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by

Duane Chapman

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Department of Agricultural Economics
Cornell University Agricultural Experiment Station
New York State College of Agriculture and Life Sciences
A Statutory College of the State University
Cornell University, Ithaca, New York, 14853

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Duane Chapman*

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*Professor of Resource Economics, Department of Agricultural Economics, Cornell University.

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Several recent scientific studies have established this basis for understanding the acid deposition problem: (a) deposition may be in solids, gases, or precipitation in rain or snow, (b) anthropogenic sulfur oxides constitute the largest identifiable category of emission precursors, (c) electric utilities constitute the largest identifiable category of sulfur oxide emissions, (d) reduction in SO_x (sulfur oxide) emissions has an almost linear relationship to reduction in acidic deposition.[1]

In general, aquatic effects are relatively well understood, but the state of knowledge of effects on human health, forests, agriculture, and other areas is still limited. We do not know, for example, whether acid precipitation and carbon dioxide climate effects are synergistic, or whether secondary effects such as positive and negative alteration in pathogen resistance are important.

In this analysis, it is assumed that additional sulfur removal is costly, technologically possible, and may be implemented regardless of the knowledge base on effects and economic damage. The study delineates some of the economic aspects of enhanced emission control, and considers how this objective may be affected by other aspects of policy such as nuclear power availability and demand fluctuations. In addition, I analyze the financial impact of the Glenn proposal which would tax all fossil fuel generation to provide coal sulfur removal in the 1990's.[2]

The Significance of Demand

In a 1972 Science article, Mount, Tyrrell, and I analyzed the economic determinants of electricity demand and concluded that historical exponential growth would not be a useful guide to demand in the 1980's. In 1974, we suggested that 2.2 trillion kWh be taken as a planning guide for 1980.[3] Industry analysts, however, expected a national level of 3.2 tkWh (trillion kWh). As shown in Figure 1, actual generation was 2.3 tkWh in 1980, and has not yet risen above that amount.

FIGURE 1.
TOTAL U.S. ELECTRICITY GENERATION, ACTUAL & FORECASTS

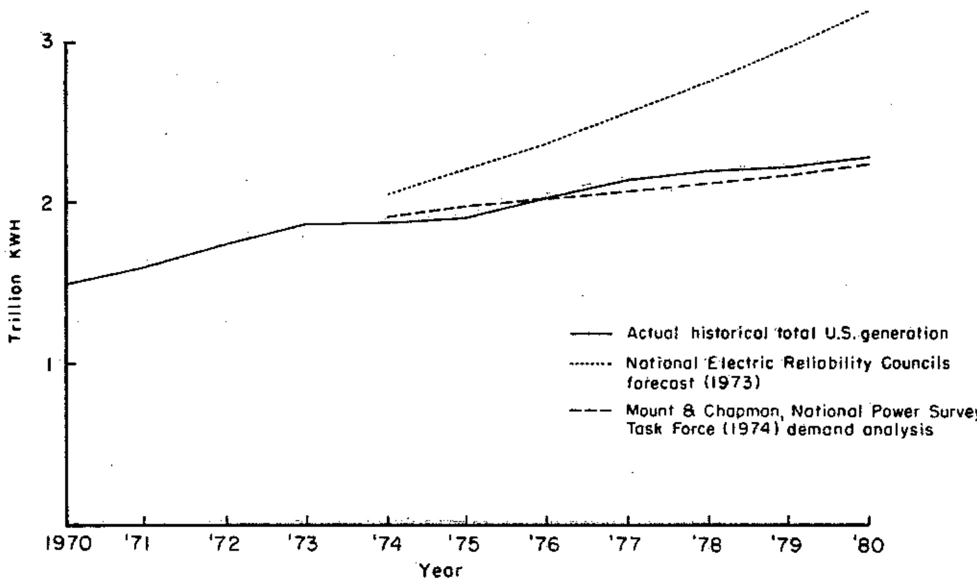
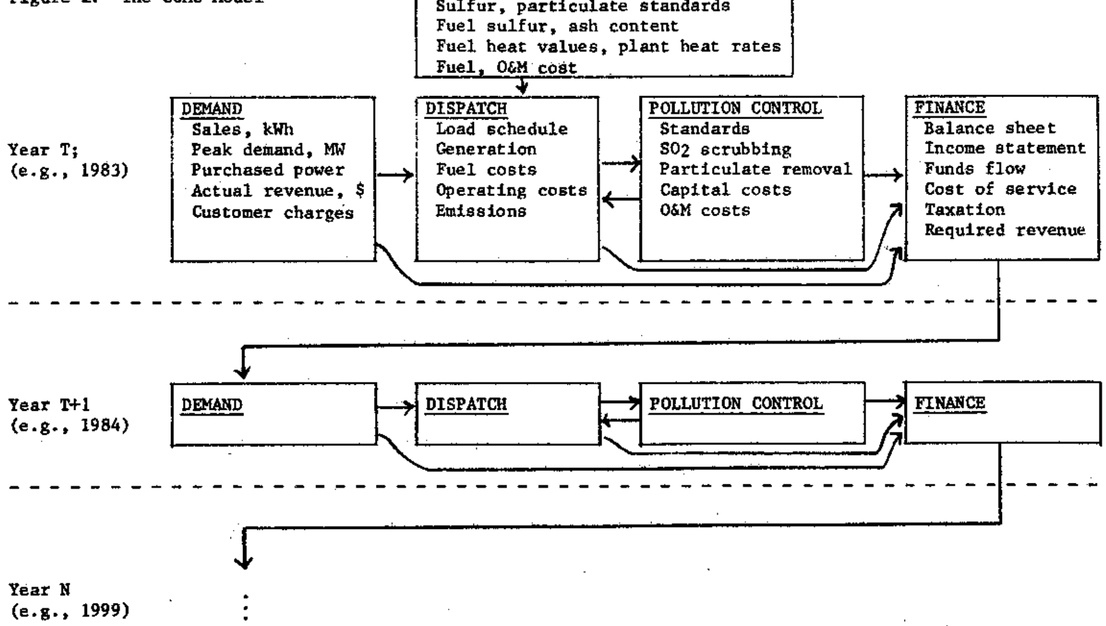


Figure 2. The CCMU Model



However, capacity planning in general and nuclear power construction in particular were based upon the upper curve. While sales are now 21% higher than in 1973, installed capacity is 59% higher. Nuclear capacity grew 300%.[4] In some regions, sales have declined from maxima reached in the late 1970's.

