method for new construction expenditure accounting is utilized. A value of zero denotes that it is not.

³ All of the depreciation-related variables for old assets are specified for each of ten different asset types. The values for the base case reflected in the table are the same for each of the asset types with the exception that the tax life, SY1, for nuclear production plants is 16 years instead of 23.

Table B.1 (Cont'd)

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- ⁴ All of the depreciation-related variables for new assets are specified individually for each of 16 different asset types. The values for the base case reflected in the table are the same for each of the asset types with the exception that the tax life, SY2, for nuclear production plants is 16 years instead of 23.
- ⁵ The declining balance depreciation factor, DEPFAC, can be 1 or 2.
- ⁶ The Capital Structure Constraint can be specified as either one (common equity and preferred stock cannot be decreased) or two (the capital structure remains the same as inputted).
- ⁷ Option 2 can be specified as either one (plant-specific CWIP and inflation data are user-supplied) or two (all new assets are assumed to have the same CWIP accounting treatment).
- ⁸ Option 3 can take on the values one through four:
- 1 = no regulatory lag.
 - 2 = a one-year lag.
 - 3 = a one and one-half year lag.
 - 4 = a two-year lag.
- ⁹ Option 4 can be specified as one (sum-of-the-years digits method) or two (declining balance method).
- ¹⁰ Option 5 can be specified as either one (analysis of one utility = link with National Coal Model) or two (analysis of multi-utilities = link with MEFS).

Table B.2. Form 1/Form 3 Input Into NUFs,
Aggregate U.S., 1978

(Amounts in Millions of Dollars)

	NUFS Code ¹	<u>Base Case Values</u>	
		Private	Public
<u>Balance Sheet</u>			
Assets:			
Steam Production	BS	58,518.4	6,642.8
Nuclear Production	BS	16,070.6	2,140.0
Hydraulic	BS	4,786.0	10,329.0
Pumped Storage	BS	0.0	0.0
Other Production	BS	4,074.2	755.3
Transmission	BS	28,485.2	5,441.1
Distribution	BS	53,341.0	5,160.8
General	BS	4,473.1	4,680.0
Working Capital	WC	537.6	876.4
Intangibles	BS	28.0	85.7
Liabilities:			
Short-Term Debt	BS	3,170.0	NA
Outstanding Bonds	BS	78,830.6	18,995.9
Preferred Stock	BS	19,082.4	NA
Deferred ITC	DITC	4,709.5	NA
Deferred Income Taxes	PRODEF	8,934.9	NA
Stockholders' Equity:			
Common Stock	BS	41,643.1	10,405.0
Retained Earnings	BS	17,306.0	7,418.9
<u>Income Statement</u>			
Volume:			
Generation	GWHTOT	1,711.7	409.5
Sales to Ultimate Customers	TOTSAL	1,562.7	279.0
Revenues	REVLG	65,427.3	10,371.8
Fuel Adjusted for Taxes	TXFUEL	43,661.0	7,579.6
Net Income	IS	8,232.7	1,202.7
General Tax Rate	GTXRT	.080	.027
Cost of Embedded Debt	EMDT	.075	.058

¹ The notation "BS" refers to an item that is reflected in the computation of the balance sheet, while "IS" refers to a computed item on the income statement.

Table B.3. MEFS Output, Generation of Electricity
(Amounts in Gigawatt-Hours)

	<u>Total Generation (GWHTOT)</u>		<u>Nuclear Generation</u>		<u>Loss Factor (XLF)</u>	
	Private	Public	Private	Public	Private	Public
1979	1813.5	433.8	282.6	67.6	9.5%	9.5%
1980	1868.5	447.0	299.6	71.7	9.5%	9.5%
1981	1925.6	460.7	317.1	75.9	9.5%	9.5%
1982	1984.9	474.8	335.3	80.2	9.5%	9.5%
1983	2046.3	489.5	354.0	84.7	9.5%	9.5%
1984	2110.2	504.8	373.3	89.3	9.5%	9.5%
1985	2176.4	520.7	393.3	94.1	9.5%	9.5%
1986	2256.2	539.7	424.3	101.5	9.5%	9.5%
1987	2338.9	559.5	457.5	109.4	9.5%	9.5%
1988	2424.8	580.1	493.2	118.0	9.5%	9.5%
1989	2514.0	601.4	531.3	127.1	9.5%	9.5%
1990	2606.5	623.5	572.1	136.9	9.5%	9.5%
1991	2683.8	642.0	600.9	143.7	9.5%	9.5%
1992	2763.8	661.2	625.6	149.7	9.5%	9.5%
1993	2846.4	680.9	646.1	154.6	9.5%	9.5%
1994	2931.9	701.4	662.5	158.5	9.5%	9.5%
1995	3020.2	722.5	674.5	161.4	9.5%	9.5%

Table B.4. MEFS Output, Fuel and Operation-Maintenance Costs
(In Millions of Dollars)

	<u>Total Fuel Cost (Fuel)</u>		<u>Nuclear Fuel Cost (XNUCEX)</u>		<u>Operation and Maintenance Cost (OM)</u>	
	Private	Public	Private	Public	Private	Public
1979	29,250	6,997	1,856	444	3,106	743
1980	32,503	7,776	2,122	508	3,452	826
1981	36,126	8,642	2,423	580	3,837	918
1982	40,160	9,607	2,763	661	4,265	1,020
1983	44,654	10,683	3,145	753	4,743	1,135
1984	49,662	11,880	3,578	856	5,274	1,262
1985	55,242	13,215	4,065	973	5,867	1,404
1986	62,983	15,067	4,894	1,171	6,919	1,655
1987	71,806	17,178	5,891	1,409	8,160	1,952
1988	81,871	19,586	7,088	1,696	9,622	2,302
1989	93,353	22,333	8,525	2,039	11,347	2,715
1990	106,445	25,465	10,245	2,451	13,383	3,202
1991	115,835	27,711	11,728	2,806	15,746	3,767
1992	126,066	30,158	13,310	3,184	18,536	4,434
1993	137,215	32,826	14,983	3,584	21,810	5,218
1994	149,368	35,733	16,744	4,006	25,677	6,143
1995	162,619	38,903	18,580	4,445	30,227	7,231

Table B.5. MEFS Output, Book Value of New Assets, By Type, Investor-Owned Utilities, 1979-1995
(In Millions of Dollars)

Asset Type	1979	1980	1981	1982	1983	1984	1985	1986
1. Gas Steam	\$ 9	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2. Oil Steam	1,353	437	446	680	-	-	-	-
3. Coal-Type I	5,107	6,172	5,159	4,601	2,219	2,868	8,572	9,234
4. Coal-Type II	3,417	6,386	4,964	7,428	2,050	2,933	756	796
5. Pumped Storage	150	158	177	187	200	218	546	593
6. Hydro	306	317	360	365	414	430	32	46
7. Nuclear	719	3,595	4,675	8,700	5,856	7,721	12,495	14,730
8. Combined Cycle	92	95	107	111	125	129	-	-
9. Turbine	338	362	393	422	456	492	629	676
10. Retrofits (3-yr Constr)	213	233	248	267	288	316	35	42
11. Retrofits (1-yr Constr)	55	59	64	69	73	81	-	-
12. Other (e.g., Solar)	76	85	89	99	104	113	154	160
13. Transmission	654	190	211	234	261	291	2,381	2,466
14. Distribution	-	-	-	-	-	-	-	-
15. Meters	-	-	-	-	-	-	-	-
16. Other	-	-	-	-	-	-	-	-
Total	<u>\$12,489</u>	<u>\$18,089</u>	<u>\$16,893</u>	<u>\$23,163</u>	<u>\$12,046</u>	<u>\$15,592</u>	<u>\$25,600</u>	<u>\$28,743</u>

(continued)

Table B.5. (Cont'd)

Asset Type	1987	1988	1989	1990	1991	1992	1993	1994	1995
1. Gas Steam	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2. Oil Steam	-	-	-	-	-	-	-	-	-
3. Coal-Type I	9,984	10,767	11,569	29,151	30,396	33,489	36,909	40,690	45,466
4. Coal-Type II	869	948	999	-	231	256	284	314	274
5. Pumped Storage	639	685	744	541	566	623	684	753	831
6. Hydro	31	47	36	836	871	955	1,049	1,153	1,251
7. Nuclear	10,189	5,575	2,562	3,877	9,519	10,508	11,602	12,814	12,597
8. Combined Cycle	-	-	-	-	-	-	-	-	-
9. Turbine	729	786	854	507	523	580	644	714	791
10. Retrofits (3-yr Constr)	41	44	48	-	-	-	-	-	-
11. Retrofits (1-yr Constr)	-	-	-	121	155	173	193	213	222
12. Other (e.g., Solar)	177	187	205	626	560	618	683	753	876
13. Transmission	2,781	3,134	3,530	2,575	3,751	4,155	4,603	5,102	5,322
14. Distribution	-	-	-	-	-	-	-	-	-
15. Meters	-	-	-	-	-	-	-	-	-
16. Other	-	-	-	-	-	-	-	-	-
Total	<u>\$25,440</u>	<u>\$22,173</u>	<u>\$20,547</u>	<u>\$38,234</u>	<u>\$46,572</u>	<u>\$51,357</u>	<u>\$56,651</u>	<u>\$62,506</u>	<u>\$67,621</u>

Table B.6. MEFS Output Book Value of New Assets, By Type, Publicly-Owned Utilities, 1979-1995
(In Millions of Dollars)

Asset Type	1979	1980	1981	1982	1983	1984	1985	1986	1987
1. Gas Steam	\$ 2	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2. Oil Steam	324	104	107	163	-	-	-	-	-
3. Coal-Type I	1,222	1,476	1,235	1,100	531	686	2,051	2,209	2,388
4. Coal-Type II	816	1,528	1,188	1,777	490	702	181	190	208
5. Pumped Storage	36	38	42	45	48	52	130	142	153
6. Hydro	73	76	86	88	99	102	8	11	7
7. Nuclear	172	860	1,119	2,081	1,401	1,847	2,989	3,524	2,437
8. Combined Cycle	22	23	25	27	30	31	-	-	-
9. Turbine	81	87	93	102	109	117	151	161	175
10. Retrofits (3-yr Constr)	51	56	59	64	69	75	9	10	10
11. Retrofits (1-yr Constr)	13	14	15	17	18	19	-	-	-
12. Other (e.g., Solar)	18	21	21	24	24	27	37	39	42
13. Transmission	156	46	50	56	63	69	570	590	665
14. Distribution	-	-	-	-	-	-	-	-	-
15. Meters	-	-	-	-	-	-	-	-	-
16. Other	-	-	-	-	-	-	-	-	-
Total	<u>\$2,987</u>	<u>\$4,329</u>	<u>\$4,040</u>	<u>\$5,544</u>	<u>\$2,882</u>	<u>\$3,727</u>	<u>\$6,126</u>	<u>\$6,876</u>	<u>\$6,085</u>

Table B.6 (Cont'd)

Asset Type	1988	1989	1990	1991	1992	1993	1994	1995
1. Gas Steam	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2. Oil Steam	-	-	-	-	-	-	-	-
3. Coal-Type I	2,576	2,767	6,974	7,272	8,011	8,830	9,734	10,877
4. Coal-Type II	227	239	-	55	61	68	75	66
5. Pumped Storage	164	178	129	136	149	163	181	198
6. Hydro	12	8	200	209	228	251	276	299
7. Nuclear	1,334	613	927	2,277	2,514	2,776	3,065	3,014
8. Combined Cycle	-	-	-	-	-	-	-	-
9. Turbine	188	204	121	125	139	154	171	189
10. Retrofits (3-yr Constr)	10	12	-	-	-	-	-	-
11. Retrofits (1-yr Constr)	-	-	29	37	41	46	52	53
12. Other (e.g., Solar)	45	49	149	134	148	164	180	207
13. Transmission	750	845	615	898	994	1,101	1,221	1,273
14. Distribution	-	-	-	-	-	-	-	-
15. Meters	-	-	-	-	-	-	-	-
16. Other	-	-	-	-	-	-	-	-
Total	<u>\$5,306</u>	<u>\$4,915</u>	<u>\$9,144</u>	<u>\$11,143</u>	<u>\$12,285</u>	<u>\$13,553</u>	<u>\$14,955</u>	<u>\$16,176</u>

APPENDIX C

SENSITIVITY RESULTS

In order to assess NUFS' over-all performance as inputs are altered and to focus attention toward input parameters for which greatest accuracy is needed, a comprehensive sensitivity analysis was performed on the NUFS code.²⁴ Since the actual computer time for a one-region analysis (i.e., one of the ten DOE regions or the aggregate U.S.) is relatively small, a "direct sensitivity study" was implemented. Utilizing this approach, derivatives of important model results with respect to model input parameters were calculated by individually perturbing each input parameter, re-running the code, and then calculating the relevant sensitivities. Thus, for any output or response, R, the calculated relative sensitivity, ϵ , with respect to any input parameter, X, is given by:

$$\epsilon_{XR} = \frac{X}{R} \frac{dR}{dX} .$$

The three sources of inputs into the NUFS code, described in Section 3 and presented in Appendix B, are the MEFS interface file, base-year financial information (Form 1/Form 1M tapes), and a myriad of user-provided parameters. For the purpose of conducting the sensitivity analysis, however, only the base-year financial variables and user-supplied inputs were varied. The outputs from MEFS were treated as non-varying parameters.

This procedure utilized for conducting the sensitivity analysis, of course, totally ignores the prospective interaction between the output of NUFS and its attendant impact on the MEFS solution through some type of supply-side and demand-side iterative process. That is, for purposes of the sensitivity analysis conducted on NUFS, the base-year financial variables and user-provided inputs were individually perturbed but the resulting relative sensitivities did not take into account the possibility that the NUFS output could — and, more than likely, does — impact the MEFS solution.

An optimal sensitivity analysis, therefore, would reflect the impact of changes induced in the variables incorporated in MEFS. However, that process would require that both NUFS and MEFS be executed in tandem. The level of effort required for execution of the latter code was well beyond the resources available in the present evaluation effort.

It must be emphasized, therefore, that analysis of the relative sensitivity coefficients provided below — and the conclusions derived therefrom — must be interpreted in the context of a unidirectional flow of information from MEFS to NUFS. This procedure is not in accord with the characterization of an optimal electric utility supply-demand framework as presented in Fig. 1 (Section 3), nor, as was delineated at the outset of Section 3, does it coincide with the manner in which EIA apparently utilizes the NUFS model.

Since the NUFS code calculates results for private utilities and public utilities separately, each individual input parameter from the base-year financial information and user-supplied inputs was perturbed upward by one percent simultaneously for both private and public utilities. The one percent increment was calculated from the base case values presented in Appendix B. The actual values of the perturbed variables are listed in Appendix D.

Each individual input parameter was perturbed separately except for the capitalization variables listed in Table B-1 (i.e., PERLT, PERST, PERCE, and PERPS). Since, by definition, those four variables are constrained to sum to one, any perturbation of one implies changes in the others. For purposes of this analysis, when one of the components of capitalization was increased by one percent, all of the components were ratably decreased to maintain a total of unity.

The actual sensitivity results are presented in Appendix D. It must be emphasized that, since many of the output variables in NUFS represent the summation of individual components (e.g., Total Debt = Long-Term Debt + Short-Term Debt on the balance sheet), and, furthermore, some results are more important than others, sensitivity coefficients are not presented for every individual output variable in Appendix D. Appendix D details the 21 output variables for which sensitivities were computed. For a more detailed analysis, however, it is possible to refer to the source computer runs and derive the sensitivities for every output variable in the code.

The remainder of this section will be devoted to an analysis of the sensitivities presented in Appendix D. Emphasis will be placed on the responsiveness of outputs with respect to capitalization inputs (PERLT, PERST, PERCE, PERPS); the return on (cost of) capital (RTNWB, RTST, RTCEQ, RTPEQ); the user-supplied regulatory variables (CWPPER, AFUDCR, FLPR1, FLPR2); and federal tax variables (TXRT, RITC). The discussion will conclude with an examination of the input variables that have the largest sensitivities in absolute value and, therefore, have the largest impact on model results.

Capitalization and its return (cost)

Table C.1 through Table C.4 present select relative sensitivity results pertaining to the structure of capital (i.e., PERLT, PERST, PERCE, and PERPS) and its associated cost or return (i.e., RTNWB, RTST, RTCEQ, and RTPEQ). The information presented in these tables reflects relative sensitivity results for the private sector only. The public sector sensitivities, in general, mirror the results of the private sector (see Appendix D). It must be emphasized that only the relative sensitivities with an absolute

Table C.1. Relative sensitivity of select output responses to
PERT^a and RTNWB^b, private sector

	PERLT			RTNWB		
	1979	1986	1993	1979	1986	1993
Revenues	0.0	-0.08	-0.07	0.0	.07	0.11
Expenses	-0.04	-0.08	-0.03	-0.02	0.01	0.01
Interest Deductions	0.61	.6	0.50	0.09	0.77	1.14
Net Income	-0.55	-0.54	-0.51	-0.18	-0.25	0.0
Utility Plant	-	-	-	-	-	-
Working Capital	-	-	-	-	-	-
Proprietary Capital	-0.49	-0.49	-0.49	-	-	-
Total Debt	0.47	0.47	0.47	-	-	-
Deferred Credits	-	-	-	-	-	-
Average Price of Electricity	0.0	-0.08	-0.07	0.0	0.07	0.11

^aPERLT = Percent capitalization, long-term debt

^bRTNWB = Return on new bonds

Table C.2. Relative sensitivity of select output responses to
PERST^a and RTST^b, private sector

	PERST			RTST		
	1979	1986	1993	1979	1986	1993
Revenues	-	-	-	0.0	0.01	0.01
Expenses	-0.002	0.002	0.001	-0.004	0.006	0.004
Interest Deductions	0.02	.03	-0.03	0.05	0.0	0.0
Net Income	-0.02	0.006	0.009	-0.05	0.03	0.03
Utility Plant	-	-	-	-	-	-
Working Capital	-	-	-	-	-	-
Proprietary Capital	-0.02	-0.02	-0.02	-	-	-
Total Debt	0.02	0.02	0.02	-	-	-
Deferred Credits	-	-	-	-	-	-
Average Price of Electricity	-	-	-	0.0	0.01	0.01

^aPERSE = Percent capitalization, short-term debt

^bRTST = Return on short-term debt

Table C.3. Relative sensitivity of select output responses to
PERCE^a and RTCEQ^b, private sector

	PERCE			RTCEQ		
	1979	1986	1993	1979	1986	1993
Revenues	0.0	0.07	0.06	0.0	0.22	0.21
Expenses	0.03	0.07	0.06	0.0	0.14	0.13
Interest Deductions	-0.47	-0.41	-0.34	0.14	0.11	0.14
Net Income	0.41	0.46	0.44	0.0	0.89	0.88
Utility Plant	-	-	-	-	-	-
Working Capital	-	-	-	-	-	-
Proprietary Capital	0.38	0.38	0.38	-	-	-
Total Debt	-0.37	-0.37	-0.37	-	-	-
Deferred Credits	-	-	-	-	-	-
Average Price of Electricity	0.0	0.07	0.07	0.0	0.22	0.21

^aPERCE = Percent capitalization, common equity

^bRTCEQ = Return on common equity

Table C.4. Relative sensitivity of select output responses to
PERPS^a and RTPEQ^b, private sector

	PERPS			RTPEQ		
	1979	1986	1993	1979	1986	1993
Revenues	0.0	0.001	0.001	0.0	0.05	0.05
Expenses	0.01	0.008	0.007	0.0	0.03	0.03
Interest	-0.17	-0.14	-0.12	0.3	0.03	0.03
Net Income	0.14	0.06	0.05	0.0	0.21	0.21
Utility Plant	-	-	-	-	-	-
Working Capital	-	-	-	-	-	-
Proprietary Capital	0.12	0.12	0.12	-	-	-
Total Debt	-0.12	-0.12	-0.12	-	-	-
Deferred Credits	-	-	-	-	-	-
Average Price of Electricity	0.0	0.002	0.001	0.0	0.05	0.05

^aPERPS = Percent capitalization, preferred stock

^bRTPEQ = Return on preferred equity

value greater than 10^{-4} (i.e., $\frac{dR}{R} \geq 10^{-6}$) have been included in Table C.1 through Table C.4 and in the results presented in Appendix D. Relative sensitivities outside of those boundaries have been designated with zeros, while output variables that have no response to perturbed input parameters are denoted by a dash.

Consider Table C.2 which presents select sensitivity results based on perturbation of the percentage of capital attributable to long-term debt (PERLT) and its return or cost (RTNWBN). *A priori*, one would expect that the relative sensitivity of PERLT with respect to Total Debt would approach +1.0 since the capital option used for sensitivity analysis allowed the end-of-year capital structure to remain as input (see Table B.1, Option 1). However, because a change in one component of capital implies changes in the others (since their sum is constrained to sum to one), PERLT was increased by +1% but the total percentage of capital was adjusted downward ratably.

The same is true, of course, for the sensitivities of the other components of capital (i.e., short-term debt, preferred stock, and common stock) presented in Tables C.2, C.3, and C.4. There again, the correspondence of a percentage change in a component of capital structure (i.e., PERLT, PERST, PERCE, or PERPS) to its representation on the balance sheet is complicated by the need to adjust the other components of capital.

From Table C.1, all of the signs of the relative sensitivity coefficients of PERLT relating to income statement effects are as expected. The inverse relationship between PERLT and Electric Expenses is attributable to the impact of long-term debt on both general taxes and income taxes [see the discussion in the context of Eq. (31) in Section 3]. There is an obvious positive relationship between PERLT and Interest Deductions because of the impact of larger amounts of long-term debt - relative to the other three components of capital - on the amount of interest expense.

Since the sensitivity results presented in Table C.1 are based on a base-case scenario wherein a one and one-half year regulatory lag was specified (see Option 3, Table B.1, Appendix B), the impact of a change in PERLT on Revenues in 1979 is insignificant. Clearly, in that case, revenues are based on prior period costs. Indeed, from Appendix D, that is the case for all relative sensitivity results of variables that affect electric operating revenues.

Moreover, the sensitivity coefficient of PERLT with respect to the (average) price of electricity is the same - except for statistical deviations - as the relative sensitivity coefficient of PERLT with respect to revenues. Since the average price of electricity in NUFS is represented as the ratio of Total Revenues [Eq. (48)] to Total Sales [Eq. (6)] for any region or ownership type and, furthermore, sales are always constant (since they emanate from MEFS), any change in revenues - generated from any source - is directly reflected as such in the average price of electricity. This phenomenon is corroborated by all of the results presented in Tables C.1 through C.4 and the comprehensive results presented in Appendix D.

This phenomenon highlights a deficiency in NUFS that was discussed in an earlier part of this section. Any input parameter change that affects the price of electricity should, theoretically, have a differential impact on electric revenues depending on electricity's price elasticity of demand. Since there is a considerable body of evidence that electricity's price elasticity of demand varies from state-to-state and region-to-region, utilizing NUFS for regional analysis can lead to erroneous results.²⁵

One of the most salient results of Table C.1 is the impact of a perturbation in PERLT on the balance sheet. Since the percentage capitalization attributable to the four components of capital is user-supplied in NUFS, any increase in one of the components necessarily implies a (net) decrease in the others. Then, PERLT is positively associated with Total Debt and inversely related to Proprietary Capital. Note from Table C.2 that the only impact on the balance sheet attributable to a perturbation in PERLT is a "trade-off" between debt and equity. There is no interaction in NUFS between Utility Plant, Working Capital, and PERLT since the former two variables emanate from MEFS and, furthermore, NUFS, as evaluated here, does not "feed back" to MEFS.

This result, of course, generalizes to the other components of capital. The impact of perturbations in the percentage of capital attributable to short-term debt (PERST), common equity (PERCE), and preferred stock (PERPS) has this same "trade-off" result as Table C.2, Table C.3, and Table C.4, respectively, reflect.

