Cost and Performance Comparison of DSM Measures and Supply Changes to Reduce Utility Carbon Emissions

Joel N. Swisher, Lund University
Karl F. Johnson, Electric Power Research Institute

This paper presents the results of an empirical case study analysis of the costs to a utility of reducing its emissions of carbon dioxide (CO_2). The utility is a composite of the electric supply system in the south-central region of the U.S., scaled down to the size of a 20 GW utility company. The data are taken from the EPRI Regional Systems database, and utility production cost analysis for the years 1990-2000 was performed using EPRI's MIDAS model. Our approach to analyzing the effects of demand-side management (DSM) is derived from the cost of conserved energy concept, applied to emission reduction costs. DSM costs are combined with the utility's costs and the level of incremental emission reductions to determine the marginal costs, from the utility's viewpoint, of DSM as an emission reduction strategy.

Through investments in energy efficiency improvements, CO_2 emissions could be reduced after 5 years by 17 percent, compared to the utility existing plan. Savings of 8 percent could be achieved at negative cost, due to savings in fuel and operating costs that exceed the marginal cost of the least expensive efficiency measures, especially in residential and commercial lighting and air-conditioning. In later years, emission reductions from end-use efficiency continue accumulating at a slower rate. At a marginal cost of about $90/ton, the utility can begin to reduce CO_2 emissions by changing their dispatch order to burn more natural gas and less coal in existing plants. A higher-cost option would be to replace some existing and planned fossil fuel capacity with either solar or nuclear power, but because end-use efficiency can obviate the need for new fossil fuel capacity in the near-term, neither appears to be cost-effective before 2000.

Introduction

This paper presents the results of an analysis of utility costs of reducing carbon dioxide (CO_2) emissions. The utility is a composite of the electric supply system in the south-central region of the U.S., scaled down to the size of a 20 GW utility company. The data are taken from the Electric Power Research Institute (EPRI) Regional Systems (ERS) database, which provides demand, supply and financial data for six such composite utility systems in different regions of the U.S. (EPRI, 1989). Costs and technical performance data for systems not included in the ERS database were taken from a variety of current literature sources (CEC, 1989; NWPPC, 1986; Hunn, et al. 1986; Geller, et al. 1987; EPRI, 1988; Miller, et al. 1989). Utility production cost analysis was performed using EPRI's MIDAS model (Farber, et al. 1988).

The expansion plan given in the ERS database is used as the base case for the analysis, and we assume that the plan takes into account existing Federal legislation regarding, for example, energy performance standards. Because the Federal Appliance Energy Efficiency Standards have been enacted since the ERS data were collected, the base case forecast is corrected to include the reductions in load growth caused by the standards. The analysis considers short-term options implemented between 1990 and 1999, before new technologies, such as advanced solar or nuclear technologies, are likely to have a great impact. Analysis over this time horizon requires simulation of the utility's operation from 1989-2004.

To determine the emission-reduction cost function, the base-case expansion plan is modified to include various combinations of emission reduction measures, including energy end-use efficiency improvements. Then, MIDAS is used to simulate the utility operation and expansion in order to determine utility costs and fuel use. These results are used to determine the average cost of each emission reduction measure. Finally, the various measures are ranked and the incremental cost is calculated for each measure, as explained in more detail below. Note that costs are calculated from the utility's viewpoint, not that of its customers or society.

Demand-Side Management

The emission-reduction measures considered include utility fuel switching, demand-side management (DSM) measures, and solar or nuclear capacity additions. One option is for the utility to reduce its output, and thus its emissions, through direct investments in energy end-use efficiency improvements.

Methods

The results of this analysis are the incremental unit costs (IUC) of emission reductions as a function of the percent emission reduction, compared to the utility's base case expansion plan. The IUC is the difference between the annualized value (using the utility's weighted average cost of capital as the discount rate) of the incremental capital cost of the conservation investment and the incremental annual savings in utility costs (including annualized construction costs), divided by the incremental annual mission reduction (in tons of carbon per year) achieved at that cost level.

$$\textit{Incremental Unit Cost (IUC)} = \Delta\,(CRF\,C_{cap} - S_{sup}) / \Delta\,R \quad (1)$$

[$/*ton*]

where:
CRF = Capital Recovery Factor (depends on discount rate and amortization time)
C_{cap} = Capital cost of measure (including administrative costs)
S_{sup} = Annual savings in operating costs and annualized construction costs
R = Emission reduction

This approach is derived from the cost of conserved energy concept and applied to emission reduction costs (Meier, et al. 1983).

$$\textit{Cost of Conserved Energy (CCE)} = (CRF\,C_{cap} + C_{op}) / ES \quad (2)$$

[$*MWh*]

where:
CRF = Capital Recovery Factor (depends on discount rate and amortization time)
C_{cap} = Capital cost of measure
C_{op} = Operating cost of the measure only
ES = Annual energy savings

The CCE is usually compared to electricity prices to determine cost-effectiveness from the consumer's viewpoint. Here, DSM costs are combined with the utility's costs and the level of incremental emission reductions to determine the cost, from the utility's viewpoint, of DSM as an emission reduction strategy. This refinement is important in evaluating the cost of various levels of DSM implementation, because the utility's cost savings S_{sup} may not be constant. As DSM is implemented to a greater degree, it obviates the need for some amount of marginal capacity (the utility's most expensive resource), helping to make DSM attractive to the utility.

Once the most expensive resources have been removed or deferred, however, the cost savings from additional measures are reduced, thus increasing the incremental cost of higher levels of emission reduction. This effect is shown by some of our results in Figure 1, which compares the marginal costs of various levels of energy savings (CCE) through DSM with the avoided utility costs for the corresponding levels of energy savings. After the most expensive supplies have been removed, the marginal CCE increases, and the marginal avoided cost decreases. By 1998, however, high levels of energy savings make it possible to delay construction of new coal-fired generating plants, thus increasing the marginal avoided costs at these higher level of savings.