This error in forecasting means that many utilities have expensive new capacity with fewer or less than expected kWh sales as the basis for cost recovery. If long run price elasticity is near -1.0, then the long run revenue elasticity is near zero, as shown here:

$$\frac{\partial(PQ)}{\partial P} = Q + P\,\frac{\partial Q}{\partial P} = Q\left(1 + \frac{P}{Q}\,\frac{\partial Q}{\partial P}\right) \qquad \text{Eq. (1)}$$

This is a basic assumption in microeconomic theory. Obviously, if $(P/Q)(\partial Q/\partial P)$ is near or exceeds in negative value -1.0, then $\partial(PQ)/\partial P$ is near zero, or actually negative. The implication is that, in these circumstances, higher costs for pollution control could not be recovered from customers. If Eq. (1) is negative, rate increases actually cause revenue decreases.

Recognition of the importance of actual customer demand for planning pollution emissions and control and for utility finance is of primary concern in the CCMU (Cornell/Carnegie-Mellon Universities) model used here.

The URGE and CCMU Models

The URGE acronym represents Universities Research Group on Energy. The Group consists of engineers and economists from the University of Illinois, Carnegie-Mellon University, and Cornell University. It is sponsored by the U.S. Environmental Protection Agency. The objective of the Group is the development of a national economic and engineering model of air pollution emissions and utilities which can be used in studying national policies for acid precipitation mitigation.

The logic of parts of the model originated from Teknekron's earlier Utility Simulation Model. The major characteristic of the URGE model which distinguishes it from the Teknekron and other models is the closed loop or annually recursive nature of the model. Year t's generation level depends upon customers' responses to prices in years t-1, t-2, etc. As the previous section indicated, the twin problems of price response and sales decline create new economic environments for utilities in the acid rain study region. Our model portrays the response of electricity customers to the variations in real prices in an ongoing, annually interactive system.

The earlier Baughman-Joskow-Kamat Regionalized Electricity Model (REM) was also dynamic in the same sense.[5] Our work differs from Baughman *et al*. in the depth of real data. REM was structured with census regions as the basic blocks. URGE uses all actual plants in a state, and all financial data for all utilities in a state.

At Cornell, we use a simplified URGE model. We term this version CCMU, for Cornell/Carnegie-Mellon Universities. It is used here to study New York. The individual architects of the submodels are listed in note 6. The CCMU model is shown in Figure 2. Note that the level of required generation in 1984 (year t+1) will be dependent upon customer demand which responds to costs and rates in 1983 (year t). This time structure is applied to all years in an analysis.

Regulatory Economics and Customer Cost

The time path of regulated prices is significantly divergent from the levelized cost of the plant and equipment. This means that a utility's financial health and the rates charged customers both have a significant time dimension, as is clear in Figure 3. That figure shows the regulated prices for a single nuclear plant; it is as if a single corporate entity were established solely to generate and sell the power from the plant.[7] Note that deflating the price curve results in a real price trajectory which declines over the planning period. Note also that the levelized

FIGURE 3. LEVELIZED COST, REGULATED PRICE, AND DEFLATED PRICE

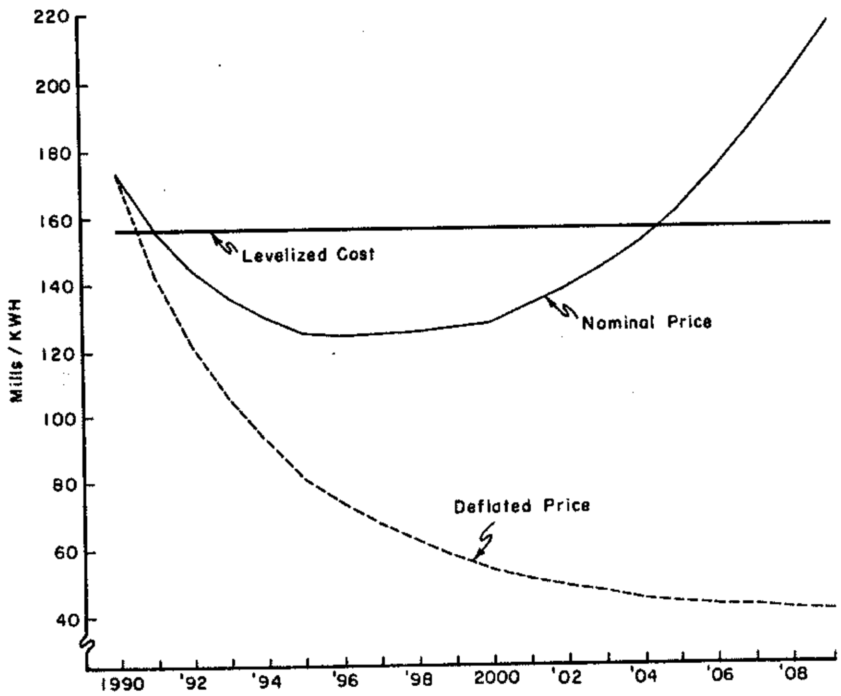
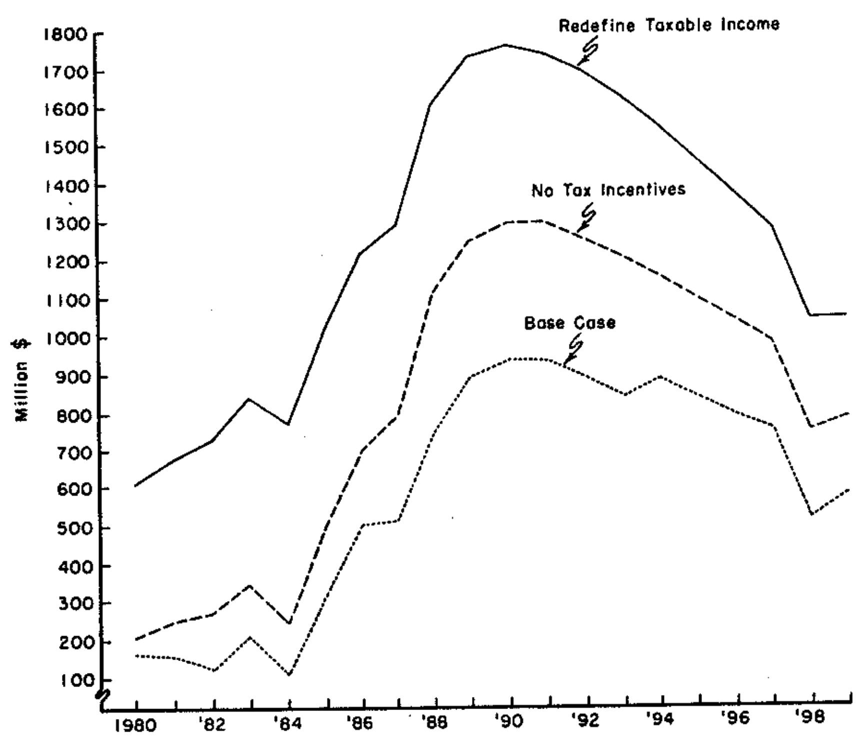