All of these conclusions with respect to revenues, the average price of electricity, and the trade-off between debt and equity, of course, are a manifestation of conducting a sensitivity analysis without executing MEFS. If, in fact, MEFS were executed to incorporate the induced changes in the output of NUFS, it is expected that there would be a differential impact on revenues and the (average) price of electricity and less than a perfect "trade-off" between debt and equity.

As might be expected, the return on new bonds, RTNWBN in Table C.2, has the largest impact on the amount of interest deductions reflected on the income statement. Since interest deductions reflected on the income statement are comprised of interest attributable to long-term debt, short-term debt, and AFUDC-Debt (see Appendix A), the sensitivities presented in Table C.1 necessarily represent a composite of those three components. The return on long-term bonds has no effect on short-term interest deductions, but impacts the amount of interest attributable to both long-term debt and AFUDC-Debt. The sensitivity coefficient of +1.14 in 1993, for example, is composed of a coefficient of +1.09 for long-term interest and 0.52 for AFUDC-Debt. The direct relationship between RTNWBN and long-term debt is self-evident, while the relationship between RTNWBN and AFUDC-Debt is evident from Eq. (28) presented in Section 3.

Perhaps the most salient aspect of the sensitivity results for RTNWBN in Table C.2 is the lack of responsiveness of Total Debt to the return on debt, RTNWBN, and, moreover, the lack of responsiveness of any balance sheet component to RTNWBN. Theoretically, at least, the utilization of capital should be a function of its cost. *Ceteribus Paribus*, an increase in the cost of long-term debt should, over time, lead to a decrease in its usage. Indeed, from Tables C.2, C.3, and C.4, perturbations in the other costs of capital (.e., RTST, RTCEQ, and RTPEQ) do not have any impact on the amount of debt or the amount of the other components of capital utilities (i.e., Proprietary Capital).

This phenomenon in NUFS, of course, is due to the particular specification of the model wherein the structure of capital and its cost are not the result of market forces but, instead, are user-specified. And; furthermore, since the book value of utility plant and the amount of

working capital emanate from NUFS and MEFS was not executed for this sensitivity analysis, a perturbation of the cost of any component of capital does not impact the investment in assets or their value. Here again, if the sensitivity analysis were conducted on the totality of the system as represented in Fig. 1 (Section 3), it is conjectured that the results would vary from those presented in Tables C.1 through C.4.

Although not explicitly presented in Tables C.1 through C.4, the relative sensitivity results pertaining to the structure of capital and its cost (or return) have implications for the financial position of electric utilities, as measured by financial ratios. Consider Equation (62) which presents the calculation of interest coverage utilizing the SEC method. Since interest on long-term debt is represented in the computation, an increase in PERLT and/or RTNWB in NUFS (Table C.1) predictably is inversely related to interest coverage. On the other hand, the other three components of capital and their cost, presented in Tables C.2, C.3, and C.4, are positively associated with the computed amount of interest coverage.

Another interesting characteristic of the NUFS code that was illuminated by the sensitivity calculations is the relationship between the external sources of capital (i.e., PERLT, PERST, PERCE, and PERPS) and their cost and external financing requirements. Consider the "statement of changes in financial position" or "sources and uses of funds" calculation in Appendix A. One of the primary measures of a business entity's performance is related to the amount of funds it can generate internally. In NUFS, the representation of that performance is reflected in the ratio of external financing to total uses (application) of funds (i.e., the external financing percentage).

All of the components of capital and their cost — with the exception of the percentage of long-term debt and its cost — are inversely related to the external financing percentage. Thus, by arbitrarily increasing the percentage of common equity (PERCE) relative to the other components of capital, for example, the external financing percentage decreases. Hence, NUFS' results will reflect a more favorable financial picture. The reverse is true if the percentage of long-term debt or its cost is increased. Therefore, a user of NUFS can arbitrarily change the financial performance of utilities in a select region by altering the user-provided proportion of external funding sources.

Federal policy variables

Table C.5 presents select relative sensitivity results for the federal policy variables in NUFS: the federal income tax rate, TXRT, and the rate of the investment tax credit, RITC. The results presented in Table 7 are for the private sector only, but, since POUs do not pay federal income taxes, the two rates have no effect on the public sector.

Since federal taxes are an allowable operating expense for revenue determination in the regulatory scheme and is reflected as such in the formulation of NUFS, one would expect that changes in the federal tax rate and, therefore, the amount of federal taxes should similarly impact both operating expenses and revenues.

From Table C.6, a change in the federal tax rate induced by the user (since TXRT is user-provided) results in a decrease in net income in 1979, the first year of the forecast period, because of the presence of a 1½-year lag period (see Table B.1) for the determination of revenues. In subsequent years of the forecast period, however, the impact on net income in terms of the relative sensitivity coefficients was relatively low because increments to operating expenses due to higher federal taxes are, for the most part, reflected in higher revenues in NUFS.

Although not explicitly represented in Table C.5, the largest impact in absolute value of the federal tax rate occurs in accounts that directly reflect federal income taxes. In 1986, for example, while the relative sensitivity coefficients for Electric Expenses and Deferred Credits are +0.25 and 0.30, respectively, the sensitivities for Income Taxes (a component of Expenses) and the Deferred Income Taxes (a component of Deferred Credits) are +1.85 and 0.53, respectively.

The same relationship between revenues and the price of electricity holds for perturbations in TXRT and RITC since, as explained above, the link between NUFS and MEFS — as utilized by EIA — was not considered in this analysis. The sign of the relative sensitivity coefficients for both TXRT and RITC with respect to the price of electricity, however, is correct. *Ceteris paribus*, an increase in the federal tax rate should lead to a higher level of electricity prices, while a reduction in federal taxes through a larger investment tax credit rate should induce lower electricity prices.

Table C.5. Relative sensitivity of select output responses to TXRT^a and RITC^b, private sector

	TXRT			RITC		
	1979	1986	1993	1979	1986	1993
Revenues	0.0	0.21	0.16	0.0	-0.005	-0.008
Expenses	0.07	0.25	0.19	0.01	0.004	0.001
Interest Deductions	0.0	-0.04	-0.06	-0.02	-0.05	-0.08
Net Income	-0.70	0.08	0.10	-0.11	-0.04	-0.03
Utility Plant	-	-	-	-	-	-
Working Capital	-	-	-	-	-	-
Proprietary Capital	-0.005	-0.04	-0.05	-0.008	-0.04	-0.06
Total Debt	-0.004	-0.04	-0.05	-0.006	-0.04	-0.06
Deferred Credits	0.05	0.30	0.37	0.08	0.35	0.49
Average Price of Electricity	0.0	0.21	0.16	0.0	-0.005	-0.008

^aTXRT = Federal tax rate

^bRITC = Investment tax credit rate

From Table C.5, a curious result in utilization of NUFS is the impact of tax rates on capitalization. Formally, there is an inverse relationship between both TXRT and RITC and the utilization of debt and other forms of capital (i.e., Total Proprietary Capital). This result, of course, is a manifestation of the manner in which capitalization is derived in MEFS. That is, the components of capital are determined by application of user-provided capital ratios to net assets that need to be financed; i.e., Assets Minus Deferrals (AMD). Since the latter variable is calculated as total assets minus deferred credits and higher federal tax rates imply larger deferred tax liabilities (see Table C.6), the base upon which capitalization is determined is lower and, hence, the utilization of capital is lower.

These results are counter-intuitive. Since the fundamental problem in the electric utility industry is the attraction of capital, the results presented in Table C.6 imply that the resolution of that problem can be attained, in part, through the imposition of a higher federal income tax rate. Indeed, the signs of the relative sensitivity coefficients between the federal income tax rate and (a) the external financing percentage, (b) interest coverage, and (c) the percentage of earnings attributable to AFUDC (i.e., $AFUDC + \text{Net Income}$) are (a) <0 , (b) >0 , and (c) <0 . Thus, *ceteris paribus*, increases in the federal income tax rate directly result in a more favorable financial performance for electric utilities under the regulatory environment modeled in NUFS.

This seemingly perverse result in NUFS is attributable, for the most part, to the lack of a link between federal taxes and investment in assets, which would occur if the sensitivity analysis reflected the interaction between the output of NUFS and the specification of MEFS. From Table C.5, perturbations in tax rates do not impact the asset side of the balance sheet. The value of Utility Plant emanates from the MEFS solution and base-year financial data (see Section 3), while the amount of working capital is calculated on the basis of MEFS' results [Eq. (7)]. From Table C.5, changes in RITC do not impact the accumulation of assets. Again, these results are based on a unidirectional flow of information from MEFS to NUFS, which, apparently, is not the manner in which the system is utilized at EIA.

Regulatory variables

A partial solution to the electric utility industry's financial problems is to allow Construction Work in Progress (CWIP) in the rate base currently. Under this scheme, a utility will earn a current return on its construction expenditures and purportedly that will improve cash flow and, consequently, financial performance. Those results, in turn, will enhance the likelihood of attracting external sources of funds. Table C.6 presents the relative sensitivity results with respect to a change in the user-provided percentage of CWIP allowed in the rate base, CWPPER, along with relative sensitivity results for the user-supplied rate at which capitalized interest is calculated, AFUDCR.

As expected, by allowing larger increments of CWIP in the rate base, the amount of capitalized interest (AFUDC) decreases since the latter amount is only computed on construction expenditures that are not permitted in the rate base. Similarly, by increasing the rate at which AFUDC is calculated, AFUDCR, the amount of AFUDC increases.

The most conspicuous aspect of the results presented in Table C.6 is the inverse relationship between CWPPER and the rate base. Recalling Eq. (14), the rate base is comprised of the sum of utility plant (UP), the amount of CWIP allowed (RBCWIP), nuclear fuel (XNUCFL), and working capital (WC) — net of accumulated depreciation (ABDE), and deferred taxes (PRODEF). Theoretically, an increase in the percentage of CWIP allowed in the rate base (CWPPER) implies that the book value of utility plant will decrease, *ceteris paribus*, because the amount of capitalized interest included in utility plant will decline. For 1979, 1986, and 1993, the sensitivity coefficients of CWPPER with respect to utility plant are -0.002, -0.02, and -0.02, respectively. And, since the book value of plant declines, the amount of accumulated depreciation drops.

In the formulation of NUFS, however, the value of construction expenditures included in the rate base (RBCWIP) also is inversely related to CWPPER. Indeed, the sensitivity of CWPPER with respect to RBCWIP is approximately -0.02 for all of the years analyzed in Table C.6. This seeming aberration in NUFS is attributable to the specification of the amount of

Table C.6. Relative sensitivity of select output responses to
CWPPER^a and AFUDCR^b private sector

	CWPPER			AFUDCR		
	1979	1986	1993	1979	1986	1993
Electric Revenues	0.0	0.002	0.002	0.0	-0.08	-0.09
Expenses	0.0	0.001	0.0	0.0	-0.05	-0.05
Interest Deductions	0.03	0.01	0.01	-0.33	-0.24	-0.31
Net Income	-0.14	-0.02	-0.03	- .82	-0.06	-0.02
Utility Plant	-0.008	-0.02	-0.02	-0.03	-0.04	-0.05
Working Capital	-	-	-	-	-	-
Proprietary Capital	-0.01	-0.02	-0.03	-0.04	-0.04	-0.04
Total Debt	-0.01	-0.02	-0.03	-0.04	-0.04	-0.04
Deferred Credits	0.0	0.0	-0.002	-0.03	-0.16	-0.23
Average Price of Electricity	0.0	0.002	0.002	0.0	-0.08	-0.09
Rate Base	-0.01	-0.02	-0.03	-0.04	-0.05	-0.05
Rate of Return	-0.01	-0.02	-0.03	-0.05	-0.05	-0.05
AFUDC	-0.15	-0.17	-0.16	.84	0.83	0.83

^aCWPPER = Percent CWIP allowed in rate base

^bAFUDCR = AFUDC rate

CWIP included in the rate base under the offset method (RBAFDC = 1 in Table B.1) wherein the amount of CWIP included equals the amount reflected on the balance sheet [see the discussion in the context of Eq. (3) in Section 3]. Furthermore, since the rate base declines with increases in CWIP, and the rate of return is essentially user-supplied, the actual return earned on the rate base is inversely related to CWPPER as noted in Table C.7

The signs of the relative sensitivity coefficients of CWPPER and AFUDCR with respect to financial variables, however, reflects established principles. Changes in CWPPER are inversely related to the external financing requirements percentage and AFUDC as a percent of income, while it is positively associated with interest coverage. Perturbations in AFUDCR lead to opposite results. Therefore, as expected, by allowing more construction expenditures in the rate base, utilities improve their financial performance - as measured by three financial ratios - under the formulation of NUFS.

While the inverse relationship between CWPPER and utility plant in Table C.6 is self-evident, the inverse relationship between AFUDCR and utility plant is suspect on a theoretical basis. Conceptually, if the rate at which capitalized interest associated with construction activity is increased, *ceteris paribus*, the book value of utility plant should increase. From Table C.6, the opposite is true in the NUFS code.

Table C.7 includes the relative sensitivity results of the percentage of the federal tax benefit attributable to accelerated depreciation and the investment tax credit (FLPR1) and the debt portion of AFUDC (FLPR2) allowed to be flowed-through currently for rate-making purposes. Conceptually, as FLPR1 and FLPR2 approach zero, increasing amounts of the federal tax benefits are deferred thereby enlarging the "interest-free loan" current rate-payers provide the utility. Therefore, revenues are supposedly larger in the current period and that is reflected in a higher rate level. The results in Table 9 corroborate those hypotheses. Both FLPR1 and FLPR2 are inversely related to revenues and, therefore, the price of electricity.

Because of an assumption in NUFS' specification, FLPR2 does not impact the balance sheet. Recalling the discussion of the specification of

Table C.7. Relative sensitivity of select output response to
FLPR1^a and FLPR2^b

	FLPR1			FLPR2 ^c		
	1979	1986	1993	1979	1986	1993
Electric Revenues	0.0	-0.01	-0.01	0.0	-0.003	-0.01
Electric Expenses	0.0	-0.006	-0.006	0.0	-0.002	-0.006
Interest Deductions	0.0	0.03	0.04	-	-	-
Net Income	-0.02	-0.06	-0.08	0.0	-0.01	-0.05
Utility Plant	-	-	-	-	-	-
Working Capital	-	-	-	-	-	-
Proprietary Capital	0.002	0.02	0.03	-	-	-
Total Debt	0.003	0.02	0.03	-	-	-
Deferred Credits	-0.04	-0.15	-0.24	-	-	-
Average Price of Electricity	0.0	-0.01	-0.01	0.0	-0.003	-0.01

^aFLPR1 = Percent of federal tax benefit due to accelerated depreciation and the investment tax credit allowed to be flowed-through in the current period.

^bFLPR2 = Percent of federal tax benefit due to the debt portion of AFUDC allowed to be flowed-through in current period.

^cSince the value of FLPR2 was set equal to 100% in the base case, FLPR2 was perturbed by -1% instead of +1%.

deferred taxes in NUFS (Section 3), the difference between tax and book income attributable to the AFUDC-Debt "timing difference" is not reflected in the deferred tax accounts. Therefore, unlike the impact of FLPR1, changes in FLPR2 do not impact the deferred tax liability and, under the formulation of NUFS, the structure of capital. Indeed, as the discussion above illuminated, the amount of capitalization attributable to debt and equity in NUFS changes proportionately (i.e., based on the user-provided percentage capitalization inputs) as a direct result of any change in the deferred liability. The sensitivity results in Table C.7 for FLPR1 corroborate this point.

It may be argued that a failure to incorporate the debt portion of AFUDC in the deferred federal income tax accounts is a pecadillo if its effect is reflected in the computation of actual federal income tax expense for income statement purposes, as it is in NUFS. Empirically, however, the manifestation of that formulation error is much more serious. Although not reflected in the sensitivity results presented in Table C.7, the signs of the sensitivity coefficients of FLPR1 with respect to (a) the external financing ratio, (b) the interest coverage ratio, and (c) the AFUDC percentage of income are (a) greater than zero, (b) less than zero, and (c) greater than zero, as theory would predict. Thus by deferring the federal tax benefits of accelerated depreciation and the investment tax credit in NUFS, as represented by FLPR1, utilities improve their financial performance.

However, although the timing difference attributable to the debt portion of AFUDC is no different conceptually than the timing difference associated with accelerated depreciation, the signs of the sensitivity coefficients of FLPR2 with respect to the same financial parameters presented above are exactly the opposite. Therefore, the formulation error in NUFS is directly manifested in its output.

Relative sensitivities in general

One of the primary uses of a sensitivity study is to focus attention on input variables that have the most significant impact on model results. Alternatively, a sensitivity study can illuminate the impact of input variables that have a negligible or insignificant effect on the value of

outputs. The discussion above in the context of Tables C.1 through C.7 was intended to analyze the impact of important user-supplied policy control variables and capitalization variables. Since an analysis of every sensitivity coefficient in a model the size of NUFS would be laborious, the discussion that follows is intended to highlight the most significant inputs into the NUFS code.

Consider Table C.8 which details the sensitivity results for the inflation rate in the private sector. More than any other variable in NUFS, the rate of inflation has the most comprehensive impact on model results. Recalling the discussion in Section 3, GINF is used primarily in conjunction with the MEFS interface file for determination of the nominal value of operating costs, fuel costs, and "new" assets coming on line in the forecast period.

Thus, from Table C.8, the initial impact of a change in the inflation rate occurs in the value of utility plant; operation, maintenance, and fuel costs; and the amount of working capital. The effect on utility plant has obvious implications for the income statement (e.g., depreciation expense, interest expense) and, in concert with the change in amount of working capital, has direct ramifications on capitalization, the rate base, and common stock.

As expected, there is a positive relationship between the rate of inflation and the financial variables forecasted in NUFS. As Table C.8 delineates, the exceptions occur in 1979, the first year of the forecast period, wherein the presence of a lag scenario causes a reduction in income taxes (and, therefore, electric expenses) and the increase in the number of common shares has the effect of reducing the average book value of common stock.

Table 11 presents the "major" relative sensitivities in NUFS as adapted from the results presented in Appendix D. As footnote 1 to Table C.9 indicates, a "major" relative sensitivity is arbitrarily defined as one with an absolute value equal to or greater than 0.8 in any forecast period. Moreover, the results presented in Table C.9 reflect the relative sensitivity calculations for the private sector only since IOUs comprise the largest share of electric utility activity. In general, the sensitivity coefficients for the public sector mirror the results for IOUs.

Table C.8 Relative sensitivity of select output responses to the general inflation rate (GINF), prive sector

	1979	1986	1993
Revenues	0.0	0.37	0.86
Expenses	-0.004	0.40	0.89
Interest Deductions	0.05	0.31	0.78
Net Income	0.05	0.24	0.76
Utility Plant	0.05	0.27	0.69
Net Utility Plant	0.07	0.36	0.89
Proprietary Capital	0.07	0.38	0.92
Total Debt	0.07	0.38	0.92
Deferred Credits	0.02	0.25	0.68
Working Capital	0.0	0.50	1.03
Sources of Funds	0.40	0.65	1.18
Application of Funds	0.18	0.05	1.18
Rate Base	0.07	0.39	0.92
Return on Rate Base	0.08	0.40	0.92
Revenue Requirements	0.01	0.40	0.90
Average Price of Electricity	0.0	0.37	0.86
Number of Common Shares	0.10	0.23	0.63
Average Book Value - Common Stock	-0.05	0.12	0.29
AFUDC	0.20	0.72	1.22
Available Earnings	0.05	0.21	0.71

Table C.9. Major relative sensitivities^a in the NUFS code, private sector

Input Parameter (X)	Response (R)	1979	1986	1993
<u>Base-Year Financial Variables:</u>				
Sales to Customers	- Net Income	-2.52	0.0	0.0
	- Return on Equity	-6.06	0.0	0.0
	- Available Earnings	-5.00	0.0	0.0
Steam Production	- Sources of Funds	1.29	0.03	0.01
	- Number of Shares	0.26	0.80	2.08
	- Avg. Book Value	-0.48	-0.63	-1.87
	- Available Earnings	3.34	0.13	0.05
Transmission	- Number of Shares	0.13	0.40	1.04
	- Avg. Book Value	-0.05	-0.27	-0.99
Distribution	- Sources of Funds	1.16	0.03	0.009
	- Number of Shares	0.26	0.74	1.95
	- Avg. Book Value	-0.05	-0.57	-1.79
	- Available Earnings	3.06	0.13	0.04
Outstanding Bonds	- Sources of Funds	-2.55	-0.004	-0.01
Common Stock	- Sources of Funds	-1.36	0.0	0.0
	- Number of Shares	.89	-3.01	-8.11
	- Avg. Book Value	0.77	2.83	8.40
Retained Earnings	- Number of Shares	.36	-1.17	-3.13
	- Avg. Book Value	0.29	1.08	3.08
Cost-Embedded Debt	- Interest Deductions	1.00	0.34	0.0
	- Available Earnings	3.11	0.06	0.02
Electric Revenues	- Electric Revenues	1.26	0.0	0.0
	- Net Income	7.64	0.0	0.0
	- Sources of Funds	0.81	0.0	0.0
	- Application of Funds	1.04	0.0	0.0
	- Avg. Price of Elec.	1.26	0.0	0.0
	- Return on Equity	15.15	0.0	0.0
	- Available Earnings	15.10	0.0	0.0
Fuel Adjusted Taxes	- Electric Revenues	-0.84	0.0	0.0
	- Net Income	-5.09	0.0	0.0
	- Avg. Price of Elec.	-0.84	0.0	0.0
	- Return on Equity	-9.09	0.0	0.0
	- Available Earnings	-1.01	0.0	0.0

Table C.9. (Cont'd)

Input Parameter (X)	Response (R)	1979	1986	1993
<u>User-Supplied Inputs</u>				
AFUDC Rate	- Net Income	0.82	-0.06	-0.02
	- AFUDC	0.84	0.83	0.83
	- Available Earnings	1.67	-0.06	-0.02
Federal Tax Rate	- Available Earnings	-1.40	1.03	1.36
Number of Shares	- Number of Shares	1.00	1.00	1.01
	- Avg. Book Value	-1.01	-0.99	-0.99
Return on New Bonds	- Interest Deductions	0.09	0.77	1.14
Return on Common Equity	- Net Income	0.0	0.89	0.88
	- Number of Shares	-0.20	-0.54	-1.39
	- Avg. Book Value	0.05	0.48	1.36
	- Available Earnings	0.0	1.13	1.12
Return on Pref. Stock	- Available Earnings	3.52	0.0	-0.01
Depreciation Rate	- Net Income	-0.82	-0.44	-0.35
	- Sources of Funds	-1.76	-1.26	-0.09
	- Application of Funds	-0.12	-1.26	-0.09
	- Number of Shares	-0.36	-1.17	-3.20
	- Available Earnings	3.20	-0.46	-0.37
% of Long-Term Debt	- Avg. Book Value	0.05	1.35	4.87
	- Number of Shares	-0.63	-1.98	-5.32
% of Common Equity	- Number of Shares	0.79	2.18	2.30
	- Avg. Book Value	-0.10	-1.35	-4.62
	- Available Earnings	1.17	0.68	0.66
% of Pref. Stock	- Number of Shares	-0.13	-0.43	1.22
	- Avg. Book Value	0.0	0.30	1.05

^aFor purposes of this table, a "major relative sensitivity" is defined as $\left| \frac{x}{R} \frac{dR}{dx} \right| \geq .8000$ for any of the three forecast periods under consideration.

Consider the first part of Table C.9, which represents the "major" relative sensitivities for base-year financial variables. Many of these input parameters have a singularly large effect on model results in the first year of the forecast period. This is an obvious manifestation of the regulatory lag scenario embodied in the base-case specification. For example, Electric Revenues and Fuel Adjusted for Taxes are directly reflected in the calculation of lagged revenues [see Eq. (48)] and, as expected, the former variable has large positive impacts on the forecasted variables, while the latter variable reflects the opposite.

