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TITLE THE FINANCIAL AND RATEPAYER IMPACTS OF NUCLEAR POWER PLANT REGULATORY REFORM

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THE FINANCIAL AND RATEPAYER IMPACTS OF NUCLEAR POWER PLANT REGULATORY REFORM

I. BACKGROUND

Three reports--"The Future Market for Electric Generating Capacity,"[1,2] "Quantitative Analysis of Nuclear Power Plant Licensing Reform,"[3] and "Nuclear Rate Increase Study"[4] are recent studies performed by the Los Alamos National Laboratory that deal with nuclear power. The following presents a short summary of these three studies. More detail is given in the reports.

A. "The Future Market for Electric Generating Capacity"[1,2]

The Economics Group and the Energy Technologies Group at the Los Alamos National Laboratory performed a study that characterizes the market for new electric generating plants in the electric utility industry in the year 2000 and beyond. A portion of that study included interviews[2, Part 3] with representatives of both investor-owned and publically-owned electric utility companies. These interviews were designed to elicit the views of the utility organizations on a wide variety of factors that influence their decisions concerning generating capacity additions.

Interviews were conducted with 23 investor-owned utilities (including interviews with electric utility holding companies which meant eliciting information on 30 individual electricity-generating companies), 3 publically-owned utilities and the Electric Power Research Institute (to provide an overview of the utility industry). The utilities were selected to reflect a diversity of operational, geographical, institutional, and environmental factors. In general, the utility interviews involved personnel from the utility planning department as well as contact with management (at the vice president level).

Interview results are given, in that report, for electric utility demand growth, new capacity additions, alternative sources of capacity, building new nuclear plants, large vs. small plants, financial risk sharing, turnkey nuclear reactors, and utility decisions on construction. The following presents a summary of results on the portion of the study dealing with building new nuclear plants and turnkey nuclear reactors.

On the subject of building new nuclear plants, no utility that was contacted would purchase or build a new nuclear plant under the present environment. In a statement that was echoed by several other companies, one utility that has a relatively successful nuclear program noted, "With the current environment the way it is, no one in their right mind would build nuclear power, and hopefully we're in our right mind." A large number of comments were received on possible changes that would be needed before nuclear reactors could again be ordered for utility applications. The major changes that were noted most frequently are listed and briefly summarized below.

- Demonstrated Public Acceptance of Nuclear Power. This is the single most important change that is needed before any new nuclear power plants can be built. What will have to occur to bring this about is uncertain. The most frequently mentioned items were the occurrence of power shortages as no new plants are built and dramatically increased concerns about SO_x, NO_x, and, eventually, CO_2 from coal burning.

- Licensing Reform. This is needed but will not be considered as sufficient without demonstrated public acceptance of nuclear power. (The political winds are just too fickle.) A major item of concern was that operating licenses are not granted until after plant construction. The risk of not being allowed to operate a completed plant is unacceptable. It was also noted that the Nuclear Regulatory Commission (NRC) is "more concerned with detailed regulations than with safety."

- More Certain Construction Schedule. This is necessary, and suggestions included shorter schedules, licensing reform, small plants, standardization, factory construction, and financial risk sharing with no feeling of assurance that any of these would work. The uncertainty is most important however. Some utilities said they could live with lead-times on the low side of what is currently occurring, but they have to be able to plan on lead-times.

- Smaller Plant Sizes. While the actual plant size that is desired varies with the size of the company, there is some feeling that plants should be smaller than the present 1,000-1,200 MWe. However, there should not be large diseconomies associated with the smaller plants.

- Modular Plants, Factory Construction. This application of small, standardized plants is important to some utilities, primarily those having low annual load growth rates (<100 GWe/yr). But any such plant must be demonstrated "by somebody else, not us."

- o Differing Financing Schemes. The two items most often mentioned were inclusion of CWIP in the rate base and innovative financial risk sharing between the utility and the reactor constructor and/or vendor.

- o Current Plant Operation. It is essential that the present nuclear plants demonstrate more reliable operation over the next decade.

- o Nuclear Waste. There must be a guaranteed solution to the nuclear waste problem in place and functioning.

- o New Reactor Types. Several utilities felt that the light water reactor technology was dead. Others stated that current operations difficulties indicate that the technology has not matured. There was some interest in new reactor types, but any new reactor must be demonstrated as to constructability, licensability, and operability. And the demonstration must be performed by "somebody else, not us." Planning for future capacity will be based on what is known.

Turnkey nuclear reactors are seen as a possible approach to reducing the uncertainties involved in nuclear plant construction. They could and probably would involve other strategies that have been discussed such as standardization, modularity, and increased factory construction. With fixed prices, there is effective financial risk sharing at least on the construction portion of the project. Standardized and/or turnkey coal-fired power plants have had advantages for some utilities.

While a number of utilities expressed some interest in turnkey plants, a number of concerns about such plants were noted. The utilities would want a plant concept that was extensively demonstrated as to licensability and operability, and the demonstration would have to involve some other utility. In addition, another objection to standardized plants is that they could be subject to uncontrollable "common cause shutdowns." And in fact, it was questioned whether nuclear plants could ever really be standardized because, as one company put it, "as long as you have (present) regulation, there will never be standardization of plants; because no two sites or utilities are the same, no two plants are alike."

A major objection to turnkey reactors raised by a number of utilities involved their desire to be intimately involved in all stages of reactor design and construction. The utilities are ultimately responsible for reactor licensing and operation. Having these responsibilities, the utility feels that it must have the knowledge of the design and construction that can only come from involvement in the entire process.

B. "Quantitative Analysis of Nuclear Power Plant Licensing Reform"[3]

The Economics Group at the Los Alamos National Laboratory performed a study that involved developing a model to analyze the licensing and construction process for commercial nuclear power plants, gathering appropriate time and cost data for the process, and analyzing the quantitative effects of proposed nuclear regulatory reforms. The model that was created uses computer network simulation techniques to analyze project evaluation and review technique (PERT) charts. The computer code identifies milestone data, activity durations, and critical path information. The model uses probabilistic data and operates in Monte Carlo fashion. The Monte Carlo technique repeats the same calculation many times using different values selected from probability distributions for those variables whose true value is not an exact number.

The code computes total capital construction costs including interest, nuclear plant cost escalation, and inflation. It distinguishes between overhead and direct costs so that cost corrections are automatically made when times vary with each Monte Carlo pass. It also spreads normalized cash flow curves for different phases of construction to fit each activity duration time for particular Monte Carlo passes.

Basic data were gathered from the Nuclear Regulatory Commission, Department of Energy, Electric Power Research Institute, Atomic Industrial Forum, Edison Electric Institute, Oak Ridge National Laboratory, private utilities, and others. These data were processed into appropriate statistical form to be used with our computer code. They are representative of current nuclear industry conditions and identify changes that occur with different regulatory structures.

The study analyzes a package of nuclear regulatory reforms that is being proposed by the Department of Energy. Although the analysis is specific to these particular reforms, the reader can easily recognize that the reform proposals of the other major reform task forces at the Nuclear Regulatory Commission and the Atomic Industrial Forum are fundamentally similar to the Department of Energy package. Therefore, the relative importance of the various "standardization," "site banking," "one-step licensing" and other variations of generic reform can be evaluated reasonably well simply by reference to these quantitative results.

Summary results indicate that with the current licensing and construction process (no reform), the time from decision to build to commercial operation is about 180.2 months with an average cost of 4,389 million in current dollars (nominal dollars summed over the entire project starting from January 1, 1982 until completion at a 7% inflation rate). The direct benefits of the Department of Energy task Force proposed nuclear licensing reforms include the following reduction in time and capital cost.

Reforms	Time Savings (Months)	Average Cost Savings in Millions of Current Dollars
Early Site Permit	5.6	237
Preapproval-of-Design	8.4	508
Early Site Permit and Preapproval-of-Design	42.1	1 556
One-Step Licensing	- 8.7	- 302
Amendments and Variances--Part 1	5.0	193
Major Backfitting (Amendments and Variances--Part 2)	24.0	1 205
Major Backfitting and Preapproval-of-Design	32.4	1 587
Hearings	2.6	102
Al. ition of Resources	0.7	29
Major Backfitting and Preapproval-of-Design and Early Site Permit	66.0	2 248
Total Reform Package	64.3	2 228

C. "The Nuclear Rate Increase Study"[4]

The Economics Group at the Los Alamos National Laboratory performed a study of the effects that new nuclear plants will have on electric utility rates during the first year of commercial operation. The nuclear rate increase study examined all nuclear plants under construction during the July to September 1983 time period by investor-owned utilities. Rate increases were calculated for 31 utilities with a total of 51 nuclear plants under construction.

The main data source for this study was personal communication with representatives from the 31 utilities during the July to September 1983 time period and publicly available published reports. The widely accepted financial-regulatory model from Baughman, Joskow, and Kamat was used to calculate the gross revenue requirement for each nuclear plant under construction.

Summary results of the study indicate that the median rate increase was estimated at 23% or 14.5 mills per kWh. The 23% median rate increase was based on gross nuclear plant revenue requirements included in the rate base during the first full year of commercial operation, projected electric sales growth for each utility, and fuel savings. The median rate increase with "optimistic" sales growth was 10.5% or 6.6 mills per kWh. This rate increase was based on each utility's electric sales growth fully matching the nuclear capacity coming on-line. Finally, the estimated fuel savings during the first year of commercial operation were: an average of $190 million for each utility, a median of $146 million per utility, and an average for each single nuclear plant of $179 million. The resultant fuel savings for all 51 nuclear plants is a fuel savings benefit to the United States of about $9.1 billion and about 700,000 barrels of oil per day.

The nuclear rate increase study lent itself to examination of coal plant costs and their effect on rates to consumers. Comparison of nuclear rate increases with coal rate increases was accomplished using two methods. The first method consisted of calculating the rate increase for a few coal plants presently under construction. The second method consisted of replacing nuclear capacity with coal capacity(as a hypothetical alternative) for several nuclear plants under construction. Main results of the coal rate increase study indicated that rate increases were not always higher for nuclear plants than for coal plants. Thus, the key question for utility planners may not be whether to build coal or nuclear plants but, instead, whether to build short rather than long lead-time plants.

II. INTRODUCTION

The Los Alamos National Laboratory has performed a study of the of the financial and ratepayer impacts of nuclear power plant licensing reform. This study is an extension of the above mentioned study entitled "Quantitative Analysis of Nuclear Power Plant Licensing Reform"[3] that uses Monte Carlo modeling to analyze project evaluation and review technique (PERT) charts for the nuclear power plant licensing and construction process. The direct benefits of savings in lead-time and construction costs of two reforms from the "Quantitative Analysis of Nuclear Power Plant Licensing Reform" study are applied to a simulation model to yield the total benefits of improvements in the financial performance of two specific utilities and reduction in the price of electricity to ratepayers.

In estimating the total benefits of nuclear reform, two reforms -- the combined early site permit and preapproval-of-design reforms and the total reform package, were compared with the current licensing and construction process. From the "Quantitative Analysis of Nuclear Power Plant Licensing Reform" study, the current licensing and construction process (no reform) was estimated to take about 15 years in project time and have a total cost of 4.389 billion in nominal dollars. The combined early site permit and preapproval-of-design reforms was estimated to take about 11.5 years in project time and have a total cost of 2.833 billion in nominal dollars. The total reform package was estimated to take about 9.7 years in project time and have a total cost of 2.161 billion in nominal dollars.

The results of the Monte Carlo modeling of PERT charts were used as inputs to a Los Alamos regulatory-financial model -- Electric Utility Policy and Planning Analysis Model (EPPAM). The EPPAM model simulates the planning, operation, capacity construction, construction financing, and price regulation over time of a typical investor-owned electric utility company subject to the rate-of-return regulation commonly practiced by the state public utility commissions. The model is initialized in 1982 and projects financial and ratepayer impacts over the 1982-2010 time period for the no reform and the reform cases for two utilities.

Data on two regions was collected for this study -- (1) the Northern California region corresponding to the service territories of the Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utility District (SMUD), and various other government-owned utility systems in northern and central California, and (2) most of the state of Georgia (153 of the 159 counties) including the service territories of Georgia Power Company (Georgia Power), Oglethorpe Power Corporation (OPC), Municipal Electric Authority of Georgia (MEAG) and the city of Dalton. Regional data was collected for these service territories in order to take account of the planning regions used by PG&E and Georgia Power for purposes of planning new capacity expansion. The regional data collected for this study included information about the resources, assets, and operations of each region's utilities as well as the regional income growth.

PG&E was selected for this study because of its large size; relatively low electric energy load growth projections; dependence on oil and gas steam generation; emphasis on conservation, load management, and cogeneration; and readily available detailed planning documents prepared by the company and the California Energy Commission. In terms of 1982 kWh sales and total revenues from sales of electricity, PG&E ranks first among the privately owned electric utilities (which account for about 76% of total privately, publicly and cooperatively owned utilities). In 1982, PG&E had electric energy sales of 60,519 million kWh and total revenues from sales of electricity of 4,477 million dollars. In terms of total electric operating revenues (total revenues from sales of electricity plus other operating revenues), PG&E ranks fourth (3,845 million dollars) due to negative other operating revenues derived from purchased power.[5] The annual growth in electric energy load after accounting for conservation and load management is estimated at 1.5% per year between 1982 and 2010. PG&E is heavily dependent on oil-gas steam generation. About 50% of the 1982 generation from company plants (company plant generation accounts for about 57% of total sources of generation) is gas and oil-fueled. The remaining generation from company plants is about 38% from hydroelectric and 12% from geothermal. During 1982, PG&E purchased about 43% of total generation from other utilities. Of this amount, about 32% was purchased hydroelectric obtained over the intertie from the Pacific Northwest. The actual amount of purchased hydroelectric can vary tremendously from year to year depending on the precipitation. The year 1982 was a very "wet" year, resulting in a large amount of purchased hydroelectric. The remaining generation from purchased power included about 17% from fossil fuel and about 9% from nuclear. Thus, for the year 1982, the sources of total power generation for this coastal utility were 43.3% purchased power, 27% gas, 21.8% hydroelectric, 6.8% geothermal, and 1.1% oil.[6,7] The availability of detailed planning documents allowed the model's base case projections to be benchmarked against the corresponding results from the company's long-term planning documents.[8-11]

The selection of Georgia Power was determined by its contrast to PG&E in many respects. Georgia Power is somewhat smaller in size than PG&E with electric energy sales in 1982 of 49,703 million kWh, total revenues from sales of electricity of 2,433 million dollars, and total electric operating revenues of

2,457 million dollars. The assumed growth in electric energy load of 2.75% per year for Georgia Power is more rapid than that for PG&E. Georgia Power is more exemplary of an interior utility having a 1982 system power generation of 89% coal, 7% nuclear, and 4% hydroelectric. Not only does this company not have any dependence on oil and gas steam generation, but it also has relatively little interest in load management and cogeneration. Rather than purchasing power from other utilities, Georgia Power sells power to certain neighboring utilities. The company is a wholly-owned subsidiary of the Southern Company.[12-14]*

The benefits of improvements in the financial performance of two utilities and reduction in the price of electricity to ratepayers of nuclear regulatory reform are examined in this study. Improvements in the financial performance are measured by examining key financial variables and comparing their performance with goals set by PG&E for the no reform and the reform cases. These goals include an internal generation of funds greater than 40%, a fraction of earnings due to allowance of funds used during construction (AFUDC) under 20%, a pretax interest coverage ratio in excess of 3.0, and a common stock market to book ratio in excess of 1.0.[2, Part 2.] The price of electricity and real price of electricity is given for all cases. The financial and ratepayer impacts were measured for two different simulations: (1) nuclear and generic capacity additions and (2) all nuclear capacity additions. Generic capacity has the characteristics of a coal plant, with (1) a forecasting horizon of 7 years, (2) construction lead-time of about 6 years, and (3) a direct construction cost of $1,000/kW. In simulations with nuclear and generic capacity additions, both types of capacities are added in fairly equal proportions to the system load. In simulations with all nuclear capacity additions, all generic capacity on-line and under construction is virtually zero, and future load growth is met solely by nuclear additions. Results of the study are given for the no reform, combined early site permit and preapproval-of-design reforms, and total reform package cases for the 1982-2010 simulation period. "New nuclear capacity" (that

*The Southern Company is the parent company of four generating companies -- Georgia Power, Alabama Power, Gulf Power, and Mississippi Power, which together jointly own generating facilities, have interconnecting transmission lines, and exchange power in four southeastern states -- the whole states of Georgia and Alabama, and the northwest portion of Florida and southeast portion of Mississippi. The Southern electric system is one of the nation's largest investor-owned electric utility systems.[15]

nuclear capacity added to meet future load growth beyond each company's present planned additions) construction for the no reform case begins in 1982 with the first unit coming on-line in 1997. New nuclear capacity construction for the combined early site permit and preapproval-of-design reforms begins in 1985.5 with the first unit coming on line in 1997. For the total reform package, two different construction intervals were run -- (1) total reform-later, and (2) total reform-early. Total reform-later refers to new nuclear capacity construction beginning in 1987.3 with the first unit coming on-line in 1997 (the same year that the no reform and combined early site permit and preapproval-of-design reforms cases begin commercial operation). Total reform-early refers to new nuclear capacity construction beginning in 1982 (the start of the simulation and the same year that the no reform case begins construction) with the first unit coming on-line in 1991.7, about 5 years sooner than any of the other cases.

Summary results of the study are presented in Tables I through III. For simulations with nuclear and generic capacity additions, all nuclear units begin commercial operation during the simulation period; whereas, for simulations with all nuclear capacity additions, all nuclear units begin commercial operation for the total reform-early case but not for the other cases. Thus, by the end of the simulation some nuclear units are still under construction for these other cases.

Table I shows the estimated rate increases or decreases for new nuclear capacity additions for PG&E and the Georgia Power for simulations with nuclear and generic capacity additions and for simulations with all nuclear capacity additions. These price increases or decreases are measured during the period of commercial operation of the new nuclear units.

For simulations with nuclear and generic capacity additions for PG&E, real price decreases for all the reform cases and increases for the no reform case as each of the five nuclear units begins commercial operation. Real price decreases about 8% for total reform-early, 3% for total reform-later, and 2% for combined early site permit and preapproval-of-design reforms and increases about 6% for no reform. The fuel cost savings (by backing out of more expensive oil and gas) obtained from these reformed nuclear units are greater than the added capital costs. For Georgia Power, real price decreases for the total reform-early case and increases for all other cases as each of the six nuclear units begin commercial operation. Real price decreases about 26% for total reform-early and increases about 2% for total reform-later, 13% for combined early site

TABLE I

ESTIMATED RATE INCREASES OR DECREASES FOR NUCLEAR CAPACITY ADDITIONS[a]

	Pacific Gas and Electric Company		Georgia Power Company	
	Nuclear and Generic Capacity Additions[f] (%)	All-Nuclear Capacity Additions[g] (%)	Nuclear and Generic Capacity Additions[h] (%)	All-Nuclear Capacity Additions[i] (%)
No reform[b]	+6	+53	+36	+78
Combined early site permit and preapproval-of-design reforms[c]	-2	+ 1	+13	+58
Total reform-later[d]	-3	- 5	+ 2	+41
Total reform-early[e]	-8	-16	-26	+17

[a]Price increases or decreases (in constant 1980 dollars) are estimated for the period corresponding to the year prior to commercial operation of the first unit and the year the last unit comes on-line for all cases.

[b]New nuclear capacity construction begins in 1982 with the first unit coming on-line in 1997.

[c]New nuclear capacity construction begins in 1985.5 with the first unit coming on-line in 1997.

[d]New nuclear capacity construction begins in 1987.3 with the first unit coming on-line in 1997.

[e]New nuclear capacity construction begins in 1982 with the first unit coming on-line in 1991.7, about 5 years sooner than any of the other cases.

[f]5.695 GW nuclear capacity additions.

[g]13.668 GW nuclear capacity additions for total reform - early; 10.25 GW nuclear capacity additions for all other cases with 3.417 GW under construction.

[h]6.934 GW nuclear capacity additions.

[i]20.502 GW nuclear capacity additions for total reform - early; 15.946 GW nuclear capacity additions for all other cases with 4.556 GW under construction

permit and preapproval-of-design reforms, and 36% for no reform. Georgia Power has predominately coal with some nuclear and hydroelectric fuel usage for system generation prior to commercial operation of the new nuclear units. Fuel costs are therefore relatively low throughout the simulation for this utility. Thus, for the three cases with price increases, the added capital costs of these new units outweigh any fuel cost savings. Also, this company is a more rapidly growing utility than PG&E and must therefore add more capacity (both generic and nuclear) at very high capital costs compared to existing units in order to meet demand growth. For the total reform-early case which exhibits a price decrease, new nuclear units begin commercial operation much earlier in the simulation while real price is already high from inclusion of Scherer and Vogtle in the rate base. Thus, the combination of an already high real price from Scherer and Vogtle and fuel cost savings from Scherer, Vogtle, and the new nuclear units cause price to decline for this reform case during the period these new units enter the rate base.

For simulations with all nuclear capacity additions for PG&E, real price decreases about 16% for total reform-early and 5% for total reform-later and increases about 1% for combined early site permit and preapproval-of-design reforms and 53% for no reform. Again, the fuel cost savings outweigh the added capital costs for the total reform cases. For Georgia Power, real price increases about 17% for total reform-early, 41% for total reform-later, 58% for combined early site permit and preapproval-of-design reforms, and 78% for no reform. Again, this utility is a more rapidly growing utility building more nuclear units than PG&E. These new nuclear units are more expensive than generic capacity, thus the higher price increases under this scenario than the nuclear and generic capacity additions scenario for this utility. Also, since fuel costs are relatively low for this utility, the added capital costs of these new nuclear units outweigh any fuel cost savings. All nuclear capacity comes on-line for the total reform-early case for PG&E (13.668 GW) and Georgia Power (20.502 GW) by the end of the simulation period. For the other cases, 10.251 GW comes on-line for PG&E by the end of the simulation with 3.417 GW under construction, and 15.946 GW comes on-line for Georgia Power by the end of the simulation with 4.556 GW under construction. Therefore, all cases except the total reform-early case (under the all nuclear capacity additions scenario) would have larger price increases than noted in Table I as remaining capital costs are added into the rate base.

Table II shows the estimated price advantage in terms of lower real price of the reform cases relative to no reform. For simulations with nuclear and generic capacity additions, the estimated price advantage is calculated for the year in which all new nuclear capital costs are included in the rate base for all cases--2,006 for PG&E, and 2,008 for Georgia Power. For simulations with all nuclear capacity additions, the estimated price advantage is calculated in the year 2010 for both companies although some nuclear capacity is still under construction for all cases except total reform-early.