FIGURE 4. TAX POLICY AND FEDERAL INCOME TAX PAID, MILLION $



price is a horizontal 15.6¢/kWh. The engineering concept of levelized cost does not reflect either the actual revenue received by a utility or the deflated real price which influences customer demand. This generalization is applicable to any investment: scrubbers, transmission lines, nuclear plant.

The basic equations for regulatory pricing and levelized cost make this evident:

$$LC = K * FCR + OC \qquad \text{Eq. (2)}$$

$$P_t = \frac{REVCAP_t}{Q_t} + OC_t \qquad \text{Eq. (3a)}$$

$$REVCAP_t = \frac{r}{1 - z}\,[K - CD_t - DTA_t - ADITC_t] + SD_t - \frac{z}{1 - z}\,INT_t \qquad \text{Eq. (3b)}$$

LC, OC, and P are expressed in mills/kWh, and represent levelized cost, operating cost including fuel and maintenance, and price. K is the investment cost including an allowance for interest during construction. FCR is the fixed charge rate in Eq. (2), and is based upon a capital recovery factor and investment-linked expenses such as property taxes and insurance. REVCAP defines revenue for capital recovery in the simplified regulatory equations and Q is generation. In Eq. (3b), r is rate of return, z is the corporate income tax rate, CD is accumulated normal straight line depreciation, DTA is deferred income tax arising from cumulative accelerated depreciation, ADITC is the cumulative investment tax credit to be deducted from rate base, and SD is current straight line depreciation.

As is evident, actual regulation defines a price which varies considerably from levelized cost.

Taxation as indicated in the discussions of Eqs. (2) and (3), has a major influence on utility and customer costs. Figure 4 shows the effect of different tax policies on New York utilities. They can be represented with Eqs. (4)-(6).

$$NI = REV + AFUDC - FC - OM - SD - TAX - DEFTAX - INT \qquad \text{Eq. (4)}$$

$$TI = REV - FC - OM - AD - INT, \text{ or} \qquad \text{Eq. (5a)}$$

$$TI = NI - AFUDC - (AD - SD) + TAX + DEFTAX \qquad \text{Eq. (5b)}$$

$$TAX = z * TI - ITC \qquad \text{Eq. (6)}$$

Net income (NI in Eq. (4)) has revenue (REV) and the allowance for funds used during construction for equity and debt (AFUDC) as positive components, and is reduced by fuel and purchased power cost (FC), operating and maintenance cost (OM), normal straight line depreciation (SD), actual corporate income tax paid (TAX), deferred and other non-current tax account items (DEFTAX), and actual interest expense (INT).

Note that AFUDC and DEFTAX are not actually current income terms. Taxable income (TI) in Eq. (5) eliminates both, uses accelerated depreciation AD rather than straight line depreciation SD, and is of course on a pre-tax basis.

Eq. (5b) shows the relationship between net income and taxable income. Eq. (6) defines actual current tax as the product of taxable income and tax rate, less the investment tax credit.

Although simplified, these equations give the basic corporate income tax structure. The base case in Figure 4 shows estimated Federal corporate income tax.[8] Current Federal income tax payment in the base case is generally \$100-\$200 million in the early 1980's as investment tax credits from New York's three new plants are utilized. For the remainder of the period, actual tax payment is between \$500 million and $1 billion.

Elimination of the investment tax credit and accelerated depreciation gives the middle "no tax incentives" case in Figure 4. Actual tax payment would exceed $1 billion in nine of the years in the period.

One tax restructuring being considered is the replacement of the corporate income profit tax with a value added tax. Under this concept, net income before interest would be taxed at equal rates whether arising from shareholder or lender capital. Most value added proposals include wage income. However, for simplicity, we define taxable income as equal to pre-tax net operating income. In Figure 4, this is "redefine taxable income," and more than doubles base case payments. In 1990, $1.8 billion for Federal taxation would be paid, and collected from customers if the tax rate remained at .46.

Tax policy is crucial in its influence on the financial impact of emission policies and nuclear power, as is discussed in the following sections.

Modelling Air Pollution Economics

The validity of the analysis of sulfur oxide emissions and control depends upon the accuracy of the model in estimating how the 91 plants are operated to meet the demand analysis projection. For the years 1980 to 1982, actual total generation by fuel type can be compared to the estimated values in the left portion of Figure 5. The result for six major fuel types has a correlation of .987. For 1980, the model estimates sulfur oxide emissions for its dispatching solution to be 559 thousand tons. We calculate the emissions from actual plant data to be 551 ktons (thousand tons). Actual and model data show 312 and 302 ktons sulfur oxide emissions for coal, and 239 and 257 for oil, again for 1980.

