REGULATORY POLICY AND THE PERFORMANCE OF ELECTRIC UTILITIES: A SYSTEM DYNAMICS ANALYSIS

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I. INTRODUCTION

The planning environment faced by the electric utility industry has become increasingly complex. Not only have there been many 'shocks', such as oil embargoes, escalating prices, and construction delays, but the reactions of once almost-predictable and benign external entities have become increasingly uncertain and disadvantageous to the utility. Consumers have reacted strongly against price increases, such that load growth has slowed dramatically and in some instances, available capacity is higher than that required from the standpoint of maintaining service reliability. Investors have required greater returns as the financial performance of utilities has fallen; and this has further weakened the utilities' financial condition. Faced with consumer pressure, regulators have become more reluctant to grant rate relief of sufficient magnitude to enable utilities to earn their cost of capital. As a result, utilities are in poor financial condition, with falling bond ratings and stock selling below book value.

Managers and regulators are likely to have a difficult time correcting these problems. This stems primarily from the interrelatedness of the problem -- there is no single cause of the utilities plight. Rather, the present situation has evolved over the last ten years as the individual actors -- utility management, consumers, investors, and regulators -- each has responded to the various shocks and the actions of the other actors in such a way as to cause a generally deteriorating situation:

- management was unable to adjust long lead-time construction programs, resulting in unwanted capacity becoming available in times of falling load growth;
- consumers responded to rapidly escalating rates by reducing usage, but this increased fixed costs per kilowatt hour further, creating upward pressures on rates;
- investors responded to inflation and the deteriorating financial peformance of utilities by requiring a higher risk premium, but this further raised utility costs, created upward pressure on rates, and worsened financial performance; and
- regulators have held down rates of return on utility stock, thereby worsening financial performance and increasing the cost of raising new equity and debt.

A downward spiral of higher costs, higher but inadequate rates, poor financial performance, slower load growth, and even higher costs has developed from the combined actions of management, consumers, investors, and regulators. As a result, there is likely to be no easy solution to the utilities' problems. Lower inflation, higher (or lower) demand growth, or more understanding investors and regulators alone will not dramatically improve the situation. Rather, it will take a combined effort to reverse the trends which have led to the present condition, and prepare utilities for the plant expansion needed to meet demand growth in the nineties.

In response to the need for an integrated look at the problems of electric utilities, Pugh-Roberts Associates, Inc. has developed a strategic planning model for electric utilities. In various forms, it has been used by utility industry investors, by individual utilities, and by research organizations for analyzing alternative investment, management, and regulatory strategies.

A wide range of policy issues can and have been explored with the model. These issues include:

1. Capital investment policy
   - o reserve margin goals
   - o size of new plants constructed
   - o customer versus shareholders interests, when funds are limited
   - o investment in end-use and load management control
   - o cancellation of plants under construction
   - o diversification
2. Financial Policy
   - o dividend levels
   - o willingness to sell stock below book value
   - o debt levels
3. Regulatory Policy
   - o allowed rate of return
   - o CWIP
   - o forward test year

This paper describes the use of the model to analyze the impact of alternative regulatory policies on utility performance. As noted above changes in regulatory policy alone will not solve all the problems of the utilities. Nevertheless, as will be shown, regulatory policy does have a strong impact on utility performance and must be a central element of any strategy to revive the industry. The results of other analyses are reported elsewhere (see 1, 2, 3 and 4). Finally, the reader is cautioned as to interpretation of the results contained in this paper. These results are

intended to be representative of the electric utility industry. However, individual utilities differ from the average, and the results may vary depending on the assumptions used.

II. STRUCTURE OF THE MODEL

Overview

The electric utility model is a behavioral simulation model useful for analysis of strategic and policy issues. The model is behavioral in the sense that it describes the cause and effect forces which determine the behavior of the utility, for example the forces which lead to investment in baseload capacity. The model is a simulation model in the sense that, given the condition of the utility at a point in time (e.g. 1975), it calculates the changes to that condition which result from the behavioral forces (as affected by external trends) at future points of time. These calculations are made every eighth of a year. So between say, 1975 and 2000, the model steps through, or simulates, 200 evolutions of the condition of the utility.

The model is primarily useful for analysis of strategic and policy issues because of its scope and level of detail. In scope, it consists of a series of sectors representing the major activities of a utility and its interaction with the external environment (customers, investors, regulators, general economy). These sectors are:

1. Demand Generation
2. Capacity Planning
3. Power Generation
4. Financial Planning
5. Accounting

6. Capital Markets
7. Regulation

The model represents the activities within these sectors at a relatively aggregate level of detail. It does not, for example, pinpoint the timings and magnitude of security issues. It does identify the order of magnitude of financing needs (± 10 percent), and more importantly shows the impact of alternative capital structures on utility performance. It provides quick turnaround analyses (several hours to a couple of days) which consider the entirety of the utility and its environment. These are the analyses useful for evaluating strategy and policy questions.

Figure 1 highlights the key interactions among model sectors. An aggregate demand for electricity is calculated in the Demand Sector, based on exogenously specified growth rates, and on the price of electricity. Demand "drives" the Power Generation Sector and also is used as the basis for load forecasting in the Capacity Planning Sector. Capacity is ordered to meet the load forecast, subject to availability of funds. The Power Generation Sector provides power in response to demand, within the constraints of capacity available. The Accounting Sector determines the utility's financial performance, based on the amount of power delivered, rates, and various categories of costs. The Financial Planning Sector raises capital in response to the utility's financial performance and the requirements of the Capacity Planning Sector, and feeds information back concerning availability of funds. The capital Markets Sector determines the cost of debt and equity capital based on utility financial performance. Finally, the Regulation Sector uses information about the utility's costs and its rate base to establish an aggregate rate for all customers.

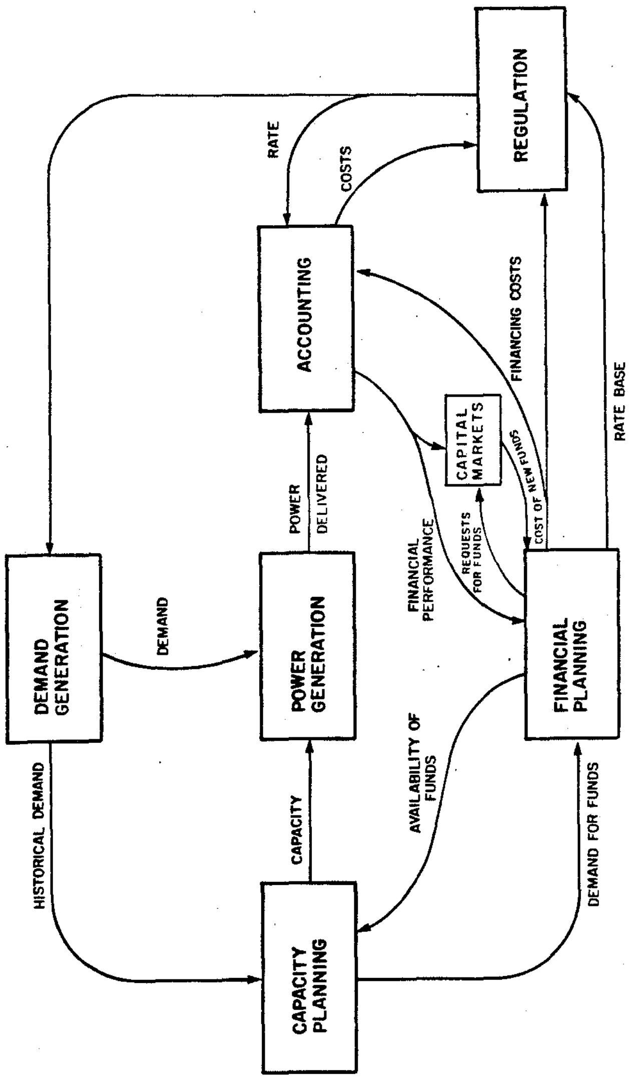


FIGURE I KEY INTERACTIONS AMONG MODEL SECTORS

Figure 2 shows a more detailed representation of model sectors and the major external inputs to the model. Demand is calculated for residential, industrial and commercial users based on the number of customers in each class (exogenously specified over time), a reference KWH per year for customers in each class (exogenously specified over time), and an effect of price on the KWH per year actually used. The effect of price can be different for each customer class, depending on the real price of electricity (adjusted for changes in real income), the short-term price elasticity, and the long-term price elasticity.

Capacity planning and construction is modeled for four categories of plant: peaking, oil-fired, nuclear and coal. When lead-times and financing permit, baseload rather than peaking units are constructed. The fuel type of the baseload units is specified exogenously as a function of time. Units constructed in the future are assumed to be coal-fired. Where lead times do not permit construction of baseload units, peaking units are constructed. This might occur when actual demand growth exceeds expectations, or when financial constraints limit or delay construction of baseload units.

The Financial Planning Sector of the model takes the demand for funds and trys to raise debt, preferred, or common equity to meet any shortfall not provided by retained earnings. The mix depends on the costs and availability of each type. When funds are not available, capacity construction is delayed or not started.

The Accounting Sector computes financial performance based on power delivered, rates, and costs. Costs are computed for five distinct categories:

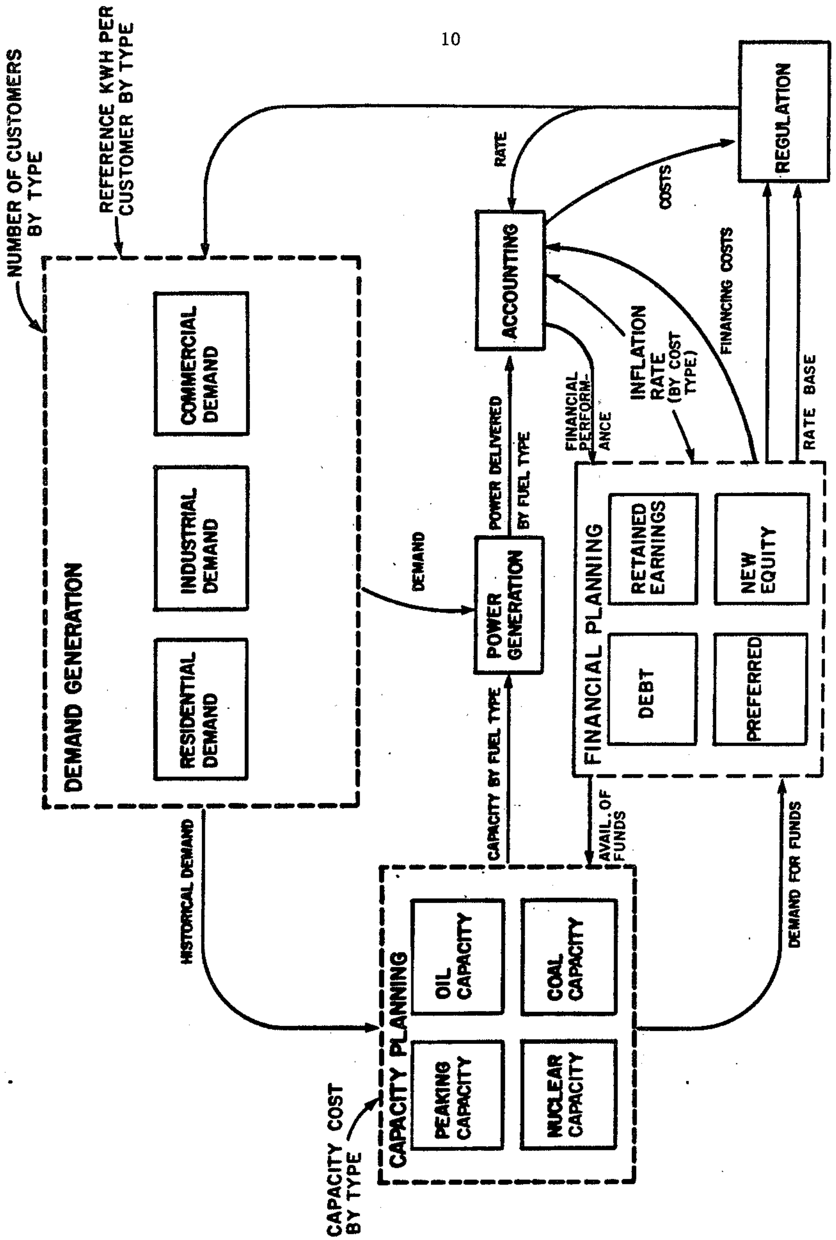


FIGURE 2 MORE DETAILED REPRESENTATION OF MODEL

1. Fuel
2. Operating and Maintenance (Fixed and Variable Components)
3. Depreciation
4. Financing (Interest)
5. Taxes (General, Income)