For simulations with nuclear and generic capacity additions, the total reform-early case has the greatest price advantage for both companies. For PG&E, the estimated price advantage in terms of lower real price for the reform cases is about 16% for total reform-early, 8% for total reform-later, and 5% for early site permit and preapproval-of-design reforms. For Georgia Power, real price is about 39% lower for total reform-early, 25% lower for total reform-later, and 16% lower for combined early site permit and preapproval-of-design reforms than for no reform. The reform cases for Georgia Power have a greater price advantage relative to no reform than the reform cases for PG&E. This is

TABLE II

ESTIMATED PRICE ADVANTAGE OF THE REFORM CASES RELATIVE TO NO REFORM[a]

	Pacific Gas and Electric Company[b]		Georgia Power Company[c]	
	Nuclear and Generic Capacity Additions[g] (%)	All Nuclear Capacity Additions[h] (%)	Nuclear and Generic Capacity Additions[i] (%)	All Nuclear Capacity Additions[j] (%)
Combined early site permit and preapproval-of-design reforms[d]	5	50	16	14
Total reform - later[e]	8	57	25	24
Total reform - early[f]	16	76	39	10

[a]In constant 1980 dollars. No reform new nuclear capacity begins construction in 1982 with the first unit coming on-line in 1997.

[b]Estimated price advantage given for the year 2006 for nuclear and generic capacity additions and for the year 2010 for all nuclear capacity additions.

[c]Estimated price advantage given for the year 2008 for nuclear and generic capacity additions and for the year 2010 for all nuclear capacity additions.

[d]New nuclear capacity construction begins in 1985.5 with the first unit coming on-line in 1997.

[e]New nuclear capacity construction begins in 1987.3 with the first unit coming on-line in 1997.

[f]New nuclear capacity construction begins in 1982 with the first unit coming on-line in 1991.7, about 5 years sooner than any of the other cases.

[g]5.695 GW nuclear capacity additions.

[h]13.668 GW nuclear capacity additions for total reform - early: 10.251 GW nuclear capacity additions for all other cases with 3.417 GW under construction.

[i]6.834 GW nuclear capacity additions.

[j]20.502 GW nuclear capacity additions for total reform - early: 15.946 GW nuclear capacity additions for all other cases with 4.556 GW under construction.

because real price is lower for all reform cases and higher for the no reform case for Georgia Power than for PG&E. For Georgia Power, the combination of low fuel costs throughout the simulation and the cheaper capital costs of the reformed nuclear units yield lower prices than for PG&E for all but the no reform case. With no reform, the fuel cost savings afforded PG&E by backing out of expensive oil and gas fuel usage keep price lower than that of the no reform case for Georgia Power.

For simulations with all nuclear capacity additions, all nuclear capacity has not come on-line by 2010 for the no reform, the combined early site permit and preapproval-of-design reforms, and the total reform-later cases. Thus, total reform-early would show an even greater price advantage than that which appears in Table II. For PG&E, the estimated price advantage in terms of lower price for the reform cases is about 76% for total reform-early, 57% for total reform-later, and 50% for combined early site permit and preapproval-of-design reforms. For Georgia Power, real price is about 10% lower for total reform-early, 24% lower for total reform-later, and 14% lower for combined early site permit and preapproval-of-design reforms than for no reform. PG&E has a greater price advantage for all reform cases relative to no reform than Georgia Power. This is because real price for the no reform case is much higher than for the other cases for PG&E. The added capital costs of the nonreformed new nuclear units greatly outweigh the fuel cost savings.

Table III shows the number of years of poor financial performance for the no reform and all reform cases for simulations with nuclear and generic capacity additions and simulations with all nuclear capacity additions for both companies. Overall, the total reform-early case exhibits the best performance. Although some financial indicators show short periods of poor performance with this reform, the magnitude and duration of poor performance is generally much less than for other cases. The no reform case generally exhibits the poorest performance financially. This case usually has a greater magnitude as well as duration of poor financial performance than other cases. Generally, the total reform-later case performs better than the combined early site permit and preapproval-of-design reforms case, and, the combined early site permit and preapproval-of-design reforms case performs better than the no reform case. Also, for all cases, simulations with all nuclear capacity additions seem to have a greater number of years of poor financial health than simulations with nuclear and generic capacity additions. (For all cases except total reform-early, the number of years of poor financial health may be greater than what is shown in the table since all nuclear capacity has not come on-line by 2010.) This is because the cheaper capital costs of generic capacity (due mainly to a short construction lead-time of six years) help the financial performance of both utilities.

III. METHODOLOGY

The EPPAM simulation model was used to analyze the financial feasibility and ratepayer impact of the no reform and the reform cases. EPPAM simulates the planning, operation, capacity construction, construction financing, and price regulation over time of a typical investor-owned electric utility company subject to rate-of-return regulation commonly practiced by the state public utility commission. It uses the system dynamics technique of modeling to emphasize the dynamic processes, feedback mechanisms, time delays, and nonlinear

TABLE III

NUMBER OF YEARS OF POOR FINANCIAL PERFORMANCE

	Nuclear and Generic Capacity Additions[a]				All Nuclear Capacity Additions[b]			
	No Reform (Years)	Combined Early Site Permit And Preapproval-of-Design Reforms (Years)	Total Reform Later (Years)	Total Reform Early (Years)	No Reform (Years)	Combined Early Site Permit And Preapproval-of-Design Reforms (Years)	Total Reform Later (Years)	Total Reform Early (Years)
PACIFIC GAS AND ELECTRIC COMPANY								
internal generation of funds	6	4	1	0	17	9	4	0
fraction of earnings due to AFUDC	11	10	9	0	18	17	16	4
pretax interest coverage ratio	8	3	0	0	16	9	3	0
common stock market to book ratio	2	0	0	0	15	1	0	0
GEORGIA POWER COMPANY[c]								
internal generation of funds	3	0	0	0	13	10	3	0
fraction of earnings due to AFUDC	14	13	12	0	19	17	17	13
pretax interest coverage ratio	16	14	12	5	23	19	18	21

[a][illegible] GW nuclear capacity additions for Pacific Gas and Electric Company; 6.834 GW nuclear capacity additions for Georgia Power Company.

[b][illegible] GW nuclear capacity additions for total reform - early; [illegible] GW nuclear capacity additions for all other cases - for Pacific Gas and Electric Company.

[illegible] GW nuclear capacity additions for total reform - early; 15.946 GW nuclear capacity additions for all other cases - for Georgia Power Company.

[c]Common stock sold at book value.

relationships observed in the electric utility industry. Various versions of EPPAM have been developed and implemented over the years since its inception at Dartmouth College in 1975. Most of the expansion and improvement of these various versions of EPPAM has occurred at the Los Alamos National Laboratory.[16-18] Applications of the EPPAM models are described in several articles.[19-27] To date, about 20 outside groups have implemented various versions of the EPPAM models. Most recently, the main activity is in adapting EPPAM to assist in electric resource planning by Corporate Planning Departments at several midwest utility companies.

The version of EPPAM used for this study was developed by combining relevant parts of three existing models: (1) the side-by-side model used to analyze PG&E's conservation programs, (2) the EPPAM models constructed for the US Department of Energy, and (3) the planning models currently under development for the Bonneville Power Administration. The resultant model is large and complex. The model was originally developed to be used for a financial feasibility case study for the above mentioned study entitled "The Future Market for Electric Generating Capacity, Volume II: Technical Documentation."[2] Information about the model is given in that report.

Data from the "Quantitative Analysis of Nuclear Power Plant Licensing Reform"[3] study were used as inputs to EPPAM. The data include the following:

- o escalation - 9%
- o inflation - 7%
- o unit size - 1.139 GW
- o direct construction cost updated to 1982 dollars:
  - o no reform - 1.481 billion
  - o combined early site permit and preapproval-of-design reforms - 1.147 billion
  - o total reform package - 1.046 billion
- o critical path length:
  - o no reform - 15.02 years
  - o combined early site permit and preapproval-of-design reforms - 11.51 years
  - o total reform package - 9.66 years
- o PERT cash flow curves for no reform, combined early site permit and preapproval-of-design reforms, and total reform package.

The weighted cost of capital was initialized at 10% in EPPAM. Although this figure is a bit higher than the 9.4% figure given in the "Quantitative Analysis of Nuclear Power Plant Licensing Reform" study, it has no effect on the results. This is due to the financial distress loop that is active in the EPPAM model and the regulatory response to the loop. A discussion of the financial distress loop and the regulatory response to it are given in the proceedings[27] of a workshop held at the Los Alamos National Laboratory on regulatory-financial models of the US electric utility industry. Because the weighted cost of capital varies with the utility's financial health (and is affected by the risk-free interest premium), the value of this variable throughout the simulation is really dependent on the financial condition of the utility and not on the initialized value.

The EPPAM model was run for the no reform case and all reform cases reported in the "Quantitative Analysis of Nuclear Power Plant Licensing Reform"[3] study. Results are given in this report for the no reform, combined early site permit and preapproval-of-design reforms, and total reform package cases for the 1982-2010 simulation period. These cases give the lower and upper boundaries for each of the financial indicators and the price of electricity. All other reform cases fall somewhere between these boundaries depending on the project time and total project cost. From the "Quantitative Analysis of Nuclear Power Plant Licensing Reform," the no reform case was estimated to take about 15 years in project time and have a total cost of 4.389 billion in nominal dollars. New nuclear capacity construction for the no reform case begins in the EPPAM model in 1982 with the first unit coming on-line in 1997. The combined early site permit and preapproval-of-design reforms case was estimated to take about 11.5 years in project time and have a total cost of 2.833 billion in nominal dollars. New nuclear capacity construction for this reform begins in the EPPAM model in 1985.5 with the first unit coming on-line in 1997. The total reform package case was estimated to take about 9.7 years in project time and have a total cost of 2.161 billion in nominal dollars. For this reform, two different construction intervals were run using EPPAM -- (1) total reform-later, and (2) total reform-early. Total reform-later refers to new nuclear capacity construction beginning in 1987.3 with the first unit coming on-line in 1997 (the same year that the no reform and combined early site permit and preapproval-of-design reforms cases begin commercial operation). Total reform-early refers to new nuclear capacity construction beginning in 1982 (the start of the simulation and the same year that the no reform case begins construction) with the first unit coming on-line in 1991.7, about 5 years sooner than any of the other cases.

For the above mentioned cases, two different simulations were run to meet future load growth: (1) nuclear and generic capacity additions and (2) all nuclear capacity additions. Generic capacity has the characteristics of a coal plant, with a forecasting horizon of 7 years, construction lead-time of about 6 years, and a direct construction cost of $1,000/kW. In simulations with nuclear and generic capacity additions, both types of capacities are added in fairly equal proportions to the system load. In simulations with all nuclear capacity additions, all generic capacity on-line and under construction is virtually zero, and future load growth is met solely by nuclear additions.

Tables IV and V show the electric resource capacity and generation as well as the growth in electric energy load for the planning regions of PG&E and Georgia Power for the years 1982 (the start of the simulation) and 2010 (the end of the simulation). A brief description of each electric resource is given in Appendix A. A more detailed description is given in the study entitled "The Future Market for Electric Generating Capacity, Volume II: Technical Documentation--Part 2. Financial Case Study."[2] The electric resource capacities and generations given in Tables IV and V are for model simulations with both nuclear and generic capacity additions. For simulations with all nuclear capacity additions, generic capacity is 0.0 GW and generation is 0.0 billion kWh/yr throughout the simulation.

In 1982, oil-gas steam generation accounts for about 44% of total generation for PG&E's planning region. Owned hydroelectric accounts for about 30% of total generation. Purchased hydroelectric accounts for only about 6% of total generation. As mentioned previously, purchased hydroelectric for 1982 is about 32% (as given in the company's 10-K report[7]). But, due to the tremendous variability in the amount of purchased hydroelectric from year to year (1982 happened to be a very "wet" year), the company assumes a dry year for planning purposes. By the end of the simulation, major sources of generation are nuclear (28%--including generation from Rancho Seco and Diablo Canyon units as well as from new nuclear units), conservation investment (19%), owned hydroelectric (16%), and generic (11%). Oil-gas steam generation decreases to about 8% of total system generation as the company's oil-gas back-out goals are achieved.

TABLE IV

ELECTRIC RESOURCE CAPACITY AND GENERATION
AND GROWTH IN ELECTRIC ENERGY LOAD FOR 1982

Electric Resource	Pacific Gas and Electric Company Capacity (GW)	Pacific Gas and Electric Company Generation (billion kWh/year)	Georgia Power Company Capacity (GW)	Georgia Power Company Generation (billion kWh/year)
Conservation Investment	0.9	4.3	0.4	1.7
Load Management	0.0	0.0	0.0	0.0
Owned Hydroelectric	6.5	25.1	0.8	2.9
Purchased Hydroelectric	1.4	5.4	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0
Cogeneration	0.2	1.3	0.0	0.0
Wind and Other PURPA Purchases	0.0	0.0	0.0	0.0
Nuclear	0.9	5.0	1.6	9.3
Geothermal	1.0	6.1	0.0	0.0
Coal	0.0	0.0	8.9	38.9
Oil–Gas Steam	7.2	37.5	0.0	0.0
Turbines (peaking)	0.4	0.4	1.2	0.7
Generic	0.0	0.0	0.0	0.0
Growth in Electric Energy Load After Accounting for Conservation and Load Management	1.5%/year		2.75%/year	

TABLE V

ELECTRIC RESOURCE CAPACITY AND GENERATION
AND GROWTH IN ELECTRIC ENERGY LOAD FOR 2010

Electric Resource	Pacific Gas and Electric Company Capacity (GW)	Pacific Gas and Electric Company Generation (billion kWh/year)	Georgia Power Company Capacity (GW)	Georgia Power Company Generation (billion kWh/year)
Conservation Investment	6.5	34.4	4.7	22.6
Load Management	2.8	0.0	0.0	0.0
Owned Hydroelectric	7.5	29.0	1.1	4.1
Purchased Hydroelectric	1.5	5.8	0.0	0.0
Pumped Storage	1.2	−0.5	0.9	−0.4
Cogeneration	1.5	10.0	0.0	0.0
Wind and Other PURPA Purchases	0.4	0.7	0.0	0.0
Nuclear	8.8	49.9	10.8	61.3
Geothermal	2.5	15.1	0.0	0.0
Coal	0.0	0.0	8.6	21.3
Oil–Gas Steam	7.2	15.0	0.0	0.0
Turbines (peaking)	1.2	0.5	2.2	1.4
Generic	4.3	19.6	6.3	30.4
	(2.8 under construction)		(4.1 under construction)	
Growth in Electric Energy Load After Accounting for Conservation and Load Management	1.5%/year		2.75%/year	

For Georgia Power's planning region, major generation is from coal plants which accounts for about 73% of total generation in 1982. By the end of the simulation, nuclear generation (including generation from Hatch and Vogtle units as well as from new nuclear units) accounts for about 44% of total generation. Other major sources of generation at this time include generic (22%), conservation investment (16%), and coal (15%).

The capacity and generation for each electric resource for both regions include generating units under construction at the beginning of the simulation. These units are scheduled to begin commercial operation at some point during the mid to late 1980 time period. Table VI gives these generating units, company-planned commercial operation dates and nameplate ratings (or nominal capabilities) for each company's planning region.[6-14]

TABLE VI

GENERATING UNITS, COMMERCIAL OPERATION DATES, AND NAMEPLATE RATINGS (OR NOMINAL CAPABILITIES) FOR THE PLANNING REGIONS OF PACIFIC GAS AND ELECTRIC COMPANY AND GEORGIA POWER COMPANY

Generating Unit	Commercial Operation Dates	Nominal Capability (MW)
Pacific Gas and Electric Company		
The Geysers Unit No. 18 (geothermal)	1983	110
Kerkoff Unit No. 2 (hydroelectric)	1983	[illegible]
Diablo Canyon Unit Nos. 1 & 2 (nuclear)	1984	2,190
Helms Unit Nos. 1,2 & 3 (pumped storage)	1985	1,185
Moss Landing Unit Nos. 6 & 7 (cogeneration)	1985	9.6
The Geysers Unit No. 20 (geothermal)	1986	110
The Geysers Unit No. 16 (geothermal)	1986	110
21 small hydroelectric projects	1983-1987	82
Georgia Power Company		
Generating Unit	Commercial Operation Dates	Nameplate Ratings (MW)
Plant Scherer Unit No. 2 (coal)	1984	818
Bartletts Ferry Unit Nos. 5 & 6 (hydroelectric)	1985	108
Plant Scherer Unit No. 3 (coal)	1987	818
Alvin W. Vogtle Nuclear Plant No. 1 (nuclear)	1987	1,160
Rocky Mountain Unit Nos. 1,2 & 3 (pumped storage)	1987	847
Alvin W. Vogtle Nuclear Plant No. 2 (nuclear)	1988	1,160
Goat Rock Unit Nos. 7 & 8 (hydroelectric)	1988	67
Plant Scherer Unit No. 4 (coal)	1989	818

IV. RESULTS

Figures 1 through 22 (presented at the end of the results section) give the main results of the financial and ratepayer impacts of nuclear power plant licensing reform. The following description of these figures will be very general in nature, since a detailed explanation of each figure is given in Appendix B and a summary of all figures (including three summary tables) is given in the introductory section of this report.

Figures 1 through 22 give the following information for the 1982-2010 simulation period: internal generation of funds, fraction of earnings due to AFUDC, pretax interest coverage ratio, common stock market to book ratio (for PG&E, only; Georgia Power's common stock is wholly owned by the Southern Company, thus, common stock is sold at book value in the model), real price of electricity (in constant dollars), and price of electricity (in nominal dollars, assuming 7% inflation per year throughout the simulation). Figures 1 through 11 are simulations using nuclear and generic capacity additions; whereas, figures 12 through 22 are simulations using all nuclear capacity additions. The improvements in the financial performance of each utility and reduction in the price of electricity to ratepayers of nuclear regulatory reform are examined in this study. Improvements in the financial performance of each utility are measured by examining key financial variables and comparing their performance with goals set by PG&E. These goals include internal generation of funds greater than 40%, fraction of earnings due to AFUDC under 20%, pretax interest coverage ratio in excess of 3.0, and common stock market to book ratio in excess of 1.0.[2, Part 2]

Prior to commercial operation of several generating units under construction at the beginning of all simulations (see Table VI), the financial indicators for each company show poor performance. This is due to the large capital costs associated with these units that are not recovered until the units begin commercial operation. Upon commercial operation of these units during the mid to late 1980's, all financial indicators improve dramatically as capital costs are recovered in the rate base and there is relatively little construction activity (with the exception of the total reform-early case). The price of electricity (in real as well as nominal dollars) increases during this period as these capital costs enter the rate base.

Figures 1 through 11 give simulation results for nuclear and generic capacity additions. For these simulation results, the total reform-early case exhibits the best overall performance. With this reform case, all financial indicators, except the pretax interest coverage ratio for Georgia Power, show good financial performance throughout the duration of the simulation after commercial operation of the several units listed in Table VI. This reform case shows less financial recovery during the mid to late 1980's than the other cases since it has the most construction activity at this time. Total reform-early has a construction start date of 1982 and an on-line date of 1991.7 (for the first new nuclear unit). The other cases have construction start dates of 1982 for no reform, 1985.5 for combined early site permit and preapproval-of-design reforms, and 1987.3 for total reform-later; and, these cases all have on-line dates of 1997 (for the first new nuclear unit). With the commercial operation of each new nuclear unit and the inclusion of the associated capital costs in the rate base (as evidenced by the peaks in all graphs), all financial indicators improve for all cases. The improvement in the financial health of each utility is more dramatic for the total reform-early case. This is because the total reform-early case has the shortest construction lead-time of 9.7 years and begins construction in 1982, thereby avoiding the increasing inflation and escalation costs in later years. Although the total reform-later case also has a construction lead-time of 9.7 years, construction begins after several years of increasing inflation and escalation costs. Generally, the total reform-later case performs better than the combined early site permit and preapproval-of-design reforms case, and, the combined early site permit and preapproval-of-design reforms case performs better than the no reform case for most of the simulation period. The exception occurs (for some financial indicators) near the end of the simulation period when longer lead-times and the resulting larger capital costs in the rate base for the no reform and combined early site permit and preapproval-of-design reforms cases cause a reversal of this trend. After the last nuclear units begin commercial operation for all cases, the companies invest only in generic capacity and the financial indicators for all cases converge. This convergence is caused by all cases having the same generic capacity characteristics, thus differences among the cases are negligible.

The real price of electricity (in constant dollars) and the price of electricity (in nominal dollars) is lower for the reform cases than for the no reform case as all new units become operational. The total reform-early case generally exhibits the lowest price. For PG&E, real price decreases for all the reform cases and increases for the no reform case as each of the five nuclear units begins commercial operation. This is because the fuel cost savings (by backing out of more expensive oil and gas) obtained from these new nuclear units are greater than the added capital costs. The increase in real price of electricity from the new nuclear units with no reform is due to the added capital costs exceeding the fuel cost savings.

For Georgia Power, real price increases for all cases except total reform-early as each of the six nuclear units begins commercial operation. The increase in the real price for the no reform, the combined early site permit and preapproval-of-design reforms, and the total reform-later cases is due to the added capital costs of the new nuclear units exceeding the fuel cost savings. Georgia Power has predominately coal with some nuclear and hydroelectric fuel for system generation prior to commercial operation of the new nuclear units. Thus, fuel costs are relatively low for this utility. Also, because Georgia Power is a more rapidly growing utility than PG&E, it must add more capacity (both generic and nuclear) at very high capital costs compared to existing units in order to meet demand growth. For this company, the total reform-early case exhibits a short-term price penalty between 1995 and 2006 due to greater added capital costs of the new nuclear units compared to the fuel cost savings. During the period following the commercial operation of Scherer and Vogtle, real price decreases dramatically for the other cases because of the more inexpensive nuclear and coal fuel usage and no added capital costs in the rate base of the new nuclear units until 1997.

For both companies, the combined early site permit and preapproval-of-design reforms and the total reform-later cases have short-term price penalties for about a ten year period prior to commercial operation of the first nuclear unit. This is because the companies are paying more income tax and have less debt interest during this period since there is less construction activity for these two cases than for the no reform case. By the end of the simulation, real price (in constant dollars) and price (in nominal, 7% per year inflated dollars) is lower for Georgia Power than for PG&E for all cases except the no reform case. This is because Georgia Power has lower fuel costs throughout the simulation (ranging from about 20% to 30% of total real price of electricity between 1982 and 2010) than PG&E (which ranges from about 73% to 50% of total real price of electricity between 1982 and 2010). Thus, for Georgia Power, the combination of low fuel costs throughout the simulation and the cheaper capital costs of the reformed nuclear units as well as the generic generating capacity cause lower prices than for PG&E for all but the no reform case. With no reform, the fuel cost savings afforded PG&E by backing out of expensive oil and gas fuel usage, keep prices lower than that of the no reform case for Georgia Power.