This study uses an engineering approach to evaluate the range of load impacts and marginal costs of DSM options, in order to find the least-cost strategy. Our method first simulates the performance of a range of DSM measures in a group of sample buildings, and normalizes the results based on the percentage load savings (or increase) in the hourly loads. These dimensionless percentages can then be applied to other buildings in the size, age, climate and occupancy class of the simulated sample. When modified to account for market penetration limitations and interactions between different DSM measures, these percentage load savings give a technically valid estimate of the load impact for the entire class of buildings.

There are many procedures and programs through which utilities can manage their loads. They range from relatively passive informational programs, to incentive programs that try to stimulate certain customer investments, to active participation and direct investment in improving the customers' end-use efficiency or load factor. In this analysis, we assume that DSM measures are implemented through direct utility investment and that the cost estimates include the administrative costs necessary to implement such programs.

Expenditures include the incremental cost of more efficient new or replacement energy end-use equipment, or the full cost of conservation measures that are installed as retrofits. Administrative costs of 20 percent for

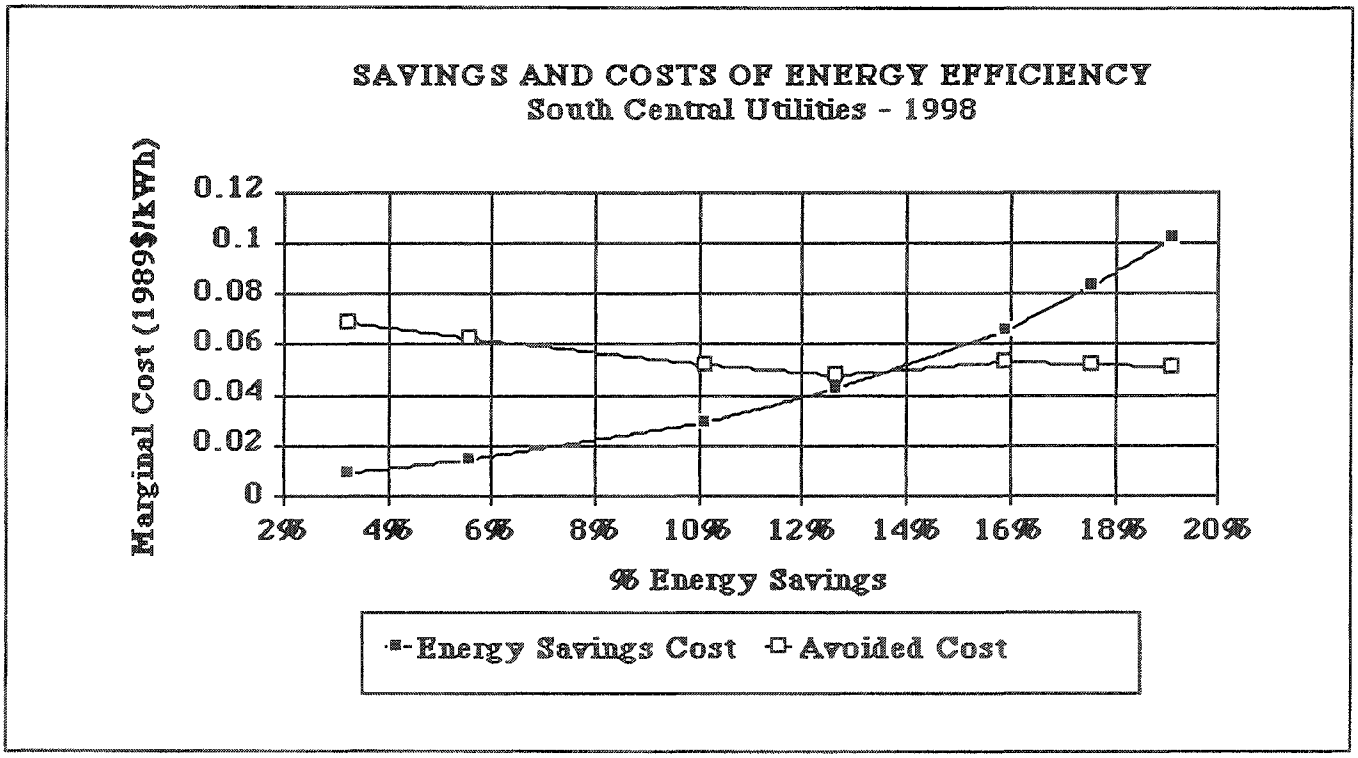

Figure 1. Marginal Costs of Energy Efficiency and Avoided Utility Costs

residential and industrial and 30 percent for commercial end-uses are added to all costs to account for program operation and losses due to unsuccessful measures (Berry, 1989). Energy or demand savings from DSM measures are evaluated over the life of the measure. Most of the relevant technologies have minimum ten-year lifetimes.

Many studies of utility DSM potential consider only the technical potential of certain measures, ignoring their market penetration limitations, which include physical, financial and customer acceptance constraints. These studies also ignore the interactions between measures themselves. This analysis explicitly considers both market penetration and interactions, and includes a detailed accounting of the stocks and flows of new and existing buildings and the measures installed in them. For each end-use, maximum penetration rates of energy efficiency technologies are taken from the Northwest Power Planning Council (NWPPC, 1986).

