EVALUATION OF CONSERVATION FOR SO_2 EMISSIONS REDUCTION USING A MULTIOBJECTIVE ELECTRIC POWER PRODUCTION COSTING MODEL

Benjamin F. Hobbs and James S. Heslin
Department of Systems Engineering and Center for Regional Economic Issues
Case Western Reserve University

In this paper, the effectiveness and cost of energy conservation as part of a comprehensive SO_2 emissions reduction strategy in Ohio is assessed. The model used is based upon probabilistic production costing and is more realistic than approaches applied in previous acid rain policy analyses. The model's output consists of curves that show tradeoffs between costs and emissions resulting from different degrees of emissions dispatching and, if desired, fuel switching under a given set of conservation and emissions control investments.

Conservation appears to have a cost-effective role in nearly any emissions reduction strategy in Ohio. Assuming that a moderate conservation effort would cost just over 2¢/kWh and would achieve a 0.5% decrease in load growth, conservation appears modestly attractive by 1998, although it actually increases total costs in 1994. By the year 2002, however, such an effort is clearly efficient, primarily because it enables utilities to delay costly capacity additions. But by that time, investments in emissions control retrofits at existing plants will also be necessary, even when the strengths of conservation, emissions dispatching, and fuel switching are combined.

The issue of rate feedback is also investigated. Increases in rates due to emissions control policies stimulate demand decreases and, thus, cost and emissions reductions. However, there may also be a loss of consumer surplus if price exceeds social marginal cost and price elasticities are nonzero. It is found that rate feedback can decrease the attractiveness of conservation as an emission reduction measure, particularly over the next decade when Ohio has surplus generation capacity.

INTRODUCTION

The purpose of this paper is to examine the cost-effectiveness of energy conservation, together with emissions dispatching (ED), as parts of a comprehensive SO_2 emissions reductions strategy in Ohio, the state having the most SO_2 emissions in the United States. Conservation reduces emissions by decreasing the output of the power generation system, and also lowers fuel and capacity expansion costs. In contrast, ED increases generation costs and decreases emissions by operating dirtier plants less and cleaner (and more expensive) plants more (Sinha and Calafiore 1990). Various degrees of ED are possible, ranging from slight deviations from traditional least cost dispatching (by shifting the output of, say, just two plants) to least emissions dispatching (in which plants are ranked in order of increasing emissions per megawatt-hour (MWh), and the cleanest plants are used first).

Most analyses of the cost of compliance with acid rain legislation have not explicitly considered conservation or ED. However, interest in those approaches has grown for two reasons. First, their potential benefits have been highlighted by recent studies. For example, analyses using linear programming or systems dynamics models have concluded that ED and energy conservation could cost-effectively lower SO_2 emissions by 50% or more in Ohio and elsewhere in the U.S. midwest (Centolella et al. 1988; Nixon and Neme 1989). Conservation and ED can be used together with other measures, such as fuel switching, new power plants, retrofit of emissions controls, and coal cleaning, to reach emissions reduction targets in a cost-effective manner (Heslin et al. 1989).

The second reason for heightened interest in conservation and ED is that, unlike the 1978 Clean Air Act Amendments, the pending reauthorization of that Act would give credit for emissions reductions achieved by those strategies. The markets for emissions rights that would be established would encourage utilities to reduce emissions using these and other innovative methods.

This paper builds upon previous studies of conservation and ED in three ways.

- These emission reduction methods are analyzed together with other approaches using recent generation unit-by-unit estimates of the costs of emerging control technologies (PEI Associates, Inc. 1989).
- The possible effects of "rate feedback", in which increases in the price of electricity motivate decreases in electricity demand (and, thus, emissions reductions), is investigated. We show that demand reductions due to rate feedback are potentially of the same order of magnitude as the energy savings directly achieved by conservation programs.
- We use a state-of-the-art method, probabilistic production costing, for estimating power plant output and emissions.

Unlike most models that are used for analyzing emissions control strategies, probabilistic production costing can accurately model, for example, random outages of generating units and unit operating constraints. Our model, called MODES (Multiple Objective Dispatch Evaluation System), generates curves showing the cost of lowering emissions by ED and fuel switching, under a given set of power plants, fuel prices, control technologies, and conservation programs. Since the model interfaces with widely used microcomputer database and spreadsheet software, users can quickly modify the inputs to reflect different technology choices, demand growth rates, or fuel prices.

In the next two sections, we review the methodology and the assumptions used. Later sections present the results of the Ohio analyses.

METHODOLOGY FOR ESTIMATING GENERATING UNIT OUTPUT AND EMISSIONS

MODES's purpose is to estimate the expected emissions and cost of ED and fuel switching for a coordinated power system. The software is intended for use in detailed state- or utility-level policy analysis and planning. Previous models for analysis of ED were designed for broad-brush regional or national assessments or real-time commitment of power plants (e.g., Yokoyama et al. 1988). MODES yields more accurate estimates of production costs and emissions than other policy models, while achieving the quick execution times and longterm perspective required for policy analysis.

Probabilistic production costing, the methodological basis of MODES, was developed by the utility industry in order to obtain more accurate estimates of expected generation costs for a system that must meet a varying level of power demand using a set of generation units that are subject to random forced outages (Baleriaux et al. 1967). Probabilistic production costing is a reasonable compromise between the need for more realistic dispatch models and the desire to avoid the computational difficulties inherent in detailed unit commitment models (Talukdar and Wu 1981).

MODES generalizes probabilistic production costing to include several objectives. For example, in an analysis of the short-term potential of ED and fuel switching in Ohio (Heslin and Hobbs 1989), three objectives are modeled: generation costs, SO_2 emissions, and employment in the Ohio coal fields. MODES generates a number of different dispatch orders ("merit orders") for the generation units, each order representing a different weighting of the various objectives. [This is the same basic approach as the "emissions tax strategy" formulation of the dispatching problem (Delson 1974)]. After calculating the expected output of the units under each ordering, the values of objectives can be calculated and the tradeoffs displayed. Each solution is efficient in that there exists no other solution that is at least as good in every objective and strictly better in at least one objective, for a specific set of loads and generation units.

