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

by

Annette Youngblood Turpin

ABSTRACT

This report estimates the financial impact on utilities and ratepayers of nuclear power plant regulatory reforms. Three situations are investigated: (1) no reform, (2) combined early-site-permit and preapproval-of-design reforms, and (3) total reform. Also, two types of capacity additions are evaluated using two utility companies as case studies: (1) nuclear plus generic capacity, and (2) all-nuclear capacity. Results indicate that both the shorter construction lead-time afforded by nuclear regulatory reform and the timing of new capacity additions are extremely important in enabling a utility to remain in a healthy financial position while adding capacity to meet future demand and at the same time reducing the price of electricity to the ratepayers. The lower added capital costs and fuel cost savings obtained from reformed nuclear units allow a utility dependent on oil and gas steam generation to experience price decreases as these new units begin commercial operation. The study also points out that in simulations excluding the shorter lead-time generic capacity, price increases were greater and financial performance was worse for both utilities. These facts indicate the importance of shortening the construction lead-time through nuclear regulatory reform so that nuclear power will be more competitive with coal.

I. INTRODUCTION

The Los Alamos National Laboratory has performed a study[1] of the financial impact on utilities and ratepayers of nuclear power plant licensing reform.* This study is an extension of a study "Quantitative Analysis of Nuclear Power Plant Licensing Reform"[2] that uses Monte Carlo modeling to analyze charts using

*Reference 1, an 81-page report, gives a more complete discussion and presents figures not included in the present report.

the project evaluation and review technique (PERT) for the nuclear power plant licensing and construction process. The results of the Monte Carlo modeling of PERT charts were used as inputs to a Los Alamos regulatory-financial model called Electric Utility Policy and Planning Model (EPPAM). This model simulates the planning, operation, capacity construction, construction financing, and price regulation over time of a typical investor-owned electric utility company.[3-5] The model is initialized in 1982 and projects financial impacts on utilities and ratepayers over the 1982-2010 period of the current licensing and construction process (no reform) and two reform cases for two utilities.

Two reforms--the combined early-site-permit and preapproval-of-design reforms package and the total reform package--were compared with the no-reform case. In the previous study,[2] 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. The combined early-site-permit and preapproval-of-design reforms were 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.

In the EPPAM model, "new nuclear capacity" (that 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 reforms--early-site-permit and preapproval-of-design--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.

The financial impact on the utilities and the ratepayer was 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) a construction leadtime 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.

Data on two regions were collected for this study: (1) the Northern California region including 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.[6-16] Regional data were collected for these two 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 regional income growth as well as the resources, assets, and operations of each region's utilities.

Improvements in the financial performance of 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 the variable's performance with goals set by PG&E for the no-reform and reform cases. These goals include an internal generation of funds greater than 40%, a fraction of earnings resulting from the 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 (see Ref. 17, Pt. 2). The price of electricity and the real price of electricity are given for all cases.

Output from the EPPAM model was generated for both utilities, using both the no-reform and reform cases for simulations with nuclear and generic capacity additions and for all-nuclear capacity additions. Examples of the output are given in Figs. 1-4, which show the internal generation of funds (one of the four financial variables) and the real price of electricity for PG&E and Georgia Power under base-case conditions for the nuclear and generic capacity additions simulation.

II. SUMMARY RESULTS

Summary results of the study are presented in Tables I-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, for these cases, some nuclear units are still under construction by the end of the simulation.

Table I shows the estimated rate increases or decreases for new nuclear capacity additions for PG&E and 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. It increases about 6% for no reform. The fuel cost savings, which are achieved when the more expensive oil and gas are backed out, are obtained from these reformed nuclear units and 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; it increases about 2% for total reform--later, 13% for combined early-site-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 with that for existing units, in order to meet demand growth. For the total reform--early case that exhibits a price decrease, new nuclear units begin commercial operation much earlier in the simulation while real price is already high from inclusion of the Scherer coal units and the

Vogtle nuclear units 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 causes the price to decline for this reform case during the period when 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; it 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 for Georgia Power with new nuclear units than with nuclear and generic capacity additions. Also, because 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 come on line for PG&E by the end of the simulation with 3.417 GW under construction; 15.946 GW come 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--2006 for PG&E and 2008 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 combined 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 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 yields lower prices than for PG&E for all but the no-reform case. With no reform, the fuel cost savings afforded PG&E by the backing out of expensive oil and gas fuel usage keep the price lower than that for the no-reform case of Georgia Power.