Figures 12 through 22 give simulation results for all nuclear capacity additions. With this scenario, all nuclear units begin commercial operation during the simulation for the total reform-early case but not for the other cases. Thus, by the end of the simulation some nuclear units are still under construction for these cases. For these simulation results, the total reform-early case exhibits the best overall performance. In fact, by the end of the simulation period (for both companies), the total reform-early case peaks at 100% for internal generation of funds and drops to 0 for the fraction of earnings due to AFUDC. This is because the fuel cost savings due to inexpensive nuclear fuel eventually outweigh the added capital costs of successive new units. This translates into less operating revenues needed to produce electricity and thus more money available for construction. For this reform case, construction costs are eventually paid solely by internal funds. Although some financial indicators show short periods of poor performance with this reform case, the magnitude and duration of the poor performance is much less than for the other cases. Generally, the financial performance for the remaining cases is somewhat worse for simulations with all nuclear capacity additions than for simulations with nuclear and generic capacity additions. This is because generic capacity has a construction lead-time of only 6 years and a direct construction cost of $1,000/kW; therefore, generic capacity has a lower capital cost than nuclear capacity. And, fuel cost savings of the new nuclear units for these cases do not outweigh these capital costs sufficiently to cause the financial indicators to perform better for simulations with all nuclear capacity additions than for nuclear and generic capacity additions. The no reform case (for all nuclear capacity additions) for PG&E is one that exhibits very poor financial performance. For example, internal generation of funds is negative between 2006 and 2009 for this case. This indicates extremely poor financial performance in that the company is funding construction of new nuclear units solely through debt financing.

The real price of electricity (in constant dollars) and the price of electricity (in nominal dollars) is generally lower for the reform cases than for the no reform case. The exception is the total reform-early case for

Georgia Power. After commercial operation of Scherer and Vogtle, real price decreases dramatically for all cases, except the total reform-early case, due to the fuel cost savings from these coal and nuclear units. The total reform-early case exhibits a slight decrease in real price at this time for a short period after which real price remains above the other cases during most of the simulation. This is because the capital costs of the new nuclear units coming on-line for this reform case outweigh the low fuel costs from Scherer (and other existing coal plants) and Vogtle. Also, with this reform case, more capacity (20.502 GW) comes on-line during the simulation than for the other cases (15.946 GW). If the simulation period was extended, the price for the total reform-early case would eventually be the lowest as all nuclear units become operational. All other cases exhibit an increase in real price (and nominal price) as the new nuclear units become operational, again, due to the added capital costs of these units outweighing the low fuel costs from Scherer (and other existing coal plants) and Vogtle.

For PG&E, real price decreases for the total reform cases as the new nuclear units become operational. This is because the fuel cost savings (by backing out of more expensive oil and gas) outweigh the added capital costs of the new nuclear units for these cases. Real price increases only slightly (about 1%) for the combined early site permit and preapproval-of-design case. For the no reform case, real price increases about 53% as the added capital costs of the new nuclear units greatly outweigh the fuel cost savings of backing out of expensive oil and gas.

For both companies, a short-term price penalty again exists for the combined early site permit and preapproval-of-design reforms and the total reform-later cases as it did for the simulations with nuclear and generic capacity additions. By the end of the simulation, real price (in constant dollars) and price (in nominal dollars) is lower for PG&E than for Georgia Power for all cases except the no reform case. This is because Georgia Power is a more rapidly growing utility building more nuclear units (six more units with total reform-early and five more units with all other cases) than PG&E. These new nuclear units are more expensive than generic capacity that is not included under this all nuclear capacity additions scenario. In addition, the fuel cost savings afforded to PG&E by backing out of expensive oil and gas fuel usage keep the price of electricity lower for all reform cases. The price of electricity is higher for the no reform case for PG&E than for Georgia Power. This is because the added capital costs of the nonreformed new nuclear units greatly outweigh the fuel cost savings.

In comparing the nuclear and generic capacity additions simulation with all nuclear capacity additions simulation, prices are lower for PG&E for the all nuclear capacity addition scenario for all cases except the no reform case. Again, a greater fuel cost savings is possible with all nuclear capacity additions than with nuclear and generic capacity additions for reformed nuclear units. For the no reform case, the added capital costs greatly outweigh the fuel cost savings for the all nuclear capacity additions scenario. For Georgia Power, prices are higher for the all nuclear capacity additions scenario than for the nuclear and generic capacity additions scenario. Because this utility has relatively low fuel costs initially (due to predominately coal with some nuclear and hydroelectric fuel usage), the added capital costs of the more expensive new nuclear units (compared to generic capacity) for all cases outweigh any fuel savings.

Finally, a sensitivity analysis was performed on two parameters--the escalation rate and the weighted cost of capital. As mentioned previously, escalation is 9%, weighted cost of capital is 10%, and inflation is 7% for the base case results (figures 1 through 22). The sensitivity analyses were performed for PG&E for simulations with nuclear and generic capacity additions. Results are given (in Appendix C for escalation rates and Appendix D for the weighted cost of capital) for all financial indicators as well as real price and price, and for the no reform and reform cases.

In the "Quantitative Analysis of Nuclear Power Plant Licensing Reform"[3] study, it was noted that escalation may be subject to improvement by regulatory reform since a large part of today's excess of escalation over ordinary inflation (about 2%) may be due to regulatory-mandated increases in cost. It was also noted that, in particular, established safety goals and more consistent design standards may make it possible to reduce escalation to nearly the overall inflation rate. It was estimated in that study that a 1% change in escalation is worth about $93/kW--almost as significant as one-fourth of the total reform package.

Figures 24 through 47 in Appendix C of this report give results of the sensitivity analysis of escalation rates for this study. For these simulations, escalation varies by 1%, ranging from 7% to 11%, including 9% which is the base case value. Overall, financial performance is best and price is lowest when escalation is 7%; and, financial performance is worse and price is highest when escalation is 11% for all cases. Specifically, the no reform case has more dramatic changes in financial performance and price than the other cases with 1% changes in escalation. One important outcome of this sensitivity analysis is that when escalation is reduced to the inflation rate of 7%, the no reform case performs slightly better than the base case (9% escalation) for combined early site permit and preapproval-of-design reforms. Also, real price is slightly lower throughout the simulation period. By the end of the simulation period, real price for the no reform case with 7% escalation is 4% lower than for the combined early site permit and preapproval-of-design reforms with base case conditions. Compared to the total reform-later base case, no reform with 7% escalation performs better financially after commercial operation of several of the new nuclear units. By 2010, real price for the no reform case with 7% inflation is about 2% lower than for the total reform-later base case. The total reform-early case exhibits the best overall performance as escalation varies from 7% to 11%. Only after the last unit begins commercial operation and future demand is met solely by generic capacity does the financial performance and price begin to decline. This is because the total reform-early case has a short construction lead-time of 9.7 years and begins construction in 1982, thereby avoiding the increasing inflation and escalation costs in later years. The generic capacity and associated capital costs occurring near the end of the simulation period include many years of increasing inflation and escalation costs. Also, generic capacity has higher fuel costs than that of the new nuclear units. By 2010, the price of electricity is about 6% lower for the total reform-early base case than for no reform with 7% inflation, again due to total reform-early having a shorter lead-time, thus avoiding the increasing inflation and escalation costs in later years. Thus, as noted in the "Quantitative Analysis of Nuclear Power Plant Licensing Reform" study, established safety goals and more consistent design standards do make it possible to reduce escalation to nearly the overall inflation level and dramatically increase the measurable benefits of reform.

It is also mentioned in the "Quantitative Analysis of Nuclear Power Plant Licensing Reform" study, that although the financial premiums associated with the riskiness of nuclear investments are not easy to determine, interest rates required by financial markets would surely drop if regulatory reform of safety goals can reduce uncertainty. It was estimated that a 1% change in market rates is worth $67/kW in capital costs.

Figures 48 through 53 in Appendix D of this report give results of the sensitivity analysis of the weighted cost of capital for this study. For these simulations, the weighted cost of capital is initialized at 13% and the risk free interest premium is increased from 2.5% per year to 5.5% per year in order to truly measure the effect of an increase in the weighted cost of capital on the financial performance of the utility and the price to the ratepayers. The financial performance of the utility is generally much worse with a higher weighted cost of capital and risk free interest rate than with base case conditions. The common stock market to book ratio exhibits much worse financial performance for all cases. Real price is 14% higher for no reform, 6% higher for combined early site permit and preapproval-of-design reforms, 5% higher for total reform-later and 4% higher for total reform-early by the end of the simulation than for base case conditions.

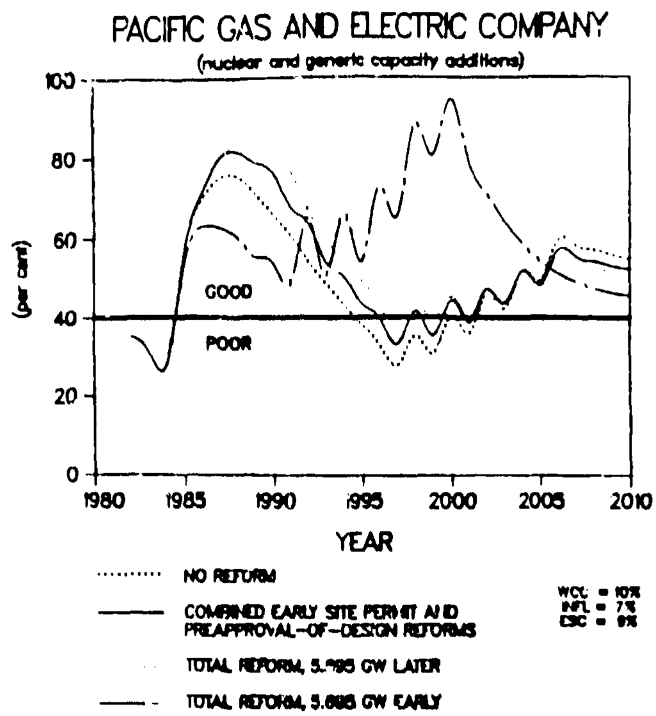

Fig. 1. Internal generation of funds.

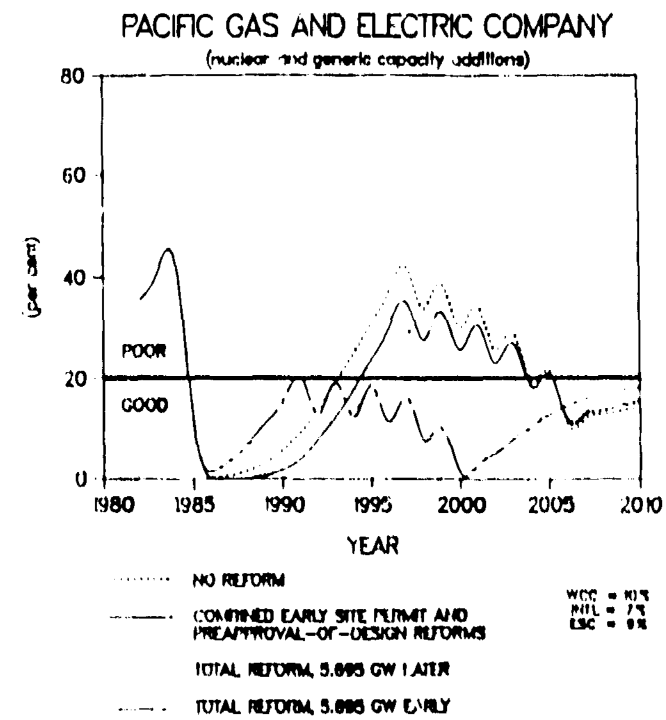

Fig. 2. Fraction of earnings due to AFUDC.

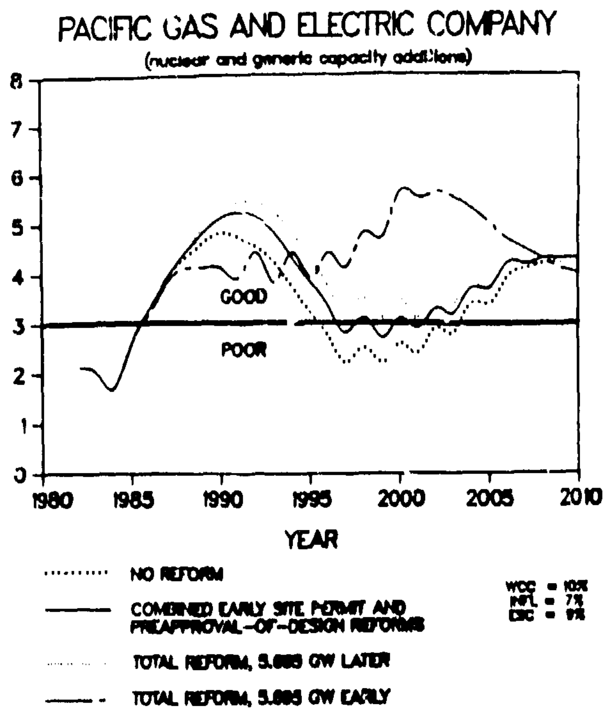

Fig. 3. Pretax interest coverage ratio.

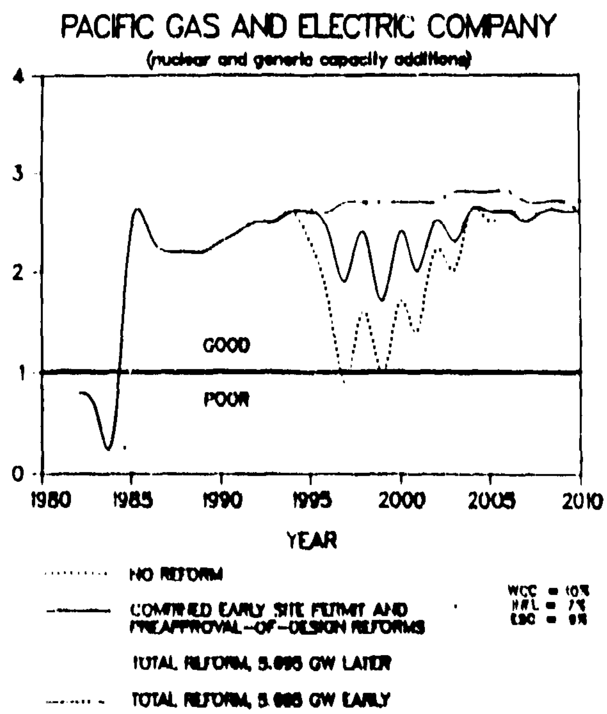

Fig. 4. Common stock market to book ratio.

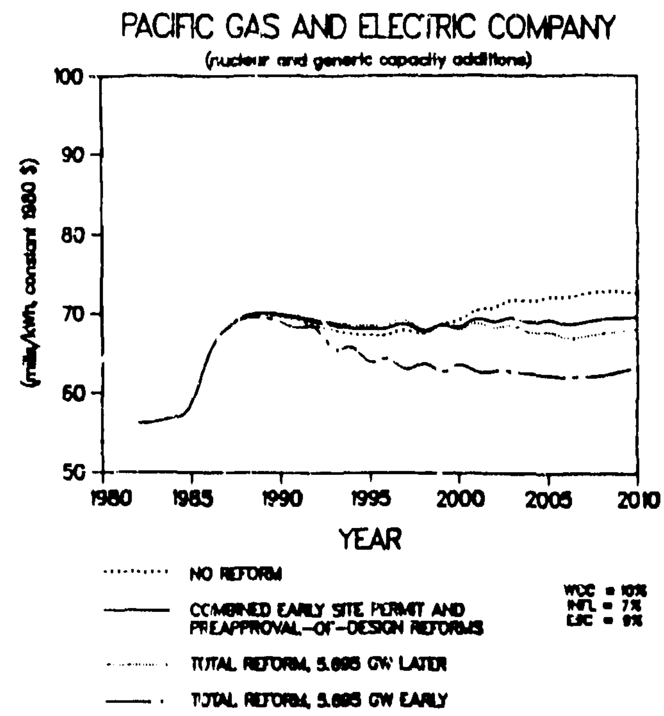

Fig. 5. Real price of electricity.

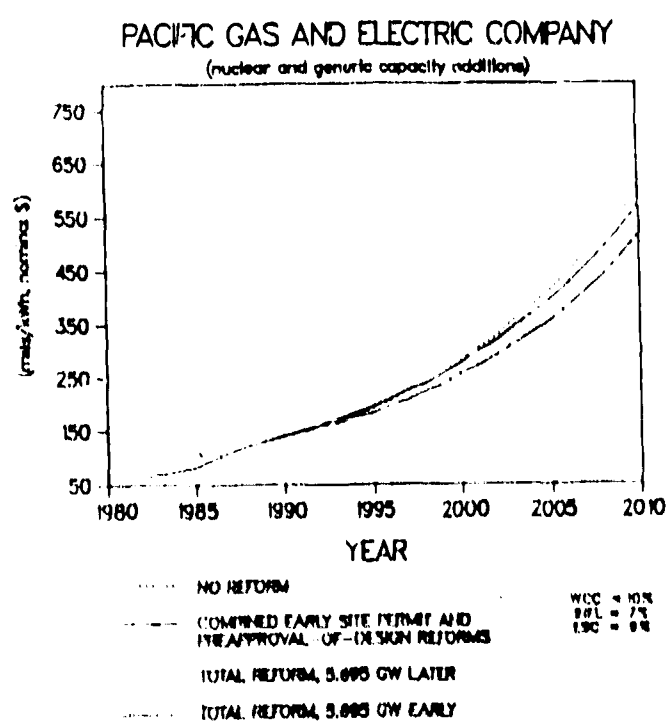

Fig. 6. Price of electricity.

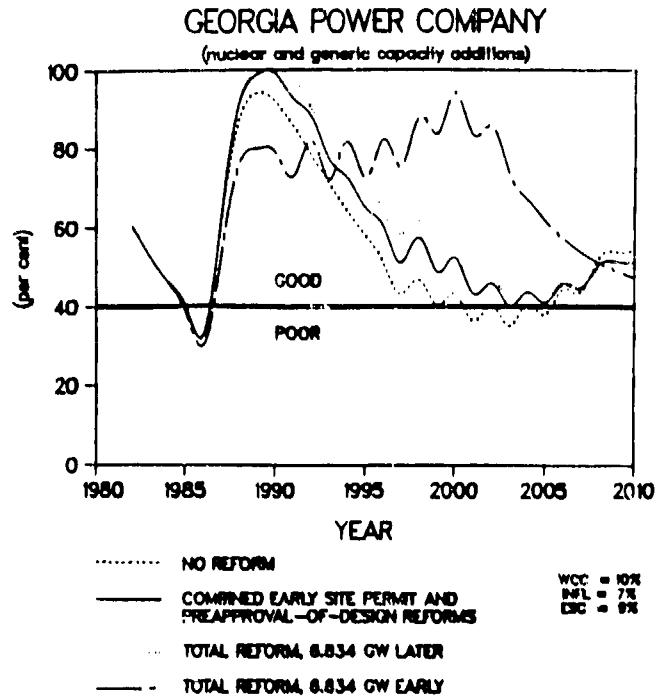

Fig. 7. Internal generation of funds.

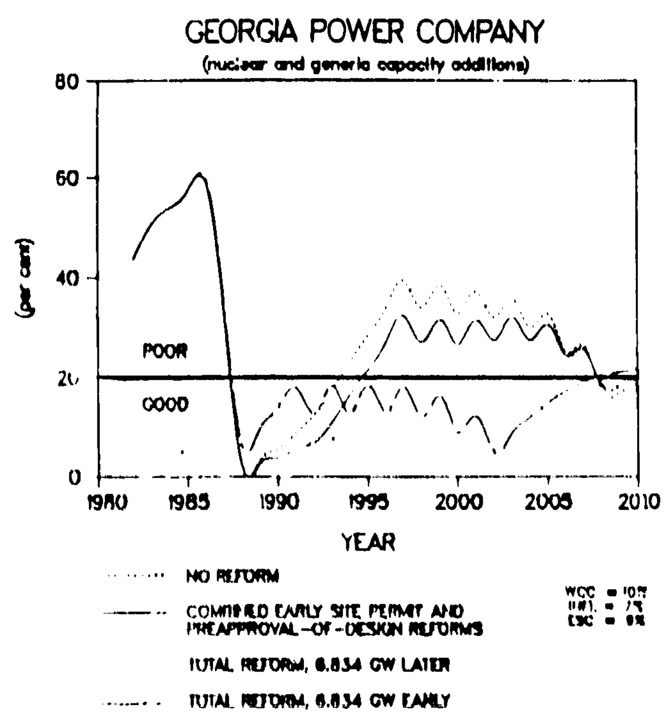

Fig. 8. Fraction of earnings due to AFUDC.

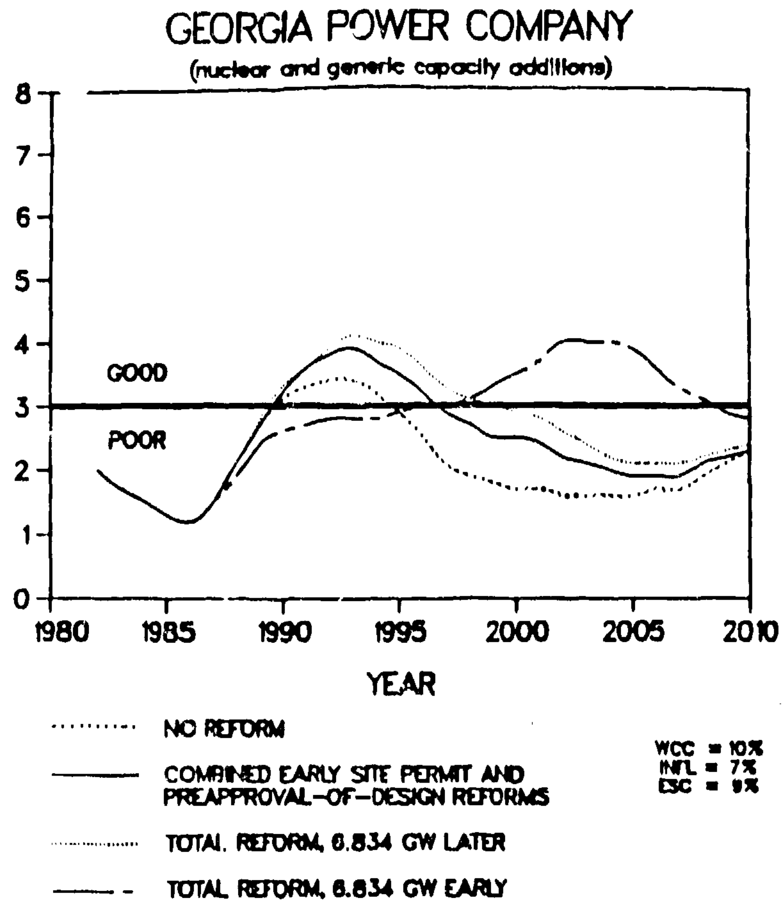

Fig. 9. Pretax interest coverage ratio.