Inflation rates, specified exogenously as a function of time, cause costs to change from a reference level (e.g., capacity construction costs of \$1000/KW in 1980).

The Regulatory Sector computes only one aggregate rate per KWH. While different rates might be computed for each customer class, this aggregation was felt appropriate given the assumption that rates are set by the same regulatory body, and that they will be allocated proportionally (by cost of service) to all customer classes.

In all, the model contains approximately 700 equations which describe the sectors, their interactions, and the external environment.

Key Feedback Relationships

The model contains a large number of feedback relationships. The key relationships, which involve price and demand, the capital markets, and regulators, are described below.

Feedbacks Involving Price and Demand. The two feedback loops involving price and demand are shown in Figure 3.* The first loop (solid lines)

* Arrows in the figure indicate the direction of causality between two variables, while the sign at the end of the arrow indicates the "polarity" of that causality. For example, an increase in cost per KWH increases rates (+); an increase in rates, however, decreases demand (-).

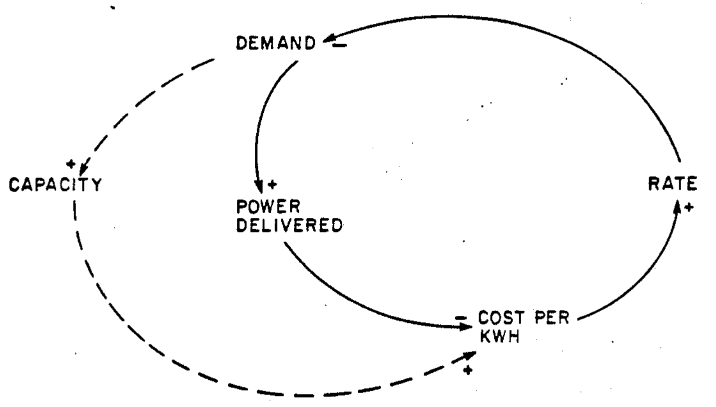


FIGURE 3 PRICE FEEDBACK LOOPS

is a positive loop, and works as follows: given a certain amount of capacity and therefore fixed costs, an increase in power delivered tends to reduce cost per KWH. Other factors affecting rates being equal, rates are also reduced, thereby increasing demand. The increase in demand further increases power delivered, lowers costs, lowers rates, and so on. This loop is called a positive feedback loop because it tends to feed on itself in an ever-growing (or declining) spiral. (In the decline mode, positive feedback loops are often called vicious circles).

The second loop shown in Figure 3 is a negative feedback loop which acts to control the positive loop. As demand grows, more capacity is needed to provide the power. As a result, fixed costs and cost per KWH increase. In response, rates increase, thereby lowering demand. The loop is negative in that an initial increase in demand stimulates actions which decrease demand, whereas in the positive loop the increases feed on themselves.

The delays in the negative feedback loop are considerably longer than those in the positive loop because of the length of time required to add new capacity. Thus, the positive loop can operate for a number of years before the negative loop acts to control it.

Historically, the positive loop has been dominated by external trends: rapid growth in population and standard of living have spurred on demand growth, such that the perturbations caused by these feedback loops have not been noticed. In fact, before the mid-seventies, the addition of capacity tended to lower, rather than to raise, costs. Both loops, therefore, acted to stimulate demand. Now, however, with slow demand growth, the effects of these loops become important and can cause wide cycles on an underlying growth trend, as will be described later in the discussion of the base case simulation.

Feedbacks Involving the Capital Markets. A second important set of feedback loops involve the capital markets, as shown in Figure 4. The first of these loops involves interest: an increase in interest rate tends to raise interest charges; the increase in interest charges raises costs, which in turn lowers interest coverage. The reduction in interest coverage, after a delay representing market perception and reaction to the change, further increases the interest rate, initiating a downward spiral. The interest loop is a positive feedback loop. The decrease in interest coverage initiates a second downward spiral; after a delay, it acts to reduce stock price, which means that more shares must be issued to raise a given volume of external funds. As more shares are issued, stock price tends to fall further because of the dilution in earnings, and so on. Both of the feedback loops further feed on themselves by reducing internal funds generation and by raising external funds required: increasing interest charges increases costs; increasing the number of shares raises dividend payments.

The downward spirals produced by the positive feedback loops are controlled by the negative loops shown by the dashed lines in Figure 5. As interest coverage and stock price deteriorate, the utility either becomes unable or unwilling to raise additional debt or equity. As a result, available funds fall short of those required and the construction program is adjusted to reduce external funds requirements. Because less new stock and debt are issued, the downward spirals are slowed or eliminated (until service and reliability criteria force construction).

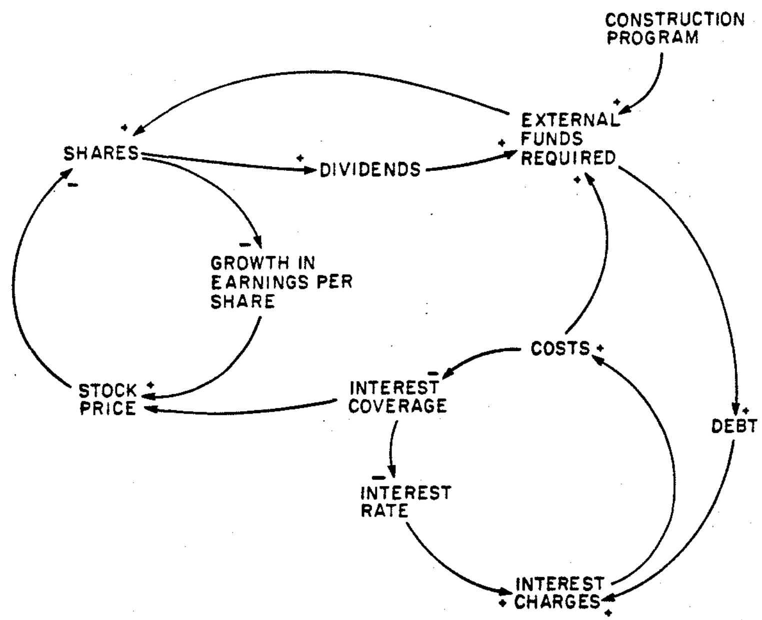


FIGURE 4 CAPITAL MARKET FEEDBACKS

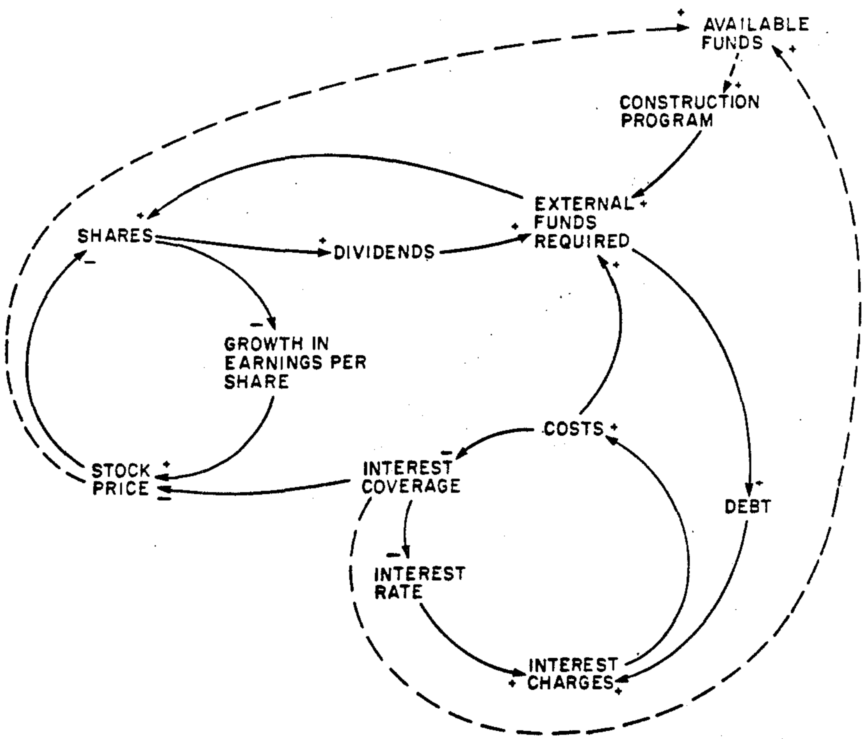


FIGURE 5 CAPITAL MARKET FEEDBACKS WITH NEGATIVE CONTROL LOOPS

While these capital market feedback loops have existed in the past, it is unclear how important they have been. As will be seen in the discussion of the Base Case, the conditions which initiate the downward spirals are likely to exist in the later eighties and early nineties.

Feedbacks Involving Regulators. An important agent in many of these feedback loops is the regulatory authority. The authority takes information about costs and rate base and converts them into rates. Changes in rates, as noted above, feed back to influence costs via demand and capacity expansion. The model represents the rate-setting process as it is in real life -- imperfect. There is assumed to be a lag of one year between the time a rate case is filed and finally approved, and significant delays in responding to change in the inflation rate.

An important set of feedback loops connect the utility, the regulators, and the capital markets, as shown in Figure 6. If, for whatever reason, interest coverage should fall, interest rates increase as described above. After regulatory delays, the increase in interest rate leads to an increase in rates, which in turn improves earnings and interest coverage, thereby halting a further increase in interest rates. In other words, as the risk to debt holders increases, the cost of this to the utility is reflected in rates. A similar feedback through risk to equity holders is also included in the model, but only takes effect for values of interest coverage below 3.0.

