Report to the 115th Maine Legislature
Joint Standing Committee on Utilities

ENVIRONMENTAL AND ECONOMIC IMPACTS

A review and analysis of its role in Maine energy policy

Prepared and submitted by the
Maine Public Utilities Commission
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Executive Summary[1]

This report responds to the Legislature's charge[2] to the Commission last year to provide it with an analysis of the extent to which environmental and economic impacts should be included in the electric utilities' least-cost planning processes. The production and distribution of electricity obviously has environmental consequences. Although existing state, federal, and local regulations address these externalities in a variety of ways, the incorporation of environmental externalities in least-cost planning by some public utility commissions in other states raises the question of whether or not Maine would also benefit from doing so.

In determining whether or not to incorporate environmental and economic impacts one must consider the following questions:

1. Is there a sound analytic basis for integrating impacts into the least-cost planning process?

It is at the conceptual level that integration is most highly developed. However, even at the conceptual level, there are some important issues that have not yet been adequately developed. The interplay between existing environmental regulation and the least-cost approach has not been thoroughly explored. In fact, it has generally been ignored, and as a result the definition and treatment of externalities currently being used is inappropriate. Additional work is needed to obtain a full and satisfactory treatment of externalities in utility planning processes. The Commission has concluded that continued work in this area may eventually offer some opportunities to improve both utility planning and environmental regulation.

2. Is there a sound empirical basis for integrating impacts to the least-cost planning process?

Methods for quantifying the impacts are not yet well developed. Existing externality values are, for the most part, based on inadequate conceptual foundations, and vary so widely that they have very little reliability. Unless the values used for externality analysis truly reflect unaccounted-for externalities, properly valued, their use will detract from least-cost planning, not add to it. No values that purport to be relevant to Maine exist at the present time, and a considerable effort would be required to develop plausible estimates.

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1 Commissioner Harrington does not join this report or the recommendations set out in its conclusion.

2 Chapter 110, P&S Law 1989.

3. If an externality approach were adopted, does it seem likely to have a substantial impact?

While this question cannot be answered definitively, it appears that for the short and intermediate terms (e.g. - this decade) an externality approach in least-cost planning would be unlikely to have a significant impact on resource planning in Maine. First, Maine is already a leader in developing environmentally responsible resources. Second, few new resources are likely to be coming on line beyond what is already committed for. Third, any new resources selected are likely to be the more environmentally beneficial ones in any event. The benefits of waiting for improved externality analysis appear to outweigh the costs of deferring actual implementation in Maine.

4. Do we have the resources to develop, and properly implement environmental and economic impacts?

At the present time (and for the foreseeable future), the Public Utilities Commission itself does not have sufficient staff or financial resources to undertake the work that will be necessary to resolve the questions raised so far and/or to implement such major changes to utility resource and environmental planning processes. The production of this report was difficult enough, given existing resources, and the work load has increased sharply with the onset of the current recession.

5. Should work on this topic continue, to the extent that resources permit?

We believe that over the longer term, the use of externality value approaches may offer significant advantages over the current reliance on command and control techniques of environmental management. Therefore, we recommend continued participation by the Commission in national and regional forums and groups that are exploring this issue. This can be done with only a modest commitment of resources. We also suggest that the Legislature consider whether the state's utilities should, if it can be done at reasonable cost, apply some of the research currently being undertaken for New England as a whole, to Maine specifically.

A more detailed set of conclusions and recommendations appears as the last section of the report.

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I. Introduction

This report responds to the Legislature's charge, in L.D. 2029 of the last session, to the Commission to provide it with an analysis, using existing Commission resources, of the desirability of including environmental externalities directly in the State's least-cost planning processes. A number of states have adopted policies designed to directly incorporate environmental externalities into their planning processes. This report explores the theoretical and empirical aspects of incorporating environmental concerns in utility planning decisions. Hopefully this report will help the Legislature in its determination of whether Maine should do likewise and if so how such a program should proceed.

A. General background

In no arena is the tension between environmental goals and our other economic goals more stark than in the energy industries. Energy industries are involved in issues of great controversy such as nuclear power plant safety, hazards such as oil spills, and even the possibility of a major climate change, known as the greenhouse effect. Because a clean environment is an economic resource like any other, a decision to pursue or even maintain a cleaner environment will mean that we have less of other goods and services, including energy, at least in the long run. Here, as elsewhere, there is unlikely to be a free lunch.

A clean environment is important both because people derive satisfaction from it directly, and because it can contribute to a healthy life and a productive economy. Both goals are important and legitimate. Concomitantly, achieving these goals must not needlessly lower our standard of living or prevent those with legitimate aspirations for growth and development from achieving those goals. The object, then, is neither to reduce pollution at all costs, nor to keep the price of energy as low as possible at all costs. The goal is to get the balance right between the two.

Over the past five years, many state public utility commissions have required "least-cost planning" - a formal optimization framework in which demand side management activities (especially conservation) by utilities are placed on a level playing field with supply-side activities (power plants) and all are subjected to a rigorous examination to ensure that customers' needs are met at the lowest overall cost. As generally formulated, least-cost planning requires utilities to finance conservation directly when it is cost effective, and to put the funding of conservation on the same footing as traditional power plants. These requirements attempt to correct possible imbalances that may otherwise occur in the allocation of society's resources.

Recently, a few public utility commissions have begun to explore ways to incorporate explicitly environmental considerations in the least-cost planning process. Typically, resources thought to be environmentally benign, such as demand-side activities, are given a "leg up" when environmental considerations are incorporated. This report explores the potential of this approach, identifies some problems that are likely to be encountered as the process goes forward, and lays out some principles that should guide these efforts. As it turns out, the report raises many more questions than it answers.

B. Principal focus is on environmental externalities

L.D. 2029 requires the Commission to investigate and describe various regulatory methods to incorporate environmental and economic impacts in the consideration of alternative energy resource plans. This report focuses almost exclusively on the problems associated with including environmental externalities in the least-cost planning process. The report does not focus on the direct effects of in-state production of electricity on employment and incomes within the State of Maine compared to imported power. There are several reasons for this.

First, the Commission has produced this report entirely with existing resources. These resources have not been abundant, primarily due to press of other work necessitated by the current recession. Because the initial impetus for the report was clearly the issue of environmental externalities, we have focussed most of our attention on that question. The report does, of course, give attention to the economic impacts (on costs and competitiveness) of including environmental effects in the least-cost planning process.

Second, employment impacts do not constitute externalities associated with electricity production as that term is generally understood. Employment and intrastate spending impacts primarily reflect the distribution of the costs that the utility will incur in meeting its obligations. Were an extra credit to be given a project simply because of its location, this could increase the costs to consumers of electricity above the true least-cost level. Although those receiving jobs as a result of locating a project within the State may benefit, consumers as a whole will be worse off if the new source is not the lowest cost source. Moreover, if there are any benefits beyond those reflected in the expenditures themselves, it is not clear on what basis employment benefits that brought unnecessarily high costs to consumers could or should be valued. So far as we are aware, there is no economically or analytically objective method available for balancing the interests of potential employees with the interests of consumers.

Third, under existing statute, the Commission may have some authority to take direct economic impacts into account when considering imported power alternatives when reviewing a petition for approval to buy power produced outside of the State, " ... the Commission may consider the comparative economic impact on the State of production of additional power within the State, investments in energy conservation, and the purchase of power from outside the State" (35-A M.R.S.A. § 3133 (9)). Unresolved, however, is the consistency of this provision with the U.S. - Canada Free Trade Act. A similar question that may be raised by externality adjustments is discussed later in the report.

C. History of this issue before the Legislature

In 1989, L.D. 306 was heard and worked by the Utilities Committee. L.D. 306 would have created a 20% premium above established avoided cost for energy and capacity purchased from non-utility providers of demand side management. An amended version of the bill, which would have created a "Commission to Study the Possibility of Including the Cost of Environmental Impacts in the Least-cost Planning Process of Electrical Utilities and the Public Utilities Commission" was approved by the Utilities Committee, but failed to receive funding and was never considered by the Senate.

In 1990, the Utilities Committee heard and worked L.D. 2029. L.D. 2029 would have required the Commission to consider the environmental impacts of public utility services in utility proceedings. Under L.D. 2029, the Commission would have had to consider the environmental impacts of generating facilities, transmission lines, power purchases and other agreements or contracts when reviewing petitions for certificates of public convenience and necessity. L.D. 2029 would have required the Commission to compare those impacts with the environmental impacts of alternative sources of power, including demand side management, when ruling on petitions for certificates of public convenience and necessity.

After considering several amendments to L.D. 2029, the Utilities Committee passed an amended bill that directed the Commission to "undertake an analysis of the extent to which the environmental and economic impacts of alternative energy resource plans should be included in the electric energy planning process subject to the Commission's jurisdiction." The amended bill directed the Commission to consult with the State Planning Office, the Department of Environmental Protection, the Public Advocate, electric utilities, customers of electric utilities, environmental organizations and developers of alterative energy resources and to file a report with the Utilities Committee on April 1, 1991.

On July 24, 1990, the Commission distributed a first draft of the report to the various parties to be consulted in the project and to other interested members of the public. The Commission held a public meeting to discuss the draft on July 13, 1990. In addition, several participants filed written comments on the draft report. These comments were reviewed and integrated into a new draft of the report during the final months of 1990. However, as the deadline for filing the report approached, it became apparent that the Commission would be unable to complete the report by April 1, 1991. In March, the Commission requested the Chairmen of the Utilities Committee to grant a one-month deadline extension to permit the Commission to complete a next-to-final draft of the report, circulate that draft to participants for written comments and file a final draft with the Committee. The Chairmen of the Utilities Committee granted the Commission's request for an extension of the deadline from April 1 to May 1, 1991.

On April 12, 1991, the Commission distributed a next-to-final draft to persons who have participated in this proceeding. Written comments were received from the Natural Resources Council of Maine, William Butler (Friends of the Maine Woods), Conrad Heeschen, the Public Advocate, Central Maine Power Company, Bangor Hydro-Electric Company, the State Planning Office, and Alternative Energy, Inc. The final draft incorporates a number of the changes proposed by the commenters.

D. Plan of the report

The next section of this report discusses in general terms the environmental effects of electricity production. It highlights the external effects which may occur in conjunction with the production of electricity. Section III provides a brief background into least-cost utility planning, the method adopted by the State and the Commission to assure that necessary resources are provided at as low a cost as possible. Proponents of direct treatment of environmental externalities by the Commission wish to incorporate the relevant environmental cost information directly into the existing least-cost planning framework. Section IV is a short analysis of externalities. It includes a definition, and a general discussion of the economic nature of environmental effects. This section also explains how the externalities "adders" might be included in least-cost planning. It contrasts this approach with other methods that are available to deal with environmental externalities. Section V expands the discussion of integrating externalities into least-cost planning, discusses the problem of externality evaluation and provides some examples of how the externality adder process might work. This is followed by a brief review of activities in other states. The final portion of section V provides some evaluation of likely effects of incorporating environmental externalities into the least-cost planning process and notes some limitations of the device. Section VI looks both at ways of achieving environmental improvement that involve existing generation and at broader electricity planning issues. Other dimensions of utility planning related to diversity, reliability, price and volatility and a wide range of environmental impacts are considered. This section also reviews work currently underway at MIT for NEPOOL which analyzes the tradeoffs between various resource planning scenarios and costs and environmental impacts. This work, which to our knowledge is the most comprehensive available in New England at the present time, may be of assistance in determining the desirability of an environmental adder program (or, for that matter, certain other environmental actions). Section VII discusses a number of other policy issues related to the coverage of the adder program, both geographically and industrially. Section VIII considers existing environmental regulation and looks at the role of the PUC and the costs and benefits should it become involved in environmental matters. Finally, a discussion of possible redundance and overlap with other environmental regulations is included. Section IX presents conclusions and recommendations, and a series of appendices provide more detail on some of the issues that have already been discussed in the body of the report.

II. Environmental Effects of Electricity Production

The environmental impacts of producing, distributing, and using electricity vary widely in their reach, nature, severity, and duration. There is just no way to produce and use electricity without some environmental impact broadly defined, although impacts can range from minimal and local to severe and global.

A noisy power plant might be little more than a local nuisance. Over a larger region, what went up the stack may come down as acid rain. The same plant, if it burns a hydrocarbon fuel, will produce carbon dioxide as it produces power.

The catalog of environmental impacts of electricity includes more than those stemming from stack emissions. Hydroelectric stations burn no fuel, but require that we dam rivers and flood land. Other fuel cycles may also affect the environment. Nuclear plant operations generate long-lived radioactive wastes. Permanent, secure isolation is especially critical with the spent nuclear fuel that must be removed regularly from the reactor core, as the intense radioactivity of this high-level waste makes it directly and immediately life-threatening if it is dispersed.

Even energy resources widely regarded as benign, including some efficiency improvements on the customer's side of the meter, may have environmental impacts sufficient to merit their weighing in the planning process. Wind turbines may be noisy, or unattractive. Photovoltaic materials for direct conversion of sunlight to electricity may require the use of hazardous solvents in their manufacture. Foam insulation may be blown with chlorofluorocarbons (CFCs) which, if released to the air, may deplete stratospheric ozone. Even weatherizing houses to improve heating and cooling efficiency by reducing air infiltration may create new problems of indoor air quality.

This is a highly complex area. Cataloguing and ensuring that policies are responsive to environmental impacts is complicated by the incomplete and changing nature of our knowledge about their severity and interrelationships. For example, the impact of the increasing discharge of carbon dioxide to our atmosphere is only beginning to be studied in detail. Finally, some control strategies have backfired on us, resulting in more or different environmental harm than the original local impacts. Tall stacks at coal burning power plants were encouraged by some Midwest states as a means of meeting local air pollution standards; 20 years later we suspect that these same stacks may be responsible for acid rain in Maine.

III. Least-Cost Utility Planning

A. Description

The Public Utilities Commission has defined an electric utility's least-cost energy resource plan as that plan that will meet the utility's projected demands with the lowest practicable operating and capital costs. Each major electric utility in Maine must file with the Commission each year for public review a set of energy resource plans. This filing contains a 30-year forecast of customer needs for electricity, a set of alternative plans for serving these needs, and a detailed projection of all direct costs that would be borne by the utility and its customers as a result of each plan, including return on capital invested. The general definition translates into a well-defined decision rule: from among all feasible and sufficiently reliable combinations of energy resources, find the one which credibly projects the lowest total cost to the ratepayers over the entire planning period, discounting costs in future years to reflect their present value.

In doing this analysis, a utility must consider not only the costs of building and operating its own plant, but also any other ways to serve the same needs, such as power purchased from other sources, and utility-sponsored efficiency gains on the customer's side of the meter (conservation). When a utility proposes a new energy management or supply program, its projected costs must be less than the value of the energy resources it will displace, as revealed by the current least-cost plan. When a utility seeks Commission approval for a new generating facility, transmission line, or large power purchase contract, it must similarly show that the addition of such resources would improve its least-cost plan.

The least-cost planning process widely adopted by utility regulators in recent years provides both a partial explanation of why utility regulators have become interested in incorporating environmental costs in a direct way and may eventually provide a model for how environmental management itself might take place.

At its simplest level, least-cost planning does nothing more than refine traditional regulation by requiring an explicit analysis of all available alternatives for meeting a goal - here, the lowest cost of reliable electric service. As least-cost planning has proliferated, utilities are no longer free to decide simply on the basis of intuition or "experience" to build a plant here or sign a contract there. To justify their choices, utilities must demonstrate, in advance, that they have carefully considered a full range of alternatives. This demonstration is required because utilities, as regulated cost-based monopolies, do not have the same incentives to reduce costs that competitive businesses do.

Least-cost planning was instituted in the hope that it would serve as a substitute for the pressures that the market imposes on most firms. Its analytic roots are embedded in optimization and pursuit of efficiency, traditional regulatory goals. Least-cost planning also expands utility activity to the demand side of the equation, and requires utilities to provide conservation and other demand management techniques when they are likely to lower the overall service costs to customers.

It is probably also fair to say that an important force behind the emphasis on demand-side management, and consequent avoidance of new transmission and generation facilities, was environmental concerns, and so a question naturally arises as to whether incorporating environmental effects into the least-cost planning process is an appropriate and natural extension of this process.

IV. Analysis of Externalities

A. Definition

An external effect or externality occurs when the activities of one economic entity (a producer, a consumer, or a unit of government) have a direct impact on another entity, but the affected entity has no say in how that activity is conducted. The term "direct" means that the impact occurs without any payment or other arrangement between the two parties. The discharge of smoke by a factory or utility, which has adverse effects on others in the region, serves as an excellent illustration. By expelling smoke, the utility or factory uses up someone else's clean air and does not have to include the cost of using the clean air in the price of the goods and services it produces. If there is no explicit payment, "too much" of the resource is used by the polluting entity. A real cost is directly imposed on people who have no say on the decision to produce pollution. When an external cost is imposed on those who do not make the production decisions, the cost to society exceeds the cost to the producer. But because the producer includes only his own private costs in his price, the social costs of production exceed the price consumers pay for the commodity.

B. Discussion

If electricity is one important service that consumers demand, surely a clean natural environment is another. Environmental quality has some unique characteristics, but is also an economic good; it can only be produced or maintained at some cost. That cost may be attributable to direct production costs, or it may result from giving up other things. While it is sometimes hard to say just what value consumers place on the environment, it is clear from observing both the marketplace and the political process, that that value is significant. Consumers/voters have often demonstrated a willingness to give up valued alternatives in exchange for a better environment. They do not, however, do so without limit.

If a company is permitted to discharge unlimited waste gasses, or is allowed to discharge waste liquids or heat freely into a waterway, or is able to engage in illegal dumping or some other unpriced use of the environment, too much of the environmental resource, in comparison to other inputs, will be employed. The production of whatever product is involved - let's say electricity - will be carried out inefficiently. Too much of the environmental resource will be used and too little of some other resources will be used. An important additional aspect of this inefficiency must be considered. Environmental costs will not be reflected in the price paid by the final purchaser of the product. Therefore, too much of the product will be consumed. The price is, in essence, subsidized.

Much of the debate over the last 20 years of growing awareness of environmental damage has been to find ways to properly price use of the environment, and ensure that the price of the final product (electricity) properly reflects <u>all</u> of its societal costs. The object is to "internalize the externalities" to the decision-making process of firms and consumers.

The approach most commonly proposed by economists is to price the environment through the use of emission taxes designed to reflect the damage costs imposed by the externality in question. The notion is simple. One should pay full costs for the right to dispose of a ton of sulphur dioxide into the atmosphere. In such a setting the company will find it reduces costs when it reduces emission levels. In addition, the fees paid will, like the costs of other inputs, flow through to the final price of the product. Consumers can then decide how much of the product to purchase based on the true cost of that product. Note that the framework proposed here requires both that the producer pay for the use of environment, and that the consumer pays a price for the product that fully reflects the producers costs - including environmental costs.

If the tax is set to reflect the true social cost of using the environment for waste disposal - that is, reflects the value of what we give up by using the environment for this purpose, the "right" amount of electricity will be produced. In addition, it will be produced as cheaply as possible taking account of all the costs, and the amount of environmental quality that people are willing to pay for will be provided as well.

This approach implies that there is some tolerable level of pollution, and that there is some positive amount of electricity production that is the right amount as well. It is in this area of getting the incentives right that least-cost planning procedures may, if certain practical requirements are met, offer important opportunities to help assure the correct production of both environmental quality and electricity. There is no question that some important progress is being made in this area.