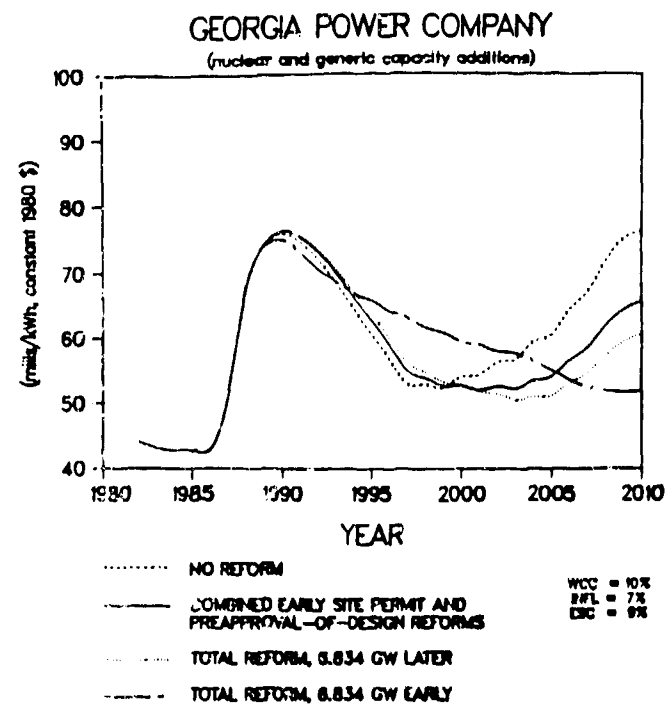

Fig. 10. Real price of electricity.

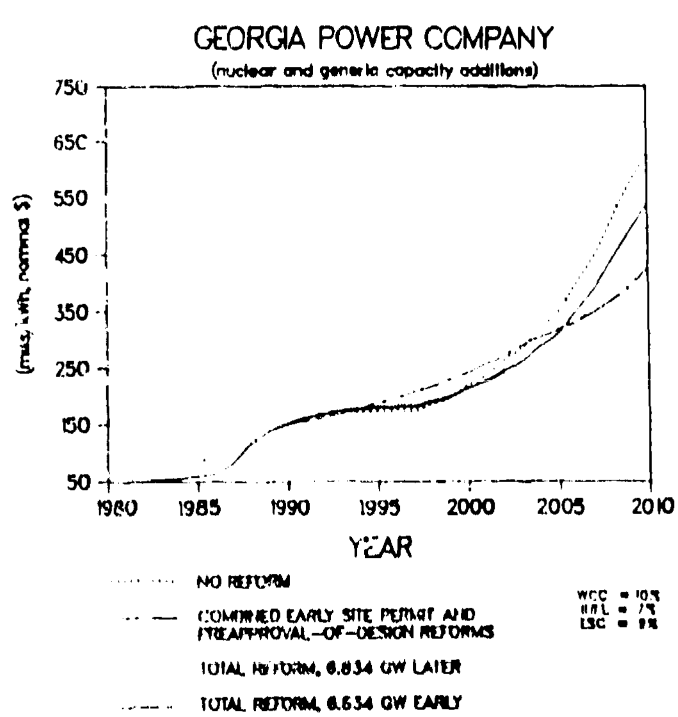

Fig. 11. Price of electricity.

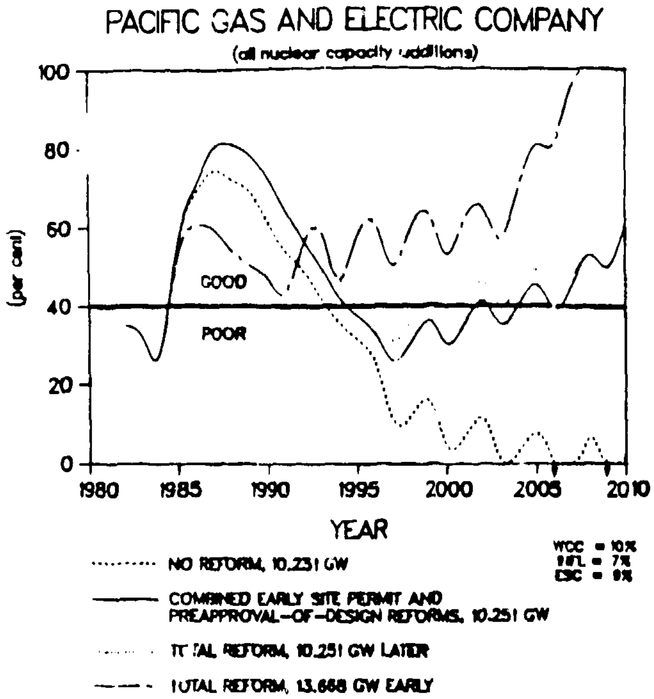

Fig. 12. Internal generation of funds.

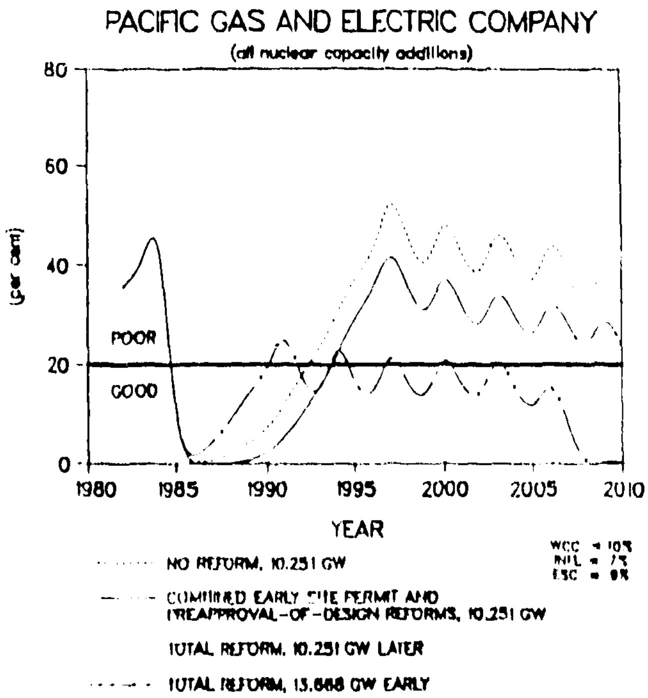

Fig. 13. Fraction of earnings due to AFUDC.

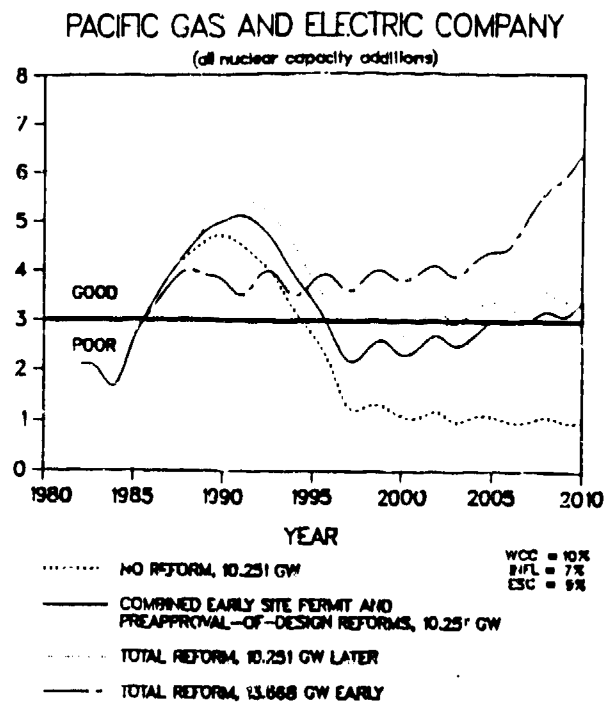

Fig. 14. Pretax interest coverage ratio.

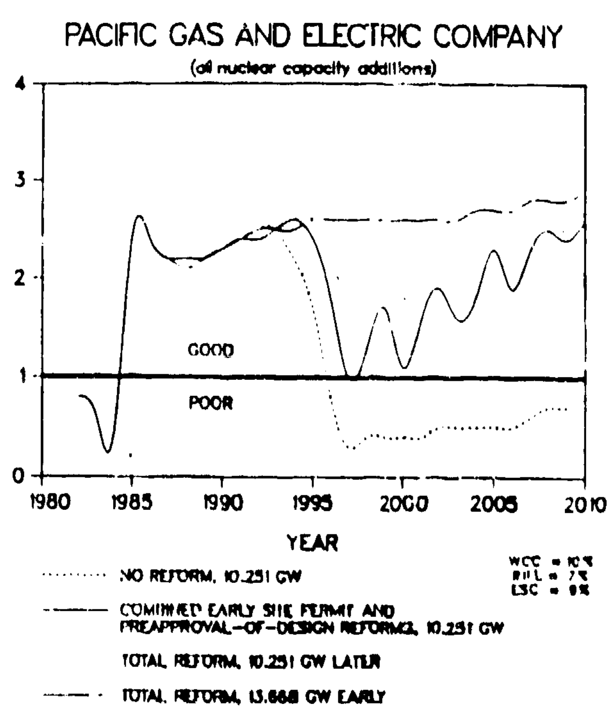

Fig. 15. Common stock market to book ratio.

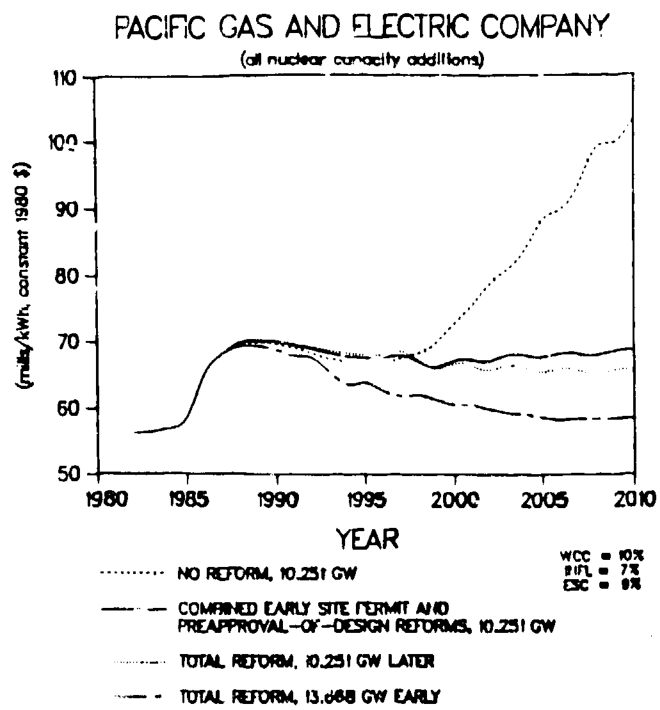

Fig. 16. Real price of electricity.

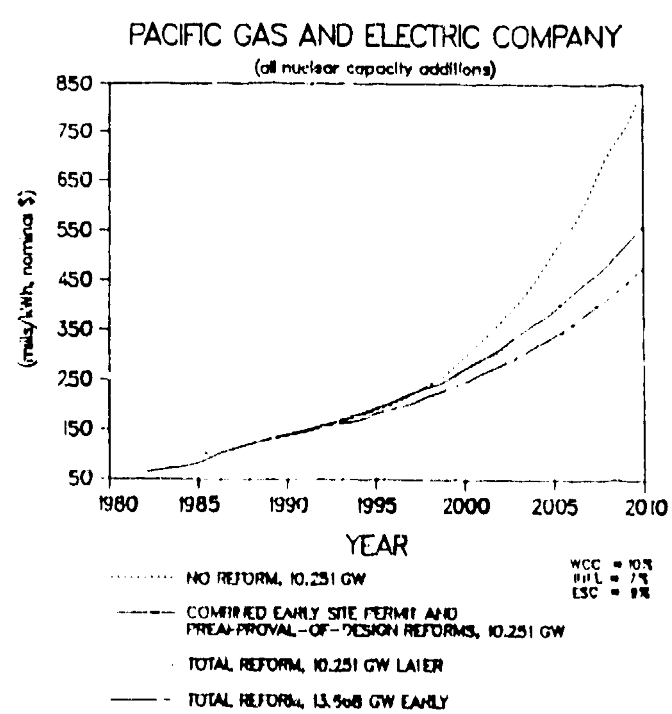

Fig. 17. Price of electricity.

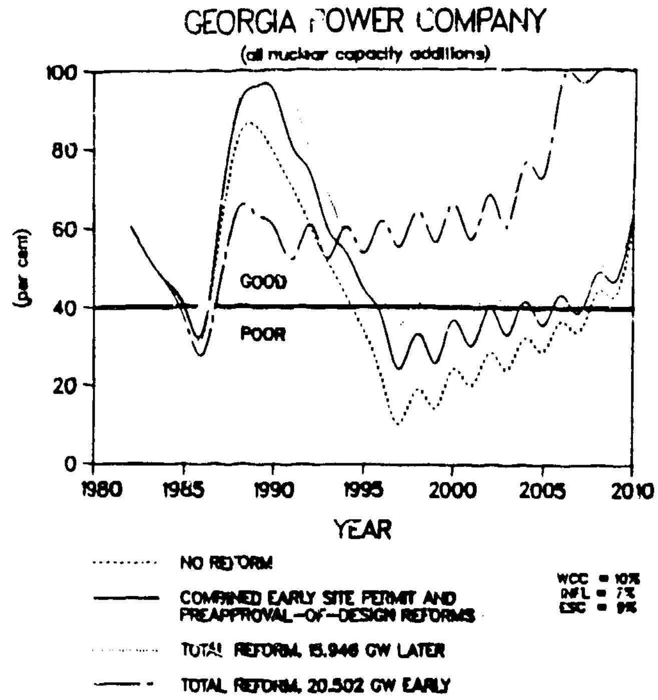

Fig. 18. Internal generation of funds.

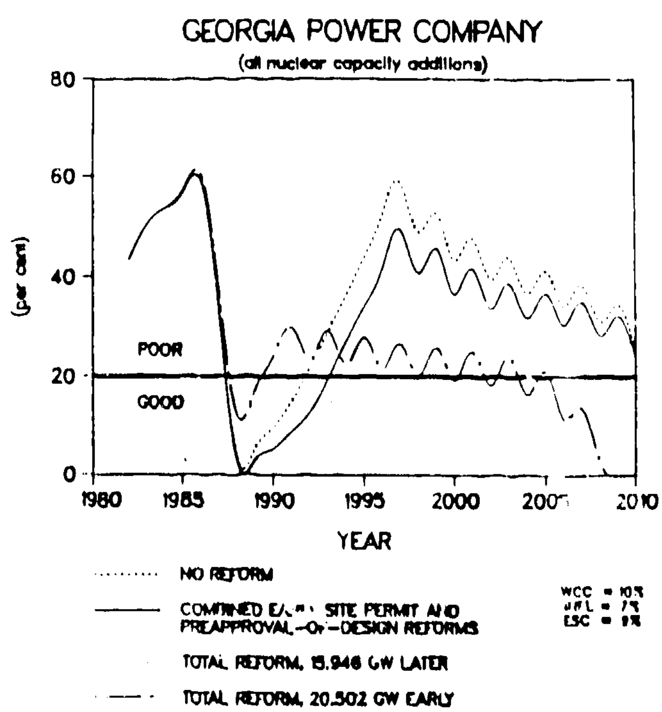

Fig. 19. Fraction of earnings due to AFUDC.

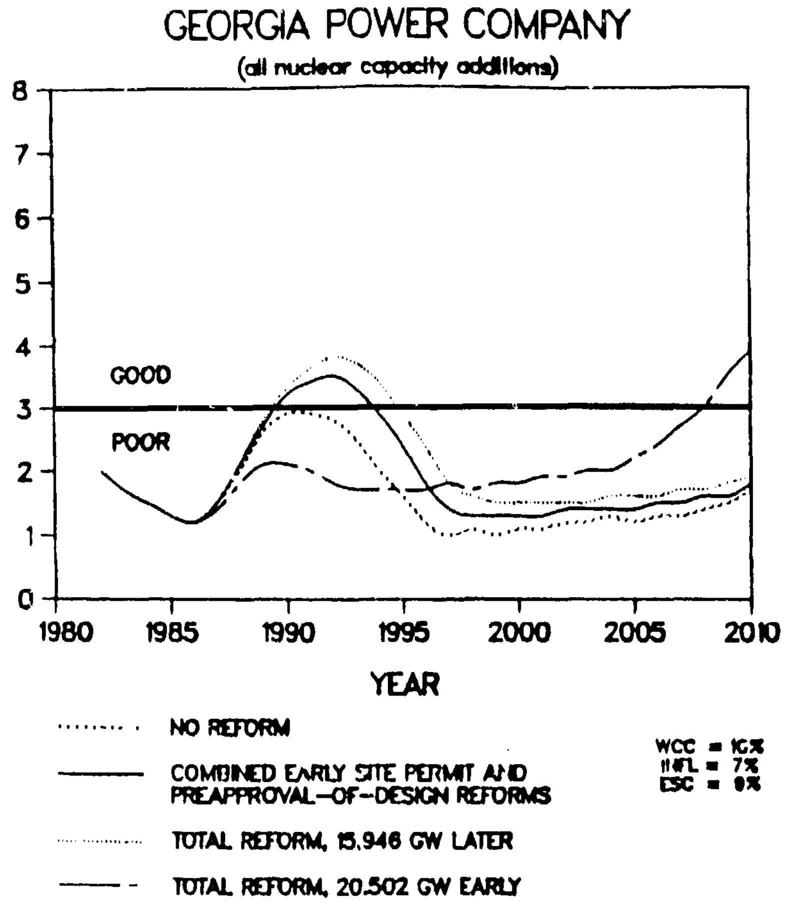

Fig. 20. Pretax interest coverage ratio.

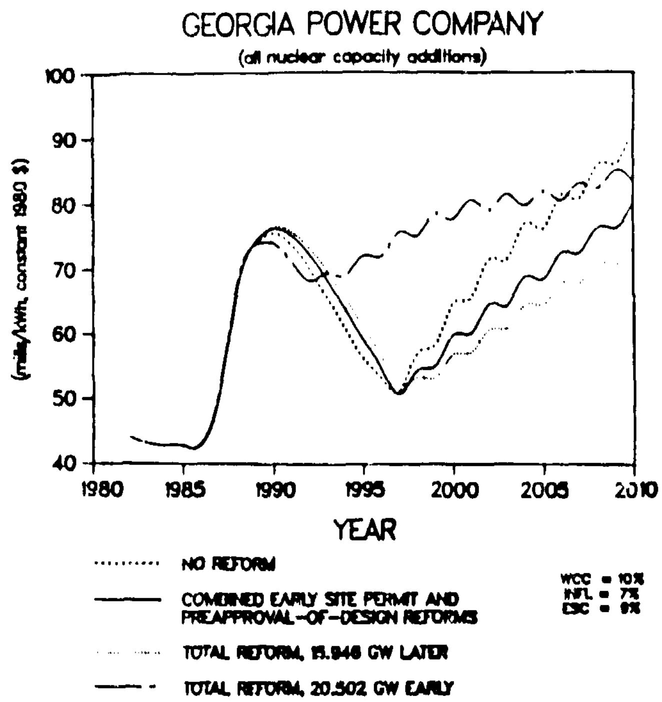

Fig. 21. Real price of electricity.

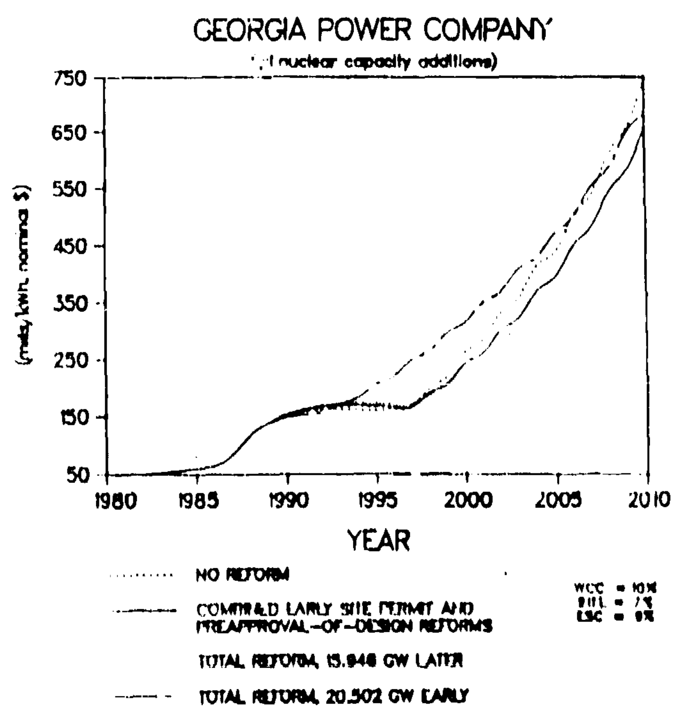

Fig. 22. Price of electricity.

V. CONCLUSIONS AND IMPLICATIONS

The improvements in the financial performance of two utilities--PG&E and Georgia Power, and reduction in the price of electricity to ratepayers of nuclear regulatory reform are examined in this study. Improvements in the financial performance are measured by examining key financial variables and comparing their performance with goals set by PG&E for the no reform and the reform cases. The results of the Monte Carlo modeling of PERT charts were used as inputs to a Los Alamos regulatory-financial model--EPPAM. The model projects financial and ratepayer impacts over the 1982-2010 time period for the no reform and the reform cases, for the two utilities, and for simulations with nuclear and generic capacity additions and with all nuclear capacity additions.

The main results of the study are presented in Figures 1 through 22. Summary results appear in Tables I through III. Results indicate that nuclear regulatory reform is very important in reducing the construction lead-time thereby improving the financial performance of the utility and reducing the price of electricity to the ratepayers. For all simulations (including nuclear and generic capacity additions and all nuclear capacity additions), the total reform-early case exhibits the best overall financial performance and the lowest price. This reform case has the shortest lead-time of 9.7 years and begins construction in 1982, thereby avoiding the increasing inflation and escalation costs in later years (as compared to the total reform-later case). This reform case also has the most new nuclear construction activity at a time when other new generating units have begun commercial operation and the associated capital costs have been included in the rate base. The utility is thus in an excellent position to internally finance most of the new nuclear construction thereby avoiding expensive debt costs. Implications are that the shorter construction lead-time afforded by nuclear regulatory reform and the timing of new capacity additions is extremely important in enabling a utility to remain in a healthy financial position while adding capacity to meet future demand and in reducing the price of electricity to the ratepayers.