For simulations with all-nuclear capacity additions, all-nuclear capacity has not come on line by 2010 for 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 both companies for the no-reform and all reform cases for simulations with nuclear and generic capacity additions and for simulations with all-nuclear capacity additions. 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; it 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. This is because the cheaper capital costs of generic capacity (resulting mainly from a short construction lead-time of six years) help the financial performance of both utilities. (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,as all-nuclear capacity has not come on line by 2010.)

III. CONCLUSIONS AND IMPLICATIONS

The changes that nuclear regulatory reform would make in the financial performance of the two utilities--PG&E and Georgia Power--and the changes in the price of electricity to ratepayers that would result 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 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 impacts on utilities and ratepayers over the 1982-2010 period for the no-reform and reform cases for the two utilities, using simulations with all-nuclear capacity additions and simulations with nuclear and generic capacity additions.

Summary results of the study appear in Tables I-III. Results indicate that a reduction in construction lead-time that can result from nuclear regulatory reform is very important in improving the financial performance of the utility and reducing the price of electricity to the ratepayers. For all simulations (including the nuclear and generic capacity additions and the 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 (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 are extremely important in enabling a utility to remain in a healthy financial position while adding capacity to meet future demand and reducing the price of electricity to the ratepayers.

Generally, Georgia Power has higher rate increases than PG&E for simulations with nuclear and generic capacity additions or for all-nuclear capacity additions. Georgia Power uses 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 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 five new nuclear units begin commercial operation. The fuel cost savings (which are achieved when the more expensive oil and gas are backed out) are obtained from these reformed nuclear units and are greater than the added capital costs. This implies 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 allows 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 results from the lack of any generic capacity (and associated cheaper total capital costs) in the all-nuclear capacity additions simulations. Generic capacity has a lead-time of only 6 years and a capital cost of $1,000/kW, whereas the total reform nuclear units 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 as the capital costs shown in this example are roughly equivalent.

Results of the "Nuclear Rate Increase Study"[18] 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 with nuclear plants than to their respective costs--absorbing smaller units (even high-cost units) has a lesser effect on rates. The above study noted 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 have a very high cost when compared with the cost of 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 study "The Future Market for Electric Generating Capacity"[17,19] 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 to 1,200 MWe, although there should not be large diseconomies associated with the smaller units. The study found that in simulations excluding the shorter lead-time generic capacity, price increases were greater. The implication is that by shortening construction lead-time through nuclear regulatory reform, nuclear power will be on a more competitive basis with coal.