The externalities "adder" approach that was proposed to the Legislature last year and the year before (and indeed already adopted in some states) is in some ways the intellectual offspring of the tax approach to pollution. It requires the utility, in its least-cost planning process, to factor directly into the least-cost plan the estimated costs of environmental damage. That plan is then simply analyzed in the normal manner and whatever new resources the utility requires are selected accordingly. To the extent that a resource has an externality associated with it, and as the amount of external cost attributed to it is larger, that resource's selection in the least-cost process becomes less likely. It is important to note in this regard, however, that the externality adder is not actually charged to the utility, and therefore does not appear in the price for the final product electricity purchased by consumers. Thus the requirement described two paragraphs above is not met by this scheme, and the full potential benefits are not achieved.

It is important to keep in mind that the externality adder approach is only one, and not necessarily the most complete, way of dealing with externalities. The first, emissions taxes, have already been discussed. They are the most obvious implication of the externalities theory analysis that we have been going through. While few jurisdictions have adopted externalities taxes, they continue to be advocated as the long run method of choice by economists. A principal reason why they have not been more widely adopted to date is the problem of estimating the value of tax to be used, a process that requires estimates of the amount of damage that is done in dollar terms by the pollution in question. Solving this problem is neither simple nor straightforward and equally affects the externality "adder" approach that we are discussing here. In addition, applying emissions taxes in a narrow jurisdiction, such as a single state presents competitive and equity problems that also afflict any rigorous pursuit of environmental benefit by a single state. These topics will be discussed further below.

The most common methods of controlling emissions, whether by federal or state regulation, center on direct control of emissions through the use of standard setting or emission limitations. The Legislature, or an administrative body operating under the authority of the Legislature, determines a quantity of pollution that may not be exceeded by the regulated entity. This can take the form of an absolute cap on emissions or a maximum rate at which emissions may occur during any period. Emission limits have traditionally been set based on a process of bargaining and tradeoffs before a legislature or authorized regulatory agency, with evidentiary hearings, but typically without <u>explicit</u> analysis of the possible costs or benefits from either higher or lower standards.

Another approach to the control of externalities is to require potential polluters to adopt the best available technology for reducing pollution. Sometimes, this is done without reference to the particular costs involved. Indeed, in a few instances environmental laws specify that the costs may not be taken into account. Such approaches are likely to be very expensive, first in that they disregard the costs of reducing pollution, and second, in that they afford the polluter less flexibility in deciding how to deal with the problem.

Finally, there is a broad array of zoning and permitting requirements at the local, state and federal levels which address a wide range of environmental concerns, ranging from local traffic noise and visual impacts to regional effects of air and water pollutants and impacts on recreation and fisheries. Procedures for the licensing of hydro electric facilities, the siting of power lines or generation stations and ash disposal permits are all examples that fall into this category. These procedures are designed to assure that externalities are taken into account, and mitigated, before the particular activity is allowed.

Last, and of great potential significance are the air emissions procedures recently adopted under the recent Federal Clean Air Act Amendments of 1990, Pub. L. 101-549, 104 Stat. 2399 (1990) (amending various provisions of the Clean Air Act, codified at 42 U.S.C. § 7401 et seq.) This law relies in part on the innovative device of "tradeable" emission permits to provide firms, including particularly electric utilities, with incentives to produce their output in an environmentally responsible and least-cost manner.

Because a facility that emits pollution must have a permit to do so, and because these permits may be bought and sold freely, a polluter will take into account the cost of acquiring or retaining the necessary permits, and second, may look for profit by taking advantage of opportunities for sale of permits by reducing his own emissions. The level of overall emissions allowed by the permits outstanding is determined by federal authorities under the Clean Air Act. The implicit cost that a polluter imposes on others, as judged by Congress in the laws it passes, is thereby made explicit. The externality cost is internalized, and polluters are provided an incentive to reduce the externality in whatever cost effective ways they can devise.

It is important to recognize that all of these approaches have the effect of internalizing externalities in one way or another. They are all designed to reduce the amount of pollution that occurs to some "acceptable" level as defined by a legislature or an administrative body operating under legislative authority. The essential point is that the process, even if not ideal, has the effect of internalizing externalities in the sense that a reduced amount of pollution results. Of course, whether it is the amount that would result if we had better knowledge of the costs of environmental damage and cleanup is uncertain.

This leads to an important point. The existence of residual environmental externalities after all existing mitigation and control requirements are taken into account does not, by itself, call for including the residual costs in the planning process. It is critical to understand why this is so. Existing (reduced) externality levels are already determined from the set of regulations described above. Only if there is an explicit recognition that those regulations are not yet sufficiently stringent is there a reason for a further incorporation of externality costs in the utility's decision making process. The existence of residual externalities by itself does not demonstrate that regulations have not gone far enough. If reductions to date have been appropriate (and the Commission has no basis for making any findings on this issue), then the legislature already has found the optimum level of allowable pollution.

The various means that society has chosen to employ in controlling externalities should be thought of as alternative ways of dealing with a problem, not a series of programs simply to be added to each other without regard for each other. Society has already made many decisions to devote very substantial resources to the reduction of pollution. Any decision to regulate environmental impacts still further should involve a weighing of the costs and benefits of doing so, in addition to exploring new and hopefully better means of achieving desired results.

V. Integrating Externalities Into LCUP

A. General description

The process of incorporating environmental externality adders into the least-cost planning process is straightforward <u>once the values are correctly estimated</u>. A utility with a resource need will have a possibly wide range of options available to meet that need. Different resources have different costs, but most of the realistic contenders will be fairly near each other in cost. The only exception to that would be resources which are appearing for the first time, or which for some reason have been relatively underdeveloped in the past despite their availability in principle. The utility then simply decides what its need is, and selects from the array of options before it in a manner that results in the lowest possible cost to consumers. Typically, for resources that come in discrete amounts, that means starting with the lowest cost resources and moving toward the higher cost ones.

The only change in this procedure that is caused by the inclusion of environmental externalities in the process, is that the dollar figures attached to each resource will change by an amount equal to the estimated cost of the associated environmental externality. The result might shift the order in which the resources are selected and lead to the choice of resources that appeared to be more expensive when externalities were not being considered. The addition of correctly determined external costs to the analysis gives a truer picture of the overall cost and can lead to a better selection of resources from the point of view of society as a whole. It is important to note that where the selection is affected by the externality adder process, the direct costs to electric consumers are likely to rise somewhat, only because the selected option is more expensive than its next lowest competitor. The utility does not actually compensate those individuals or businesses that feel the environmental impacts in question.

B. Valuing the externalities

There can be little doubt that the most critical -- and difficult -- part in the entire procedure of externality analysis is determining the actual dollar costs that should be attached to each resource to reflect its impact on the environment. The theoretically correct way to proceed in this area is to estimate, in money terms, the actual damages, whether to humans, to ecosystems, to crops, fisheries, and other activities that are affected by pollution and similar environmental impacts. The reason for doing so is that environmental controls should be directed to reducing the damage that is occurring to society. Only in this way will costs incurred lead to benefits received.

Many investigators of environmental externalities over the years have addressed the problem of valuing the harmful effects of pollution and similar externalities. In principle, dealing with this is fairly straightforward. The amount of damage is simply the value of the harm done, the value of what has been lost. Alternatively, the value of environmental improvement can be measured by the willingness of people to pay to avoid the particular polluted outcome. Determining this value in practice requires several steps. First, the direct effects in any area must be determined. Then it must be determined what health or other impacts occur as a result, and how these change as the externality changes. Finally, this information must be translated into dollar terms as just described. While progress has been made on the issue of valuing externalities, there is a great deal of variation in published estimates and a substantial amount of disagreement as to the reliability and appropriateness of many of the estimates that have been derived. This can be seen in the wide variation in adders used in different states, below.

The fact is that the estimation of relevant costs is quite difficult. Agreement on which costs are relevant among parties with different constituencies may be difficult or impossible to obtain. It is clear that the marginal social costs of externalities will change over time as additional knowledge is gained, and as consumers change their evaluation of environmental amenities. Because average incomes are increasing in the U.S., and population densities are growing (factors that tend to increase the significance of externalities), it is plausible to expect a continued increase in the value assigned to environmental amenities and therefore a rise in the costs of losing them.

Second, very difficult valuation problems are apparent when we realize that different individuals can have different evaluations of the same environmental impacts. Somehow these differing evaluations must be averaged into societal consensus, since the amount of pollution that is generated from a particular plant will be the same for all who live near that plant, whether rich or poor, environmentally concerned or indifferent.

There are several additional issues in using damage valuation of environmental risk. First, it is the risks of damage, not simply the actual damages, that should be valued. The question here is what people will pay to avoid such risks, particularly when the risk is viewed as being an average for a population. The preferences of consumers are important in determining the value of this risk and may sometimes be revealed by the particular choices they make with regard to risky exposures. In other cases, it may be possible to use market valuations for damage, particularly where impacts on crops or fisheries are at issue or where the question is one of damage to buildings and structures.

In sum, the damage valuation (or willingness to pay to avoid damage) process is the appropriate way to proceed in setting environmental externality adders, or for that matter, emissions taxes. While some progress has been made in recent years on methods of estimating these values, it cannot be said that there is yet a reliable manual where we can simply look up, or easily calculate, the values that we need to have. The evidence suggests that we cannot have a high degree of confidence in the estimates that have been made available to date. The value of the externality adder process rests critically on the premise that it will bring better information to the environmental regulatory process. With current damage values, this premise is not yet satisfied.

Another method sometimes used to estimate damage costs, and "adders", is to look at the control costs for pollution reduction under existing legislative standards. It can be argued that existing control costs reflect a legislative determination of appropriate tradeoffs, and therefore that at least that quantity of cost is worth incurring for the purpose of benefiting the environment. The statement is correct as far as it goes, but the cost of cleaning up damages, or avoiding or mitigating them, is simply not the same thing as the damages that result when pollution does occur. Moreover, legislatures have sometimes explicitly required certain standards to be met without any regard to cost. In such cases, no cost-damage relationship can be presumed to exist. Thus, while the numbers have the virtue of availability, they provide no way of measuring the value of additional damages. Therefore they provide no information that can be used to make better resource choices in the future.

C. Examples of possible outcomes

In order to see how the addition of externality adders works, and may (or may not) change the resource selection process, hypothetical and highly simplified examples that illustrate the process may prove helpful.

Begin by looking at a utility (Example 1) which has a need for 100 MW of additional capacity. It is choosing from a menu of choices that includes coal, gas, wind and two conservation plans. (The actual numbers used are illustrative only, and do not relate to actual costs of alternatives within Maine or New England.)

Example 1

Options (50 MW each)	Cost/KWh	External Cost/KWh	Total Cost
Coal generation	$ 0.06	$ 0.02	$ 0.08
Gas generation	0.065	0.01	0.075
Wind generation	0.075	0.00	0.075
Conservation 1	0.04	0.00	0.04
Conservation 2	0.07	0.00	0.07

An ordinary least-cost selection process would look only at the Cost/KWh column, and would select Conservation 1 at $0.04 and the coal project at $0.06. The average cost of the two resources taken together is therefore $0.05, from a private perspective.

When we also take into account the external costs/KWh the picture changes. The example assumes that coal pollutes, that gas does also, but less so, and that the other resources are environmentally benign. Adding in the externality costs now leads to the selection of the two conservation options, with Conservation 2 replacing the coal plant. At an average cost of $0.055 this is a least-cost solution. While it is above the $0.05 cost of the initial selections, it is below the full costs of that earlier selection, which was $0.06, an average of $0.08 and $0.04.

Clearly, because the selection of resources has changed there will be some avoidance of environmental harm due to coal burning, although it is not possible to say precisely what it is worth.

The previous result is not the only possible outcome. Consider the following example:

Example 2

Options (50 MW each)	Cost/KWh	External Cost/KWh	Total Cost
Coal generation	$ 0.065	$ 0.02	$ 0.085
Gas generation	0.05	0.01	0.06
Wind generation	0.075	0.00	0.075
Conservation 1	0.04	0.00	0.04
Conservation 2	0.07	0.00	0.07

Here, the unmodified least-cost selection process leads to choosing Conservation 1 and the gas generation option to meet the resource need. Now, include the consideration of externalities. The choice remains gas generation along with Conservation option 1. The explicit inclusion of externalities in the choice process makes no difference - simply because the original least-cost solution also had sufficiently desirable environmental characteristics, along with its direct cost benefits. To the extent that the resource choices, practically speaking, tend to look like this, the practical value of the externality adder approach, while still theoretically attractive, is reduced. Available information on likely resource plans for New England as a whole, and their environmental impacts, are discussed below in Section VI.

D. Review of other externality efforts

With funding from the U.S. Department of Energy, scientists in the Utility Planning and Policy Group at the Lawrence Berkeley Laboratory recently surveyed public utilities commissions in 49 states to determine how, if at all, each incorporates environmental externalities in utility planning and regulation. We have reviewed this study (hereinafter, the "LBL survey") and found it to be consistent with our own understanding of the major regulations currently in place or under development in several states. The LBL survey found that PUCs around the country are exploring a broad range of methods to incorporate environmental concerns into electric utility resource planning. These approaches include changes to ratemaking, such as a higher authorized rate of return for demand-side management, as well as changes in the regulation of resource planning and acquisition. Since the ratemaking changes are the subject in Maine of separate Commission proceedings and legislative analysis, we will focus here on the resource planning area of regulation, as does the LBL survey itself. Within this area, the LBL survey identified three basic methods, which are outlined below. For a more complete description, see the LBL survey itself, especially pages 8 to 13.

CAUTIONARY NOTE: In the discussion which follows, and in appendices to those discussions, externality adder values appear. They are presented for informational purposes only. There is no way of knowing whether they correctly measure externality damages, and no way to apply them directly in Maine, where circumstances may be different.

1. Qualitative treatments

Without specifying or requiring quantitative methods, several states have adopted or are considering rules giving their PUCs broad discretion to consider environmental externalities in the resource planning process. The Nevada statute in effect at the time of the LBL survey directed its commission to determine whether the utility's resource plan "adequately demonstrates the economic, environmental, and other benefits to this state and to the customers of the utility associated with conservation, load management, improvements in efficiency, renewable energy, and hydrogeneration." Since then, in January 1991, the Nevada commission has adopted regulations which require explicit quantification of both environmental costs and economic benefits of alternate energy resource plans. We review the Nevada rule in more detail in Section 4, below. Arizona's commission considers environmental externalities, such as sulfur oxide and carbon dioxide emissions, in its least cost planning activities. For over ten years, the Minnesota commission has incorporated environmental considerations into its Certificate of Need process. The Ohio rules for determining the reasonableness of integrated resource plans include a category, separate from the cost analysis, for qualitative consideration of environmental impacts and associated costs, and there is a similar provision in Texas.

2. Direct quantification

Several states have adopted or are adopting methods involving direct quantification of externality costs as part of resource planning, and a number of utilities have put in place bidding systems in which environmental impacts of a bidder's project are evaluated explicitly in a weighing or point scheme. For example, proceedings underway in California would require its energy commission to include air emission impacts in its long term resource planning, with dollar values based on control costs, while a parallel proceeding before the PUC is considering how to incorporate environmental costs into its bidding system for Qualifying Facilities (QFs). The Oregon PUC requires its utilities to consider external costs in the cost-effectiveness evaluation resource options, employing both qualitative and quantitative approaches. The Wisconsin planning requirements include a "NEEDS" factor, which includes external environmental, social, and political costs that are "Not Easily Expressed in Dollars." As an initial step, the utilities must include a 15% cost credit for planning options that do not involve combustion, and must develop alternate plans based on major planning goals, such as minimizing carbon dioxide emissions. Future filings will also require comparisons of the environmental and other non-monetary factors for all planning options, but the methods for doing so are still under development. The New York commission has ordered utility bidding programs to assign specific cents-per-kilowatt-hour penalties to environmentally-inferior projects, based on their levels of air and water emissions and land degradation. New Jersey utilities and QFs have agreed to broad bidding guidelines that include a weighing of environmental issues and fuel efficiency. The Colorado commission has approved (but not yet used) a bidding process that specifies bonus points by fuel type, reflecting environmental and economic externalities. The Northwest Power Planning Council, as part of its 1990 Power Plan, has developed an issue paper which reviews environmental pollutants associated with major resource types and their major effects on the environment.

3. Percentage adders

The LBL survey found that some states use a simple, technology-based percentage adder to give a bonus in the planning process to demand-side resources and a penalty to the supply-side, as a rough means of quantifying environmental costs and benefits. The Northwest Power Planning Council applies a ten percent credit to conservation resources, relative to power supply; if avoided supply costs are 5 cents/kWh, all conservation that costs less than 5.5 cents/kWh is considered economical. As noted above, Wisconsin requires a fifteen percent credit to non-combustion sources in utility resource planning. Similarly, Vermont has ruled that utility plans should discount the cost of demand-side resources by ten percent to reflect their "comparative risk and flexibility" advantages, while initially increasing the cost of supply-side resources by five percent to capture some externalities, pending completion of a rulemaking that would further define these adders. In Maine, 1988 legislation for a twenty percent conservation adder failed to pass.

4. The Nevada rule

In July 1989, the Public Service Commission of Nevada opened a rulemaking, designated as Docket No. 89-752, to adopt resource planning regulations that determine the level of preference to be given to those energy resources that provide the greatest economic and environmental benefits to that state, consistent with other planning requirements. The Nevada commission adopted its final rule in January, 1991. A copy of the Nevada order and rule is attached as Appendix A.

Analysis of societal costs. Nevada's amendment to its least-cost planning rule requires each electric utility to include in its energy resource plan a "statement quantifying the environmental costs and the net economic benefits added to the state from each option for future supply." In addition to the conventional analysis of alternate plans, in which the utility compares the present worth of the future requirements for revenue associated with each plan, the utility is required to consider societal costs in its ranking of resource options. Societal costs are defined as the sum of future environmental costs and future revenue requirements, calculated in terms of discounted present worth. Economic benefits enter the analysis when competing plans have similar societal costs, and in the analysis of purchased power options.

If a plan selected by a Nevada utility as its preferred plan is not the least-cost plan, in terms of either revenue requirements or societal cost, then the utility must fully justify its choice by setting forth whatever other criteria it used.

Measuring environmental costs. The Nevada rule provides that "environmental costs to the state associated with operating and maintaining a plan for supply or demand must be quantified for air emissions, water and land use. Environmental costs are those costs, wherever they may occur, which result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the plan." It is worth noting that analytic foundation of this definition does not conform to our discussion, above (page 11) of externality factors.

In addition to this language including environmental costs "wherever they may occur," the rule adds a section to clarify the intent to capture costs and benefits "whether the generation source is located inside or outside Nevada." In particular, the rule provides that environmental costs of generation from sources outside the state should be calculated the same as if the electricity were generated within the state.

The rulemaking itself reviewed technical evidence on the measurement and valuation of environmental costs. As adopted, the rule provides a table of air emissions factors for 10 combustion products, for each of 20 types of baseload generation plant and 7 types of peaker plant, as well as a valuation of unit environmental costs associated with each of the combustion products. The valuations are derived in several ways, but principally from an analysis of the marginal control costs and social benefits implied by current air emissions regulations. (See the discussion above, page 14, for a critique of this approach.) The rule requires the utility to "use the general emission rates and the environmental damage costs established by the Commission unless the utility justifies deviating from these values." All of the environmental factors, emission rates and environmental costs "may be subject to elimination or modification, and new factors may be added" as new information becomes available.

Tables 1 and 2, attached to the Nevada order (see Appendix B), show the emissions factors and environmental costs adopted in that state. We have used these data to develop two additional tables, attached to this report. Figure 1 compares the set of valuations adopted in Nevada with several others in current use, while Figure 2 converts each set of valuations to a table of environmental costs per kilowatt-hour generated by a variety of sources, using the emissions factors adopted in Nevada. We reemphasize our earlier caution that these numbers are presented for illustrative purposes only, and that we have not concluded that they appropriate for use in Maine, were such an approach to be adopted.

