Environmental Policies and Their Effects on Utility Planning and Operations

Benjamin F. Hobbs, Case Western Reserve University
Paul A. Centolella, Science Applications International Corporation

This paper presents a taxonomy and analysis of public policies that address the environmental impacts of power production. The paper consists of two parts. The first is a classification of policy options, including command-and-control regulations, emission caps, taxes, marketable permits, emission adders, and environmental performance standards along with a review of recent developments. In the second part, we explore how various policies can affect a utility's choice from among emissions dispatch, fuel switching, and resource options. Some policies yield inefficient outcomes: i.e., strategies for which there exist alternatives that would result in both lower emissions and costs. Other policies are more likely to motivate the utility to choose efficient strategies, which generally involve a mix of DSM, investments in clean capacity, and emissions dispatch. Some policies which appear to be very different, such as emission allowances, taxes, and environmental performance standards, can yield similar-and efficient-outcomes.

Introduction

It is becoming more widely accepted that traditional command-and-control environmental regulation is an inefficient means of achieving emission reductions from the electric power sector for pollutants which mix uniformly over broad geographic areas. Energy conservation, emissions dispatching, and other pollution prevention measures often are not counted towards compliance with command-and-control requirements, although they can substantially reduce the cost of achieving environmental objectives (Centolella et al. 1988; Hobbs and Heslin 1990; Centolella 1993). Alternate regulatory policies, including emission caps, taxes, allowances, adders, and performance incentives are receiving greater attention. In the first part of this paper, we provide a comprehensive overview and classification of policy options for limiting the environmental impacts of utility operations. The second section of the paper illustrates the economic and environmental implications of alternate policies.

Our frame of reference is the extent to which alternate policies tend to produce economically efficient results from a societal perspective. Environmental regulation is intended to address the existence of environmental externalities, environmental impacts which shift costs from the sources of pollution to other people in a manner not directly controlled by markets for goods and services. A negative environmental externality arises when some individual's utility (e. g., health, security, enjoyment, etc.) or production relationships are affected by real (i.e., non-monetary) environmental variables under the influence or control of others who are not required to pay a price for their activities equal to the cost which those activities impose on others (Baumol and Oates 1988). As this definition implies, not all residual emissions are environmental externalities. In an efficient world in which all environmental costs were internalized-where sources were required to pay for each incremental ton of emissions an amount equal to its societal cost—there would still be pollution. Further emission reductions would not be made if the damage caused by the last ton of emissions were less than the cost of an additional ton of emission reduction. Under conditions of economic efficiency, sources of pollution (and customers in the product markets they serve) would adopt every measure to avoid or reduce emissions which had an incremental cost less than the marginal societal benefits from such emission reductions. Our analysis focuses on utility operations and resource acquisition and the extent to which alternate policies permit or encourage the identification and implementation of least-cost environmental strategies. We also recognize that different policies may have pricing implications which affect the efficient allocation of resources.

Classification of Environmental Policies Affecting Utility Planning and Operations

This section identifies and differentiates types of environmental and utility regulatory policy affecting the environmental impacts of utility operations. It includes a brief history of policy development, examples of policy implementation, and general comments on the effectiveness of policies in internalizing environmental costs.

Command-and-Control Regulation

Most U.S. environmental regulation has been in the form of "command-and-control" requirements. "Command-and-control" approaches require groups of similar sources to use a specific control technology or comply with a uniform emission rate requirement, typically expressed for utility air emissions in pounds of emissions per million Btu of boiler heat input. "Command-and-control" regulation developed as a result of historical limitations on emissions monitoring technology, fear that more sophisticated approaches could be circumvented, and the apparent administrative efficiency and fairness of uniform standards. Although continuous emissions monitoring and data management technology has advanced, environmental regulation largely has continued to follow the "command-and-control" model.

"Command-and-control" air pollution control requirements typically must be met either through the use of a specified fuel or by the installation of a specified combustion or post-combustion control technology. For an electric utility, this means that the potential environmental benefits of demand-side management, improvements in heat rates, power purchases from cleaner sources, or emissions ("full cost") unit commitment and dispatching are not recognized for purposes of environmental compliance. The residual emissions, after the required control measures are implemented, are treated as having a zero economic value. Economists and policymakers have been critical of the "command-and-control" approach because:

- some low cost emission reduction measures are not pursued;
- uniform requirements for broad categories of sources ignore differences in the costs of control at and the environmental impacts of emissions from different facilities;
- regulators are not in a position to identify the most cost-effective portfolio of control measures or how that mix may change over time;
- it creates disincentives to technology development in that new, potentially more efficient facilities are typically subject to more stringent requirements and that sources may be required to place any new emission control technology on all their facilities; and
- development of detailed technology standards has been time-consuming, politically controversial, and administratively costly.

Emission Caps

An emission cap imposes a tonnage or average emission rate limitation on a set of sources typically owned by a single firm. The emissions bubble or averaging created by this approach offers sources internal flexibility in selecting compliance strategies. Firms cannot, however, go outside the sources included in the cap to find less costly emission reduction options.

One example of emission caps is Rule 1135 of the South Coast Air Quality Management District (SCAQMD), which sets system-wide caps on nitrogen oxide (NO_x) emissions from Southern California Edison, the Los Angeles Department of Water and Power, and the municipal utilities of Burbank, Glendale, and Pasadena (SCAQMD 1989). The rule contains three NO_x emissions limitations. First, it sets maximum daily average NO_x emission rates expressed in pounds of emissions per megawatt-hour of net generation for each utility system's total generation in the District. Because district-wide rates are utilized, each utility can adjust its generation within the District and use of other resources to meet this limit. The rule also imposes on each utility a maximum daily number of pounds of NO_x emissions and, beginning in the year 2000, a maximum annual tonnage of NO_x emissions.