Since, for the most part, the base-year financial variables are fixed and exogenous to the NUFS code, the user can exercise little discretion with respect to the values that they are assigned. However, recalling the discussion of Section 3, some of the values of base-year variables have been apportioned to electric utility operations via an allocation scheme designed to "ferret out" the impact of natural gas operations for utilities that provide a dual electric-gas service. Since some of the major sensitivities presented in Table C.9 are attributable to apportioned base-year financial variables (e.g., outstanding bonds, common stock, and retained earnings), the NUFS results are, in good measure, sensitive to the allocation routine devised for segregating electric and gas activity.

The major relative sensitivities attributable to "User-Supplied Inputs" in Table C.9 have, for the most part, been discussed in the context of Tables C.1 through C.7 above. The one exception is the impact of the depreciation rate for book purposes. As Table C.9 details, the book depreciation rate has a significant impact on the income statement and the flow-of-funds statement in the NUFS framework.

Perhaps as important as the input parameters that have a significant impact on model results are those parameters which induce no change in any of the forecasted variables. In the sensitivity analysis conducted on NUFS, it was discovered that five input parameters do not have a significant

impact on NUFS' forecasted results: (1) generation of electricity; (2) intangible assets; (3) the discount rate; (4) price of common stock; and (5) the salvage value percentage.

Since the NUFS' solution algorithm solves separately for private and public utilities, the sensitivity analysis for every input parameter was performed simultaneously for privately-owned and publicly-owned utilities. As a result, the base-year information with respect to generation of electricity was concomitantly perturbed by +1% for both IOUs and POUs. And, since the base-year values of generation are used exclusively to apportion the forecasted electricity generation amounts between IOUs and POUs, a simultaneous perturbation of both by +1% does not change the proportion between the two.

The nonsignificant impact of a one percent perturbation in intangible assets is attributable to its small value in relation to other components of utility plant. The discount rate is utilized exclusively in the determination of the present value of forecasted electric revenues in NUFS (an addendum to the financial statements) and, as a consequence, does not impact the primary financial statements (see Appendix A).

The price of common stock has a minor effect on another addendum to the primary financial statements: the end-of-year, book value of common stock. Finally, the salvage percentage in NUFS is only utilized when an asset retires and, since "old" assets were arbitrarily assigned 21 years of life (30 less 9) and "new" assets were specified to have a 30-year book life (see Table B.1), none of the assets were retired in the 17-year time horizon that the sensitivity analysis was based on.

Perhaps as important as the relative sensitivities with the largest impact (in absolute value) on model results (i.e., output responses) are relative sensitivities with the smallest impact. As explained above, the relative sensitivities included in Appendix D are those for which the absolute value is greater than 10^{-4} (i.e., $|\frac{dr}{R}| > 10^{-6}$). Those relative sensitivities less than 10^{-4} (including those which are zero) are eliminated from the analysis.

Table C.10 presents the smallest relative sensitivities for each of the ten income statement and balance sheet variables for which relative sensitivities were calculated. For each of those ten variables, the input

Table C.10. The smallest relative sensitivities¹ in the
NUFS code, private sector

Response (R)	Input Parameter (X)	1979	1986	1993
Revenues	- General Tax Rate	0.05		
	- Sales Tax Rate		0.002	
	- % Preferred Stock			0.001
Expenses	- % Short Term Debt	-0.002		
	- % CWIP in Rate Base		0.001	
	- % Short Term Debt			0.001
Interest Deductions	- General Assets	0.02		
	- Hydraulic		0.01	
	- General Assets			0.005
Net Income	- Property Tax Rate	-0.02		
	- Hydraulic		0.01	
	- Hydraulic			0.003
Utility Plant	- % CWIP in Rate Base	-0.01		
	- Other Production		0.01	
	- Other Production			0.004
Net Utility Plant	- % CWIP in Rate Base	-0.01		
	- Other Production		0.01	
	- Other Production			0.001
Working Capital	- Inflation Rate	0.00		
	- Inflation Rate		0.50	
	- Inflation Rate			1.03
Proprietary Capital	- % Flow-Thru (Dept. & ITC)	0.002		
	- Other Production		0.006	
	- General Assets			0.001
Total Debt	- % Flow-Thru (Dep. & ITC)	0.003		
	- Other Production		0.006	
	- General Assets			0.001
Deferred Credits	- Nuclear Production	0.01		
	- Steam Production		0.04	
	- % CWIP in Rate Base			-0.003

¹ The smallest relative sensitivities are provided from Appendix D.
Therefore, they are constrained to be at least 10^{-4} in absolute value.

parameter with the smallest relative sensitivity for the three years in which relative sensitivities were calculated are presented.

The most salient characteristic of the results presented in Table C.10 is that the user-supplied inflation rate accounts for the smallest relative sensitivities for working capital in all three years of the sensitivity calculations. Indeed, from Appendix D, the only input parameter that has any impact on the amount of working capital is the general inflation rate. This rather curious result, as we have seen, is attributable to the assumptions made in the computation of working capital in NUFS (i.e., working capital is a constant fraction of fuel, operation, and maintenance costs).

D-1

APPENDIX D

RELATIVE SENSITIVITY RESULTS

PARAMETER: SALES TO ULTIMATES
RELATIVE SENSITIVITIES

YEAR =	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	-0.4150	0.0	0.0	-0.3500	0.0	0.0
TOTAL ELECTRIC EXPENSES	-0.2490	0.0	0.0	-0.0210	0.0	0.0
NET INCOME	-2.5200	0.0	0.0	-3.3000	0.0	0.0
TOTAL SOURCES	-0.2680	0.0	0.0	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.3430	0.0	0.0	0.0	0.0	0.0
AVERAGE PRICE OF ELECTRICITY	-0.4140	0.0	0.0	-0.3500	0.0	0.0
% OF SHARES	0.0	0.0335	0.1040	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.0480	-0.0300	-0.0980	0.0	0.0	0.0
RETURN ON EQUITY	-6.0600	0.0	0.0	0.0	0.0	0.0
AVAILABLE EARNINGS	-5.0000	0.0	0.0	-3.3000	0.0	0.0

PARAMETER: STEAM PRODUCTION
RELATIVE SENSITIVITIES

YEAR =	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0530	0.0220	0.0	0.0270	0.0086
TOTAL ELECTRIC EXPENSES	0.0	0.0440	0.0170	0.0210	0.0145	0.0043
TOTAL INTEREST DEDUCTIONS	0.3490	0.1410	0.0330	0.1840	0.0790	0.0
NET INCOME	-0.5000	0.1190	0.0390	-0.4340	0.0800	0.0260
TOTAL UTILITY PLANT	0.2360	0.1410	0.0700	-0.1220	0.0720	0.0345
NET UTILITY PLANT	0.2010	0.0830	0.0102	0.1020	0.0300	0.0085
TOTAL PROPRIETARY CAPITAL	0.2110	0.0860	0.0220	0.0940	0.0390	0.0078
TOTAL DEBT	0.2110	0.0860	0.0220	0.1010	0.0390	0.0086
TOTAL DEFERRED CREDITS	0.0250	0.0350	-0.0160	0.0	0.0	0.0
TOTAL SOURCES	1.2200	0.0330	0.0103	0.6250	0.0	0.0
TOTAL APPLICATIONS	0.0580	0.0370	0.0103	0.0	0.0	0.0
RATE BASE	0.2050	0.0820	0.0206	0.1000	0.0390	0.0060
RETURN ON RATE BASE	0.2240	0.0920	0.0210	0.1340	0.0486	0.0053
REVENUE REQUIREMENTS	0.1350	0.0525	0.0174	0.0610	0.0210	0.0065
AVERAGE PRICE OF ELECTRICITY	0.0	0.0617	0.0220	0.0	0.0260	0.0090
% OF SHARES	0.2630	0.0030	2.0800	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.4300	-0.6300	-1.8700	0.0	0.0	0.0
AVAILABLE EARNINGS	3.3400	0.1350	0.0470	-0.4340	0.0800	0.0260

PARAMETER: NUCLEAR PRODUCTION
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0170	0.0069	0.0	0.0076	0.0034
TOTAL ELECTRIC EXPENSES	0.0	0.0130	0.0050	0.0	0.0	0.0
TOTAL INTEREST DEDUCTIONS	0.0070	0.0400	0.0140	0.0	0.0	0.0
NET INCOME	-0.1340	0.0313	0.0122	0.0	0.0	0.0
TOTAL UTILITY PLANT	0.0650	0.0390	0.0190	0.0390	0.0235	0.0113
NET UTILITY PLANT	0.0550	0.0220	0.0040	0.0326	0.0126	0.0026
TOTAL PROPRIETARY CAPITAL	0.0570	0.0240	0.0073	0.0330	0.0140	0.0026
TOTAL DEBT	0.0590	0.0250	0.0073	0.0310	0.0130	0.0025
TOTAL DEFERRED CREDITS	0.0045	0.0	-0.0160	0.0	0.0	0.0
TOTAL SOURCES	0.3560	0.0089	0.0031	0.2040	0.0	0.0
TOTAL APPLICATIONS	-0.0167	0.0089	0.0031	0.0	0.0	0.0
RATE BASE	0.0560	0.0236	0.0070	0.0320	0.0123	0.0025
RETURN ON RATE BASE	0.0610	0.0270	0.0069	0.0450	0.0121	0.0
REVENUE REQUIREMENTS	0.0360	0.0150	0.0050	0.0230	0.0072	0.0014
AVERAGE PRICE OF ELECTRICITY	0.0	0.0176	0.0048	0.0	0.0085	0.0029
# OF SHARES	0.0460	0.0340	0.0110	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.0480	-0.1800	-0.0600	0.0	0.0	0.0
AVAILABLE EARNINGS	-0.3150	0.0390	0.0155	-0.1740	0.0268	0.0

PARAMETER: HYDRO CONV.
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0054	0.0010	0.0	0.0420	0.0134
TOTAL ELECTRIC EXPENSES	0.0	0.0037	0.0013	0.0318	0.0194	0.0087
TOTAL INTEREST DEDUCTIONS	0.0350	0.0100	0.0047	0.2760	0.1166	0.0165
NET INCOME	-0.0450	0.0063	0.0030	-0.6160	0.1070	0.0340
TOTAL UTILITY PLANT	0.0190	0.0160	0.0057	0.1910	0.1100	0.0536
NET UTILITY PLANT	0.0160	0.0068	0.0014	0.1610	0.0620	0.0130
TOTAL PROPRIETARY CAPITAL	0.0160	0.0068	0.0017	0.1550	0.0620	0.0130
TOTAL DEBT	0.0180	0.0069	0.0017	0.1550	0.0610	0.0135
TOTAL SOURCES	-0.1080	0.0022	0.0	0.9790	0.0	0.0
TOTAL APPLICATIONS	0.0	0.0	0.0	0.0	0.0	0.0
RATE BASE	0.0169	0.0068	0.0018	0.1550	0.0616	0.0133
RETURN ON RATE BASE	0.0203	0.0091	0.0014	0.2920	0.0730	0.0106
REVENUE REQUIREMENTS	0.0100	0.0036	0.0014	0.0190	0.0325	0.0027
AVERAGE PRICE OF ELECTRICITY	0.0	0.0050	0.0018	0.0	0.0410	0.0140
# OF SHARES	0.0330	0.0650	0.1740	0.0	0.0	0.0
AVERAGE BOOK VALUE	0.0	-0.0600	-0.1680	0.0	0.0	0.0
AVAILABLE EARNINGS	-0.0900	0.0158	0.0039	-0.6090	0.1070	0.0390

PARAMETER: OTHER PRODUCTION
RELATIVE SENSITIVITIES

YEAR =	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0046	0.0018	0.0	0.0	0.0
TOTAL ELECTRIC EXPENSES	0.0	0.0037	0.0013	0.0	0.0	0.0
TOTAL UTILITY PLANT	0.0165	0.0069	0.0048	0.0148	0.0085	0.0041
NET UTILITY PLANT	0.0144	0.0059	0.0012	0.0117	0.0042	0.0007
TOTAL PROPRIETARY CAPITAL	0.0146	0.0058	0.0014	0.0094	0.0056	0.0013
TOTAL DEBT	0.0150	0.0055	0.0013	0.0088	0.0026	0.0012
TOTAL SOURCES	0.0216	0.0025	0.0	0.0680	0.0	0.0
RATE BASE	0.0143	0.0057	0.0014	0.0114	0.0041	0.0013
RETURN ON RATE BASE	0.0150	0.0061	0.0014	0.0	0.0	0.0
REVENUE REQUIREMENTS	0.0086	0.0036	0.0014	0.0	0.0	0.0
AVERAGE PRICE OF ELECTRICITY	0.0	0.0043	0.0016	0.0	0.0030	0.0010
# OF SHARES	0.0330	0.0670	0.1740	0.0	0.0	0.0
AVERAGE BOOK VALUE	0.0	-0.0603	-0.1540	0.0	0.0	0.0
AVAILABLE EARNINGS	-0.0900	-0.0079	0.0039	0.0	0.0	0.0

PARAMETER: TRANSMISSION
RELATIVE SENSITIVITIES

YEAR =	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0370	0.0130	0.0	0.0230	0.0069
TOTAL ELECTRIC EXPENSES	0.0110	0.0290	0.0120	0.0106	0.0097	0.0043
TOTAL INTEREST REDUCTIONS	0.1750	0.0707	0.0142	0.0920	0.0390	0.0
NET INCOME	-0.3410	0.0626	0.0210	-0.3480	0.0535	0.0130
TOTAL UTILITY PLANT	0.1150	0.0650	0.0340	0.1000	0.0590	0.0280
NET UTILITY PLANT	0.0273	0.0404	0.0088	0.0840	0.0320	0.0072
TOTAL PROPRIETARY CAPITAL	0.1030	0.0440	0.0097	0.0800	0.0310	0.0066
TOTAL DEBT	0.1040	0.0440	0.0096	0.0840	0.0320	0.0074
TOTAL SOURCES	0.6180	0.0178	0.0052	0.6520	0.0	0.0
TOTAL APPLICATIONS	-0.0420	0.0180	0.0052	0.0	0.0	0.0
RATE BASE	0.1000	0.0420	0.0091	0.8210	0.0320	0.0069
RETURN ON RATE BASE	0.1110	0.0490	0.0084	0.1120	0.0370	0.0053
REVENUE REQUIREMENTS	0.0790	0.0310	0.0100	0.0540	0.0180	0.0049
AVERAGE PRICE OF ELECTRICITY	0.0	0.0373	0.0131	0.0	0.0217	0.0075
# OF SHARES	0.1320	0.4020	1.0440	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.0480	-0.2700	-0.9900	0.0	0.0	0.0
AVAILABLE EARNINGS	-0.7660	0.0714	0.0230	-0.3480	0.0540	0.0130

PARAMETER: DISTRIBUTION
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0590	0.0280	0.0	0.0230	0.0069
TOTAL ELECTRIC EXPENSES	0.0193	0.0540	0.0220	0.0110	0.0097	0.0043
TOTAL INTEREST REDUCTIONS	0.3140	0.1410	0.0290	0.0920	0.0390	0.0
NET INCOME	-0.4360	0.1150	0.0398	-0.3480	0.0540	0.0130
TOTAL UTILITY PLANT	0.2150	0.1250	0.0640	0.0970	0.0560	0.0270
NET UTILITY PLANT	0.1630	0.1290	0.0160	0.0790	0.0310	0.0066
TOTAL PROPRIETARY CAPITAL	0.1940	0.0820	0.0101	0.0750	0.0310	0.0066
TOTAL DEBT	0.1270	0.0820	0.0180	0.0746	0.0290	0.0062
TOTAL SOURCES	1.1540	0.0340	0.0093	0.4090	0.0	0.0
TOTAL APPLICATIONS	-0.0790	0.0360	0.0093	0.0	0.0	0.0
RATE BASE	0.1080	0.0780	0.1710	0.0780	0.0300	0.0070
RETURN ON RATE BASE	0.2080	0.0886	0.0167	0.0896	0.0370	0.0053
REVENUE REQUIREMENTS	0.1480	0.0591	0.0141	0.0461	0.0180	0.0049
AVERAGE PRICE OF ELECTRICITY	0.0	0.0698	0.0246	0.0	0.0211	0.0071
# OF SHARES	0.2640	0.7360	1.9480	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.0530	-0.5710	-1.7920	0.0	0.0	0.0
AVAILABLE EARNINGS	3.0650	0.1348	0.0430	-0.3480	0.0535	0.0130

PARAMETER: GENERAL
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0061	0.0022	0.0	0.0191	0.0069
TOTAL ELECTRIC EXPENSES	0.0	0.0047	0.0017	0.0110	0.0097	0.0043
TOTAL INTEREST REDUCTIONS	0.0170	0.0101	0.0047	0.0920	0.0390	0.0
NET INCOME	-0.0480	0.0063	0.0031	-0.0347	0.0535	0.0130
TOTAL UTILITY PLANT	0.0182	0.0109	0.0053	0.0870	0.0509	0.0240
NET UTILITY PLANT	0.0150	0.0065	0.0014	0.0723	0.0281	0.0069
TOTAL PROPRIETARY CAPITAL	0.0160	0.0066	0.0014	0.0706	0.0282	0.0066
TOTAL DEBT	-0.0171	0.0069	0.0013	0.0707	0.0265	0.0062
TOTAL SOURCES	0.0280	0.0022	0.0	0.4350	0.0	0.0
RATE BASE	0.0160	0.0067	0.0014	0.0707	0.0274	0.0063
RETURN ON RATE BASE	0.0203	0.0091	0.0014	0.0896	0.0243	0.0053
REVENUE REQUIREMENTS	0.0115	0.0044	0.0017	0.0461	0.0144	0.0049
AVERAGE PRICE OF ELECTRICITY	0.0	0.0059	0.0021	0.0	0.0199	0.0064
# OF SHARES	0.0330	0.0670	0.1740	0.0	0.0	0.0
AVERAGE BOOK VALUE	0.0	-0.0500	-0.1680	0.0	0.0	0.0
AVAILABLE EARNINGS	-0.1350	0.0159	0.0039	-0.3480	0.0535	0.0130

PARAMETER: OUTSTANDING BONDS
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)	0.0	-0.0192	-0.0094	0.0	-0.0153	-0.0069
ELECTRIC REVENUES	0.0193	-0.0037	-0.0057	0.0	0.0	0.0
TOTAL ELECTRIC EXPENSES	-0.3490	-0.1920	0.0	-0.3680	-0.1580	-0.0165
TOTAL INTEREST REDUCTIONS	0.2270	-0.0188	-0.0367	0.2610	0.0	-0.0131
NET INCOME	-2.5540	-0.0045	-0.0103	-1.2160	0.0	0.0
TOTAL SOURCES	0.0335	-0.0045	-0.0103	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.1016	-0.0611	0.0	-0.0672	-0.0486	-0.0053
RETURN ON RATE BASE	-0.0331	-0.0192	0.0	-0.0230	-0.0144	0.0
REVENUE REQUIREMENTS	0.0	-0.0820	-0.0095	0.0	-0.0154	-0.0257
AVERAGE PRICE OF ELECTRICITY	0.4510	-0.0158	-0.0506	0.2610	0.0	-0.0522
AVAILABLE EARNINGS						

PARAMETER: SHORT-TERM DEBT
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)	-0.1010	0.0	0.0			
TOTAL SOURCES						

PARAMETER: COMMON STOCK
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)	-1.3620	0.0	0.0	-1.4140	0.0	0.0
TOTAL SOURCES	-0.8905	-3.0140	-8.1070	0.0	0.0	0.0
# OF SHARES	0.7714	2.8280	8.3990	0.0	0.0	0.0
AVERAGE BOOK VALUE						

PARAMETER: PREFERRED STOCK
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
TOTAL SOURCES	-0.6220	0.0	0.0			

PARAMETER: RETAINED EARNINGS
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
TOTAL SOURCES	-0.5660	0.0	0.0	-1.0060	0.0	0.0
# OF SHARES	-0.3630	-1.1720	-3.1315	0.0	0.0	0.0
AVERAGE BOOK VALUE	0.2090	1.0630	3.0800	0.0	0.0	0.0

PARAMETER: COST EMBEDDED DEBT
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0400	0.0036	0.0	0.0343	0.0035
TOTAL ELECTRIC EXPENSES	-0.0570	0.0103	0.0022	0.0	0.0	0.0
TOTAL INTEREST DEDUCTIONS	-0.9260	0.3440	0.0	-0.9200	0.2370	0.0
NET INCOME	-0.6820	0.0439	0.0153	-0.9560	0.0535	0.0130
TOTAL SOURCES	-0.0720	0.0112	0.0031	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.0721	0.0112	0.0031	0.0	0.0	0.0
RETURN ON EAT BASE	0.2490	0.1130	0.0	0.2465	0.0050	0.0
REVENUE REQUIREMENTS	0.0036	0.0314	0.0	0.0045	0.0243	0.0
AVERAGE PRICE OF ELECTRICITY	0.0	0.0399	0.0034	0.0	0.0324	0.0034
AVERAGE BOOK VALUE	0.0	-0.0300	-0.0240	0.0	0.0	0.0
AVAILABLE EARNINGS	3.1100	0.0634	0.0195	-0.9560	0.0535	0.0130

PARAMETER: ELECTRIC REVENUES
RELATIVE SENSITIVITIES

YEAR		PRIVATE SECTOR			PUBLIC SECTOR		
		1979	1986	1993	1979	1986	1993
	OUTPUT QUANTITY (RESPONSE)						
	ELECTRIC REVENUES	1.2560	0.0	0.0	1.3040	0.0	0.0
	TOTAL ELECTRIC EXPENSES	0.7515	0.0	0.0	0.0637	0.0	0.0
	NET INCOME	7.6410	0.0	0.0	12.0870	0.0	0.0
	TOTAL SOURCES	0.8150	0.0	0.0	0.0	0.0	0.0
	TOTAL APPLICATIONS	1.0420	0.0	0.0	0.0	0.0	0.0
	AVERAGE PRICE OF ELECTRICITY	1.2570	0.0	0.0	1.3126	0.0	0.0
	# OF SHARES	-0.0330	0.1000	-0.3130	0.0	0.0	0.0
	AVERAGE BOOK VALUE	0.0	0.0900	0.2933	0.0	0.0	0.0
	RETURN ON EQUITY	15.1500	0.0	0.0	0.0	0.0	0.0
	AVAILABLE EARNINGS	15.1030	0.0	0.0	12.0870	0.0	0.0

PARAMETER: NET INCOME
RELATIVE SENSITIVITIES

YEAR		PRIVATE SECTOR			PUBLIC SECTOR		
		1979	1986	1993	1979	1986	1993
	OUTPUT QUANTITY (RESPONSE)						
	# OF SHARES	-0.0329	0.0335	0.1044	0.0	0.0	0.0
	AVERAGE BOOK VALUE	-0.0480	-0.0300	-0.0980	0.0	0.0	0.0

PARAMETER: WORKING CAPITAL
RELATIVE SENSITIVITIES

YEAR		PRIVATE SECTOR			PUBLIC SECTOR		
		1979	1986	1993	1979	1986	1993
	OUTPUT QUANTITY (RESPONSE)						
	TOTAL APPLICATIONS	-0.0209	0.0	0.0	-0.2220	0.0	0.0

PARAMETER: DEFERRED ITC
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	-0.0031	-0.0015			
TOTAL ELECTRIC EXPENSES	-0.0043	-0.0028	-0.0017			
TOTAL INTEREST DEDUCTIONS	-0.0349	-0.0101	0.0			
NET INCOME	0.0602	0.0063	0.0031			
TOTAL PROPRIETARY CAPITAL	-0.0247	0.0102	0.0024			
TOTAL DEBT	-0.0246	-0.0104	-0.0023			
TOTAL DEFERRED CREDITS	0.2913	0.0052	0.0102			
TOTAL SOURCES	-0.1440	0.0022	0.0			
TOTAL APPLICATIONS	0.0125	0.0022	0.0			
REVENUE REQUIREMENTS	-0.0050	-0.0029	-0.0014			
AVERAGE PRICE OF ELECTRICITY	0.0	-0.0027	-0.0014			
# OF SHARES	-0.0330	-0.1000	-0.2435			
AVERAGE BOOK VALUE	0.0	0.0601	0.2380			
AVAILABLE EARNINGS	0.1003	0.0159	0.0039			