<u>Analysis of economic benefits</u>. If it finds that a competing resource plan shows societal costs within ten percent of the lowest societal cost plan, a Nevada electric utility must now include an analysis of the net (positive and negative) economic benefits added to the state from electricity-producing or electricity-saving resources in each plan. Economic benefits are defined as the portion of utility revenue requirements expended within the state for both the construction and operation phases of any project. Specifically, the rule lists land and facilities located within the state; equipment manufactured in the state; materials, supplies, and fuel purchased in the state; wages paid for work in the state; taxes and fees paid to the state or its subdivisions; and fees for services performed within the state.

For purchased power sources, the rule requires utilities to quantify net economic benefits from each such source.

The rule allows the commission to adjust the societal costs of competing resources to consider all or part of the calculated economic benefit.

5. In New England, two states have incorporated externality values into their least-cost planning process. In Vermont, demand side measures costs get a 10% discount, and supply side measures a 5% adder. Massachusetts has provided a range of cost adders for supply side resources, most notably a very high penalty on the use of coal.

The other New England states, including Maine (along with Massachusetts and Vermont) have been studying this issue extensively in the Power Planning Committee of the New England Governors' Conference. Major elements of that work have involved use of the results of the Analysis Group for Regional Electricity Alternatives at M.I.T. Some of the results of this work are discussed below on page 24. Finally, the Power Planning Committee has contracted with Florentin Krause of the Lawrence Berkeley Laboratories to estimate the effects on electricity costs in the region of reducing CO_2 emissions by 10% to 20% over the next decade, compared to allowing them to grow by the same amounts. The results of this work have not yet been presented to the Power Planning Committee.

E. Assessment of results and efforts to date

The clearest result available so far is that there is wide variation among the states that have embarked on the environmental adder process with respect to the evaluation of damage and the ways in which that damage is introduced into the planning process. It is too early to tell whether this process will lead to a net improvement in dealing with environmental externalities related to power production. Evaluating the effectiveness of this approach requires distinguishing causes and effects that occur solely as a result of this approach from effects arising from traditional means of controlling external effects.

It is notable that no program to date has involved passing through the real costs of environmental externalities to consumers. As noted earlier in this report, this was a major reason for including such externalities in a firm's decision processes. Nor, from the perspective of fairness, does it ensure that the cost causer bears his or her full share of the costs he or she imposes on society.

Perhaps the most important omission (obvious once it is pointed out) in the methods proposed in environmental externality adder programs, is that they are addressed at the introduction of sources, almost exclusively generating facilities and DSM programs, into utilities' plans. In situations where demand is growing at a rapid pace, and where environmental externalities would otherwise not be incorporated into the planning process, the adder approach may have the desirable effect of phasing-in, on a gradual but steady basis, improved planning for externalities. Where, on the other hand, the need for new capacity is relatively modest because of excess capacity and modest demand, and where the major environmental problems and potential gains are related to the way in which <u>existing</u> generation is used, these approaches will not bear as much fruit.

Because Maine and New England are currently in an excess power situation likely to continue through the end of the decade, and because Maine and the other states of the region in which we participate in the power pool are already engaging in substantial least-cost planning and are subject to reasonably stringent environmental regulation, it is not clear whether or not environmental externality adders would result in a net improvement in either the environment or the planning process. We turn to this question in the next section.

VI. Broader Electricity Planning Issues

In this section we expand our discussion beyond the issues involved in planning for generation and demand-side resources to meet expected growth in demand, and consider a wider range of issues connected with the treatment and use of existing generation, as well as other goals and aspects of the electric utility planning process. The basic issues concerning electricity planning fall into four broad categories.

First is the question of the cost of electricity. This in turn has two aspects. The overall level of cost is important for the impact it has on customers directly, and for the effect it may have on the ability of Maine to compete with other states and other regions of the country or world. Although CMP's electric costs are still slightly lower than those in the rest of New England, the region as a whole is a very high cost area. Moreover, Maine's current cost advantage appears to be eroding. Price or cost can be measured in at least two dimensions. The average unit cost of electric service, a measure that captures end use service costs by incorporating enhancements such as conservation or demand-side management is one way of viewing costs. Alternatively, we can look at the unit cost of electricity itself, the traditional price of electricity, a quantity of considerable importance to decision makers who are attempting to minimize their own costs. Finally, the total cost of electric service can be considered as an indicator of tradeoffs between this and other variables. Another aspect of cost which requires some attention by utility planners is the degree of volatility in costs. The inability of firms to predict costs accurately may be a detriment in making locational decisions.

The second broad issue is environment. Environmental impacts always flow from the production of electricity, whether from new or existing facilities. Factors which might be taken into account in this connection are acid deposition, SO_2 emissions, local air quality, nitrogen oxide emissions, emissions leading to global climate change such as cumulative carbon dioxide emissions, and finally, other more localized kinds of impacts on land use and water resources.

A third attribute of an electric utility that must be taken into account in selecting resources is its generation reliability, normally measured by the average reserve margin. Fourth and finally, the issue of vulnerability to cost changes is a significant concern in electricity planning. Natural gas, fuel costs, other supply side costs, and demand-side costs, all create a certain degree of vulnerability in the system, which planning tries to take into account.

As already mentioned, the environmental adder approach focuses almost exclusively on the impact of new resources as a means of improving the stock of resources. If, however, our principal concern is to achieve whatever environmental quality is deemed appropriate at the lowest possible cost, it may be a serious mistake to ignore the improvement possibilities inherent in the way existing facilities are operated. Decisions in at least three areas are of interest in this regard. First, and most obvious, is the possibility of fuel switching. About 50% of <u>all</u> the energy used in Maine is derived from oil. However, for electricity production this figure was 19% in 1989, and in 1990 fell to only 13.4%. As is clear from an examination of Figures 1 and 2 on the next two pages, Maine has already made significant progress in moving to more environmentally responsible forms of electric power generation, and is a national leader in the use of renewable resources.

Nevertheless, it appears that one substantial opportunity for improving environmental performance in the region at a relatively low cost, relative to other means of achieving the same goals, is simply to switch fuel from high sulphur to lower sulphur oils. While this results in increased fuel costs, it may provide a degree of environmental improvement that is unattainable through other means at comparable costs. The externality adder approach simply does not consider this particular tactic.

A second area is policies toward abandonment of older facilities, and the terms on which life extensions of existing facilities will be permitted. Cases where existing facilities in a satisfactory location can be repowered with lower emission fuels need to be explored. From one viewpoint, of course, this is nothing more than a more sophisticated version of the fuel switching which was already mentioned. In this regard it is important to note that New England already appears to be embarked upon a gas strategy for both conversions of existing generation, as well as new generation, an approach that recent investigation suggest should bring additional environmental benefits at reasonable costs. The Commission has been actively engaged in exploring possibilities for bringing additional reliable gas

Electricity Generation and Purchases for Maine Consumption by Resource Type

Table 1 -- 1989					
(Mwh's)	CMP	BHE	MPS	TOTAL	PERCENT
NUCLEAR	3,200,920	477,575	369,315	4,047,810	32.10%
CANADIAN	1,138,043	238,416	167,855	1,544,314	12.25%
PETROLEUM	2,084,656	215,582	93,829	2,394,067	18.99%
HYDRO	1,945,641	297,757	5,676	2,249,074	17.84%
BIOMASS	1,557,713	331,902	126,678	2,016,293	15.99%
OTHER	219,318	139,159	0	358,477	2.84%
TOTAL	10,146,291	1,700,391	763,353	12,610,035	100.00%
Table 2 -- 1990					
NUCLEAR	2,323,512	401,264	253,321	2,978,097	24.38%
CANADIAN	1,166,201	255,728	305,304	1,727,233	14.14%
PETROLEUM	1,432,615	148,951	59,074	1,640,640	13.43%
HYDRO	2,456,213	350,320	6,947	2,813,480	23.03%
BIOMASS	1,858,368	311,399	128,338	2,298,105	18.81%
OTHER	600,423	156,879	254	757,555	6.20%
TOTAL	9,837,332	1,624,540	753,238	12,215,110	100.00%

Notes

1. NUCLEAR -- includes Maine's share of Maine Yankee generation and contracted energy from Millstone 3, Connecticut Yankee, Vermont Yankee, Yankee Atomic, and Seabrook.
2. BIOMASS -- indigenous non-utility wood-fired generation and cogeneration -- may include small amounts of oil, tires and other fuel used in some multi-fuel boilers. Does not include solid waste or large multi-fuel boilers (e.g. Boise Cascade) with high coal-capability.
3. OTHER -- includes generation fueled by municipal solid waste, coal and wind. Also includes some bulk purchases from other New England utilities.
4. Data includes only contracted energy. Net NEPEX and economy transactions not included. In 1989, Maine's net NEPEX and economy interchange was negative 62,983 Mwh. In 1990, this was plus 291,886 Mwh.
5. Total includes only generation and purchases for resale by utilities. Data does not include self-generation, which in Maine is mostly hydro and biomass.
6. Sources: FERC Form 1's, data requests from individual utilities.

Maine State Planning Office -- April 1991

Figure 1 Maine's electricity mix -- 1989

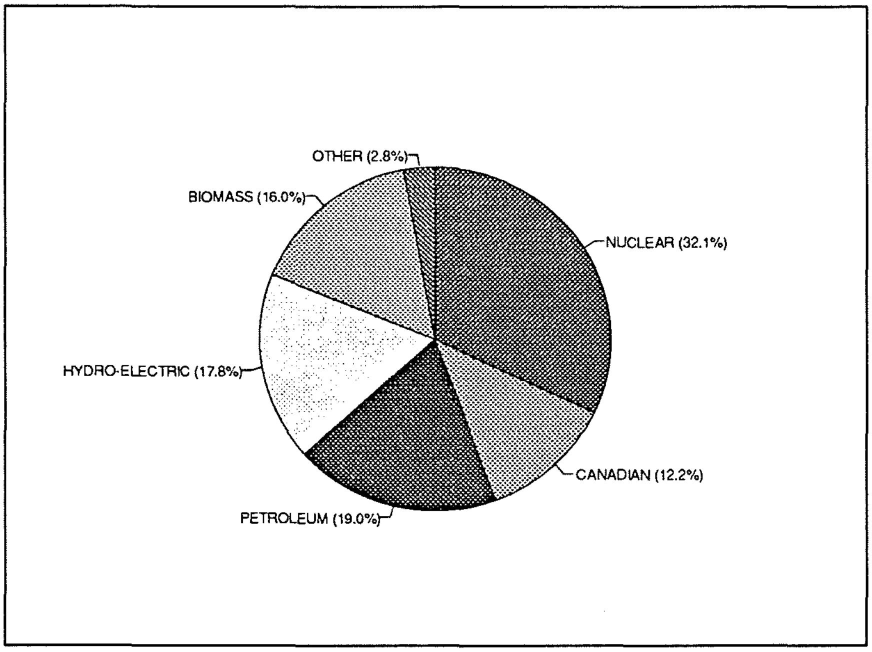
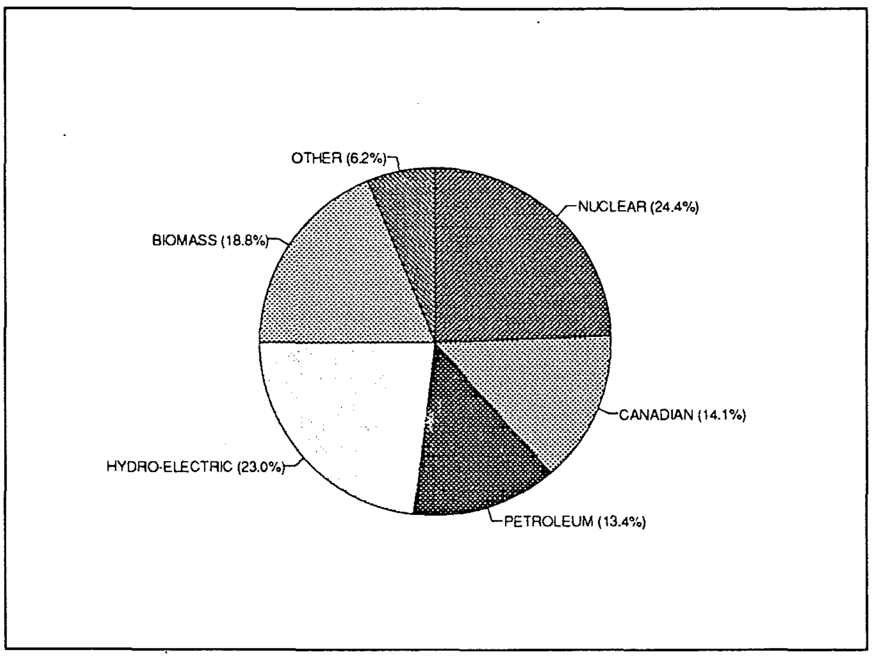


Figure 2 Maine's electricity mix -- 1990



supplies to Maine on a cost effective basis, and will continue those efforts.

Finally, and perhaps most controversially within the utility industry, it is in principle possible to dispatch the generation units that comprise the power grid in accordance with their full costs, including environmental costs, rather than simply the economic costs that are used to dispatch the units today. Again, this would have an upward impact on the costs of electricity but might, over the long run, prove an effective means of reducing the costs of achieving environmental goals. There is a legitimate question about how responsive the existing system could be to this approach in the short run, however. The dispatch approach to achieving environmental improvement in existing facilities is neither directly nor indirectly addressed by the externality "adder" approach.

<u>The Federal Clean Air Act</u>. It is worth noting, in contrast, that the federal Clean Air Act Amendment, reducing allowable emissions and providing for the issuance of tradeable emission permits, <u>does</u> implicitly address these issues <u>along with</u> new generation planning choices. Under the Clean Air Act, a utility must possess an air emission permit in order to produce electricity in a manner that adds to the stock of regulated pollutants. Because these permits will be relatively expensive (a result of the fact that maximum emissions are sharply limited), the utility has an incentive to cut down on its emissions, where this can be done cost effectively, in <u>any</u> area of its operations where that is possible. Therefore, a cost minimizing utility will look not only to new generation as a way of lowering emissions costs, but will consider modifying its dispatch order, repowering its plants and perhaps engaging in fuel switching <u>whether or not it is being required to do so directly</u> by an emission standard. While the tradeable emissions program of the Clean Air Act is not yet up and running, and therefore its practical effectiveness cannot be fully evaluated, it shows great promise of directly addressing the issues that are of concern in this report. If the program proves workable, nothing would prevent it serving as a model for similar state programs, if emission reductions beyond those already achieved in existing state and federal programs were deemed necessary. To the extent that the emission permit trading system leads to clear incentives for all utilities (and other industries) to reduce emissions, and to do so in whatever way is least costly, the importance and attractiveness of alternative systems may well be diminished.

<u>The New England Project: Analyzing Regional Electricity Alternatives</u>. Approximately two years ago a group of scholars at MIT, working under an advisory board consisting of public utility commission members, electric utility executives and other interested parties, began a study of the regional electricity

alternatives for New England, to analyze the effects of various strategies on such factors as cost, the environment, reliability, and the vulnerability of various strategies to external influences. Although the study is still under way, a number of major conclusions have been reached that cast important light on the desirability of an environmental improvement strategy that focuses solely on resource selection, versus an approach that considers modifications to existing resources. (For an analysis of the externality adder approach by Clinton J. Andrews, a member of this group, see Appendix C, attached to this report.)

The study examines various combinations of supply and demand conditions, and modification of existing facility strategies, under a wide range of assumptions with respect to prices of the various fuels in use, demand growth predictions for the utilities, and capital and operating costs for the various technologies. While still under way, the results obtained to date provide the most complete information available on power planning and operation, and environmental impacts, in New England. Therefore, we are describing some of its results in some detail.

While the scenarios examined relate to planning in New England as a whole, many of the general conclusions reached should hold for Maine as well. In conjunction with this, it is important to recall that Maine is a part of NEPOOL, and hence is affected directly by planning decisions in other portions of New England. In addition, it is clear that much of the environmental benefit to be enjoyed in Maine is itself dependent on decisions made in the rest of New England and indeed perhaps even further west and south, since some portion of our pollution comes from elsewhere in the region or even outside the region.

The major results of the New England project can be categorized under five headings.

Costs. First, the study considers the effectiveness of various options in meeting cost control objectives. Of considerable significance, conservation strategies, generally relatively environmentally benign, seem effective for reducing costs in most scenarios, even if utility program costs have been underestimated by as much as 25%. What this means, in essence, is that even without environmental adders, conservation will be a significant element in most strategies.

Second, and interestingly in light of the subject of this report, probable choices among new supply technologies makes little difference in costs. On average a gas emphasis is cheaper than a coal/gas combination, which in turn is less than coal and less than nuclear. However, the difference in costs is relatively small compared to the range of uncertainty due to fuel and capital cost variations, also important considerations in selecting resources.

Third, scheduled retirement of older generating plants consistently costs slightly more than repowering, which in turn costs more than life extension. Fourth, as mentioned earlier in this report, shifting existing generation over to low sulphur oil costs only a little more than current operating procedures. Lastly, a high reserve margin strategy consistently costs slightly more than base reserve margins.

Environmental Effects. Now, we look at the effectiveness of various options in meeting SO_2 reduction objectives. First, low sulphur oil in existing generation plant is extremely effective at reducing SO_2 emissions. Second, scheduled retirement of older (polluting) facilities and repowering are also extremely effective in reducing SO_2 emissions. Choice among likely new supply technologies, however, does not affect SO_2 emissions very much. Fourth, and interestingly, increased demand-side management also does not affect SO_2 emissions very much, all else constant. Lastly, allowing a relatively high reserve margin has slightly lower SO_2 than the base reserve margin.

A similar analysis was done on the effectiveness of various options in meeting NO_x reduction objectives. First, scheduled retirement and repowering are extremely effective in reducing NO_x emissions because they increase the amount of new technology that enters use. In low growth cases, scheduled retirement is a surer way to bring on new technology than is repowering. Second, increased demand-side management does not affect NO_x emissions very much. Third, choice among new supply technologies does not affect NO_x emissions very much either. Fourth, low sulphur oil does not affect NO_x emissions at all. Fifth, high reserve margin has slightly lower NO_x than base reserve margin.

What seems clear from the scenarios that the MIT working group has examined, is that the way in which the existing plant is constructed and operated is an extremely important determinant of environmental well-being in the New England region. The simple fact that there exists a large stock of polluting utility plants in the region, coupled with the fact that expected additions to plant are relatively low, even including repowering or life extension of existing facilities, makes clear that the greatest gains to be had are in the way that existing plants are operated. Thus a serious interest in reducing SO_2 and NO_x emissions requires a willingness to repower plants where possible, and to close them and replace them with alternative resources where that is necessary.

It even appears to be the case, perhaps paradoxically, that a very intensive demand-side effort could have the effect, at least in the nearer term, of reducing environmental benefits by delaying the retirement of older, polluting plants, and thus delaying the construction of more modern, clean plants.

Two more sets of results need to be reported. The effectiveness of options for meeting CO_2 (the principal greenhouse gas) reduction objectives looks somewhat different than the objectives for traditional pollutants, such as sulfur and nitrogen oxides. The choice of supply technologies is very important in determining CO_2 emissions. Nuclear and hydro are the most effective. Gas is next. The gas/coal combined strategy and a coal strategy is clearly the worst with respect to CO_2 emissions. It is clear that an oil based strategy also performs somewhat poorly with respect to reducing CO_2 emissions. Second, conservation is also effective at reducing CO_2 emissions. Thirdly, scheduled retirement and repowering are fairly effective at reducing CO_2 emissions since they tend to move towards a gas strategy. Low sulphur oil, of course, does not affect CO_2 emissions at all.