Other Feedback Relationships. As noted previously, there are many feedback loops in the model beyond those given in Figures 3, 4, and 5. An example of some of the more subtle feedback loops involving price are shown in Figure 7. These loops show how efforts to hold down rates in the short-term can increase them in the long-term. Historically, regulatory

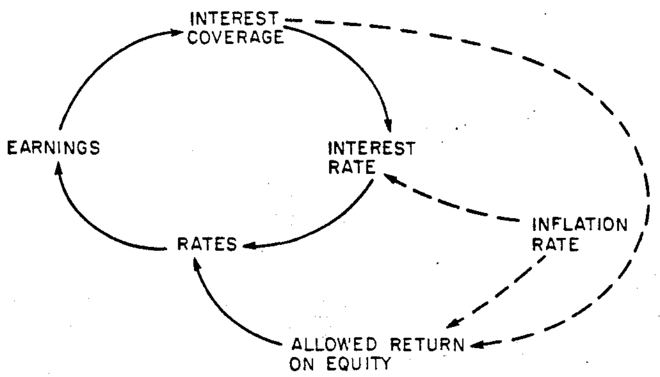


FIGURE 6 FEEDBACKS INVOLVING REGULATION

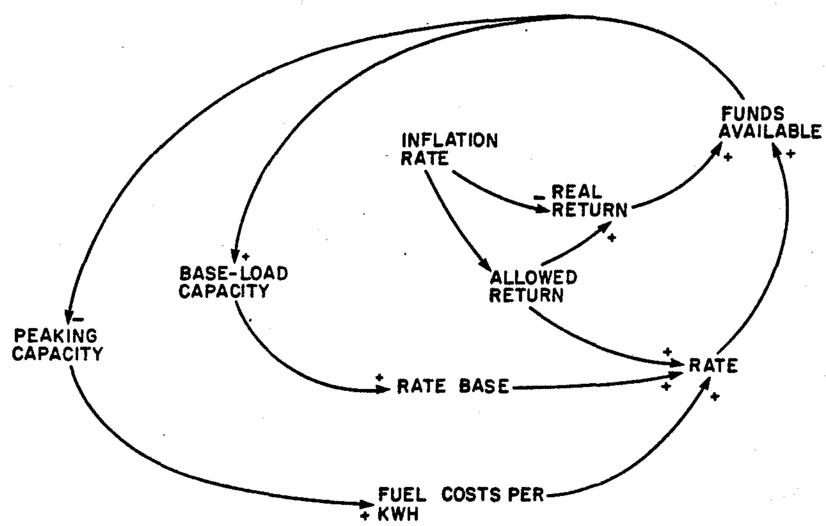


FIGURE 7 MORE SUBTLE FEEDBACK LOOPS INVOLVING PRICE

bodies have been slow to increase allowed return in response to changes in inflation rate. While this tends to slow the rate of increase in rates, it also reduces funds available for construction in two ways: first, by directly reducing internal cash flow; and second, by reducing the real return to investors, and/or increasing the risk of those investments, thereby making external financing more difficult to obtain and/or more costly. As a result, shortages of funds constrain the construction of base-load units. Should demand continue to grow (as it is likely to do with the added stimulus from the price feedback loops), peaking capacity will eventually be needed to meet demand. But the use of peaking capacity for baseloads raises fuel costs per KWH, thereby raising rates over what they might have been, had base-load units been constructed. The model contains many feedback relationships of this type.

Important Model Assumptions

In addition to a structure which states how the pieces of the utility and the environment interact, the model contains assumptions about external trends, the strength of reactions by external agents (e.g. capital markets and regulators), and management policies. The structure together with the assumptions determine the time behaviour of variables in the model. Important assumptions are noted below. These assumptions are meant to be reasonable and representative of the utility industry. They constitute a hypothetical electric utility.

External Trends. Assumptions regarding external trends fall into two categories: (1) factors affecting demand growth, and (2) cost inflation rates. Specific assumptions used in the Base Case simulation of the model

are given in Table 1. As can be seen in the table, demand growth, exclusive of price changes, is expected to average 2.3 percent per year. Price changes work through short- and long-term elasticities (additive effects) to change demand growth from the rates given above. Inflation in utility costs is assumed to exceed general inflation rates.

Reactions By External Agents. External agents determine three factors of importance to utilities: interest rates, stock price, and rates. How each is modeled is discussed below.

The interest rate on new debt NINTR equals the sum of three components: a risk-free rate RFINT, inflation premium IFPD, and a risk-premium RPD:

$$NINTR=RFINT+IFPD+RPD$$

NINTR - New Interest Rate (fraction/year)
IFPD - Inflation Premium for Debt (fraction/year)
RFINT - Risk-free Interest Rate (fraction/year)
RPD - Risk Premium for Debt (fraction/year)

The risk-free rate is assumed to equal a constant 2.5 percent; the inflation premium is simply a one-year average of the inflation rate. The risk premium for debt is modeled as a function of interest coverage, since interest coverage is a key factor in utility bond ratings, and is also a reasonable proxy for other risk indicators. The risk-premium is assumed to rise steeply as interest coverage falls. The interest coverage used is a weighted average of coverage including and excluding allowance for funds used during construction (AFUDC).

Investors in utility stock are assumed to value it much like debt, that is, by a dividend yield. As indicated in the equations below, market price per share MPS equals dividends per share DIVPS divided by net stock discount rate NSDR, where NSDR equals the sum of a risk-free interest rate

RFINT, an inflation premium IFPD (same premium as for debt), a risk-premium for equity RPE, and the negative of anticipated growth in dividends per share AGDPS.

MPS = DIVPS/NSDR

NSDR = RFINT+IFPD+RPE-AGDPS

MPS	-	Market Price Per Share ($/share)
DIVPS	-	Dividends Per Share ($/year/share)
NSDR	-	Net Stock Discount Rate (fraction/year)
RFINT	-	Risk-Free Interest Rate (fraction/year)
IFPD	-	Inflation Premium for Debt (fraction/year)
RPE	-	Risk-premium for Equity (fraction/year)
AGDPS	-	Anticipated Growth in Dividends Per Share (fraction/year)

The risk-free rate and inflation premium of debt are the same as that used in determining new interest rate.

The risk premium of equity is a function of interest coverage (same coverage as for risk premium of debt). Given that most utility stockholders view their stocks as near-debt, interest coverage is a reasonable indicator of the risk of being paid dividends. In the model, risk-premium rises steeply when interest coverage falls.

Anticipated growth in dividends per share is based on historical dividend growth. Anticipated growth is assumed to equal historical rates of growth, as calculated by the model, over the last several years. The higher the growth rate, the lower the discount rate. The above stock valuation model gives a good fit to the historical stock prices of many utilities modeled in earlier work.

The rate set by the regulatory body for this hypothetical utility is the sum of three components: (1) fuel cost adjustment; (2) other costs; and (3) return on rate base. Changes in fuel costs are passed through with

TABLE 1

BASE CASE ASSUMPTIONS: EXTERNAL ENVIRONMENT

1. Demand Growth Rates Assuming Constant Real Prices and Real Income: 2.3% per annum

2. Price Elasticity: -1.0 for all customer classes

3. Inflation and Real Income:

   General Inflation Rate of 8% p.a. (actual CPI used 1980,1981)

   Increment in Utility Costs from General Rate -

	Increment 1983-1990	Increment After 1990
Capacity Cost	+1%	+1%
Oil Cost	+1.5%	+1.5%
Nuclear Fuel Cost	+7%	-1%
Coal Cost	+0.5%	+0.5%
O&M Cost	+1%	+1%
General Taxes	+1%	+1%

4. Regulation:
   - Assuming stable inflation rate, regulators will allow a real return on equity consistent with risk level by 1990 (assumed to be 8%).
   - Regulatory Delay of 1 year.
   - No forward test year or CWIP.

a three-month lag; the latter two components must be approved in a regulatory proceeding. The delay in granting a new rate is set at a constant one year. There is no forward test year nor CWIP allowed.

The allowed rate of return is the sum of the allowed debt, preferred, and equity returns, weighted by their percentage of the capital structure. Debt and preferred returns are based on actual charges paid; the allowed return on equity is the sum of a real return and an inflation adjustment, which is a function of a five-year average of the inflation rate. Historically, allowed returns on equity have not kept pace with inflation such that real returns have fallen. There are two possible explanations for this: (1) regulators have been slow in recognizing the permanence of high rates of inflation; and (2) regulators have responded to consumer pressures and allowed real returns to fall, even though they accept the high inflation rates as "permanent". Either way, the model represents both of these explanations by basing the allowed return on equity on an average of inflation.

Management Policy Variables. The two important areas of management policy relevant to a strategic planning model are capacity expansion policy and financing policy. Table 2 lists the key elements of the hypothetical utility's policies. Policies in the model state how utility management (and for that matter investors and regulators) respond to changing conditions. They are an integral part of the feedback structure of the model.

TABLE 2
BASE CASE ASSUMPTIONS: UTILITY POLICIES

1. Capacity
   - Desired Reserve Margin - 20%
   - Desired Fuel Type - Only new coal plants after present construction, except for normal amounts of peaking capacity.
   - Construction Lead Times - 8 years for coal Baseload
     3 years for peaking
   - No significant investment in conservation or load management.

2. Financing
   - Desired Capital Structure - 50% Debt, 38% Common, 12% Preferred
   - Dividend Payout Objective - 75%

III. BASE CASE PERFORMANCE OF HYPOTHETICAL UTILITY

The Base Case is simply a simulation from 1975 to 2000 which is produced assuming a continuation of present management and regulatory practices, and likely assumptions regarding the evolution of external trends. It is a look at the historical and likely future performance of a hypothetical electric utility.

Coal Base Case.

Figures 8 through 15 show the projected Base Case performance of the hypothetical coal-based electric utility from 1980 to 2005. Figure 8 shows the trends in capacity, peak load, power delivered, and reserve margin. Time runs across the bottom axis; the scales for the variables plotted are given along the vertical axis (in the scales, "T" stands for thousands, "M" for millions, and "B" for billions).

From 1980 to 2005 demand growth averages 2.2 percent, slightly below the growth rate of 2.3 percent in customers and usage per customer assuming constant prices. However, the rate of growth over the period is not at all smooth, whereas customer growth is. Both of these deviations are caused by variations in real price, as shown in Figure 9.