In the base case, hydropower is a steady 27 billion kWh (bkWh), and nuclear power is nearly constant at 27 bkWh after the addition of the Shoreham and Nine Mile 2

FIGURE 5. GENERATION BY FUEL TYPE, BASE CASE
MODEL: 1980-1999, ACTUAL: 1980-1982

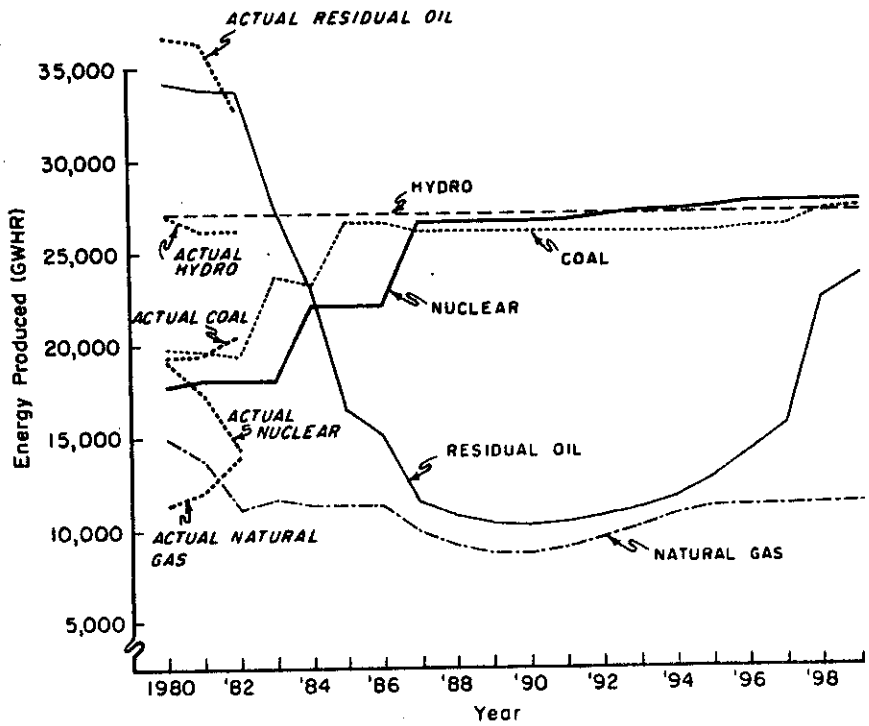
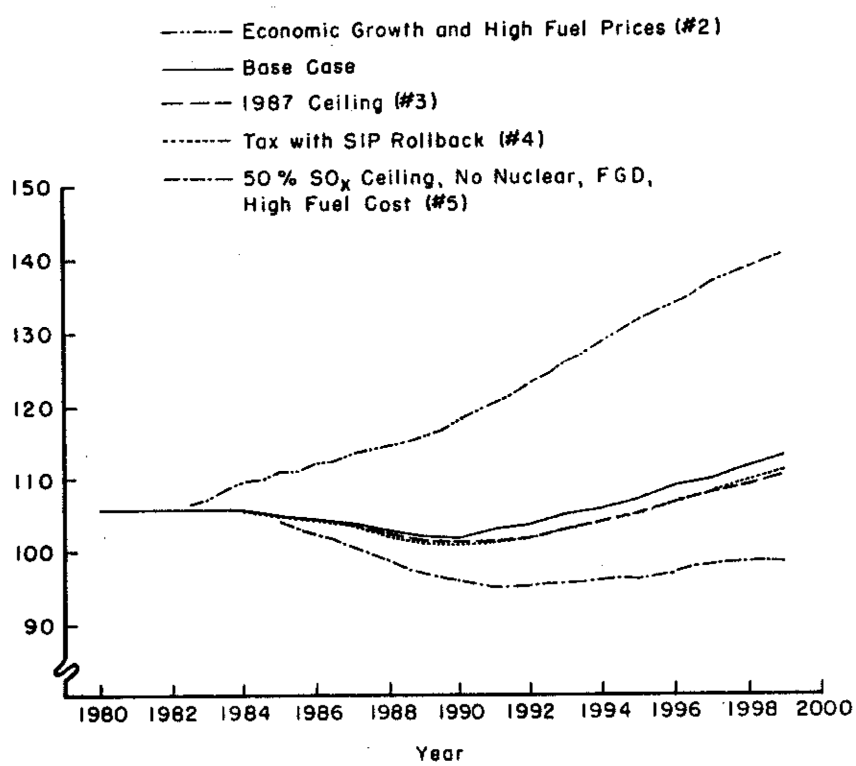


FIGURE 6. ELECTRICITY SALES, billion kWh annual



plants to the state's generating capacity. After completion of the Somerset plant, coal generation varies between 26 and 27 bkWh. Natural gas generation declines slowly, then increases and stabilizes. Residual oil generation declines rapidly, then recovers as old capacity is brought back into use in the 1990's.

In mid-1983, applicable sulfur emission regulations are determined by the year in which physical construction of the plant was initiated. "Old" plants are those under construction by August 1971. Their emission standards are determined by states as part of the State Implementation Plans to meet national ambient air quality standards. These limits are termed SIP limits, and, in New York, include a requirement that coal plants not exceed a 1.9 lbs sulfur or 3.8 lbs $SO_2/\overline{M}Btu$ limit.

The second regulatory phase applies to plants whose construction was initiated between August 1971 and September 1978. The applicable coal limit is 1.2 lbs $SO_2/\overline{M}Btu$. This is termed new source performance standards, or NSPS. It is a Federal EPA standard.

The third phase is revised new source performance standards (RNSPS), and applies to plants that began construction after 1978. This EPA standard varies by sulfur and heat content, and requires 1.2 lbs $SO_2/\overline{M}Btu$ with 90% SO_2 removal, or 0.6 lb $SO_2/\overline{M}Btu$ with 60% SO_2 removal.

Generally, urban SIP standards are much stricter than those applying to rural areas. Consequently, generating plants in urban areas will burn natural gas or low sulfur coal. Coal plants and medium and high sulfur oil plants will be located in rural areas, as are most nuclear plants.