Vulnerability. Lastly, with respect to the perennial issue of fuel and capital related vulnerability issues, some problems appear in certain of the strategies that have been proposed. Natural gas availability is an important risk for the gas dependent new technology option as well as for repowering. In a coal dependent or life extension scenario gas availability is somewhat less of an issue. Fossil fuel cost uncertainty is of course least risky for nuclear and life extension cases. It is riskier where there is a higher percentage of natural gas use. Third, capital cost risk is most severe for the capital intensive operations of nuclear and coal. Electricity prices in these cases are highly vulnerable to even a 25% capital cost overrun. The DSM programs, however, are somewhat less vulnerable to price effects from cost overruns.

It is interesting to note that in examining a very large number of scenarios, combining different supply and demand options with particular desired characteristics with respect to costs, environment, reliability and lack of vulnerability to price shifts, certain strategies tend to dominate in enough aspects to clearly be preferred strategies even without additional direct account being taken of the value of externalities. These strategies are first and foremost conservation dependent. Although it is possible to carry conservation to the point where environmental impacts are made worse, this is fairly unlikely, and even moderately strong conservation programs are consistent with improved environment and, importantly, minimizing the cost to ratepayers, whether on a price per unit electricity or electric service basis. What this appears to mean, simply put, is that conservation will be an important component of any reasonably balanced least-cost plan even under current rules. Moreover, on the supply side the region seems already to be moving toward a strategy that emphasizes increasing quantities of gas. The studies show environmental benefits and in addition only a modest effect on the cost of electricity. Because of its (possibly) improved siting ability, the gas strategy is expected to appear prominently in utility plans.

Perhaps the most important implication of this analysis is that the cost-environmental-reliability-vulnerability tradeoffs inherent in the power planning process are far more complex than can be captured in a simple environmental externality adder approach. Indeed, done incorrectly, it could as easily reduce overall efficiency (including the environmental aspects of efficiency) as increase it. Overall, the results of the MIT project to date suggest that the goals of environmental improvement that the externality adder approach seeks are likely to be achieved in significant degree in any event. While the authors of the MIT work have not yet directly modeled the effects of the Clean Air Act, including the constraints it will impose on emissions, those requirements will further reinforce the need to reduce environmental emissions.

VII. Other Policy Issues

A. The optimal area of control

A practical problem (of any environmental improvement action) centers on the geographic region in which the approach will be applied. Least-cost planning processes are carried out exclusively at the state level. Complications of several sorts could arise if and when environmental considerations are incorporated into that process.

First, and most obvious, pollution problems do not originate entirely in the state undertaking action, nor will the benefits of pollution control be confined to a particular state. Spillovers abound. For example, a significant share of Maine's and New England's pollution problems do not arise within the region at all, but are brought to the region by prevailing wind patterns from the Upper Midwest and Ohio Valley. Clearly, regulating or applying adders to effluent emitters in Maine or even in the New England region will do nothing to alleviate that problem.

Nonetheless, it may be possible to take such factors into account. Regional emitters should only "pay" effluent adders according to the incremental damage that they do, not according to the total damage that is being done by pollution. This does suggest, however, that a geographically limited approach to the problem only gets us part way to the solution we are seeking, and illustrates the advantages of regional and national action.

The other side of the coin also raises potential difficulties. Suppose that a substantial fraction of the pollutants generated within a state falls on other states. If we take the in-state approach to controlling pollution, the companies in question will still be producing such effluent at too high a rate. If we adopt an effluent control approach that accounts for all the pollution costs, some of the benefits will be enjoyed outside the region.

Additionally, firms operating inside the control region will experience substantially higher costs than those outside the region. The result will be that unless other jurisdictions take similar actions, controlled firms will have a harder time competing with untaxed firms in their industry.

This suggests that any approach that incorporates effluent costs should be as broad as possible, so that one state or a few firms are not disadvantaged. This does not, however, mean that the effluent damages should be assumed uniform across all regions. Costs may vary, even vary widely, across different regions, and businesses should be allowed to take advantage of that fact in locational decisions.

If the introduction of environmental externalities into the least-cost planning process actually involves passing on the full cost of damages to consumers, the regional spillover problem could be extremely serious. Because of this, no jurisdiction will want to be the only one to adopt full scale internalization. Ultimately, this approach to solving environmental problems must, if it is to make a real contribution toward environmental improvement, extend over a broad area.

Finally, as noted earlier in this report, there is an unresolved issue with respect to possible conflicts between the environmental adder approach, if applied to power imports from Canada, and the U.S. - Canada Free Trade Agreement. Because Canadian Power has been an important part of Maine's power mix, and is likely to continue to be an important option in the future, this issue could become of some significance if the adder approach were to be adopted.

B. Industry coverage

A third problem is the extent to which environmental externalities should be considered only in the utility planning process or across all industry. Two points should be made.

First, while the utilities are obviously a major contributor to pollution problems, they are by no means the only contributor.

A solution to environmental problems that leaves consumers as well off as they can be, and thereby allows the maximum amount of environmental improvement, must cover all industries, the transportation sector, and any other source of pollution including households. There is a danger that by directly incorporating environmental externalities only in the least-cost utility planning process, a disproportionately large share of the burden will be borne by the utility industry.

A second point is that the size of the regulated industry might shrink if the cost increases were substantial. If utilities pass through to consumers the full costs of environment degradation but private energy producers do not, there will be an incentive to substitute private generation of electricity for utility generation, or to shift to an alternative fuel. Because self-generation can already, independently of this effect, sometimes be cost effective, it would not make sense to ban such shifts. Rather, the incorporation of environmental costs must cover the broader scope of energy production. That cannot happen through a least-cost utility planning process alone. Thus, while we may begin the process with utilities, it should be understood that this is an initial step in extending these practices to a broader framework.

VIII. Other Regulatory Controls and New Administrative Processes

A. Redundancy, overlap and conflict

A major area of concern is how integrating environmental costs into least-cost planning will fit in with existing environmental regulation. There is already a lot of environmental regulation. The costs of complying with existing laws are already included in resource cost analysis. Proponents of the externality adder approach hope that it might, among other things, streamline the existing permitting and approval procedures. Such a happy outcome might be the result if this approach were being offered as a <u>substitute</u> for existing procedures. However, if, as is likely, firms in the utility industry continue to be subject to all the requirements of existing environmental laws, this process might simply create an additional layer of complexity in the regulatory process. At a minimum, ways must be found to take into account the fact that utilities already must meet substantial environmental compliance requirements, and care must be taken that this approach not lead to excessive overlap and costs.

B. The current process of environmental regulation at the D.E.P.

The purpose of the Department of Environmental Protection is to prevent, abate and control the pollution of the air, water and land and preserve, improve and prevent diminution of the natural environment of the State.

By and large, the environmental rules and laws of Maine consist of specific performance standards designed to minimize adverse effects on the environment. They are often referred to as "end-of-the-pipe" standards or standards concerned with the "quality" of the discharge to the air or water. In the case of land development, the performance standards deal with, among other things, erosion control, traffic movement, wildlife habitat and groundwater. The applicant bears the burden of proof that each environmental standard has been met and that the public's health, safety and general welfare are adequately protected. If the applicant has met all environmental regulatory standards, the Department must issue the permit or license.

The general statutory framework the Department operates in does not empower it to look at such things as public need for the project, the economics of the project (other than the developer's financial capacity to complete the project) or alternatives to the project (unless certain standards would not be met by the original project proposal). It is not within the Department's regulatory purview to evaluate the socioeconomic costs or benefits of a proposed project.

In some cases, both the PUC and DEP are involved in approving proposed energy facilities. For example, a large electric-generating facility may require several different permits or licenses from DEP before any construction can begin. These might include a Site Location of Development permit, waste water discharge license, air emissions license and one or more permits under the Natural Resources Protection Act (wetlands, aquifers, etc.). The Site Law requires that, in addition to meeting the other standards of the law, a power generating facility or transmission line must have been approved by the Public Utilities Commission. If the utility files a Site application with the Department before receiving PUC approval, it must also file a bond or other satisfactory evidence of financial capacity to reimburse the Department for its cost in processing the application in the event the applicant does not receive PUC approval. Typically, the Department's review would not begin until the proposed project had received a certificate of public convenience and necessity from the PUC. In the case of a transmission line or gas pipeline, the Department must, in addition to other requirements of the Site Law, consider the proposed project's location, character, and impact on the environment; and whether any proposed alternatives to the proposed location and character may lessen the impact on the environment or the risks to public health or safety without unreasonably increasing its cost.

A problem could arise with the current system when a utility issues requests for proposals for the purchase of power, which may involve the construction of new power-generating facilities. Proposals are received and evaluated, prices for purchasing the power are negotiated, and a date for power delivery is set. These steps typically occur without the knowledge or involvement of DEP.

The problem would be most evident in the Bureau of Air Quality Control and could come into play if the utility, in its review of applications, did not adequately consider a project's ability to comply with air emission laws and regulations. The price per kilowatt-hour (KWh) is agreed to prior to any DEP involvement and because the air laws and regulations are technology forcing, an applicant may propose to construct a generating facility based on what it perceives to be acceptable emission limits. In DEP's review of an air emission license application using Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER), the degree of control required may be greater than that originally designed by the applicant, thereby requiring more advanced and more expensive equipment. If applicants perceive a difficulty in renegotiating the price received per KWh, they will have an incentive to resist such controls.

Once a proposal is accepted by the utility, a power delivery date is set. Depending on the applicant, DEP may or may not learn of the project until a great deal of time has elapsed. In these situations the DEP finds itself in a position where priorities need to be shifted to accommodate the applicant's power contract date. While accommodations may eventually be worked out, there is considerable time and expense on the part of all parties.

C. The current process, the role of the Public Utilities Commission

The traditional role of public utility commissions has been to regulate firms which are, first, "affected with a public interest" and second, typically receive a monopoly franchise to provide service to the public. Public policy makers have usually concluded that the most efficient way to provide electric service is through a sole provider. Once that determination has been made, usually on the grounds that it is the most efficient way to produce the service, a determination is made that regulation is necessary so as to ensure that the efficiencies attained by monopoly provision are not lost to consumers because of the absence of competition.

In light of this, it is often said that regulation's principal task has been to prescribe standards for rates and utility services that mimic, insofar as possible in a declining cost industry, the prices that would obtain in a competitive industry.

In order to carry out this function, the Commission conducts regular proceedings with respect to the rates charged and the services offered by the utilities. In a typical rate case, major expenses are examined by the staff and other intervenors, both to determine the correct reporting and classification of the expense incurred, and to establish whether its treatment as an allowable expense to ratepayers is appropriate. A somewhat analogous process is followed for new facilities and major contracts. Importantly, the actual cost assigned to a particular activity or service is rarely at issue, since it is typically derived through the objective accounting procedures of the firm. But the treatment and/or acceptability of those expenses may be very much at issue.

The essential point here is that the costs themselves typically have some degree of reality outside the regulatory process itself. For example, there would rarely be a question about what the wage rate paid a particular class of labor was, what the price paid for a particular transformer or quantity of wire was, or even the amount of overdue billing that was outstanding. The Commission staff and other intervenors in the current regulatory process use relatively objective information in arguing their cases, and making the determinations of appropriate treatment. Even in forecasting issues, where judgement is very important, the basis of the exercise rests in data and methodologies available to all the parties.

While it may appear at first glance that using externality "adders" to modify resource costs is simple and straightforward (and several parties have so argued), the extension of regulatory activity into the environmental sphere does mark a fundamental departure from the traditional regulatory model, whether justified or not. Some parties have viewed this process as one where the Commission simply adds to its traditional least-cost duties the task of environmental least-cost planning.

While it is undoubtedly the case that introducing least-cost planning principles into environmental regulation would be highly desirable, much more than just the inverse of that would be taking place if the PUC were charged with building environmental effects into the electricity least-cost planning process. If the Commission were charged with the responsibility of developing environmental adders, it would be undertaking a valuation activity similar to that done by consumers or businesses when they decide to make (or avoid) a purchase. The reason is that no objective measure of the level of environmental damage, and/or how it should be valued, is available for the staff and other intervenors to use. This distinction is of critical importance. Wages, as mentioned earlier, are an independent and objective indicator of costs. They are primarily determined in the labor market, certainly not by the Commission, which usually takes them as a given. If, on the other hand, the Commission sets specific values on environmental externalities which utility companies in the State then use in their least-cost planning process, it is essentially performing the valuation task that the Legislature normally has performed, either implicitly or explicitly, when it has adopted environmental regulations or authorizes an agency such as the Department of Environmental Protection to act in its place.

As discussed earlier in this report, it is clear that valuing the externality is critical to the result, and achieving that value objectively and accurately is critical if efficient environmental improvement is to have any chance of being a result of the process. We have already pointed out that valuing environmental objectives is not the same kind of objective process that valuing wage rates or materials costs is. Because environmental outputs typically affect more than one person, the values that are established are for an average of people, and thus must be at least in part politically determined.

It is clear that the Public Utilities Commission does not now have the expertise and objective information to carry out this task. If a decision is reached that the PUC should carry out environmental analyses, it should be done in a manner that does not lead the Commission into a position where it is essentially making the subjective tradeoff decisions for society, under the cloak of an ostensibly objective and disinterested procedure. An immediate effect of the Commission's assuming such a task could be to politicize its activities to a degree, and in a way, that has not occurred to date.

We would like to point out that there is one area in which environmental externalities can find a way into our processes under existing regulation, and for which no additional authorization is, we believe, required. To the extent that a utility or the Commission reasonably believes that there is a substantial likelihood of a new environmental regulation, whether local, state or federal, a utility may reasonably incorporate those expectations into its planning process as a matter of ordinary prudent behavior. For example, if there were a high degree of likelihood that the Legislature was about to adopt a new emission limit on coal fired generation, then it would obviously be appropriate for the utility to take that into account in its planning decision. Indeed, the Commission would probably find the utility imprudent to not do so. In that sense, judgment may already enter in, but without the necessity of specific determinations of environmental tradeoffs. The example just given relies on the likelihood of an action external to the Commission, in this example through the Legislature.

Additionally, it should be pointed out that the current regulatory process already considers environmental costs that are incorporated in the power generation and distribution process. For example, the costs of scrubbers where required, the additional cost of low sulphur oil rather than high sulphur oil, and other mitigation features of the electrical system cause additional expense, and may appropriately find their way into rates at the present time. Moreover, the Commission examines the prudency and appropriateness of these expenditures.

Finally, there is a simple, but in the current budgetary context very important, question of whether or not the Commission has the capacity in terms of either personnel and budget to initiate and carry out environmental activities on an ongoing basis. It is the Commission's position that such an activity, if undertaken, should be done in as objective and defensible manner as possible. We believe that carrying out environmental valuation responsibilities would place a substantial demand on our resources and require significant additional staff, as well as a substantial increase in our budget.

There are serious questions, that remain unanswered, about the extent to which there would be redundancy and overlap between the Public Utilities Commission and other environmental agencies in dealing with these problems. It is likely that the Commission's regulation of economic and environmental impacts would conflict or overlap with processes already established for accomplishing the same goals. Indeed, it is widely acknowledged there is already some degree of conflict and overlap among the existing environmental agencies. If environmental regulation by the Public Utilities Commission were to simply overlap and complicate the existing overall environmental process, it is likely that more would be lost than would be gained.

Finally, at the core of these issues is the question of whether or not to further tighten environmental constraints on electricity production in Maine. There is no question that the environment has been an important goal of Maine people and the Maine Legislature for many years. Indeed many tradeoffs in favor of the environment that raise the cost of electricity and the price of other goods and services have already been made by the Legislature. Some of the consequences of these decisions have already been discussed in this report. We believe it is always appropriate for the Legislature to consider whether or not further tradeoffs should be made.

We note that the work currently under way in the M.I.T. Regional Energy Project, already extensively discussed in this report, along with work undertaken for New England by Florentin Krause of the Lawrence Berkeley Laboratories, offers the potential for the Legislature and other interested parties to study what the nature of these tradeoffs is. With the information developed in these projects, it is possible to ask questions such as: "If we wish to reduce pollutants by 10% over the next 5 years, or 10 years or 20 years, what would be the impact on electricity prices, cost of electricity service, reliability, etc.? The availability of this information offers an opportunity to make explicit and better understood tradeoffs between environmental improvement and other factors than ever before.

IX. Conclusions and Recommendations

Based on the foregoing analysis and materials, we reach the following conclusions.

1) Methods that offer an incentive approach to firms to improve environmental conditions hold substantial promise and should continue to be pursued. The least-cost planning framework adopted by the utilities in Maine and in many other parts of the nation in recent years offers a good conceptual framework for minimizing the overall impact of electricity production on society and consumers. It may also offer a broad analytic approach that could be helpful in minimizing the costs of the environmental actions society determines appropriate.

2) Electric production in Maine is currently subject to a range of environmental controls, including the regulation of air emissions at both the state and federal levels, discharges into water, at both the state and federal level, effects on waterways, fisheries and recreation, again at both the federal and state levels. Electric production and distribution facilities in Maine are also subject to local zoning and permitting regulation. We have seen that, at least in the electricity area, Maine has made great progress in controlling emission externalities and in the use of renewable resources.

We have been unable to draw any conclusion that there exist un-addressed externalities associated with the production of electricity in Maine. Nor can we conclude that any remaining environmental impacts in the state, which certainly exist, are either the right amount, too much, or too little. We have no comprehensive knowledge of the amount of expenditure that has occurred in Maine for the purpose of improving the environment, nor do we have any reliable means of estimating the benefits that have flowed from that expenditure. Without this information, it is not clear where any incremental action, if needed, should be taken.

3) A central problem is that there is no information available for estimating the marginal value of environment externalities in Maine at the present time. A wide range of estimates have been proposed elsewhere, and states that have

introduced environmental factors in the least-cost planning process have adopted values which differ by very large amounts. In the absence of convincing values, there is no presumption that the introduction of such values, whether as adders in the least-cost planning process, or for that matter in some other form, would necessarily lead to improvements in the environment that are cost justified and/or in the overall interest of consumers.

We also would like to address the objection some parties have raised that, while we may not know the exact figure, we do know that it is not zero, and that therefore, any positive value will necessarily be an improvement. If there were no existing environmental rules, this argument could be true. But that is not the case. Electric utilities operate under an extensive and complex set of environmental constraints and mitigation requirements. Because of this, it can no longer automatically be concluded that additional environmental controls are desirable and should be required. Whether that is true or not depends on a careful weighing of the costs and benefits of further action.

4) The available evidence for New England also suggests that the environmental adder program, if imposed, would be unlikely to have significant effects either on environmental conditions or the costs of producing electricity, at least in the near term. There are several reasons for this.

First, as noted in the earlier analysis, the imposition of the environmental adder only revalues particular resources in the selection order. If the adder is insufficient to change that order, there will be no effect. The research program at M.I.T. reported earlier, suggests strongly that the resources that would be likely to be advantaged through the imposition of an environmental adder program are in general the ones already being selected in the least-cost planning process. Moreover, these resources are generally the ones yielding the largest environmental benefits, at least at the present time.

Second, and perhaps most importantly, electricity demand conditions throughout Maine and New England are such that only modest amounts of new resources are likely to be required in the early part of this decade and perhaps through the end of the decade. When this is combined with the likelihood that it is the cleaner resources, including conservation, that are likely to be selected, any additional benefits of incorporating externalities are likely to be very modest. We also note that such adders have not been in place long enough in other jurisdictions to determine what, if any, effect they might have had in practice.

These considerations, taken together, suggest that the likely result of imposing such a process on least-cost planning would be quite limited at least for the next five to ten years. In light of that fact, we conclude that it is not imperative that the Legislature require the Commission to embark on a program of incorporating external environmental effects directly into the least cost planning process at this time.

5) There are also serious administrative reasons for not embarking on such a program at this time.

First, the resource requirement to develop an environmental program in a credible way, so that it contributes in an efficient manner to an improved environment and more efficient electricity production overall, requires very substantial staff resources. It would take a minimum of two full time staff positions plus a substantial support budget for specialized technical and consulting help, to determine externality values that are not simply ad hoc and without serious empirical foundation.