The percentage energy (or demand) saved by a given measure (ES%j) depends on the marginal cost threshold for energy-saving measures (given by CCEj) and the interactions with other measures (Xj). For DSM measures that affect heating and cooling loads, building energy simulations are used to estimate energy and demand savings, to prioritize measures according to cost-effectiveness, and to identify the interactions between measures. Interactions between end-use measures can either increase energy and peak savings, such as cooling savings resulting from lighting efficiency gains, or compromise savings, such as when equipment efficiency reduces the energy demand that can also be reduced by improvements to the building shell. For example, measures that reduce shell heat flow by 50 percent and equipment improvements that reduce air-conditioning demand by 50 percent can together save about 75, not 100 percent of the base demand.

$$L2j = L1j \{1 - ES\%j(CCEj)\ [1 - Xj]\} \quad [MWh/customer] \tag{3}$$

where:

L1j	= Base energy demand for end-use affected by measure j
L2j	= Energy demand with measure j
CCEj	= Incremental cost for implementing measure j
ES%j(CCEj)	= Percent energy saved by measure j at marginal cost CCEj
Xj	= Fraction of measure j savings negated by interactions (can be negative)

The flows of customers' buildings and equipment, and the corresponding end-uses, are illustrated in Figure 2. Efficient new and replacement equipment is assumed installed up to the maximum penetration rate (PNji), and all retrofit measures have a similar maximum rate at which they approach the full penetration (PEji), corrected for the annual turnover in building and equipment stock (Tj). In each year during the planning cycle, existing buildings remain and new buildings appear. Both provide DSM opportunities, either retrofits or new installations, some of which are captured and some missed. New buildings that do not receive DSM measures become candidates for retrofits. Some equipment in existing buildings turns over and is replaced, offering additional opportunities. Also, some existing buildings remain into the following year.

For new buildings and equipment replacements, the energy and demand savings depend on the penetration rate, growth in the end-use sector (Gji) and the rate of turnover of old stock (Tj).

$$ESNji = [L1j - L2j]\ PNji\ [Gji + Tj\ Eji] \quad [MWh] \tag{4}$$

where:

ESNji = Savings from measure j in new buildings and equipment replacements in year i

PNji = Maximum penetration rate for end-use measure j in new buildings in year i

Gji = Growth in number of customers for end-use affected by measure j in year i

Tj = Turnover rate of equipment for end-use affected by measure j

Eji = Number of existing customers in year i not yet retrofitted for end-use measure j

For retrofit measures installed in existing buildings, the savings depend on the penetration rates and the remaining stock of existing buildings in which retrofit measures have not yet been installed.

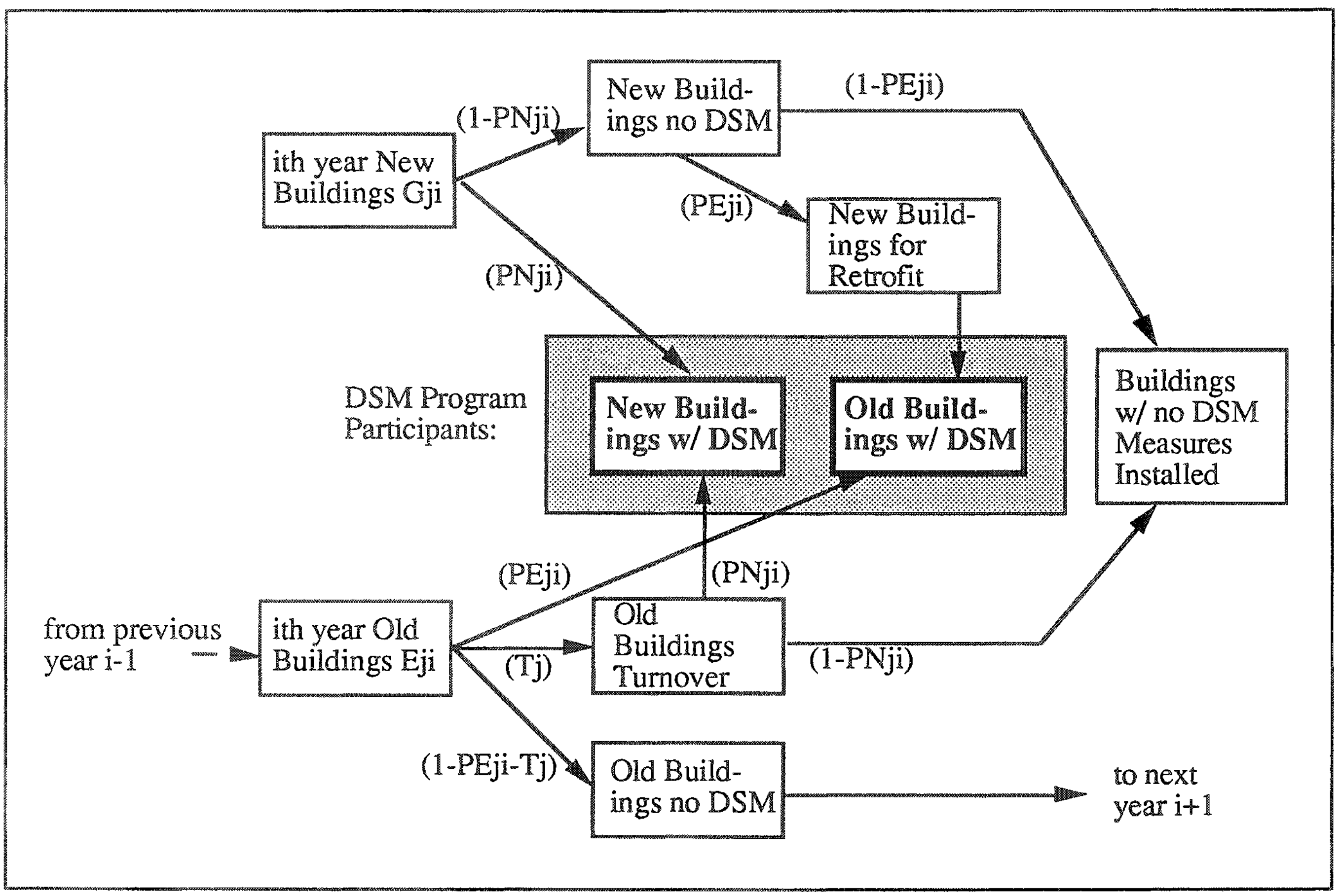

Figure 2. DSM Load Impacts: Tracing Building and Equipment Stocks and Flows

$$ESNji = [L1j - L2j]\ PEji\ [Eji + (1 - PNji)\ Gji] \quad (5)$$

[MWh]

where:

ESEji = Savings from retrofit measure j in year i

PEji = Maximum penetration rate for end-use affected by retrofit measure j in year i

Eji+1 = Eji [1- PEji - Tj]

$\Sigma(i)$ PEji $\leq$ 1 for all j

Results

Because of the slow turnover of end-use equipment, and the gradual penetration of retrofit measures, the maximum energy and emissions savings from energy efficiency cannot be achieved immediately; they gradually increase each year. At the end of the assumed five-year phase-in time for retrofit measures (1994), CO_2 emissions could be reduced through end-use efficiency by about 17 percent, compared to the base case given by the utility's expansion plan. About 13 percent savings could be achieved at lower cost than through other measures, and the first 8 percent can be achieved at negative cost (Swisher, 1991). The latter result is due to savings in utility fuel and operating costs that exceed the marginal cost of the least expensive efficiency measures. In later years, the emission reductions from end-use efficiency continue to accumulate. By 1998, 18 percent savings could be achieved at lower cost than through other measures; and the first 12 percent can be achieved at negative cost (see Figure 3).

Figure 3 gives the percent emission reduction, compared to the utility's base case expansion plan, as a function of the incremental unit cost (IUC) for that level of reduction. The corresponding costs curves for absolute tons of emissions are given in Figure 4, which shows that relatively low-cost emission reductions (less than \$50/ton-carbon) are sufficient to keep absolute emissions in 1998 below the 1989 level (17 million tons). The increasing

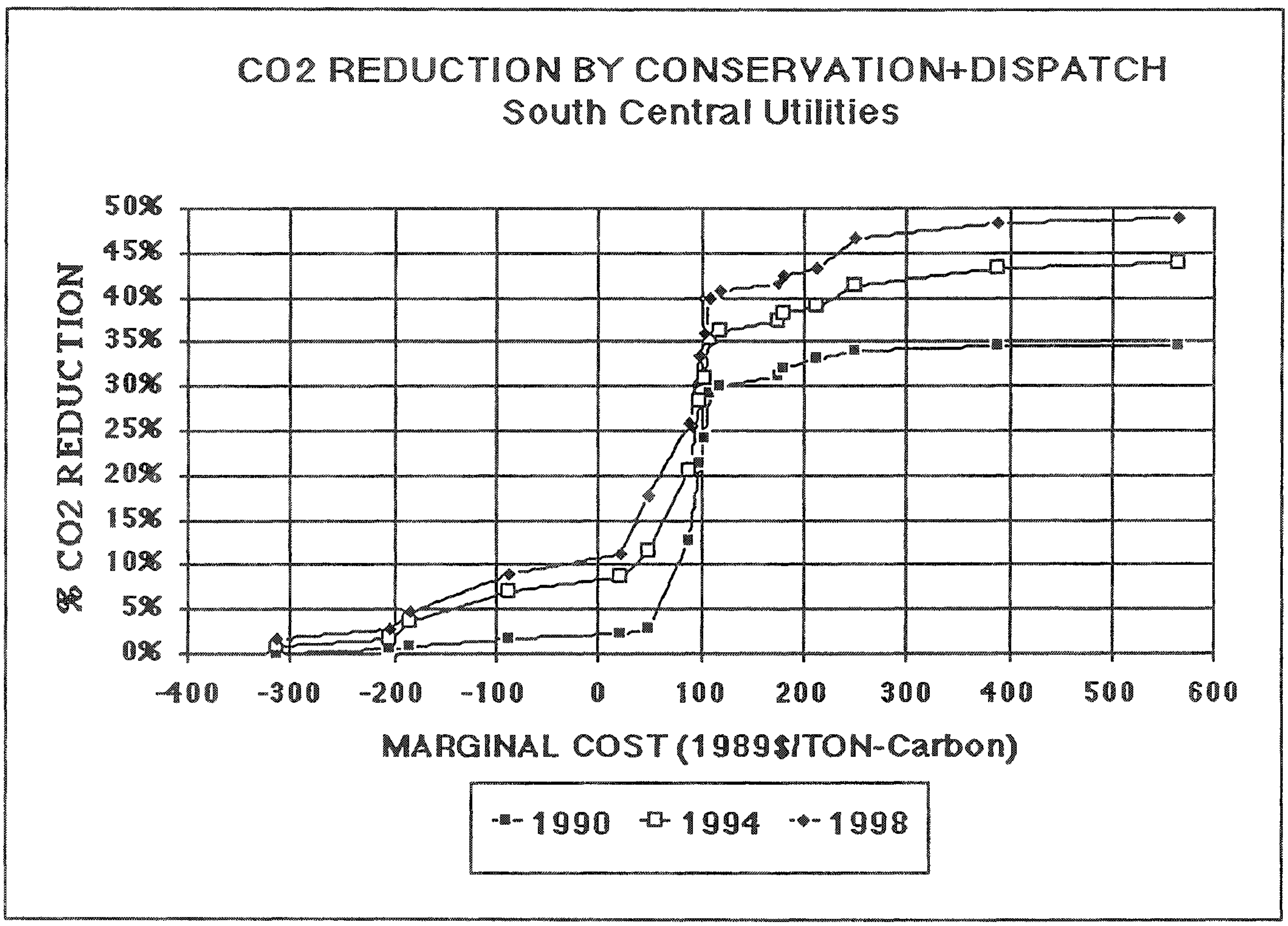

Figure 3. Carbon Emission Reduction (%) Cost Curves for Supply and DSM Measures

penetration of DSM measures increases the percentage emission savings over time. After 1994, however, absolute emissions increase at all marginal cost levels, although the relatively high-cost emission reductions decrease 1998 emissions to about one-third below the 1989 level.