Since each power plant can usually be operated on a least cost basis with a fuel having a sulfur content just under its limit, sulfur oxide emissions become a function of the dispatching solution. This can be seen by observing base case results for sales (Figure 6), generation by fuel type (Figure 5), and sulfur oxide emissions (Figure 7). The increment in coal generation in the mid-1980's (Figure 5

FIGURE 7. SULFUR OXIDE EMISSIONS, THOUSAND TONS ANNUALLY

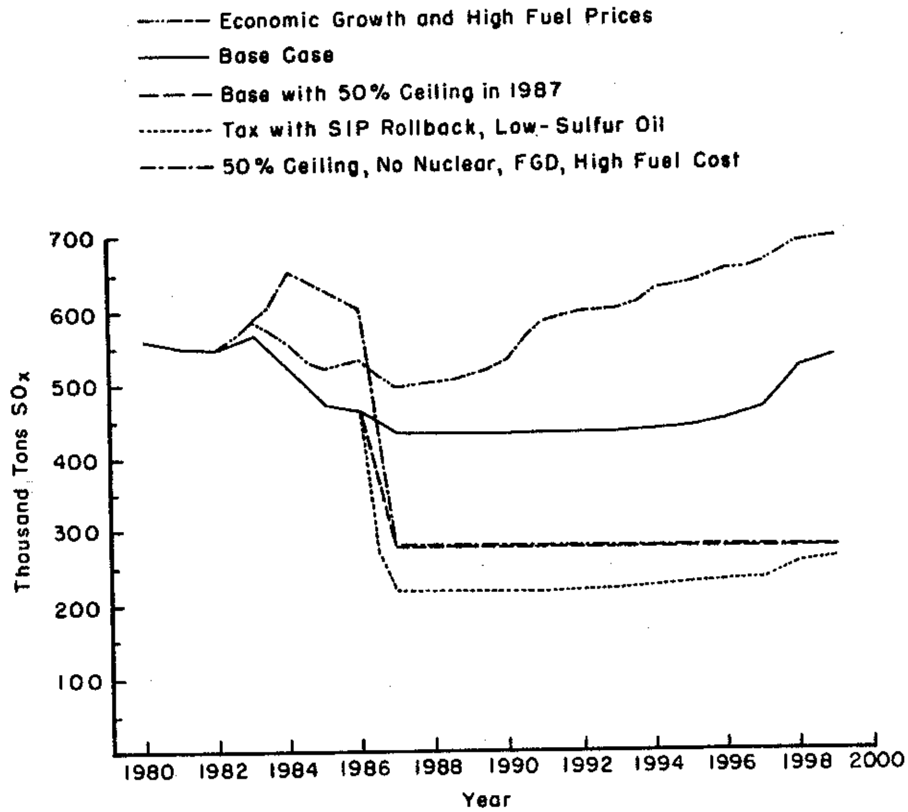
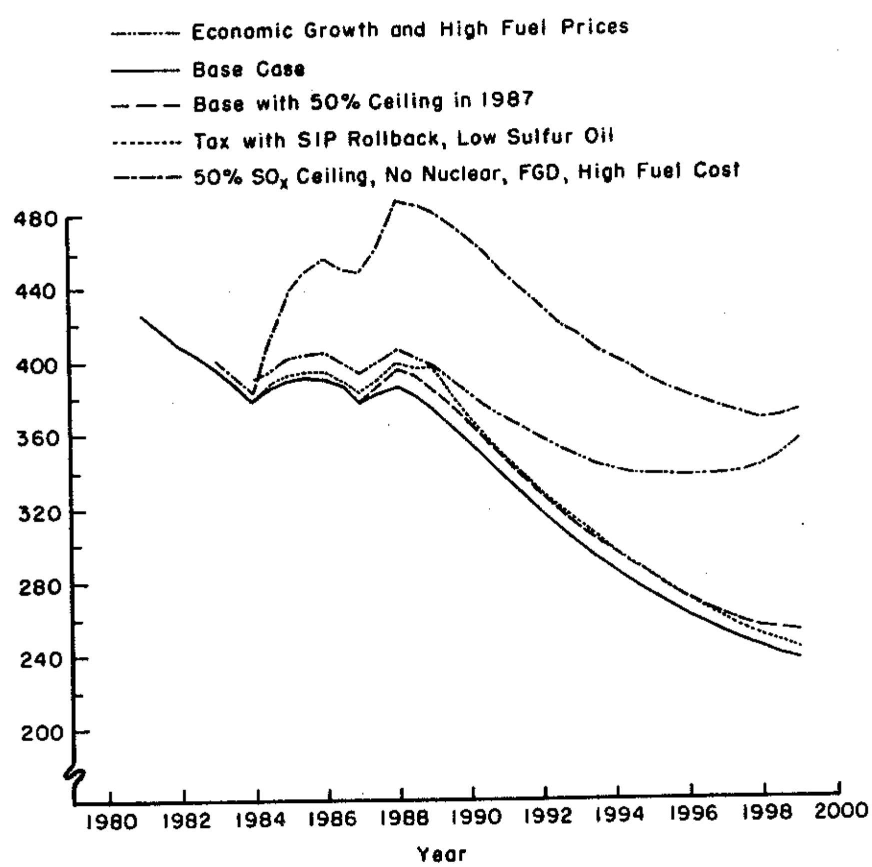


FIGURE 8. AVERAGE RESIDENTIAL BILL, 1980 $



again) arises from the utilization of the new 625 MW Somerset coal plant with FGD (flue gas desulfurization). Because of its FGD, this increase in coal generation does not cause a significant change in SO_x emissions. In fact, it will displace emissions from oil plants, leaving the total unchanged while providing less costly electricity.

The variability in generation, then, lies primarily with the dispatching of residual oil. This concave curve for oil creates the variation in the total sulfur oxide curve (Figure 7). Remember that in 1980 New York's oil plants produced 40% of total sulfur oxides. Hence, given the base case consistency in coal generation, variability in oil generation creates the emissions variability.

Four variations in emissions are reported here, and the next section examines the impact of nuclear power availability on emission control policies. In Table 1, Case 2 is traditional in that it uses assumptions common to utility planning. Present SIP, NSPS, and RNSPS are maintained for each individual plant. Nuclear power is fully utilized. The significant assumptions are economic: energy prices and the state economy both rise more rapidly than inflation. Consequently, electricity sales increase by one-third (Figure 6), and SO_2 emissions by the same proportion.