A set of such solutions is called an efficient set; if only two objectives (e.g., cost and emissions) are considered, then this set is a two dimensional tradeoff curve. A distinct tradeoff curve can be obtained for each set of assumptions concerning conservation programs, generation plant additions and retirements, and emissions control technologies. By plotting several such curves together, as in Figure 1, strategies that achieve the desired emissions reductions at least cost can be identified. [See White (1981) for a similarly framed analysis of tradeoffs between SO_2 and electricity costs.]

Individual points on a tradeoff curve are obtained by first ranking the loading blocks of generating units in order of their performance per MWh on a composite emissions-cost objective. This composite objective is a weighted sum of (1) the variable cost per MWh and (2) the SO_2 emissions per MWh. A weight of 1 for cost and 0 for emissions results in the traditional "least cost" dispatch order; placing higher weights on emissions yields increasing degrees of ED. Probabilistic production costing models such as MODES can accommodate must-run limitations, limited energy units (hydropower), maintenance outages, non-dispatchable units (e.g., wind or cogeneration), and pumped storage (Yamayee 1985). An innovative feature of MODES is its inclusion of the possibility of fuel switching, if the user wishes to allow that option. Basically, if

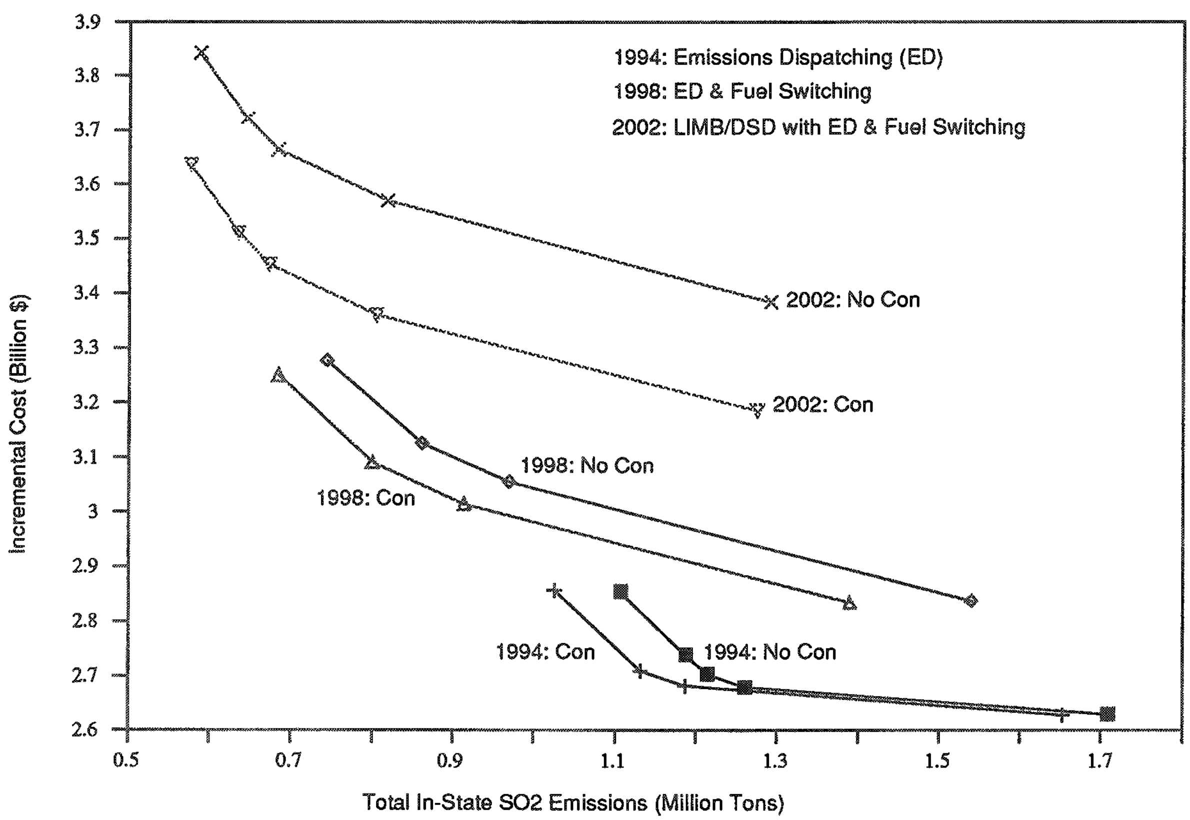

Figure 1. Incremental Cost of Reducing SO_2 Emissions for Ohio: 1994, 1998, 2002

fuel switching would help a generating unit perform better on the composite objective, the fuel is changed.

Despite these complications, tradeoff curves can be generated quickly on a microcomputer even for large power systems. Details on MODES's computational procedures are available in Heslin and Hobbs (1989).

ASSUMPTIONS

In this section, we summarize our assumptions concerning compliance targets, electric loads, conservation programs, generation units, fuel switching, and control technologies. Assumptions concerning interest rates and taxes are consistent with EPRI (1986). All costs are expressed in real 1987 dollars.

Compliance Targets

Here, strategies are developed to lower utility emissions in Ohio to compliance targets for each of three years (1994, 1998, and 2002). These targets are representative of SO_2 emissions targets in several previously proposed acid rain bills, such as S. 5562, and are comparable to the ceilings assumed in the analysis by Centolella et al. (1988). The compliance targets are 1,300,000 tons of SO_2 per yr (1994), 1,050,000 tons/yr (1998), and 525,000 tons/yr (2002). As a comparison, Ohio's 1988 SO_2 emissions were 2,100,000 tons. We also show strategies which yield emissions reductions above and below those targets so that the costs of other targets can be estimated.