In the early eighties, prices are high relative to the levels of the seventies. Hence, price feedback effects on consumption are keeping demand nearly constant in spite of the 2.3 percent per year growth in customers and usage per customer assuming constant real prices. Reserve margins therefore continue to grow over the 1980 to 1985 period as construction

FIGURE 8

DEMAND AND CAPACITY

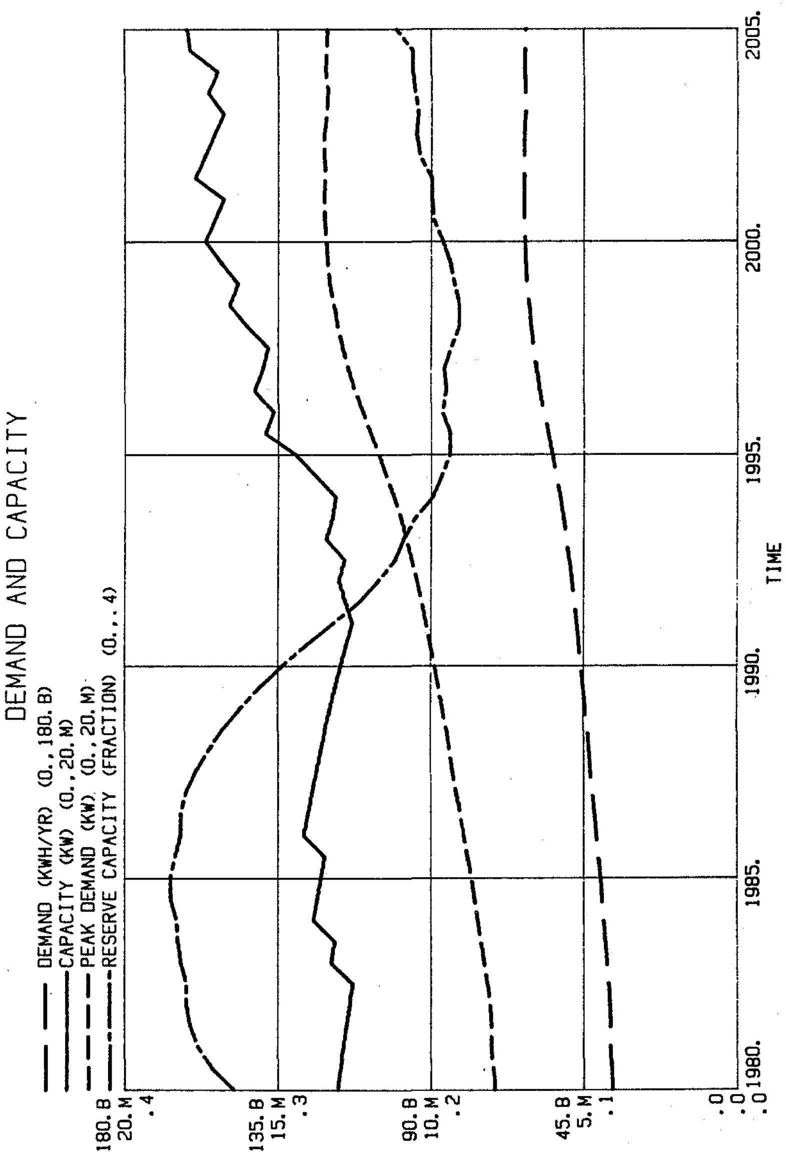
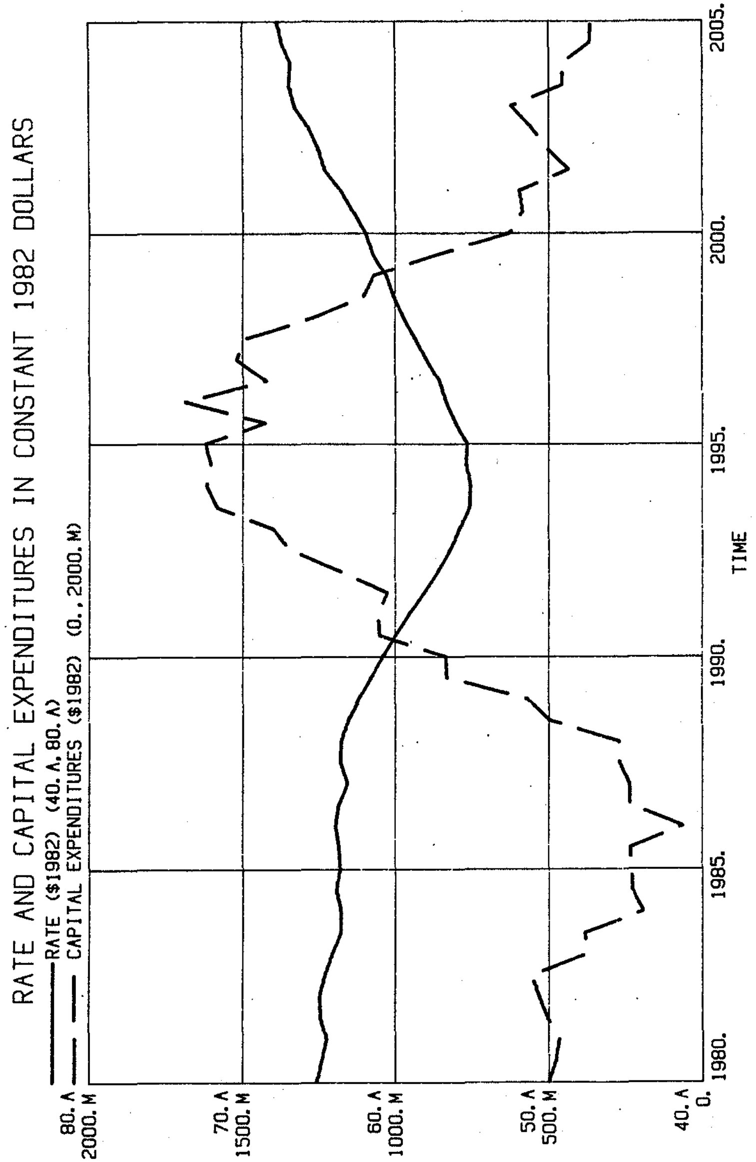


FIGURE 9



started earlier is completed. Prices are high for two reasons: first, increases in fuel costs above the rate of inflation; and second, increases in fixed charges per KWH at the high reserve margins mean that the costs of unused capacity must be spread across a smaller base of power delivered.

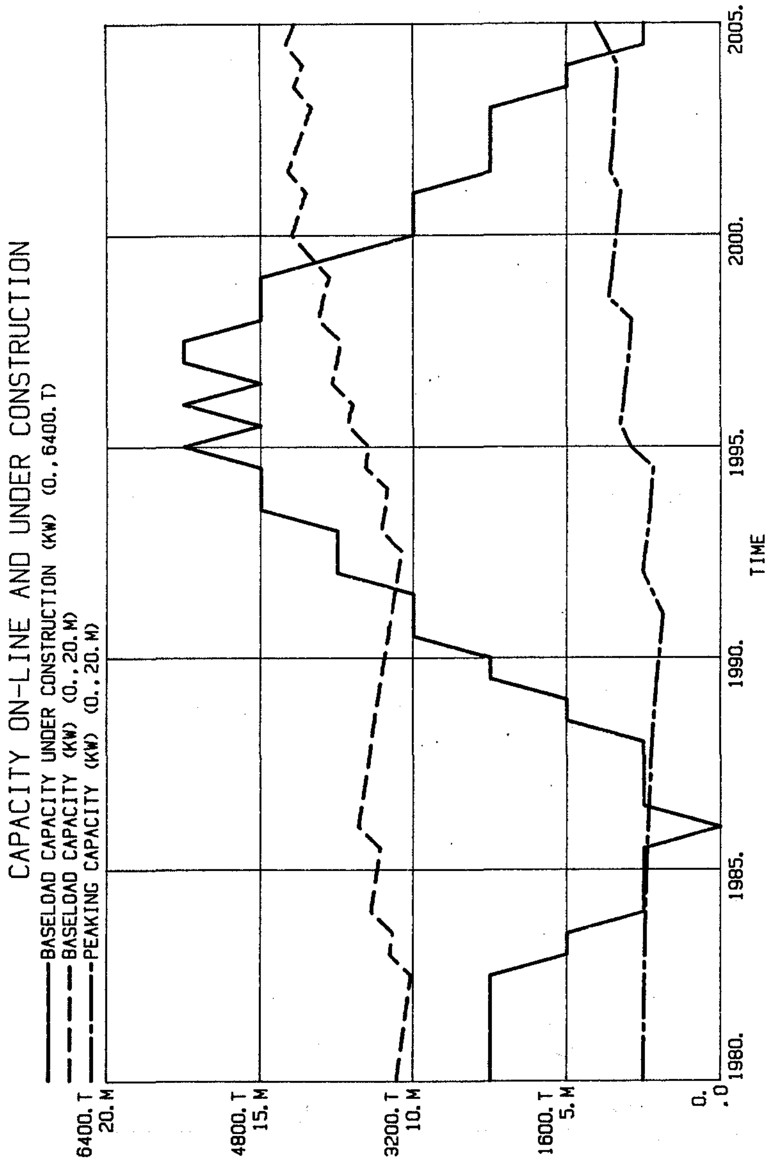
As the utility perceives the slow load growth and high reserve margin, the construction program is reduced (see Figure 10): in 1980, 3 plants were under construction; by 1985 only one is. This low level of construction is maintained until 1988.

With the reduced construction program, real prices are nearly flat from 1980 to 1989. Demand growth then acts to drive down reserve margins; as a result fixed charges are spread over a larger KWH base. A fall in real prices then further stimulates demand growth--between 1987 and 1995 demand growth exceeds the rate inherent in customer growth.

In response to the renewed load growth and declining reserve margins, the utility once again gears up the construction program. But the unanticipated growth stimulated by falling real prices causes reserve margins to fall below the utility's 20 percent objective because of the long lead times of base load plants. Peaking units are added, and margins improve in the late nineties.

The cost of fuel for the peaking units begins to drive up real prices. Increases in utility costs above general inflation and the arrival of new baseload units into the rate base continue the upward trend. As a result, price feedback effects cause demand to reach a peak and level off between 2000 and 2005 such that reserve margins rise above 20 percent.

FIGURE 10



The financial performance of the utility is shown in the remaining figures. Figure 11 gives the behavior of return on equity and return on rate base. By assumption, the allowed return on equity increases to 16 percent (8 percent inflation plus 8 percent real return.) Realized returns, however, except for a brief period near 1990, average well below allowed. Returns fluctuate because of the discrete nature of rate cases: they rise immediately after a rate case, then deteriorate as inflation drives up costs while rates remain constant (except for fuel charge pass-throughs), and as new plants are brought into service but regulatory lag delays their inclusion in the rate base. Returns are therefore the lowest when inflation is highest and when the most construction is occurring. Conversely, returns increase toward allowed when costs are falling and the construction program is low (as in the late eighties).

Figure 12 shows some 'per share' data for the utility. Earnings and dividends per share grow at rates averaging 4 percent per year from 1982 to 1992 as the reduced construction program, relative to internal funds flow, obviates the need for new equity, falling reserve margins improve equity returns, and then as AFUDC begins to grow again after 1987. But funding construction in the nineties requires new equity and flattens earnings and dividend growth, particularly when regulatory lag causes delays in converting AFUDC to return on rate base and expenses to revenue. During the eighties, AFUDC percentage of earnings falls to 25 percent, but rises to high levels in the late nineties because of the very high levels of construction work in progress relative to present assets.