Generally, Georgia Power has higher rate increases for simulations with nuclear and generic capacity additions and all nuclear capacity additions than PG&E. Georgia Power has predominately coal with some nuclear and hydroelectric fuel usage for system generation prior to commercial operation of the new nuclear units. Fuel costs are relatively low throughout the simulation for this utility. Thus, for the most part, the added capital costs of the new nuclear units outweigh any fuel cost savings. Also, this company is a more rapidly growing utility than PG&E and must therefore add more capacity (both generic and nuclear) at very high capital costs compared to existing units in order to meet demand growth. For PG&E, the reform cases all exhibit price decreases (with the exception of a 1% price increase for the combined early site permit and preapproval-of-design reforms case for the simulation with all nuclear capacity additions) as each of the 5 new nuclear units begin commercial operation. The fuel cost savings (by backing out of more expensive oil and gas) obtained from these reformed nuclear units are greater than the added capital costs. The implication of this is that the combination of lower added capital costs of nuclear units constructed under nuclear regulatory reform and fuel cost savings obtained from these new nuclear units displacing expensive oil and gas allow a utility such as PG&E to experience price decreases as these new units begin commercial operation.

With the exception of the total reform cases for PG&E, simulations with all nuclear capacity additions have higher price increases and worse financial performance than simulations with nuclear and generic capacity additions as the new nuclear units begin commercial operation. This is due to the lack of any generic capacity (and associated cheaper total capital costs) with the all nuclear capacity additions simulations. Generic capacity has a lead-time of only 6 years and a capital cost of $1,000/kW compared to the total reform nuclear units that have a lead-time of 9.7 years and capital cost of $1,046/kW. Once again, this shows the importance of shortening the lead-times through nuclear regulatory reform since, in this example, the capital costs are roughly equivalent.

Results of the "Nuclear Rate Increase Study" indicated that nuclear plant rate increases were not always higher than coal plant rate increases. Implications of that finding were that rate shock is not solely the result of building nuclear plants. The smaller rate increases generally expected for new coal plants are more the result of the smaller capacity (and shorter construction time) of these plants compared to nuclear plants than to their respective costs. Absorbing smaller units (even high-cost units) has a lesser effect on rates. It was further noted in that study that virtually any new unit going into the rate base now will raise rates for utilities whose rates are based on historical costs. The inflation of the last 15 years assures that all new plants will be very high-cost compared to most existing ones. The advantage goes to smaller capacity additions, both in moderating rate shocks and in combating the planning/demand uncertainties faced by the larger (longer lead-time) plants. These advantages are not inherently a characteristic of either coal or nuclear technologies but can be captured by either plant type using foresighted technological and institutional arrangements. Results of the utility interviews in "The Future Market for Electric Generating Capacity" study indicated that one major change that utilities felt was needed before nuclear reactors could again be ordered for utility applications was smaller plant sizes than the present 1,000-1,200 MWe, although there should not be large diseconomies associated with the smaller units. In this study--"The Financial and Ratepayer Impacts of Nuclear Regulatory Reform," it was found that in simulations excluding the shorter lead-time generic capacity, price increases were greater. The implication of this is that by shortening construction lead-time through nuclear regulatory reform, nuclear power will be on a more competitive basis with coal.

APPENDIX A

A. Conservation Investment

The size of the conservation resource summarizes the result of residential, commercial, and industrial customers' investments in increased energy efficiency due to a combination of higher prices of electricity, company subsidy programs (in the case of PG&E), and taxpayer subsidies.

B. Load Management

Load management programs are assumed to reduce peak load but to leave the total demand for electric energy unchanged. The amount, timing and costs of these programs are user inputs to the simulation model. For PG&E, an additional 100 MW of peak shaving capability is added each year as the company's combination of load management programs are implemented. Georgia Power has no load management programs underway or planned for the future.

C. Owned Hydroelectric

The capacity and generation shown in Tables IV and V are for "average hydroelectric conditions."

D. Purchased Hydroelectric

For PG&E, purchased hydroelectric refers to the energy obtained over the intertie from the Pacific Northwest. The amount and shape of the purchased hydroelectric contribution are exogenously specified according to PG&E's long-term plan. The actual amount of purchased hydroelectric can vary tremendously from year to year. As mentioned previously, 43.3% of the company's generation was purchased in 1982 -- 32.1% of that was purchased hydroelectric. That year was a very "wet" year. For planning purposes the company assumes a dry year (due to the great variability of hydroelectric). Georgia Power does not purchase any hydroelectric energy at any time during the simulation.

E. Pumped Storage

For PG&E, it is assumed that the 1,185 MW Helms pumped storage unit will begin operation in 1985. The shape of the pumped storage generation and loss factor is user specified. The shape-and-loss assumptions lead to net losses of around 50%. In other words, the simulated dispatching of Helms requires about 1.5 kWh of electric energy during off peak periods for every 1 kWh obtained from falling water during peak intervals. Georgia Power has an 847 MW pumped storage facility -- Rocky Mountain Unit Nos. 1,2 & 3 assumed to begin commercial operation in 1987.

F. Cogeneration

For PG&E, the amount and shape of the cogeneration contribution are exogenously specified in the model to correspond to the estimates in the company's long-term plan. The company is assumed to pay the avoided cost for each kWh purchased. Georgia Power is assumed to have no significant PURPA purchases from cogenerators.

G. Wind and Other PURPA Purchases

This category is similar to cogeneration, but it is much smaller. The amount and shape of the wind-other PURPA contribution are exogenously specified according to PG&E's planning estimates. Wind generation is treated as a load reduction, and the company is assumed to pay the avoided cost for each kWh purchased. Georgia Power is assumed to have no significant purchases from wind farms and other PURPA qualifying facilities.

H. Nuclear

For PG&E, 0.9 GW of nuclear capacity at the beginning of the simulation corresponds to SMUD's Rancho Seco plant. Nuclear capacity increases to 3.07 GW with the assumed completion of the Diablo Canyon units. Thereafter, new nuclear capacity is added to help meet the 1.5% per year growth in electric energy load for each type of regulatory reform previously mentioned. For Georgia Power, 1.6 GW of nuclear capacity in 1982 corresponds to the Hatch plant. Nuclear capacity increases to 3.9 GW with the assumed completion of the Vogtle units. Thereafter, new nuclear capacity is added to help meet the 2.75% per year growth in electric energy load. The nuclear units are dispatched first in the merit order and operate at their full availability (65%).

I. Geothermal

For PG&E, it is assumed that this capacity is owned by the utility and dispatched after the nuclear units in the merit order. It is also assumed that geothermal additions occur in small chunks with short lead-time; therefore AFUDC is not calculated during construction. For Georgia Power, no significant geothermal generation is assumed.

J. Coal

For PG&E, there is no coal capacity or generation during the simulation period. For Georgia Power, 8.9 GW of coal capacity are in commercial operation in 1982 with 1 GW being retired during the simulation. Also, 2.45 GW of coal capacity (the Scherer units) are under construction during the early part of the simulation. Coal plants are operated after the generic units (and just before the peaking units) in the merit order. Consequently, their usage drops significantly once the nuclear units begin operation.

K. Oil-Gas Steam

For PG&E, the simulation begins with 7.2 GW of oil-gas fired steam capacity in 1982. Since the exact amount of retirement of these units is not crucial to the model simulations, the capacity remains at this initial value for the remainder of the simulation. The operation of the oil-gas units is an endogenous variable that changes from one simulation to another depending on the rate of growth in demand and the timing of new capacity additions. Oil-gas generation mostly declines during the simulation period to match PG&E's oil-gas back-out goals (see Figure 23). Most of the decline occurs during the first half of the simulation when the Diablo Canyon units begin operation. A slight decline during the latter half of the simulation is made possible by the addition of new nuclear and generic capacity additions (or all nuclear capacity additions). PG&E's oil-gas back-out goals are used as targets in judging how much new nuclear and generic capacity (or all nuclear capacity) should be added to the system. For Georgia Power, it is assumed that there is no significant oil-gas steam generation.

L Turbines

Gas turbines are used in the model as a proxy for all of both regions peaking units. Turbine operation is based on a user-specified maximum duration, and the model calculates internally the electric energy output. For PG&E, implementation of the load management programs and operation of the Helms pumped storage unit tend to reduce the generation from the gas turbines.

M. Generic Capacity

Investment in generic capacity is internally determined based on growth in load, additions of other generating resources, the northern California region's oil-gas back-out goals and the Georgia region's desired reserve margin of 20%. In this study, generic capacity has the characteristics of a coal plant, with a planning and construction lead-time of about 6 years, a direct construction cost of $1,000 per kilowatt, and a forecasting horizon of 7 years. Generic capacity is dispatched after the geothermal units in the merit order. With this dispatching rule, the generic units do not necessarily operate at their full, user-specified availability (70%).

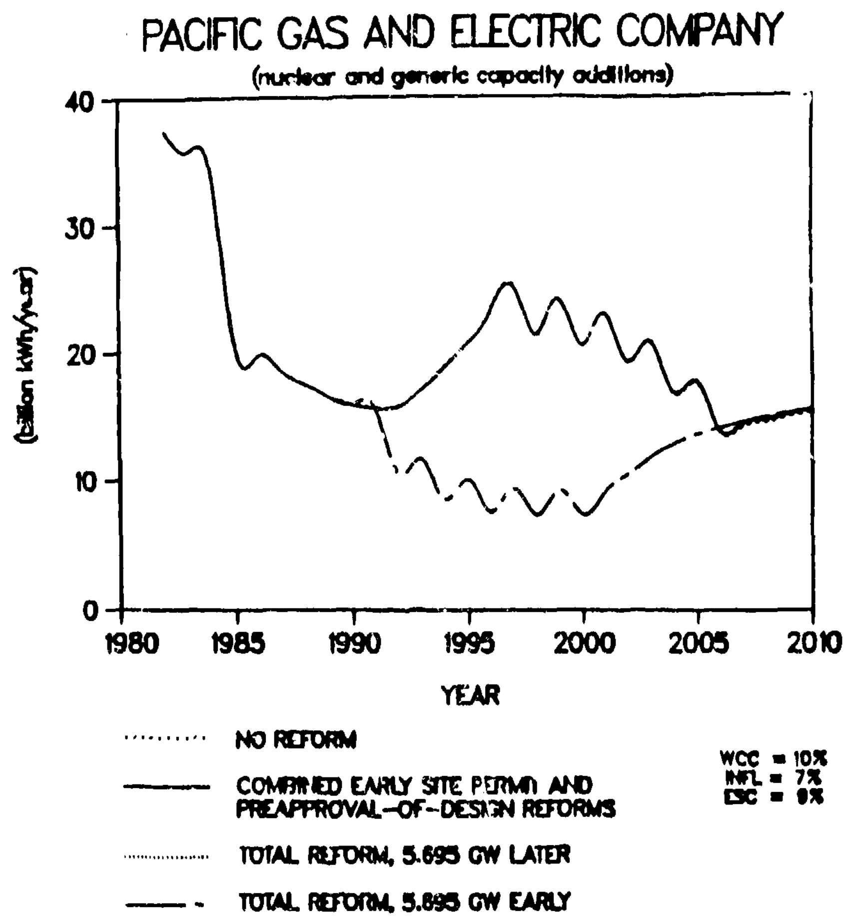

Fig. 23. Oil and gas steam electricity generation.

APPENDIX B

Figures 1 through 7 give model simulations for PG&E for nuclear and generic capacity additions for the no reform and the reform cases. Several generating units begin commercial operation early in the simulation (see Table VI). Between the years 1977 and 2005, five new nuclear units begin commercial operation (one 1.139 GW unit every other year) for all cases except the total reform - 5.695 GW early case for which commercial operation of the 5 units occurs between 1991.7 and 1999.7.

1. Figure 1. Internal Generation of Funds

Prior to commercial operation of several generating units under construction at the beginning of the simulation (mainly Diablo Canyon Units Nos. 1 & 2 and Helms Unit Nos. 1, 2, & 3) this financial indicator falls below the 40% goal, indicating poor performance, for all cases. With the inclusion of Diablo Canyon (in 1984) and Helms (in 1985) in the rate base, and with relatively little construction in progress during the late 1980's, internal generation of funds is projected to peak at about 75% for no reform, 82% for combined early site permit and preapproval-of-design reforms, and 84% for total reform - 5.695 GW later. At this time the company has the most construction activity for the no reform case (of these 3 cases) since it has a 1982 construction start date. The combined early site permit and preapproval-of-design reforms and the total reform - 5.695 GW later cases have construction start dates of 198[illegible].5 and 1987.3, respectively. Thus, internal generation of funds is lowest for the no reform case and highest for the total reform - 5.695 GW later case at this peak period (for these 3 cases). Prior to commercial operation in 1997 of the first of 5 nuclear units, internal generation of funds again falls below the 40% level to about 28% for no reform (about the same level as prior to the commercial operation of Diablo Canyon and Helms), 33% for combined early site permit and preapproval-of-design reforms, and 39% for total reform - 5.695 GW later. Internal generation of funds continually improves for these cases as each successive unit comes on-line and the capital costs are recovered in the rate base. After commercial operation of the last nuclear unit in 2005, internal generation of funds is projected to increase to about 59% for no reform, 57% for combined early site permit and preapproval-of-design reform, and 56% for total reform - 5.695 GW later. Higher internal generation of funds at the end of the simulation for the no reform case is caused by longer lead-times and the resulting larger capital costs that are recovered in the rate base. The combined early site permit and preapproval-of-design reforms also have a greater value for internal generation of funds than the total reform - 5.695 GW later case, also due to greater capital costs recovered in the rate base. Internal generation of funds decreases slightly near the end of the simulation for these cases due to continuing generic capacity construction.

Internal generation of funds for total reform - 5.695 GW early is projected to be about 60% (in 1986) after commercial operation of Diablo Canyon and Helms. With a construction start date of 1982 and an on-line date of 1991.7, this reform case has the most construction activity during this period, and thus, the lowest internal generation of funds. Prior to commercial operation of the first nuclear unit in 1991.7, internal generation of funds is projected to decrease to about 49%, thereafter continually increasing with the inclusion of successive units in the rate base. Internal generation of funds is projected to peak at about 95% around the year 2000 after commercial operation of the last nuclear unit. Because the company invests heavily in generic capacity thereafter, internal generation of funds falls below the projections for the other cases. Total reform - 5.695 GW early has more generic construction at the end of the simulation than the other cases. Since 5.695 GW of new nuclear capacity begins commercial operation earlier in the simulation for this case, generic capacity construction is very limited until the last nuclear unit comes on-line. A greater amount of generic construction is needed toward the end of the simulation to meet load growth.

Internal generation of funds for the total reform - 5.695 GW early case exhibits the best overall performance (after commercial operation of Diablo Canyon and Helms). This financial indicator remains well above the 40% level during the 1985-2010 time period. This reform case has the shortest construction lead-time of 9.7 years and begins construction in 1982, thereby avoiding the increasing inflation and escalation costs in later years. Internal generation of funds for the total reform - 5.695 GW later case falls below the 40% goal for only 1 year at 39%. Although this reform case also has a construction lead-time of 9.7 years, construction begins after several years of increasing inflation and escalation costs. Internal generation of funds for the combined early site permit and preapproval-of-design reforms case falls below the 40% goal for 4 years, the lowest value being 33%. For the no reform case, this financial indicator falls below the 40% goal for 6 years, the lowest value being 28%.

2. Figure 2. Fraction of Earnings Due to AFUDC

Prior to commercial operation of Diablo Canyon and Helms, AFUDC exceeds 20% of earnings, indicating poor performance, at about 43% for all cases. Once Diablo Canyon and Helms begin commercial operation, AFUDC decreases (in 1986) to about zero for the no reform, the combined early site permit and preapproval-of-design reforms, and the total reform - 5.695 GW later cases. Prior to commercial operation in 1997 of the first of 5 nuclear units, AFUDC peaks at about 42% of earnings for no reform, 35% of earnings for combined early site permit and preapproval-of-design reforms, and 30% of earnings for total reform - 5.695 GW later. AFUDC continually decreases for these cases as each successive nuclear unit comes on-line. After commercial operation of the last nuclear unit in 2005, the goal of limiting AFUDC to less than 20% of earnings is again achieved. The fraction of earnings due to AFUDC is about 11% for no reform, and 12% for combined early site permit and preapproval-of-design reforms and total reform - 5.695 GW later. Again, the slightly higher figure for the no reform case is due to the greater capital costs recovered in the rate base of t· time. The fraction of earnings due to AFUDC increases slightly near the end of the simulation due to continuing generic capacity construction.

AFUDC for total reform - 5.695 GW early is projected to be about 1.5% of earnings (in 1986) after commercial operation of Diablo Canyon and Helms. AFUDC is greater for this case than for any of the other cases during the early part of the simulation. Again, with a construction start date of 1982 and an on-line date of 1991.7, this reform case has the most construction activity underway during this period. Prior to commercial operation of the first nuclear unit in 1991.7, AFUDC peaks at about 20% of earnings, thereafter, continually decreasing with the inclusion of successive units in the rate base. After commercial operation of the last unit in 1999.7, AFUDC increases due to high generic construction activity.

The fraction of earnings due to AFUDC for the total reform - 5.695 GW early case exhibits the best overall performance. For this reform case, AFUDC remains below 20% of earnings during the 1985-2010 time period with the exception of one year (1991) when AFUDC is 20% of earnings. For the total reform - 5.695 GW later case, this financial indicator exceeds 20%, indicating poor performance, for 9 years, the highest value being 30%. For the combined early site permit and preapproval-of-design reforms case, the fraction of earnings due to AFUDC exceeds 20% for 10 years, the highest value being 35%. For the no reform case, the fraction of earnings due to AFUDC exceeds 20% for 11 years, the highest value being 42%.

3. Figure 3. Pretax Interest Coverage Ratio

Prior to commercial operation of Diablo Canyon and Helms, the pretax interest coverage ratio is below the 3 times interest goal, indicating poor performance, at 1.7 for all cases. As the company's earnings improve with the inclusion of Diablo Canyon and Helms in the rate base, the company's coverage ratio peaks to 4.8 for no reform, 5.2 for combined early site permit and preapproval-of-design reforms, and 5.4 for total reform - 5.695 GW later. Prior to commercial operation in 1997 of the first nuclear unit, the pretax interest coverage ratio is once again below the 3 times interest goal for the no reform (at 2.2) and the combined early site permit and preapproval-of-design reforms (at 2.8) cases. The company's coverage for the total reform - 5.695 GW later case remains above the 3.0 goal at 3.2. Pretax interest coverage increases for these cases as each successive nuclear unit comes on-line and earnings improve. After commercial operation of the last nuclear unit in 2005, the goal of providing coverage in excess of 3 times the interest is again achieved. The company's coverage is 3.9 for the no reform case and 4.2 for the combined early site permit and preapproval-of-design reforms and total reform - 5.695 GW later cases. These values remain at about these levels for the duration of the simulation.

The pretax interest coverage ratio for total reform - 5.695 GW early is projected to be 3.2 (in 1986) after commercial operation of Diablo Canyon and Helms. The company's coverage is less for this case than for the other cases during the early part of the simulation. Again, with a construction start date of 1982 and an on-line date of 1991.7, the company has the most construction activity with this reform during this period. Prior to commercial operation of the first nuclear unit in 1991.7, the pretax interest coverage ratio is 3.9. The company's coverage continually increases with the inclusion of successive nuclear units in the rate base. The company's coverage peaks at 5.6 after commercial operation of the last nuclear unit in 2000. Thereafter, the pretax interest coverage ratio decreases for the remainder of the simulation to 4.0 in the year 2010 due to high generic construction activity.

The pretax interest coverage ratio for total reform - 5.695 GW early case exhibits the best overall performance. For this reform case, the company's earnings are consistently sufficient enough to provide coverage well in excess of the 3 times interest goal during the 1985-2010 time period. The total reform - 5.695 GW later case also maintains a pretax interest coverage ratio greater than 3.0 during the simulation period, although not as high as the total reform - 5.695 GW early case. For the combined early site permit and preapproval-of-design reforms, the pretax interest coverage ratio is below the 3 times interest goal, indicating poor performance, for 3 years, the lowest value being 2.8. For the no reform case, the coverage ratio is below the 3 times interest goal for 8 years, the lowest value being 2.2.

4. Figure 4. Common Stock Market to Book Ratio

One of the most important financial goals is to maintain a common stock price in excess of the company's book value. Prior to the commercial operation of Diablo Canyon and Helms, the market value is below book value for all cases, decreasing from 0.8 in 1982 to 0.4 in 1984. The common stock market to book ratio falls below 1, indicating poor performance at this time, because of heavy discounting of the company's dividends due to high risk. Once Diablo Canyon and Helms begin commercial operation and the company achieves its goals for interest coverage and quality of earnings, the common stock dividend discount rate (used to convert from dividends to market price) falls to more normal values and the market price increases dramatically. Thus, the market value exceeds book value in the simulation by 1985 for all cases. Throughout the remainder of the simulation, market value continues to exceed book value for all cases except no reform. For no reform the common stock market to book ratio falls below 1.0, indicating poor performance, for 2 years, the lowest value being 0.9.

The total reform - 5.695 GW early case exhibits the best overall performance. For this case, market value is well above book value during the 1985 to 2010 time period with values ranging from 2.4 to 2.8. For the total reform - 5.695 GW later and the combined early site permit and preapproval-of-design reforms cases, the common stock market to book ratio is also above 1.0 with values ranging from 2.2 to 2.7 and 2.2 to 2.6, respectively. As mentioned previously, the common stock market to bo . ratio for the no reform case falls below 1.0, indicating poor performance, for 2 years, the lowest value being 0.9.

5. Figure 5. Real Price of Electricity

The real price of electricity, in constant 1980 dollars, is about 56 mills/kWh for all cases in 1982. About 73% of the revenues generated by this initial rate are used to pay for fuel--mostly oil and gas used in steam plants. Once Diablo Canyon and Helms begin commercial operation, the real price of electricity is projected to increase to about 65 mills/kWh in 1987 for all cases. Increases in the real price (and price, in nominal dollars) of electricity are phased in over a one year time period due to regulatory lag in updating the capital related costs in the region. These increases are necessary since the added capital costs exceed the fuel cost savings obtained from the new projects.