Base Case Load Projections

Projections for Ohio's load growth are taken from Centolella et al. (1988). In the absence of additional conservation programs, a growth rate of 1.5%/yr for both energy and the system peak was forecast. Future loads are projected from a base year of 1987 (133,470 GWh/yr with a peak of 21,553 MW).

Energy Conservation Programs

Our focus is on so-called "strategic conservation" programs whose aim is to reduce total energy use in all periods. Other types of demand-side management programs, such as peak clipping, load management, and valley-filling (Gellings and Chamberlin 1986), are disregarded, even though their impacts on emissions might be significant. For instance, load management might lower the output of clean peaking units, while increasing the generation from dirtier shoulder- or base-loaded units.

We use Centolella et al.'s (1988) findings concerning the cost and effectiveness of a "moderate effort" conservation program. The program is based on the assumption that electric utilities will pay for 50% of the cost of any conservation measure whose levelized expense (based on a 6% real discount rate) is less than \$0.06/kWh. We presume that the utility's costs are recovered from ratepayers at the time that the savings take place; i.e., program costs are ratebased and are recovered over several years. Most of the savings come from industrial motors and lights; residential refrigerators, hot water and space heating, and lights; and commercial cooling and lights. Penetration rates are calculated assuming that any conservation investment whose net perceived cost to the consumer (evaluated at the higher "implicit" discount rates of 35%-75%) is less than the price of electricity.

Centolella et al. (1988) conclude that such a program can lower the load growth from 1.5% to 1.0%/yr at an average levelized cost of \$20.70/MWh saved. The MODES runs show that this cost is close to the short run marginal cost of plant operation in Ohio, and is considerably less than the long run expense of plant construction.

Included in Centolella et al.'s (1988) estimates of energy savings are those that result from additional conservation investments motivated by conservation-induced electric rate increases. However, no price-induced fuel substitution and reductions in energy services beyond those reflected in the base case load projections were considered in that study. Later in this paper, we examine the possible implications of additional price-induced load decreases.

We also undertake sensitivity analyses in which we look at the effect of a less successful program that lowers the growth rate to only 1.2%/yr at the same total cost, and an "aggressive" program that drops the growth rate to 0.7% at an assumed average cost of \$26.5/MWh (Centolella et al. 1988). Under the latter program, utilities are assumed to pay 90% of the cost of conservation measures (rather than 50%), and information programs lower implicit consumer discount rates to 15%-25%. The cost of the increment of savings over the "moderate" program is approximately $36/MWh, which exceeds the short run cost of power production.

Generation Units

The generation units considered are those that are owned and operated by Ohio utilities and which are expected to be on-line in the early 1990s. The total capacity is about 33,000 MW. Of this amount, 80% is coal-fired, with nuclear plants and combustion turbines making up most of the remainder. Power system and fuel use data are obtained from industry and federal sources (Ohio EPA 1986; Stone and Webster, Inc. 1986; USDOE 1986). "Must-run" constraints on each unit's output are included in the model. The amount of power provided by non-Ohio state units owned by Ohio utilities is assumed to be fixed, so that the analysis can focus on the costs and emissions of Ohio facilities. The emissions and costs of non-Ohio facilities are excluded from the results presented below. Future analyses should consider multistate regions.

Unit retirement data are taken from industry data (Stone and Webster, Inc. 1986). Additional retirements assumed for 2002 include all small, old units with high heat rates. New coal-fired units with scrubbers plus combustion turbines for meeting system peaks are added to replace the retired capacity and to maintain a reserve margin of at least 20%. Consistent with Centolella et al. (1988), the construction cost of new coal-fired units is assumed to be $1216/kW in 1987, escalating at 2.1%/yr in real terms.

Emissions Control Retrofit Technologies

Energy conservation alone is unable to achieve the assumed compliance targets in 1998 and 2002, even in tandem with ED. Other measures will be needed in addition, including fuel switching and/or retrofits of emissions control technologies. Elsewhere (Heslin et al. 1989), we used a generating unit specific data base (PEI Associates, Inc. 1989) to investigate a wide range of emissions control technologies that can be retrofitted. In this paper, we combine conservation with the technologies that appeared most cost-effective in the three target years. In 1994, we concluded that ED alone is the least expensive means of achieving the compliance target. By 1998, ED together with fuel switching seemed cheapest (but only by a slight margin compared to a mix of retrofitted flue gas desulfurization and ED).

But by the year 2002, we concluded that fuel switching and ED alone would be insufficient to achieve proposed SO_2 reductions. Control technology retrofits then become necessary for some generation units. The most attractive technologies are limestone injection multistage burners (LIMB) and duct spray drying (DSD). Their SO_2 removal rates are only about 50%, but for some Ohio units, their estimated capital costs are much lower than for traditional scrubber technologies (PEI Associates, Inc. 1989). Heslin et al. (1989) list the generation units at which retrofits are assumed to take place.

Fuel Switching

Coal-fired units that have been identified as being feasible candidates for fuel switching (Ohio EPA 1986) are assumed to be able to switch to a generic imported low sulfur coal. We assume that any unit that fuel switches would burn low-sulfur coal costing $58/ton. This price was derived by examining the prevailing prices of low sulfur coal currently burned in Ohio and then adjusting for low sulfur premiums that Energy Ventures Analysis, Inc. (1987) projects will occur if an acid rain law is passed. To this expense was added the levelized cost of modifying electrostatic precipitators (Ohio EPA 1986).

BASE RESULTS (NO ADDITIONAL RATE FEEDBACK)

In this and the next section, two sets of results are presented for Ohio. In the first, we assume that there is no rate feedback in addition to that calculated by Centolella et al. (1988). In the second set, we investigate the possible impacts of additional rate feedback due to fuel substitution and cutbacks in demands for energy services.