The Commission does not currently have sufficient resources to carry out this program, and given the current workload of the Commission, is unlikely to be able to find resources internally for the foreseeable future.

In addition, without substantial and careful coordination with other environmental agencies in the State, there is likely to be redundancy, overlap, and duplication of function. We believe that the imposition of adders in this setting could complicate rather than simplify the environmental regulatory process for utilities. New environmental approaches should simplify, not further complicate, the overall compliance process.

If a well designed environmental adder or tax approach to environmental considerations for utilities were to be adopted in place of alternative state and local regulation, there could be substantial benefits from streamlining and simplification of the administrative process. The Legislature may wish to consider this option for utility environmental regulation. We note, however, that federal law could not be substituted for in this fashion and would continue to operate.

6) With little growth in generation resources expected in the near and intermediate term, any substantial environmental improvement will have to come from modifications of the existing resources and alterations in the way those resources are used. The Clean Air Act recently adopted by Congress provides incentives to engage in that sort of modification, and thus is likely to have a beneficial impact on environmental conditions in Maine and elsewhere.

If the legislature feels that further environmental improvement may be appropriate, a productive approach might be to investigate such options as switching Maine's generation facilities from relatively high sulphur oils to low sulphur oils that are available on the market. This option could provide, if chosen, the fastest and lowest cost method of gaining a large environmental impact.

Recommendation:

Although, for the reasons stated above, we do not recommend that a system of environmental adders be adopted at the present time, we do believe the process of investigating these questions, both in Maine and throughout New England, has been productive. It has provided a substantial body of information, that did not previously exist, which can allow interested parties, including the State of Maine or its individual public utilities, to begin to approximate the trade off between environmental improvement and the cost of electricity, reliability, diversity and protection from sudden changes in circumstances. This work has been underway at M.I.T. for about a year and a half to two years for New England as a whole.

Maine, and its utilities, have not yet been studied separately, but were adequate resources available to do so, the work could proceed in a relatively straightforward manner using existing data. The results of such an investigation could provide the Legislature, and the community as a whole, with far more information than it has ever had before when making determinations on environmental rules and regulations. Moreover, the analytic framework can be used to achieve whatever environmental benefits are deemed desirable on a least-cost basis. Pursuing this approach would be a substantial improvement over practice to date, and is well worth trying to achieve.

The Legislature may wish to authorize the Commission to direct Maine's utilities to conduct studies for Maine and their own territories specifically, in order to better understand what is at issue in making environmental improvements. We believe that by employing existing study methodologies along the lines of the M.I.T and Lawrence Berkeley Laboratory work that is ongoing, results could be obtained in a relatively expeditious way, and on an economical basis.

In conclusion, while an environmental adder process, as initially envisaged, seems unlikely to add to the information available to effect environmental regulation at this stage of its development, and as a practical matter has little likelihood of having any substantial effects in the near term, we nevertheless believe that this has been an entirely productive process and may, over the longer term, prove fruitful. If the Legislature agrees with the suggestions we offer for a continuation of work on this issue, the terms of environmental debates in Maine and elsewhere will be vastly improved and choices will be made by legislatures and other authorized parties that better reflect the costs of the choices and the desires of citizens for a better environment.

Appendix A

BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

In Re rulemaking regarding resource)
planning changes pursuant to SB 497.)
)

Docket No. 89-752

At a general session of the Public Service Commission of Nevada, held at its offices in Carson City, Nevada, January 22, 1991.

PRESENT: Chairman Thomas E. Stephens
Commissioner Stephen Wiel
Commissioner Jo Ann Kelly
Commissioner Michael A. Pitlock
Commissioner Rose McKinney-James
Secretary William H. Vance

ORDER

The Public Service Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

1. In July 1989, the Commission opened a rulemaking docket to adopt regulations relating to the resource plans of electric utilities with annual operating revenue in Nevada of $2,500,000 or more.

2. The matter has been designated as Docket No. 89-752.

3. Nevada Revised Statute ("NRS") 704.746, as amended in October 1989, directs the Commission to adopt regulations which determine the level of preference to be given to those measures and sources of supply that (1) provide the greatest economic and environmental benefits to the State, (2) are consistent with the provisions of NRS 704.746, and (3) provide levels of service that are adequate and reliable.

4. On May 1, 1990, the Commission issued a Notice of Workshop and Request for Comments Regarding the Development of Proposed Regulations.

5. The Commission received written comments from the Attorney General's Office of Advocate for Customers of Public Utilities

("OCA"), Sierra Pacific Power Company ("SPPC"), the State of Nevada's Commission on Economic Development ("CED"), Nevada Power Company ("NPC"), the State of Nevada's Office of Community Services ("NOCS"), California Energy Company, LUZ Development and Finance Corporation and its parent company LUZ International ("LUZ"), Bonneville Pacific Corporation ("Bonneville"), Ormat Energy Systems, Inc. ("Ormat"), the Clark County Health District and the Regulatory Operations Staff of the Commission ("Staff").

6. The workshop was held in Las Vegas on May 31, 1990.

7. On July 10, 1990, the Commission issued a Notice of Workshop for an "experts panel workshop".

8. On July 23, 1990, the Commission issued a Corrected Notice of Workshop.

9. The "experts panel workshop" was held in Carson City on August 7, 8 and 15, 1990.

10. On August 20, 1990, the Commission issued a Notice of Workshop.

11. A workshop was held in Las Vegas on September 21, 1990.

12. On October 2, 1990, the Commission issued a Notice of Consumer Session.

13. Consumer sessions were held in Las Vegas on October 25, 1990 and in Reno on October 29, 1990.

14. At a regularly scheduled agenda meeting on November 19, 1990, the Commission voted to issue a proposed regulation for this docket.

15. On November 21, 1990, the Commission issued a Notice of Intent to Adopt Regulation, Request for Comments and Notice of Hearing ("Notice of Intent")

16. In addition to inviting comments from interested persons on all aspects of the proposed rule, the Notice of Intent specifically solicited comments on the following issues:

a. whether the final rule should retain present worth of revenue requirement ("PWRR") as the primary selection criterion, establish present worth of societal costs ("PWSC") as the primary selection criterion or leave the issue for determination by the Commission in each resource plan?

b. whether a party other than the company has the burden to establish the PWSC for an option?

c. how the quantification of the environmental costs and economic benefits of demand side programs should be utilized in establishing the PWRR or PWSC of an option?

d. whether the PWSC associated with a power purchase from an existing plant should be treated differently than a plant to be constructed?

e. whether the Commission should include language (in table form) in its final Order (and not within the rule itself) which provides values for pollutant emission factors and environmental costs which shall be used by all affected utility companies from the date of that Order until the Commission's decision in each company's next resource plan.

17. The Commission received comments from Staff, OCA, LUZ and California Energy Company, Inc., Sierra Pacific Resources, Ormat, NPC, SPPC, American Wind Association, Dr. Timothy Duane, Clark County Health District and Les Simmons.

18. The hearing commenced on January 8, 1991, and concluded on January 9, 1991.

19. At the beginning of the hearing, five public witnesses provided comments.

20. Participating at the hearing were Staff, OCA, Sierra Pacific Resources, SPPC, NPC, LUZ, Ormat, California Energy Company, Clark County Health District and the Utility Shareholder's Association.
21. The record for this docket includes 1,718 pages of transcript and 60 exhibits.
22. The workshops and hearing were noticed in conformance with NRS 233B.
23. Attached to the Notice of Intent were three tables reflecting values of emission factors and environmental costs.
24. At the hearing, there was significant support for eliminating Table 3 and revising Tables 1 and 2.
25. The values of emission factors and environmental costs listed in the attached Tables 1 and 2 shall be used by all affected utility companies as default values from the date of this Order until the Commission's decision in each company's next resource plan.
26. The concept of "societal dispatch" was discussed at the hearing. NPC volunteered to provide such an analysis in its next resource plan.

Therefore, it is ORDERED that:

1. The regulations, as attached hereto, are hereby ADOPTED as the final rule. By this reference, said rule is incorporated in the instant Order.
2. The attached Tables 1 and 2 are hereby incorporated in the instant Order.
3. The values of emission factors and environmental costs listed in the attached Tables 1 and 2 shall be used by all affected utility companies as default values from the date of this Order until the Commission's decision in each company's next resource plan.

4. The Commission retains jurisdiction for the purpose of correcting any errors which may have occurred in the drafting or issuance of this Order.

By the Commission,

THOMAS E. STEPHENS, Chairman

STEPHEN WIEL, Commissioner

JO ANN KELLY, Commissioner

MICHAEL A. PITLOCK, Commissioner

ROSE McKINNEY-JAMES, Commissioner

Attest: William H. Vance
WILLIAM H. VANCE, Secretary

Dated: Carson City, Nevada
2/1/91

(SEAL)

TABLE 1

1/11/91

Electric Facilities Emissions Factors and Water Use

	Emissions (lbs/MMBtu In)										Water Use (gals per MMBtu In)
	NOx	SOx	TSP	CO	VOC	CO2	CH4	N2O	H2S	NH3	
New Utility Facilities											
Baseload											
1a. Combined Cycle NG	0.3933	0.0006	0.001	0.021	0.033	117	0.0019	0.0078	NA	NA	17.5
b. Combined Cycle NG w/SWI	0.0787	0.0006	0.001	0.021	0.033	117	0.0019	0.0078	NA	NA	17.5
c. Combined Cycle NG w/SWI + SCR	0.0283	0.0006	0.001	0.021	0.033	117	0.0019	0.0078	NA	0.037	17.5
2a. Combined Cycle Distillate Oil	0.5	0.315	0.001	0.018	0.0165	163	0.0016	0.0325	NA	NA	17.5
b. Combined Cycle Distillate Oil w/SCR	0.1	0.315	0.001	0.018	0.0165	163	0.0016	0.0325	NA	0.039	17.5
3a. Combined Cycle Residual Oil	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
4a. Coal, Pulverized w/scrubbers	0.6	0.6	0.03	0.024	0.004	238	0.0015	0.0325	NA	NA	48.4
5a. Coal, Atmospheric Fluidized Bed	0.5	0.6	0.01	0.15	0.0028	238	0.0015	0.0325	NA	NA	1590
6a. Coal, Integrated Gasificaton Comb. Cycle	0.20	0.33	0.003	0.01	0.003	198	0.0015	0.0325	NA	NA	NA
7a. Geothermal Flashed steam w/injection	NA	NA	NA	NA	NA	0.03	1E-05	NA	0.00166	NA	55.6
8a. Solar, Thermal	0	0	0	0	0	0	0	0	0	0	69
b. NG, Boiler back-up unit	0.150	0.0006	0.00290	0.038	0.0013	119	0.0002	0.028	NA	NA	93
c. NG, Boiler back-up unit with LNB	0.031	0.0006	0.0029	0.038	0.0013	119	0.0002	0.028	NA	NA	93
d. NG, Boiler back-up unit with LNB + SCR	0.012	0.0006	0.0029	0.038	0.0013	119	0.0002	0.028	NA	NA	93
9a. Solar, Photovoltaic	0	0	0	0	0	0	0	0	0	0	0
10a. MSW, Steam Boiler	0.308	0.38	0.4700	0.93	0.0300	165	0.001	0.033	NA	NA	NA
b. MSW, Steam Boiler w/FFB	0.308	0.38	0.00470	0.93	0.0300	165	0.001	0.033	NA	NA	NA
11a. Wood, Steam Boiler	0.155	0.0083	0.4862	0.221	0.0773	212	0.033	0.033	NA	NA	NA
b. Wood, Steam Boiler w/FFB	0.155	0.0083	0.00486	0.221	0.0773	212	0.033	0.033	NA	NA	NA
12a. Wind	0	0	0	0	0	0	0	0	0	0	0
13a. Small Hydroelectric	0	0	0	0	0	0	0	0	0	0	0
14a. Purchases	Check source note.										
Peakers											
1a. Combustion Turbine NG	0.3933	0.0006	0.0133	0.1095	0.012	119	0.012	0.018	NA	NA	0.03
b. Combustion Turbine NG w/SWI	0.0787	0.0006	0.0133	0.1095	0.012	119	0.012	0.018	NA	NA	0.03
c. Combustion Turbine NG w/SWI + SCR	0.0283	0.0006	0.0133	0.1095	0.012	119	0.012	0.018	NA	0.037	0.03
2a. Combustion Turbine Distillate Oil	0.8	0.212	0.03	0.116	0.0359	164	0.0016	0.0211	NA	NA	0.03
b. Combustion Turbine Distillate Oil w/SWI	0.2	0.212	0.03	0.116	0.0359	164	0.0016	0.0211	NA	NA	0.03
3a. Reciprocating Engine, Diesel	3.3500	0.0557	0.2393	0.7286	0.2293	162	NA	NA	NA	NA	NA
b. Reciprocating Engine, Diesel w/SCR	0.5025	0.0557	0.2393	0.7286	0.2293	162	NA	NA	NA	0.039	NA
4a. Pump-storage Hydroelectric	Check source note.										0
5a. Purchases	Check source note.										

Electric Facilities Emissions Factors and Water Use

New Utility Facilities	Heat Rate	Emissions (lbs/MWhr out) NOx	SOx	TSP	CO	VOC	CO2	CH4	N2O	H2S	NH3	Water Use (gals per MWhr out)
Baseload												
1a. Combined Cycle NG	8140	3.2	0.005	0.01	0.17	0.27	952	0.015	0.063	NA	NA	142
b. Combined Cycle NG w/SWI	8140	0.64	0.005	0.01	0.17	0.27	952	0.015	0.063	NA	NA	142
c. Combined Cycle NG w/SWI + SCR	8140	0.23	0.005	0.01	0.17	0.27	952	0.015	0.063	NA	0.3	142
2a. Combined Cycle Distillate Oil	8140	4	2.56	0.01	0.15	0.13	1330	0.013	0.265	NA	NA	142
b. Combined Cycle Distillate Oil w/SCR	8140	0.8	2.56	0.01	0.15	0.13	1330	0.013	0.265	NA	0.32	142
3a. Combined Cycle Residual Oil	8250	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
4a. Coal, Pulverized w/scrubbers	9400	6	6	0.3	0.23	0.038	2240	0.014	0.306	NA	NA	455
5a. Coal, Atmospheric Fluidized Bed	10000	5	6	0.1	1.5	0.03	2380	0.015	0.325	NA	NA	15900
6a. Coal, Integrated Gasificaton Comb C	9280	1.9	3.1	0.03	0.09	0.03	1840	0.014	0.302	NA	NA	NA
7a. Geothermal, Flashed steam w/injectio	40000	NA	NA	NA	NA	NA	1.20	0.0004	NA	0.0664	NA	2224
8a. Solar, Thermal	14600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1007
b. NG, Boiler back-up unit	11000	1.65	0.007	0.032	0.42	0.014	1310	0.002	0.31	NA	NA	1023
c. NG, Boiler back-up unit w/LNB	11000	0.34	0.007	0.032	0.42	0.014	1310	0.002	0.31	NA	NA	1023
d. NG, Boiler back-up w/LNB + SCR	11000	0.13	0.007	0.032	0.42	0.014	1310	0.002	0.31	NA	NA	1023
9a. Solar, Photovoltaic	24000	0	0	0	0	0	0	0	0	0	0	0
10a. MSW, Steam Boiler	16800	5.17	6.4	7.896	16	0.504	2770	0.02	0.55	NA	NA	NA
b. MSW, Steam Boiler w/FFB	16800	5.17	6.4	0.079	16	0.504	2770	0.02	0.55	NA	NA	NA
11a. Wood, Steam Boiler	16740	2.59	0.14	8.139	3.7	1.29	3550	0.55	0.55	NA	NA	NA
b. Wood, Steam Boiler w/FFB	16740	2.59	0.14	0.08136	3.7	1.29	3550	0.55	0.55	NA	NA	NA
12a. Wind	7600	0	0	0	0	0	0	0	0	0	0	0
13a. Small Hydroelectric	3800	0	0	0	0	0	0	0	0	0	0	0
14a. Purchases		Check source note.										
Peakers												
1a. Combustion Turbine NG	13100	5.152	0.008	0.174	1.434	0.16	1560	0.16	0.24	NA	NA	0.4
b. Combustion Turbine NG w/SWI	13100	1.03	0.008	0.174	1.434	0.16	1560	0.16	0.24	NA	NA	0.4
c. Combustion Turbine NG w/SWI + SC	13100	0.371	0.008	0.174	1.434	0.16	1560	0.16	0.24	NA	NA	0.4
2a. Combustion Turbine Distillate Oil	13100	8	2.78	0.4	1.52	0.470	2150	0.021	0.276	NA	NA	0.4
b. Combustion Turbine Distillate Oil w/S	13100	3	2.78	0.4	1.52	0.470	2150	0.021	0.276	NA	NA	0.4
3a. Reciprocating Engine, Diesel	10000	33.500	0.557	2.393	7.286	2.293	1620	NA	NA	NA	NA	NA
b. Reciprocating Engine, Diesel w/SCR	10000	5.025	0.557	2.393	7.286	2.293	1620	NA	NA	NA	0.39	NA
4a. Pump-storage Hydroelectric	4900	Check source note.										
5a. Purchases		Check source note.										

Source Notes:

Bibliographic Key.

Tellus (a)	'Evaluation of Repowering the Manchester Street Station'. A report to the Rhode Island Division of Public Utilities and Carriers, Rhode Island Division of Statewide Planning, and Rhode Island Governor's Energy Office of Energy Assistance.
Tellus (b)	'The Role of Hydro-Quebec Power in a Least-Cost Resource Plan for Vermont'. A Report to the Vermont Department of Public Service, January 19, 1990.
ASF	'Atmospheric Stabilization Framework'. Model used to develop 'Policy Options for Stabilizing Global Climate: Draft Report to Congress', February 1989.
CEC (a)	California Energy Commision. 'Staff Recommendations for Generic Power Plant Emissions Factors (Final Version)', August, 1989.
CEC (b)	California Energy Commission, 'Energy Technology Status Report, July, 1990. Draft Copy.
ETH	'Energy Technology Characterization Handbook', DOE, March, 1983.
UNEP	United Nations Environment Program, 'The Environmental Impacts of Production and Use of Energy', January, 1985
Gleick	Peter H. Gleick et. al., 'Greenhouse-Gas Emissions from the Operation of Energy Facilities', July, 1989.
ADL	Arthur D. Little, Inc., 'Selective Catalytic NOx Reduction Technology for Cogeneration Plants', November, 1988
LUZ	Personal Communication with LUZ Development and Finance Corporation, 1990.
Goddard & Goddard	Goddard & Goddard, 'Global Warming and Geothermal Energy', Geothermal Resources Council Bulletin, January, 1990
Mintzer	Mintzer & Hedman, Externalities Associated with Electric Power Supply and Demand-Side Technologies.

:ew Utility Facilities

Baseload

1a. Combined Cycle NG. Sulfur content 0.0007%. Oxidation catalyst at 80% control for CO. Source: Tellus (a) for emissions (except NOx which is from CEC (a)) and chosen CO control level. Water consumption from CEC (b).

b. Combined Cycle NG w/SWI. Sulfur content is 0.0007%. Oxidation catalyst at 80% control for CO and SWI at 80% control for NOx. Source: Tellus (a) for emissions and chosen CO control level, CEC (a) for chosen NOx control level.Water consumption from CEC (b).

c. Combined Cycle NG w/SWI + SCR. Sulfur content is 0.0007%. Oxidation catalyst at 80% control for CO. SWI + SCR at 92.8% control for NOx which corresponds to 9 ppm . SWI reduces NOx emissions by 66.4% going from approximately 125 ppm to 42 ppm. This is followed by an additional 78.6 % reduction from SCR going from 42 ppm to 9 ppm. In the Northeast, this was considered the least cost combination of NOx control to achieve the NESCAUM regulation of 9 ppm. Source: Tellus (a) for emissions and chosen CO control level, CEC (a) for chosen NOx control level. NH# emissions are a Tellus calculation (see explanatory notes). Water consumption is from CEC (b).