The electric end-uses with the greatest potential savings in this analysis are commercial lighting and air-conditioning, which offer significant cost-effective savings in both energy consumption and peak demands, and residential air-conditioning, where savings can best be achieved by improved envelope design in new buildings and more efficient hardware in existing buildings. Other significant savings potential is found in industrial motors, commercial and residential refrigeration, and residential lighting, although the latter does not offer significant peak demand reductions.

As shown earlier, the resulting savings in energy and emissions depend on the marginal cost threshold, the fraction that can be saved at that cost, and the total consumption in the end-use category. For example, at the lowest CCE threshold ($0.01/kWh), only the least expensive commercial lighting and residential envelope improvements, in new buildings, are cost-effective. No retrofit measures qualify. A CCE threshold of $0.03/kWh justifies additional lighting measures in new and existing commercial and industrial buildings, some commercial cooling measures, heat pumps in new residences, and residential water heating measures.

Below a threshold of $0.07/kWh, which corresponds to about $80/ton-carbon reductions in carbon emissions, end-use measures provide emission reductions more cheaply than most any supply-side measure. However, measures that cost more than this exceed the marginal cost of a great deal of the fuel-switching potential and are therefore relatively unattractive. Measures that could be implemented at this cost threshold, in addition to those mentioned above, include many commercial lighting, cooling, refrigeration and water heating technologies; some industrial motor improvements; and efficient residential lights, refrigerators and air-conditioners.

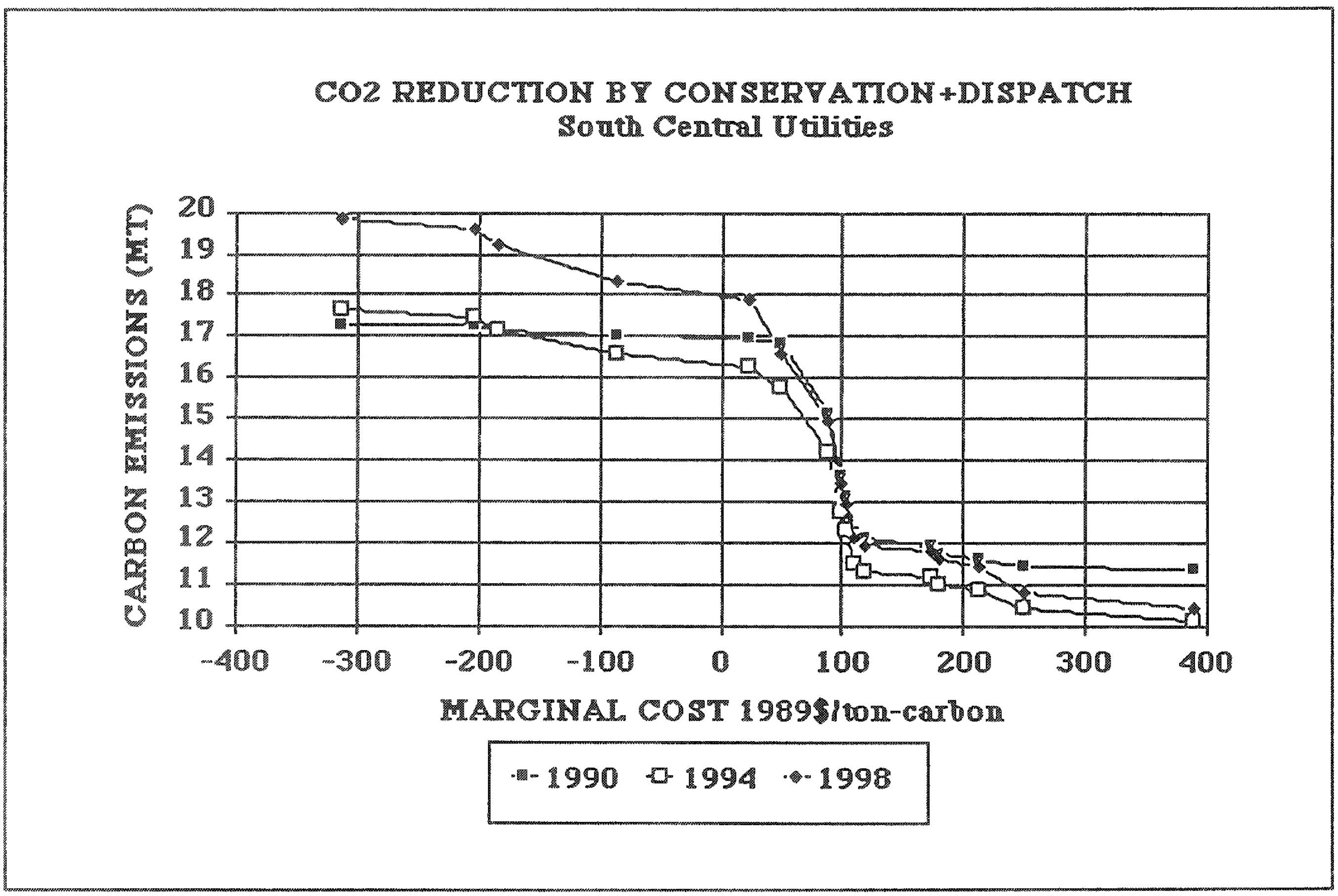

Figure 4. Carbon Emission Reduction (tons) Cost Curves for Supply and DSM Measures

Measures analyzed here that are not cost-effective at this level include heat pumps and shell improvements in existing residential buildings, and some industrial motor improvements and commercial lighting retrofits.

For this threshold, the percentage energy savings in 1994 (five years after programs begin) for each sector and end-use category is given in Table 1, which also shows the percentage of the total consumption and peak demand savings contributed by each end-use and sector. The total energy savings amount to 12 percent of the base case forecast, and these savings provide a 13 percent reduction in carbon emissions (Swisher, 1991). In later years, the total quantity of energy savings and emission reductions from efficiency improvements in each end-use continue to accumulate, as new buildings are built, old equipment turns over and the penetration of retrofits progresses.