PARAMETER: DEFERRED INCOME TAX
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	-0.0138	-0.0062			
TOTAL ELECTRIC EXPENSES	0.0043	-0.0065	-0.0031			
TOTAL INTEREST DEDUCTIONS	-0.0074	-0.0404	-0.0189			
NET INCOME	0.0455	-0.0438	-0.0183			
TOTAL PROPRIETARY CAPITAL	-0.0494	-0.0321	-0.0153			
TOTAL DEBT	-0.0480	-0.0312	-0.0153			
TOTAL DEFERRED CREDITS	0.5760	0.2640	0.1190			
TOTAL SOURCES	-0.2080	-0.0112	-0.0031			
TOTAL APPLICATIONS	0.0084	-0.0112	-0.0031			
PAYE BASE	-0.0472	-0.3000	-0.0142			
RETURN ON PAYE BASE	-0.0503	-0.0305	-0.0139			
REVENUE REQUIREMENTS	-0.0245	-0.0124	-0.0050			
AVERAGE PRICE OF ELECTRICITY	0.0	-0.0136	-0.0064			
# OF SHARES	-0.0659	-0.2000	-0.4070			
AVERAGE BOOK VALUE	0.0	0.1200	0.4620			
AVAILABLE EARNINGS	0.1350	-0.0396	-0.0195			

PARAMETER: AFUC RATE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
TOTAL INTEREST DEDUCTIONS	-0.3320	-0.2426	-0.3080	-0.4600	-0.2760	-0.2970
NET INCOME	0.0180	-0.0626	-0.0214	0.7830	-0.0535	-0.0392
ELECTRIC REVENUES	0.0	-0.0621	-0.0947	0.0	-0.0611	-0.0691
TOTAL ELECTRIC EXPENSES	0.0	-0.0457	-0.0527	0.0	-0.0049	-0.0065
TOTAL UTILITY PLANT	-0.0327	-0.0411	-0.0533	-0.0353	-0.0429	-0.0547
NET UTILITY PLANT	-0.0417	-0.0532	-0.0655	-0.0443	-0.0549	-0.0661
TOTAL PROPRIETARY CAPITAL	-0.0426	-0.0386	-0.0418	-0.0471	-0.0537	-0.0643
TOTAL DEBT	-0.0416	-0.0382	-0.0421	-0.0442	-0.0531	-0.0640
TOTAL DEFERRED CREDITS	-0.0257	-0.1645	-0.2340	0.0	0.0	0.0
TOTAL SOURCES	-0.2380	-0.1820	-0.1810	-0.3810	-0.2360	-0.2410
TOTAL APPLICATIONS	0.1419	-0.1826	-0.1810	-0.0987	-0.2340	-0.2410
RATE BASE	-0.0429	-0.0473	-0.0548	-0.0456	-0.0533	-0.0653
RETURN ON RATE BASE	-0.0457	-0.0488	-0.0557	-0.0448	-0.0607	-0.0639
REVENUE REQUIREMENTS	-0.1190	-0.0759	-0.0300	-0.0768	-0.0614	-0.0730
AVERAGE PRICE OF ELECTRICITY	0.0	-0.0918	-0.0948	0.0	-0.0603	-0.0691
# OF SHARES	-0.0657	-0.1570	-0.4520	0.0	0.0	0.0
AVERAGE BOOK VALUE	0.0	0.1203	0.4060	0.0	0.0	0.0
AFUC	0.8440	0.8314	0.8300	0.8550	0.8890	0.8310
AVAILABLE EARNINGS	1.6680	-0.0634	-0.0156	0.7830	-0.0535	-0.0392

PARAMETER: FEDERAL TAX RATE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.2080	0.1640			
TOTAL ELECTRIC EXPENSES	0.0664	0.2460	0.1880			
TOTAL INTEREST DEDUCTIONS	0.0	-0.0404	-0.0619			
NET INCOME	-0.7050	0.0752	0.0979			
TOTAL PROPRIETARY CAPITAL	-0.0040	-0.0365	-0.0471			
TOTAL DEBT	-0.0043	-0.0368	-0.0468			
TOTAL DEFERRED CREDITS	-0.0453	0.3120	0.3710			
TOTAL SOURCES	-0.0753	0.0179	0.0226			
TOTAL APPLICATIONS	-0.0963	0.0179	0.0226			
RATE BASE	-0.0037	-0.0345	-0.0442			
RETURN ON RATE BASE	-0.0051	-0.0336	-0.0446			
REVENUE REQUIREMENTS	0.2720	0.2110	0.1700			
AVERAGE PRICE OF ELECTRICITY	0.0	0.2680	0.1640			
AVERAGE BOOK VALUE	0.0	-0.0300	-0.0420			
AVAILABLE EARNINGS	-1.3970	1.0310	1.3630			

PARAMETER: FULL ADJ. FOR TAXES
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	-0.9390	0.0	0.0	-0.9624	0.0	0.0
TOTAL ELECTRIC EXPENSES	-0.9030	0.0	0.0	-0.9531	0.0	0.0
NET INCOME	-5.0900	0.0	0.0	-0.2610	0.0	0.0
TOTAL SOURCES	-0.5430	0.0	0.0	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.6050	0.0	0.0	0.0	0.0	0.0
AVERAGE PRICE OF ELECTRICITY	-0.8390	0.0	0.0	-0.8590	0.0	0.0
# OF SHARES	0.0139	0.0669	0.2087	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.0682	-0.0600	-0.1820	0.0	0.0	0.0
RETURN ON EQUITY	-9.0009	0.0	0.0	0.0	0.0	0.0
AVAILABLE EARNINGS	-1.0100	0.0	0.0	-0.2608	0.0	0.0

PARAMETER: GENERAL TAX RATE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0494	0.0823	0.0849	0.0039	0.0267	0.0276
TOTAL ELECTRIC EXPENSES	0.0792	0.1080	0.1060	0.0319	0.0339	0.0347
NET INCOME	-0.2270	0.0	0.0	0.1739	0.0	0.0
TOTAL SOURCES	-0.0229	0.0	0.0	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.0293	0.0	0.0	0.0	0.0	0.0
REVENUE REQUIREMENTS	0.0079	0.0823	0.0887	0.0307	0.0253	0.0276
AVERAGE PRICE OF ELECTRICITY	0.0501	0.0885	0.0885	0.0177	0.0270	0.0278
AVAILABLE EARNINGS	-0.4500	0.0	0.0	-0.1739	0.0	0.0

PARAMETER: INVEST. TAX CREDIT
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	-0.0054	-0.0084			
TOTAL ELECTRIC EXPENSES	0.0107	0.0037	0.0013			
TOTAL INTEREST DEDUCTIONS	-0.0175	-0.0505	-0.0759			
NET INCOME	-0.1137	-0.0376	-0.0306			
TOTAL PROPRIETARY CAPITAL	-0.0079	-0.0423	-0.0617			
TOTAL DEBT	-0.0064	-0.0423	-0.0617			
TOTAL DEFERRED CREDITS	0.0341	0.2450	0.4870			
TOTAL SOURCES	-0.0099	-0.0112	-0.0092			
TOTAL APPLICATIONS	-0.0126	-0.0112	-0.0093			
REVENUE REQUIREMENTS	-0.0043	-0.0088	-0.0092			
AVERAGE PRICE OF ELECTRICITY	0.0	-0.0054	-0.0085			
AVAILABLE EARNINGS	-0.1800	-0.0317	-0.0195			

PARAMETER: FLOW THRU ADJUST
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	-0.0115	-0.0113			
TOTAL ELECTRIC EXPENSES	0.0	-0.0065	-0.0067			
TOTAL INTEREST DEDUCTIONS	0.0	0.0303	0.0340			
NET INCOME	-0.0227	-0.0627	-0.0795			
TOTAL PROPRIETARY CAPITAL	0.0022	0.0219	0.0299			
TOTAL DEBT	0.0032	0.0215	0.0302			
TOTAL DEFERRED CREDITS	-0.0380	-0.1498	-0.2379			
TOTAL SOURCES	0.0	-0.0157	-0.0196			
TOTAL APPLICATIONS	0.0	-0.0157	-0.0196			
RATE BASE	0.0011	0.0098	0.0121			
RETURN ON RATE BASE	0.0	0.0127	0.0125			
REVENUE REQUIREMENTS	-0.0150	-0.0134	-0.0119			
AVERAGE PRICE OF ELECTRICITY	0.0	-0.0113	-0.0112			
AVAILABLE EARNINGS	-0.0451	-0.0872	-0.1090			

PARAMETER: FLOW EXPORT ADJUST
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	-0.0031	-0.0112			
TOTAL ELECTRIC EXPENSES	0.0	-0.0019	-0.0065			
NET INCOME	0.0	-0.0125	-0.0459			
TOTAL SOURCES	0.0	-0.0022	-0.0113			
TOTAL APPLICATIONS	0.0	-0.0022	-0.0113			
REVENUE REQUIREMENTS	-0.0029	-0.0027	-0.0119			
AVERAGE PRICE OF ELECTRICITY	0.0	-0.0030	-0.0109			
AVAILABLE EARNINGS	0.0	-0.0159	-0.0584			

PARAMETER: STATE TAX RATE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0054	0.0051	0.0	0.0038	0.0035
TOTAL ELECTRIC EXPENSES	0.0021	0.0065	0.0057	0.0	0.0049	0.0043
NET INCOME	-0.0227	0.0	0.0031	0.0	0.0	0.0
REVENUE REQUIREMENTS	0.0050	0.0051	0.0051	0.0	0.0	0.0
AVERAGE PRICE OF ELECTRICITY	0.0	0.0056	0.0048	0.0	0.0034	0.0031

PARAMETER: PROPERTY TAX RATE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0192	0.0254	0.0	0.0229	0.0274
TOTAL ELECTRIC EXPENSES	0.0021	0.0270	0.0340	0.0	0.0339	0.0400
NET INCOME	-0.0227	-0.0291	-0.0184	-0.0869	-0.0535	-0.0302
TOTAL SOURCES	0.0	-0.0047	-0.0052	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.0042	-0.0067	-0.0052	0.0	0.0	0.0
REVENUE REQUIREMENTS	0.0020	0.0233	0.0286	0.0077	0.0253	0.0308
AVERAGE PRICE OF ELECTRICITY	0.0	0.0161	0.0255	0.0	0.0214	0.0276
AVAILABLE EARNINGS	-0.0902	-0.0238	-0.0272	-0.0869	-0.0535	-0.0392

PARAMETER: SALES TAX RATE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0015	0.0022	0.0	0.0	0.0
TOTAL ELECTRIC EXPENSES	0.0	0.0028	0.0026	0.0	0.0	0.0
REVENUE REQUIREMENTS	0.0014	0.0015	0.0021	0.0	0.0	0.0
AVERAGE PRICE OF ELECTRICITY	0.0	0.0015	0.0021	0.0	0.0019	0.0024

PARAMETER: # OF SHARES
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
# OF SHARES	0.2070	1.0040	1.0070			
AVERAGE BOOK VALUE	-1.0120	-0.5930	-0.9740			

PARAMETER: COM. DIV. PAYOUT RAT
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
TOTAL SOURCES	0.0557	0.2090	0.1957			
TOTAL APPLICATIONS	0.0712	0.2090	0.1957			
# OF SHARES	0.0	-0.6335	-0.1044			
AVERAGE BOOK VALUE	0.0	0.0300	0.0980			

PARAMETER: RETURN ON NEW BONDS
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0676	0.1140	0.0	0.0802	0.1190
TOTAL ELECTRIC EXPENSES	-0.0150	0.0037	0.0135	0.0	0.0049	0.0043
TOTAL INTEREST DEDUCTIONS	0.0074	0.7680	1.1440	0.0920	0.8303	1.1050
NET INCOME	-0.1020	-0.2510	0.0	-0.3480	-0.1070	-0.1040
TOTAL SOURCES	-0.0164	-0.0067	0.0052	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.0207	-0.0067	0.0052	0.0	0.0	0.0
RETURN ON RATE BASE	0.0762	0.2960	0.4290	0.0896	0.3040	0.4740
REVENUE REQUIREMENTS	0.0231	0.0824	0.1250	0.0307	0.0939	0.1330
AVERAGE PRICE OF ELECTRICITY	0.0	0.0678	0.1140	0.0	0.0780	0.1200
AVAILABLE EARNINGS	-0.3606	-0.0317	-0.0273	-0.3480	-0.1070	-0.1040

PARAMETER: RET. ON 5-TERM DEBT
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0084	0.0079	0.0	0.0	0.0
TOTAL ELECTRIC EXPENSES	-0.0043	0.0056	0.0044	0.0	0.0	0.0
TOTAL INTEREST DEDUCTIONS	0.0524	0.0	0.0	0.0	0.0	0.0
NET INCOME	-0.0455	0.0313	0.0336	0.0	0.0	0.0
TOTAL SOURCES	-0.0033	0.0089	0.0082	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.0042	0.0089	0.0082	0.0	0.0	0.0
RETURN ON RATE BASE	0.0203	0.0183	0.0167	0.0	0.0	0.0
REVENUE REQUIREMENTS	0.0058	0.0060	0.0082	0.0	0.0	0.0
AVERAGE PRICE OF ELECTRICITY	0.0	0.0084	0.0078	0.0	0.0027	0.0025
AVAILABLE EARNINGS	-0.0902	0.0356	0.0420	-0.0069	0.0268	0.0130

PARAMETER: NET. ON COMMON EQUITY
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.7230	0.7140	0.0	0.1833	0.1711
TOTAL ELECTRIC EXPENSES	0.0	0.1350	0.1310	0.0	0.0097	0.0097
TOTAL INTEREST DEDUCTIONS	0.1390	0.1110	0.1376	0.1840	0.1190	0.1320
NET INCOME	0.0	0.4857	0.4810	0.0	1.2310	1.2270
TOTAL SOURCES	0.0	0.2360	0.2100	0.0	0.0	0.0
TOTAL APPLICATIONS	0.0	0.2360	0.2190	0.0	0.0	0.0
RETURN ON RATE BASE	0.4030	0.4670	0.4490	0.6720	0.5955	0.4173
REVENUE REQUIREMENTS	0.2067	0.2276	0.2251	0.2380	0.1840	0.1900
AVERAGE PRICE OF ELECTRICITY	0.0	0.2238	0.2137	0.0	0.1823	0.1712
# OF SHARES	-0.1980	-0.2360	-1.3920	0.0	0.0	0.0
AVERAGE BOOK VALUE	0.0482	0.4413	1.3580	0.0	0.0	0.0
AVAILABLE EARNINGS	0.0	1.1340	1.1220	0.0	1.2310	1.2270

PARAMETER: NET. ON PREFERRED STOCK
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0514	0.0494			
TOTAL ELECTRIC EXPENSES	0.0	0.0326	0.0300			
TOTAL INTEREST DEDUCTIONS	0.0349	0.0303	0.0332			
NET INCOME	0.0	0.2070	0.2050			
TOTAL SOURCES	0.0196	0.0741	0.0690			
TOTAL APPLICATIONS	0.0251	0.0741	0.0690			
RETURN ON RATE BASE	0.1169	0.1099	0.1030			
REVENUE REQUIREMENTS	0.0663	0.0518	0.0518			
AVERAGE PRICE OF ELECTRICITY	0.0	0.0517	0.0493			
AVERAGE BOOK VALUE	0.0	-0.0300	-0.0280			
AVAILABLE EARNINGS	3.5170	0.0	-0.0117			

PARAMETER: GEN. INFLATION RATE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.3470	0.4570	0.0	0.4010	0.4065
TOTAL ELECTRIC EXPENSES	-0.0043	0.3949	0.4119	0.0	0.4557	0.4495
TOTAL INTEREST DEDUCTIONS	-0.0524	0.3133	0.7780	0.0	0.3550	0.7592
NET INCOME	0.0455	0.2380	0.7560	0.0	0.1874	0.6654
TOTAL UTILITY PLANT	0.0517	0.7670	0.6097	0.0576	0.2834	0.7091
NET UTILITY PLANT	0.0659	0.3450	0.4860	0.0699	0.3760	0.4920
TOTAL PROPRIETARY CAPITAL	0.0673	0.3820	0.9173	0.0659	0.3816	0.8062
TOTAL DEBT	0.0683	0.3820	0.9170	0.0707	0.3793	0.8964
TOTAL DEFERRED CREDITS	0.0194	0.2530	0.6780	0.0	0.0	0.0
WORKING CAPITAL	0.0	0.5040	1.0260	0.0	0.5263	1.0100
TOTAL SOURCES	0.4027	0.7510	1.1010	0.3807	0.4140	1.3350
TOTAL APPLICATIONS	0.1740	0.0510	1.1910	0.2220	0.4140	1.3350
RATE BASE	0.0679	0.3860	0.9180	0.0680	0.3800	0.8960
RETURN ON RATE BASE	0.0762	0.4030	0.9180	0.0896	0.4010	0.8940
REVENUE REQUIREMENTS	0.0115	0.4013	0.8976	0.0154	0.4299	0.9190
AVERAGE PRICE OF ELECTRICITY	0.0	0.3671	0.4572	0.0	0.4010	0.4060
# OF SHARES	0.0929	0.2340	0.6260	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.0482	0.1203	0.2740	0.0	0.0	0.0
AFUDC	0.2045	0.7154	1.2209	0.1068	0.7275	1.2040
AVAILABLE EARNINGS	0.045	0.2050	0.7080	0.0	0.1874	0.6

PARAMETER: LONG-TERM DEBT COR
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	-0.0752	-0.0689	0.0	-0.0222	-0.0190
TOTAL ELECTRIC EXPENSES	-0.0450	-0.0774	-0.0274	0.0	0.0	0.0
TOTAL INTEREST DEDUCTIONS	-0.6115	-0.5960	0.4940	0.7359	0.5931	0.4620
NET INCOME	-0.5460	-0.5390	-0.5110	-0.9565	-0.6426	-0.6267
TOTAL PROPRIETARY CAPITAL	-0.4913	-0.4916	-0.4912	-0.5041	-0.5032	-0.5039
TOTAL DEBT	0.4665	0.4644	0.4665	0.4731	0.4722	0.4728
TOTAL SOURCES	-0.0600	-0.1527	-0.1369	0.0	0.0	0.0
TOTAL APPLICATIONS	-0.0039	-0.1527	-0.1369	0.0	0.0	0.0
RETURN ON RATE BASE	-0.0661	-0.0519	-0.0640	-0.0896	-0.0722	-0.0751
REVENUE REQUIREMENTS	-0.1000	-0.0759	-0.0774	-0.0307	-0.0217	-0.0275
AVERAGE PRICE OF ELECTRICITY	0.0	-0.0754	-0.0693	0.0	-0.0225	-0.0194
# OF SHARES	-0.6266	-1.9760	-5.3230	0.0	0.0	0.0
AVERAGE BOOK VALUE	0.0482	1.3530	4.8720	0.0	0.0	0.0
AVAILABLE EARNINGS	-0.5060	-0.5470	-0.5141	-0.9565	-0.6426	-0.6267

PARAMETER: SHORT-TERM DEBT COR
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	-0.0021	0.0019	0.0009	0.0	0.0	0.0
TOTAL ELECTRIC EXPENSES	-0.0175	0.0303	-0.0285	0.0	0.0	0.0
TOTAL INTEREST DEDUCTIONS	-0.0227	0.0063	0.0092	0.0	0.0	0.0
NET INCOME	-0.0202	-0.0197	-0.0195	-0.0141	-0.0113	-0.0105
TOTAL PROPRIETARY CAPITAL	0.0192	0.0187	0.0189	0.0088	0.0079	0.0049
TOTAL DEBT	0.0	0.0022	0.0010	0.0	0.0	0.0
TOTAL SOURCES	-0.0042	0.0022	0.0010	0.0	0.0	0.0
TOTAL APPLICATIONS	0.0	-0.0030	-0.0028	0.0	0.0	0.0
RETURN ON RATE BASE	-0.0330	-0.0670	-0.1739	0.0	0.0	0.0
# OF SHARES	0.0	0.0300	0.1480	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.0451	0.0159	0.0156	-0.0469	0.0	0.0
AVAILABLE EARNINGS						

PARAMETER: COMMON EQUITY COR
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0722	0.0644	0.0	0.0229	0.0190
TOTAL ELECTRIC EXPENSES	0.0343	0.0671	0.0614	0.0	0.0042	0.0022
TOTAL INTEREST DEDUCTIONS	-0.4710	-0.4145	-0.3416	-0.8279	-0.6327	-0.4786
NET INCOME	0.4094	0.4574	0.4405	0.8695	0.6425	0.6131
TOTAL PROPRIETARY CAPITAL	0.3047	0.3851	0.3053	0.5088	0.5117	0.5114
TOTAL DEBT	-0.3672	-0.3672	-0.3649	-0.4819	-0.4828	-0.4627
TOTAL SOURCES	0.0360	0.1145	0.1019	0.0	0.0	0.0
TOTAL APPLICATIONS	0.0502	0.1145	0.1019	0.0	0.0	0.0
RETURN ON RATE BASE	0.0064	0.0764	0.0808	0.1120	0.0726	0.0798
REVENUE REQUIREMENTS	0.0940	0.0715	0.0733	0.0384	0.0217	0.0259
AVERAGE PRICE OF ELECTRICITY	0.0	0.0719	0.0665	0.0	0.0229	0.0194
# OF SHARES	0.7915	2.1760	2.2960	0.0	0.0	0.0
AVERAGE BOOK VALUE	-0.0964	-1.3530	-4.6200	0.0	0.0	0.0
AVAILABLE EARNINGS	1.1720	0.6820	0.6620	0.8690	0.6425	0.6136

PARAMETER: DEPRECIATION RATE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)	0.0	-0.0099	-0.0084	0.0	-0.0076	-0.0064
ELECTRIC REVENUES	0.0	0.0932	0.0797	0.0	0.1212	0.1029
TOTAL ELECTRIC EXPENSES	-0.1370	-0.4240	-0.4220	-0.4520	-0.3954	-0.4126
TOTAL INTEREST DEDUCTIONS	-0.4890	-0.4450	-0.3550	-0.6088	-0.4820	-0.3660
NET INCOME	-0.0190	-0.3260	-0.3540	-0.2750	-0.3560	-0.3280
NET UTILITY PLANT	-0.2935	-0.3740	-0.3200	-0.2730	-0.3450	-0.3199
TOTAL PROPRIETARY CAPITAL	-0.3070	-0.3740	-0.3200	-0.2730	-0.3450	-0.3199
TOTAL DEBT	-0.3064	-0.3740	-0.3200	-0.2690	-0.3470	-0.3170
TOTAL DEFERRED CREDITS	-0.0647	-0.3880	-0.5257	0.0	0.0	0.0
TOTAL SOURCES	-1.7580	-1.2570	-0.0947	-1.4410	0.0	0.0
TOTAL APPLICATIONS	-0.1173	-1.2570	-0.0947	0.0	0.0	0.0
RATE BASE	-0.2969	-0.3550	-0.3010	-0.2710	-0.3460	-0.3180
RETURN ON RATE BASE	-0.3252	-0.3420	-0.3000	-0.3140	-0.3280	-0.3107
REVENUE REQUIREMENTS	0.0	-0.0055	-0.0150	-0.0077	-0.0100	-0.0211
AVERAGE PRICE OF ELECTRICITY	0.0	-0.0099	-0.0084	0.0	-0.0097	-0.0084
# OF SHARES	-0.3630	-1.1720	-3.2010	0.0	0.0	0.0
AVAILABLE EARNINGS	3.1990	-0.4600	-0.3660	-0.6086	-0.4820	-0.3650