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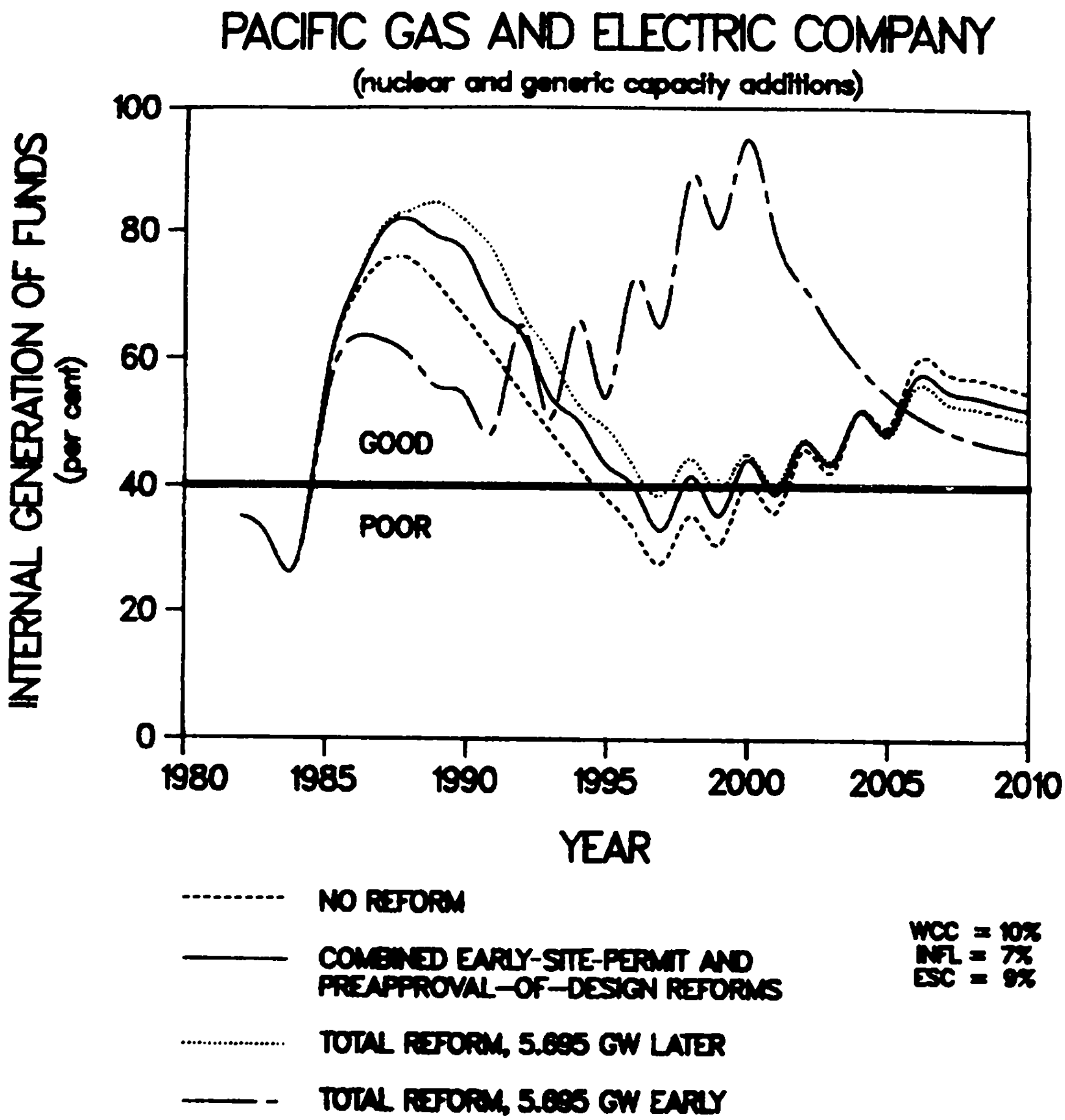

Fig. 1. Internal generation of funds.