Market-Based Systems of Regulation

In general, there are two basic types of market-based systems of environmental regulation: emissions taxes or effluent fees and marketable permit or allowance systems.[1] Such systems provide affected sources the incentive and flexibility to achieve the lowest cost mix of pollution prevention and emission reduction measures. One classical solution to the problem of environmental externalities is a Pigovian tax, a tax on emissions equal to the marginal environmental damage cost at the point where the marginal control cost and marginal damage cost functions intersect. To date, emissions taxes have not been popular in the United States because of the costs which can be imposed on affected sources. Sources pay both for their emission reductions (with an incremental cost below the tax rate) and taxes on any residual emissions. For example, if the 1990 Clean Air Act Amendments had relied on a tax, rather than an allowance, system for Title IV sulfur dioxide (SO_2) controls, the direct costs paid by utilities could have more than doubled. These direct costs do not, of course, represent the overall economic impact. The macroeconomic impact of emissions taxes is highly dependent on the distribution of tax revenues. If broad-based and used to reduce other taxes, emissions taxes can increase economic efficiency by moving prices in towards societal marginal costs and redistributing demand to less polluting substitutes. An alternative form which reduces direct impacts on some sources is the "feebate" in which fees collected from high emission rate sources are rebated to cleaner sources.

Marketable permit or allowance systems distribute limited authorizations to emit, which can be traded among sources as fungible commodities and are exhausted when a specified quantity of pollutant is emitted. In some systems, unused allowances may be banked from period to period. Given unhindered trading, actual emission reductions are made by the sources which can most cost-effectively do so. The distribution of compliance costs, however, depends on the original distribution of allowances. Allowances may be either distributed to specified sources—existing sources may receive allowances at no cost—or sold at auction. If allowances are auctioned off, sources compliance costs may resemble their costs under an equivalent emissions tax, because in either case the polluter makes a per-ton payment to the government. In some marketable permit systems, a small fraction of allowances is held back from distribution and sold in a zero revenue auction to ensure market liquidity, provide price discovery, and inhibit oligopoly power. In a "zero revenue" auction, auction revenues would not be retained by the government and may be distributed in proportion to the original distribution of allowances.

From 1977 to 1986, the U.S. Environmental Protection Agency (U.S. EPA) began to supplement command-and control requirements with limited market-based system: the Emission Reduction Credit (ERC) trading programs. These included netting, offsets, bubbles, and banking (Tietenberg 1985). In each of the ERC trading programs, to create a tradeable ERC the underlying emission reduction had to be: surplus to that required to meet existing requirements; enforceable by state and federal authorities; permanent; and quantifiable in comparison to an established level of baseline emissions (U.S. EPA 1986). The cost and difficulty of identifying potential transactions and securing prior regulatory approval has substantially limited the creation and transfer of such credits. Because only permanent and enforceable reductions can be certified, ERC trading programs have not certified reductions based on energy conservation, emissions dispatching, or other pollution prevention measures. Despite limited use, these market-based mechanisms reduced air pollution control costs by billions of dollars (Hahn and Hester 1989).

The 1990 Clean Air Act Amendments include two major market-based reforms: the Title IV Acid Deposition Control SO_2 Allowance Program and Title I Economic Incentive Programs (EIPs). Covering virtually all electric generating facilities, Title IV will set a permanent ceiling on annual SO_2 allowance allocations to utilities at 8.95 million tons. The allowance system internalizes the acid deposition costs by attaching potential economic value to each increment of SO_2 emissions. For every ton of emissions, the utility either must pay to acquire an allowance, or suffers an opportunity cost, in that, it could have sold an allowance. To date, over $125 million of the allowances have been traded.

Title I authorizes use in State and Federal Implementation Plans of EIPs, including emission fees, emission allowance systems, and other economic incentives for achieving emission reductions. U.S. EPA rules governing EIPs offer greater flexibility than EPA policies governing ERC trading programs (U. S. EPA 1994). Some areas with significant ozone (0_3) non-attainment problems are developing NO_x EIPs to reduce NO_x contributions to 0_3 formation:

- The SCAQMD Regional Clean Air Incentives Market (RECLAIM) program allocates NO_x (and to non-utility sources SO_2) RECLAIM trading credits to most major stationary sources and provides for the generation of credits from mobile source reduction programs (SCAQMD 1993).

- A collaborative design team including representatives from the Illinois EPA, Commonwealth Edison, and the Environmental Defense Fund have developed a proposed NO_x trading system for 63 major utility and non-utility sources in Northeast Illinois (Illinois E.P.A. 1993).

- Northeast States for Coordinated Air Use Management (NESCAUM), a regional air quality regulation coordination agency, is developing a proposed regional system of NO_x caps which could cover the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont (and potentially could be extended to other states in the Ozone Transport Region) (NESCAUM 1992).

NO_x EIPs are an attractive 0_3 attainment strategy because the alternative could be a costly second phase of Reasonably Available Control Technology standards requiring installation of retrofit control technology on all existing sources (Centolella 1993).

The basic difference between the tax and allowance approaches is that a tax system limits the maximum amount that any source is likely to spend on emission reductions, while an allowance system ensures that emissions from covered sources will not exceed a specified (annual or cumulative) quantity without regard to the cost of the last unit of emission reduction. If policy makers had perfect knowledge, either approach could be structured to achieve an equivalent result. Under conditions of uncertainty, however, if the marginal cost of further emission reductions is rising more rapidly than the rate of change in the value of marginal emission reductions (i.e., slope of the marginal cost function exceeds the slope of the marginal benefit function), an emissions tax approach may tend to produce smaller distortions from an economically efficient result (Baumol and Oates 1988).

Adders and Consideration of Externalities in Resource Planning

Public utility commissions are requiring utilities to consider environmental externalities in resource planning and long-term resource acquisition, either qualitatively or through the use of an adder or shadow price that is added to the direct costs of resource options for planning and resource selection purposes only. By 1992, utility regulators in 41 states had begun implementing integrated resource planning (IRP). In 31 of these states, regulators are in some way considering environmental externalities in the resource planning or resource acquisition process. Of these, 13 states reported that externalities are either explicitly quantified and included in economic tests (8), considered on both a qualitative and quantitative basis (8, with overlap of 4), or considered quantitatively through the internalization of the risk of future regulation (1) (NARUC 1993).