Figure 1 summarizes the results of the analyses in which it is assumed that changes in electric rates affect power demands only to the extent estimated by Centolella et al. (1988). Six curves are shown, one pair for each of the target years (1994, 1998, 2002). Within each pair, one curve represents the impact of increasing degrees of ED (and, in 1998 and 2002, fuel switching), assuming no additional conservation effort. The other half of each pair indicates the effect of ED and, in the later years, fuel switching together with the "moderate effort" conservation program.

The lower right-hand point on each curve is the "least cost" dispatching point, in which generating unit merit orders are constructed based only on cost. Due to recent additions of new, cleaner capacity, emissions in 1994 are lower than historical levels, even in the absence of any additional measures to reduce emissions. ED can lower those emissions by an additional 500,000 or so tons at relatively little cost (averaging \$200/ton of SO_2 removed). No other combination of measures, either excluding or including conservation, is a significantly less expensive means of achieving the compliance target.

Figure 1 shows that the moderate effort conservation program does not appreciably lower the costs of achieving the compliance target in 1994, primarily because (1) marginal supply costs are low (averaging 2¢/kWh) and (2) programs have trimmed demand by only 2% by that point. The programs do not appear attractive until 1998 when desired emissions levels fall to 1.1 million tons/yr. The primary effect of conservation in that year is to lower emissions by about 60,000 - 80,000 tons per year (i.e., conservation shifts the cost-emissions curve to the left by that amount). However, because conservation investments will yield savings for many years, efforts made before 1994 may still more than pay for themselves later on.

ED is not quite so cheap or effective after 1994 because the cushion of extra generating capacity is eaten up by demand growth. However, it is still a cost-effective part of any emissions control strategy, yielding an inexpensive 300,000 to 400,000 tons/yr of reductions. In 1998, some fuel switching is required, but no emissions control retrofits. By the year 2002, retrofits of LIMB and DSD prove attractive, together with ED and fuel switching.

Figure 1 reveals that, unlike 1994, a strategy including conservation is less costly and leads to fewer emissions in 1998 and 2002 than otherwise identical strategies which exclude it. For a given level of emissions in 1998, a conservation program is about \$70,000,000 per year less costly (roughly 0.5 \$/MWh). (However, if the DSM programs perform disappointingly and achieve only a 0.3%/yr reduction in load growth, rather than 0.5%/yr, this cost advantage disappears.) By the year 2002, conservation programs definitely appear worthwhile, even if they do not achieve the full 0.5%/yr decrease in load growth. In particular, a moderate but successful conservation effort could lower the cost of reaching a 600,000 ton/yr target by about \$230,000,000/yr. A large part of the cost savings in the year 2002 case results from 1940 fewer MW of capacity being needed in the conservation case.

But the year 2002 curves confirm a preliminary conclusion of NAPAP (South 1990) that, in the long run, conservation merely replaces the relatively low emissions from new generating plants. This is shown by conservation's effect on the cost-emissions curve; the curve shifts downward, not leftward. Costs are lowered, but not emissions. Only if the amount of new generating capacity is held constant does conservation also lower emissions. Thus, conservation is desirable in the year 2002 not because it decreases emissions, but because it saves capacity expansion costs. (Note, this conclusion will change if conservation is used to retire older, dirtier plants more quickly, rather than to cancel new facilities.)

Under our assumptions, the aggressive conservation program (not shown in the figures), which achieves more savings at a higher price, is not more attractive than the moderate program in any year. It is considerably inferior in 1994 and 1998, because the incremental cost of the additional savings (compared to the moderate program) significantly exceeds the short run cost of generation. However, such a program will become attractive after the year 2002, because it will defer costly capacity additions.

In Heslin et al. (1989), we estimated the employment impacts of the conservation strategies using an economic input-output model of Ohio. Both backward linkages (stemming from inputs bought by Ohio utilities, including DSM programs, plant construction, and coal purchases) and forward linkages (resulting from the effects of electric rates upon industrial competitiveness and disposable income) were considered. In 1994 and 1998, strategies including conservation resulted in fewer net job losses in the state than strategies which excluded it. The difference in 1994 was about 3000 jobs, while in 1998 it was more significant (20,000 jobs, out of a total of several million for the state). In the year 2002, however, conservation resulted in slightly less job, mainly because of decreases in plant construction. However, we judge that difference to be too small to be significant.

We note, however, that from a national perspective, such job losses might be compensated for by gains in employment in other states. The inclusion of such secondary benefits in benefit-cost analyses is controversial.

There are other considerations that apply in evaluating conservation programs. One is that conservation may lower load growth uncertainty, which is valuable to an industry that must make capacity decisions a decade ahead of time (Hirst and Schweitzer 1989). Another is that conservation also would increase electric rates in the short run in Ohio (Centolella et al. 1988), more so than other strategies, although it would lower rates in the long run. This is because, in the short run, a utility's fixed costs must be spread over fewer sales, if average-cost based rates are greater than the marginal cost of providing power. These rate increases may motivate further decreases in electricity demand. This rate feedback is the subject of the next section.

THE EFFECT OF ENERGY CONSERVATION UNDER RATE FEEDBACK

Any strategy, including conservation, that lowers SO_2 and NO_x emissions will change electric rates. If prices increase, and price elasticity is nonzero, then the quantity of power demanded will be less than it would have been otherwise. In the less likely case that prices fall (or rate increases are smaller than they would have otherwise been), then quantity demanded will increase. In the case of energy conservation, we show below that these demand changes can be on the same order of magnitude as the original savings. As the original California "Standard Practice" (1983) notes, such changes should, in theory, be considered in assessing the net savings from conservation programs.

The questions we ask are: How can such changes be estimated? Are such changes good or bad? Our purpose is to provoke discussion and to illustrate the potential importance of rate feedback and how it can be evaluated.