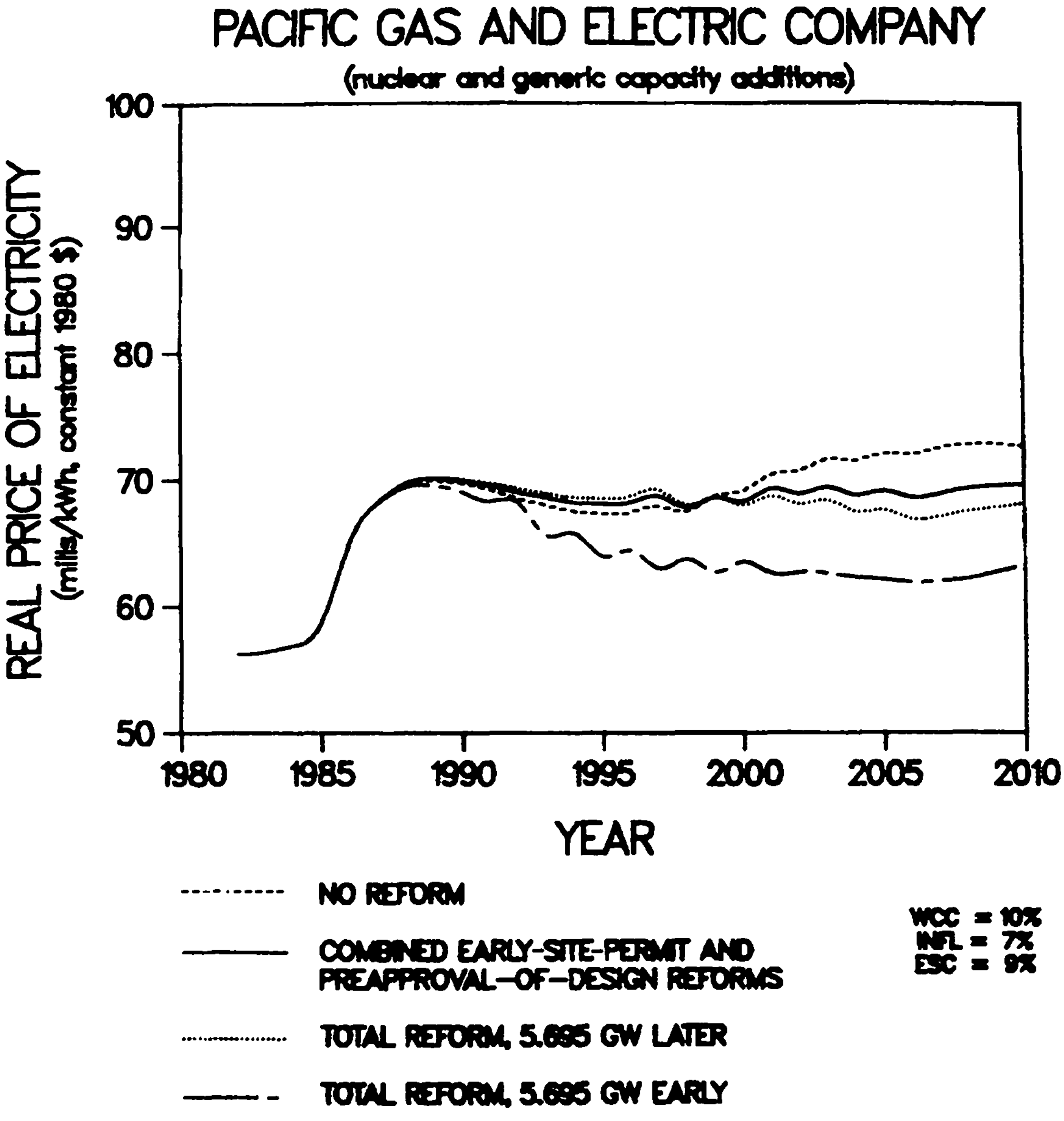

Fig. 2. Real price of electricity.