2a. Combined Cycle Distillate Oil. Sulfur content is 0.3%, and ash is less than 0.1%. Oxidation catalyst at 80% control for CO. Source: Tellus (a) for emissions and chosen CO control level. Water consumption is assumed equivalent to CC NG

b. Combined Cycle Distillate Oil w/SCR. Sulfur content is 0.3%, and ash is less than 0.1%. Oxidation catalyst at 80% control for CO and SCR at 80% control for NOx. Source: Tellus (a) for emissions and chosen CO control level, CEC (a) for chosen NOx control level. The NH3 emissions are a Tellus calculation (see explanatory notes). Water consumption is assumed equivalent to CC NG.

3a. Combined Cycle Residual Oil. NA

4a. Coal, pulverized w/scrubbers. Sulfur content is 2.5% and ash content is 12%. Scrubbers at 83% control for SOx and 90% control for TSP. Source: Tellus (a) for emissions (except CO2 which comes from Gleick to reflect Western coal). Internal calculation to estimate control levels. Water consumption from ETH.

5a. Coal, Atmospheric Fluidized Bed Combustion. Sulfur content is 2.5% and ash content is 12%. Source: Tellus (a) (except coal which comes from Gleick to reflect Western coal). Water consumption from CEC (b).

6a. Coal, Integrated Gasification Combined-Cycle. Sulfur content is 1.4% and ash content is 6.25%. Source: Tellus (a) (except CO2 which comes from Gleick to reflect Western coal).

7a. Geothermal, Flashed steam w/injection. Average of the 9 CECI Coso plants, 8 under construction. Air Emissions Control Systems (AECS) utilizing noncondensible gas injection. Heat Rate is assumed 40000 Btu/KWhr. Source: Goddard & Goddard for emissions, Tellus for Heat Rate.

Water consumption from LUZ.

8a. Solar, Thermal. The cycle consists of tracking heliostats which are automatically steered to reflect direct solar radiation onto the receiver. The energy is transferred to a working fluid which is a heat source for the thermodynamic cycle. Source: UNEP. This cycle generates electricity. Water consumption from LUZ.

b. NG Boiler back-up unit. Sulfur content is .0007%. Source: CEC (a) for SOx, TSP, CO, CO2 and VOC emissions, ASF for CH4 and N2O emissions. Emissions for a solar thermal facility with NG boiler back-up will be a weighted (by % of generation) average of these two facilities. Water consumption from LUZ.

c. NG Boiler back-up unit w/LNB. Sulfur content is .0007%. Source: CEC (a) for SOx, TSP, CO, CO2 VOC emissions, LUZ for NOx emissions, ASF for CH4 and N2O emissions. The NOx value reflects emissions at the LUZ SEGS VIII and IX projects. Emissions for a solar thermal facility with NG boiler back-up will will be a weighted (by % of generation) average of these two facilities. Water consumption from LUZ.

d. NG Boiler back-up unit w/LNB + SCR. Sulfur content is .0007%. Source: CEC (a) for SOx, TSP, CO, CO2 VOC emissions, LUZ for NOx emissions, ASF for CH4 and N2O emissions. The NOx value reflects emissions at the LUZ SEGS VII and IX projects. Emissions for a solar thermal facility with NG boiler back-up will be a weighted average (by % of emissions) of these two facilities. Water consumption from LUZ.

9a. Solar, Photovoltaic. Source: UNEP. The plant consists of single-crystal silicon photovoltaic cell which convert the solar radiation directly into electricity.

10a. MSW, Steam boiler. Sulfur content is 0.17%. Source: CEC (a) for NOx, SOx, TSP, CO, VOC, and CO2 emissions. Source: ASF for CH4 and N2O emissions.

b. MSW, Steam Boiler. Sulfur content is 0.17%. FFB at 99% control for TSP. Source: CEC (a) for NOx, SOx, TSP, CO, VOC, CO2 emissions, and chosen TSP control level. ASF for CH4 and N2O emissions.

11a. Wood, Steam Boiler. Using Douglas fir wood waste. Source: CEC (a) for NOx, SOx, TSP, CO, VOC, and CO2 emissions. Source: ASF for CH4 and N2O emissions.

b. Wood, Steam Boiler. Using Douglas fir wood waste. FFB at 99% control for TSP. Source: CEC (a) for NOx, SOx, TSP, CO, VOC, CO2 emissions, and chosen TSP control level, ASF for CH4 and N2O emissions.

12a. Wind. This represents a central wind farm. Source: ETH.

13a. Small Hydroelectric. A plant with less than 15 MW of capacity and usually fed by a dam with height no more than 65 ft. Impounding is less than 500 acres. Source: UNEP.

14a. Purchases. Emission coefficients from purchases should reflect the appropriate fuel mix and emission coefficients from utility system from which purchases originate.

Peakers

1a. Combustion Turbine NG. Sulfur content is 0.0007%. Source: CEC for NOx, SOx, TSP, CO, VOC, and CO2 emissions, ASF for CH4 and N2O emissions. Water consumption from CEC (b).

b. Combustion Turbine NG. Sulfur content is 0.0007%. SWI at 80% control for NOx. Source: CEC for NOx, SOx, TSP, CO, VOC, CO2 emissions and chosen NOx control level. ASF for CH4 and N2O emissions. Water consumption from CEC (b).

c. Combustion Turbine NG w/SWI + SCR. Sulfur content is 0.0007%. SWI + SCR at 92.8% control for NOx which corresponds to 9 ppm . SWI reduces NOx emissions by 66.4% going from approximately 125 ppm to 42 ppm. This is followed by an additional 78.6 % reduction from SCR going from 42 ppm to 9 ppm. In the Northeast, this was considered the least cost combination of NOx control to achieve the NESCAUM regulation of 9 ppm. Source: Tellus (a) for emissions and chosen CO control level, CEC (a) for chosen NOx control level. NH# emissions are a Tellus calculation (see explanatory notes). Water consumption is from CEC (b).

2a. Combustion Turbine Distillate Oil. Sulfur content is 0.2%. Source: Tellus (b). Water consumption assumed equivalent to NG CT.

b. Combustion Turbine Distillate Oil w/SWI. Sulfur content is 0.2%. SWI at 70% control for NOx. Source: Tellus (b) for uncontrolled emissions, CEC (a) for chosen NOx control level. Water consumption assumed equivalent to NG CT.

3a. Reciprocating Engine, Diesel. Sulfur content is .25%, HR is a Tellus estimate. Source: CEC (a).

b. Reciprocating Engine, Diesel w/SCR. Sulfur content is .25%, HR is a Tellus estimate. SCR at 85% control for NOx. Source: CEC (a) for emissions and chosen control level. The NH3 emissions are a Tellus calculation. See explanatory notes.

4a. Pump-storage Hydroelectric. A typical plant may consist of four 250 MW pumps and drivers that utilize base load power during off-peak demand for pumping water from a lower to a higher reservoir. The pumping units become turbines driving electrical generators when the stored water is during periods of high demand. Source: UNEP. Emissions from pump storage hydroelectric arise from the pumping stage and not the released electricity generation stage. The emissions will therefore depend on the mix of pumping devices.

5a. Purchases. Emission coefficients from purchases should reflect fuel mix and emission coefficients from utility system from which purchases originate.

Explanatory Notes and Adjustment Specifications:

Control Devices.

Control levels can be adjusted on the facilities with control devices in place (affecting only the level of the controlled pollutant). The adjustment can be performed as follows:

$$E1 = E0 * (1-Y)/(1-X)$$

where E1 is the pollutant emission rate after desired control adjustment, E0 is the pollutant emission rate before adjustment, X is the original control level (in decimal from), Y is the desired control level (in decimal form). Refer to the explanatory notes for a reasonable range of control level. This adjustment should be made on both emissions per energy in and energy out.

Heat Rates.

The above emission coefficients per unit energy out can be adjusted if a different heat rate is desired. The adjustment can be performed as follows:

$$E1\ out = E0\ out * (HR1/HR0)$$

where E1 out is the pollutant emission rate after desired heat rate adjustment, E0 out is the pollutant emission rate before adjustment, HR1 is the adjusted heat rate, HR0 is the original heat rate.

Fuel Sulfur Content.

SOx emissions can be adjusted by changing the amount of sulfur present in the fuel. This adjustment can be made as follows:

$$SOx1 = SOx0 * (S1/S0)$$

where SOx1 is the adjusted SOx emission rate, SOx0 is the original SOx emission rate, S1 is the adjusted fuel sulfur percentage (in decimal form), and So is the original fuel sulfur percentage (in decimal form).

NH3 Emissions

Ammonia emissions are given in ADL 1989 for existing energy producing facilities with SCR devices enabled. These emission rates ranged from .0157 lbs/MMBtu to .0777 lbs/MMBtu. An average of these emission rates, .0391 lbs/MMBtu corresponds to an average control level of 83%. This NH3 emission level was linearly adjusted in the tables to reflect the SCR control level. These values are considered approximate.

Non-System Offsets

1. COGENERATION: Electricity producing facilities that produce usable steam in addition to their output of electricity can displace emissions from steam producing devices. The expression for the net emission rate for a cogenerator can be expressed as follows:

$$En = Eg - Eb*(Sc/Sb)$$

where En is the net cogenerator emission rate, Eg the gross cogenerator emission rate, Eb the gross avoided boiler emission rate, Sb the steam efficiency of the displaced boiler (out/in), and Sc the steam efficiency of the cogenerating facility (=[1-3414/HR]*F, where HR is tre electric heat rate and F is the fraction of waste heat captured for thermal uses). We recommend that the power developer quantify the offsets (i.e. Eb*(Sc/Sb)).

2. LANDFILL DECOMPOSITION OFFSETS: The use of municipal solid waste and wood waste in electricity generating facilities can displace emissions from decomposition in landfills. Average emissions from municipal solid waste landfills are 5 lbs/MMBtu and 12 lbs/MMBtu for CH4 and CO2, respetively. We recommend that the power developer quantify these offsets.

3. SUSTAINABLE WOOD YIELD OFFSETS: Live biomass respiration can displace some of the emissions of wood burning facilities. We recommend that the power developer quantify the offsets.

Geothermal Emissions

The geothermal emissions presented here are not considered wholly representative of potential geothermal emissions in Nevada. Geothermal emissions are very site-specific and emission values should be submitted by potential developers if anticipated emissions are substantially different from those presented here.

w Utility Facilities

Baseload

a. Combined Cycle NG. The potential range for the CO control using oxidation catalyst is 80 - 90%. Source: CEC (a) for control range.
b. Combined Cycle NG w/SCR. The potential range for CO control using oxidation catalyst is 80 - 90%. The potential range for NOx control using SCR is 80 - 90%. Source: CEC (a) for control ranges.
a. Combined Cycle Distillate Oil. The potential range for CO control using oxidation catalyst is 80 - 90%. Source: CEC (a) for control range.
b. Combined Cycle Distillate Oil w/SCR. The potential range for CO control using oxidation catalyst is 80 - 90%. The potential range for NOx control using SCR is 80 - 90%. Source: CEC (a) for control ranges.
a. Combined Cycle Residual Oil.
a. Coal, pulverized w/scrubbers.
a. Coal, Atmospheric Fluidized Bed Combustion.
a. Coal, Integrated Gasification Combined-Cycle.
a. Geothermal, Flashed steam w/injection.
a. Solar, Thermal.
b. NG Boiler back-up unit.
c. NG Boiler back-up unit w/LNB.
d. NG Boiler back-up unit w/SCR.
a. Solar, Photovoltaic.
0a. MSW, Steam boiler.
b. MSW, Steam Boiler w/FFB.
1a. Wood, Steam Boiler.
b. Wood, Steam Boiler w/FFB.
2a. Wind.
3a. Small Hydroelectric.
4a. Purchases.

eakers

a. Combustion Turbine NG.
b. Combustion Turbine NG. The potential range for NOx control using SWI is 70 - 82%. Source: CEC for control range.
a. Combustion Turbine Distillate Oil.
b. Combustion Turbine Distillate Oil w/SWI. The potential range for NOx control using SWI is 70 - 82%. Source: CEC for control range.
a. Reciprocating Engine, Diesel.
b. Reciprocating Engine, Diesel w/SCR. The potential range for NOx control using SCR is 80 - 90%. Source: CEC for control range.
a. Pump-storage Hydroelectric.
a. Purchases

TABLE 2

VALUATION OF ENVIRONMENTAL COSTS

Pollutant	Valuation (1990 dollars/lb)
Carbon Dioxide (CO_2)	0.011
Methane (CH_4)	0.11
Nitrous Oxide (N_2O)	2.07
Nitrogen Oxides (NO_2)	3.4[1]
Sulfur Oxides (SO_x)	0.78
Volatile Organic Compounds (VOC)	0.59[2]
Carbon Monoxide (CO)	
Ambient Air Quality +	0.43[1]
Global Warming Contribution	0.03
Total	0.46
Total Suspended Particulates/ Particulate Matter (Diam<10MM) TSP/PM_{10}	2.09[1]
Hydrogen Sulfide (H_2S)	NA[3]
NH_1	0
Water Impact	Site Specific (Determined by Utility)
Land Use	Site Specific (Determined by Utility)

[1]The value is applicable to EPA attainment areas. The value for an EPA non-attainment area is equal to or greater than the amount and is likely to be site specific.

[2]The value for VOC has been adjusted to reflect the state of Nevada's status as attainment for VOC. This value is representative of an actual cost incured in Nevada to control fugitive VOC ammissions from gasoline. The value for an EPA non-attainment area is \$2.75/lb.

[3]A national marginal control cost for H_2S in attainment areas would be approximately \$0.9 per lb. (OTA, 1989). The valuation of H_2S in progress at this time.

FINAL RULE FOR DOCKET NO. 89-752

AS ADOPTED BY THE PUBLIC SERVICE COMMISSION OF NEVADA

JANUARY 22, 1991

Section 1. NAC 704.9365 is hereby amended to read as follows:

A utility's plan for supply must develop and document the origins of:

1. Its assumptions, data and projections used to calculate the costs and benefits of its options.

2. The costs, benefits and feasibility of power transactions with other utilities including nonfirm and firm energy and the costs of transmission;

3. Its basic economic limitations and availability of fuels;

4. Required controls to mitigate pollution at planned facilities when estimating the costs of the facilities for the plan;

5. Criteria selected for determining the reserve margin;

6. Assumptions for conventional generation;

7. Assumptions for renewable resources;

8. Assumptions for nonutility generators;

9. Estimates of the cost of, the requirements of time for and the feasibility of converting to the use of coal;

10. A statement of the limits on its import or export of power within its primary system of generation and transmission;

11. A statement of the utility's requirements for research and development;

12. A statement of potential projects for upgrading existing systems for transmission of new interties;

13. The criteria used by the utility in setting the dates for the retirement of its facilities; and

14. A statement quantifying the environmental costs and the net economic benefits added to the state from each option for future supply.

Section 2. NAC 704.937 is hereby amended to read as follows:

NAC 704.937 List of [options] alternative plans for future supply of electricity; criteria for selection.

1. A utility's plan must include a list of all existing and planned facilities for conventional generation, facilities for using renewable resources, nonutility generators, programs for reducing demand for and use of energy and other sources available as options to the utility for the future supply of electricity. The listing must include the capacity and projected loads of the facilities and resources for each year of the plan.

2. A utility shall identify the criteria it has used for the selection of its options for meeting the expected future demands for electricity and shall explain how any conflicts among criteria are resolved.

3. In comparing [its options,] alternate plans containing different resource options, the basic criterion which the utility shall use to select and rank [its options] the alternate plans for the supply of power is the present worth of future requirements for revenue (PWRR). [If an option selected by the utility as its preferred option fails to produce the lowest present worth of revenue requirements, the utility must fully justify its choice by setting forth the other criteria which influenced the utility's choice.] A comparison of the PWRR for each alternate plan shall be presented in each resource plan.

4. Another important criterion which the utility shall use to select and rank its options for the supply of power is the present worth of societal costs (PWSC). The present worth of societal costs of a particular plan is obtained by adding the environmental costs to the PWRR.

[4.]5. Other criteria which the utility shall consider are the avoidance of risk by means of:

(a) Flexibility;

(b) Diversity;

(c) Reduced size of commitments;

(d) Choice of projects which can be completed in short periods; [and]

(e) Reliability; and

[(e)](f) Displacement of fuel.

[5.]6. The utility's selections must:

(a) Provide adequate reliability;

(b) Be within regulatory and financial constraints; and

(c) Meet the requirements for environmental protection.

7. If a plan selected by the utility as its preferred plan fails to produce the lowest present worth of future revenue requirements (PWRR) or the lowest present worth of societal costs (PWSC), the utility must fully justify its choice by setting forth the other criteria which influenced the utility's choice. As more fully described in Section 5, the selection of a plan by the utility must in certain cases include an analysis of the net economic benefits to the State of Nevada for that plan.

Section 3. NAC 704.939 is hereby amended to read as follows:

1. A utility's plan must contain a list showing:

(a) All sources of electric power from which the utility has plans or potential opportunities to buy electric power during the 20 years covered by the plan; and

(b) The amount of electric power to be purchased from each source and the years for which delivery is contracted.

The nature and source of the purchase must be described (e.g. nonfirm electric power in winter months [only] from a combustion turbine fueled by natural gas). The net environmental costs and the net economic benefits added to the state from each source or mix of resources must be quantified. If a purchase is not from a specific source of supply then the environmental costs and any economic benefits added from the mix of resources of the seller must be described. Major new commitments for purchases of power must be documented and justified as economical options for supply of power.

Section 4. NAC 704.9395 is hereby amended to read as follows:

1. The estimated costs of construction, including:

(a) Annual flows of expenditures, in current dollars, with allowance for funds used during construction; and

(b) Annual flows of expenditures, in current dollars, without allowance for funds used during construction;

2. The estimated costs of operation, including:

(a) Costs which are variable, in current dollars, per kilowatt-hour, with expenses for fuel and other items indicated separately; and

(b) Costs which are fixed in current dollars, per kilowatt-hour;

3. Net environmental costs and net economic benefits to the state which are more fully described in Sections 5 and 7.

[3.]4. The rates of escalation of cost, including:

(a) Capital costs;

(b) Costs which are variable and related to fuel;

(c) Operating costs which are variable and unrelated to fuel; [and]

(d) Operating costs which are fixed; and

(e) Environmental costs.

[4.]5. The annual average cost per kilowatt-hour at projected loads in current dollars for each year of the plan for each facility, both existing and planned.

Section 5. Economic Benefits Analysis

1. An analysis of the changes which result in net economic benefits added to the State of Nevada from electricity producing or electricity saving resources shall be conducted by the utility in selecting a resource option. The net economic benefit added to the state must be quantified to reflect both the positive and negative changes. The projected present worth of societal costs (PWSC) of a competing resource plan must be within ten (10) percent of the lowest societal cost plan before proceeding with an analysis of the economic benefits to the State of Nevada.

2. The economic benefits analysis shall be achieved by calculating the portion of the present worth of future requirements for revenue (PWRR) that is expended within the State of Nevada including the following for both the construction and operation phases of any project:

(a) Capital expenditures for land and facilities located within the state or equipment manufactured in the state;

(b) The portion of the cost of materials, supplies, and fuel purchased in the state;

(c) Wages paid for work done within the state;

(d) Taxes and fees paid to the state or subdivisions thereof; and

(e) Fees paid for services performed within the state.

3. The analysis shall consider only the net benefit added to the economy of the state of that portion of expenditures made within the State.

4. The PWSC's of the competing resources shall then be adjusted by the Commission to consider either all, or only a portion, of the calculated economic benefit.