Interestingly, the demand growth in this case is almost wholly due to the assumed growth in population, incomes, and employment. Although electricity rates rise significantly in response to the accelerating fuel prices, the negative direct response of demand is almost exactly offset by the substitution effect of switching from oil and natural gas to electricity. This substitution effect actually exceeds the electricity price effect for the industrial sector.

I should note that the probability of significant economic growth and electricity sales over the remainder of the century seems quite low to me. Therefore, I am unconcerned at present about the apparent major growth in SO_x emissions.

Case 3 returns to the base case economic assumptions, and introduces the Carnegie-Mellon emissions dispatch ceiling.[9] The State's power plants must be utilized

Table 1. Cases Reported

Number	1	2	3	4	5	6	7	8	9
Name	Base	Traditional assumptions	Emission ceiling	Tax and rollback	Conventional rollback, no nuclear	Tax, no Shoreham	Tax, no new nuclear	Extra-ordinary A	Extra-ordinary B
Fuel pollution tax, mills[1]	0	0	0	3	0	3	3	0	0
Coal SIP roll-back[2]	0	0	0	50%	50%	50%	50%	90%	90%
SO_2 cost, \$/kW	0	0	0	\$203	\$203	\$203	\$203	\$330	\$330
Dispatching ceil-ing, 280 ktons	no	no	yes	no	yes	no	no	yes	yes
Existing nu-clear[3]	yes	yes	yes	yes	0	yes	yes	0	0
New nuclear	yes	yes	yes	yes	0	NM2 only	0	0[6]	0[6]
Real fuel cost escalation[4]	0	1%-4%	0	0	1%-4%	0	0	1%-4%	1%-4%
State economy[5]	stable	1% growth	stable	stable	stable	stable	stable	1% growth	1% decline

[1]The 3 mill tax is applied to fossil fuel kWh from 1986 through 1995. It is increased in steps from 1 mill in 1984 and 2 mills in 1985. The 3 mill tax is constant from 1986 through 1995.

[2]Each SIP rollback case is accompanied by an oil standard of 0.6% sulfur.

[3]This is 5 plants with 18,115 MW, excluding Indian Point #1.

[4]Positive rates are 1% nuclear and coal, and 3% oil and natural gas above the 6% overall inflation.

[5]Percentages apply to annual rates of change in per capita income, population, employment, and total personal income.

[6]In these two cases, the full 8 billion dollars is included in the rate base and recovered from customers.

in a schedule which will produce no more than 280 ktons of sulfur oxide emissions per year. No FGD is considered, nor, in this case, is the option to switch to higher cost lower sulfur fuel. The emissions ceiling is introduced in 1987, and the state's plants are dispatched in a least-cost manner up to the constraint.

As Figure 8 indicates, this sizeable reduction in emissions adds only a slight increment to residential bills. Similarly, average prices to commercial and industrial customers rise by very small percentages. The economic implication is that utility managements can develop efficient operational procedures to meet assigned pollution goals.

Case 4 introduces the sulfur removal/fossil fuel tax as a means of Federal financing of FGD installation. As applied to New York, the tax increases by one mill/kWh increments to 1986, and is applied at 3 mills/kWh through 1995. The tax collects approximately $130 million annually throughout the period, and borrows money in the early years to finance FGD installation. The tax has accumulated $580 million by 1995, and this is available to finance FGD installation in other states. The dispatching pattern is essentially unaffected by the tax. Again, Figures 6-8 may be used to compare sales, emissions, and annual residential bills for these policies.

Table 2 reports emissions, total customer price, and company revenues for three reduction policies. Cases 1, 3, and 4 have been noted above. Case 10 is additional.

Note that SO_x emissions are almost identical in Cases 10 and 4. Apparently, whether customers pay for sulfur removal through conventional rate-base inclusion of pollution investment (Case 10) or the innovative tax on fossil fuel use (Case 4), the net effect on customer price or company revenue is insignificant.

A paradox exists. Although the tax accrues a net $580 million in New York for distribution to other states, its revenues and prices are very slightly below the figures for the rate-base Case 10. The resolution of the puzzle is in Eqs. (2) and

Table 2. Economic Impact of Policies

A. Sulfur Oxide Emissions, ktons

	(1) Base Case	(3) 50% Ceiling (280 ktons)	(10) 50% SIP Rollback, Rate-base Costing	(4) Tax with 50% SIP Rollback
1984	521	521	521	521
1989	434	280	225	220
1994	436	280	227	227
1999	536	280	260	262

B. Average Cost, 1983 $, ¢/kWh

	(1) Base Case	(3) 50% Ceiling (280 ktons)	(10) 50% SIP Rollback, Rate-base Costing	(4) Tax with 50% SIP Rollback
1984	6.76¢	6.76¢	6.76¢	6.76¢
1989	7.13	7.35	7.47	7.41
1994	5.55	5.79	5.84	5.81
1999	4.66	5.04	4.87	4.82

C. Revenue Collected, future dollars, billion

	(1) Base Case	(3) 50% Ceiling (280 ktons)	(10) 50% SIP Rollback, Rate-base Costing	(4) Tax with 50% SIP Rollback
1984	$ 7.611	$ 7.611	$ 7.611	$ 7.611
1989	10.344	10.602	10.724	10.653
1994	11.159	11.473	11.499	11.479
1999	13.368	14.081	13.686	13.596

Note: 1980 model values are 559.5 ktons SO_x, 7.44¢/kWh, and $6.616 billion. Actual 1980 values are 551 ktons, 7.55¢/kWh, and $6.742 billion.

(3). For the tax Case 4, the tax is passed along directly as an operating cost in Eq. (3a). However, when the $850 million sulfur removal investment goes into the rate base in Case 10, Eq. (3b) shows that a fair cost of service determination will provide a return on investment and a tax allowance. Consequently, the Glenn tax means more funds for pollution control at less cost to customers, but with reduced payments of Federal income tax.