PARAMETER: A CWP IN RATE BASE
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1986	1993	1979	1986	1993
OUTPUT QUANTITY (RESPONSE)	0.0	0.0023	0.0018	0.0	0.0	0.0
ELECTRIC REVENUES	0.0	0.0009	0.0	0.0	-0.0049	-0.0043
TOTAL ELECTRIC EXPENSES	0.0	0.0101	0.0142	0.0	0.0	0.0
TOTAL INTEREST DEDUCTIONS	-0.0349	-0.0184	-0.0336	-0.1739	-0.0135	-0.0392
NET INCOME	-0.1360	-0.0179	-0.0232	-0.0093	-0.0182	-0.0016
NET UTILITY PLANT	-0.0061	-0.0215	-0.0245	-0.0117	-0.0275	-0.0240
TOTAL PROPRIETARY CAPITAL	-0.0112	-0.0233	-0.0204	-0.0141	-0.0226	-0.0262
TOTAL DEBT	-0.0107	-0.0234	-0.0205	-0.0133	-0.0212	-0.0259
TOTAL DEFERRED CREDITS	0.0	0.0	-0.0027	0.0	0.0	0.0
TOTAL SOURCES	-0.0556	-0.0067	-0.0103	-0.0544	0.0	0.0
TOTAL APPLICATIONS	-0.0335	-0.0067	-0.0103	-0.0247	0.0	0.0
RATE BASE	-0.0100	-0.0223	-0.0270	-0.0114	-0.0219	-0.0254
RETURN ON RATE BASE	-0.0101	-0.0214	-0.0270	0.0	-0.0243	-0.0244
REVENUE REQUIREMENTS	0.0130	-0.0007	-0.0014	0.0077	-0.0034	-0.0010
AVERAGE PRICE OF ELECTRICITY	0.0	0.0023	0.0018	0.0	-0.0004	-0.0010
# OF SHARES	0.0	-0.0335	-0.1740	0.0	0.0	0.0
AVERAGE BOOK VALUE	0.0	0.0	0.0420	0.0	0.0	0.0
AFUDC	-0.1530	-0.1740	-0.1640	-0.2136	-0.1617	-0.1720
AVAILABLE EARNINGS	-0.2710	-0.0159	-0.0351	-0.1739	-0.0264	-0.0342

PARAMETER: PREFERRED STOCK COR
RELATIVE SENSITIVITIES

YEAR	PRIVATE SECTOR			PUBLIC SECTOR		
	1979	1984	1993	1979	1984	1993
OUTPUT QUANTITY (RESPONSE)						
ELECTRIC REVENUES	0.0	0.0015	0.0011			
TOTAL ELECTRIC EXPENSES	0.0107	0.0084	0.0069			
TOTAL INTEREST DEDUCTIONS	-0.1747	-0.1415	-0.1234			
NET INCOME	0.1364	0.0627	0.0501			
TOTAL PROPRIETARY CAPITAL	0.1245	0.1247	0.1252			
TOTAL DEBT	-0.1217	-0.1222	-0.1221			
TOTAL SOURCES	0.0229	0.0314	0.0299			
TOTAL APPLICATIONS	0.0413	0.0314	0.0299			
RETURN ON RATE BASE	-0.0203	-0.0183	-0.0167			
REVENUE REQUIREMENTS	0.0043	0.0015	0.0021			
AVERAGE PRICE OF ELECTRICITY	0.0	0.0019	0.0009			
# OF SHARES	-0.1320	-0.4350	-1.2179			
AVERAGE BOOK VALUE	0.0	0.3000	1.0500			
AVAILABLE EARNINGS	-0.5060	-0.1507	-0.1675			

RELATIVE SENSITIVITIES FOR
ELECTRIC REVENUES

PRIVATE SECTOR					
YEAR	1979		1984		1993
PARAMETER		PARAMETER		PARAMETER	
ELECTRIC REVENUES	1.2560	GEN. INFLATION RATE	0.3470	GEN. INFLATION RATE	0.0570
FUEL ADJ. FOR TAXES	-0.0370	RET. ON COMMON EQUITY	0.2230	RET. ON COMMON EQUITY	0.2140
SALES TO ULTIMATES	-0.4150	FEDERAL TAX RATE	0.2080	FEDERAL TAX RATE	0.1640
GENERAL TAX RATE	0.0494	GENERAL TAX RATE	0.0403	RETURN ON NEW BONDS	0.1140
COMMON EQUITY COR	0.0	AFUDC RATE	-0.0821	AFUDC RATE	-0.0547
GEN. INFLATION RATE	0.0	LONG-TERM DEBT COR	-0.0752	GENERAL TAX RATE	0.0859
DEPRECIATION RATE	0.0	COMMON EQUITY COR	0.0722	LONG-TERM DEBT COR	-0.0689
RET. ON COMMON EQUITY	0.0	DISTRIBUTION	0.0690	COMMON EQUITY COR	0.0644
RET. ON S-TERM DEBT	0.0	RETURN ON NEW BONDS	0.0676	RET. ON PREFERRED STOCK	0.0494
RETURN ON NEW BONDS	0.0	STEAM PRODUCTION	0.0530	PROPERTY TAX RATE	0.0258
% FLOW THRU ADH*ITC	0.0	RET. ON PREFERRED STOCK	0.0514	DISTRIBUTION	0.0250
% FLOW THRU ADH*ITC	0.0	COST EMBEDDED DEBT	0.0400	STEAM PRODUCTION	0.0220
INVEST. TAX CREDIT	0.0	TRANSMISSION	0.0370	TRANSMISSION	0.0130
SALES TAX RATE	0.0	OUTSTANDING BONDS	-0.0192	% FLOW THRU ADH*ITC	-0.0113
PROPERTY TAX RATE	0.0	PROPERTY TAX RATE	0.0192	% FLOW THRU ADH*ITC	-0.0112
STATE TAX RATE	0.0	NUCLEAR PRODUCTION	0.0170	OUTSTANDING BONDS	-0.0094
PREFERRED STOCK COR	0.0	DEFERRED INCOME TAX	-0.0130	DEPRECIATION RATE	-0.0084
AFUDC RATE	0.0	% FLOW THRU ADH*ITC	-0.0115	INVEST. TAX CREDIT	-0.0074
LONG-TERM DEBT COR	0.0	DEPRECIATION RATE	-0.0099	RET. ON S-TERM DEBT	0.0079
% CWIP IN RATE BASE	0.0	RET. ON S-TERM DEBT	0.0084	NUCLEAR PRODUCTION	0.0069
DEFERRED INCOME TAX	0.0	GENERAL	0.0061	DEFERRED INCOME TAX	-0.0062
DEFERRED ITC	0.0	HYDRO CONV.	0.0054	STATE TAX RATE	0.0051
RET. ON PREFERRED STOCK	0.0	INVEST. TAX CREDIT	-0.0054	COST EMBEDDED DEBT	0.0036
COST EMBEDDED DEBT	0.0	STATE TAX RATE	0.0054	SALES TAX RATE	0.0022
OUTSTANDING BONDS	0.0	OTHER PRODUCTION	0.0046	GENERAL	0.0022
GENERAL	0.0	DEFERRED ITC	-0.0031	HYDRO CONV.	0.0018
DISTRIBUTION	0.0	% FLOW THRU ADH*ITC	-0.0031	OTHER PRODUCTION	0.0018
TRANSMISSION	0.0	% CWIP IN RATE BASE	0.0023	% CWIP IN RATE BASE	0.0018
OTHER PRODUCTION	0.0	PREFERRED STOCK COR	0.0015	DEFERRED ITC	-0.0015
HYDRO CONV.	0.0	SALES TAX RATE	0.0015	PREFERRED STOCK COR	0.0011
NUCLEAR PRODUCTION	0.0	ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
STEAM PRODUCTION	0.0	FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
FEDERAL TAX RATE	0.0	SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR
ELECTRIC REVENUES

PUBLIC SECTOR						
YEAR	1979		1986		1993	
PARAMETER			PARAMETER		PARAMETER	
ELECTRIC REVENUES	1.3840		GEN. INFLATION RATE	0.4018	GEN. INFLATION RATE	0.8465
FUEL ADJ. FOR TAXES	-0.9624		RET. ON COMMON EQUITY	0.1833	RET. ON COMMON EQUITY	0.1711
SALES TO ULTIMATES	-0.3588		RETURN ON NEW BONDS	0.0802	RETURN ON NEW BONDS	0.1190
GENERAL TAX RATE	0.0039		AFUDC RATE	-0.0611	AFUDC RATE	-0.0691
GEN. INFLATION RATE	0.0		HYDRO CONV.	0.0420	GENERAL TAX RATE	0.0274
RET. ON COMMON EQUITY	0.0		COST EMBEDDED DEBT	0.0343	PROPERTY TAX RATE	0.0276
DEPRECIATION RATE	0.0		STEAM PRODUCTION	0.0270	COMMON EQUITY COR	0.0190
RETURN ON NEW BONDS	0.0		GENERAL TAX RATE	0.0267	LONG-TERM DEBT COR	-0.0190
SALES TAX RATE	0.0		TRANSMISSION	0.0230	HYDRO CONV.	0.0139
PROPERTY TAX RATE	0.0		DISTRIBUTION	0.0230	STEAM PRODUCTION	0.0086
STATE TAX RATE	0.0		LONG-TERM DEBT COR	-0.0229	DEPRECIATION RATE	-0.0086
AFUDC RATE	0.0		COMMON EQUITY COR	0.0226	OUTSTANDING BONDS	-0.0069
RET. ON S-TERM DEBT	0.0		PROPERTY TAX RATE	0.0224	GENERAL	0.0069
LONG-TERM DEBT COR	0.0		GENERAL	0.0191	TRANSMISSION	0.0069
% CHIP IN RATE BASE	0.0		OUTSTANDING BONDS	-0.0153	DISTRIBUTION	0.0069
COST EMBEDDED DEBT	0.0		NUCLEAR PRODUCTION	-0.0076	STATE TAX RATE	0.0035
OUTSTANDING BONDS	0.0		DEPRECIATION RATE	-0.0076	COST EMBEDDED DEBT	0.0035
GENERAL	0.0		STATE TAX RATE	0.0038	NUCLEAR PRODUCTION	0.0034
DISTRIBUTION	0.0		% CHIP IN RATE BASE	0.0	% CHIP IN RATE BASE	0.0
TRANSMISSION	0.0		SALES TAX RATE	0.0	SALES TAX RATE	0.0
OTHER PRODUCTION	0.0		ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
HYDRO CONV.	0.0		RET. ON S-TERM DEBT	0.0	RET. ON S-TERM DEBT	0.0
NUCLEAR PRODUCTION	0.0		FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
STEAM PRODUCTION	0.0		OTHER PRODUCTION	0.0	OTHER PRODUCTION	0.0
COMMON EQUITY COR	0.0		SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

PRIVATE SECTOR

D-20

-PUBLIC SECTOR

D-21

RELATIVE SENSITIVITIES FOR

TOTAL INTEREST DEDUCTIONS

PRIVATE SECTOR

YEAR	1979	1986	1993
PARAMETER			
COST EMBEDDED DEBT	0.2960	0.7600	1.1440
LONG-TERM DEBT COR	0.6115	-0.5960	0.7780
DEPRECIATION RATE	-0.4470	-0.4240	0.4980
COMMON EQUITY COR	-0.4710	-0.4145	-0.4220
STEAM PRODUCTION	0.3420	0.3440	-0.3416
OUTSTANDING BONDS	-0.3420	0.3133	-0.3080
AFUDC RATE	-0.3320	-0.2426	0.1374
DISTRIBUTION	0.3140	-0.1920	-0.1234
TRANSMISSION	0.1750	-0.1415	-0.0750
PREFERRED STOCK COR	-0.1747	0.1410	-0.0619
RET. ON COMMON EQUITY	0.1320	0.1410	0.0340
RETURN ON NEW BONDS	0.0874	0.1110	0.0332
DEFERRED INCOME TAX	-0.0874	0.0707	0.0330
NUCLEAR PRODUCTION	0.0070	-0.2505	0.0290
GEN. INFLATION RATE	-0.0524	-0.0404	-0.0285
RET. ON S-TERM DEBT	0.0524	-0.0404	-0.0142
HYDRO CONV.	0.0350	0.0400	0.0142
RET. ON PREFER. STOCK	0.0349	0.0303	0.0142
% CHIP IN RATE BASE	0.0349	0.0303	0.0142
DEFERRED ITC	-0.0349	0.0303	0.0142
SHORT-TERM DEBT COR	0.0175	0.0101	0.0047
INVEST. TAX CREDIT	-0.0175	-0.0101	0.0
GENERAL	0.0170	0.0101	0.0
FEDERAL TAX RATE	0.0	0.0100	0.0
% FLOW THRU ADP*ITC	0.0	0.0	0.0
PARAMETER			
RETURN ON NEW BONDS	0.7600	1.1440	
LONG-TERM DEBT COR	-0.5960	0.7780	
DEPRECIATION RATE	-0.4240	0.4980	
COMMON EQUITY COR	-0.4145	-0.4220	
COST EMBEDDED DEBT	0.3440	-0.3416	
GEN. INFLATION RATE	0.3133	-0.3080	
AFUDC RATE	-0.2426	0.1374	
OUTSTANDING BONDS	-0.1920	-0.1234	
PREFERRED STOCK COR	-0.1415	-0.0750	
DISTRIBUTION	0.1410	-0.0619	
STEAM PRODUCTION	0.1410	0.0340	
RET. ON COMMON EQUITY	0.1110	0.0332	
TRANSMISSION	0.0707	0.0330	
INVEST. TAX CREDIT	-0.2505	0.0290	
FEDERAL TAX RATE	-0.0404	-0.0285	
DEFERRED INCOME TAX	-0.0404	-0.0142	
NUCLEAR PRODUCTION	0.0400	0.0142	
RET. ON PREFER. STOCK	0.0303	0.0142	
SHORT-TERM DEBT COR	0.0303	0.0142	
% FLOW THRU ADP*ITC	0.0303	0.0142	
% CHIP IN RATE BASE	0.0101	0.0047	
DEFERRED ITC	-0.0101	0.0	
GENERAL	0.0101	0.0	
HYDRO CONV.	0.0100	0.0	
RET. ON S-TERM DEBT	0.0	0.0	

RELATIVE SENSITIVITIES FOR

TOTAL INTEREST DEDUCTIONS

PUBLIC SECTOR

YEAR	1979	1986	1993
PARAMETER			
COST EMBEDDED DEBT	0.2200	0.0303	1.1060
COMMON EQUITY COR	-0.0279	-0.6327	0.7592
LONG-TERM DEBT COR	0.7357	0.5931	-0.4784
DEPRECIATION RATE	-0.5520	-0.3954	0.4620
AFUDC RATE	-0.4600	0.3554	-0.4126
OUTSTANDING BONDS	-0.3600	-0.2760	-0.2970
HYDRO CONV.	0.2760	0.2370	0.1320
RET. ON COMMON EQUITY	0.1840	-0.1580	-0.0165
STEAM PRODUCTION	0.1840	0.1190	0.0165
TRANSMISSION	0.0920	0.1100	0.0
GENERAL	0.0920	0.0790	0.0
DISTRIBUTION	0.0920	0.0390	0.0
RETURN ON NEW BONDS	0.0220	0.0390	0.0
SHORT-TERM DEBT COR	0.0	0.0390	0.0
% CHIP IN RATE BASE	0.0	0.0	0.0
GEN. INFLATION RATE	0.0	0.0	0.0
NUCLEAR PRODUCTION	0.0	0.0	0.0
RET. ON S-TERM DEBT	0.0	0.0	0.0
PARAMETER			
RETURN ON NEW BONDS	0.0303	1.1060	
COMMON EQUITY COR	-0.6327	0.7592	
LONG-TERM DEBT COR	0.5931	-0.4784	
DEPRECIATION RATE	-0.3954	0.4620	
AFUDC RATE	0.3554	-0.4126	
OUTSTANDING BONDS	-0.2760	-0.2970	
HYDRO CONV.	0.2370	0.1320	
RET. ON COMMON EQUITY	-0.1580	-0.0165	
STEAM PRODUCTION	0.1190	0.0165	
TRANSMISSION	0.1100	0.0	
GENERAL	0.0790	0.0	
DISTRIBUTION	0.0390	0.0	
RETURN ON NEW BONDS	0.0390	0.0	
SHORT-TERM DEBT COR	0.0	0.0	
% CHIP IN RATE BASE	0.0	0.0	
GEN. INFLATION RATE	0.0	0.0	
NUCLEAR PRODUCTION	0.0	0.0	
RET. ON S-TERM DEBT	0.0	0.0	

RELATIVE SENSITIVITIES FOR

NET INCOME

PRIVATE SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	
ELECTRIC REVENUES	7.6410	RET. ON COMMON EQUIT	0.8897
FUEL ADJ. FOR TAXES	-5.0000	LONG-TERM DEBT CON	-0.5320
SALES TO ULTIMATES	-2.5200	COMMON EQUITY COR	-0.4574
DEPRECIATION RATE	-0.0190	DEPRECIATION RATE	-0.4450
AFUDC RATE	0.0100	RETURN ON NEW BONDS	-0.2510
FEDERAL TAX RATE	-0.7050	GEN. INFLATION RATE	0.2380
COST EMBEDDED DEBT	-0.6820	RET. ON PREFER. STOCK	0.2070
DISTRIBUTION	-0.6360	DISTRIBUTION	0.1190
LONG-TERM DEBT CON	-0.5450	STEAM PRODUCTION	0.1190
STEAM PRODUCTION	-0.5000	FEDERAL TAX RATE	0.0752
COMMON EQUITY COR	0.4024	% FLOW THRU ACH*ITC	-0.0427
TRANSMISSION	-0.3410	PREFERRED STOCK COR	-0.0627
OUTSTANDING BONDS	0.2270	AFUDC RATE	-0.0624
GENERAL TAX RATE	-0.2270	TRANSMISSION	0.0624
RETURN ON NEW BONDS	-0.1820	COST EMBEDDED DEBT	0.0434
PREFERRED STOCK COR	0.1364	DEFERRED INCOME TAX	-0.0438
% CHIP IN RATE BASE	-0.1360	INVEST. TAX CREDIT	-0.0374
NUCLEAR PRODUCTION	-0.1360	RET. ON S-TERM DEBT	0.0317
INVEST. TAX CREDIT	-0.1137	NUCLEAR PRODUCTION	-0.0313
DEFERRED ITC	0.0682	PROPERTY TAX RATE	-0.0251
GENERAL	-0.0680	% CHIP IN RATE BASE	-0.0108
DEFERRED INCOME TAX	0.0455	OUTSTANDING BONDS	-0.0104
GEN. INFLATION RATE	-0.0455	% FLOW D/PORT AFUDC	-0.0124
RET. ON S-TERM DEBT	-0.0455	GLACIAL	0.0063
HYDRO CONV.	-0.0450	SHORT-TERM DEBT CON	0.0063
% FLOW THRU ACH*ITC	-0.0227	DEFERRED ITC	0.0063
SHORT-TERM DEBT CON	-0.0227	HYDRO CONV.	0.0063
STATE TAX RATE	-0.0227	STATE TAX RATE	0.0
PROPERTY TAX RATE	-0.0227	GENERAL TAX RATE	0.0
% FLOW D/PORT AFUDC	0.0	FUEL ADJ. FOR TAXES	0.0
RET. ON COMMON EQUIT	0.0	ELECTRIC REVENUES	0.0
RET. ON PREFER. STOCK	0.0	SALES TO ULTIMATES	0.0
		PARAMETER	
		RET. ON COMMON EQUIT	0.8810
		GEN. INFLATION RATE	0.7560
		LONG-TERM DEBT CON	-0.5110
		COMMON EQUITY COR	-0.4405
		DEPRECIATION RATE	-0.3550
		RET. ON PREFER. STOCK	0.2050
		FEDERAL TAX RATE	0.0979
		% FLOW THRU ACH*ITC	-0.0794
		PREFERRED STOCK COR	0.0401
		% FLOW D/PORT AFUDC	-0.0459
		DISTRIBUTION	0.0328
		STEAM PRODUCTION	0.0340
		OUTSTANDING BONDS	-0.0367
		RET. ON S-TERM DEBT	0.0334
		% CHIP IN RATE BASE	-0.0336
		INVEST. TAX CREDIT	-0.0306
		AFUDC RATE	-0.0214
		TRANSMISSION	0.0210
		PROPERTY TAX RATE	-0.0184
		DEFERRED INCOME TAX	-0.0183
		COST EMBEDDED DEBT	0.0153
		NUCLEAR PRODUCTION	0.0122
		SHORT-TERM DEBT CON	0.0092
		STATE TAX RATE	0.0031
		GENERAL	0.0031
		DEFERRED ITC	0.0031
		HYDRO CONV.	0.0030
		GENERAL TAX RATE	0.0
		RETURN ON NEW BONDS	0.0
		FUEL ADJ. FOR TAXES	0.0
		ELECTRIC REVENUES	0.0
		SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR

NET INCOME

PUBLIC SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		RET. ON COMMON EQUIT	1.2310	PARAMETER	
ELECTRIC REVENUES	12.0870	LONG-TERM DEBT COR	-0.0426	RET. ON COMMON EQUIT	1.2270
SALES TO ULTIMATES	-3.3000	COMMON EQUITY COR	0.6425	GEN. INFLATION RATE	0.6659
LONG-TERM DEBT COR	-0.9505	DEPRECIATION RATE	-0.4920	LONG-TERM DEBT COR	-0.6267
COST EMBEDDED DEBT	-0.9560	GEN. INFLATION RATE	0.1874	COMMON EQUITY COR	-0.6131
COMMON EQUITY COR	0.8695	RETURN ON NEW BONDS	-0.1070	DEPRECIATION RATE	-0.3660
AFUDC RATE	0.7430	HYDRO CONV.	0.1070	RETURN ON NEW BONDS	-0.1040
HYDRO CONV.	-0.6000	STEAM PRODUCTION	0.0000	% CHIP IN RATE BASE	-0.0392
DEPRECIATION RATE	-0.6068	DISTRIBUTION	0.0540	PROPERTY TAX RATE	-0.0392
STEAM PRODUCTION	-0.4340	TRANSMISSION	0.0535	AFUDC RATE	-0.0392
DISTRIBUTION	-0.3480	COST EMBEDDED DEBT	-0.0535	HYDRO CONV.	0.0390
TRANSMISSION	-0.3480	PROPERTY TAX RATE	-0.0535	STEAM PRODUCTION	0.0260
RETURN ON NEW BONDS	-0.3480	AFUDC RATE	-0.0535	OUTSTANDING BONDS	-0.0131
FUEL ADJ. FOR TAXES	-0.2610	GENERAL	0.0535	TRANSMISSION	0.0130
OUTSTANDING BONDS	0.2610	% CHIP IN RATE BASE	-0.0135	DISTRIBUTION	0.0130
% CHIP IN RATE BASE	-0.1739	SHORT-TERM DEBT COR	0.0	COST EMBEDDED DEBT	0.0130
GENERAL TAX RATE	-0.1739	FUEL ADJ. FOR TAXES	0.0	GENERAL	0.0130
PROPERTY TAX RATE	-0.0009	OUTSTANDING BONDS	0.0	SHORT-TERM DEBT COR	0.0
GENERAL	-0.0347	GENERAL TAX RATE	0.0	FUEL ADJ. FOR TAXES	0.0
SHORT-TERM DEBT COR	0.0	RET. ON S-TERM DEBT	0.0	GENERAL TAX RATE	0.0
RET. ON COMMON EQUIT	0.0	ELECTRIC REVENUES	0.0	RET. ON S-TERM DEBT	0.0
RET. ON S-TERM DEBT	0.0	NUCLEAR PRODUCTION	0.0	ELECTRIC REVENUES	0.0
NUCLEAR PRODUCTION	0.0	STATE TAX RATE	0.0	NUCLEAR PRODUCTION	0.0
STATE TAX RATE	0.0	SALES TO ULTIMATES	0.0	STATE TAX RATE	0.0
GEN. INFLATION RATE	0.0			SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR

TOTAL UTILITY PLANT

PRIVATE SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		GEN. INFLATION RATE	0.2670	PARAMETER	
STEAM PRODUCTION	0.2360	STEAM PRODUCTION	0.1410	GEN. INFLATION RATE	0.6897
DISTRIBUTION	0.2150	DISTRIBUTION	0.1290	STEAM PRODUCTION	0.0700
TRANSMISSION	0.1150	TRANSMISSION	0.0690	DISTRIBUTION	0.0640
NUCLEAR PRODUCTION	0.0650	AFUDC RATE	-0.0411	AFUDC RATE	-0.0533
GEN. INFLATION RATE	0.0517	NUCLEAR PRODUCTION	0.0390	TRANSMISSION	0.0340
AFUDC RATE	-0.0727	% CHIP IN RATE BASE	-0.0175	% CHIP IN RATE BASE	-0.0239
HYDRO CONV.	0.0190	HYDRO CONV.	0.0160	NUCLEAR PRODUCTION	0.0190
GENERAL	0.0102	GENERAL	0.0109	HYDRO CONV.	0.0057
OTHER PRODUCTION	0.0105	OTHER PRODUCTION	0.0099	GENERAL	0.0053
% CHIP IN RATE BASE	-0.0001			OTHER PRODUCTION	0.0048

RELATIVE SENSITIVITIES FOR
TOTAL UTILITY PLANT

PUBLIC SECTOR					
YEAR	1979		1986		1993
PARAMETER		PARAMETER		PARAMETER	
HYDRO CONV.	0.1910	GEN. INFLATION RATE	0.2834	GEN. INFLATION RATE	0.7091
STEAM PRODUCTION	-0.1728	HYDRO CONV.	0.1100	AFUDC RATE	-0.0547
TRANSMISSION	0.1000	STEAM PRODUCTION	0.0720	HYDRO CONV.	0.0936
DISTRIBUTION	0.0970	TRANSMISSION	0.0590	STEAM PRODUCTION	0.0345
GENERAL	0.0470	DISTRIBUTION	0.0560	TRANSMISSION	0.0200
GEN. INFLATION RATE	0.0576	GENERAL	0.0500	DISTRIBUTION	0.0270
NUCLEAR PRODUCTION	0.0390	AFUDC RATE	-0.0420	GENERAL	0.0240
AFUDC RATE	-0.0353	NUCLEAR PRODUCTION	0.0235	NUCLEAR PRODUCTION	-0.0113
OTHER PRODUCTION	0.0148	% CHIP IN RATE BASE	-0.0102	OTHER PRODUCTION	0.0041
% CHIP IN RATE BASE	-0.0093	OTHER PRODUCTION	0.0008	% CHIP IN RATE BASE	-0.0016

RELATIVE SENSITIVITIES FOR
NET UTILITY PLANT

PRIVATE SECTOR					
YEAR	1979		1986		1993
PARAMETER		PARAMETER		PARAMETER	
DEPRECIATION RATE	-0.2935	DEPRECIATION RATE	-0.3860	GEN. INFLATION RATE	0.0060
STEAM PRODUCTION	0.2010	GEN. INFLATION RATE	0.3650	DEPRECIATION RATE	-0.3540
DISTRIBUTION	0.1830	DISTRIBUTION	0.1290	AFUDC RATE	-0.0655
TRANSMISSION	0.0970	STEAM PRODUCTION	0.0430	% CHIP IN RATE BASE	-0.0264
GEN. INFLATION RATE	0.0659	AFUDC RATE	-0.0532	STEAM PRODUCTION	0.0102
NUCLEAR PRODUCTION	0.0556	TRANSMISSION	0.0404	DISTRIBUTION	0.0160
AFUDC RATE	-0.0417	NUCLEAR PRODUCTION	0.0220	TRANSMISSION	0.0088
HYDRO CONV.	0.0160	% CHIP IN RATE BASE	-0.0215	NUCLEAR PRODUCTION	0.0049
GENERAL	0.0150	HYDRO CONV.	0.0060	GENERAL	0.0014
OTHER PRODUCTION	0.0144	GENERAL	0.0065	HYDRO CONV.	0.0014
% CHIP IN RATE BASE	-0.0098	OTHER PRODUCTION	0.0050	OTHER PRODUCTION	0.0012

RELATIVE SENSITIVITIES FOR
NET UTILITY PLANT

PUBLIC SECTOR					
YEAR	1979		1986		1993
PARAMETER		PARAMETER		PARAMETER	
DEPRECIATION RATE	-0.2750	GEN. INFLATION RATE	0.3760	GEN. INFLATION RATE	0.0920
HYDRO CONV.	0.1410	DEPRECIATION RATE	-0.3560	DEPRECIATION RATE	-0.3280
STEAM PRODUCTION	0.1020	HYDRO CONV.	0.0620	AFUDC RATE	-0.0661
TRANSMISSION	0.0940	AFUDC RATE	-0.0549	% CHIP IN RATE BASE	-0.0268
DISTRIBUTION	0.0790	STEAM PRODUCTION	0.0390	HYDRO CONV.	0.0130
GENERAL	0.0723	TRANSMISSION	0.0320	STEAM PRODUCTION	0.0045
GEN. INFLATION RATE	0.0699	DISTRIBUTION	0.0310	TRANSMISSION	0.0072
AFUDC RATE	-0.0443	GENERAL	0.0281	DISTRIBUTION	0.0046
NUCLEAR PRODUCTION	0.0326	% CHIP IN RATE BASE	-0.0225	GENERAL	0.0050
OTHER PRODUCTION	0.0117	NUCLEAR PRODUCTION	0.0120	NUCLEAR PRODUCTION	0.0026
% CHIP IN RATE BASE	-0.0117	OTHER PRODUCTION	0.0042	OTHER PRODUCTION	0.0007

RELATIVE SENSITIVITIES FOR

WORKING CAPITAL

PRIVATE SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
GEN. INFLATION RATE	0.0	GEN. INFLATION RATE	0.5040	GEN. INFLATION RATE	1.0260

RELATIVE SENSITIVITIES FOR

WORKING CAPITAL

PUBLIC SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
GEN. INFLATION RATE	0.0	GEN. INFLATION RATE	0.5263	GEN. INFLATION RATE	1.0300

RELATIVE SENSITIVITIES FOR

TOTAL PROPRIETARY CAPITAL

PRIVATE SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		PARAMETER		PARAMETER	
LONG-TERM DEBT COR	-0.4913	LONG-TERM DEBT COR	-0.4916	GEN. INFLATION RATE	0.9173
COMMON EQUITY COR	0.3847	COMMON EQUITY COR	0.3851	LONG-TERM DEBT COR	-0.4912
DEPRECIATION RATE	-0.3070	GEN. INFLATION RATE	0.3820	COMMON EQUITY COR	-0.3853
STEAM PRODUCTION	0.2110	DEPRECIATION RATE	-0.3740	DEPRECIATION RATE	-0.3200
DISTRIBUTION	0.1940	PREFERRED STOCK COR	0.1247	PREFERRED STOCK COR	0.1252
PREFERRED STOCK COR	0.1245	STEAM PRODUCTION	0.0860	INVEST. TAX CREDIT	-0.0617
TRANSMISSION	0.1030	DISTRIBUTION	0.0820	FEDERAL TAX RATE	-0.0471
GEN. INFLATION RATE	0.0673	TRANSMISSION	0.0440	AFUDC RATE	-0.0418
NUCLEAR PRODUCTION	0.0570	INVEST. TAX CREDIT	-0.0423	% FLOW THRU ADR*ITC	0.0299
DEFERRED INCOME TAX	-0.0494	AFUDC RATE	-0.0386	% CWIP IN RATE BASE	-0.0286
AFUDC RATE	-0.0426	FEDERAL TAX RATE	-0.0365	STEAM PRODUCTION	0.0220
DEFERRED ITC	-0.0247	DEFERRED INCOME TAX	-0.0321	SHORT-TERM DEBT COR	-0.0195
SHORT-TERM DEBT COR	-0.0202	NUCLEAR PRODUCTION	0.0240	DISTRIBUTION	0.0181
HYDRO CONV.	0.0168	% CWIP IN RATE BASE	-0.0233	DEFERRED INCOME TAX	-0.0153
GENERAL	0.0160	% FLOW THRU ADR*ITC	0.0219	TRANSMISSION	0.0097
OTHER PRODUCTION	0.0146	SHORT-TERM DEBT COR	-0.0197	NUCLEAR PRODUCTION	0.0073
% CWIP IN RATE BASE	-0.0112	DEFERRED ITC	0.0102	DEFERRED ITC	0.0024
INVEST. TAX CREDIT	-0.0079	GENERAL	0.0066	HYDRO CONV.	0.0017
FEDERAL TAX RATE	-0.0048	HYDRO CONV.	0.0066	OTHER PRODUCTION	0.0014
% FLOW THRU ADR*ITC	0.0022	OTHER PRODUCTION	0.0058	GENERAL	0.0014

RELATIVE SENSITIVITIES FOR
TOTAL PROPRIETARY CAPITAL

PUBLIC SECTOR			
YEAR	1979	1986	1993
PARAMETER		PARAMETER	
COMMON EQUITY COR	0.5044	COMMON EQUITY COR	0.5117
LONG-TERM DEBT COR	-0.5041	LONG-TERM DEBT COR	-0.5032
DEPRECIATION RATE	-0.2730	GEN. INFLATION RATE	0.3814
HYDRO CONV.	0.1550	DEPRECIATION RATE	-0.3450
STEAM PRODUCTION	0.4940	HYDRO CONV.	0.0420
TRANSMISSION	0.0820	AFUDC RATE	-0.0537
DISTRIBUTION	0.0750	STEAM PRODUCTION	0.0390
GENERAL	0.0704	TRANSMISSION	0.0310
GEN. INFLATION RATE	0.0659	DISTRIBUTION	0.0310
AFUDC RATE	-0.0471	GENERAL	0.0202
NUCLEAR PRODUCTION	-0.0330	% CWIP IN RATE BASE	-0.0226
SHORT-TERM DEBT COR	-0.0141	NUCLEAR PRODUCTION	0.0140
% CWIP IN RATE BASE	-0.0141	SHORT-TERM DEBT COR	-0.0113
OTHER PRODUCTION	0.0094	OTHER PRODUCTION	0.0056
		PARAMETER	
		GEN. INFLATION RATE	0.0962
		COMMON EQUITY COR	0.5118
		LONG-TERM DEBT COR	-0.5039
		DEPRECIATION RATE	-0.3190
		AFUDC RATE	-0.0643
		% CWIP IN RATE BASE	-0.0262
		HYDRO CONV.	0.0130
		SHORT-TERM DEBT COR	-0.0105
		STEAM PRODUCTION	0.0078
		TRANSMISSION	0.0046
		GENERAL	0.0066
		DISTRIBUTION	0.0056
		NUCLEAR PRODUCTION	0.0026
		OTHER PRODUCTION	0.0013

RELATIVE SENSITIVITIES FOR
TOTAL DEBT

PRIVATE SECTOR			
YEAR	1979	1986	1993
PARAMETER		PARAMETER	
LONG-TERM DEBT COR	0.4665	LONG-TERM DEBT COR	0.4664
COMMON EQUITY COR	-0.3672	GEN. INFLATION RATE	0.3820
DEPRECIATION RATE	-0.3064	DEPRECIATION RATE	-0.3740
STEAM PRODUCTION	0.2110	COMMON EQUITY COR	-0.3672
DISTRIBUTION	0.1970	PREFERRED STOCK COR	-0.1222
PREFERRED STOCK COR	-0.1217	STEAM PRODUCTION	0.0860
TRANSMISSION	0.1040	DISTRIBUTION	0.0820
GEN. INFLATION RATE	0.0683	TRANSMISSION	0.0440
NUCLEAR PRODUCTION	0.0530	INVEST. TAX CREDIT	-0.0423
DEFERRED INCOME TAX	-0.0430	AFUDC RATE	-0.0302
AFUDC RATE	-0.0416	FEDERAL TAX RATE	-0.0368
DEFERRED ITC	-0.0246	DEFERRED INCOME TAX	-0.0319
SHORT-TERM DEBT COR	0.0172	NUCLEAR PRODUCTION	0.0250
HYDRO CONV.	0.0100	% CWIP IN RATE BASE	-0.0236
GENERAL	0.0171	% FLOW THRU ADP*ITC	0.0215
OTHER PRODUCTION	0.0150	SHORT-TERM DEBT COR	0.0187
% CWIP IN RATE BASE	-0.0107	DEFERRED ITC	-0.0104
INVEST. TAX CREDIT	-0.0064	GENERAL	0.0066
FEDERAL TAX RATE	-0.0043	HYDRO CONV.	0.0069
% FLOW THRU ADP*ITC	0.0032	OTHER PRODUCTION	0.0055
		PARAMETER	
		GEN. INFLATION RATE	0.9170
		LONG-TERM DEBT COR	0.4665
		COMMON EQUITY COR	-0.3669
		DEPRECIATION RATE	-0.3200
		PREFERRED STOCK COR	-0.1221
		INVEST. TAX CREDIT	-0.0617
		FEDERAL TAX RATE	-0.0464
		AFUDC RATE	-0.0421
		% FLOW THRU ADP*ITC	0.0302
		% CWIP IN RATE BASE	-0.0205
		STEAM PRODUCTION	0.0220
		SHORT-TERM DEBT COR	0.0189
		DISTRIBUTION	0.0180
		DEFERRED INCOME TAX	-0.0153
		TRANSMISSION	0.0096
		NUCLEAR PRODUCTION	0.0073
		DEFERRED ITC	-0.0023
		HYDRO CONV.	0.0017
		OTHER PRODUCTION	0.0013
		GENERAL	0.0013

RELATIVE SENSITIVITIES FOR

TOTAL DEBT

PUBLIC SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		COMMON EQUITY COR	-0.4828	GEN. INFLATION RATE	0.0964
COMMON EQUITY COR	-0.4819	LONG-TERM DEBT COR	0.4722	COMMON EQUITY COR	-0.4827
LONG-TERM DEBT COR	0.4731	GEN. INFLATION RATE	0.3793	LONG-TERM DEBT COR	0.4728
DEPRECIATION RATE	-0.2690	DEPRECIATION RATE	-0.3470	DEPRECIATION RATE	-0.3176
HYDRO CONV.	0.1550	HYDRO CONV.	0.0610	AFUDC RATE	-0.0640
STEAM PRODUCTION	0.1010	AFUDC RATE	-0.0531	% CWIP IN RATE BASE	-0.0259
TRANSMISSION	0.0840	STEAM PRODUCTION	0.0390	HYDRO CONV.	0.0135
DISTRIBUTION	0.0796	TRANSMISSION	0.0320	SHORT-TERM DEBT COR	0.0079
GENERAL	0.0707	DISTRIBUTION	0.0290	STEAM PRODUCTION	0.0086
GEN. INFLATION RATE	0.0707	GENERAL	0.0265	TRANSMISSION	0.0074
AFUDC RATE	-0.0442	% CWIP IN RATE BASE	-0.0212	GENERAL	0.0062
NUCLEAR PRODUCTION	0.0310	NUCLEAR PRODUCTION	0.0130	DISTRIBUTION	0.0062
% CWIP IN RATE BASE	-0.0133	SHORT-TERM DEBT COR	0.0079	NUCLEAR PRODUCTION	0.0025
SHORT-TERM DEBT COR	0.0008	OTHER PRODUCTION	0.0026	OTHER PRODUCTION	0.0012
OTHER PRODUCTION	0.0008				

RELATIVE SENSITIVITIES FOR

TOTAL DEFERRED CREDITS

PRIVATE SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		DEPRECIATION RATE	-0.3880	GEN. INFLATION RATE	0.6780
DEFERRED INCOME TAX	0.5760	INVEST. TAX CREDIT	0.3440	DEPRECIATION RATE	-0.5257
DEFERRED ITC	0.2913	FEDERAL TAX RATE	0.3020	INVEST. TAX CREDIT	0.4870
INVEST. TAX CREDIT	0.0941	DEFERRED INCOME TAX	0.2640	FEDERAL TAX RATE	0.3710
DEPRECIATION RATE	-0.0647	GEN. INFLATION RATE	0.2530	% FLOW THRU ADR*ITC	-0.2379
FEDERAL TAX RATE	0.0453	AFUDC RATE	-0.1645	AFUDC RATE	-0.2340
% FLOW THRU ADR*ITC	-0.0380	% FLOW THRU ADR*ITC	-0.1498	DEFERRED INCOME TAX	0.1190
AFUDC RATE	-0.0259	DEFERRED ITC	0.0852	DEFERRED ITC	0.0188
STEAM PRODUCTION	0.0250	STEAM PRODUCTION	0.0350	STEAM PRODUCTION	-0.0160
GEN. INFLATION RATE	0.0194	NUCLEAR PRODUCTION	0.0	NUCLEAR PRODUCTION	-0.0160
NUCLEAR PRODUCTION	0.0065	% CWIP IN RATE BASE	0.0	% CWIP IN RATE BASE	-0.0027
% CWIP IN RATE BASE	0.0				

RELATIVE SENSITIVITIES FOR

TOTAL DEFERRED CREDITS

PUBLIC SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		% CWIP IN RATE BASE	0.0	% CWIP IN RATE BASE	0.0
% CWIP IN RATE BASE	0.0	DEPRECIATION RATE	0.0	DEPRECIATION RATE	0.0
DEPRECIATION RATE	0.0	GEN. INFLATION RATE	0.0	GEN. INFLATION RATE	0.0
GEN. INFLATION RATE	0.0	AFUDC RATE	0.0	AFUDC RATE	0.0
AFUDC RATE	0.0	NUCLEAR PRODUCTION	0.0	NUCLEAR PRODUCTION	0.0
NUCLEAR PRODUCTION	0.0	STEAM PRODUCTION	0.0	STEAM PRODUCTION	0.0
STEAM PRODUCTION	0.0				

PRIVATE SECTOR

PARAMETER	
DEPRECIATION RATE	-1.2570
GEN. INFLATION RATE	0.0510
RET. ON COMMON EQUITY	0.2360
COM. DIV. PAYOUT RAT	0.2020
AFUDC RATE	-0.1820
LONG-TERM DEBT COR	-0.1527
COMMON EQUITY COR	0.1145
RET. ON PREFER. STOCK	0.0741
DISTRIBUTION	0.0340
STEAM PRODUCTION	0.0330
PREFERRED STOCK COR	0.0314
FEDERAL TAX RATE	0.1175
TRANSMISSION	0.0175
% FLOW THRU ADW*ITC	-0.0157
DEFERRED INCOME TAX	-0.0112
COST EMBEDDED DEBT	0.0112
INVEST. TAX CREDIT	-0.0112
RET. ON S-TERM DEBT	0.0089
NUCLEAR PRODUCTION	0.0089
RETURN ON NEW BONDS	-0.0067
% CHG IN RATE BASE	-0.0067
PROPERTY TAX RATE	-0.0067
OUTSTANDING BONDS	-0.0045
OTHER PRODUCTION	0.0025
SHORT-TERM DEBT COR	0.0022
DEFERRED ITC	0.0022
%FLOW D/PORT AFUDC	-0.0022
GENERAL	0.0022
HYDRO CONV.	0.0022
SHORT-TERM DEBT	0.0
GENERAL TAX RATE	0.0
ELECTRIC REVENUES	0.0
FUEL ADJ. FOR TAXES	0.0
RETAINED EARNINGS	0.0
PREFERRED STOCK	0.0
COMMON STOCK	0.0
SALES TO ULTIMATES	0.0

	1993
PARAMETER	
GEN. INFLATION RATE	1.1210
RET. ON COMMON EQUITY	0.2120
COM. DIV. PAYOUT RAT	0.1957
AFUCC RATE	-0.1210
LONG-TERM DEBT COR	-0.1369
COMMON EQUITY COR	-0.1019
DEPRECIATION RATE	-0.0947
RET. ON PREFER. STOCK	0.0490
PREFERRED STOCK COR	0.0279
FEDERAL TAX RATE	0.0728
% FLOW THRU ADJUSTC	-0.0176
% FLOW D/PORT AFUCC	-0.0113
% CTRIP IN RATE BASE	-0.0193
OUTSTANDING BONDS	-0.0103
STEAM PRODUCTION	7.0103
DISTRIBUTION	0.0023
INVEST. TAX CREDIT	-0.0092
RET. ON S-TERM DEBT	0.0082
PROPERTY TAX RATE	-0.0052
RETURN ON NEW BONDS	0.0052
TRANSMISSION	0.0052
DEFERRED INCOME TAX	-0.0031
COST EMBEDDED DEBT	0.0031
NUCLEAR PRODUCTION	0.0031
SHORT-TERM DEBT COR	7.0010
RETAINED EARNINGS	0.0
GENERAL TAX RATE	0.0
SHORT-TERM DEBT	0.0
FUEL ADJ. FOR TAXES	0.0
GENERAL	0.0
DEFERRED ITC	0.0
ELECTRIC REVENUES	0.0
OTHER PRODUCTION	0.0
HYDRO CONV.	0.0
PREFERRED STOCK	0.0
COMMON STOCK	0.0
SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR

TOTAL SOURCES

PUBLIC SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	
DEPRECIATION RATE	-1.4410	GEN. INFLATION RATE	0.9140
COMMON STOCK	-1.4140	AFUDC RATE	-0.2360
OUTSTANDING BONDS	-1.2100	COMMON EQUITY COR	0.0
RETAINED EARNINGS	-1.0060	% CWIP IN RATE BASE	0.0
HYDRO CONV.	0.9750	SHORT-TERM DEBT COR	0.0
TRANSMISSION	0.6520	LONG-TERM DEBT COR	0.0
STEAM PRODUCTION	0.6250	RET. ON COMMON EQUIT	0.0
DISTRIBUTION	0.4490	RET. ON S-TERM DEBT	0.0
GENERAL	0.4350	RETURN ON NEW BONDS	0.0
AFUDC RATE	-0.3810	PROPERTY TAX RATE	0.0
GEN. INFLATION RATE	0.3807	DEPRECIATION RATE	0.0
NUCLEAR PRODUCTION	0.2040	GENERAL TAX RATE	0.0
OTHER PRODUCTION	0.0600	FUEL ADJ. FOR TAXES	0.0
% CWIP IN RATE BASE	-0.0544	ELECTRIC REVENUES	0.0
COMMON EQUITY COR	0.0	COST EMBEDDED DEBT	0.0
SHORT-TERM DEBT COR	0.0	RETAINED EARNINGS	0.0
LONG-TERM DEBT COR	0.0	COMMON STOCK	0.0
ELECTRIC REVENUES	0.0	OUTSTANDING BONDS	0.0
FUEL ADJ. FOR TAXES	0.0	GENERAL	0.0
RET. ON COMMON EQUIT	0.0	DISTRIBUTION	0.0
COST EMBEDDED DEBT	0.0	TRANSMISSION	0.0
RETURN ON NEW BONDS	0.0	OTHER PRODUCTION	0.0
PROPERTY TAX RATE	0.0	HYDRO CONV.	0.0
RET. ON S-TERM DEBT	0.0	NUCLEAR PRODUCTION	0.0
GENERAL TAX RATE	0.0	STEAM PRODUCTION	0.0
SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR

TOTAL APPLICATIONS

PRIVATE SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	PARAMETER
ELECTRIC REVENUES	1.0420	DEPRECIATION RATE	-1.2570
FUEL ADJ. FOR TAXES	-0.0930	RET. ON COMMON EQUITY	0.2360
SALES TO ULTIMATES	-0.3430	COM. DIV. PAYOUT RAT	0.2090
GEN. INFLATION RATE	0.1760	AFUDC RATE	-0.1420
DEPRECIATION RATE	-0.1173	LONG-TERM DEBT COR	-0.1527
FEDERAL TAX RATE	-0.0963	COMMON EQUITY COR	0.1145
COST EMBEDDED DEBT	-0.0421	RET. ON PREFER. STOCK	0.0741
LONG-TERM DEBT COR	-0.0434	GEN. INFLATION RATE	0.0510
DISTRIBUTION	-0.0790	STEAM PRODUCTION	0.0370
COM. DIV. PAYOUT RAT	0.0712	DISTRIBUTION	0.0360
STEAM PRODUCTION	0.0500	PREFERRED STOCK COR	0.0314
COMMON EQUITY COR	0.0502	TRANSMISSION	0.0100
TRANSMISSION	-0.0420	FEDERAL TAX RATE	0.0175
PREFERRED STOCK COR	0.0419	% FLOW THRU ADH*ITC	-0.0157
AFUDC RATE	0.0419	DEFERRED INCOME TAX	-0.0112
% CHIP IN RATE BASE	-0.0335	INVEST. TAX CREDIT	-0.0112
OUTSTANDING BONDS	0.0335	COST EMBEDDED DEBT	0.0112
GENERAL TAX RATE	-0.0293	RET. ON 5-TERM DEBT	0.0089
RET. ON PREFER. STOCK	0.0251	NUCLEAR PRODUCTION	0.0085
RETURN ON NEW BONDS	-0.0209	RETURN ON NEW BONDS	-0.0067
WORKING CAPITAL	-0.0209	% CHIP IN RATE BASE	-0.0067
NUCLEAR PRODUCTION	-0.0167	PROPERTY TAX RATE	-0.0067
INVEST. TAX CREDIT	-0.0124	OUTSTANDING BONDS	-0.0044
DEFERRED ITC	0.0124	SHORT-TERM DEBT COR	0.0022
DEFERRED INCOME TAX	0.0004	% FLOW D/PURT AFUDC	-0.0022
SHORT-TERM DEBT COR	-0.0042	DEFERRED ITC	0.0022
RET. ON 5-TERM DEBT	-0.0042	GENERAL TAX RATE	0.0
PROPERTY TAX RATE	-0.0042	ELECTRIC REVENUES	0.0
% FLOW D/PURT AFUDC	0.0	HYDRO CONV.	0.0
RET. ON COMMON EQUITY	0.0	FUEL ADJ. FOR TAXES	0.0
HYDRO CONV.	0.0	WORKING CAPITAL	0.0
% FLOW THRU ADH*ITC	0.0	SALES TO ULTIMATES	0.0
			PARAMETER
			GEN. INFLATION RATE
			RET. ON COMMON EQUITY
			COM. DIV. PAYOUT RAT
			AFUDC RATE
			LONG-TERM DEBT COR
			COMMON EQUITY COR
			DEPRECIATION RATE
			RET. ON PREFER. STOCK
			PREFERRED STOCK COR
			FEDERAL TAX RATE
			% FLOW THRU ADH*ITC
			% FLOW D/PURT AFUDC
			STEAM PRODUCTION
			% CHIP IN RATE BASE
			OUTSTANDING BONDS
			DISTRIBUTION
			INVEST. TAX CREDIT
			RET. ON 5-TERM DEBT
			RETURN ON NEW BONDS
			PROPERTY TAX RATE
			TRANSMISSION
			DEFERRED INCOME TAX
			COST EMBEDDED DEBT
			NUCLEAR PRODUCTION
			SHORT-TERM DEBT COR
			ELECTRIC REVENUES
			GENERAL TAX RATE
			FUEL ADJ. FOR TAXES
			HYDRO CONV.
			DEFERRED ITC
			WORKING CAPITAL
			SALES TO ULTIMATES

RELATIVE SENSITIVITIES FOR

TOTAL APPLICATIONS

PUBLIC SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	
GEN. INFLATION RATE	0.2220	GEN. INFLATION RATE	1.3350
WORKING CAPITAL	-0.2220	AFUDC RATE	-0.2410
AFUDC RATE	-0.0937	LONG-TERM DEBT COR	0.0
% CWIP IN RATE BASE	-0.0247	SHORT-TERM DEBT COR	0.0
DEPRECIATION RATE	0.0	DEPRECIATION RATE	0.0
SHORT-TERM DEBT COR	0.0	% CWIP IN RATE BASE	0.0
RET. ON COMMON EQUITY	0.0	RET. ON COMMON EQUITY	0.0
RET. ON S-TERM DEBT	0.0	RET. ON S-TERM DEBT	0.0
RETURN ON NEW BONDS	0.0	RETURN ON NEW BONDS	0.0
PROPERTY TAX RATE	0.0	PROPERTY TAX RATE	0.0
COMMON EQUITY COR	0.0	COMMON EQUITY COR	0.0
GENERAL TAX RATE	0.0	GENERAL TAX RATE	0.0
FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
LONG-TERM DEBT COR	0.0	WORKING CAPITAL	0.0
ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
COST EMBEDDED DEBT	0.0	COST EMBEDDED DEBT	0.0
OUTSTANDING BONDS	0.0	OUTSTANDING BONDS	0.0
DISTRIBUTION	0.0	DISTRIBUTION	0.0
TRANSMISSION	0.0	TRANSMISSION	0.0
HYDRO CONV.	0.0	HYDRO CONV.	0.0
NUCLEAR PRODUCTION	0.0	NUCLEAR PRODUCTION	0.0
STEAM PRODUCTION	0.0	STEAM PRODUCTION	0.0
SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR

RATE BASE

PRIVATE SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	
DEPRECIATION RATE	-0.2989	GEN. INFLATION RATE	0.9180
STEAM PRODUCTION	0.2050	DEPRECIATION RATE	-0.3010
DISTRIBUTION	0.1800	DEFERRED INCOME TAX	0.1710
TRANSMISSION	0.1000	STEAM PRODUCTION	-0.0548
GEN. INFLATION RATE	0.0679	DISTRIBUTION	-0.0442
NUCLEAR PRODUCTION	0.0560	AFUDC RATE	-0.0270
DEFERRED INCOME TAX	-0.0472	TRANSMISSION	0.0206
AFUDC RATE	-0.0429	FEDERAL TAX RATE	-0.0142
HYDRO CONV.	0.0169	% CWIP IN RATE BASE	0.0121
GENERAL	0.0160	STEAM PRODUCTION	0.0091
OTHER PRODUCTION	0.0143	DEFERRED INCOME TAX	0.0070
% CWIP IN RATE BASE	-0.0190	% FLOW THRU ADR*ITC	0.0018
FEDERAL TAX RATE	-0.0037	TRANSMISSION	0.0014
% FLOW THRU ADR*ITC	0.0011	NUCLEAR PRODUCTION	0.0014
		HYDRO CONV.	
		GENERAL	
		OTHER PRODUCTION	

RELATIVE SENSITIVITIES FOR

RATE BASE

PUBLIC SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	PARAMETER
TRANSMISSION	0.0210	GEN. INFLATION RATE	0.0960
DEPRECIATION RATE	-0.2710	DEPRECIATION RATE	-0.3180
HYDRO CONV.	0.1550	HYDRO CONV.	-0.0653
STEAM PRODUCTION	0.1000	AFUOC RATE	-0.0254
DISTRIBUTION	0.0710	% CHIP IN RATE BASE	0.0133
GENERAL	0.0707	STEAM PRODUCTION	0.0400
GEN. INFLATION RATE	0.0400	TRANSMISSION	0.0070
AFUOC RATE	-0.0456	DISTRIBUTION	0.0069
NUCLEAR PRODUCTION	0.0320	GENERAL	0.0063
OTHER PRODUCTION	0.0114	% CHIP IN RATE BASE	0.0029
% CHIP IN RATE BASE	-0.0114	NUCLEAR PRODUCTION	0.0013
		OTHER PRODUCTION	

RELATIVE SENSITIVITIES FOR

RETURN ON RATE BASE

PRIVATE SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	PARAMETER
RET. ON COMMON EQUITY	0.4930	RET. ON COMMON EQUITY	0.9100
DEPRECIATION RATE	-0.3252	GEN. INFLATION RATE	0.4490
COST EMBEDDED DEBT	0.2490	DEPRECIATION RATE	0.4240
STEAM PRODUCTION	0.2200	RETURN ON NEW BONDS	-0.3000
DISTRIBUTION	0.2080	COST EMBEDDED DEBT	0.1030
RET. ON PREFER. STOCK	0.1169	RET. ON PREFER. STOCK	0.0800
TRANSMISSION	0.1110	STEAM PRODUCTION	-0.0440
OUTSTANDING BONDS	-0.1016	DISTRIBUTION	-0.0557
COMMON EQUITY COR	0.0464	COMMON EQUITY COR	-0.0446
GEN. INFLATION RATE	0.0762	OUTSTANDING BONDS	-0.0270
RETURN ON NEW BONDS	0.0762	LONG-TERM DEBT COR	0.0210
LONG-TERM DEBT COR	-0.0461	TRANSMISSION	0.0167
NUCLEAR PRODUCTION	0.0610	AFUOC RATE	-0.0167
DEFERRED INCOME TAX	-0.0508	FEDERAL TAX RATE	-0.0167
AFUOC RATE	-0.0457	DEFERRED INCOME TAX	-0.0139
PREFERRED STOCK COR	-0.0203	% FLOW THRU ADP+ITC	0.0129
GENERAL	0.0203	TRANSMISSION	0.0094
RET. ON S-TERM DEBT	0.0203	NUCLEAR PRODUCTION	0.0069
HYDRO CONV.	0.0203	SHORT-TERM DEBT COR	-0.0020
OTHER PRODUCTION	0.0150	HYDRO CONV.	0.0014
% CHIP IN RATE BASE	-0.0161	OTHER PRODUCTION	0.0014
FEDERAL TAX RATE	-0.0051	GENERAL	0.0014
SHORT-TERM DEBT COR	0.0	COST EMBEDDED DEBT	0.0
% FLOW THRU ADP+ITC	0.0	OUTSTANDING BONDS	0.0

RELATIVE SENSITIVITIES FOR
RETURN ON RATE BASE

PUBLIC-SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		RET. ON COMMON EQUITY	0.5955	GEN. INFLATION RATE	0.8940
RET. ON COMMON EQUITY	0.6740	GEN. INFLATION RATE	0.4010	RET. ON COMMON EQUITY	0.6173
DEPRECIATION RATE	-0.3140	DEPRECIATION RATE	-0.3200	RETURN ON NEW BONDS	0.4740
COST EMBEDDED DEBT	0.2405	RETURN ON NEW BONDS	0.3040	DEPRECIATION RATE	-0.3193
HYDRO CONV.	0.2020	COST EMBEDDED DEBT	0.0850	LONG-TERM DEBT COR	-0.0851
STEAM PRODUCTION	0.1340	HYDRO CONV.	0.0730	COMMON EQUITY COR	0.0758
TRANSMISSION	0.1120	LONG-TERM DEBT COR	-0.0725	AFUDC RATE	-0.0638
COMMON EQUITY COR	0.1120	COMMON EQUITY COR	-0.0725	% CHIP IN RATE BASE	-0.0266
LONG-TERM DEBT COR	-0.0996	AFUDC RATE	-0.0607	HYDRO CONV.	0.0106
RETURN ON NEW BONDS	0.0996	OUTSTANDING BONDS	-0.0486	DISTRIBUTION	0.0053
GENERAL	0.0896	STEAM PRODUCTION	0.0486	TRANSMISSION	0.0053
GEN. INFLATION RATE	0.0896	DISTRIBUTION	0.0370	OUTSTANDING BONDS	-0.0053
DISTRIBUTION	-0.0896	TRANSMISSION	0.0370	GENERAL	0.0053
OUTSTANDING BONDS	-0.0672	% CHIP IN RATE BASE	-0.0243	STEAM PRODUCTION	0.0053
NUCLEAR PRODUCTION	0.0450	GENERAL	0.0243	SHORT-TERM DEBT COR	0.0
AFUDC RATE	-0.0448	NUCLEAR PRODUCTION	0.0120	OTHER PRODUCTION	0.0
% CHIP IN RATE BASE	0.0	RET. ON S-TERM DEBT	0.0	RET. ON S-TERM DEBT	0.0
RET. ON S-TERM DEBT	0.0	OTHER PRODUCTION	0.0	NUCLEAR PRODUCTION	0.0
OTHER PRODUCTION	0.0	SHORT-TERM DEBT COR	0.0	COST EMBEDDED DEBT	0.0
SHORT-TERM DEBT COR	0.0				

RELATIVE SENSITIVITIES FOR
REVENUE REQUIREMENTS

PRIVATE SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		GEN. INFLATION RATE	0.4013	GEN. INFLATION RATE	0.8976
RET. ON COMMON EQUITY	0.2867	RET. ON COMMON EQUITY	0.2274	RET. ON COMMON EQUITY	0.2251
FEDERAL TAX RATE	0.2720	FEDERAL TAX RATE	0.2110	FEDERAL TAX RATE	0.1700
DISTRIBUTION	0.1460	GENERAL TAX RATE	0.0983	RETURN ON NEW BONDS	0.1250
STEAM PRODUCTION	0.1350	RETURN ON NEW BONDS	0.0824	GENERAL TAX RATE	0.0887
AFUDC RATE	-0.1190	AFUDC RATE	-0.0755	LONG-TERM DEBT COR	-0.0774
LONG-TERM DEBT COR	-0.1000	LONG-TERM DEBT COR	-0.0754	COMMON EQUITY COR	0.0733
COMMON EQUITY COR	0.0900	COMMON EQUITY COR	-0.0715	RET. ON PREFER. STOCK	0.0514
COST EMBEDDED DEBT	0.0936	DISTRIBUTION	0.0591	AFUDC RATE	-0.0300
GENERAL TAX RATE	0.0879	STEAM PRODUCTION	0.0525	PROPERTY TAX RATE	0.0286
TRANSMISSION	0.0790	RET. ON PREFER. STOCK	0.0512	DISTRIBUTION	0.0191
RET. ON PREFER. STOCK	0.0663	COST EMBEDDED DEBT	0.0314	STEAM PRODUCTION	0.0174
NUCLEAR PRODUCTION	0.0360	TRANSMISSION	0.0310	DEPRECIATION RATE	-0.0150
OUTSTANDING BONDS	-0.0331	PROPERTY TAX RATE	0.0233	% FLOW D/PORT AFUDC	-0.0119
DEFERRED INCOME TAX	-0.0245	OUTSTANDING BONDS	-0.0107	% FLOW THRU ADR*ITC	-0.0119
RETURN ON NEW BONDS	0.0231	NUCLEAR PRODUCTION	0.0150	TRANSMISSION	0.0100
% FLOW THRU ADR*ITC	-0.0158	% FLOW THRU ADR*ITC	-0.0138	INVEST. TAX CREDIT	-0.0092
% CHIP IN RATE BASE	0.0130	DEFERRED INCOME TAX	-0.0124	RET. ON S-TERM DEBT	0.0082
GEN. INFLATION RATE	0.0115	DEPRECIATION RATE	-0.0095	DEFERRED INCOME TAX	-0.0058
GENERAL	0.0100	INVEST. TAX CREDIT	-0.0088	STATE TAX RATE	0.0051
HYDRO CONV.	0.0100	RET. ON S-TERM DEBT	0.0080	NUCLEAR PRODUCTION	0.0050
OTHER PRODUCTION	0.0086	GENERAL	0.0051	PREFERRED STOCK COR	0.0021
DEFERRED ITC	-0.0058	HYDRO CONV.	0.0044	SALES TAX RATE	0.0021
RET. ON S-TERM DEBT	0.0058	OTHER PRODUCTION	0.0036	GENERAL	0.0017
STATE TAX RATE	0.0058	DEFERRED ITC	-0.0025	DEFERRED ITC	-0.0014
PREFERRED STOCK COR	0.0043	% FLOW D/PORT AFUDC	-0.0022	% CHIP IN RATE BASE	-0.0014
INVEST. TAX CREDIT	-0.0043	SALES TAX RATE	0.0015	OTHER PRODUCTION	0.0014
% FLOW D/PORT AFUDC	-0.0029	PREFERRED STOCK COR	0.0015	HYDRO CONV.	0.0014
PROPERTY TAX RATE	0.0028	% CHIP IN RATE BASE	-0.0007	COST EMBEDDED DEBT	0.0
SALES TAX RATE	0.0014			OUTSTANDING BONDS	0.0
DEPRECIATION RATE	0.0				

RELATIVE SENSITIVITIES FOR
REVENUE REQUIREMENTS

PUBLIC SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
PARAMETER		GEN. INFLATION RATE	0.4299	PARAMETER	
RET. ON COMMON EQUITY	0.2300	RET. ON COMMON EQUITY	0.1840	GEN. INFLATION RATE	0.9190
COST EMBEDDED DEBT	0.0845	RETURN ON NEW BONDS	0.0939	RET. ON COMMON EQUITY	0.1400
AFUDC RATE	-0.0768	AFUDC RATE	-0.0614	RETURN ON NEW BONDS	0.1330
STEAM PRODUCTION	0.0610	HYDRO CONV.	0.0325	AFUDC RATE	-0.0730
TRANSMISSION	0.0540	GENERAL TAX RATE	0.0253	PROPERTY TAX RATE	0.0308
GENERAL	0.0461	COST EMBEDDED DEBT	0.0253	LONG-TERM DEBT COR	-0.0276
DISTRIBUTION	0.0461	PROPERTY TAX RATE	0.0253	GENERAL TAX RATE	0.0276
COMMON EQUITY COR	0.0314	COMMON EQUITY COR	0.0217	COMMON EQUITY COR	0.0259
RETURN ON NEW BONDS	0.0307	LONG-TERM DEBT COR	-0.0217	DEPRECIATION RATE	-0.0211
GENERAL TAX RATE	-0.0307	STEAM PRODUCTION	0.0210	HYDRO CONV.	0.0097
LONG-TERM DEBT COR	-0.0307	TRANSMISSION	0.0180	STEAM PRODUCTION	0.0065
OUTSTANDING BONDS	-0.0230	DISTRIBUTION	0.0190	TRANSMISSION	0.0049
NUCLEAR PRODUCTION	0.0230	GENERAL	0.0144	DISTRIBUTION	0.0049
HYDRO CONV.	0.0190	OUTSTANDING BONDS	-0.0144	GENERAL	0.0049
GEN. INFLATION RATE	0.0154	DEPRECIATION RATE	-0.0109	% CHIP IN RATE BASE	-0.0018
% CHIP IN RATE BASE	0.0077	NUCLEAR PRODUCTION	0.0072	NUCLEAR PRODUCTION	0.0018
DEPRECIATION RATE	-0.0077	% CHIP IN RATE BASE	-0.0036	COST EMBEDDED DEBT	0.0
PROPERTY TAX RATE	0.0077	RET. ON S-TERM DEBT	0.0	RET. ON S-TERM DEBT	0.0
RET. ON S-TERM DEBT	0.0	SALES TAX RATE	0.0	OUTSTANDING BONDS	0.0
SALES TAX RATE	0.0	OTHER PRODUCTION	0.0	SALES TAX RATE	0.0
OTHER PRODUCTION	0.0	STATE TAX RATE	0.0	OTHER PRODUCTION	0.0
STATE TAX RATE	0.0			STATE TAX RATE	0.0

RELATIVE SENSITIVITIES FOR
AVERAGE PRICE OF ELECTRICITY

PRIVATE SECTOR

YEAR	1979	1986	1993		
PARAMETER		PARAMETER	PARAMETER		
ELECTRIC REVENUES	1.2570	GEN. INFLATION RATE	0.3671	GEN. INFLATION RATE	0.8572
FUEL ADJ. FOR TAXES	-0.0330	RET. ON COMMON EQUITY	0.2238	RET. ON COMMON EQUITY	0.2137
SALES TO ULTIMATES	-0.4140	FEDERAL TAX RATE	0.2080	FEDERAL TAX RATE	0.1640
GENERAL TAX RATE	0.0501	GENERAL TAX RATE	0.0885	RETURN ON NEW BONDS	0.1140
COMMON EQUITY COR	0.0	OUTSTANDING BONDS	-0.0820	AFUDC RATE	-0.0948
GEN. INFLATION RATE	0.0	AFUDC RATE	-0.0818	GENERAL TAX RATE	0.0885
DEPRECIATION RATE	0.0	LONG-TERM DEBT COR	-0.0754	LONG-TERM DEBT COR	-0.0693
RET. ON COMMON EQUITY	0.0	COMMON EQUITY COR	0.0719	COMMON EQUITY COR	0.0665
RET. ON S-TERM DEBT	0.0	DISTRIBUTION	0.0698	RET. ON PREFER. STOCK	0.0493
RETURN ON NEW BONDS	0.0	RETURN ON NEW BONDS	0.0678	PROPERTY TAX RATE	0.0255
% FLOW D/PORT AFUDC	0.0	STEAM PRODUCTION	0.0517	DISTRIBUTION	0.0246
% FLOW THRU ADR*ITC	0.0	RET. ON PREFER. STOCK	0.0517	STEAM PRODUCTION	0.0220
INVEST. TAX CREDIT	0.0	COST EMBEDDED DEBT	0.0395	TRANSMISSION	0.0131
SALES TAX RATE	0.0	TRANSMISSION	0.0373	% FLOW THRU ADR*ITC	-0.0112
PROPERTY TAX RATE	0.0	PROPERTY TAX RATE	0.0191	% FLOW D/PORT AFUDC	-0.0109
STATE TAX RATE	0.0	NUCLEAR PRODUCTION	0.0176	OUTSTANDING BONDS	-0.0099
PREFERRED STOCK COR	0.0	DEFERRED INCOME TAX	-0.0136	INVEST. TAX CREDIT	-0.0085
AFUDC RATE	0.0	% FLOW THRU ADR*ITC	-0.0112	DEPRECIATION RATE	-0.0084
LONG-TERM DEBT COR	0.0	DEPRECIATION RATE	-0.0099	RET. ON S-TERM DEBT	0.0078
% CHIP IN RATE BASE	0.0	RET. ON S-TERM DEBT	0.0084	NUCLEAR PRODUCTION	0.0068
DEFERRED INCOME TAX	0.0	GENERAL	0.0059	DEFERRED INCOME TAX	-0.0064
DEFERRED ITC	0.0	STATE TAX RATE	0.0056	STATE TAX RATE	0.0048
RET. ON PREFER. STOCK	0.0	INVEST. TAX CREDIT	-0.0054	COST EMBEDDED DEBT	0.0034
COST EMBEDDED DEBT	0.0	HYDRO CONV.	0.0030	SALES TAX RATE	0.0021
OUTSTANDING BONDS	0.0	OTHER PRODUCTION	0.0043	GENERAL	0.0021
GENERAL	0.0	% FLOW D/PORT AFUDC	-0.0030	% CHIP IN RATE BASE	0.0019
DISTRIBUTION	0.0	DEFERRED ITC	-0.0027	HYDRO CONV.	0.0018
TRANSMISSION	0.0	% CHIP IN RATE BASE	0.0023	OTHER PRODUCTION	0.0016
OTHER PRODUCTION	0.0	PREFERRED STOCK COR	0.0019	DEFERRED ITC	-0.0014
HYDRO CONV.	0.0	SALES TAX RATE	0.0015	PREFERRED STOCK COR	0.0009
NUCLEAR PRODUCTION	0.0	ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
STEAM PRODUCTION	0.0	FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
FEDERAL TAX RATE	0.0	SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR
AVERAGE PRICE OF ELECTRICITY