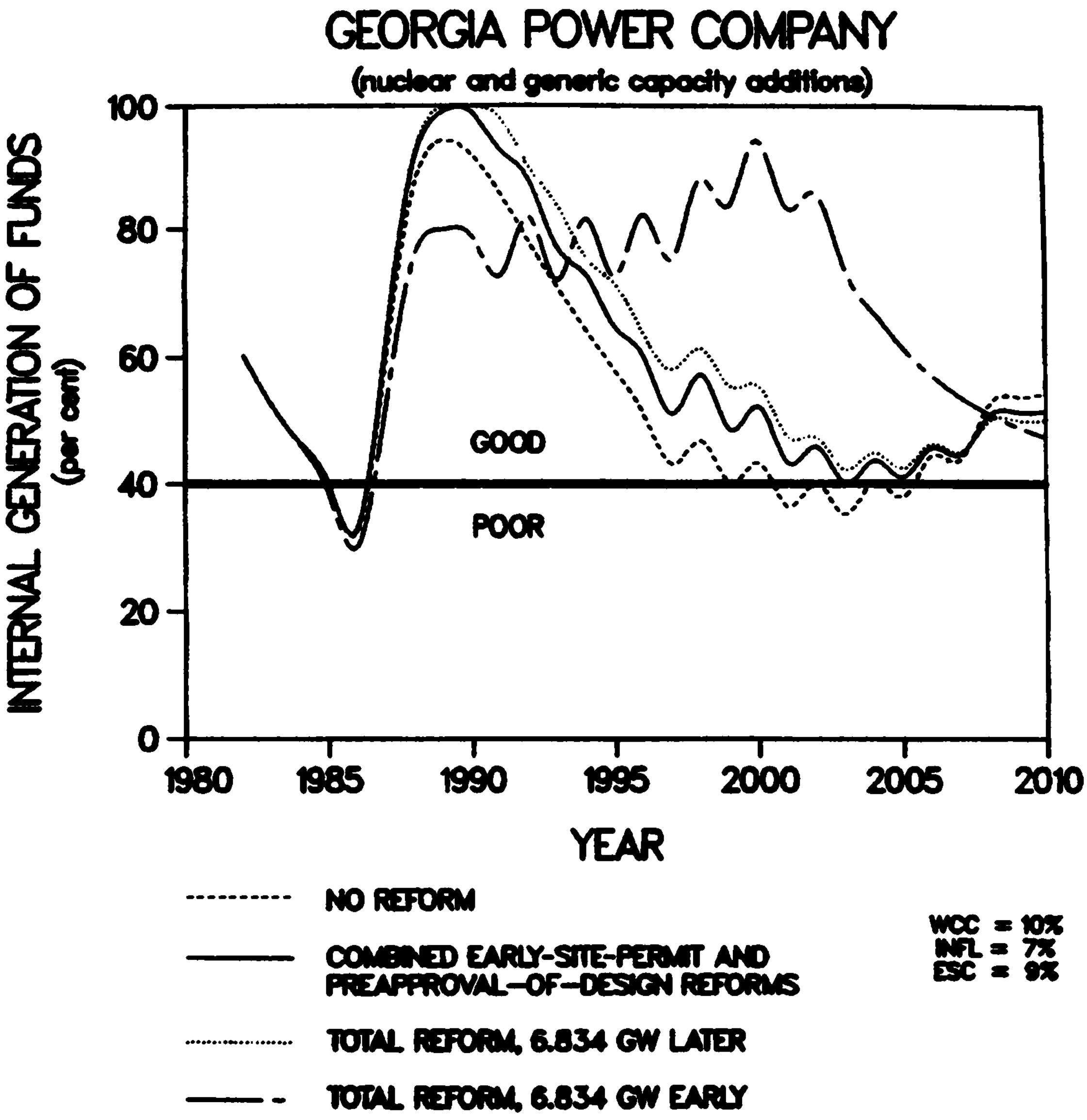

Fig. 3. Internal generation of funds.