For some states (e.g., Massachusetts, Nevada, and New York), the application of adders reflecting quantified monetary valuations of environmental impacts has been a logical result of applying benefit/cost tests which seek to quantify the total cost of alternate resource options. In other jurisdictions (e.g., Utah and Wisconsin), adders were quantified in order to meet narrower objectives, such as prudent anticipation of likely future environmental regulation or of factors which would be raised in siting proceedings.

In a few states (e.g., Virginia), state statutes have been found to limit the authority of state utility regulators to use quantified externality values. Other commissions have proceeded slowly in quantifying externalities recognizing the complexity involved in imposing adders on top of existing environmental regulation. For example, the Maine Commission recommended further study citing:

- The need for analytical work on the relationship between consideration of externalities and environmental regulation;
- The lack of sufficiently reliable methods for quantifying environmental impacts;
- In the short and intermediate term few and generally environmentally beneficial resources would be selected in any event; and
- A lack of Commission staff and financial resources (Maine P.U.C. 1991).

Connecticut is the first state to adopt a trade-off analysis approach in which the direct costs and emission levels associated with alternate resource plans are compared, but externality valuations are not monetized in advance (Connecticut D. P. U. C. 1993). Multi-attribute trade-off analysis can identify relatively low cost emission reductions and resource options that are robust under alternate futures, help parties supporting different externality valuations to focus on actual resource choices, and preserve regulatory discretion.

The discussion of adders has led commissions to consider the often significant environmental impacts of electricity generation, but adders have not been used to fully internalize environmental costs:

- Application of adders has been limited to the planning or acquisition of new resources, where such decisions are subject to explicit Commission review, and has not yet been extended to unit commitment and dispatch or other aspects of utility operations;
- Adders, in some cases, have been applied to the emissions of new resources, ignoring the impact of introducing such resources into the existing utility generation mix; and
- Adders do not create the direct incentives to lower emission reduction costs which would be created by an actual emissions tax.

Because of the difficulty in developing reliable and comprehensive environmental damage cost assessments, adder values in some cases have been based on marginal control costs which may greatly exceed the minimum cost for achieving desired environmental objectives. It should be remembered that “command-and-control” environmental regulations are designed not only to lower emissions, but to allocate costs among new and existing units. Indeed, in some cases, more stringent new source standards imply higher total regional emissions as the purchase of fewer offsetting emission reductions would be required to permit the new source. While several efforts are underway to improve damage cost assessment, uncertainty over valuation continues to hinder public utility commission consideration of environmental impacts.

Performance Standards and Shared Environmental Savings

Utility regulators could utilize performance standards to mimic the incentives of market-based environmental regulation. Performance standards could function as a "soft" emissions cap, in that the utility would have an emissions reduction target, but would not be expected to implement measures with an incremental cost higher than a pre-specified limit.

There have been efforts to negotiate environmental performance incentives, although, to date, no commission has adopted this approach. There are four key elements in an incentive-based performance standard:

- A baseline level of emissions from which to measure environmental performance;
- A reasonable target for environmental improvement such that incentives (and disincentives) may be tied to the percentage of target improvement achieved;
- A maximum authorized incremental cost per ton of reduction up to which the utility may reasonably spend; and
- A structure of incentives (and disincentives) sufficient to motivate performance.

Baseline emissions could be average historical emissions for a representative period. This approach, however, does not take into consideration the range of external factors, e.g., population, economic growth, fuel costs, weather, etc., which may influence a utility's environmental performance. An alternative would be the development of a statistical baseline. Much as utilities develop statistical models for making short term load forecasts, for many utilities it may be possible to develop a reasonable statistical model which would estimate emissions based on coefficients developed from historical data. Actual utility emissions could then be compared to a model backcast of expected emissions and the percentage change used as an indicator of progress.

Public utility commissions could develop standards based on a broad index of emissions or find performance incentives to be an attractive policy for rewarding achievement of utility carbon emission stabilization commitments under the Department of Energy's Climate Challenge program. The Climate Challenge Program is a voluntary program under which agreements will be negotiated with utilities to limit greenhouse gas emissions. Resulting emission reductions can be reported to the Department under the 1992 Energy Policy Act § 1605(b) voluntary reporting guidelines and might receive credit in any future mandatory program. The relatively simple but elegant approach of environmental performance standards could provide the utility shareholders an opportunity share in the public benefits of reduced greenhouse gas or other emissions.

Effect of Policies on Utility Planning and Operations

The various environmental policies discussed above—command-and-control regulations, emission caps, taxes, marketable permits, and emission adders—can impact all aspects of utility system planning and operation. In the remainder of this paper, we explore the relationships between utility choices and environmental impacts, as they are affected by the particular policies adopted.

We do this using as an example a simple generation system that has two "products": electricity and CO_2. Different planning and operating decisions result in different combinations of generation cost and emissions. We focus here on resource operation and acquisition; however, there are also other options available to utilities for lowering net emissions. One is offsets, such as the purchase of SO_2 allowances or the planting of trees in Central America. Another is the adoption of rate policies that reflect external costs in the price of power. We explore how various regulatory policies can affect a utility's resource decisions. Some policies will yield inefficient (dominated) outcomes: i.e., plans and operating strategies for which there exist alternatives that would result in both lower emissions and costs. Other policies are more likely motivate the utility to choose efficient (nondominated) mixes.

A Multiobjective Framework for Evaluating Resource Options and Operating Strategies

Multiobjective plots, such as Figure 1, are a useful tool for understanding how coherent environmental compliance plans can be assembled. We use this device to illustrate how long-run resource acquisition decisions and short-run system operation strategies complement each other; both are needed in order to ensure an efficient outcome. Multiobjective plots can show how the options available to the utility affect important objectives, such as costs, rates, emissions, resource use, and financial indices. Figure 1 is a two-dimensional plot in which the only objectives are incremental internal cost (the y-axis) and CO_2 emissions (the x-axis). Internal cost represents all variable costs of