There is a short-term price penalty for the combined early site permit and preapproval-of-design reforms and the total reform - 5.695 GW later cases during the 1987 to 1998 time period. The company pays more income tax and has less debt interest during this period because there is less construction activity for these two cases. As each of the 5 nuclear units begins commercial operation between 1997 and 2005, the real price of electricity for the no reform case increases from 67.9 mills/kWh in 1997 to 72.0 mills/kWh in 2006. This increase (about 6%) is due to the added capital costs exceeding the fuel cost savings obtained from the new projects. For the combined early site permit and preapproval-of-design reforms case and the total reform - 5.695 GW later case, the real price of electricity decreases during the 1997-2006 time period. This is because the fuel cost savings (by backing out of more expensive oil and gas) obtained from these new nuclear units are greater than the added capital costs. The real price of electricity for the combined early site permit and preapproval-of-design reforms case decreases from 68.7 mills/kWh in 1997 to 68.6 mills/kWh in 2006 (about 2%). For the total reform - 5.695 GW later case, the real price of electricity decreases from 69.2 mills/kWh in 1997 to 66.9 mills/kWh in 2006 (about 3%). For the total reform - 5.695 GW early case, the real price of electricity decreases during the 1991 to 2000 time period, since commercial operation of the first unit is 1991.7 and of the last unit is 1999.7. The real price of electricity for this case is 68.3 mills/kWh in 1991 and decreases to 63.5 mills/kWh in 2000 (about 8%). Again, the company is able to replace more expensive oil and gas with inexpensive nuclear fuel. The real price of electricity increases slightly near the end of the simulation due to the company's investment in new generic generating capacity.

By the year 2006, all new nuclear capacity costs are recovered in the rate base. At this time, the real price of electricity is 72.0 mills/kWh for no reform, 68.6 mills/kWh for combined early site and preapproval-of-design reforms, 66.9 mills/kWh for total reform - 5.695 GW later, and 61.9 mills/kWh for total reform - 5.695 GW early. Compared to the no reform case, the real price of electricity is about 5% lower for the combined early site permit and preapproval-of-design reforms, about 8% lower for total reform - 5.695 GW later, and about 16% lower for total reform - 5.695 GW early.

6. Figure 6. Price of Electricity

The price of electricity, in nominal dollars (assuming 7% inflation per year throughout the simulation), is about 65 mills/kWh for all cases in 1982. Once Diablo Canyon begins commercial operation, the price of electricity is projected to increase from 75.3 mills/kWh in 1984 to 83.2 mills/kWh in 1985 for all cases. This 10.5% rate increase due to commercial operation of Diablo Canyon's 2 units (2.190 GW total net capability) is very close to the 11% rate increase estimated by the Los Alamos National Laboratory in another study entitled "Nuclear Rate Increase Study."[4] In that study, it is noted that the company also estimated the rate increase due to Diablo Canyon to be 11%. Once Helms comes on-line, the price of electricity is projected to increase from 83.2 mills/kWh in 1985 to 98.9 mills/kWh in 1986 (about 19%).

With the commercial operation of each of the five nuclear units (and company investment in generic capacity), the price of electricity, in nominal dollars, increases for all cases. During the 1997 to 2006 time period, the price of electricity increases from 223.3 to 444.4 mills/kWh for no reform, from 225.8 to 423.3 mills/kWh for combined early site permit and preapproval-of-design reforms, and from 227.5 to 412.8 mills/kWh for total reform - 5.695 GW later. During the 1991 to 2000 time period, the price of electricity for total reform - 5.695 GW early increases from 147.4 to 257.6 mills/kWh. Beyond the year 2000, the company invests heavily in generic capacity to meet load growth.

Figures 7 through 11 give model simulations for Georgia Power for nuclear and generic capacity additions. Detailed descriptions of remaining figures will not be given since details for the remaining figures are similar to those for Figures 1 through 6 given above. For Georgia Power, Figures 7 through 11, several generating units begin commercial operation early in the simulation (see Table VI). The financial indicators and price effects are examined for the time period following commercial operation of these generating units that are under construction at the beginning of the simulation. Between the years 1997 and 2007, 6 new nuclear units begin commercial operation (one 1.139 GW unit every other year) for all cases except the total reform - 6.834 GW early case for which commercial operation of the 6 units occurs between 1991.7 and 2001.7.

7. Figure 7. Internal Generation of Funds

Internal generation of funds for the total reform - 6.834 GW early case exhibits the best overall performance. This financial indicator remains well above the 40% level during the 1987-2010 time period, peaking at 94% in the year 2000 after the fifth of 6 new nuclear plants begins commercial operation. Internal generation of funds also remains at or above the 40% level for the total reform - 6.834 GW later and combined early site permit and preapproval-of-design reforms cases during the 1987-2010 time period. This financial indicator is at its lowest value for the cases during 2003, as the fourth nuclear unit begins commercial operation, at about 42% for total reform - 6.834 GW later and slightly over 40% (40.1%) for the combined early site permit and preapproval-of-design reforms. For the no reform case, this financial variable falls below the 40% goal for 3 years during the 1987-2010 time period, the lowest value being about 35%.

8. Figure 8. Fraction of Earnings Due to AFUDC

The fraction of earnings due to AFUDC for the total reform - 6.834 GW early case exhibits the best overall performance. For this case, AFUDC consistently remains below 20% of earnings during the 1988-2008 time period. Between 2008 and 2010, AFUDC slightly exceeds 20% of earnings because the company invests heavily in generic capacity near the end of the simulation to meet load growth. For the total reform - 6.834 GW later case, this financial indicator exceeds 20%, indicating poor performance, for 12 years, the highest value being 30%. For the combined early site permit and preapproval-of-design reforms, the fraction of earnings due to AFUDC exceeds 20% for 13 years, the highest value being 32%. For the no reform case, the fraction of earnings due to AFUDC exceeds 20% for 14 years, the highest value being 39%. Georgia Power has a longer time interval when the fraction of earnings due to AFUDC exceeds 20% than PG&E. This is because Georgia Power is a more rapidly growing utility and has more nuclear and generic capacity under construction than PG&E.

9. Figure 9. Pretax Interest Coverage Ratio

The pretax interest coverage ratio for total reform - 6.834 GW early exhibits the best overall performance. The company's coverage is below the 3 times goal for 5 years, the lowest value being 2.4. As several of the new nuclear units come on-line, coverage reaches 3.1 in 1998, peaking at 4.0 between 2002 and 2004, and declining thereafter to below the goal for 2 years at the end of the simulation (due to generic construction activity). For the total reform - 6.834 GW later case, coverage is below the 3 times interest goal for 12 years, the lowest value being 2.1. For the combined early site permit and preapproval-of-design reforms, coverage is below the goal for 14 years, the lowest value being 1.9. For no reform, pretax interest coverage is below the goal for 16 years, the lowest value being 1.6.

10. Figure 10. Real Price of Electricity

Although the real price of electricity, in constant dollars, for total reform - 6.834 GW early is lower than the other cases at the end of the simulation, it has higher values between 1995 and 2006. As each of the 6 nuclear units begin commercial operation between 1991.7 and 2001.7, the real price of electricity decreases from 73.2 mills/kWh in 1991 to 58.0 mills/kWh in 2002 (about 26%). The short-term price penalty for this case is due to greater added capital costs of the new nuclear units compared to the fuel cost savings. During the period following the commercial operation of Scherer and Vogtle, real price decreases dramatically for the other cases because of the more inexpensive nuclear and coal fuel usage and no added capital costs in the rate base of these new units until 1997. This dramatic decrease is not apparent for PG&E because of expensive oil and gas fuel usage for system generation. For total reform - 6.834 GW later, the real price of electricity increases from 56.3 to 57.3 mills/kWh (about 2%) as each of the 6 nuclear units begins commercial operation between 1997 and 2007. For the combined early site permit and preapproval-of-design reforms, the real price of electricity increases from 55.0 to 62.0 mills/kWh (about 13%). For no reform, real price increases from 52.9 to 71.9 mills/kWh (about 36%).

By the year 2008, all new nuclear capacity capital costs are recovered in the rate base. At this time, the real price of electricity is 71.9 mills/kWh for no reform, 62.0 mills/kWh for the combined early site permit and preapproval-of-design reforms, 57.3 mills/kWh for total reform - 6.834 GW later, and 51.9 mills/kWh for total reform - 6.834 GW early. Compared to the no reform case, the real price of electricity is about 16% lower for combined early site permit and preapproval-of-design reforms, about 25% for total reform - 6.834 GW later, and about 39% lower for total reform - 6.834 GW early.

11. Figure 11. Price of Electricity

With the commercial operation of each of the six nuclear units (and company investment in generic capacity), the price of electricity, in nominal dollars, increases for all cases. During the 1997 to 2008 time period, the price of electricity increases from 173.8 to 510.7 mills/kWh for no reform, from 180.8 to 440.9 mills/kWh for combined early site permit and preapproval-of-design reforms, and from 184.9 to 406.9 mills/kWh for total reform - 6.834 GW later. During the 1991 to 2002 time period, the price of electricity for total reform - 6.834 GW early increases from 158.0 to 270.4 mills/kWh.

By the year 2008, all new nuclear capital costs are recovered in the rate base. At this time, the price of electricity is 510.7 mills/kWh for no reform, 440.1 mills/kWh for combined early site permit and preapproval-of-design reforms, 406.9 mills/kWh for total reform - 6.834 GW later, and 368.4 mills/kWh for total reform - 6.834 GW early.

Figures 12 through 17 give model simulations for PG&E for all nuclear capacity additions. The financial indicators and price effects are examined for the time period following commercial operation of the generating units that are under construction at the beginning of the simulation (see Table VI). Between the years 1997 and 2010, 9 new nuclear units (1.139 GW each) begin commercial operation (with 3 units under construction by 2010) for all cases except the total reform - 13.668 GW early case for which 12 units begin commercial operation during the 1991.7 to 2010 time period. The pattern of commercial operation dates for these cases is one - 1.139 GW unit on-line each year for 2 years with no on-line activity for 1 year.

12. Figure 12. Internal Generation of Funds

Internal generations of funds for the total reform - 13.668 GW early case exhibits the best overall performance. This financial indicator remains well above the 40% level during the 1985-2010 time period, peaking in the years 2008 to 2010 at 100%. For this reform case, the fuel cost savings due to inexpensive nuclear fuel eventually outweigh the added capital costs of successive new units. This translates into less operating revenues needed to produce electricity and thus more money available for construction. In this case, construction costs are eventually paid solely by internal funds.

For the total reform - 10.251 GW later case, internal generation of funds falls below 40%, indicating poor performance, for 4 years, the lowest value being 31%. By the end of the simulation, internal generation of funds is about 60%. For the combined early site permit and preapproval-of-design reforms, this financial variable falls below 40% for 9 years, the lowest value being 26%. By the end of the simulation, internal generation of funds is 60%. For the no reform case, internal generation of funds falls below 40% for 17 years between 1994 and the end of the simulation. During the years 2006 and 2009, internal generation of funds is negative. This indicates extremely poor financial performance in that the company is funding construction of new nuclear units solely through debt financing.

13. <u>Figure 13. Fraction of Earnings Due to AFUDC</u>

The fraction of earnings due to AFUDC for the total reform - 13.668 GW early case exhibits the best overall performance. For this case, AFUDC exceeds 20% of earnings indicating poor performance for 4 years, the highest value being 25%. By the end of the simulation, AFUDC drops to 0 as internal generation of funds is 100%. For the total reform - 10.251 GW later case, the fraction of earnings due to AFUDC exceeds 20% for 16 years, the highest value being 36%. By the end of the simulation, AFUDC is about 22% of earnings. For the combined early site permit and preapproval-of-design reforms case, the fraction of earnings due to AFUDC exceeds 20% for 17 years, the highest value being 42%. By the end of the simulation, AFUDC is about 24% of earnings. For the no reform case, AFUDC exceeds 20% of earnings for 18 years, the highest value being about 52%. By the end of the simulation, AFUDC is about 32% of earnings.

14. <u>Figure 14. Pretax Interest Coverage Ratio</u>

The pretax interest coverage ratio for total reform - 10.251 GW early reform exhibits the best overall performance. This financial indicator remains well above the 40% level during the 1986-2010 time period. By the end of the simulation, pretax interest coverage is 6.4. For the total reform - 10.251 GW later, this financial indicator is below the 3 times interest goal for 3 years, the lowest value being . .7. By the end of the simulation, pretax interest coverage is 3.7. For the combined early site permit and preapproval-of-design reforms, coverage is below the goal for 9 years, the lowest value being 2.2. By the end of the simulation, pretax interest coverage is 3.4. For the no reform case, coverage is below the goal for 16 years, the lowest value being 1.0. By the end of the simulation, pretax interest coverage is 1.0.

15. Figure 15. Common Stock Market to Book Ratio

The total reform - 13.668 GW early exhibits the best overall performance. For this case market value is well above book value during the 1985 to 2010 time period with values ranging from 2.1 to 2.9 (in 2010). For the total reform - 10.251 GW later case, market value is also above book value with values ranging from 2.2 to 2.7 (in 2010). For the combined early site permit and preapproval-of-design reforms case, the common stock market to book ratio is 1.0, indicating poor performance for 1 year (in 1997 as the first of 9 units begins commercial operation). By the end of the simulation, this ratio is 2.6. For the no reform case, the common stock market to book ratio is below 1.0 for 15 years, the lowest value being 0.3. By the end of the simulation, this ratio is 0.8.

16. Figure 16. Real Price of Electricity

For the total reform - 13.668 GW early case, the real price of electricity, in constant dollars, decreases during the 1991-2010 time period from 67.8 to 58.5 mills/kWh (about 16%). This is because the fuel cost savings (by backing out of more expensive oil and gas) greatly outweigh the added capital costs of the new nuclear units. There is a short-term price penalty for the total reform - 10.251 GW later and the combined early site permit and preapproval-of-design reforms cases during the 1988 to 1997 time period. The company pays more income tax and has less debt interest during this period because there is less construction activity for these two cases. As each of the 9 units begins commercial operation, the real price of electricity decreases for the total reform - 10.251 GW later case from 68.6 mills/kWh in 1997 to 65.6 mills/kWh in 2010 (about 5%). The real price of electricity increases for the combined early site permit and preapproval-of-design reforms case from 68.0 mills/kWh in 1997 to 68.8 mills/kWh in 2010 (about 1%). For the no reform case, the real price of electricity increases from 67.6 mills/kWh in 1997 to 103.3 mills/kWh in 2010 (about 53%).

By the year 2010, all new nuclear capital costs are recovered in the rate base for the total reform - 13.668 GW early case. For the other cases, capital costs are recovered for 9 units by 2010, with three 1.139 GW units still under construction. By 2010, the real price of electricity is 103.3 mills/kWh for no reform, 68.8 mills/kWh for combined early site permit and preapproval-of-design reforms, 65.6 mills/kWh for total reform - 10.251 GW later and 58.5% for total reform - 13.668 GW early. Compared to the no reform case, the real price of electricity is about 50% lower for combined early site permit and preapproval-of-design reforms, about 57% lower for total reform - 10.251 GW later, and about 76% lower for total reform - 13.668 GW early.

17. Figure 17. Price of Electricity

With the commercial operation of each nuclear unit, the price of electricity, in nominal dollars, increases for all cases. During the 1997 to 2010 time period, the price of electricity increases from 222.1 to 843.4 mills/kWh for no reform. form 223.5 to 561.5 mills/kWh for combined early site permit and preapproval-of-design reforms, and from 225.5 to 536.1 mills/kWh for the total reform - 10.251 GW later case. For the total reform - 13.668 GW early case, the price of electricity increases from 146.4 mills/kWh (in 1991) to 477.8 mills/kWh (in 2010).

By the year 2010, all new nuclear capital costs are recovered in the rate base for the total reform - 13.668 GW early case. For the other cases, capital costs are recovered for 9 units by 2010, with three 1.139 GW units still under construction. By 2010, the price of electricity is 843.4 mills/kWh for no reform, 561.5 mills/kWh for combined early site permit and preapproval-of-design reforms, 536.1 mills/kWh for total reform - 10.251 later, and 477.8 mills/kWh for total reform - 13.668 GW early.

Figures 18 through 22 give model simulations for Georgia Power for all nuclear capacity additions. The financial indicators and price effects are examined for the time period following commercial operation of the generating units that are under construction at the beginning of the simulation (See Table VI). Between the years 1997 and 2010 (the end of the simulation), 14 new nuclear units begin commercial operation (two 1.139 GW units every other year) for all cases except the total reform - 20.502 GW early case for which 18 new nuclear units begin commercial operation (two 1.139 GW units every other year) during the 1991.7 to 2010 time period.

18. Figure 18. Internal Generation of Funds

Internal generation of funds for the total reform - 20.502 GW early case exhibits the best overall performance. This financial indicator remains well above the 40% level during the 1987 to 2010 time period, peaking in the years 2008 to 2010 at 100%. For this reform case, the fuel cost savings due to inexpensive nuclear fuel eventually outweigh the added capital costs of successive new units. This translates into less operating revenue needed to produce electricity and thus more money available for construction. In this case, construction costs are eventually paid solely by internal funds. For the total reform - 15.946 GW later case, internal generation of funds falls below 40%, indicating poor performance, for 3 years, the lowest value being 35%. By the end of the simulation, internal generation of funds is 63%. For the combined early site permit and preapproval-of-design reforms, internal generation of funds falls below 40% for 10 years, the lowest value being 24%. By the end of the simulation, internal generation of funds is about 62%. For the no reform case, internal generation of funds is below the 40% level for 13 years, the lowest value being about 10%.

19. Figure 19. Fraction of Earnings Due to AFUDC

The fraction of earnings due to AFUDC for total reform - 20.502 GW early exhibits the best overall performance although AFUDC exceeds 20% of earnings, indicating poor performance, for 13 years, the lowest highest value being 30%. By the end of the simulation, AFUDC drops to 0 as internal generation of funds is 100%. For the total reform - 15.946 GW later case, the fraction of earnings due to AFUDC exceeds 20% for 17 years, the highest value being 42%. By the end of the simulation, AFUDC is about 23% of earnings. For the combined early site permit and preapproval-of-design reforms, AFUDC exceeds 20% of earnings for 17 years, the highest value being 50%. By the end of the simulation, AFUDC is 24% of earnings. For the no reform case, AFUDC exceeds 20% of earnings for 19 years, the highest value being 59%. By the end of the simulation, AFUDC as a per cent of income is 26%.

20. Figure 20. Pretax Interest Coverage Ratio

The pretax interest coverage ratio for total reform - 20.502 GW early remains below the 3 times interest goal for most of the simulation period, the lowest value being 1.7. The pretax interest coverage ratio is above the 3 times interest goal during 2009 and 2010 at 3.5 and 3.9, respectively. For total reform-15.946 GW later, pretax interest coverage is below the goal for 18 years, the lowest value being 1.5. By the end of the simulation, pretax interest coverage is 1.9. For the combined early site permit and preapproval-of-design reforms, pretax interest coverage is below the goal for 19 years, the lowest value being 1.3. By the end of the simulation, pretax interest coverage is 1.8.

For the no reform, coverage is below the goal for 23 years, the lowest value being 1.0. By the end of the simulation, pretax interest coverage is 1.7.

21. Figure 21. Real Price of Electricity

The real price of electricity, in constant dollars, increases for all cases during the periods that commercial operation of the new nuclear units occurs. The real price of electricity for the total reform, 20.502 GW early case is higher than the other cases between 1994 and 2005; thereafter, the real price for the no reform case is higher. The higher real price for the total reform - 20.502 GW early is due to 2 factors: (1) commercial operation of the new units for this case begin in 1991.7 rather than 1997 (for the other cases), and (2) 4 units (1.139 GW each) more come on-line during the simulation period for this case. During the period 1991 to 2010, the real price of electricity increases from 71.0 to 83.3 mills/kWh (about 17%). During the period 1997 to 2010, the real price of electricity increases from 52.2 to 73.6 mills/kWh (about 41%) for total reform - 15.946 GW later, from 50.8 to 80.2 mills/kWh (about 58%) for combined early site permit and preapproval-of-design reforms, and 51.2 to 91.3 mills/kWh (about 78%) for no reform.

By the year 2010, all nuclear capital costs are recovered in the rate base for the total reform - 20.502 GW early case. For the other cases, capital costs are recovered for 14 units by 2010, with four 1.139 GW units still under construction. By the year 2010, the real price of electricity is 91.3 mills/kWh for no reform, 80.2 mills/kWh for combined early site permit and preapproval-of-design reforms, 73.6 mills/kWh for total reform - 15.946 GW later, and 83.3 mills/kWh for total reform - 20.502 GW early. Compared to the no reform case, the real price of electricity is about 14% lower for combined early site permit and preapproval-of-design reforms, about 24% lower for total reform - 15.946 GW later, and about 10% lower for total reform - 20.502 GW early.

22. Figure 22. Price of Electricity

With the commercial operation of each nuclear unit, the price of electricity, in nominal dollars, increases for all cases. During the 1997 to 2010 time period, the price of electricity increases from 168.3 to 745.7 mills/kWh for no reform, from 166.9 to 654.9 mills/kWh for combined early site permit and preapproval-of-design reforms, and from 171.5 to 601.3 mills/kWh for total reform - 15.946 GW later. For the total reform - 20.502 GW early case, the price of electricity increases from 153.3 (in 1991) to 680.6 mills/kWh (in 2010).

By the year 2010, all nuclear capital costs are recovered in the rate base for the total reform - 20.502 GW early case. For the other cases, capital costs are recovered for 14 units by 2010 with four 1.139 GW units still under construction. By 2010, the price of electricity is 745.7 mills/kWh for no reform, 654.9 mills/kWh for combined early site permit and preapproval-of-design reforms, 601.3 mills/kWh for total reform - 15.946 GW later, and 680.6 mills/kWh for total reform - 20.502 GW early.

APPENDIX C

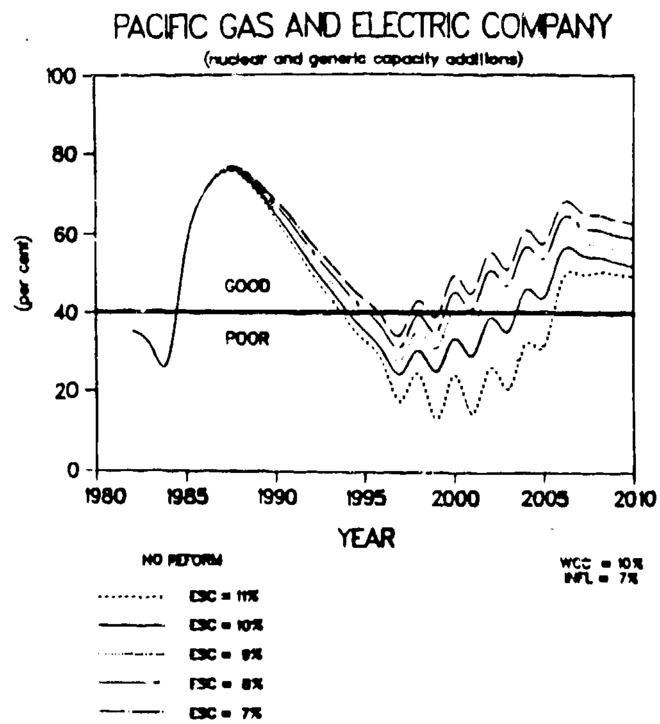

Fig. 24. Internal generation of funds.