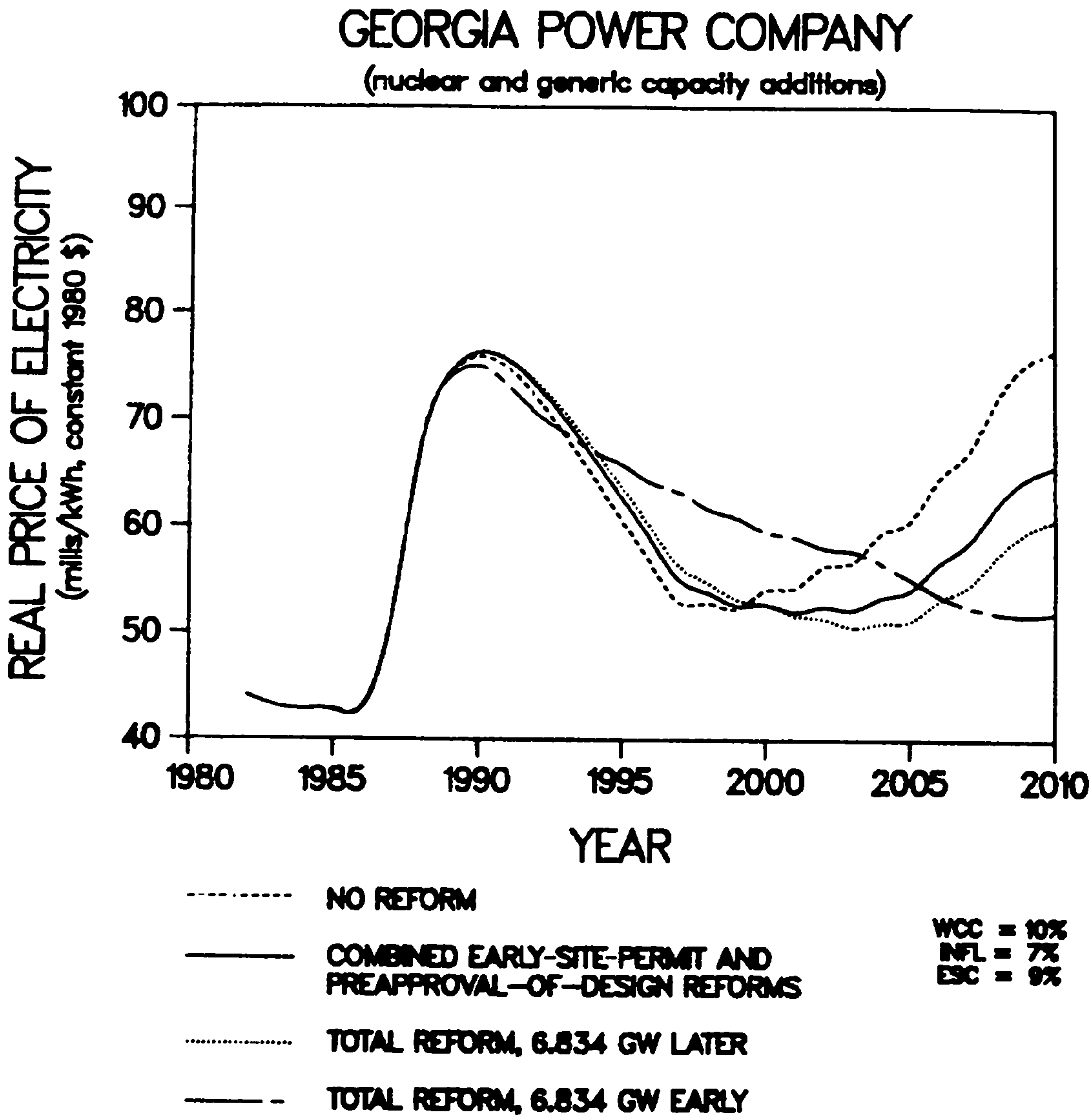

Fig. 4. Real price of electricity.

TABLE I

ESTIMATED RATE INCREASES OR DECREASES FOR NUCLEAR CAPACITY ADDITIONS

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

NOTE: For all cases, 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.

[a] 5.695-GW nuclear capacity additions.

[b] 13.668-GW nuclear capacity additions for total reform--early; 10.251-GW nuclear capacity additions for all other cases.

[c] 6.834-GW nuclear capacity additions.

[d] 20.502-GW nuclear capacity additions for total reform--early; 15.946-GW nuclear capacity additions for all other cases.

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

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

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

[h] 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.

TABLE II

ESTIMATED PRICE ADVANTAGE OF THE REFORM CASES RELATIVE TO NO REFORM

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

Note: Constant 1980 dollars assumed. No-reform new nuclear capacity begins construction in 1982, with the first unit coming on line in 1997.

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

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

[c]5.695-GW nuclear capacity additions.

[d]13.668-GW nuclear capacity additions for total reform--early; 10.251-GW nuclear capacity additions for all other cases.

[e]6.834-GW nuclear capacity additions.

[f]20.502-GW nuclear capacity additions for total reform--early; 15.946-GW nuclear capacity additions for all other cases.

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

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

[i]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.

TABLE III

NUMBER OF YEARS OF POOR FINANCIAL PERFORMANCE

	Nuclear and Generic Capacity Additions[a]				All-Nuclear Capacity Additions[b]			
	No Reform (yr)	Combined Early-Site-Permit and Preapproval-of-Design Reforms (yr)	Total Reform --Later (yr)	Total Reform --Early (yr)	No Reform (yr)	Combined Early-Site-Permit and Preapproval-of-Design Reforms (yr)	Total Reform --Later (yr)	Total Reform --Early (yr)
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] 5.695-GW nuclear capacity additions for Pacific Gas and Electric Company; 6.834-GW nuclear capacity additions for Georgia Power Company.

[b] 13.668-GW nuclear capacity additions for total reform--early; 10.251-GW nuclear capacity additions for all other cases--for Pacific Gas and Electric Company.

20.502-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.

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