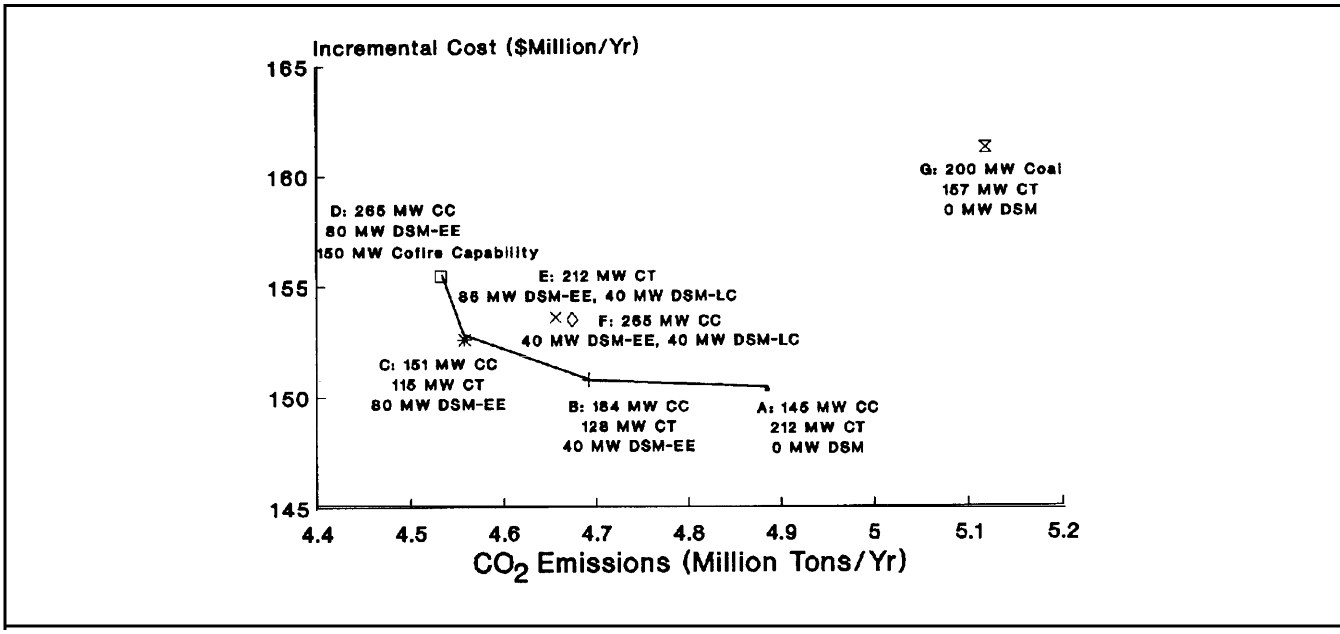

Figure 1. Tradeoff Plot: CO_2 vs. Cost for Seven Plans (Least Utility Cost Dispatch Assumed)

generation plus the annualized expense of any new generation plants and DSM programs. In general, each point can be a distinct plan representing a particular combination of supply sources, environmental controls, demand-side management programs, and rate design, along with a unique operating strategy.

To be concrete, we illustrate the concepts by examining the options facing a hypothetical small utility in the year 2010. The utility's peak load in that year is projected to be 1050 MW. Its present generation mix consists of three coal units (totaling 500 MW), an oil-fired steam unit (150 MW), and natural gas-fired combustion turbines (200 MW). The options it has available for meeting loads and decreasing emissions include emissions dispatch (operating cleaner plants more and dirtier plants less), fuel switching (in particular, cofiring natural gas at the second coal unit), acquiring supplies (new pulverized coal plants, gas-fired combined cycle, or combustion turbine capacity), and investing in energy efficiency (DSM-EE) and load controls (DSM-LC). The costs of the DSM options are described using a "conservation supply curve" in which the per unit cost of savings increases for larger programs. Figure 1 shows the resource additions made in each of several plans, under the assumption that least cost dispatch is used to operate the system's power plants.[2]

Some plans in Figure 1 yield both high internal costs and high emissions (e.g., Plan G). These plans are obviously less desirable than other plans which have both lower costs and emissions (such as Plan A). Plans that are not dominated in this manner by any other plans are known as efficient alternatives (here, Plans A, B, C, and D, which we connect by a dotted line). Alternatives to a particular efficient plan have either worse costs or worse emissions. If all a planner cares about is revenue requirements and CO_2, then only efficient plans are of interest (Merrill and Schweppe 1984; Andrews 1991; Gjengedal et al. 1992; Croussilat et al. 1993).

In Figure 2, we expand the options to include emissions dispatch and natural gas cofiring.[3] Emissions dispatch is the operation of a power system so that more generation is obtained from cleaner units than would be the case under least cost dispatch. Emissions dispatch is implemented in practice by constructing emissions rate based on the sum of variable utility cost plus a penalty on emissions. In Figure 2, a range of penalties between $0 and $30/ton are applied; increasing the penalty results in lower emissions but higher costs. Thin lines connect points that represent different operating policies using the same set of facilities. One plan (Plan D) also includes the operating option of burning natural gas in one of the coal units; this is done if the CO_2 penalty is sufficiently high to overcome the cost penalty of gas relative to coal.

Comparing Figures 1 and 2, we see that including operational strategies has greatly increased the possibilities for decreasing emissions. Indeed, it turns out that every efficient strategy except the least cost point involves some degree of emissions dispatch. Several recent studies of actual utility systems confirm this fact (e.g., Hobbs and Heslin 1990; Hess 1992; Jackson 1993; Marnay 1993). In Figure 2 we label the efficient points P_0 through P_{30}, and connect them with a thick line. The subscript represents the CO_2 penalty at which an efficient point minimizes the sum of utility costs plus CO_2 penalties. For example, P_{20}