PUBLIC SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	
ELECTRIC REVENUES	1.3126	GEN. INFLATION RATE	0.4010
FUEL ADJ. FOR TAXES	-0.9590	RET. ON COMMON EQUITY	0.1823
SALES TO ULTIMATES	-0.3500	RETURN ON NEW BONDS	0.0780
GENERAL TAX RATE	0.0177	AFUDC RATE	-0.0603
GEN. INFLATION RATE	0.0	HYDRO CONV.	0.0410
RET. ON COMMON EQUITY	0.0	COST EMBEDDED DEBT	0.0324
DEPRECIATION RATE	0.0	GENERAL TAX RATE	0.0270
RETURN ON NEW BONDS	0.0	STEAM PRODUCTION	0.0260
SALES TAX RATE	0.0	COMMON EQUITY COR	0.0229
PROPERTY TAX RATE	0.0	LONG-TERM DEBT COR	-0.0225
STATE TAX RATE	0.0	TRANSMISSION	0.0217
AFUDC RATE	0.0	PROPERTY TAX RATE	0.0214
RET. ON S-TERM DEBT	0.0	DISTRIBUTION	0.0211
LONG-TERM DEBT COR	0.0	GENERAL	0.0190
% CHIP IN RATE BASE	0.0	OUTSTANDING BONDS	-0.0154
COST EMBEDDED DEBT	0.0	DEPRECIATION RATE	-0.0097
OUTSTANDING BONDS	0.0	NUCLEAR PRODUCTION	0.0080
GENERAL	0.0	STATE TAX RATE	0.0034
DISTRIBUTION	0.0	OTHER PRODUCTION	0.0030
TRANSMISSION	0.0	RET. ON S-TERM DEBT	0.0027
OTHER PRODUCTION	0.0	SALES TAX RATE	0.0019
HYDRO CONV.	0.0	% CHIP IN RATE BASE	-0.0004
NUCLEAR PRODUCTION	0.0	FUEL ADJ. FOR TAXES	0.0
STEAM PRODUCTION	0.0	ELECTRIC REVENUES	0.0
COMMON EQUITY COR	0.0	SALES TO ULTIMATES	0.0
		PARAMETER	
		GEN. INFLATION RATE	0.0860
		RET. ON COMMON EQUITY	0.1712
		RETURN ON NEW BONDS	0.1200
		AFUDC RATE	-0.0691
		GENERAL TAX RATE	0.0270
		PROPERTY TAX RATE	0.0276
		OUTSTANDING BONDS	-0.0257
		COMMON EQUITY COR	0.0178
		LONG-TERM DEBT COR	-0.0194
		HYDRO CONV.	0.0140
		STEAM PRODUCTION	0.0090
		DEPRECIATION RATE	-0.0088
		TRANSMISSION	0.0079
		DISTRIBUTION	0.0071
		GENERAL	0.0064
		COST EMBEDDED DEBT	0.0034
		STATE TAX RATE	0.0031
		NUCLEAR PRODUCTION	0.0029
		RET. ON S-TERM DEBT	0.0025
		SALES TAX RATE	0.0024
		% CHIP IN RATE BASE	-0.0010
		OTHER PRODUCTION	0.0010
		FUEL ADJ. FOR TAXES	0.0
		ELECTRIC REVENUES	0.0
		SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR

OF SHARES

PRIVATE SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	
# OF SHARES	0.2030	COMMON STOCK	-3.0140
COMMON STOCK	-0.0905	COMMON EQUITY COR	2.1760
COMMON EQUITY COR	0.7915	LONG-TERM DEBT COR	-1.0760
LONG-TERM DEBT COR	-0.6246	DEPRECIATION RATE	-1.1720
DEPRECIATION RATE	-0.3630	RETAINED EARNINGS	-1.1720
RETAINED EARNINGS	-0.3630	# OF SHARES	1.0040
DISTRIBUTION	0.2640	STEAM PRODUCTION	0.0030
STEAM PRODUCTION	0.2630	DISTRIBUTION	0.7360
RET. ON COMMON EQUITY	-0.1980	RET. ON COMMON EQUITY	-0.5360
TRANSMISSION	0.1320	PREFERRED STOCK COR	-0.4350
PREFERRED STOCK COR	-0.1320	TRANSMISSION	0.4020
GEN. INFLATION RATE	0.0909	GEN. INFLATION RATE	0.2340
NUCLEAR PRODUCTION	0.0660	NUCLEAR PRODUCTION	0.2340
AFUDC RATE	-0.0459	DEFERRED INCOME TAX	-0.2000
DEFERRED INCOME TAX	-0.0459	AFUDC RATE	-0.1670
SHORT-TERM DEBT COR	-0.0330	ELECTRIC REVENUES	0.1000
ELECTRIC REVENUES	-0.0330	DEFERRED ITC	-0.1000
OTHER PRODUCTION	0.0330	HYDRO CONV.	0.0690
GENERAL	0.0330	SHORT-TERM DEBT COR	-0.0670
DEFERRED ITC	-0.0330	OTHER PRODUCTION	0.0670
FUEL ADJ. FOR TAXES	0.0330	GENERAL	0.0670
HYDRO CONV.	0.0330	FUEL ADJ. FOR TAXES	0.0665
NET INCOME	0.0329	NET INCOME	0.0335
% CHIP IN RATE BASE	0.0	% CHIP IN RATE BASE	-0.0335
COM. DIV. PAYOUT RAY	0.0	COM. DIV. PAYOUT RAY	-0.0335
SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0335
		PARAMETER	
		COMMON STOCK	-8.1070
		LONG-TERM DEBT COR	-5.3230
		DEPRECIATION RATE	-3.2010
		RETAINED EARNINGS	-3.1315
		COMMON EQUITY COR	2.2460
		STEAM PRODUCTION	2.0000
		DISTRIBUTION	1.9480
		RET. ON COMMON EQUITY	-1.3920
		PREFERRED STOCK COR	-1.2170
		TRANSMISSION	1.0440
		# OF SHARES	1.0090
		GEN. INFLATION RATE	0.6260
		NUCLEAR PRODUCTION	0.5610
		DEFERRED INCOME TAX	-0.4870
		AFUDC RATE	-0.4520
		ELECTRIC REVENUES	-0.3130
		DEFERRED ITC	-0.2435
		FUEL ADJ. FOR TAXES	0.2087
		OTHER PRODUCTION	0.1740
		GENERAL	0.1740
		HYDRO CONV.	0.1740
		SHORT-TERM DEBT COR	-0.1739
		NET INCOME	0.1044
		COM. DIV. PAYOUT RAY	-0.1044
		% CHIP IN RATE BASE	-0.1040
		SALES TO ULTIMATES	0.1040

N OF SHARES

YEAR	1979	1986	1993
PARAMETER		PARAMETER	PARAMETER
COMMON EQUITY COR	0.0	COMMON EQUITY COR	0.0
SHORT-TERM DEBT COR	0.0	SHORT-TERM DEBT COR	0.0
LONG-TERM DEBT COR	0.0	LONG-TERM DEBT COR	0.0
% CHIP IN RATE BASE	0.0	% CHIP IN RATE BASE	0.0
DEPRECIATION RATE	0.0	DEPRECIATION RATE	0.0
GEN. INFLATION RATE	0.0	GEN. INFLATION RATE	0.0
RET. ON COMMON EQUIT	0.0	RET. ON COMMON EQUIT	0.0
AFUDC RATE	0.0	AFUDC RATE	0.0
FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
NET INCOME	0.0	NET INCOME	0.0
ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
RETAINED EARNINGS	0.0	RETAINED EARNINGS	0.0
COMMON STOCK	0.0	COMMON STOCK	0.0
GENERAL	0.0	GENERAL	0.0
DISTRIBUTION	0.0	DISTRIBUTION	0.0
TRANSMISSION	0.0	TRANSMISSION	0.0
OTHER PRODUCTION	0.0	OTHER PRODUCTION	0.0
HYDRO CONV.	0.0	HYDRO CONV.	0.0
NUCLEAR PRODUCTION	0.0	NUCLEAR PRODUCTION	0.0
STEAM PRODUCTION	0.0	STEAM PRODUCTION	0.0
SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

AVERAGE BOOK VALUE

YEAR		1979		1986		1993
PARAMETER			PARAMETER		PARAMETER	
# OF SHARES	-1.0120		COMMON STOCK	2.0280	COMMON STOCK	9.3990
COMMON STOCK	-0.7714		LONG-TERM DEBT COR	1.3530	LONG-TERM DEBT COR	4.0720
STEAM PRODUCTION	-0.4900		COMMON EQUITY COR	-1.3530	COMMON EQUITY COR	-4.6200
RETAINED EARNINGS	-0.2890		RETAINED EARNINGS	1.0030	RETAINED EARNINGS	3.0000
COMMON EQUITY COR	-0.0964		# OF SHARES	-0.2930	STEAM PRODUCTION	-1.0700
DISTRIBUTION	-0.0530		STEAM PRODUCTION	-0.6300	DISTRIBUTION	-1.7920
LONG-TERM DEBT COR	0.0482		DISTRIBUTION	-0.5710	RET. ON COMMON EQUIT	1.3580
RET. CN COMMON EQUIT	0.0482		RET. ON COMMON EQUIT	0.4013	PREFERRED STOCK COR	1.0500
FUEL ADJ. FOR TAXES	-0.0482		PREFERRED STOCK COR	0.3000	# OF SHARES	-0.9940
GEN. INFLATION RATE	-0.0402		TRANSMISSION	-0.2700	TRANSMISSION	-0.9900
SALES TO ULTIMATES	-0.3480		NUCLEAR PRODUCTION	-0.1800	NUCLEAR PRODUCTION	-0.5600
TRANSMISSION	-0.0480		AFCDC RATE	0.1203	DEFERRED INCOME TAX	0.4620
NET INCOME	-0.0480		GEN. INFLATION RATE	0.1203	AFCDC RATE	0.4060
NUCLEAR PRODUCTION	-0.0400		DEFERRED INCOME TAX	0.1200	GEN. INFLATION RATE	0.2940
FEDERAL TAX RATE	0.0		ELECTRIC REVENUES	0.0900	ELECTRIC REVENUES	0.2933
SHORT-TERM DEBT COR	0.0		DEFERRED ITC	0.0601	DEFERRED ITC	0.2340
RET. CN PREFER. STOCK	0.0		HYDRO CONV.	-0.0600	FUEL ADJ. FOR TAXES	-0.1820
PREFERRED STOCK COR	0.0		GENERAL	-0.0600	HYDRO CONV.	-0.1680
% CHIP IN RATE BASE	0.0		FUEL ADJ. FOR TAXES	-0.0600	GENERAL	-0.1680
ELECTRIC REVENUES	0.0		OTHER PRODUCTION	-0.0600	SHORT-TERM DEBT COR	0.1680
COST EMBEDDED DEBT	0.0		COST EMBEDDED DEBT	-0.0300	OTHER PRODUCTION	-0.1540
DEFERRED ITC	0.0		NET INCOME	-0.0300	NET INCOME	-0.0980
COM. DIV. PAYOUT RAT	0.0		COM. DIV. PAYOUT RAT	0.0300	COM. DIV. PAYOUT RAT	0.0980
GENERAL	0.0		RET. ON PREFER. STOCK	-0.0300	SALES TO ULTIMATES	-0.0900
HYDRO CONV.	0.0		FEDERAL TAX RATE	-0.0300	% CHIP IN RATE BASE	0.0420
AFCDC RATE	0.0		SHORT-TERM DEBT COR	0.0300	FEDERAL TAX RATE	-0.0420
OTHER PRODUCTION	0.0		SALES TO ULTIMATES	-0.0300	COST EMBEDDED DEBT	-0.0280
DEFERRED INCOME TAX	0.0		% CHIP IN RATE BASE	0.0	RET. ON PREFER. STOCK	-0.0280

RELATIVE SENSITIVITIES FOR

AVERAGE BOOK VALUE

PUBLIC-SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	PARAMETER
COMMON EQUITY COR	0.0	COMMON EQUITY COR	0.0
SHORT-TERM DEBT COR	0.0	SHORT-TERM DEBT COR	0.0
LONG-TERM DEBT COR	0.0	LONG-TERM DEBT COR	0.0
% CHIP IN RATE BASE	0.0	% CHIP IN RATE BASE	0.0
GEN. INFLATION RATE	0.0	GEN. INFLATION RATE	0.0
RET. ON COMMON EQUITY	0.0	RET. ON COMMON EQUITY	0.0
AFUDC RATE	0.0	AFUDC RATE	0.0
FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
NET INCOME	0.0	NET INCOME	0.0
ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
COST EMBEDDED DEBT	0.0	COST EMBEDDED DEBT	0.0
RETAINED EARNINGS	0.0	RETAINED EARNINGS	0.0
COMMON STOCK	0.0	COMMON STOCK	0.0
GENERAL	0.0	GENERAL	0.0
DISTRIBUTION	0.0	DISTRIBUTION	0.0
TRANSMISSION	0.0	TRANSMISSION	0.0
OTHER PRODUCTION	0.0	OTHER PRODUCTION	0.0
HYDRO CONV.	0.0	HYDRO CONV.	0.0
NUCLEAR PRODUCTION	0.0	NUCLEAR PRODUCTION	0.0
STEAM PRODUCTION	0.0	STEAM PRODUCTION	0.0
SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR

RETURN ON EQUITY

PRIVATE-SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	PARAMETER
ELECTRIC REVENUES	15.1500	FUEL ADJ. FOR TAXES	0.0
FUEL ADJ. FOR TAXES	-5.0400	ELECTRIC REVENUES	0.0
SALES TO ULTIMATES	-6.0600	SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR

RETURN ON EQUITY

PUBLIC SECTOR

YEAR	1979	1986	1993
PARAMETER		PARAMETER	PARAMETER
FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR
AFUDC

PRIVATE SECTOR					
YEAR	1979		1986		1993
PARAMETER		PARAMETER		PARAMETER	
AFUDC RATE	0.0440	AFUDC RATE	0.0314	GEN. INFLATION RATE	1.2209
GEN. INFLATION RATE	0.2045	GEN. INFLATION RATE	0.7154	AFUDC RATE	0.0300
% CWIP IN RATE BASE	-0.1430	% CWIP IN RATE BASE	-0.1740	% CWIP IN RATE BASE	-0.1640

RELATIVE SENSITIVITIES FOR
AFUDC

PUBLIC SECTOR					
YEAR	1979		1986		1993
PARAMETER		PARAMETER		PARAMETER	
AFUDC RATE	0.0550	AFUDC RATE	0.0090	GEN. INFLATION RATE	1.2040
% CWIP IN RATE BASE	-0.2136	GEN. INFLATION RATE	0.7275	AFUDC RATE	0.0310
GEN. INFLATION RATE	0.1069	% CWIP IN RATE BASE	-0.1617	% CWIP IN RATE BASE	-0.1720

RELATIVE SENSITIVITIES FOR
AVAILABLE EARNINGS
PRIVATE SECTOR

YEAR	1979	PARAMETER	1986	PARAMETER	1993
		ELECTRIC REVENUES	15.1030	FEDERAL TAX RATE	1.3630
		SALES TO ULTIMATES	-5.0000	RET. ON COMMON EQUITY	1.1220
		RET. ON PREFER. STOCK	3.5170	GEN. INFLATION RATE	0.7080
		STEAM PRODUCTION	3.3400	COMMON EQUITY COR	0.6620
		DEPRECIATION RATE	3.1930	LONG-TERM DEBT COR	-0.5141
		COST EMBEDDED DEBT	3.1130	DEPRECIATION RATE	-0.3860
		DISTRIBUTION	3.0650	PREFERRED STOCK COR	-0.1679
		AFUDC RATE	1.0600	% FLOW THRU ACR+ITC	-0.1020
		FEDERAL TAX RATE	-1.3970	% FLOW D/PORT AFUDC	-0.0584
		COMMON EQUITY COR	-1.1720	OUTSTANDING BONDS	-0.0406
		FUEL ADJ. FOR TAXES	-1.0100	STEAM PRODUCTION	0.0470
		TRANSMISSION	-0.7660	DISTRIBUTION	0.0430
		PREFERRED STOCK COR	-0.5060	RET. ON S-TERM DEBT	0.0420
		LONG-TERM DEBT COR	-0.5040	% CHIP IN RATE BASE	-0.0351
		OUTSTANDING BONDS	0.4510	RETURN ON NEW BONDS	-0.0273
		GENERAL TAX RATE	-0.4504	PROPERTY TAX RATE	-0.0272
		RETURN ON NEW BONDS	-0.3604	TRANSMISSION	0.0230
		NUCLEAR PRODUCTION	-0.3150	INVEST. TAX CREDIT	-0.0195
		% CHIP IN RATE BASE	-0.2710	COST EMBEDDED DEBT	-0.0195
		DEFERRED ITC	0.1003	DEFERRED INCOME TAX	-0.0195
		INVEST. TAX CREDIT	-0.0100	AFUDC RATE	-0.0196
		GENERAL	-0.0350	SHORT-TERM DEBT COR	0.0156
		DEFERRED INCOME TAX	0.1350	NUCLEAR PRODUCTION	0.0155
		PROPERTY TAX RATE	-0.0702	RET. ON PREFER. STOCK	-0.0117
		RET. ON S-TERM DEBT	-0.0702	DEFERRED ITC	0.0039
		HYDRO CONV.	-0.0700	OTHER PRODUCTION	0.0039
		OTHER PRODUCTION	-0.0700	GENERAL	0.0039
		% FLOW THRU ACR+ITC	-0.0451	HYDRO CONV.	0.0039
		SHORT-TERM DEBT COR	-0.0451	GENERAL TAX RATE	0.0
		GEN. INFLATION RATE	0.0451	ELECTRIC REVENUES	0.0
		RET. ON COMMON EQUITY	0.0	FUEL ADJ. FOR TAXES	0.0
		% FLOW D/PORT AFUDC	0.0	SALES TO ULTIMATES	0.0
		PARAMETER		PARAMETER	
		RET. ON COMMON EQUITY	1.1340	FEDERAL TAX RATE	1.3630
		FEDERAL TAX RATE	1.0310	RET. ON COMMON EQUITY	1.1220
		COMMON EQUITY COR	0.6620	GEN. INFLATION RATE	0.7080
		LONG-TERM DEBT COR	-0.5141	COMMON EQUITY COR	0.6620
		DEPRECIATION RATE	-0.4690	LONG-TERM DEBT COR	-0.5141
		GEN. INFLATION RATE	0.2050	DEPRECIATION RATE	-0.3860
		PREFERRED STOCK COR	-0.1507	PREFERRED STOCK COR	-0.1679
		STEAM PRODUCTION	0.1350	% FLOW THRU ACR+ITC	-0.1020
		DISTRIBUTION	0.1340	% FLOW D/PORT AFUDC	-0.0584
		% FLOW THRU ACR+ITC	-0.0872	OUTSTANDING BONDS	-0.0406
		TRANSMISSION	0.0714	STEAM PRODUCTION	0.0470
		AFUDC RATE	-0.0634	DISTRIBUTION	0.0430
		COST EMBEDDED DEBT	-0.0634	RET. ON S-TERM DEBT	0.0420
		DEFERRED INCOME TAX	-0.0396	% CHIP IN RATE BASE	-0.0351
		RET. ON S-TERM DEBT	0.0306	RETURN ON NEW BONDS	-0.0273
		NUCLEAR PRODUCTION	0.0306	PROPERTY TAX RATE	-0.0272
		RETURN ON NEW BONDS	-0.0317	TRANSMISSION	0.0230
		INVEST. TAX CREDIT	-0.0317	INVEST. TAX CREDIT	-0.0195
		PROPERTY TAX RATE	-0.0230	COST EMBEDDED DEBT	-0.0195
		% FLOW D/PORT AFUDC	-0.0156	DEFERRED INCOME TAX	-0.0195
		% CHIP IN RATE BASE	-0.0156	AFUDC RATE	-0.0196
		DEFERRED ITC	0.0156	SHORT-TERM DEBT COR	0.0156
		SHORT-TERM DEBT COR	0.0156	NUCLEAR PRODUCTION	0.0155
		OUTSTANDING BONDS	-0.0196	RET. ON PREFER. STOCK	-0.0117
		GENERAL	0.0156	DEFERRED ITC	0.0039
		HYDRO CONV.	0.0156	OTHER PRODUCTION	0.0039
		OTHER PRODUCTION	-0.0076	GENERAL	0.0039
		GENERAL TAX RATE	0.0	HYDRO CONV.	0.0039
		RET. ON PREFER. STOCK	0.0	GENERAL TAX RATE	0.0
		ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
		FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
		SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

RELATIVE SENSITIVITIES FOR
AVAILABLE EARNINGS

		PUBLIC SECTOR	
YEAR	1979	1986	1993
PARAMETER		PARAMETER	
ELECTRIC REVENUES	12.0070	RET. ON COMMON EQUITY	1.2310
SALES TO ULTIMATES	-3.3000	LONG-TERM DEBT COR	-0.6426
LONG-TERM DEBT COR	-3.9505	COMMON EQUITY COR	-0.6425
COST EMBEDDED DEBT	-0.9560	DEPRECIATION RATE	-0.4820
COMMON EQUITY COR	0.0690	GEN. INFLATION RATE	0.1874
AFUDC RATE	0.7830	RETURN ON NEW BONDS	-0.1070
HYDRO CONV.	-0.6090	HYDRO CONV.	0.1070
DEPRECIATION RATE	-0.6086	STEAM PRODUCTION	0.0900
STEAM PRODUCTION	-0.4340	TRANSMISSION	0.0540
TRANSMISSION	-0.3480	GENERAL	0.0535
GENERAL	-0.3480	PROPERTY TAX RATE	-0.0535
DISTRIBUTION	-0.3480	AFUDC RATE	-0.0535
RETURN ON NEW BONDS	-0.3480	DISTRIBUTION	0.0535
OUTSTANDING BONDS	0.2010	COST EMBEDDED DEBT	0.0535
FUEL ADJ. FOR TAXES	-0.2608	% CHIP IN RATE BASE	-0.0268
NUCLEAR PRODUCTION	-0.1740	RET. ON S-TERM DEBT	0.0268
% CHIP IN RATE BASE	-0.1739	NUCLEAR PRODUCTION	0.0268
GENERAL TAX RATE	-0.1739	SHORT-TERM DEBT COR	0.0
RET. ON S-TERM DEBT	-0.0069	FUEL ADJ. FOR TAXES	0.0
PROPERTY TAX RATE	-0.0069	ELECTRIC REVENUES	0.0
SHORT-TERM DEBT COR	-0.0069	GENERAL TAX RATE	0.0
RET. ON COMMON EQUITY	0.0	OUTSTANDING BONDS	0.0
OTHER PRODUCTION	0.0	OTHER PRODUCTION	0.0
GEN. INFLATION RATE	0.0	SALES TO ULTIMATES	0.0
PARAMETER		PARAMETER	
RET. ON COMMON EQUITY	1.2270	RET. ON COMMON EQUITY	1.2270
GEN. INFLATION RATE	0.6659	GEN. INFLATION RATE	0.6659
LONG-TERM DEBT COR	-0.6267	LONG-TERM DEBT COR	-0.6267
COMMON EQUITY COR	0.6136	COMMON EQUITY COR	0.6136
DEPRECIATION RATE	-0.3650	DEPRECIATION RATE	-0.3650
RETURN ON NEW BONDS	-0.1040	RETURN ON NEW BONDS	-0.1040
OUTSTANDING BONDS	-0.0522	OUTSTANDING BONDS	-0.0522
AFUDC RATE	-0.0392	AFUDC RATE	-0.0392
PROPERTY TAX RATE	-0.0392	PROPERTY TAX RATE	-0.0392
% CHIP IN RATE BASE	-0.0392	% CHIP IN RATE BASE	-0.0392
HYDRO CONV.	0.0390	HYDRO CONV.	0.0390
STEAM PRODUCTION	0.0260	STEAM PRODUCTION	0.0260
RET. ON S-TERM DEBT	0.0130	RET. ON S-TERM DEBT	0.0130
GENERAL	0.0130	GENERAL	0.0130
DISTRIBUTION	0.0130	DISTRIBUTION	0.0130
TRANSMISSION	0.0130	TRANSMISSION	0.0130
COST EMBEDDED DEBT	0.0130	COST EMBEDDED DEBT	0.0130
SHORT-TERM DEBT COR	0.0	SHORT-TERM DEBT COR	0.0
FUEL ADJ. FOR TAXES	0.0	FUEL ADJ. FOR TAXES	0.0
ELECTRIC REVENUES	0.0	ELECTRIC REVENUES	0.0
GENERAL TAX RATE	0.0	GENERAL TAX RATE	0.0
NUCLEAR PRODUCTION	0.0	NUCLEAR PRODUCTION	0.0
OTHER PRODUCTION	0.0	OTHER PRODUCTION	0.0
SALES TO ULTIMATES	0.0	SALES TO ULTIMATES	0.0

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Figure Captions

Fig. 1. Information Flow In NUFS.

Fig. 2. The Ten DOE Regions.

Fig. 3. A Schematic Representation of MEFS.
[From Glenn DeSouza, "Mid-Range Energy Forecasting System: Structure, Forecasts, and Critique," Energy Systems and Policy 4 (1980)]