Centolella et al.'s (1988) model considered the effect of changing prices upon conservation investments, but not fuel switching or the amount of energy services demanded. Fuel switching, especially in the form of "by-pass", is important in many service territories. Energy service effects are potentially significant, particularly in states, such as Ohio, in which industrial customers are vulnerable to foreign competition. The potential impact of rate feedback upon supply costs, emissions, and the net benefits of conservation and other emissions control programs in Ohio is estimated below.

Estimating Rate Feedback and Its Benefits

Several assumptions underlie the procedure used here to calculate the amount Q_{rf} (kWh/yr) by which electricity demands change because of rate feedback. [See Hobbs (1989) for details.] They are as follows:

- there is a single price of electricity P ($/kWh) which is adjusted so that the utility's revenues equal its costs;
- the base load growth forecast (1.5%/yr) is consistent with the price resulting from the right hand-most (least-cost) dispatch point in the nonconservation curves of Figure 1;
- if there is a conservation program, the amount of energy savings Q_s (kWh/yr) is a small portion (say, a few percent) of the total load;
- the price elasticity of demand E for electricity usage unaffected by the conservation program (i.e., so-called nonparticipating kWh) is positive, while the price elasticity for participants is negligible. In general, elasticities for nonparticipants are higher than for participants because nonparticipants' elasticities incorporate fuel substitution, conservation investment, and energy service elasticity effects, while participants'

elasticities only include the latter effect. E could be lessened by marketing programs which cushion the effect of higher rates upon the most elastic customers (P. Centolella, personal communication);

- Q_s and Q_{rf} have the same general load shape and load factor as the overall system demand; and
- the marginal cost of supply MC ($/kWh), averaged over the year, is constant over the changes in loads being considered.

Under these conditions, the increase in demand because of rate feedback due to conservation can be shown to equal (Hobbs 1989):

$$Q_{rf} = E*RIM/[P-E(P-MC)] \quad (1)$$

where RIM is the California "Standard Practice" (1987) Ratepayer Impact Measure in the year in question (modified to include emissions control costs):

$$RIM = MC*Q_s - P*Q_s - C_{dsm} - C_{em} \quad (2)$$

RIM is the net benefits to nonparticipants of a control program, equal to the avoided supply costs, minus revenue losses, conservation program costs C_{dsm} ($/yr), and the increase in emissions control costs C_{em} compared to a base case (the least cost dispatch solution without conservation).

The above expression for Q_{rf} is obtained by setting utility revenues equal to the utility's costs, and then solving for the Q_{rf} that maintains that equality. The expression is a first order approximation that assumes that Q_{rf} is a small fraction of the total demand. Its denominator accounts for the net revenue gains that occur because of the price-induced changes in demands Q_{rf}. For utility systems in which P exceeds MC, RIM will be negative, as will Q_{rf}.

How can the worth of Q_{rf} be evaluated? A place to start is with the cost and emissions changes. The change in supply costs resulting from rate feedback equals $MC*Q_{rf}$. If ME (tons/kWh) is the marginal emissions of SO_2, averaged over the year, then the change in emissions due to rate feedback will be $ME*Q_{rf}$. These changes are added to the supply costs and emissions of individual points on the emissions-cost curves discussed in the previous section to determine the supply costs and emissions net of rate feedback.

In sum, if an emissions control program increases rates, then rate feedback will drop emissions further, while simultaneously decreasing supply costs. This would (seemingly) enhance the attractiveness of the program.

But changes in supply costs and emissions give an incomplete picture of the effects of rate feedback. The change in demands Q_{rf} also has value. Assuming that the price that customers are willing to pay for electricity is a good measure of the value of that electricity (an assumption that is debated), then the change in the gross benefits nonparticipants receive from electricity is $P*Q_{rf}$. For instance, consider an industrial customer who would produce its own power using natural gas and thus "bypass" the utility if P exceeds its self-generation cost of $0.08/kWh. If, in the absence of the conservation program, P is just shy of $0.08/kWh, and implementation of the program would push price over that mark, then society loses $0.08 (in natural gas costs) for every kWh that this customer no longer buys because of the price increase.

[As P. Centolella (personal communication) points out, this assumes that the $0.08 is the true social cost of the natural gas alternative. However, because gas prices are also regulated, the social cost may actually be less or more than that amount.]

[Other assumptions are possible. In particular, engineering end-use models, such as Centolella et al.'s (1988), assume that price-induced demand changes result from adoption of conservation measures whose true cost is generally less than the price of electricity. Fuel switching and decreases in energy services are not considered, nor are intangible transaction ("hassle") costs. Consequently, their implied worth of Q_{rf} is much less than what we assume. Basically, we adopt a revealed preference paradigm in which we assume that if a price increase from, say, $0.08/kWh to $0.09/kWh causes a consumer to invest in conservation, then the cost to the consumer of that conservation must be at least $0.08/kWh. Whether the revealed preference or engineering approach is more accurate is a debate which cannot be resolved here. Our objective is to point out the implications of accepting the revealed preference framework.]

However, this loss in value is at least partially offset by the electricity supply cost changes of MC^*Q_{rf}, and any external cost changes MEx^*Q_{rf}, where MEx ($/kWh) is the marginal external cost of power production. Thus, under our assumptions, the net benefit to society of the change in electricity demands due to rate feedback is $(P\text{-}MC\text{-}MEx)Q_{rf}$. (A derivation of this expression, based on the maximization of consumer surplus, is given in Hobbs (1989). See also Hobbs and Nelson (1989) for a non-technical presentation, and Costello and Galen (1984) for a like analysis of the benefits of rate feedback.)

Therefore, the net increase in societal cost (including loss of value and external costs) resulting from rate feedback is not MC^*Q_{rf}, but rather $-(P\text{-}MC\text{-}Ex)Q_{rf}$. The change in SO_2 emissions is still ME^*Q_{rf}. These quantities are added to the points on the conservation curves of Figure 1 to determine the overall costs and emissions under conservation, net of rate feedback.