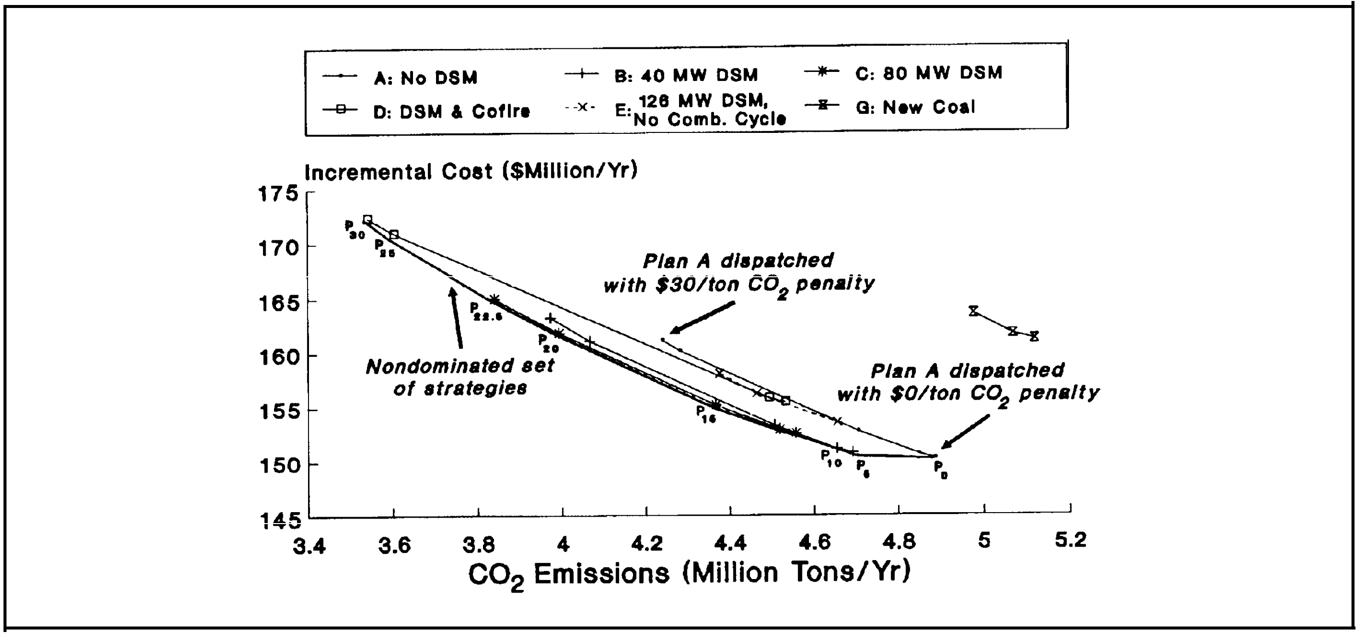

Figure 2. Identification of Efficient Combinations of Resource and Operating Strategies

is the strategy which has the lowest value of utility cost plus $20/ton times the CO_2 emissions.

Environmental planning can be viewed as the process by which the utility chooses from the possibilities in Figure 2. The government sets some rules as to which points are admissible and how the utility should weigh the tradeoffs between the two objectives of minimizing internal costs and minimizing emissions. These rules may be very tight, giving the utility little discretion, or they may allow considerable flexibility.

In the rest of this paper, we discuss how in general alternative government environmental policies affect utility planning. The policies we consider include: traditional command-and-control regulations; constrained emissions; internalization of environmental costs via taxes or marketable emissions rights; and internalization of environmental costs via planning regulations.

The policies are compared in terms of whether they motivate the utility to choose an efficient plan, and whether that plan also minimizes total social cost. "Social" cost is defined for our purposes as the sum of utility costs plus emissions of each type times the appropriate damage cost per ton for each type. As a hypothetical case, if damages are, say, $10/ton for CO_2, then the least social cost plan in Figure 2 is Plan P_{10}, which is the point at which the marginal internal cost of reducing emissions further by moving to Plan P_{15} exceeds $10/ton.[4]

Command-and-Control Regulations

Examples of command-and-control regulation include local restrictions on fuel sulfur content and New Source Performance Standards. The effect of policies of this type would be to render some of the points in Figure 2 illegal. Only those plans that conform to the regulations can be considered. The utility is then free to choose from the permissible plans in order to minimize its internal cost. The emissions of those plans are ignored.

For instance, say that a CO_2 policy is adopted that prohibits new coal plants or new fossil-fuel plants with heat rates worse than 9,000 BTU/kWh. For our hypothetical utility, this results in elimination of all alternatives involving new combustion turbines and coal plants, leaving just the strategies represented by the thinner of the two lines in Figure 3. The utility will choose Plan $P_{C\&C}$ (for "command-and-control plan"), which is the cheapest plan that excludes new plants of that type.

By focusing on individual supply resources, fuels, and emissions controls, the command-and-control approach ignores the environmental control benefits of DSM and emissions dispatch. As a result, superior solutions that have lower costs and emissions may be prematurely eliminated. For instance, Plan P_{10} in Figure 3 represents a combination of DSM programs and emissions dispatch together with some combustion turbine additions. The new turbines lower the system's cost, but also make the plan

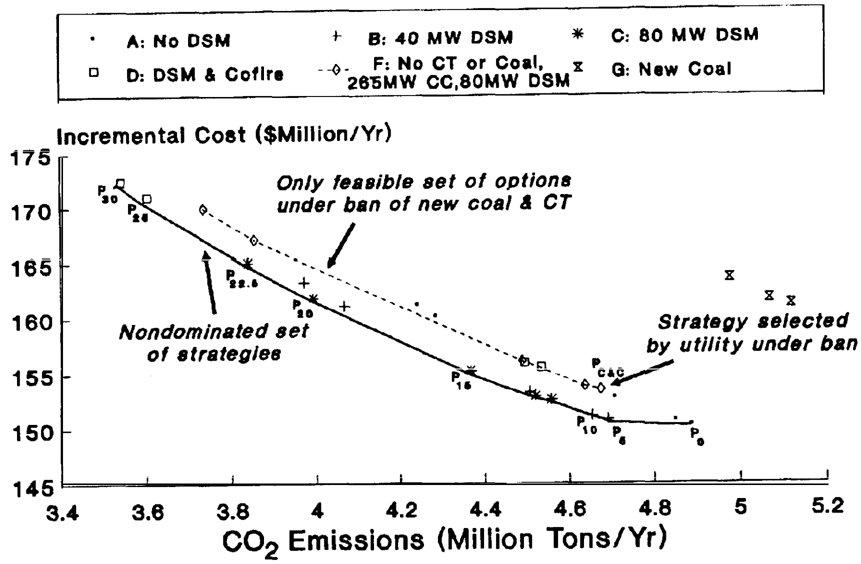

Figure 3. lnefficiency of a Ban on New Coal and Combustion Turbine Facilities

illegal in this case. The utility could compensate for the higher emissions rate of the turbines through dispatch and DSM, but command-and-control regulations do not permit consideration of that strategy. The result is that the utility will choose $P_{C\&C}$ instead, which unfortunately gives both higher costs *and* more emissions than point P_{10}.