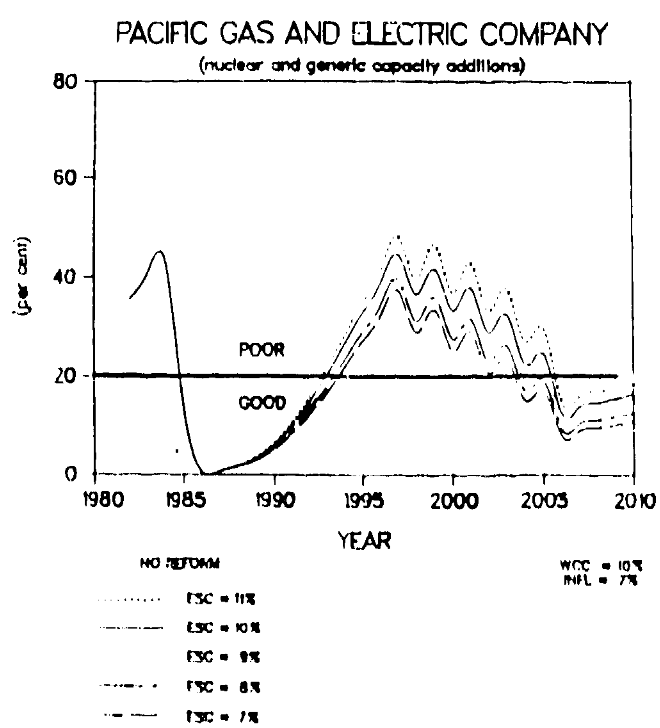

Fig. 25. Fraction of earnings due to AFUDC.

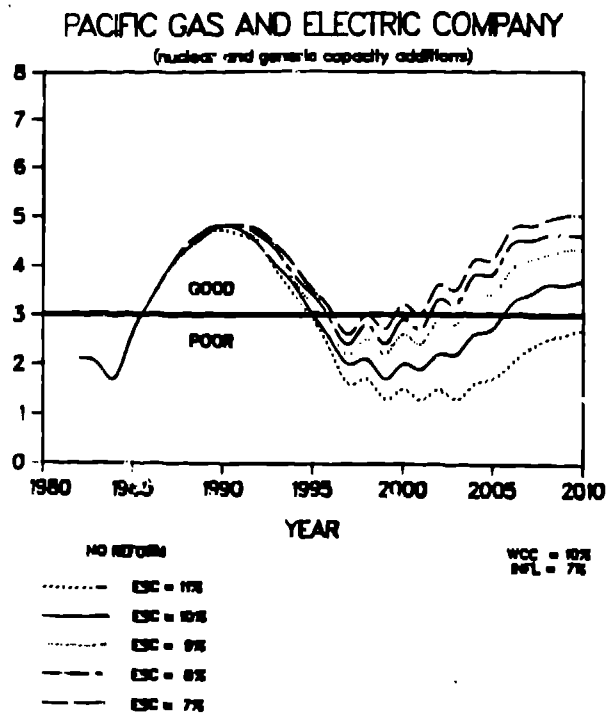

Fig. 26. Pretax interest coverage ratio.

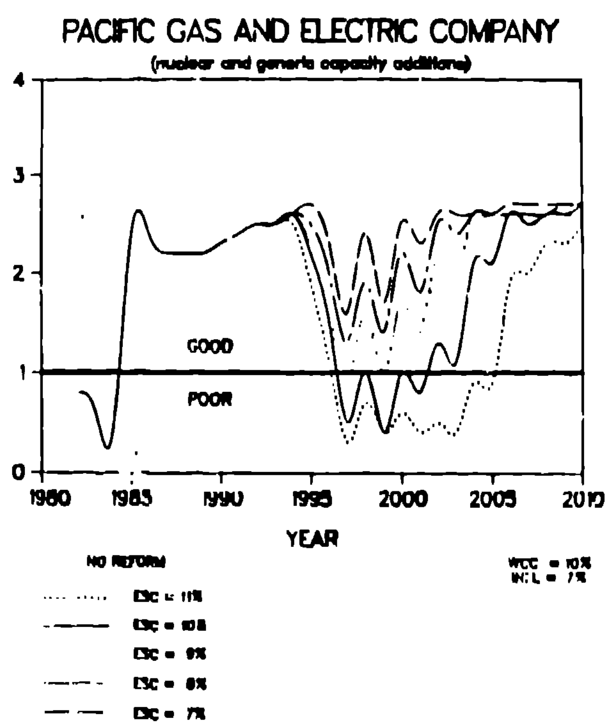

Fig. 27. Common stock market to book ratio.

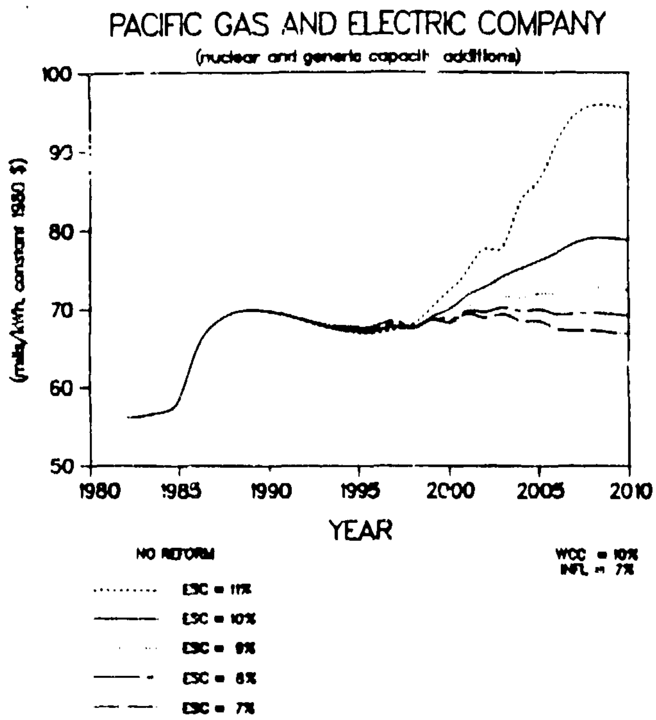

Fig. 28. Real price of electricity.

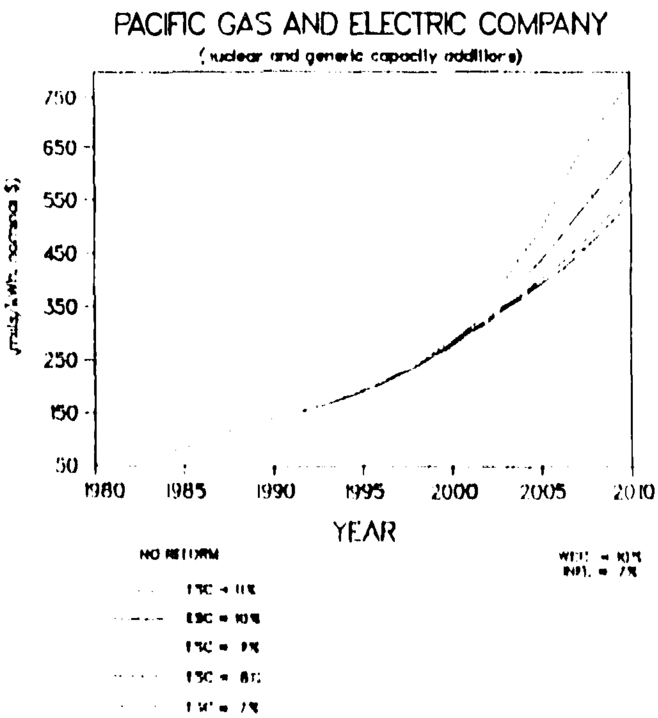

Fig. 29. Price of electricity.

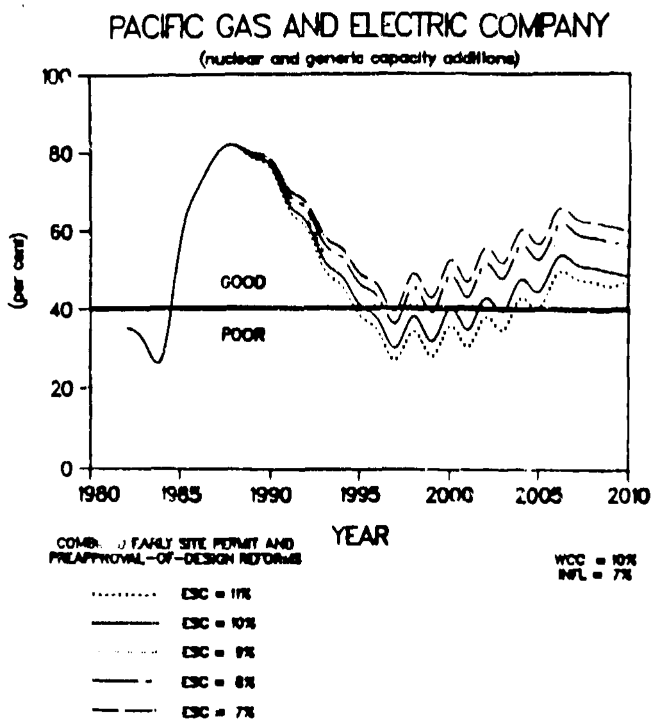

Fig. 30. Internal gen tion of funds.

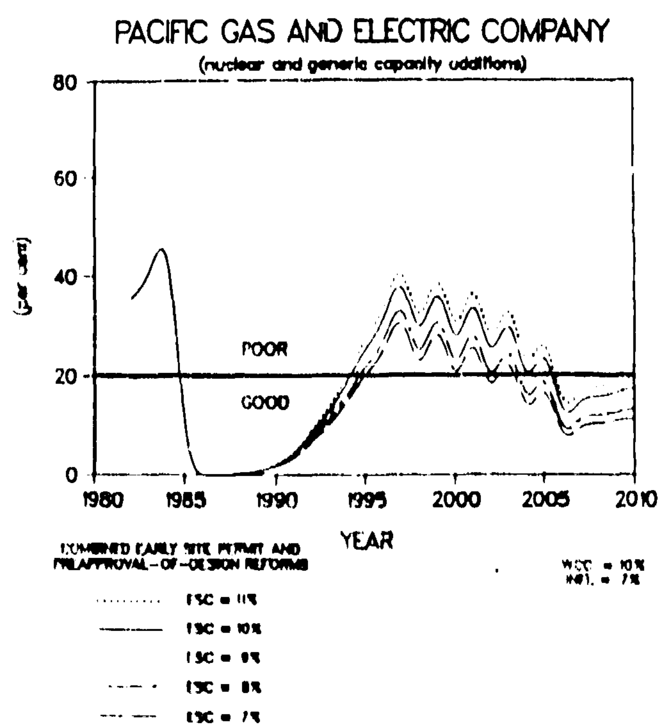

Fig. 31. Fraction of earnings due to AFUDC.

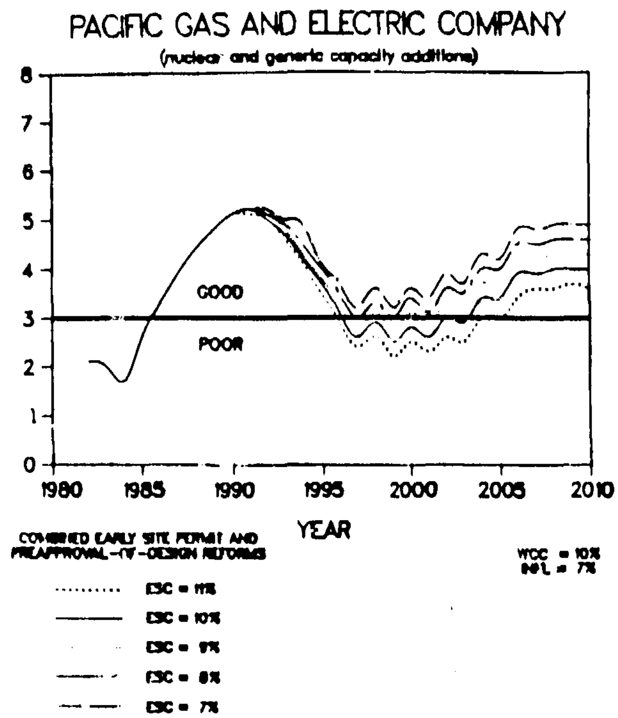

Fig. 32. Pretax interest rage ratio.

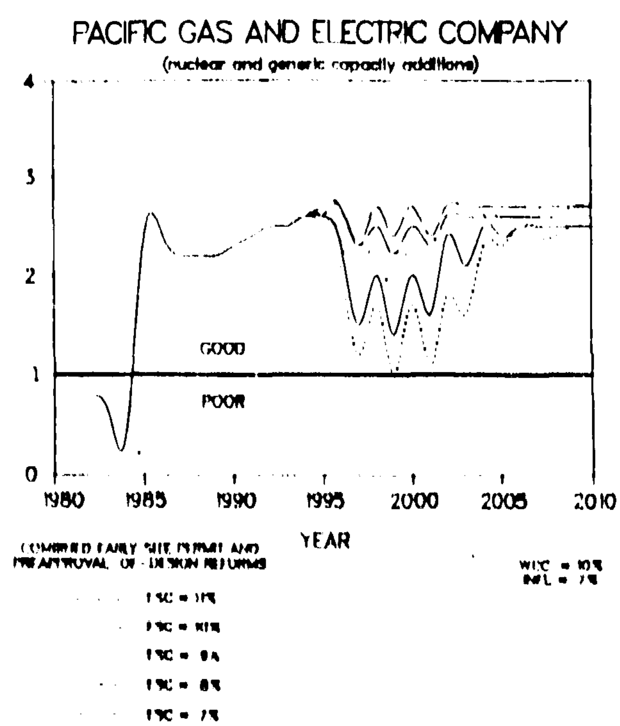

Fig. 33. Common stock market to book ratio.

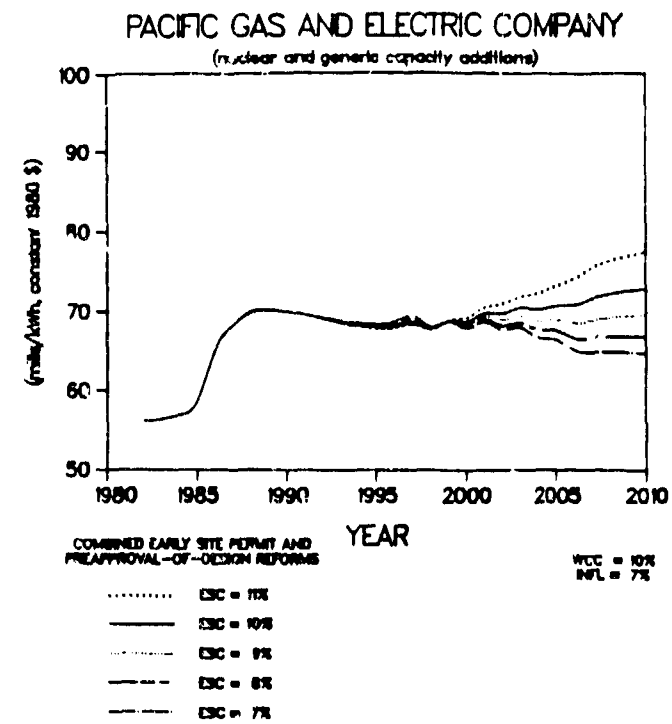

Fig. .4. Real price of electricity.

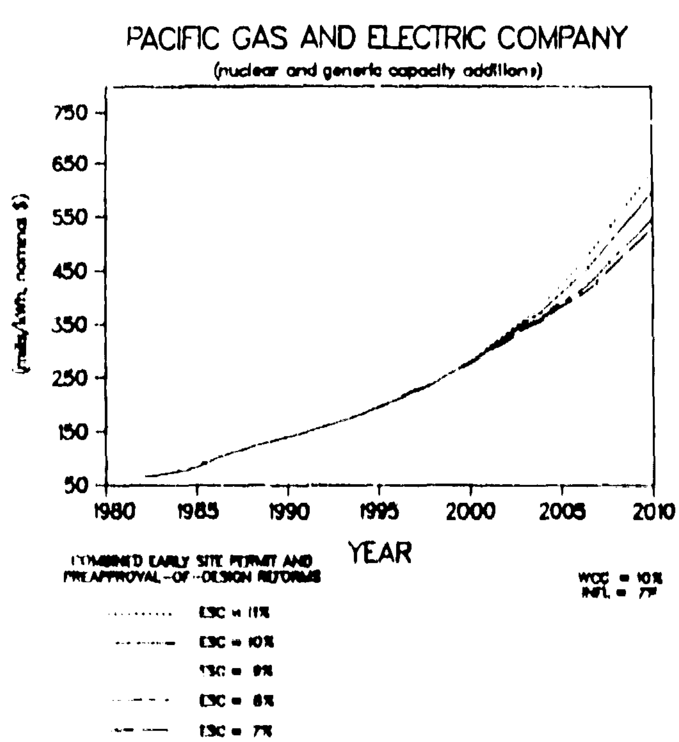

Fig. 55. Price of electricity.

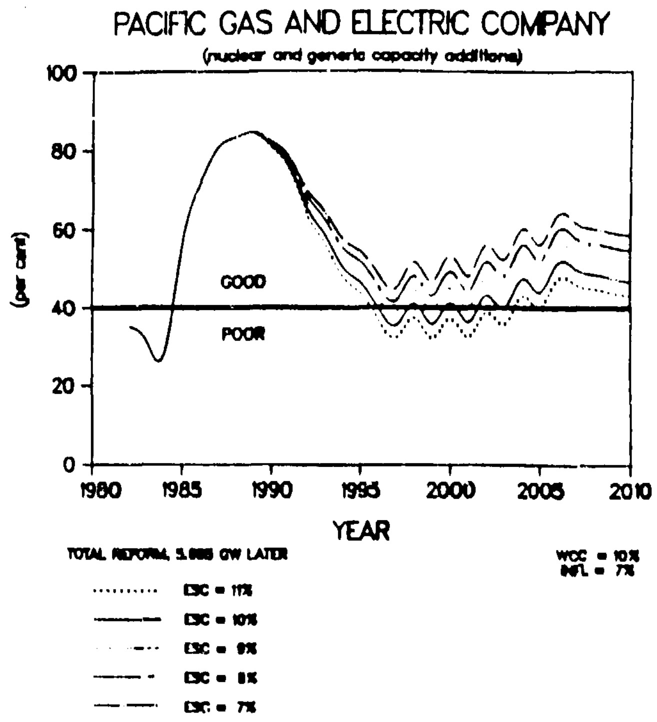

Fig. 36. Internal generation of funds.

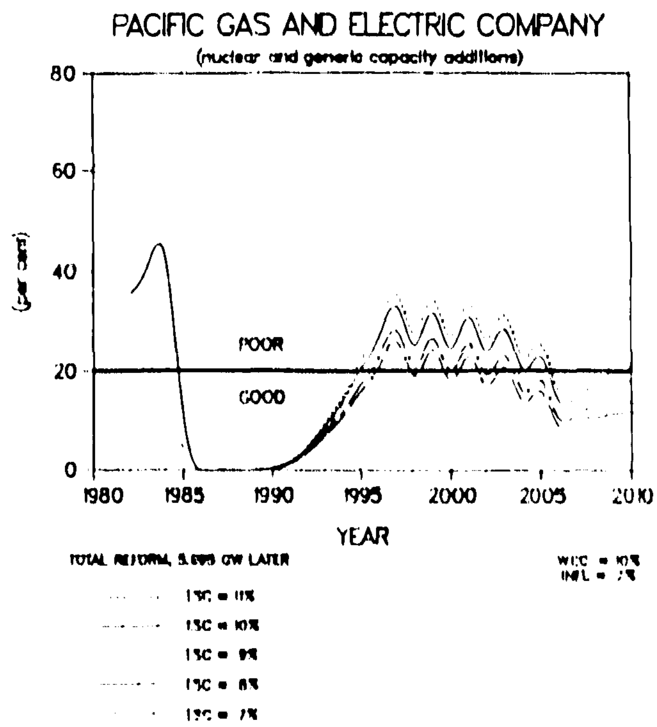

Fig. 37. Fraction of earnings due to AFUDC.

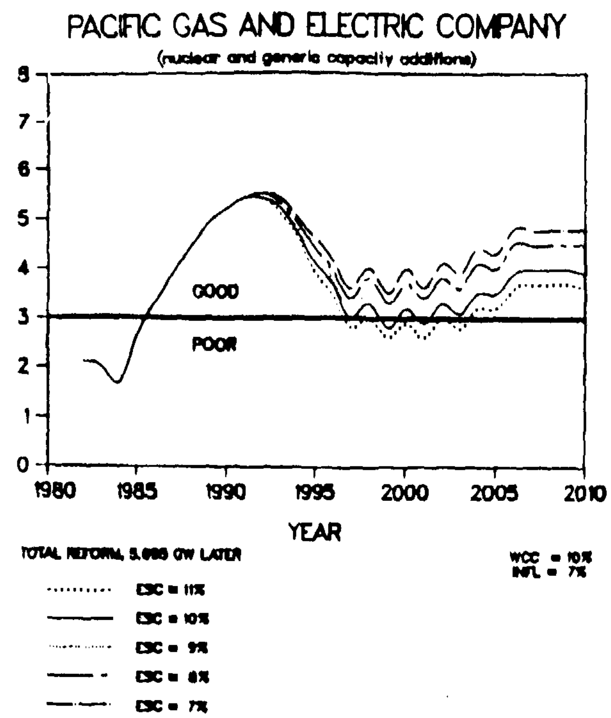

Fig. 38. Pretax interest coverage ratio.