For a brief time near 1990, market price per share equals book value per share (Figure 13). A reduction in interest rates, dividend growth, and a reduction in risk premium all act to stimulate market price. The

FIGURE 11

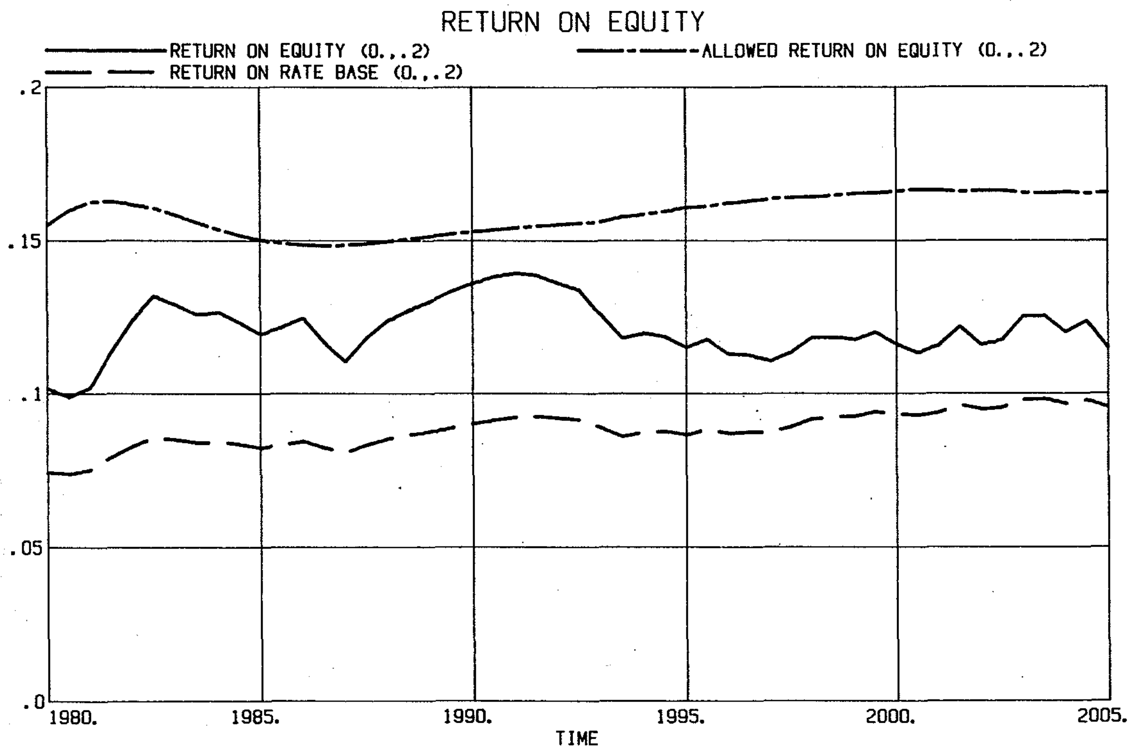


FIGURE 12

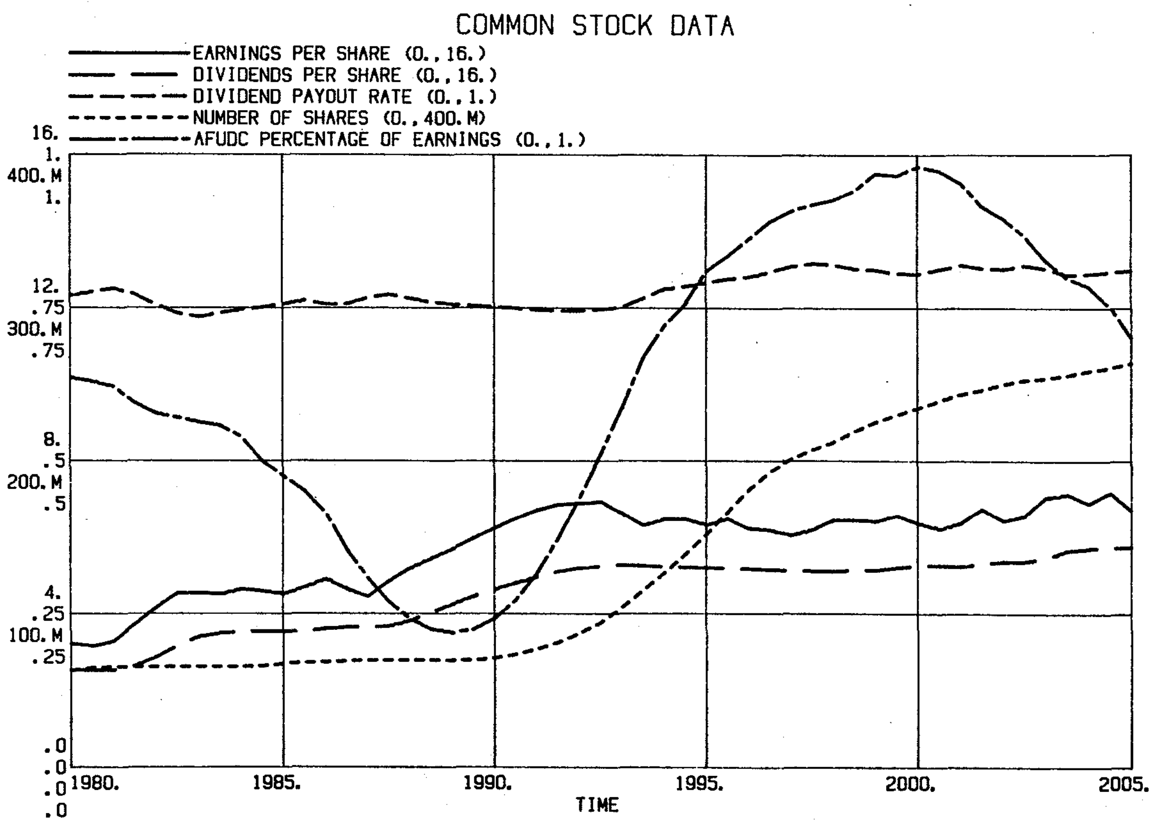
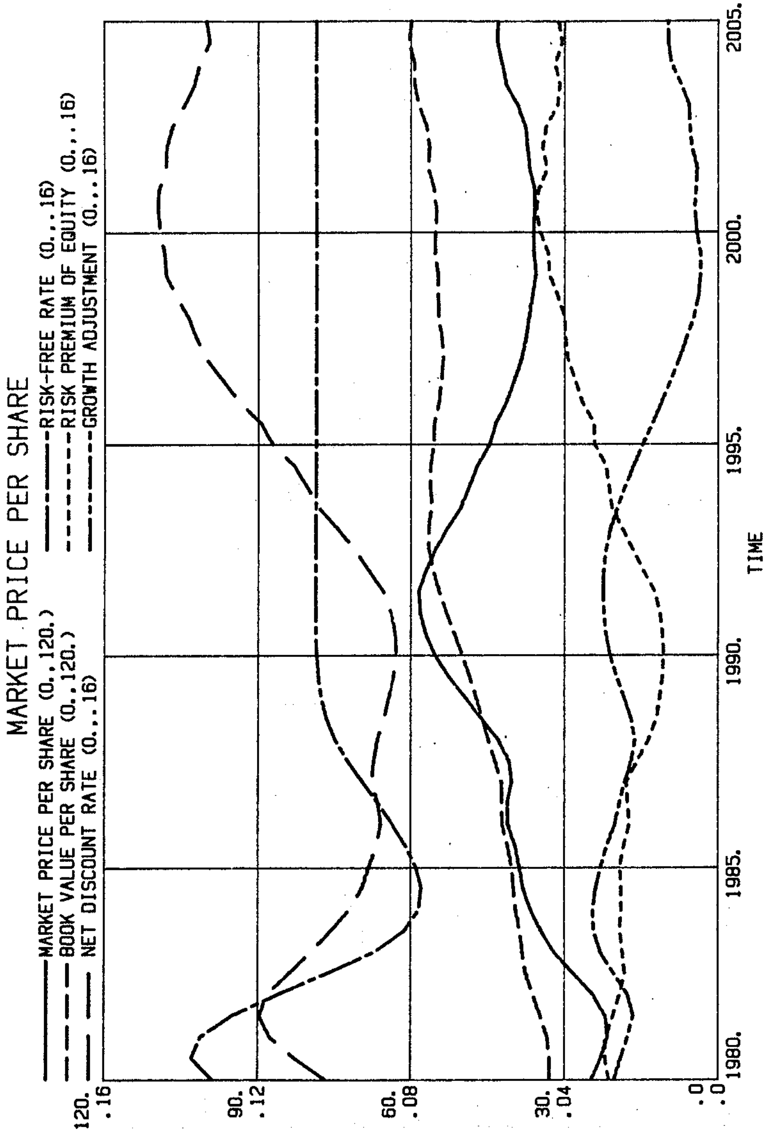


FIGURE 13



reduction in risk occurs because, with the reduced construction, interest coverage improves dramatically (see Figure 14) and earnings quality improves (reduction in AFUDC percentage, Figure 12). But the improvement is short-lived. Once construction resumes, a downward capital markets spiral causes financial performance to rapidly deteriorate: financing construction reduces interest coverage and earnings growth; as these fall the cost of additional financing increases; performance further deteriorates with the next round of financing. The spiral is broken only when performance falls to such a low level that baseload construction outlays must be limited. As a result, the utility in 2005 is using more than 'normal' peaking generation.

Finally, Figure 15 shows the capital structure of the utility and internal financing. During the late eighties, internal funds are nearly sufficient to cover all construction expenditures. No new debt is issued except that to cover retirements. Extra growth in retained earnings reduces debt percentage of total capital. But once construction resumes, internal financing adequacy falls sharply.