Most of the savings are achieved in the commercial and residential sectors. Industrial energy savings are the least, only 3 percent of the base case, while commercial energy savings amount to more than one-quarter of the base case. The differences in sectoral penetration of energy-efficient technologies stem from the assumption that the base case forecast already includes conservation measures that would be accomplished without direct utility involvement. The industrial sector savings are less, because industry is better able to respond to cost-effective conservation opportunities and energy price increases, even without utility incentives. This behavior is evidenced by the relatively large price elasticities of demand reported for the industrial sector (Bohi, 1982).

Energy consuming (and saving) behavior in the other sectors is less elastic and is constrained by many institutional and market barriers. In the residential sector, however, these barriers are partially overcome by energy performance standards for buildings and appliances. In particular, the newly enacted Federal Appliance Efficiency Standards capture a significant share of the potential near-term residential savings. This is not to say that energy is not saved in home appliances compared to previous practice, only that these savings are implicit in the base case forecast and are not affected by a utility program to reduce carbon emissions through further end-use measures.

Table 1. Relative 1994 Energy and Peak Demand Savings by End-Use (at Marginal CCE Threshold of $0.07/kWh)

	% End-Use Savings	% of Total Savings		
		Consumption	Peak	Peak (with Load Management)
Residential Lighting	30	9	0	
Residential Other	10	13	13	
Residential Cooling	12	10	27	
Residential Heating	8	4	0	
Commercial Lighting	35	26	25	
Commercial HVAC	25	20	29	
Commercial Other	20	10	2	
Industrial Lighting	30	5	3	
Industrial Other	2	3	1	
Total	12	100	100	100
Residential	13	36	40	46
Commercial	27	56	56	51
Industrial	3	8	4	3

Commercial energy efficiency is less affected by Federal standards, particularly in the important lighting category. There are many mandatory and voluntary standards dealing with the safety and performance of energy-using equipment, but standards governing energy consumption are weaker in most areas. Furthermore, the large fraction of commercial space that is built on speculation and occupied by tenants creates a situation where there are few incentives to invest in energy-efficient buildings and equipment, no matter how cost-effective. Because of the relative lack of either market or mandatory incentives for end-use efficiency measures, the untapped potential appears largest in the commercial sector.

Commercial end-use technologies also provide the majority of peak demand reductions. Because commercial lighting and cooling contribute directly to summer peak loads, efficiency measures in these end-uses are especially effective at reducing peak demand. Residential cooling also presents considerable potential for peak load reduction. Further peak load reductions can be achieved through load management programs such as commercial thermal energy storage and direct load control of residential air-conditioners. These programs are not intended to reduce carbon emissions directly, because they do not necessarily decrease, and may increase total consumption.

In fact, these load management programs do result in modest reductions in emissions, due to the use of more efficient generation plants off-peak in place of the less efficient plants used during peak demand hours. Although essentially neutral in terms of total emissions, the important effect of load management programs is that they save money by reducing the use of high variable-cost peaking plants and delaying the need for new plants and transmission expansion. Thus, load management reduces utility costs, making the entire program of emission reductions through DSM more cost-effective.

Supply-Side Options

Although most of the feasible efficiency savings could be achieved at an average cost of less than $100/ton-carbon, the most economically efficient strategy is to implement the measures with the lowest marginal cost. At a marginal cost of about $90/ton, the utility can begin to significantly reduce CO_2 emissions by changing their dispatch order to burn more natural gas and less coal in their existing plants. The net cost of this measure varies with changes in heat rate (thermal efficiency) and variable operating costs, but the major difference is the higher fuel cost for natural gas. Thus, most of the feasible savings from fuel-switching have a marginal cost of $90 to $120 per ton-carbon (Swisher, 1991). Together with the less expensive efficiency measures, which provide the first 8 percent savings at negative cost, fuel-switching makes it possible to reduce emissions after five years by 35 percent at a marginal cost of $100/ton, or 40 percent at $200/ton (See Figure 3).

Beyond $200/ton-carbon incremental cost, additional emission reductions can be achieved through further end-use efficiency measures. Indeed, the total potential may be greater than shown here because such expensive measures are not widely reported when they are not considered cost-effective. However, another relatively high-cost option would be to replace some existing and planned fossil fuel capacity with non-combustion resources, either solar or nuclear, or perhaps with fossil fuel plants fitted with CO_2 emission control.

The base case expansion plan includes two nuclear stations already on-line and one under construction. Of course, because of the low variable costs and negligible carbon emissions of nuclear power, these plants are dispatched as base load and operate as much as possible in all emission reduction scenarios. Some regions have significant hydro, geothermal, wind and solar resources that can yet be exploited. The most promising renewable resources in the south-central region appear to be solar in West Texas and perhaps wind in Oklahoma. We considered two non-combustion options, nuclear power and line-focus solar thermal power in West Texas. Nuclear power does not appear to have significant near-term potential for reducing CO_2 emissions. Assuming a minimum construction lead time, for a 1300 MW plant, of six years from the completion of the plant already under construction, no additional nuclear capacity could be operational before 1999, too late to significantly figure in our results.

The solar thermal plants have a shorter lead time, but it would take some time before the industry's building capacity could far surpass the current level of about 80 MW per year. Assuming a maximum construction rate in Texas of 160 MW per year, solar would not likely make a significant impact on emissions until at least 1997. Cost and performance data (corrected for climate) were taken from California Energy Commission projections for line-focus plants built for utility ownership, at larger scale than the present plants and with no on-site gas-fired backup (CEC, 1989).