The above procedure does not consider the benefits of any "rebound" or "takeback" that might occur. Rebound/takeback is the decrease in energy savings that results if participants choose to take advantage of a conservation program to increase the level of energy services, rather than to lower energy bills. As Foley (1989) points out, rebound has value that should be included in net benefit calculations; a method for doing so is given in Hobbs (1989).

Results of Rate Feedback Analysis

We assume below that marginal external costs are zero. Marginal emissions and costs have been estimated for each solution by changing the mean load by a small amount and computing the resulting changes in emissions and costs. A mean price of $60/MWh (in 1987 dollars) is assumed, along with a mean price elasticity of 0.25. That value is lower than ones estimated by Ohio utilities, but is used here because we are analyzing only the portion of rate feedback that results from fuel switching and decreases in energy services.

Because of the many assumptions we make, the results below should be interpreted as indications of the general direction and magnitude of rate feedback's effects. The impacts will be greater, for instance, if larger prices or elasticities are used. On the other hand, impacts are lower if DSM programs can be designed so that participants shoulder most of the costs. Further, feedback's benefits would increase, if we assume higher external costs.

Figure 2 shows the effect of rate feedback in 1994. Consider first the no-conservation case (Figure 2a). By definition, there is no rate feedback for the least cost dispatching point in Figure 2a, since its price is assumed to be consistent with the load forecast. But as the degree of emissions control increases, rates go up, which dampens demand, emissions, and supply costs. This yields the lower curve, which shows tradeoffs between supply costs and emissions. However, if the loss of value associated with Q_{rf} is added to the supply cost, assuming that price is a good indicator of value, then the uppermost curve results. This reveals that price feedback's net effect is negative; the cost and emissions savings it yields are more than offset by a loss of value. This happens because price (at $60/MWh) is much higher than the marginal cost in 1994 (less than $25/MWh) plus the worth of reduced emissions.

Figure 2b displays rate feedback's effects in the 1994 conservation case. The impact here is several times larger than in Figure 2a, primarily because of revenue losses due to conservation. These losses must be made up by other ratepayers, yielding higher rates and lower demands. Ignoring value impacts, rate feedback significantly lowers supply costs and emissions (the lower curve in Figure 2b). This is because the decrease in demands due to rate feedback Q_{rf} is one-third as large as the energy savings directly attributable to the conservation program. But if the loss of value is added in (approximately $50,000,000/yr), then the upper curve results. As in the nonconservation case, this shows that rate feedback's overall impact is negative.

The effect of rate feedback is negative even in 2002, when marginal costs are significantly higher (approximately $45/MWh). This is in part because there still remains a gap between price and marginal cost.

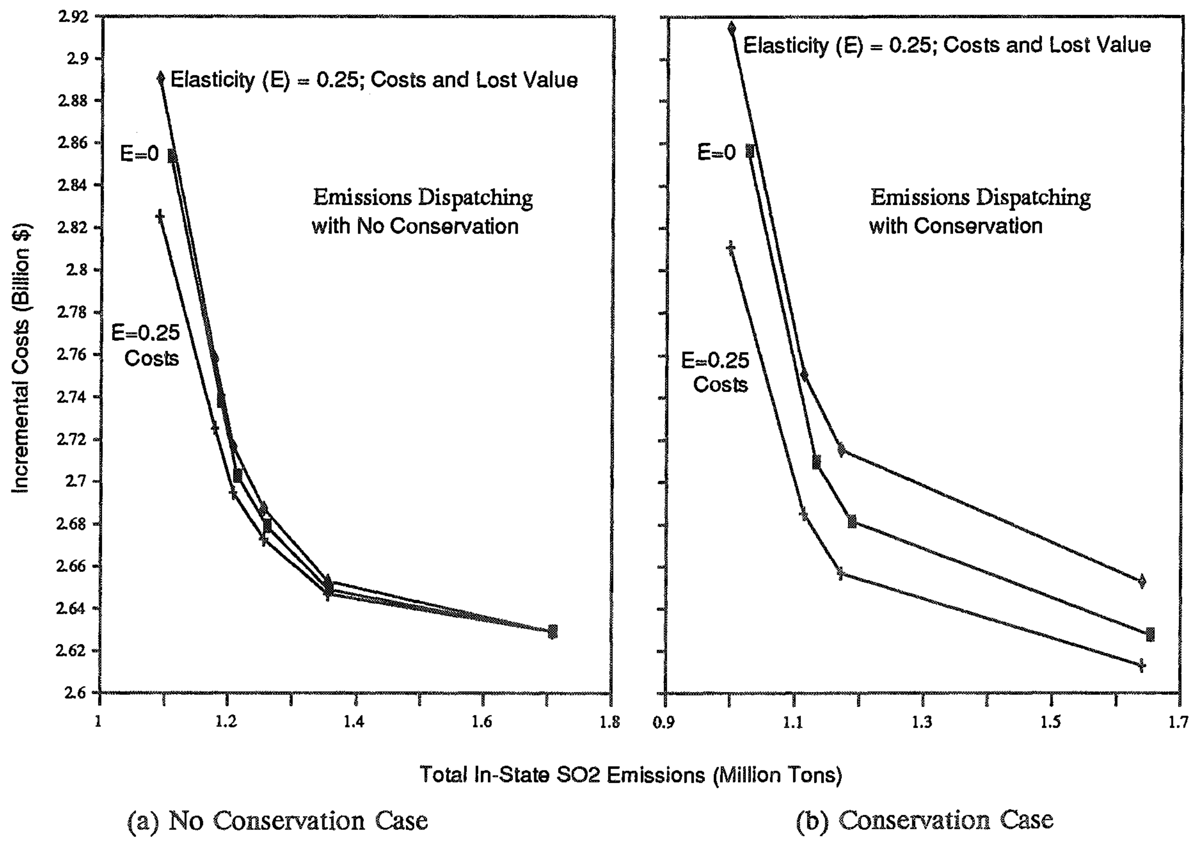

Figure 2. Effects of Price Feedback on Cost-Emission Tradeoff Curves, 1994

Only if marginal capacity costs are higher than we assumed, or if external costs of power production are $20/MWh or more, will rate feedback's impacts be neutral or positive.