An unfortunate consequence of command-and-control regulations is that even if the environmental damages of CO_2 are high, the utility has no incentive to use dispatch and DSM to reduce emissions beyond what the law requires. This is true even if the cost of doing so is small compared to those damages. Thus, the utility's choice under command-and-control regulation is unlikely to minimize total social cost.

Constrained Emissions

Another philosophy of environmental regulation, called "environmental least-cost utility planning" (ELCUP), instead specifies the problem as follows (Brick and Edgar 1990). The utility is to minimize its internal cost, subject to a constraint on overall emissions. For instance, Figure 4 shows the effect of imposing of a cap of 4.4 million tons/year of CO_2, 10% below the least cost level. It would motivate the utility to choose point P_{15}, as all the lower cost points to the right of the constraint are rendered infeasible by the cap.

The advantage of ELCUP over the command-and-control approach is that the utility can freely choose from any combination of supply resources, emissions controls, DSM programs, and dispatch strategies in order to meet the constraint. Unlike command-and-control regulations, an efficient point will always result from this process, at least in theory. If the cap happens to be set at the least social cost point, then this policy is also optimal.

A variation of the ELCUP approach is to constrain the average emissions *rate,* measured in terms of kg/kWh or lb/MBTU of heat input. Constraining a rate rather than total emissions can yield operating difficulties (Hess et al. 1992) and dominated solutions, especially if the rate is based on only the generation of a subset of units. No incentive is given for DSM or to shift generation to less sensitive areas by, for instance, power purchases.

Taxes and Emissions Rights/Allowances

External environmental costs can be internalized by imposing emissions taxes or by creating marketable rights to pollute. The effect of taxes and marketable rights is to make emissions an internal cost from the utility's perspective. For instance, let us assume that a CO_2 tax of $15/ton is levied or, alternatively, that a utility must secure emissions allowances whose market price is $15/ton. Our hypothetical utility will minimize its costs by minimizing the sum of its capital, fuel, and variable costs COST (the y axis of the figures) plus $\$15*CO_2$ where CO_2 is its emissions (the x axis). This process is shown in Figure 5 in which isoquants of the quantity COST + $\$ 15*CO_2$ are shown. The point lying on the lowest such isoquant is the plan that minimizes the utility's total cost. In Figure 5, this is point P_{15}.

Like the ELCUP approach, but unlike command-and-control regulations, the chosen strategy is in theory efficient because the benefits of *all* options for reducing

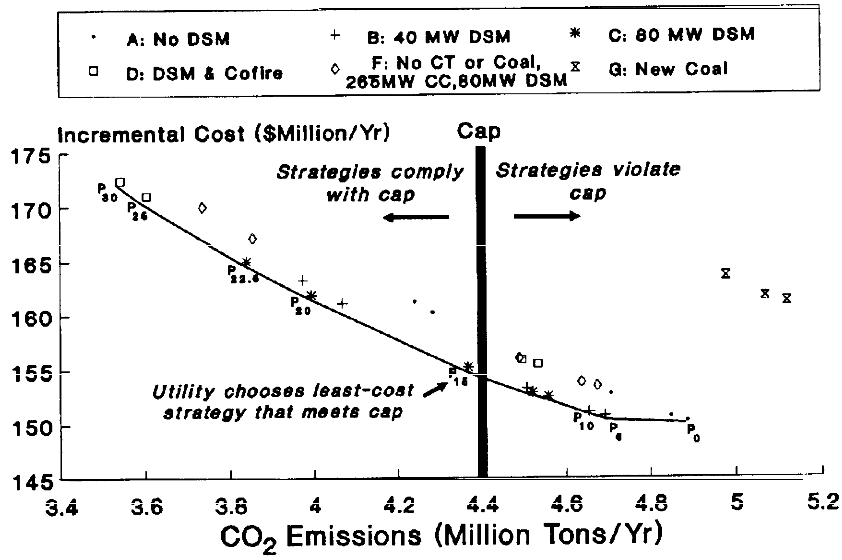

Figure 4. Environmental Least Cost Planning: Imposition of a CO_2 Cap

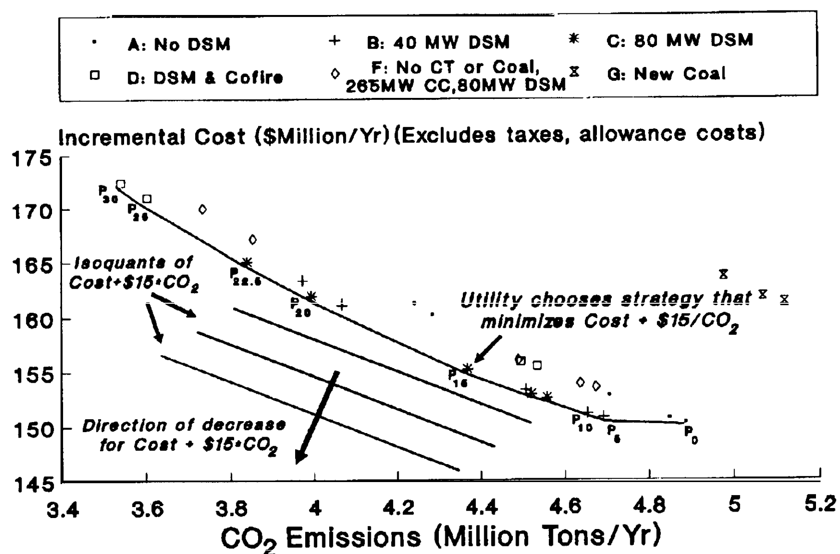

Figure 5. Effect of CO_2 Tax of $15/Ton Upon Plan Choice

emissions, including DSM and dispatch, are recognized. If the allowance price/tax happens to equal the marginal damage of emissions, then the solution is also socially optimal.