FIGURE 14

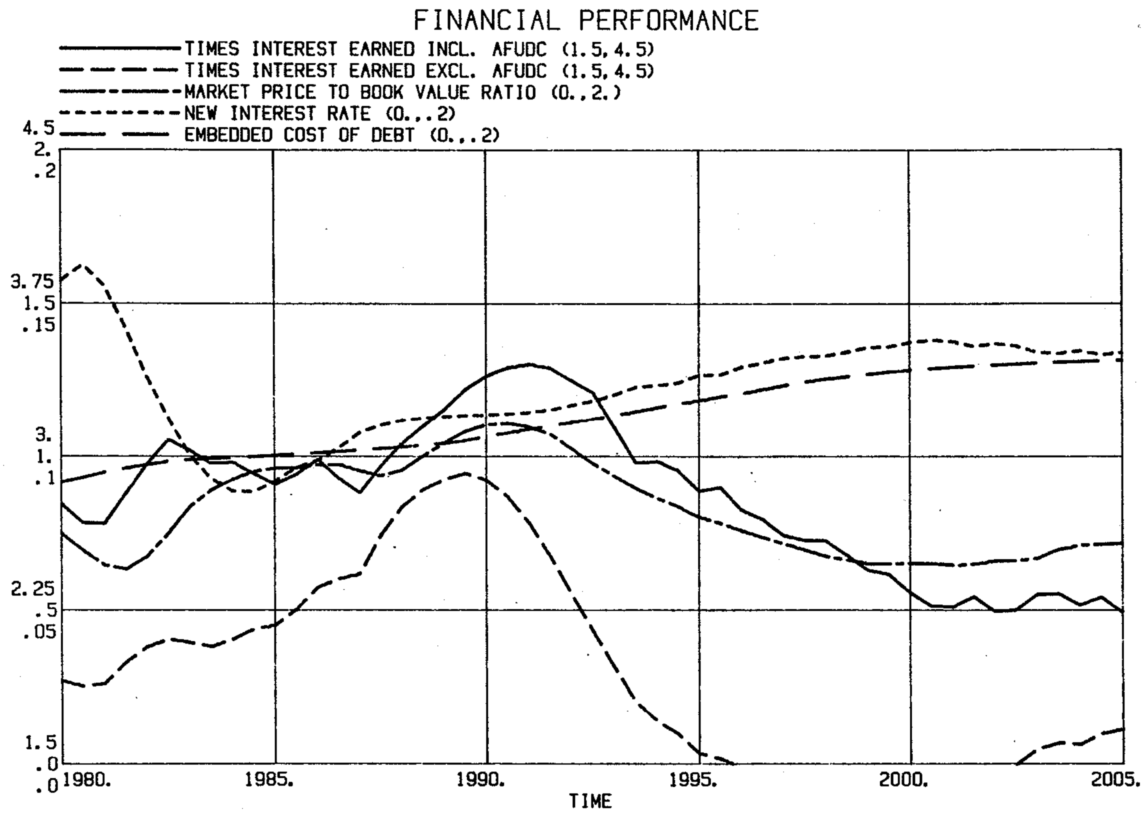
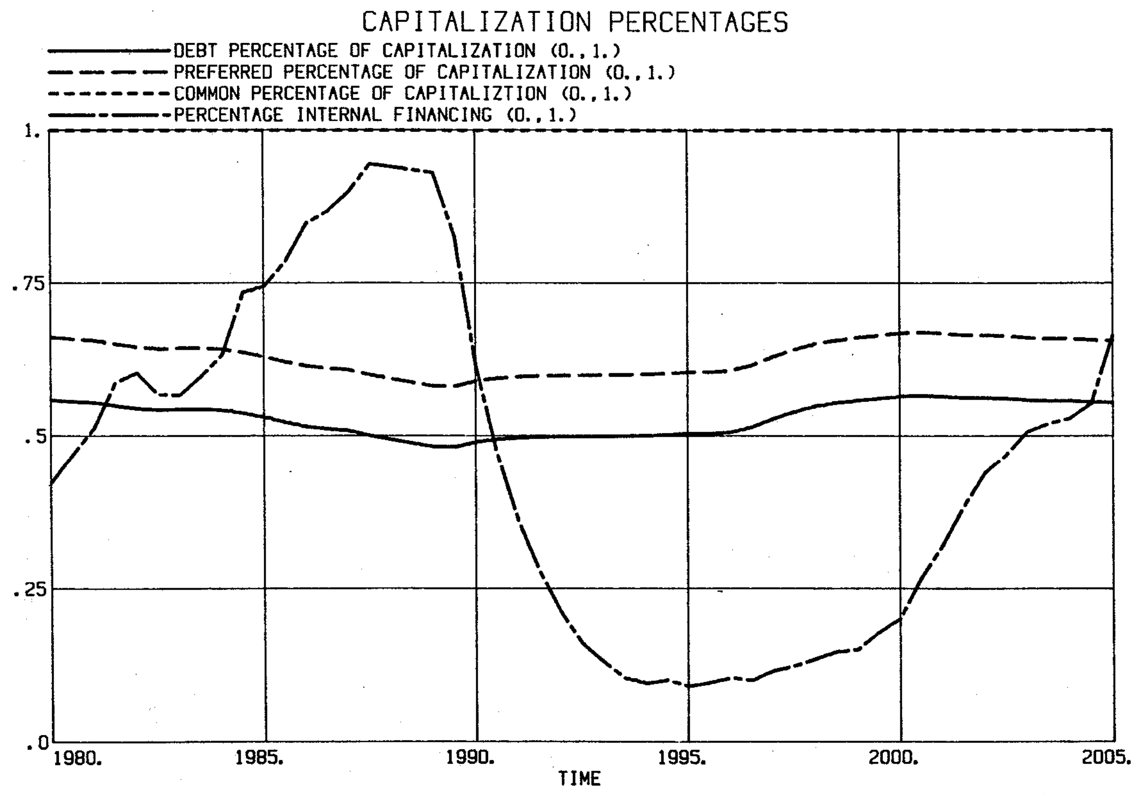


FIGURE 15



IV. REGULATORY POLICY AND UTILITY PERFORMANCE

A number of regulatory policy changes have been proposed to improve the financial condition of electric utilities. These changes include:

1. Allowing a Higher Return on Equity -- Regulators have been reluctant to allow the real return on equity to keep pace with inflation and increased financial risk. In the late sixties and early seventies, when inflation was low, many utilities were allowed a real return on equity near 9 percent. Today, that real return is between 4 and 6 percent, depending on one's perception of the underlying rate of inflation. As inflation stabilizes, the real return will move toward 8 percent in the Base Case. What would be the consequences if regulators allowed the utilities a 9 percent real return on equity, approximately the level historically allowed in low-inflation periods?
2. Reducing the delay between filing and granting of rates to 3 months from 1 year in Base Case;
3. Calculating rates based on expected costs and rate base in a "forward test year."
4. Allowing construction-work-in-progress (CWIP) to be included in the rate base (with full AFUDC between rate cases) -- For most utilities, a return is allowed only on producing electric plant, and not on construction, on the argument that it is not fair to charge today's customers for construction needed for tomorrow's customers. But including CWIP should improve the utilities cash flow and improve financial performance.
5. "Nearly perfect regulation" -- higher return, CWIP, and instantaneous pass-through of cost and rate base changes.

A primary objective of all these policies is to raise the earned return on equity. Figure 16 shows how the policies perform in this regard. Allowing a higher rate of return has a surprisingly small effect, less than the full percentage point increase indicated by the policy change. This occurs because, with higher allowed return, financial performance improves somewhat and

relaxes Base Case pressures, which were already allowing more than the 8 percent normal return. A similar relaxation occurs in the other policies. Note that as regulatory lag is progressively relieved through shorter delay, forward test year, and immediate pass-through, return on equity increases. CWIP also improves return on equity because it reduces the strength of the capital market feedbacks, which were acting to 'inflate' interest costs and thereby drive down allowed return given regulatory lag.

As return on equity improves, so do the other measures of financial performance. Figures 17, 18, 19 and 20 compare the behavior of earnings per share, interest coverage, market price per share and market-price-to-book-value ratio, respectively. Table 3 provides a numerical comparison. The improvement in these other financial measures are consistent with the improvement seen in return on equity.

Note that market price to book value ratio remains above 1.0, and earnings per share growth keeps pace with inflation, only with nearly perfect regulation (although forward test year comes close). The other policy changes improve performance over Base Case levels, but reasonable performance cannot be sustained once construction expenditures resume. The need to finance these expenditures at inadequate rates of return drive financial performance down to minimum acceptable levels via the capital markets feedback loops. Note that with policies which improve financial performance, capital expenditures are actually higher than Base Case levels in spite of lower demand. In the Base Case, construction expenditures are being held down below planned levels because of poor financial performance--peaking capacity is being added and baseload construction needed after 2005 being deferred. As financial performance improves, expenditures increase and drive down performance.