Figure 3 shows the tradeoff curves between costs (including loss of value) and emissions for all three target years. In terms of their general form, they are similar to the curves in Figure 1: conservation is attractive in 1998 and 2002, but not in 1994. However, there are some important differences between the two figures. First, the conservation cases are penalized by about $30,000,000/yr more than the non-conservation solutions in 1994 and 1998. For instance, the 1998 conservation and non-conservation curves are about $60,000,000 apart in the absence of rate feedback, but are only $30,000,000 apart with feedback. Second, the overall cost (compared to the base, least cost dispatching solution) of achieving the compliance targets has increased in 1994 and 1998. This increase is basically the loss of value, net of marginal supply and emissions control costs, resulting from price feedback.

Figure 3 shows three curves for the year 2002. The two conservation curves result from different assumptions concerning the marginal cost of supply. Conservation is most beneficial if it defers capacity additions (the lower of the three curves for that year). In that case, marginal costs are high and conservation yields important cost savings whose benefits more than offset any losses in value. However, few emissions reductions result, because the capacity that is deferred is relatively nonpolluting. But if conservation is instead assumed to only lower operating levels of a fixed set of generation plants, the middle curve for that year results. Emissions reductions occur in that case, but total costs are higher because of the value losses that result from a relatively large gap between price and short run marginal costs.

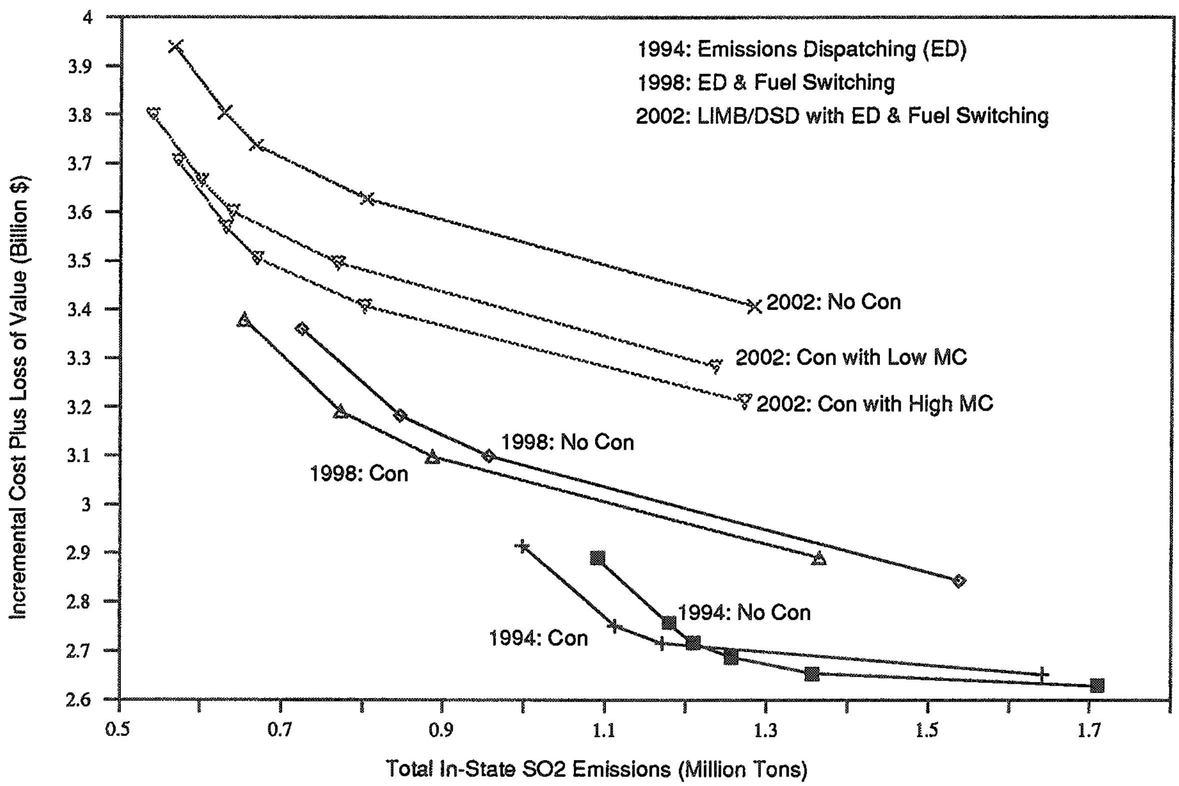

Figure 3. Incremental Cost, Plus Loss of Value Due to Price Feedback, of Reducing SO_2 Emissions for Ohio: 1994, 1998, 2002

CONCLUSIONS

Our use of a probabilistic production costing model, together with a detailed data base of Ohio's generation plants and emissions control options, has made it possible to rigorously analyze the cost and SO_2 emissions benefits of conservation programs in Ohio. On an annualized cost basis, the moderate program appears justified in 1998 and 2002, but not in 1994. However, from a present worth standpoint, it is likely that a moderate program started in the early 1990s can be justified, because its later benefits would compensate for costs incurred earlier. A second version of MODES, now nearing completion, will have the capability of automatically evaluating the tradeoffs involved in multiyear programs.

However, we show that this conclusion can be changed if loss of customer value due to rate feedback is considered. A procedure is presented for estimating rate feedback and its benefits and costs, given information on price elasticities, marginal costs, and prices. Our analysis of rate feedback in Ohio is a simple one because, for example, we treat all customers as a single customer class. Nonetheless, this study is an improvement over the many analyses which have given no recognition to the potential importance of rate feedback. Future research should be directed at refining the computational procedures and inputs that are needed to evaluate priced-induced changes in power demands.