The least-cost emission ceiling has similar cost and emission reductions (Case 3). Recall that, here, the model dispatches the 91 plants with their existing fuels in such a way as to meet the total state ceiling of 280 ktons at minimum operating cost. Increases in operating costs are passed along directly to customers as in Eq. (3a). This third policy--the state emissions ceiling--achieves emission levels, prices, and revenues similar to the other two policies in Table 2.

Incidentally, observe that emissions with the 50% SIP rollback are noticeably lower than those in the 50% ceiling case. I have no persuasive explanation for this.

Overall, each of the three policies adds about 2 or 3 mills to average cost in the 1980's and 1990's. In 1989, for example, the highest cost Case 10 has revenues of $10.7 billion and an average price of 7.47¢/kWh, only 4% above base case values. This rather low increment is due to the low proportion of coal generation which is 26% of total generation with a 71% capacity utilization. Extrapolation to a state with total coal generation suggests a cost increment of 1.3¢/kWh for a 50% reduction in SIP standards.

Finally, Table 2 and Figure 8 generally show declining real average price and residential bills. This arises directly from historic regulatory policies which define the maximum rate base and equity return for new plants in their first year, and depreciate the plant as it ages. Consequently, a 35 year old plant operating at high efficiency will earn nothing for its shareholders, while a new plant will normally earn a full return regardless of the level of efficiency. In addition, the corporate income tax system shelters earnings in early years: Eq. (6) will be negative. In later years, when tax depreciation is exhausted and previous credits are still being subtracted from rate base,[10] there may be positive current tax liability even if net income is negative. As a consequence, state regulatory rate-making and the Federal corporate income tax interact to stimulate new investment in plant, but have financial disincentives for the operation of old plants or the development of stable sales and generation.

As a general conclusion, it appears that very major reductions could be made in sulfur emissions without significant problems in capacity availability. The average price of electricity would rise about 3 mills per kWh, and perhaps 1.3¢/kWh in a state with all coal generation. Any one of three broadly different pollution control policies achieves comparable gains in emission control and cost to customers.

The fossil fuel tax would have lesser corporate income tax payments, marginally lower costs to customers, and accumulate a surplus in New York for distribution to other states.

However, these felicitous conclusions are strongly dependent upon nuclear power availability.

Nuclear Power Economics and Air Pollution

The results of this study indicate that nuclear power and air pollution policies are closely linked. The small cost and revenue increases for the Table 2 air pollution policies are dependent upon the continuing availability of existing and new nuclear plants.

Examining utility financial impact may use several kinds of analytical information. Rates of return on equity and rate base, dividend payout ratios, AFUDC proportions, and interest coverage ratios are all commonly used. These analytical ratios are each taken from data reported in income, balance sheet, and funds flow statements.

Figure 9 reports one of these analytical ratios. Interest coverage means the amount of income available each year to pay debt obligations. A ratio of 2.0 is viewed as a minimum: it implies that income is sufficient to pay current interest expenses, and provide an equivalent amount of equity income.

However, the growth of "paper money" in utility accounting suggests two offsetting corrections. First, AFUDC enters net income as positive items. It is a recognition of future income to be earned when a facility is in use. Therefore, it is not available for current interest or dividend payments. It may be deducted from net income to give a better picture of funds currently available.

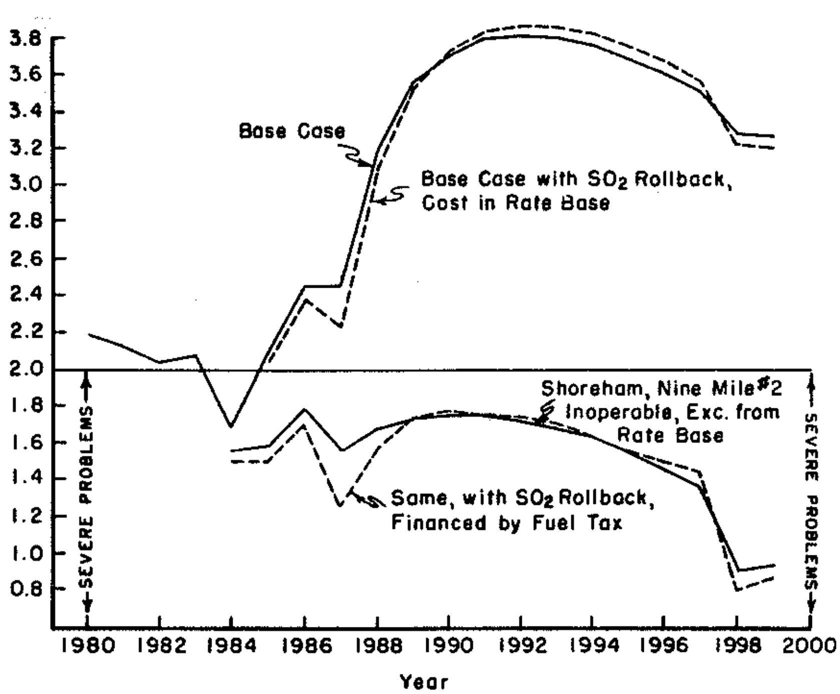
In the offsetting direction, federal income tax expense in the current year will include significant amounts of deferred income tax which will not be payable until future years. Consequently, one approach is to add back to net income the difference between tax charges and taxes paid.

Note that both forms of "paper money" arise from new construction. Figure 9 reports interest coverage where net income has been adjusted by subtracting AFUDC entries and adding reported tax charges, thereby approximating a conventional definition of pre-tax profit.

In the base case, the state's utilities generally exhibit a high degree of financial strength. There are problems in the early 1980's as debt from new plants increases before those plants are operable. However, as the new plants begin operation, the financial situation looks positive.

The top broken line indicates the variation in interest coverage caused by a 50% rollback in individual coal SIP plant standards and the required usage of higher cost, lower sulfur fuel in oil plants. FGD plants are built over the 1984-1986 period, adding $1 billion to the rate base in 1987. No significant financial problems

FIGURE 9. INTEREST COVERAGE RATIOS. FINANCIAL ASPECTS OF POLLUTION CONTROL WITH NUCLEAR PROBLEMS. INTEREST COVERAGE DEFINED AS THE RATIO OF PRE-TAX OPERATING INCOME TO INTEREST EXPENSE.



are encountered, and, as shown previously, emissions decline considerably below the 300 kton level throughout the period.