FIGURE 16

RETURN ON EQUITY -- REGULATORY POLICIES

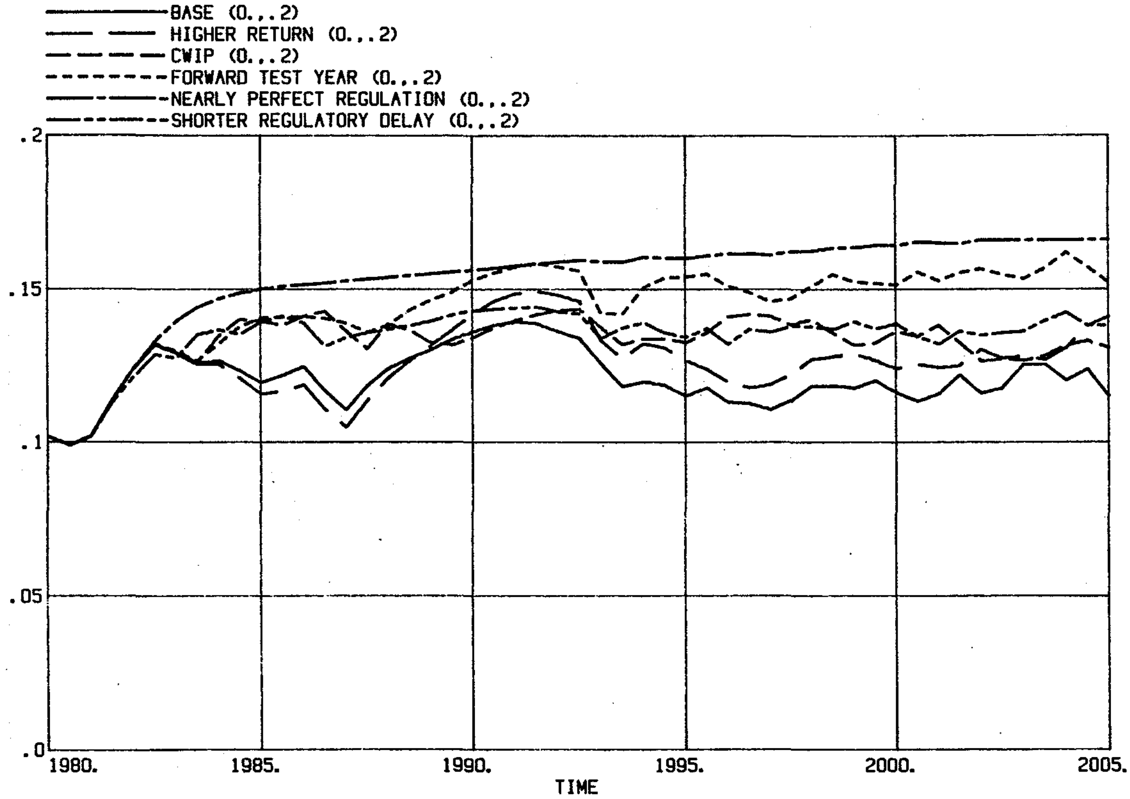


FIGURE 17

EARNINGS PER SHARE -- REGULATORY POLICIES

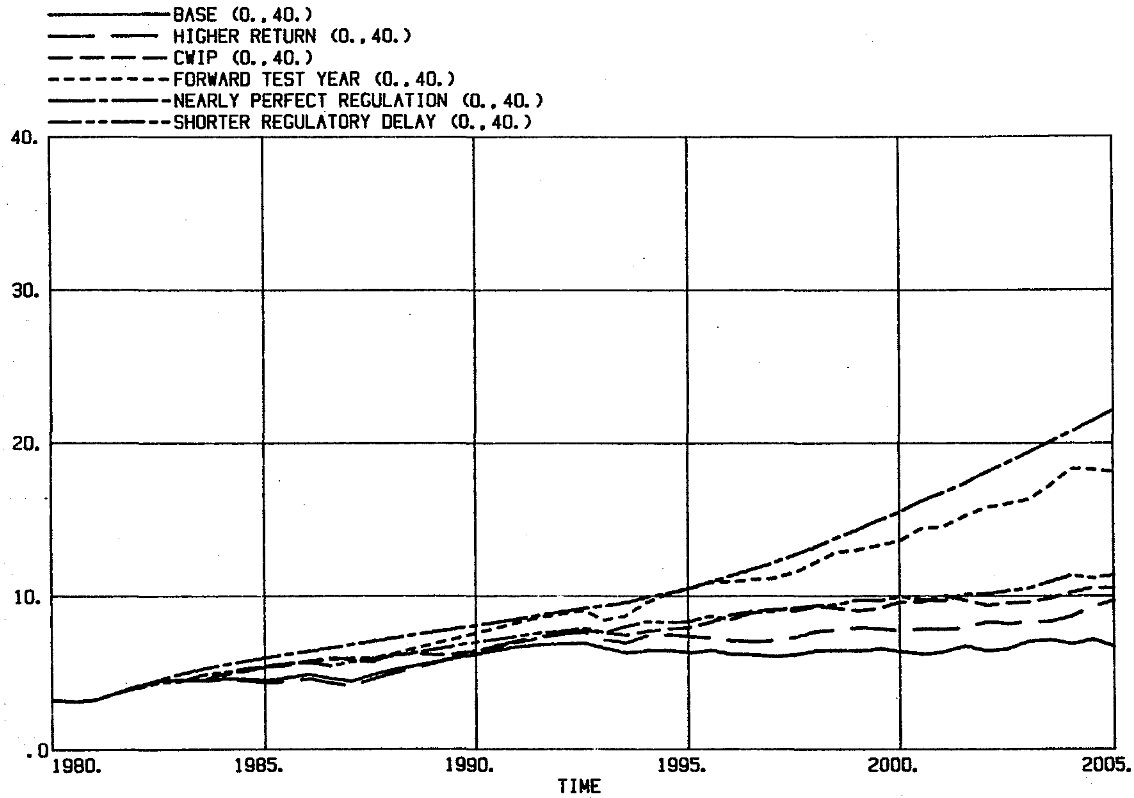


FIGURE 18

INTEREST COVERAGE -- REGULATORY POLICIES

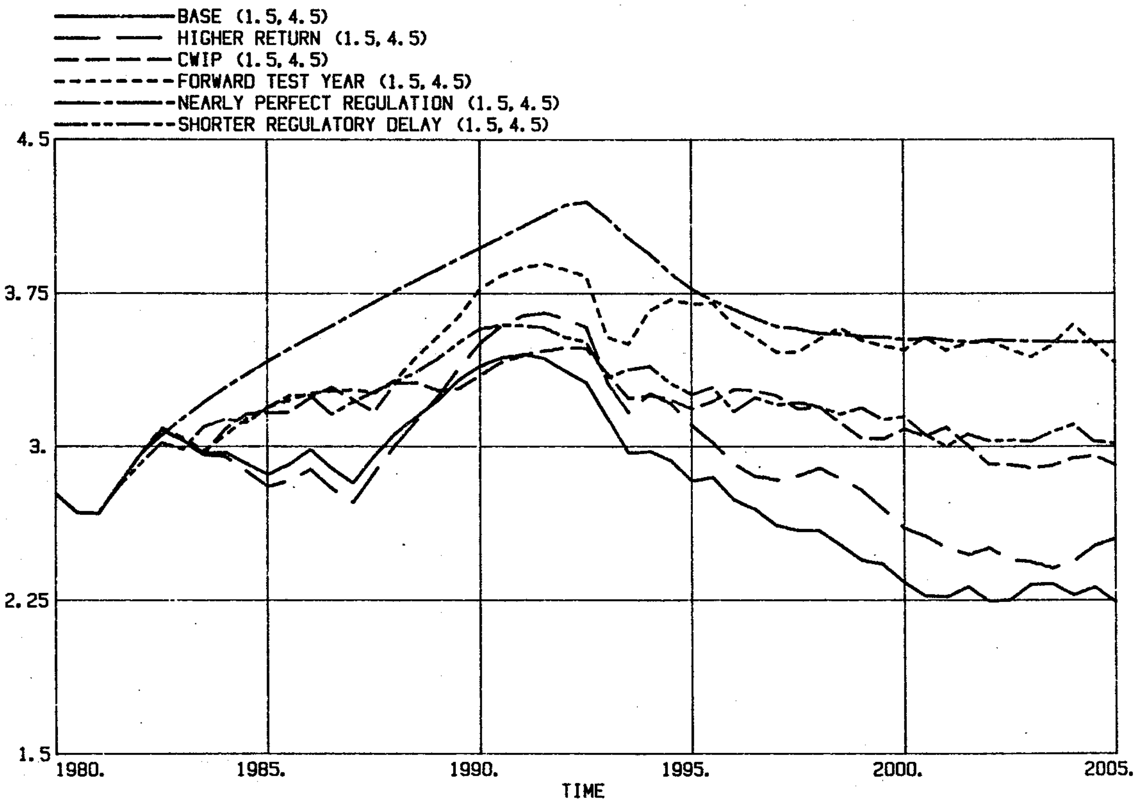
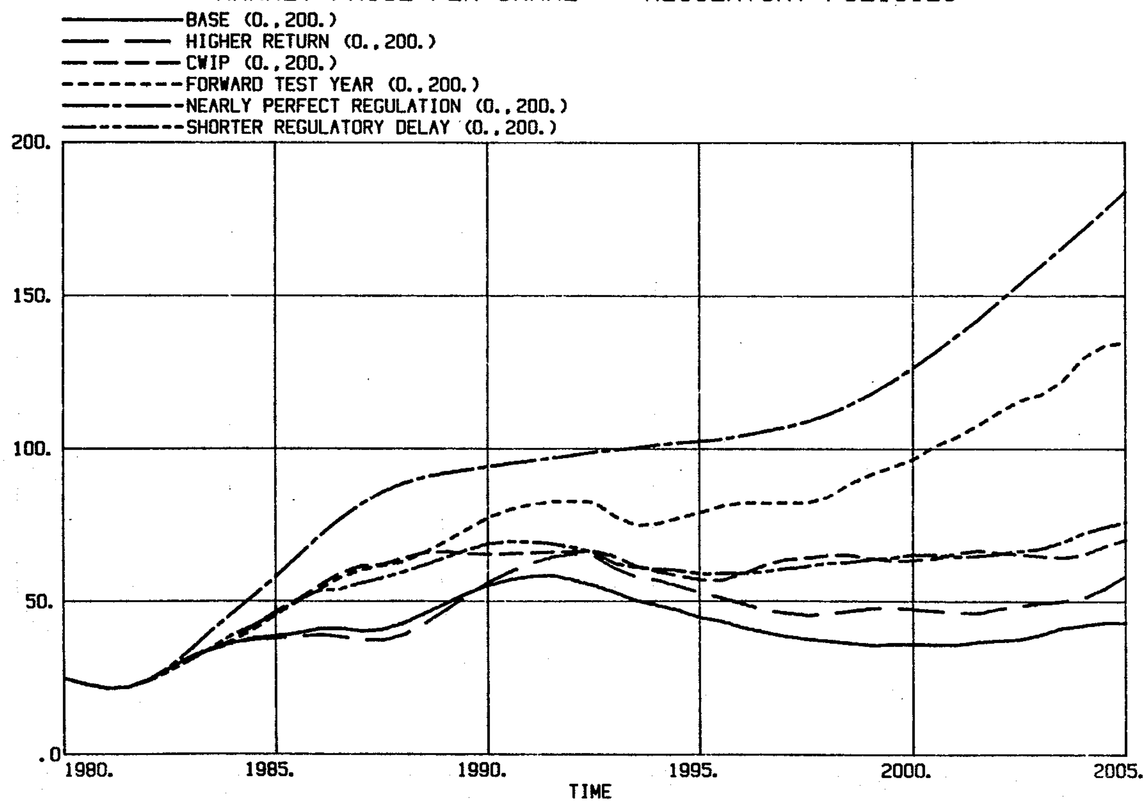


FIGURE 19

MARKET PRICE PER SHARE -- REGULATORY POLICIES



CWIP helps somewhat, but in between rate cases, AFUDC lowers the quality of reported earnings. With regulatory lag, a full cash return on construction is not realized.

Improvement in financial performance is not without cost to consumers (see Figure 21). In fact, to achieve sustained reasonable performance via nearly perfect regulation requires substantially higher prices. It is likely that some combination of changed utility policies and improved regulation can achieve sustained reasonable performance at less cost to consumers.

Finally, Figures 22 and 23 show the consequences of these policy changes for demand and reserve margin.

FIGURE 20

MARKET PRICE-BOOK VALUE RATIO -- REGULATORY POLICIES

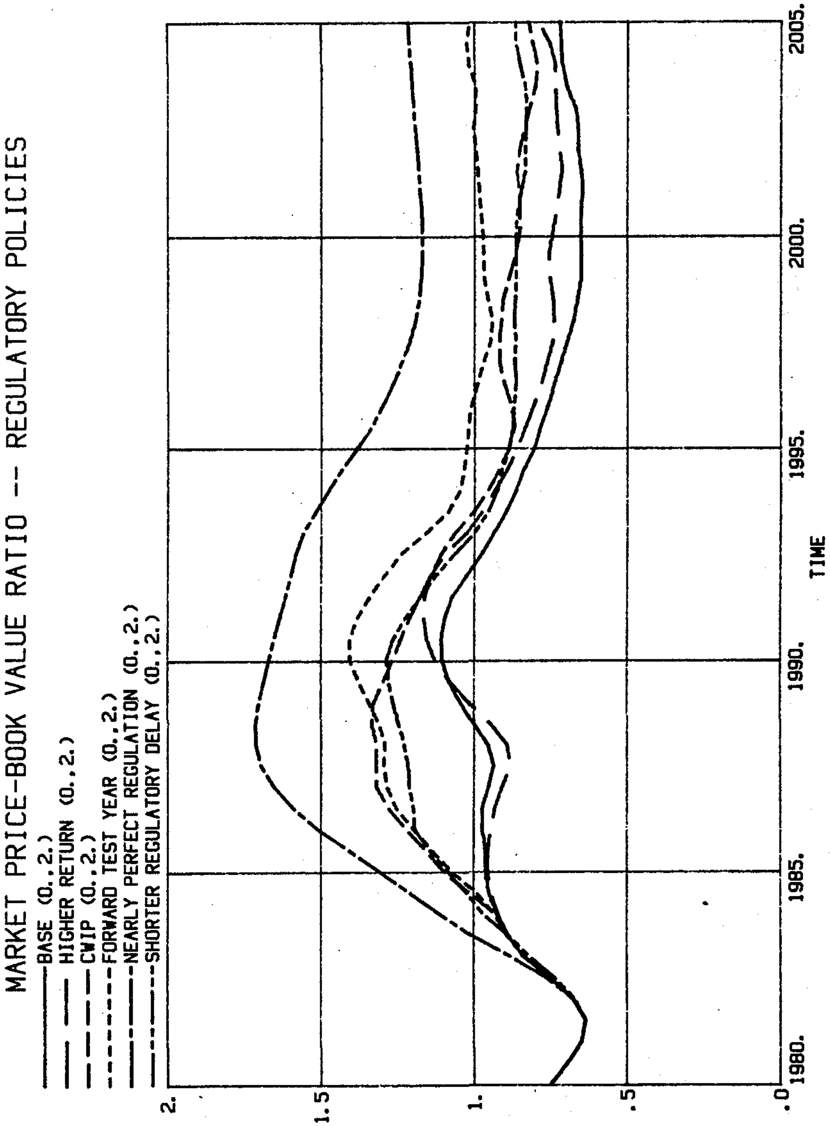


TABLE 3
COMPARISON OF ALTERNATIVE REGULATORY POLICIES, 1982- 2005

	Base	Higher Return	Shorter Delay	Forward Test Year	CWIP	Nearly Perfect Regulation
Growth in Power Delivered	2.2%/year	1.9%/year	1.8%/year	1.5%/year	1.5%/year	1.0%/year
Growth in Earnings Per Share	1.8%/year	3.4%/year	4.1%/year	6.3%/year	3.8%/year	7.3%/year
Total Capital Expenditures (Billion 1982 $)	18.7	22.6	25.2	24.3	24.0	21.0
Total Net Income to Common (Billion 1982 $)	7.9	9.1	10.4	11.4	9.3	9.7
Total Revenue Requirements (Billion 1982 $)	74.6	75.3	75.2	75.0	74.9	72.0