Requirements for Considering External costs

Another means of internalizing environmental costs is for the government to require that the utility estimate and consider external costs when making resource acquisition or operation decisions. Environmental impact statements are examples of such requirements. Several states have gone further by specifying particular numerical adders to be considered in the decision calculus. The utility does not actually pay these costs, unlike the tax or emissions allowance systems; it is merely forced by regulation to make decisions as if it does. The most common version of this requirement in the U.S. applies only to decisions concerning resource acquisition. For our hypothetical utility, this would mean that the "cost," including adders, of new combustion turbines, combined cycle facilities, and coal plants would be increased relative to energy conservation. In theory, however, adders could also be extended to dispatch and pricing decisions (Bernow et al. 1991; Busch and Krause 1993).

If the utility is forced to consider external costs in all its resource operation and procurement decisions, the effect would be the same as an emissions tax (Figure 5). An efficient plan would be chosen and, if the estimated external cost was an accurate estimate of actual damages, the least social cost plan would be achieved.

This happy outcome is unlikely to occur, however, if external costs are only factored into resource procurement decisions and not into operation. The environmental costs of capacity expansion and DSM programs would be considered, but the utility would dispatch its resources to minimize internal cost. This is inefficient because, as we pointed out earlier, efficient alternatives almost always include some degree of emissions dispatch. These inconsistent incentives can lead to inefficient decisions, such as the adoption of expensive pollution controls when changes in dispatch order would accomplish the same emissions reductions at less cost. Thus, just like command-and-control regulations, this policy can result in the choice of an inferior alternative over a superior one (Andrews 1991).

As another example of such an inefficiency, uneconomic life extension of coal units might be encouraged because such decisions would not be subject to the adders system. As a specific example, consider three resource options that might be compared by our hypothetical utility:

- construction of 145 MW of combined cycle capacity
- a load control program that clips 40 MW off the system peak, plus 86 MW (peak) of energy efficiency programs
- life extension of a 145 MW coal-fired unit that would otherwise be retired

Each option is paired with 212 MW of new combustion turbines. The amount of each resource is chosen so that the system achieves a 15% reserve margin.

The different resources might be compared on a $ per MWh basis, with the following definitions of the numerator and denominator:

- The numerator would be either the utility cost (which excludes CO_2 costs) or total societal cost (which includes those costs) associated with just the investment and operation of the new resources. Changes in the dispatch and resulting variable costs of existing resources are ignored.
- The denominator would be the anticipated energy output of the resource (if a supply resource) or the energy savings (if DSM). Again, we disregard changes in operation of existing resources.

For the sake of argument, we assume in the societal cost calculation that the external cost of CO_2 emissions is $30/ton but no emissions dispatch takes place. Under these assumptions, life extension has the lowest $ per MWh cost from the utility's perspective, costing $43/MWh. But from society's point of view, the CO_2 penalty causes repowering's cost to jump to $76/MWh; in that case, the DSM program is the least expensive, costing $70/MWh. In contrast, the combined cycle plant is apparently the most costly program from either perspective, with a utility cost of $74/MWh and a social cost of $89/MWh.

However, these results are misleading because those resources are used very differently. Under least-cost dispatch, the combined cycle would have a capacity factor of 0.29, while the repowered coal unit would have one of 0.85. A comparison of the *total system* cost and emissions reveals that the combined cycle unit results in the lowest system-wide cost for the utility, mainly because of its dispatching flexibility. This flexibility allows the utility to displace generation from existing expensive (and CO_2 intensive) units. In contrast, the DSM option has the highest system-wide utility cost. So, in the absence of an adder or tax upon CO_2 emissions, the utility would recommend construction of the combined cycle unit, even if its $ per MWh cost is the worst among all the resource costs.

However, if a $30 adder was applied to CO_2 emissions from just new resources, and *not* life extension of existing units, then the decision would be different. Regulators would conclude that DSM has the lowest social cost—whether measured in terms of $/MWh or total dollars. As a result, the combined cycle plant would not be approved. In that case, the utility would decide instead to extend the life of the coal unit, since that decision is not subject to the adders system and has the next lowest utility system cost. If that happens, the result would be both higher costs *and* higher emissions than would be the case if the regulator did not apply a CO_2 adder (which would instead motivate the utility to choose the more efficient combined cycle option).

Although this example is contrived, it does illustrate the possibility that adders applied only to new resource additions can make matters worse from both an economic and environmental perspective.

Conclusion

At least with respect to pollutants which mix uniformly over broad geographic areas, such as SO_2, NO_x, greenhouse gases, and some air toxics, broad market-based environmental regulation offers the greatest potential for minimizing the costs of obtaining emission reductions. [5] In the absence of a market-based system of environmental regulation, utility regulators can achieve similar results by implementing environmental performance standards. Such standards can efficiently produce near-term emission reductions and create incentives to identify and implement lower cost pollution prevention and emission reduction measures. If a guideline on maximum allowable incremental cost for emission reductions is included, performance standards are less likely to depart significantly from an efficient balance of costs and environmental quality than an absolute emissions cap. In contrast, externality adders provide limited near-term benefits, no direct incentive to reduce emission control costs, and, under some conditions, can worsen both utility costs and environmental impacts.

If retail competition is introduced into the generation services market, new policy tools may be required to reconcile (1) the commodity price reduction incentives produced by competition and other energy and (2) environmental policy objectives. Market-based environmental regulation represents one means of achieving environmental objectives given a competitive generation services market. With a spot market or U.K.-style pool for generation services, a environmental performance standard implemented by the pool through revenue neutral "feebates" could approximate the effects of market-based environmental regulation.

Acknowledgments

We gratefully acknowledge the sponsorship of this research by the National Regulatory Research Institute, funded by participating member commissions of the National Association of Regulatory Utility Commissioners. Any opinions or errors are solely the authors' responsibility.

Endnotes

1. It is also possible to have a hybrid system in which regulators intervene to set a price ceiling or floor for some or all participants in a marketable permit system. See for example: 42 U.S.C. § 7651o(c).