The existing expansion plan has two large coal-fired plants due to begin operation in 1997. Either the aggressive solar or nuclear strategy would obviate the need for these plants. Indeed, neither supply strategy can save much in emissions, compared to the base case expansion plan, until the time these plants would be replaced. Until then, the non-fossil plants would replace gas-fired plants, resulting in smaller emission savings. In 1996, the solar plants can reduce emissions by about 2 percent, at an incremental cost of $175/ton, more expensive than most other measures. By replacing the coal-fired plants, solar can reduce emissions by 7 percent in 1998, or nuclear could provide 11 percent reduction in the year 2000. Either technology, implemented by itself, would have an incremental cost of about $90/ton compared to the base case, roughly equivalent to the cost of fuel-switching.

Without the option of reducing emissions through inexpensive DSM, replacement of new coal-fired capacity with solar or nuclear capacity would be competitive with the fuel-switching option, especially if gas prices were expected to increase more than assumed here. However, these technologies will not represent least-cost opportunities until the less expensive DSM measures described above have already been implemented. This is an example of how the supply-side effect of DSM measures can change the utility's incremental costs and emissions, in a way that makes additional emission reduction measures appear more expensive.

The most cost-effective of the conservation measures alone are enough to eliminate the need for the coal-fired plants planned for 1997. Thus, neither the solar nor the nuclear options would replace the new coal-fired plants, at the margin. As a result, the incremental emission reduction from these options would be only about 40 percent as much as suggested above (when they are implemented alone). This result reduces the savings for solar to 2.5 percent (in 1998) and for nuclear to 4.5 percent (in 2000), and it increases the incremental cost from $90 to $230/ton-carbon. Figure 3 shows these emission savings from solar as a small increment at around $230/ton-carbon. Emission savings from nuclear would not appear until after 1998.

The other major class of emission reduction technologies involves removing emissions from the power plant stack gases. This is the most common method of mitigating SO_2 emissions. Removing CO_2 from combustion product gases would, however, require new technology that would not necessarily help reduce other emissions. CO_2 emissions are about 100 times greater in volume than SO_2 emissions from a high-sulphur coal plant, and CO_2 is less reactive than SO_2. In fact, the mass of CO_2 in the stack gas is three times that of the coal fuel! Thus, the feasibility of CO_2 removal and disposal, considering the huge material quantities involved, is very speculative at present. One recent estimate put the cost of direct CO_2 control, if it could be done, at over $500/ton-carbon (Chernick and Caverhill, 1989).

Extension to Other Regions

The results presented above apply to utilities in the south-central region of the U.S., but one might expect similar general trends in other regions as well. The following comparison of the regional variations in the results is based on a simplified analysis of the supply-side parameters using MIDAS. Assuming that energy end-use efficiency improvements have the same costs and percentage energy savings, these supply-side variations determine the regional differences in the emission reduction potential as a function of incremental cost. Of course, differences in climate, building practices and costs, and existing end-use technology will create regional variations in the performance of DSM measures as well. However, in the energy efficiency "supply curve" analysis performed to date in several regions, the total percentage energy savings for a given end-use at a given cost level do not seem to vary greatly (Geller, et al. 1987; Miller, et al. 1989). Rather, supply-side differences, especially the generating capacity and fuel mix, can be expected to drive most of the regional variations.

The regional results are shown in Figure 5, in the form of incremental cost curves, for percentage carbon emission reductions using both DSM and supply-side measures. The curve for the south-central region is the 1994 curve from Figure 3. The results suggest significant differences across the regions. Because of the assumption of equal DSM performance across the regions, the percentage savings for the inexpensive DSM options are similar for each region.

The effect of fuel-switching is less for all the other regions, compared to the south-central region. This result reflects this region's relatively large amount of gas-fired capacity, which allows for a large fraction of the load met by coal-fired plants to be shifted to gas-fired plants. The west and northeast regions, which have relatively less emissions before fuel-switching, can still achieve significant reductions because of their gas-fired capacity. The other regions have both higher base-case emissions and less emission reduction potential because of less gas-fired capacity, especially the east-central region, which is so dominated by coal-fired supply capacity that there is little potential for fuel switching, both in percentage terms and absolute quantities. Only in the West do renewable sources contribute significantly by 2000, but their impact is diluted by the load-growth reductions available though end-use efficiency, as discussed above. Note that the east-central region produces greater absolute emission reductions than the south-central region, and the west and northeast regions produce less. These results simply reflect the carbon-intensity of the base case plan, which is