Section 6. NAC 704.9475 is hereby amended to read as follows:

1. A utility shall conduct an analysis of sensitivity for all major assumptions and estimates used in its plan. The analysis must include the:

(a) Forecast of load;

(b) Dates when proposed acquisitions will be in service;

(c) Unit availability;

(d) Costs of power plants;

(e) Price of fuel;

(f) Amount of purchased power and corresponding costs;

(g) The schedule, impact and costs of programs of conservation and load management;

(h) Capacity of plans in megawatts;

(i) Discount rates;

(j) Rate of inflation; [and]

(k) Cost of capital;

(l) Environmental costs; and

(m) Economic benefit.

2. The utility shall state the ranges and consequences of uncertainty for each of the assumptions and methods of combining various uncertainties.

Section 7. Environmental cost quantification.

1. The environmental costs to the state associated with operating and maintaining a plan for supply or demand must be quantified for air emissions, water and land use. Environmental costs are those costs, wherever they may occur, which result from harm or risks of harm to the environment after the

application of all mitigation measures required by existing environmental regulation or otherwise included in the plan.

2. The utility must use the general emission rates and the environmental damage costs established by the Commission unless the utility justifies deviating from these values.

Section 8.

The environmental factors identified as a result of this rule and the emission rates and environmental costs set by the Commission may be subject to elimination or modification, and new factors may be added for consideration, as new scientific, engineering, economic, or other technical information becomes available to the commission. Information purporting to establish a need for the deletion or addition of any environmental factor or the revision of any emission rates or environmental costs may be presented by any party at the time of a hearing on the utility's resource plan.

SECTION 9.

"Environmental costs and economic benefits to the state" defined. "Environmental costs and economic benefits to the state" means costs and benefits inuring to the state from electricity produced for consumption within the state whether the generation source is located within or outside Nevada. To calculate environmental costs of generation from sources outside the state, the cost should be calculated the same as if the electricity were generated in the State of Nevada.

Appendix B

Figure 1

AIR EMISSIONS VALUATIONS (1990 $/lb) IN SEVERAL JURISDICTIONS

EMISSIONS	Nevada PSC	New York PSC	New York utility (LILCo)	California Energy Commission (CEC)	Southern Cal. Air Quality (SCAQMD)
Nitrogen oxides (NOx)	3.40	0.96	1.03	4.65	136.90
Sulfur oxides (SOx)	0.78	0.43	0.45	9.07	39.19
Particulates (TSP/PM10	2.09	0.17	0.17	6.11	22.99
Carbon monoxide (CO)	0.46	n/a	n/a	n/a	0.43
Volatile organics (VOC)	0.59	n/a	n/a	2.61	15.15
Carbon dioxide (CO2)	0.01	0.00058	0.00068	0.0040	n/a
Methane (CH4)	0.11	n/a	n/a	n/a	n/a
Nitrous oxide (N20)	2.07	n/a	n/a	n/a	n/a

SOURCES

Nevada PSC: Order, Docket No. 89-752, attached as Appendix ___.

Others: Nevada PSC, Doc. No. 89-752, "White paper: Incorporating environmental externalities into Nevada's Energy Planning Process." Submitted on Behalf of the Attorney General's Office of Advocate for Customers of Public Utilities (OCA), July 30, 1990. Calculated from Table 7, page 37.

I. Baseload plant types, by fuel used.

	Nevada EMISSION FACTORS (POUNDS PER MWHr OUT)								ENVIRONMENTAL COSTS ADDED ($/MWHr)				
	NOx	SOx	PART	CO	VOC	CO2	CH4	N20	NEVPSC	NYPSC	LILCo	CEC	SCAQMD
NATURAL GAS													
Combined Cycle	3.2	0.005	0.01	0.17	0.27	952	0.015	0.063	21.75	3.61	3.95	19.50	442.65
Combined cycle with SWI	0.64	0.005	0.01	0.17	0.27	952	0.015	0.063	13.04	1.16	1.31	7.60	92.20
Combined Cycle w/SWI&SCR	0.23	0.005	0.01	0.17	0.27	952	0.015	0.063	11.65	0.77	0.88	5.69	36.08
COAL													
Pulverized, with scrubbers	6	6	0.3	0.23	0.038	2240	0.014	0.306	51.11	9.69	10.46	93.19	1064.07
Atmospheric fluidized bed	5	6	0.1	1.5	0.03	2380	0.015	0.325	49.45	8.78	9.48	87.86	923.00
Integ. gasification/Comb C	1.9	3.1	0.03	0.09	0.03	1840	0.014	0.302	29.87	4.23	4.60	44.56	382.76
MUNICIPAL SOLID WASTE													
Steam boiler	5.17	6.4	7.896	16	0.504	2770	0.02	0.55	78.34	10.70	11.41	142.73	1154.57
Steam boiler with FFB	5.17	6.4	0.079	16	0.504	2770	0.02	0.55	62.00	9.33	10.10	94.94	974.86
WOOD													
Steam boiler	2.59	0.14	8.139	3.7	1.29	3550	0.55	0.55	68.64	6.00	6.50	80.64	568.29
Steam boiler with FFB	2.59	0.14	0.08136	3.7	1.29	3550	0.55	0.55	51.80	4.59	5.15	31.38	383.05
Solar, photovoltaic	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00
Wind	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00
Small hydroelectric	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00

II. Peaker plants, by fuel used.

Nevada

	EMISSION FACTORS (POUNDS PER MWHr OUT)								ENVIRONMENTAL COSTS ADDED ($/MWHr)				
	NOx	SOx	PART	CO	VOC	CO2	CH4	N20	NEVPSC	NYPSC	LILCo	CEC	SCAQMD
NATURAL GAS													
Combustion turbine	5.152	0.008	0.174	1.434	0.16	1560	0.16	0.24	36.32	5.86	6.41	31.75	712.64
Combustion turbine w/SWI	1.03	0.008	0.174	1.434	0.16	1560	0.16	0.24	22.30	1.92	2.15	12.58	148.35
Combustion turbine,SWI,SCR	0.371	0.008	0.174	1.434	0.16	1560	0.16	0.24	20.06	1.29	1.47	9.52	58.14
DISTILLATE OIL													
Combustion turbine	8	2.78	0.4	1.52	0.47	2150	0.021	0.276	55.40	10.17	11.03	74.68	1221.07
Combustion turbine w/SCR	3	2.78	0.4	1.52	0.47	2150	0.021	0.276	38.40	5.38	5.87	51.43	536.60
Diesel engine	33.5	0.557	2.393	7.286	2.293	1620	n/a	n/a	141.86	33.65	36.37	187.94	4700.69
Diesel engine with SCR	5.025	0.557	2.393	7.286	2.293	1620	n/a	n/a	45.05	6.40	6.94	55.52	802.61

SOURCES

Emission factors: Nevada order, Table 1, page 2.

Environmental costs/MWH: Calculated as the sum of the products of emission factors (lbs/MWH) and valuations ($/lb), summed over all listed emissions, using the valuations shown in Figure 1.

Appendix C

The Marginality of Regulating Marginal Investments:

Why We Need a Systemic Perspective on Environmental Externality Adders

Clinton J. Andrews
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Abstract

Some regulators are directing utilities to include the externality of pollutant emissions by applying adders to project benefit-cost ratios when making new capacity planning decisions. I argue that targeting only these marginal investments provides only marginal value, by missing many cost-effective emissions reduction opportunities. Weaknesses of the method stem in part from the continued operation of existing power plants and the dynamic of new supply technology development. The existing rules for dispatching power plants, the characteristics of other emissions reduction options, and the limited purview of state regulators also limit their value. A superior approach is to take a systemic perspective on the emissions reduction challenge, and compare complete resource portfolios rather than options at the margin. Cost-effective regulation can then be achieved by imposing systemwide emissions limits in the spirit of the recent Clean Air Act amendments, or mastering the difficult job of applying externality adders to operational as well as investment decisions.

Introduction

Electric utilities throughout North America are adopting an integrated resource planning philosophy. While this means different things to different people, many utilities and their regulators are emphasizing three principles. First, the planning process should integrate both demand- and supply-side options. Second, it should integrate multiple perspectives – those of the utility and the various parties affected by planning decisions. Third, it should integrate multiple decision criteria, such as financial costs, fuel-related risks, health and safety issues, and especially environmental impacts.

An increasingly popular way to integrate environmental factors into the resource planning process is to apply externality adders. When these shadow prices are included in project benefit-cost ratios, they correct for the uncosted externality of pollutant emissions. Thus a zero-emissions conservation project might become more attractive than a new, but polluting coal-fired power plant, even though the power plant has lower financial costs on a life-cycle basis. The correct level of externality adder is difficult to estimate because of uncertain damage costs associated with pollutant emissions. Nevertheless, praiseworthy efforts to estimate and then apply environmental externality adders in the integrated resource planning context are currently underway.

Many states are developing regulations in this area (Cohen et al, 1990). Most such regulations direct utilities to apply externality adders only to decisions about new capacity. They focus on getting a socially superior decision for the next, or marginal investment made by the utility. In the long term, this pushes the utility's portfolio of investments in an environmentally beneficial direction. While this is satisfying as an application of textbook cost-benefit economics, is it good enough?

This paper argues that environmental externality adders which only target marginal investments are of only marginal value. In the context of a complex interconnected electric power system, a focus on the marginal investment misses several things. It ignores the continued operation of existing power plants. It ignores the fact that the marginal unit you avoid with zero-emissions conservation is often your best unit, because of the dynamic of technological change. It muddies the important distinction between long-run and short-run marginal units. Finally, given a goal of environmental protection, it ignores many cost-effective investment and operational options. I will illustrate each of these points using data from a recent major modeling effort in New England (see the Appendix for details). Then I will introduce a systemic perspective to environmental externality evaluation that may improve the value of these well-intentioned regulations.

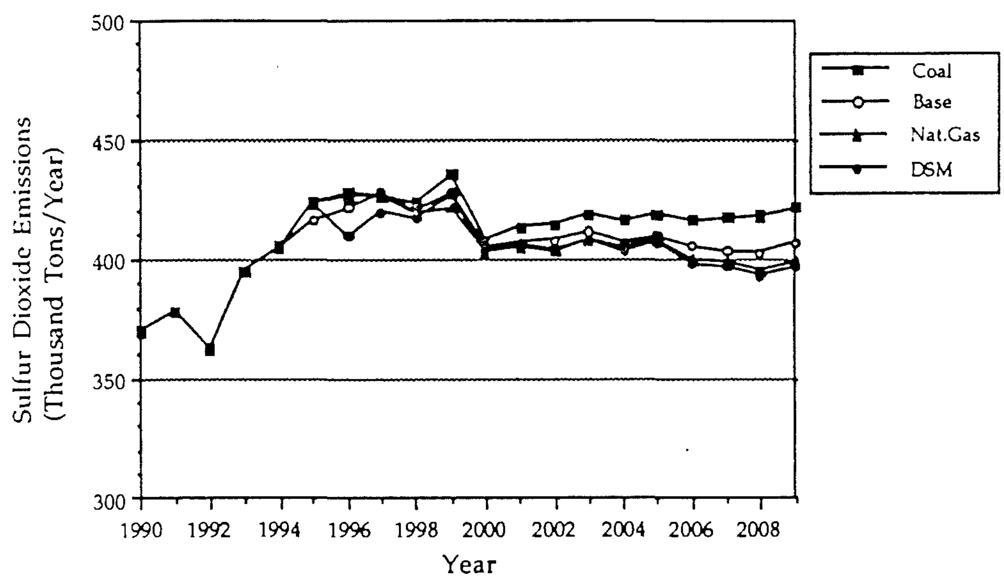
Problem: Continued Operation of Existing Power Plants

Students of project evaluation are typically – and rightly – told to ignore sunk costs in comparing project alternatives. Some practitioners have inappropriately interpreted this to mean that they should ignore the existing capital stock when evaluating new capacity investments. While it is reasonable to ignore sunk capital costs, it is not reasonable to ignore the role of the existing electric power plants in determining the utility's total operating costs and pollutant emissions.

The existing power plants provide most of the system's electricity and pollutant emissions, and the huge inertia of that system is only minutely perturbed by the marginal investment. Figure 1 shows the relatively minor effects of new capacity on sulfur dioxide emissions from New England for four quite different new technology strategies. Given reasonable rates of load growth and capacity expansion (see Appendix), it is not until the end of twenty years of system operation that the lowest marginal emissions strategy (DSM) begins to significantly reduce aggregate emissions compared to the highest emissions strategy (Coal).

Simple arithmetic is what provides this result. New England currently has a 20,000 MW system that grows at about 2% annually over the long term. Given an expressed policy of life-extending existing power plants rather than retiring them at the end of their book lives, only about 500 MW of new capacity will be introduced each year. Thus, even after twenty years, new capacity will represent less than one third of total generating capacity. The existing capital stock will remain the dominant factor in system performance. Regulating only the marginal capacity investment is a very slow way to transform a large electric power system serving a mature economy.

Figure 1: New England SO_2 Emissions for Four New Technology Strategies



Problem: The Dynamic of Technology Improvement

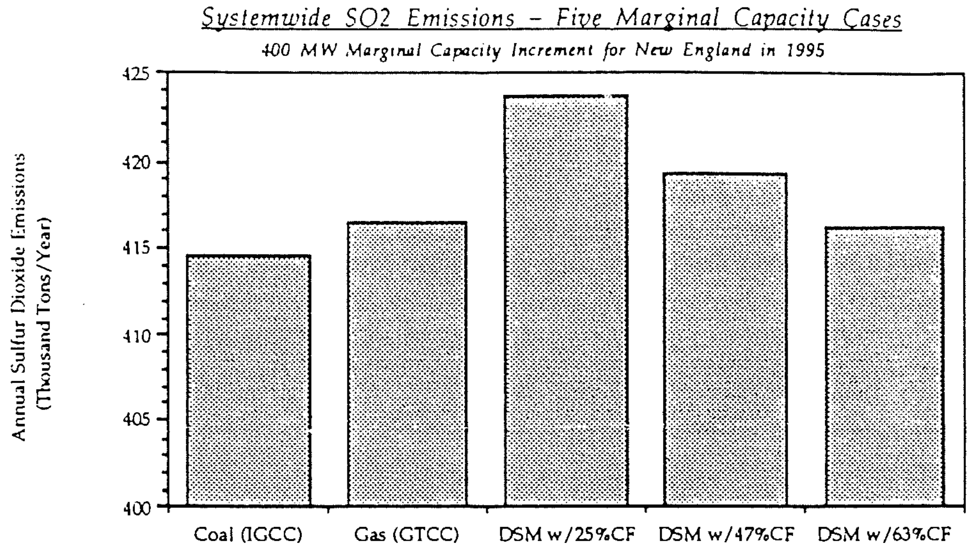
In regions with older infrastructure, such as New England, new generating technologies are vastly cleaner and more efficient than the existing stock of operating power plants. The average operating efficiency of fossil-fired units in New England is about 32% for the regional system (Connors and Andrews, 1991). New commercially available units operate in the range of 39% to 50% efficiency, depending on fuel and technology type (EPRI, 1989; Gas Turbine World, 1988). They are also designed to produce lower emissions by separating or capturing pollutants prior to or during the combustion process. Indeed, there are distinct differences in emissions rates among plants of different vintages, largely due to grandfathering provisions of previous pollution control regulations. Some new technologies also rely on cleaner fuels, especially on natural gas. These three factors (combustion efficiency, emissions rates, and cleaner fuels) make new technology much cleaner than existing technology on a megawatt-for-megawatt basis.

One of the main thrusts of integrated resource planning regulations has been to encourage competition between demand- and supply-side capacity investments at the margin. Demand-side activities such as conservation and peak management are said to be environmentally valuable because they avoid the need for new, polluting power plants. Externality adders applied to marginal capacity options encourage the use of zero-emissions conservation over positive-emissions supply investments. This calculus would encourage environmentally beneficial decisions if all of the electric service was provided by operating only the new capacity.

However, since much of the electric service is produced by existing power plants, a perverse outcome can occur when the existing capacity is relatively old and dirty. In New England, at least, investing in demand-side management in lieu of new capacity can lead to higher systemwide emissions of important pollutants (see Figure 2). Five different marginal capacity investment cases aimed at meeting an expected regional load increase of 400 MW in 1995 are shown. Two are supply options: clean coal (integrated gasification combined cycle) and natural gas (gas turbine combined cycle). The remaining three are demand-side options, representing 400 MW reductions in load with various annual capacity factors. The 25% capacity factor case represents New England utilities' current mix of demand-side management programs (including conservation and peak management)(NEPOOL, 1990a). The 47% capacity factor case is typical of New England programs emphasizing conservation only (no peak management). The 63% capacity factor case is hypothetical, in which the demand-side management achieves the same capacity factor as system average demand profile.

This counterintuitive outcome occurs because electric service is actually provided by some combination of zero-emissions conservation, low-emissions new generation, and high-emissions existing generation. The displacement of new generation by conservation leads to continued utilization of high-emissions existing generation. Current life-extension policies for existing units prevent natural turnover in that capital stock. Thus, when considering the evolution of the power system over time, the application of environmental externality adders only to marginal capacity investments actually hinders environmental progress. The marginal unit of new low-emissions capacity that is avoided with zero-emissions conservation would have been one of the system's cleanest units.

Figure 2: New England SO_2 Emissions for Five Marginal Investments in 1995



Problem: Rules for Dispatching Power Plants

Power plants operate in a systemic context, within which hundreds of interconnected units are dispatched so as to minimize total operating costs. A unit's short-run marginal cost determines its place in the loading order and hence its capacity factor. Dispatching rules mean that new capacity investments interact with the existing capital stock, whether or not regulations governing capacity planning decisions acknowledge it. This relationship between long run marginal capacity investments and short run marginal operating costs has several important environmental implications.

The first of these is the relative capacity factors of new and existing power plants. Because new technology is often much more efficient than existing technology, it typically enjoys lower operating costs on a ¢/kWh basis. It will thus operate more hours, i.e., have a higher capacity factor, than older technology burning the same fuel. This enhances the systemwide environmental benefits of new technology, because not only is it more efficient, emits less, and often consumes cleaner fuel, but it also causes existing technology to operate less by displacing it in the loading order.

Capacity factor is an important part of the story told in Figure 2. In New England, power plants burning residual oil (#6) are currently the major source of utility-related regional SO_2 emissions. They have a high capacity factor and many of them operate in the intermediate-to-base load range.

Figure 3 shows the primary location within the loading order of each fuel type, under the five marginal investment cases discussed earlier. The clean coal unit beats existing low- and medium-sulfur residual oils (LSO6, MSO6) in the loading order, and affects high-sulfur oil (HSO6) usage. The natural gas plant moves its fuel (NGAS) to a new place in the loading order, beating out MSO6. New gas-fired units displace old oil boilers because there is typically a large efficiency differential and only a small fuel cost differential (between oil #6 and natural gas). Alternatively, new coal-fired units enjoy a small efficiency differential but a large fuel cost advantage. Both types of new technology thus enjoy a higher capacity factor than many of the existing oil-fired plants.