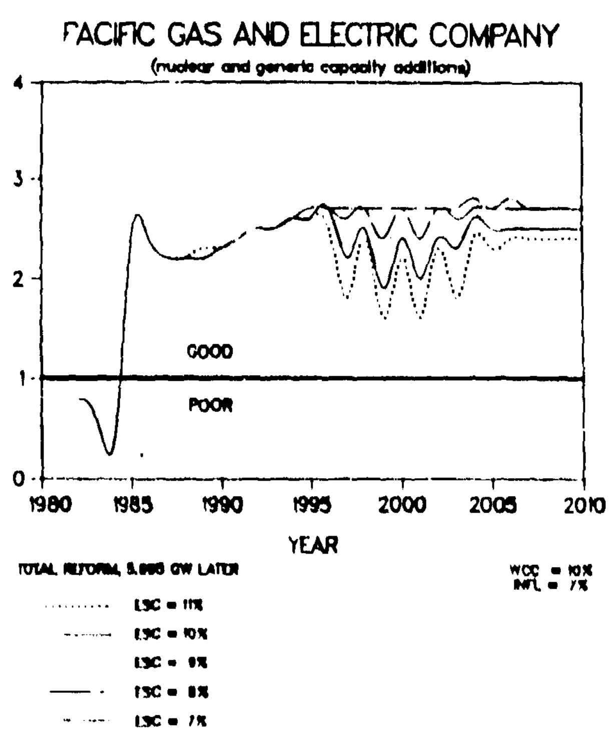

Fig. 39. Common stock market to book ratio.

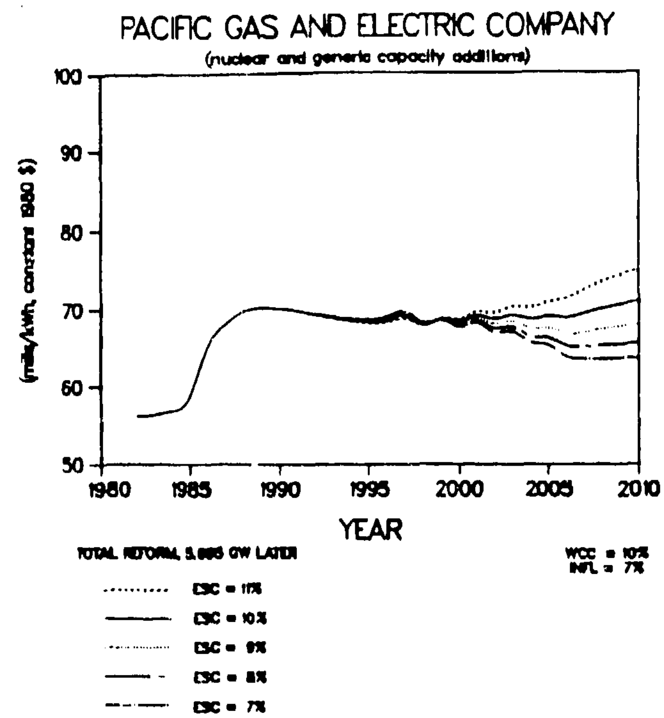

Fig. 40. Real price of electricity.

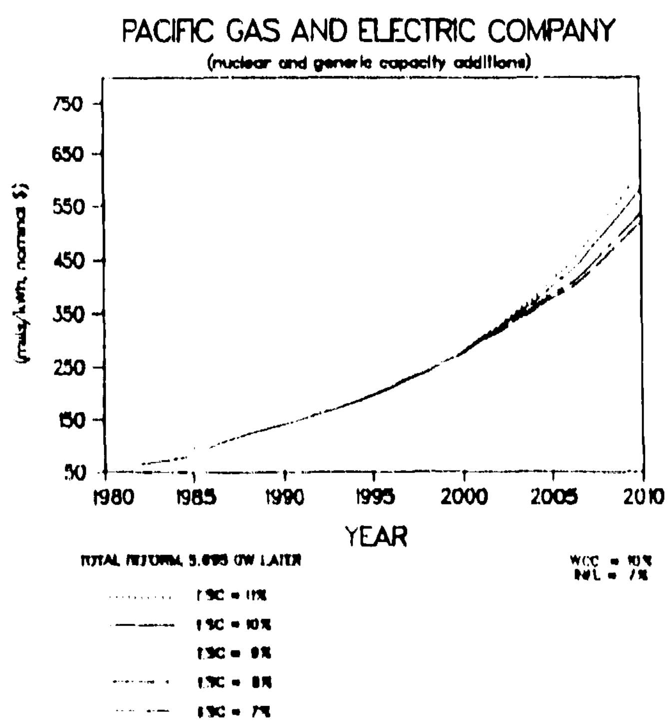

Fig. 41. Price of electricity.

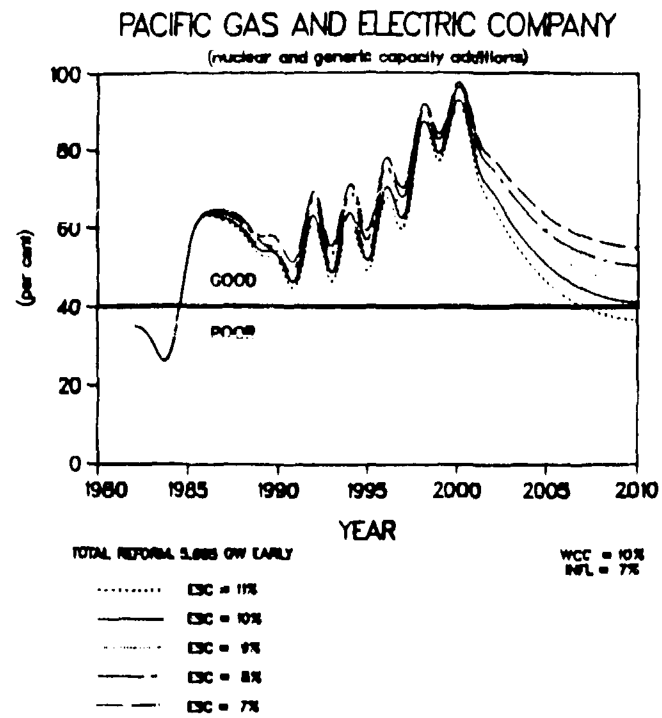

Fig. 42. Internal generation of funds.

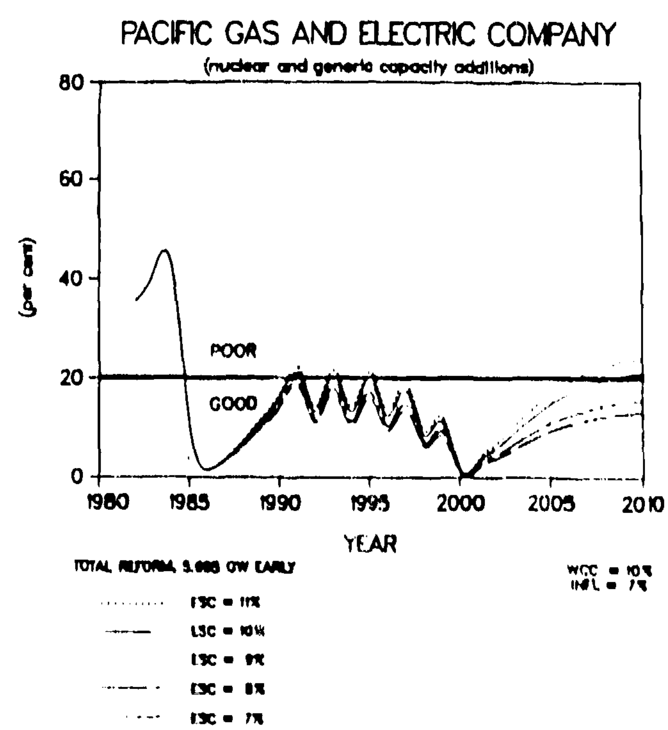

Fig. 43. Fraction of earnings due to AFUDC.

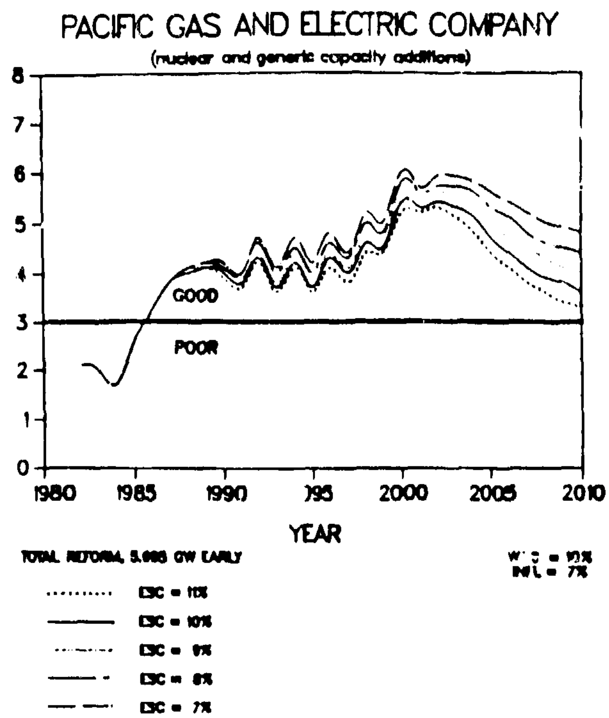

Fig. 44. Pretax interest coverage ratio.

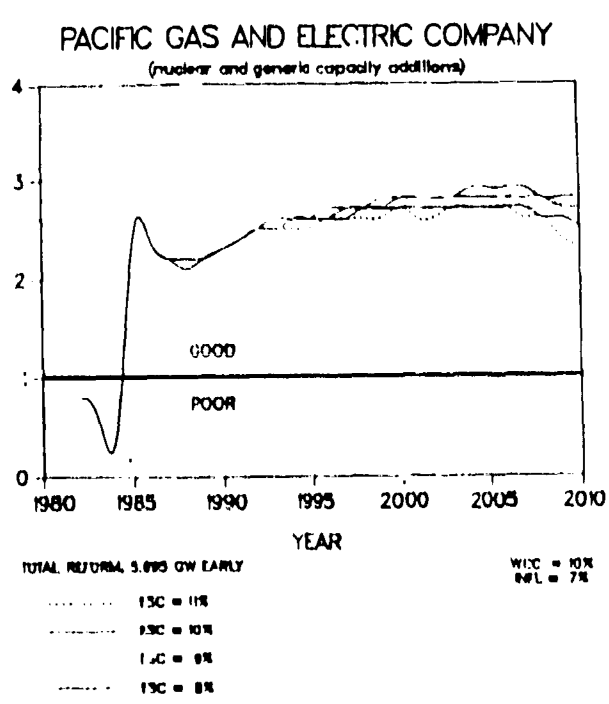

Fig. 45. Common stock market to book ratio.

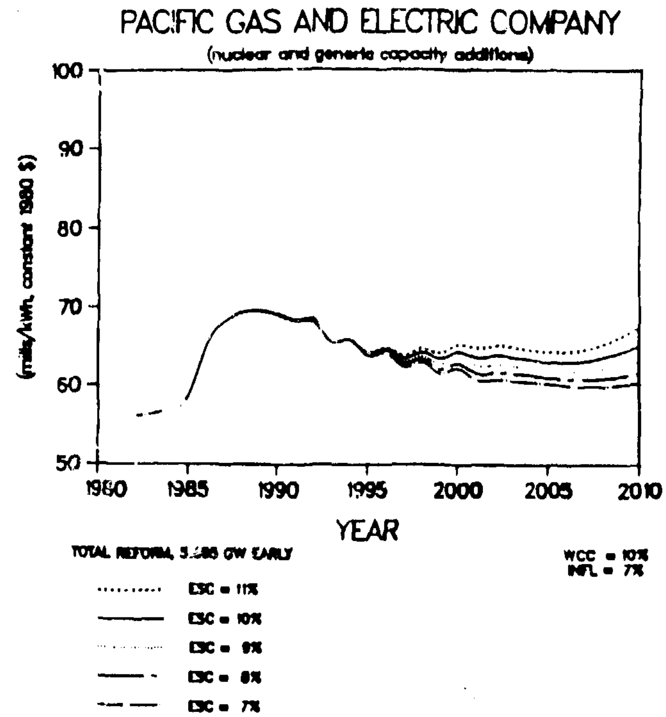

Fig. 46. Real price of electricity.

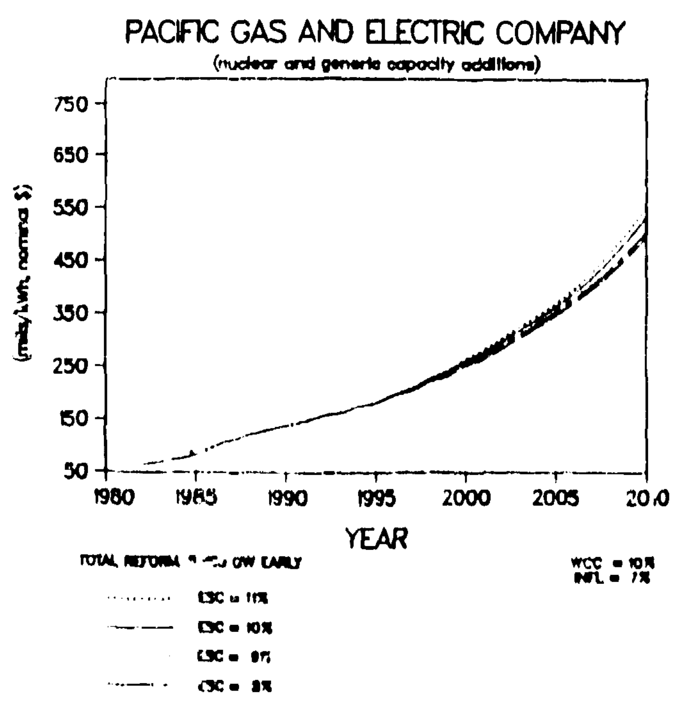

Fig. 47. Price of electricity.

APPENDIX D

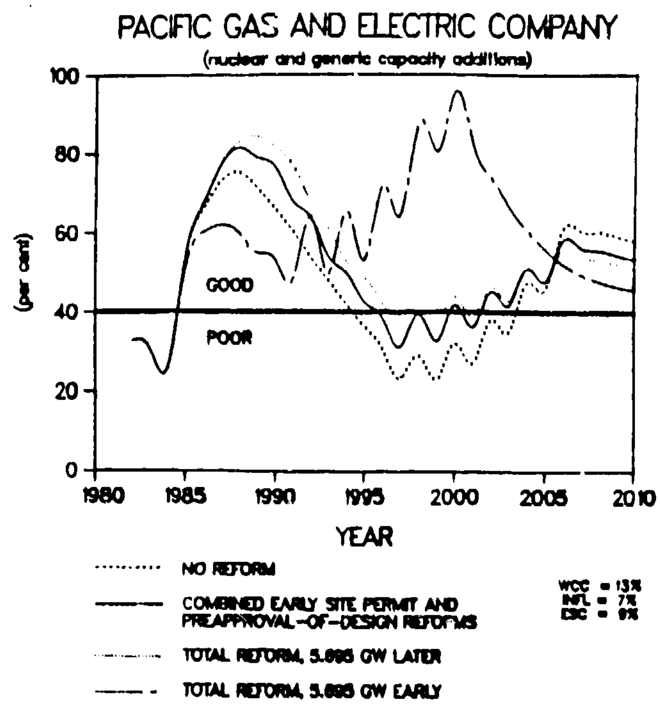

Fig. 48. Internal generation of funds.

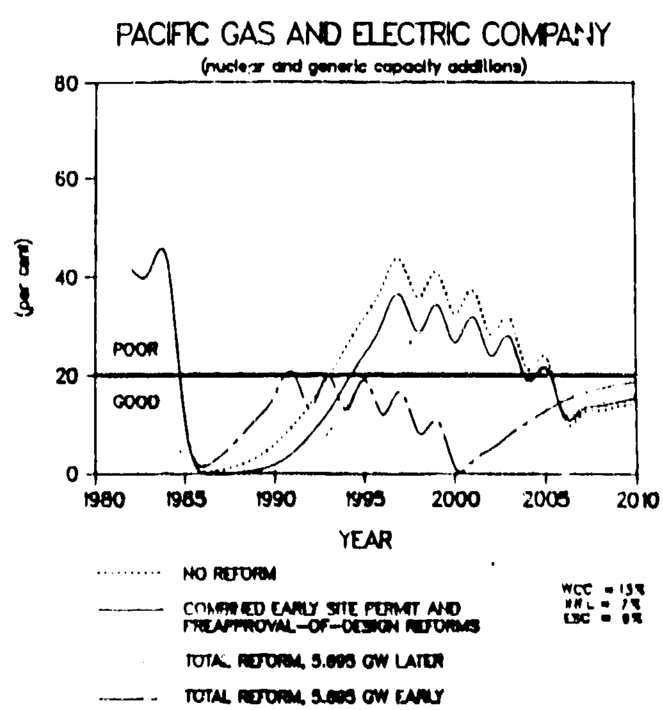

Fig. 49. Fraction of earnings due to AFUDC.

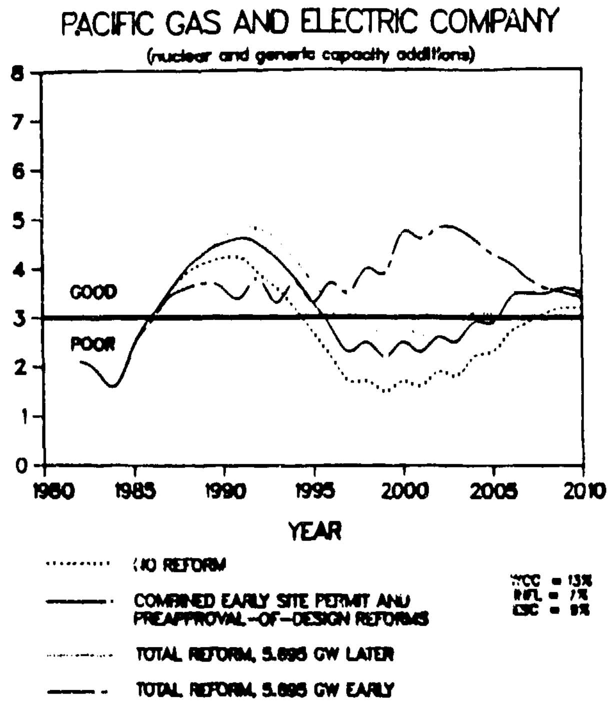

Fig. 50. Pretax interest coverage ratio.

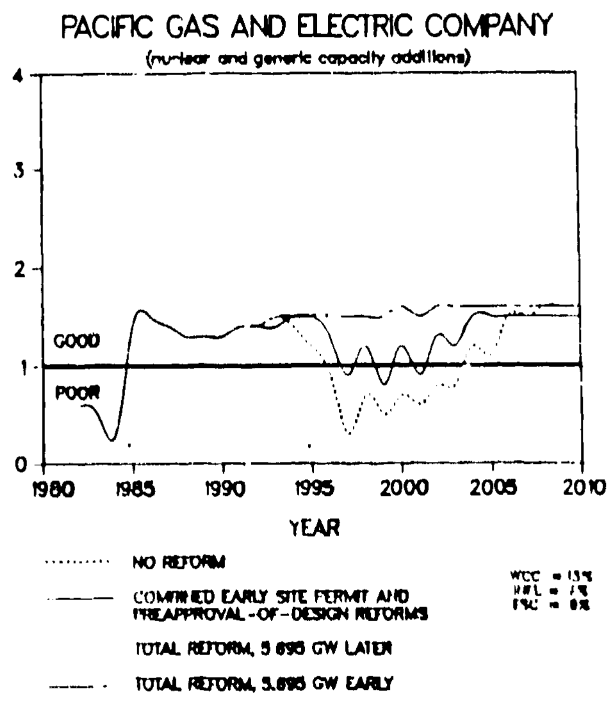

Fig. 51. Common stock market to book ratio.

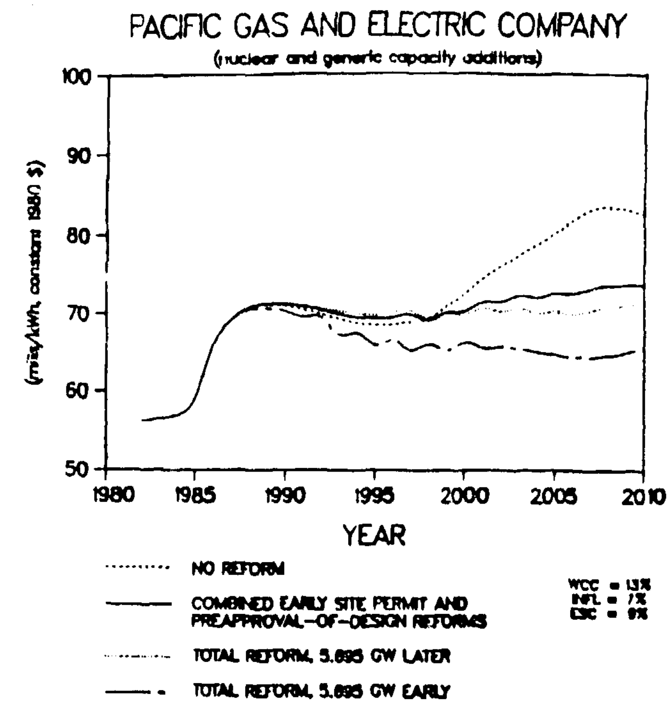

Fig. 52. Real price of electricity.

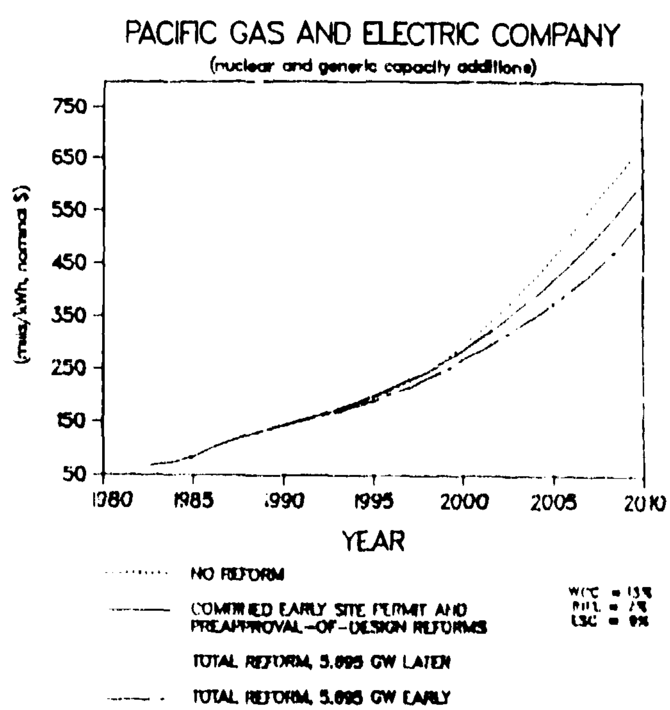

Fig. 53. Price of electricity.

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