The lower curve pair shows the impact of not operating the new nuclear plants and excluding their assumed $8 billion cost from the state's rate base. Although the financial impact is lessened by the significant tax cushion in Figure 4, it is apparent that the state's utilities would encounter severe economic problems in such a case. Interest coverage ratios as defined here which are consistently below a value of 2.0 mean that the state's utilities would, on the average, discontinue all dividends and be unable to meet debt obligations. Note, however, that adding a fuel tax and SO_2 reductions does not have much impact. In these circumstances, it is inconceivable that the state's utilities could implement new emission control policies.

The important conclusion is that the financial ability to implement air pollution reduction policies will depend upon nuclear power and its problems, and not upon economic factors specific to enhanced emissions control.

Summary and Implications

New York now differs from the United States in having less coal generation (16% vs. 53%) and more oil generation (35% vs. 6%). Although New York has proportionally greater inexpensive hydropower (27% vs. 17%), it has equivalent proportions of its generation in nuclear power (13%) and gas generation (10%). New York has one of the highest cost utility systems (8¢/kWh average price vs. 5¢/kWh), but one of the lowest amounts of SO_2 per kWh (.010 lb/kWh vs. .015). (See note 11.)

The national implications of nuclear power availability may be generalizable from this analysis. As noted, New York and nationwide, nuclear generation is currently 13% of total electricity generation. New York plans a 50% increase in capacity. Overall, U.S. utilities now plan a 100% increase above current capacity.[12] Therefore, for much of the country, I expect that nuclear policy has a greater impact on the economics of enhanced pollution control than do the air pollution policies themselves. For two cases reported, financial strength as measured by adjusted interest coverage ratios was high or low depending upon nuclear problems. Imposing major reductions on emissions in each case did not change the overall strength or weakness in a noticeable way.

In New York, the average cost of electricity in the late 1980's would be about 3 mills/kWh higher with various air pollution policies leading to significantly lower emissions. For a state with all coal generation, the average cost increase would be about 1.3¢/kWh.

Three distinct types of emission policies were examined: (1) dispatching existing plants and fuels in a manner to meet specified state ceilings without necessarily changing individual plant SIP standards, (2) reducing individual plant SIP standards and using FGD on existing coal plants and low sulfur oil in current high-sulfur oil plants, and (3) again, the reduction in plant standards, but with the fossil fuel tax financing the installation of FGD.

In the first kind of case, the higher O&M and fuel costs necessitated by the ceiling are passed along directly to customers through the fuel adjustment clause. In the second case, $850 million in FGD cost is incorporated into the rate base in accordance with conventional regulatory policy. In the third case, a tax is used to finance FGD in New York, and accumulate a surplus for use in other states.

Surprisingly, the same FGD emissions reduction is less costly to customers when financed by the fuel tax; it removes the normal profit earned on rate base investment.

The tax has the unique characteristic of providing a financial surplus from New York for use in other states. Most of New York's most damaging Adirondack deposition originates in Canada and other states.[13] The tax provides a national mechanism to balance regional differences in costs and benefits.

The overall similarity in economic impact of widely different types of policies implies that meeting state or company goals may be best managed by individual companies, or states. It seems that the most efficient technical means of meeting a geographic constraint can be selected by plant operators.

References and Notes

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2. L.B. Parker, "Distributing Acid Rain Mitigation Costs: Analysis of a Three-Mill User Fee on Fossil Fuel Electricity Generation," U.S. Congressional Research Service (April 11, 1983).

3. D. Chapman, T. Mount, T. Tyrrell, Science 178, 703 (1972); D. Chapman et al., Power Generation: Conservation, Health, and Fuel Supply, U.S. Federal Power Commission (1976).

4. From data in Monthly Energy Review (August 1983) and Statistical Yearbook of the Electric Utility Industry (December 1982).

5. M.L. Baughman, P.L. Joskow, and D.P. Kamat, Electric Power in the United States: Models and Policy Analysis (Cambridge, Mass.: MIT Press, 1979).

6. The overall URGE project is described by Stukel et al. in The Advanced Utility Simulation Model, Urbana, Illinois, March 1983. Individual module components for CCMU are the work of T. Mount and M. Czerwinski (demand), S. Talukdar and N. Tile (dispatch), E. Rubin and C. Bloyd (sulfur emission control technologies), K. Cole and M. Younger (utility economics), G. Fry (plant data), and Czerwinski and Younger (policy analysis programming). The CCMU and URGE models undergo continuous development. This paper uses the CCMU version as of September 26, 1983. See also T. Mount, "The Effects of Changing Economic Conditions on Stack Emissions from New York Power Plants," presented at the Symposium on Atmospheric Deposition, Albany, October 1983; M. Younger, "The Glenn Tax in New York," Cornell Agricultural Economics Staff Paper No. 83-17, September 1983; K. Cole, The Effects of Acid Rain Legislation on a Representative Midwestern Utility, Ph.D. dissertation, in preparation.

7. Graph prepared by K. Cole.

8. The state's seven private and one public utility are viewed as a single system, reflecting their participation in the New York Power Pool and shared ownership in new plants which constitute one-half or more of rate base.

9. As developed by Talukdar *et al*. at Carnegie-Mellon, the dispatch linear program finds the least cost utilization of all the state's power plants which will supply load curve segments while constraining total state emissions from all plants not to exceed the specified ceiling.

10. DTA and ADITC remain positive rate base deductions in Eq. (3b) while tax liability grows in Eq. (6).

11. Data from *Electric Power Monthly*, June 1983; *Statistical Yearbook of the Electric Utility Industry* (December 1982); and "Emission Estimates" *op. cit*. I include New York's Pennsylvania generation in New York's SO_2 production.

12. North American Electric Reliability Council, *Electric Power Supply and Demand: 1982-1991*, August 1982, Table 13, p. 34.

13. J.A. Fay *et al*., "Controlling Acid Rain," Table 3, p. 18.