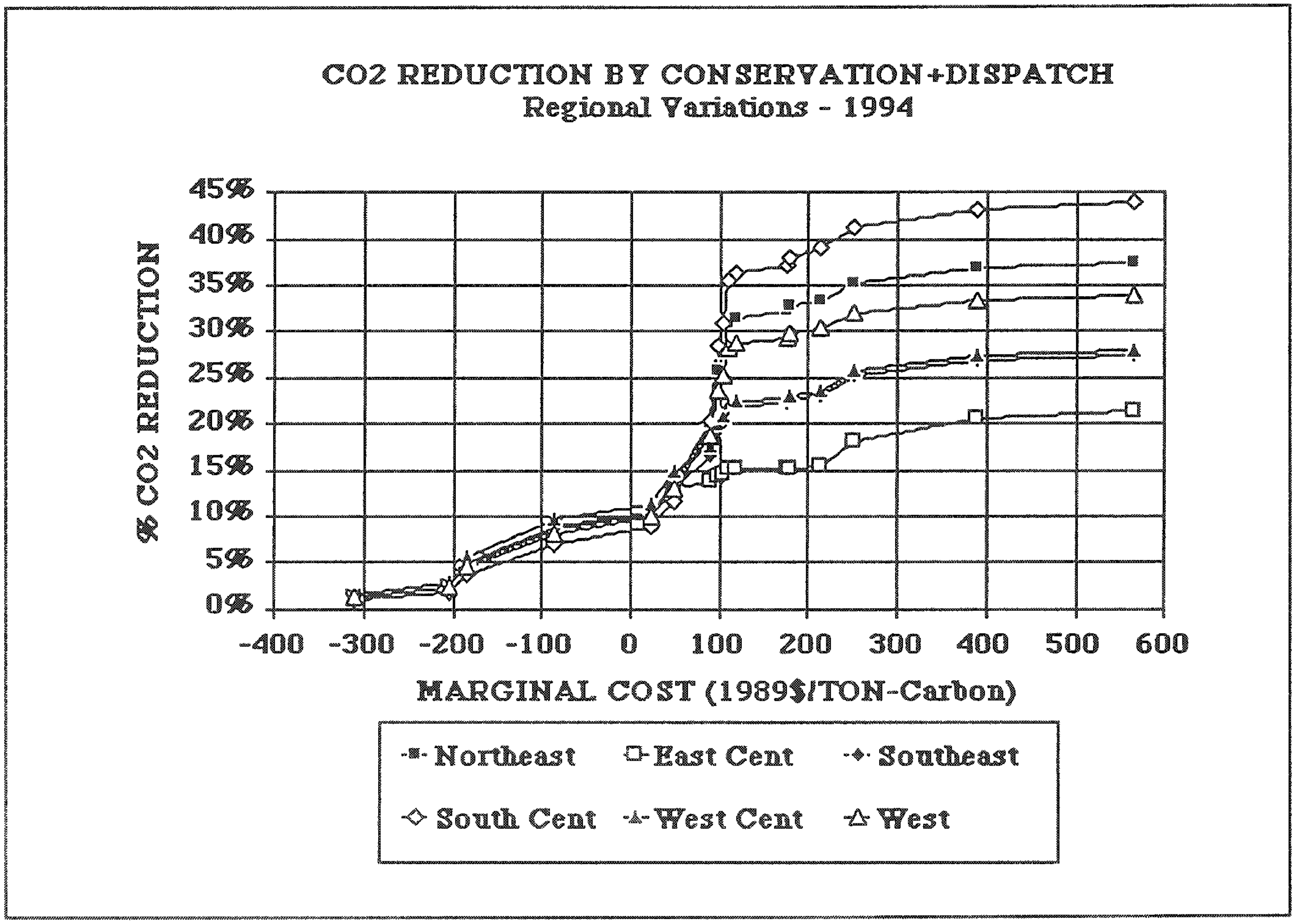

Figure 5. Carbon Emission Cost Curves for Six Geographic Regions

high for the coal-dependent east-central region and lower in the west and northeast.

Effects of Price Feedback

The cost analysis of CO_2 reduction measures does not consider the feedback effects of changes in electricity prices caused by increased costs and lost sales. In general, higher cost generation, through fuel switching for example, will raise costs and prices, resulting in decreased demand and additional reductions in emissions. Thus, the average cost of the reductions are reduced somewhat by this effect. This benefit comes at the expense of consumer surplus lost from the price increase.

Another price feedback results from the changes in utility revenues due to end-use measures such as energy end-use efficiency. The costs of the end-use measures will tend to increase prices and lead to a feedback similar to that described above. However, even if the cost to the utility of a DSM program is zero, the utility may have to increase prices to compensate for revenues lost due to the energy savings. This result occurs when price is greater than short-run marginal cost (as in this case study), because for every kWh saved, the utility saves the marginal cost and loses the price (assuming zero cost of saved energy). The price increase leads to decreased demand, especially for non-participants (Hobbs, 1990). As the cost of the end-use measures increases, this effect is enhanced.

How great is the price feedback effect from the end-use efficiency measures considered in this analysis? To answer this question, let us again concentrate on the $0.07/kWh marginal CCE threshold, where most of the attractive measures have been implemented. The average cost to the utility (net of utility cost savings) at this level is almost zero. Thus, the price feedback effect would only result from price increases due to lost revenues, not from increased costs.

As stated earlier, the utility is assumed to implement end-use programs by direct investment, recovering the costs through the rate base (as expenses). The details of how and from which customers the costs would be recovered are not considered. However, one possibility is that the utility selectively recovers some fraction of the costs from the beneficiaries of the investments, i.e. the participants in the DSM program. This approach reduces the fraction of costs that must be recovered from the non-participants, thus mitigating their price increase and the resulting demand feedback. Also, improved end-use efficiency makes an end-use less expensive at the margin for the participant, producing a positive price feedback on demand. This rebound effect is limited because participants normally have smaller price elasticities than non-participants (Henly, et al. 1988). Also, most of the savings are achieved in the residential and commercial sectors, which have relatively low price elasticities of demand.

With low DSM investment costs, partial cost recovery, and the participants' rebound effect, there are many pressures mitigating the price feedback effects of end-use efficiency investment and lost revenue. At an average unit cost of zero, it is possible that the combination of these pressures could compensate entirely for the revenue effect. Thus, the more important price feedback effect is that caused by a positive average unit cost of the DSM measures. This price feedback is similar to that caused by other types of cost increases, such as switching to more expensive fuel or other supply-side measures.

Conclusion

The results presented in Figures 4 and 5 suggest that substantial near-term reductions in utility carbon emissions, on the order of 35 percent or more for the case analyzed here, could be achieved at a marginal cost of less than $100/ton-carbon. This suggests that a carbon tax on the order of $100/ton would stimulate utilities to invest in measures to achieve reductions of this magnitude. Alternatively, if the price of carbon emission permits, or some other market-based instrument, were as high as $100/ton, the same result would be achieved.

Slightly more than half of the 35 percent emission reduction achieved at an incremental cost of $100/ton-carbon results from fuel switching and redispatch on the supply side; the remainder is from end-use efficiency measures. Although this analysis does not extend far into the future, it appears that non-fossil generating sources such as nuclear and/or solar energy would be able to compensate for future load growth and maintain emissions at the reduced level. Of course, the cost of these technologies is still relatively uncertain, and new technological developments might make additional end-use efficiency measures attractive beyond those analyzed here. Although end-use efficiency opportunities may become saturated over time, exploiting these opportunities in the near-term can control emissions at reasonable costs while advanced supply technologies are being developed.

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