FIGURE 21

PRICE (1982$) -- REGULATORY POLICIES

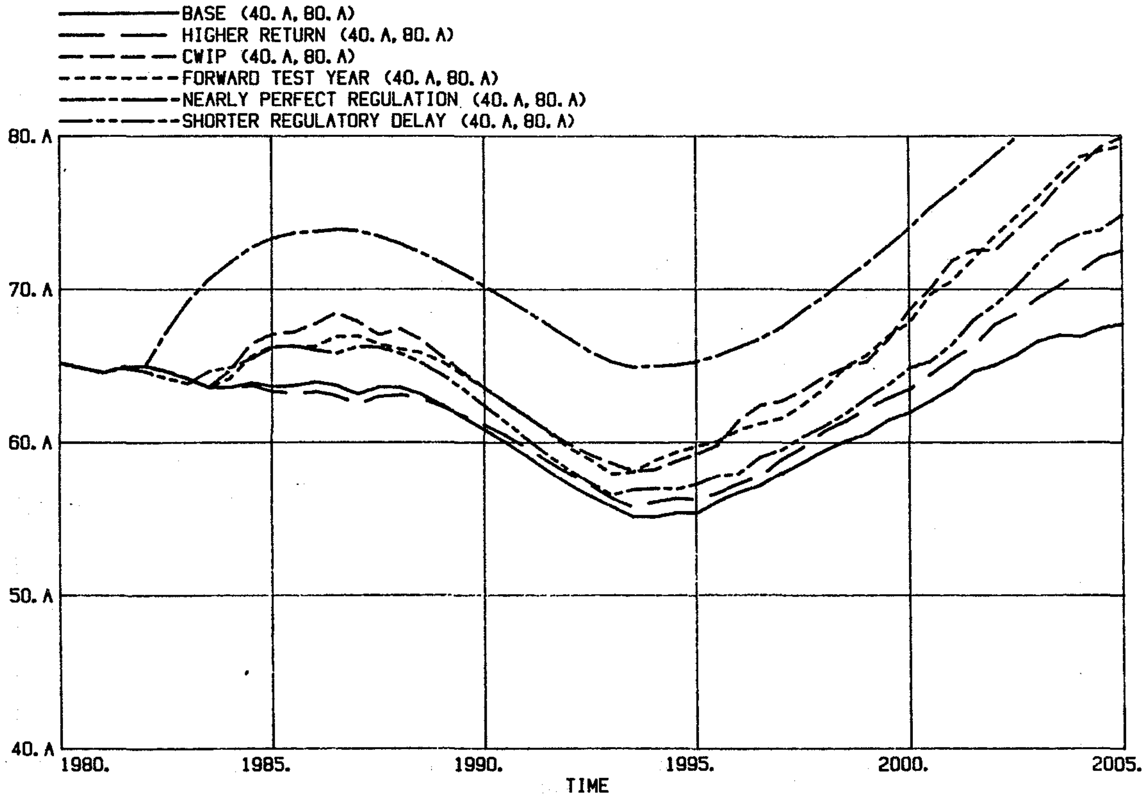


FIGURE 22

POWER DELIVERED -- REGULATORY POLICIES

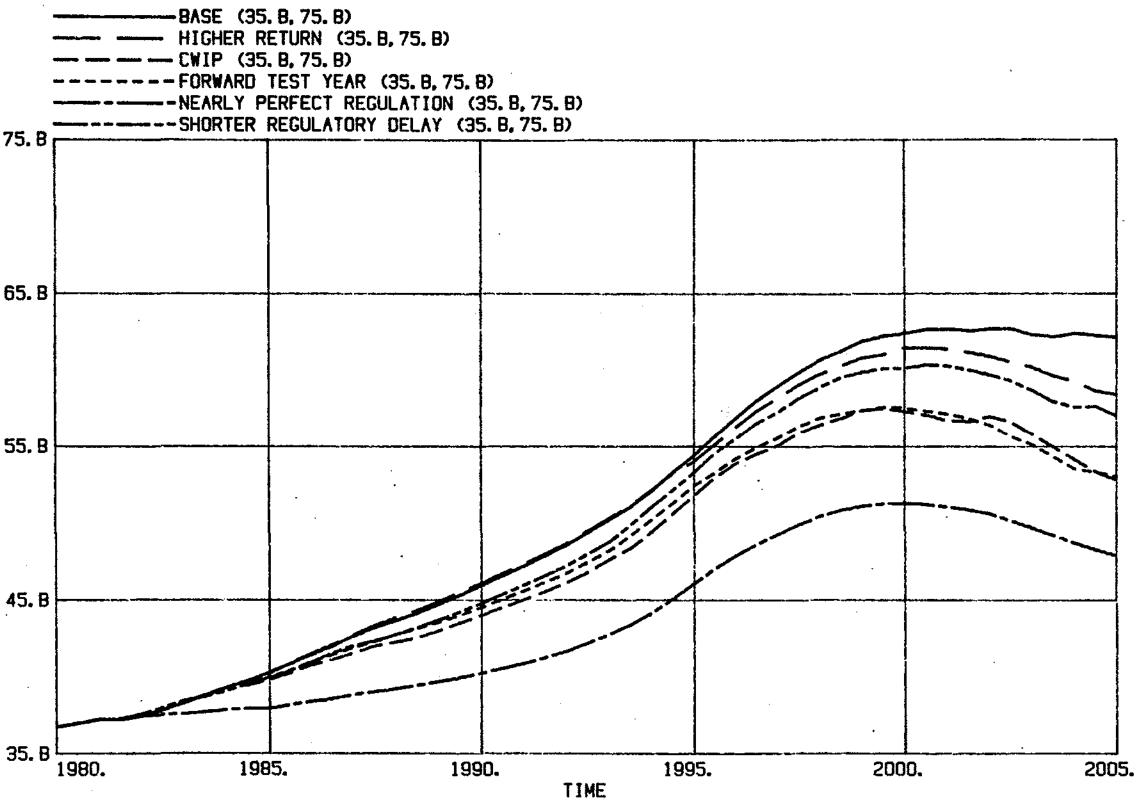


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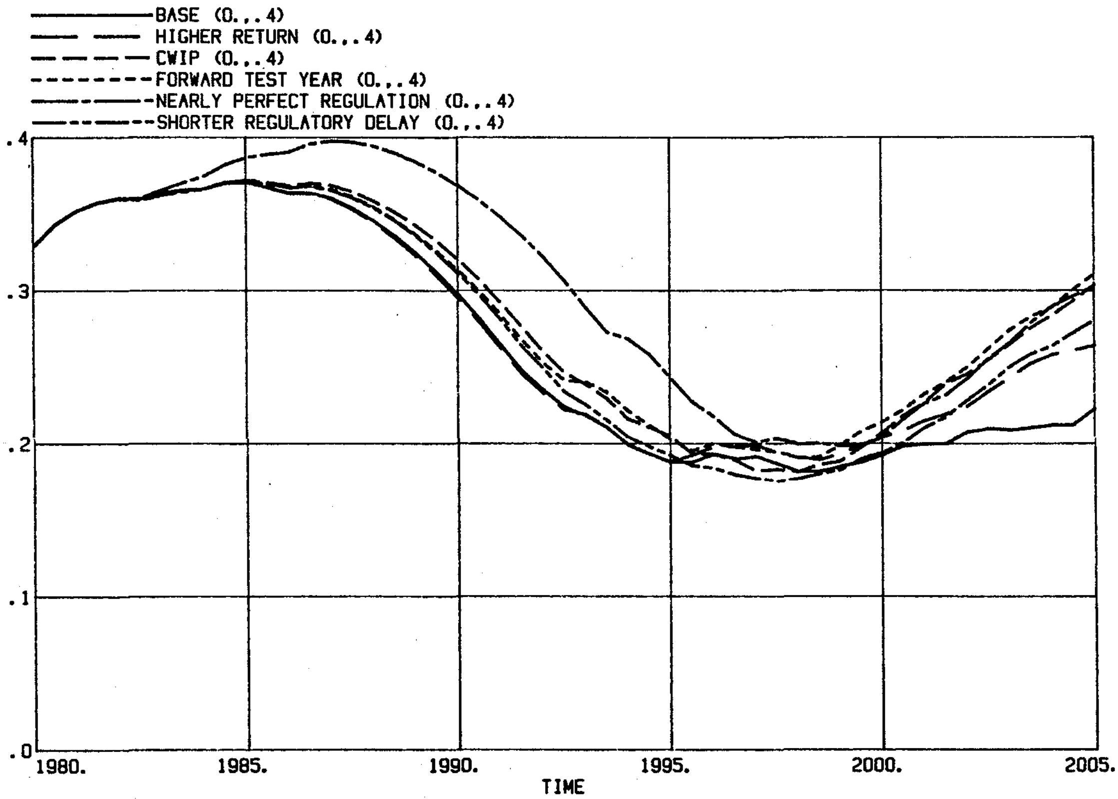
FIGURE 23

RESERVE MARGIN -- REGULATORY POLICIES



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V. CONCLUSIONS

The performance of the utility is strongly affected by regulatory policy. Most actions which significantly improve financial performance are in the regulatory area. Increased rates, however, need not be counter to the interests of the utility's customers. In fact, an adequately funded baseload construction program should in the long-run (here beyond 2005) provide better service and lower rates by reducing reliance on purchased power and peaking units. Further, we have assumed here that utility management will continue to invest in spite of returns below the cost of capital. Should this not be the case, the benefits of improved regulation become more pronounced.

Improved regulation in combination with actions by the utility, can improve performance at little cost to consumers (based on additional simulations not included here). Examples of such actions are: (1) the installation of end-use and load management controls in the 1990's to reduce demand, improve reserve margins, and reduce construction needs; and (2) less reliance on debt to improve interest coverage, thereby reducing interest costs and raising stock price. By themselves, these actions tend to reduce prices, and therefore offset the price increases accompanying improved regulation.

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