2. Details on the case study assumptions and results can be found in our full report (Rose et al. 1994). The exact cost assumptions do not affect our conclusions concerning the relative efficiency of the different policies. Solutions were generated using a linear programming capacity expansion model. The model is based on the formulation of Turvey and Anderson (1977), as modified by Hoog and Hobbs (1993) to include DSM options and price elastic demands.

3. In Plan D of Figure 1, the capability to cofire natural gas has been installed at one coal-fired unit, but no gas is actually cofired. In Figure 2, gas is actually cofired under this plan when the CO_2 penalty is high enough.

4. We assume that changes in the expense of electricity do not induce consumers to alter the amount of power they consume. Rate feedback tends to lower costs, emissions, and the value received by customers; see Hobbs and Heslin (1990). We also ignore emissions from energy sources that compete with electricity, which might increase if the price of electricity is raised.

5. Where the assumption of pollutants being well-mixed is not acceptable, then allowance systems or taxes may result in redistributions of pollutants that improve air quality in some areas at the expense of worsened quality elsewhere.

References

Andrews, C. J. 1992. "The Marginality of Regulating Marginal Investments: Why We Need a Systemic Perspective on Environmental Externality Adders." *Energy Policy* May: 450.

Baumol, W. J. and W. E. Oates. 1988. *The Theory of Environmental Policy.* 2nd Edition. Cambridge University Press, Cambridge, England.

Bernow, S., B. Biewald, and D. Marron. 1991. "Full-Cost Dispatch: Incorporating External Costs in Power System Operations." The *Electricity Journal* March: 20-33.

Brick, S. and G. Edgar. 1990. "Blunting Risk with Caution: the Next Step for Least-Cost Planning." *The Electricity Journal* July, 56-63.

Busch, J. F., and F. L. Krause. 1993. "Environmental Externality Surcharges in Power System Planning: A Case Study of New England." *IEEE Transactions on Power Systems* 8(3): 789-795.

Centolella, P. A., et al. 1988. *Clearing the Air: Using Energy Conservation to Reduce Acid Rain Compliance Costs in Ohio,* Ohio Office of the Consumers' Counsel, Columbus, Ohio.

Centolella, P. A. 1993. "Title I Economic Incentive Programs: Will There Be a Role for DSM in Ozone Attainment?" *Proceedings of the DSM and the Global Environment Conference,* pp. 125 et seq. Synergic Resources Corp., Philadelphia, Pennsylvania.

Connecticut Department of Public Utility Control. 1993. *Investigation of the External Costs and Benefits Associated with Energy Consumption.* Docket No. 92-09-29. Report to the General Assembly, Hartford, Connecticut.

Crousillat, E. O., P. Dorfner, P. Alvarado, and H. M. Merril. 1993. "Conflicting Objectives and Risk in Power Systems Planning." *IEEE Transactions on Power Systems* 8(3): 887-893.

Gjengedal, T., O. Hansen, and S. Johansen. 1992. "Qualitative Approach to Economic-Environmental Dispatch; Treatment of Multiple Pollutants." *IEEE Transactions on Energy Conversion* 7(3); 367-373.

Hahn, R. W., and G. L. Hester. 1989. "Where Did All The Markets Go? An Analysis of EPA's Emissions Trading Program," *Yale Journal on Regulation* 6:109-153.

Hess, S. W., D. Parker, J. E. Alms, K. D. Le, J. T. Day, and M. J. Malone. 1992. "Planning System Operations to Meet NO_x Constraints." *IEEE Computer Applications in Power* 5(3): 10-14.

Hobbs, B. F., and J. S. Heslin. 1990. "Evaluation of Conservation for SO_2 Emissions Reduction Using a Multiobjective Electric Power Production Costing Model. " *ACEEE 1990 Summer Study on Energy Efficiency in Buildings,* pp. 4.65-4.77. American Council for an Energy Efficient Economy, Washington, D.C.

Hoog, D. T., and B. F. Hobbs. 1993. "A Nonlinear Programming Integrated Resource Planning Modeling Including Emissions, Value, and Regional Economic Effects." *Energy* 18:1153-1160.

Illinois Environmental Protection Agency. 1993. *Draft Proposal: Design for NO_x Trading System.* Springfield, Illinois, September 22.

Jackson, T. M., et al. 1993. "Evaluating Soft Strategies for Clean-Air Compliance." *IEEE Computer Applications in Power* 6(2): 46-50.

Maine Public Utilities Commission. 1991. *Environmental and Economic Impacts: A Review and Analysis of its Role in Maine Energy Policy,* May 1.

Merrill, H. M., and F. C. Schweppe. 1984. "Strategic Planning for Electric Utilities: Problems and Analytic Methods." *Interfaces* 14(1): 72-83.

National Association of Regulatory Utility Commissioners. 1993. *Utility Regulatory Policy in the United States and Canada,* p. 420. Washington, D.C.

Northeast States for Coordinated Air Use Management. 1992. *Development of a Market-Based Emissions Cap System for NO_x in the NESCAUM Region: Project Summary for Section 105 State Air Grant Funds for Market-Based Initiatives.* Boston, Massachusetts.

Rose, K., P. A. Centolella, and B. F. Hobbs. 1994. *Public Utility Commission Treatment of Environmental Externalities.* NRRI-94-10, National Regulatory Research Institute, Columbus, Ohio.

South Coast Air Quality Management District. 1991. *Rule 1135. Emissions of Oxides of Nitrogen from Electric Power Generating Systems.* Adopted August 4, 1989, Amended December 21, 1990 and July 19, 1991, Los Angeles, California.

South Coast Air Quality Management District. 1993. *Regulation XX, Rule 2000 et seq.*. Los Angeles, California, October.

Tietenberg, T. H. 1985. *Emissions Trading and Exercise in Reforming Pollution Policy.* Resources for the Future, Washington, D.C.

Turvey, R., and D. Anderson. 1977. *Electricity Economics: Essays and Case Studies.* The Johns Hopkins University Press, Baltimore, Maryland.

U.S. EPA. 1986. "Emissions Trading Policy Statement: General Principles for Creation, Banking and Use of Emission Reduction Credits." *Federal Register* 51:43829, December 4.

U.S. EPA. 1994. "Economic Incentive Program Rules," *Federal Register,* 59:16690, April 7.