ACKNOWLEDGMENTS

Funding was provided by the Ameritech Corporation, through the Case Western Reserve University Center for Regional Economic Issues, the Ohio Air Quality Development Authority, and the National Science Foundation, grant ECE-8552524. Comments by reviewers and especially P. Centolella lead to significant improvements in the paper.

REFERENCES

Baleriaux, H., E. Jamoulle, and Fr. Linard de Guertechin. 1967. "Establishment of a mathematical model simulating operation of thermal electricity-generating units combined with pumped storage plants." *Revue E* (Belgium) 5(7).

California Public Utilities Commission and California Energy Commission. 1983. *Standard Practice for Cost-Benefit Analysis of Conservation and Load-Management Programs*. San Francisco, California.

California Public Utilities Commission and California Energy Commission. 1987. *Standard Practice Manual, Economic Analysis of Demand-Side Management Programs*. San Francisco, California.

Centolella, P. A., et al. 1989. *Clearing The Air: Using Energy Conservation to Reduce Acid Rain Compliance Costs in Ohio*. Ohio Office of the Consumers' Counsel, Columbus, Ohio.

Costello, K. W., and P. S. Galen. 1984. *A Proposed Methodology for Evaluating Utility Conservation Programs*. Docket Nos. 83-0034 to 83-0043. Illinois Commerce Commission, Policy Analysis and Research Division, Springfield, Illinois.

Delson, J. K. 1974. "Controlled Emissions Dispatch." *IEEE Trans on Power App. Sys.* 93: 1359-1366.

Electric Power Research Institute. 1986. *TAG - Technical Assessment Guide, Volume 1: Electricity Supply*. EPRI P-4463-SR, Special Report, Palo Alto, California.

Energy Ventures Analysis, Inc. 1987. *Coal Markets and Utilities' Compliance Decisions*. EPRI P-5444, Electric Power Research Institute, Palo Alto, California.

Foley, T. 1989. "The 'Most-Value' Method of Setting Maximum DSM Payments is Wrong." *Electricity Journal* 2(10): 40-46.

Gellings, C. W., and J. H. Chamberlin. 1986. *Demand-Side Management: Concepts and Methods*. Fairmont Press.

Heslin, J. S., and B. F. Hobbs. 1989. "A Multiobjective Production Costing Model for Analyzing Emissions Dispatching and Fuel Switching." *IEEE Trans. on Power Sys.* 4(3): 836-843.

Heslin, J. S., B. F. Hobbs, and K. Sullenberger. 1989. *Alternative SO_2 Emission Reduction Strategies for Ohio: Effectiveness, Costs, and Regional Economic Impacts*. Center for Regional Economic Issues, Case Western Reserve University, Cleveland, Ohio.

Hirst, E., and M. Schweitzer. 1989. "Uncertainty: A Critical Element of Integrated Resource Planning." *Electricity Journal* 2(6): 16-27.

Hobbs, B. F., and S. K. Nelson. 1989. "Assessing Conservation Payments: Least- Cost, Least-Rates, or Most-Value?", *Electricity Journal* 2(6): 28-39.

Hobbs, B. F. 1989. *The 'Most Value' Criterion: Economic Evaluation of Utility Demand-Side Measures Considering Customer Value*. Report, Department of Systems Engineering, Case Western Reserve University, Cleveland, Ohio.

Nixon, L., and C. Neme. 1989. *An Efficient Approach To Reducing Acid Rain: The Environmental Benefits of Energy Conservation*. Center for Clean Air Policy, Washington, D.C.

Ohio Environmental Protection Agency. 1986. *Analysis of the Cost of H.R. 4567 to Electric Utilities in Ohio*. Division of Air Pollution Control, Columbus, Ohio.

PEI Associates, Inc. 1989. *Evaluation of Acid Rain Controls For Ohio Electric Utility Coal-Fired Power Plants*. Cincinnati, Ohio, Prepared for the Ohio Coal Development Office, Columbus, Ohio.

Sinha, J., and A. Calafiore. 1990. "Acid Rain Legislation and Utility Compliance Tactics." Proceedings of the Conference on *Innovations in Pricing and Planning*. Electric Power Research Institute, Palo Alto, California.

South, D. W., et al. 1990. *Technologies and Other Measures for Controlling Emissions: Performance, Costs, and Applicability*. National Acid Precipitation Assessment Program Report 25, Draft, Argonne National Laboratory, Argonne, Illinois.

Stone and Webster, Inc. 1986. *Feasibility Investigation of the Benefits and Constraints of a Power Pooling System Among the Ohio Regulated Electric Companies, Segment II Report*. Denver, Colorado, submitted to the Public Utilities Commission of Ohio.

Stremel, J. P., R. T. Jenkins, R. A. Babb, et al. 1980. "Production Costing Using the Cumulant Method of Representing the Equivalent Load Curve." *IEEE Trans. on PAS* 99:1947-1954.

Talukdar, S. N., and F. F. Wu. 1981. "Computer-Aided Dispatch for Electric Power Systems." *Proc. of the IEEE* 69: 1212.

U.S. Department of Energy. 1986. *Cost and Quality of Fuels for Electric Utility Plants, 1986.* DOE/EIA-0191(86), Washington, D.C.

White, D. C. 1981. *Strategic Planning for Electric Energy in the 1980's for New York City and Westchester County*, Report MIT-EL-81-008, MIT Energy Laboratory, Cambridge, Massachusetts.

Yamayee, Z. A. 1985. "Production Simulation for Power System Studies." *IEEE Trans. Power App. Sys.* 104: 3376-3381.

Yokoyama, R., et al. 1988. "Multiobjective Optimal Generation Dispatch Based on Probability Security Criteria." *IEEE Trans. on Power Sys.* 3(1): 317-322.