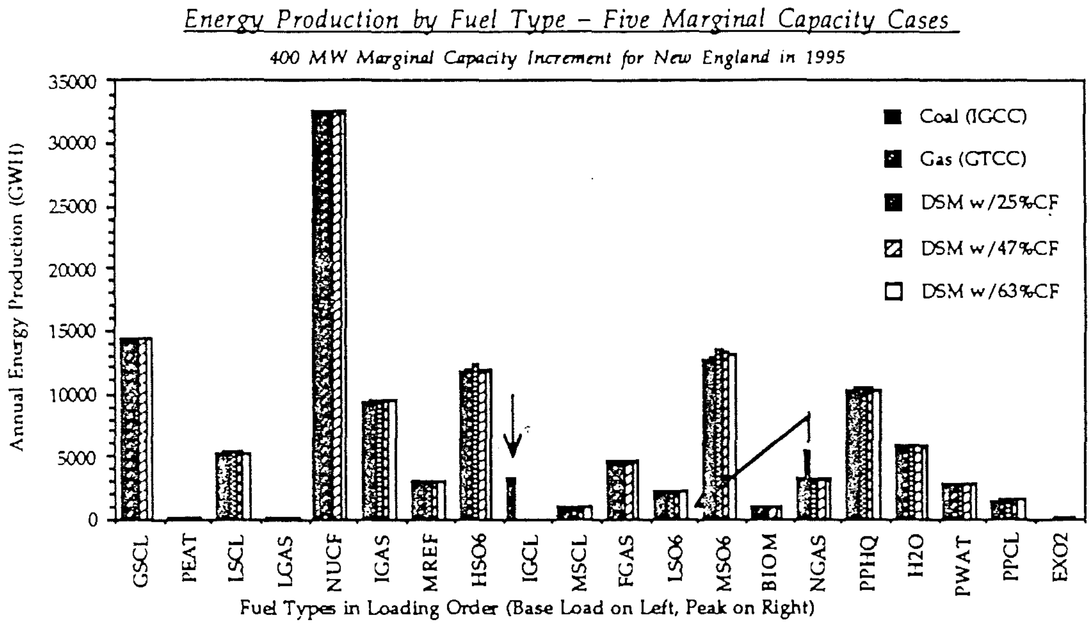
Demand-side management is relatively ineffective at reducing SO_2 emissions when it only reduces peak and shoulder kilowatthours, which are largely supplied by power purchases (PPHQ, PPCL), hydro (H2O), pumped storage (PWAT), and peaking units burning diesel fuel (EXO2). Only when its capacity factor exceeds that of residual oil-fired capacity does it reduce emissions. Thus, new generating technology appears to be more effective because it consistently beats oil-fired capacity in the loading order. Table 1 shows the systemwide energy production and the capacity factor for each of the five marginal capacity options. Even though fewer kilowatthours are generated under the DSM cases, SO_2 emissions remain higher until the DSM activity achieves the critical capacity factor of 63%. By contrast, CO_2 emissions are less fuel-specific; thus all three DSM cases have lower CO_2 emissions than the new gas or coal cases because fewer kilowatthours of fossil-fueled generation occur.

Table 1: Five Marginal Capacity Options – Operating Performance

Case	Energy (GWH)	Capacity Factor
Coal (IGCC)	128313	87%
Gas (GTCC)	128313	64%
DSM w/25%CF	127437	25%
DSM w/47%CF	126666	47%
DSM w/63%CF	126095	63%

Regulations that assign environmental externality adders a priori to specific technologies may miss these important interactions between new and existing capacity in the dispatch order. Such adders must assume a fixed capacity factor for the new unit and typically ignore the emissions of existing units. They thus ignore the fact that pollution is not caused uniformly by all of the kilowatthours generated, but instead is due largely to generation by older, dirtier plants with high capacity factors. Important but subtle factors such as efficiency and fuel price differentials, and the effects of grandfathering under clean air regulations, make it unrealistic to estimate both capacity factors and environmental impacts without examining the new technology in the context of the existing system.

Figure 3: Fuel Types in the New England Loading Order



Technology-based externality adders thus appear to be excessively crude policy tools for improving electric power system environmental performance for systems like that of New England. Impact-based adders, assigned to emissions rather than technologies, are better. They can account for the effect of context on the performance of a specific piece of hardware. The importance of this distinction is likely to depend on the characteristics of the system being studied.

Current dispatch logic seeks to minimize total systemwide operating costs. This decision rule is inconsistent with the purpose of environmental externality adders, and thus dilutes their effectiveness. Consistency could be achieved by applying the adders not only to long term investment decisions but also to short term operating decisions. This total cost dispatch would move the environmentally marginal unit closer to the operating margin, although it would not remove the need to maintain a systemic perspective on environmental impacts. It would also need to surmount certain institutional problems that are discussed below.

Problem: Other Emissions Reduction Options

There are many investment and operational options that are cost-effective at reducing pollutant emissions. Yet marginal analysis will find only a few of them, and may miss some that are highly cost-effective. For the pollutant SO_2, the following identity outlines the range of options that could be applied to achieve emissions reductions.

$$\text{SO}_2 \text{ Emissions (lbs)} = \text{Total kWh Produced} \times \frac{\text{Fossil kWh Produced}}{\text{Total kWh Produced}} \times \frac{\text{Btu Fuel Input}}{\text{Fossil kWh Produced}} \times \frac{\text{Sulfur (lbs) Content}}{\text{Btu Fuel Input}} \times \frac{\text{Sulfur (lbs) Emitted}}{\text{Sulfur (lbs) Content}}$$

Each term in this identity suggests a component of an emissions reduction strategy, as follows:

End-Use Efficiency	Non-Fossil Generation	Combustion Efficiency	Fuel Choice	Emissions Controls

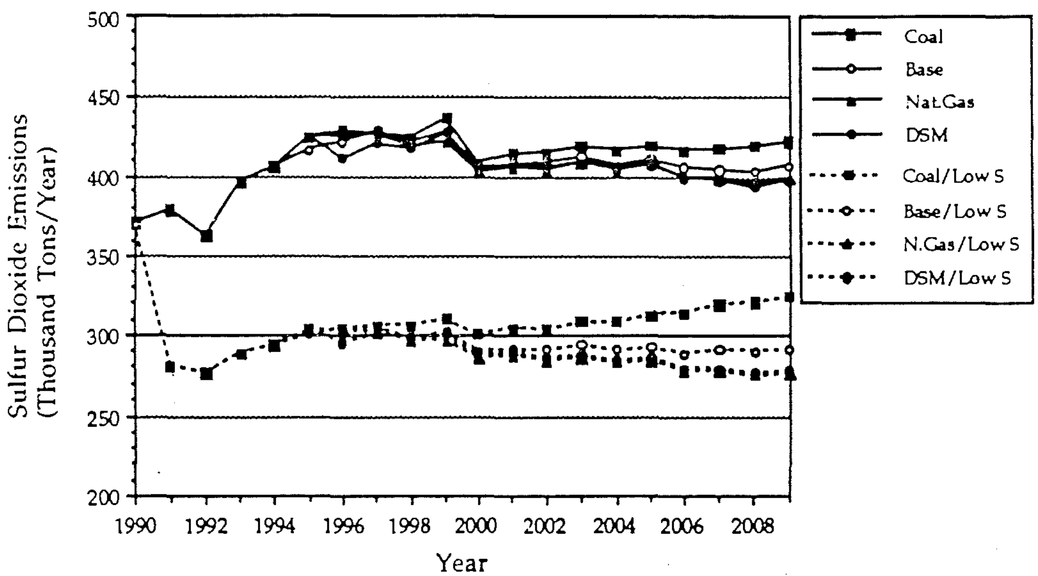
Specific options within this framework could include:

Utility DSM	Photovoltaics	New Capacity	Natural Gas	Scrubbers
Gov't Standards	Nuclear	Repowering	Low Sulfur Oil	Catalytic Red'n

Most of these options could be applied to existing capacity as well as new capacity. Because there is so much existing capacity, the impact of such decisions will be quite large. For example, a decision could be made to burn low (0.5%) sulfur residual oil instead high (1.0% - 2.2%) sulfur residual oil as is currently done in most of New England's existing utility boilers. The impact of this policy on regional SO_2 emissions is dramatic. Figure 4 contrasts the emissions trajectories for the four new technology cases (described earlier in Figure 1) for two treatments of existing capacity – with and without a low sulfur oil requirement. As can be seen, the decision to use low sulfur oil in existing capacity is much more effective at reducing SO_2 emissions than merely building new clean capacity. The electricity cost premium for this low sulfur oil option is about +5% on average for the region, well within the range of uncertainty for the new technology options.

The application of environmental externality adders to both investment and operating decisions could uncover many of these cost-effective emissions reduction options. Yet the evaluation must compare the relative impacts of options embedded within their systemic context, and evaluate the marginal change. Looking at technologies in isolation will not reveal enough about their performance in operation.

Figure 4: New England SO_2 Emissions – With Low Sulfur Oil Cases



Problem: Limits of Regulatory Purview

There are two important mismatches between regulatory purview and emissions reduction opportunities. The first is the fractionated responsibility among agencies within each state government for reviewing different aspects of utility investment and operating decisions. The second is the multi-jurisdictional scale at which electric power systems are operated.

Public utility commissions have targeted new capacity decisions for their environmental externality regulations because that is their primary area of purview. Other emissions reduction strategies, such as fuel choice, emissions limits, and incentives for accelerated retirement of existing capacity may lie outside of their domain. This depends on the legislative mandate of each agency. In many states, the Department of Environmental Management governs most emissions-related decisions, and is the agency specifying fuel options and emissions limits. Likewise, taxation authorities typically enforce depreciation rules affecting the economics of existing capacity.

Fractionated regulatory purview presently hinders the implementation of multi-option emissions reduction strategies such as those described above.

It takes coordinated efforts among regulators to help develop and then approve efficient multi-option strategies to produce clean, reasonably priced electric service. It may take legislation to ensure that this coordination occurs. This suggests a fourth principle of integrated resource planning – integration of disjointed regulatory oversight responsibilities.

This need for integrated regulations goes beyond state borders. Today's electric power systems achieve economies of scale in operation that are larger than all but the biggest states; thus regional coordination is crucial. If, as has happened in New England, some states adopt externality adders but others do not, then spillovers with profound equity implications may occur. Consumers in Rhode Island, for example, might have to pay for the effects of regulations imposed within Massachusetts. Close-knit regions like New England will have less trouble coordinating their regulations than other regions. Yet it may be necessary to turn to the federal government to rationalize conflicting state regulations in some areas.

There is an important political dynamic in externalities regulation. Several regulators have made the point that it is necessary, from a political point of view, to start with an easy target – new capacity – because its very irrelevance makes it relatively non-controversial. After the concept gains acceptance in the minor area of marginal capacity investments, then it will be easier to apply to other areas, such as system operations. This is certainly a valid general point; yet, with the passage of the strong new 1990 Clean Air Act amendments, such timidity is no longer reasonable for the case of the electric power sector.

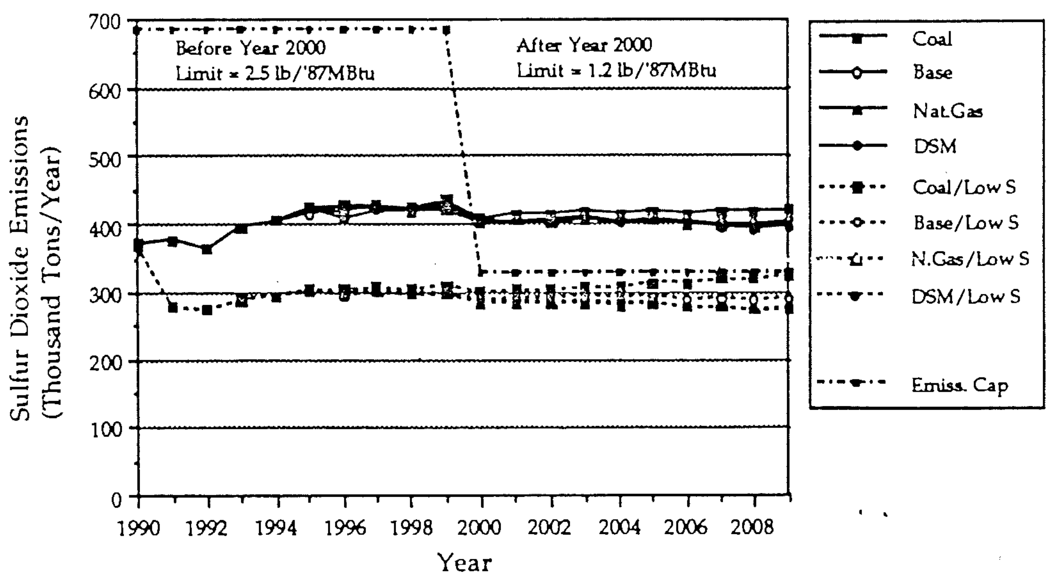
The 1990 amendments require utilities to reduce emissions much sooner than the regulation of marginal investments can bring about. Within the next ten years, many utilities will need to resort to options as dramatic as switching from high to low sulfur fuel oil in existing capacity. For example, after the year 2000 even New England, which has one of the nation's cleaner electric power systems, will have to target existing capacity. Figure 5 shows the emissions caps imposed on the region by the 1990 Clean Air Act amendments.

Marketable emissions permits are likely to encourage utilities to change both investment and operating behavior so as to internalize part of the emissions-related environmental externality. When performing both capacity expansion planning and production cost calculations, many utilities will in fact apply externality adders to re-optimize their systems for this new environmental constraint. This will eventually percolate up from to the level of individual utilities to that of the regional power pool. Thus, the technical feasibility of applying adders to both investment and operational decisions will improve. The political feasibility of that activity is a larger question.

Legislators (and then regulators) can take two distinct paths under these conditions – assigning pervasive externality adders or tightening emissions limits. Adders are market-oriented policy tools, i.e., taxes that influence behavior but do not impose absolute constraints. These tools must be rationalized so that they apply to system operations as well as investments, implying legislative intervention to coordinate diverse state agencies. To be effective they must also apply equally to the whole marketplace, and be harmonized across state lines, just as sales tax rates tend to equilibrate among states (Mikesell, 1970).

If the practical difficulties of developing a strong regime of environmental externalities adders appear too daunting, regulation can follow a more traditional path. In the spirit of the current Clean Air Act amendments, tighter emissions limits may be imposed, forcing utilities to re-optimize their systems to accommodate new constraints. While emissions limits sound like a planning-oriented policy tool, the creation of marketable permits adds opportunities for market-based efficiencies. This approach has a number of practical benefits: in the decentralized U.S. federal system it can be imposed on a state-by-state basis because it does not require new regional dispatching rules. It also maintains the separation of responsibilities among environmental and economic regulators within states.

Figure 5: New England SO_2 Emissions Caps under Revised Clean Air Act



Solution: Taking a Systemic Perspective

The discussion so far has shown that the application of environmental externality adders only to marginal capacity investment decisions may be both problematic and ineffective. Existing power plants remain the cause of most pollution problems, the dynamic of technical change has made marginal signals misleading, most types of new capacity are cleaner than existing capacity, the rules for dispatching power plants currently ignore environmental factors, and many of the most effective emissions reductions options have nothing to do with incremental new capacity. These factors suggest that a systemic perspective will be more valuable for reducing environmental impacts.

The techniques of portfolio analysis are more appropriate than those of project evaluation for evaluating systemwide emissions reduction strategies. A portfolio analysis typically includes the following steps. Packages of options – different mixes of existing capacity, new power plants, demand-side investments, and operating rules – are formulated for comparison as multi-part portfolios rather than on their own. The operation of each portfolio as an integrated system is simulated so that net financial costs and environmental impacts may be estimated. Impact-based environmental externality adders considering the aggregate performance of the system may then be calculated. Alternative portfolios may be compared, and that with the lowest net "social cost" can be identified.

This approach gives useful results. As an example, the unit externality adders specified by the Massachusetts Department of Public Utilities (1990) have been applied on a portfolio basis to the eight regional cases described earlier. Total costs (investment, operations, etc.) over twenty years are reported for two different decision rules. The first decision rule is simple financial cost, i.e., no externality adder, assuming normal dispatching procedures. The second decision rule includes the Massachusetts adders to applied to systemwide emissions, while maintaining normal dispatching procedures. The resulting net system costs are shown in Table 2. Costs are in billions of 1989 dollars, cumulative over a twenty year study horizon. Financial costs are discounted at the market rate (11.85%), but externality costs are not. Note that only the financial costs are actually paid by the region's electricity consumers. The total tax imposed by the adders is the difference in financial costs between strategies, and not the social cost numbers.

Of the eight alternatives, the portfolio with the lowest social cost is quickly identified – it emphasizes DSM plus low sulfur oil in existing units. Only a systemwide perspective will uncover this attractive package. One can see that adders were not really necessary in finding this result, because multi-attribute analysis with a simple dominance sort could also have done the job.

Figure 6 shows a comparison of the multi-attribute results for each strategy with the requirements of the revised Clean Air Act. The constraint on SO_2 emissions imposed by the regulation makes the choice of DSM with low sulfur oil an easy one. The important factor in discovering this cost-effective strategy was taking a systemwide perspective on the issue, rather than imposing externality adders. In summary, we should add a fifth principle to our basis for integrated resource planning. It should integrate new and existing capacity, considering investment and operational options.

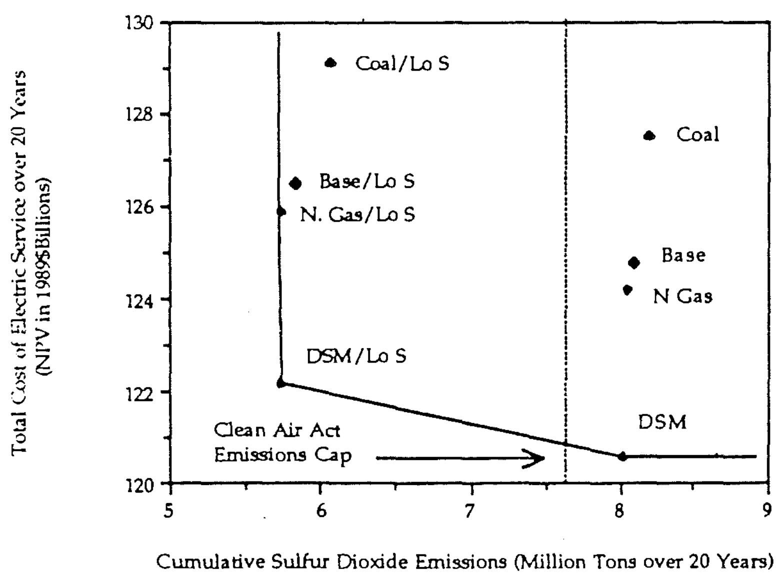
Table 2: Applying Externality Adders to Systemwide Emissions to Compare Alternative Multi-Option Portfolios for New England (Normal Dispatch)

Resource /Fuel Case	*Cumulative Emissions - Million Tons*				*Total Cost of Service*	*Rank Order*
	SO2	*NOx*	*TSP*	*CO2*		
Base	8.09	3.79	2.91	1408.8	124.8	4
Natural Gas	8.05	3.78	2.92	1365.1	124.2	3
Coal	8.21	3.83	2.90	1501.2	127.5	7
DSM	8.02	3.73	2.91	1305.5	120.6	1
Base/LS Oil	5.83	3.68	2.82	1413.2	126.5	6
Nat.Gas/LS Oil	5.73	3.66	2.83	1368.7	125.9	5
Coal/LS Oil	6.06	3.75	2.81	1510.0	129.1	8
DSM/LS Oil	5.74	3.63	2.82	1312.5	122.2	2
					NPV B$'89	
Resource /Fuel Case	*Massachusetts Externality Costs ($/ton)*				*"Social" Cost of Service*	*Revised Rank Order*
	$1,500 /Ton	*$6,500 /Ton*	*$4,000 /Ton*	*$22 /Ton*		
	SO2	*NOx*	*TSP*	*CO2*		
Base	12.13	24.67	11.66	31.0	204.3	6
Natural Gas	12.07	24.60	11.70	30.0	202.6	5
Coal	12.31	24.91	11.59	33.0	209.3	8
DSM	12.03	24.26	11.66	28.7	197.3	2
Base/LS Oil	8.75	23.95	11.29	31.1	201.5	4
Nat.Gas/LS Oil	8.59	23.81	11.33	30.1	199.7	3
Coal/LS Oil	9.08	24.38	11.24	33.2	207.0	7
DSM/LS Oil	8.61	23.58	11.30	28.9	194.6	1
	B$'89	*B$'89*	*B$'89*	*B$'89*	*B$'89*	

The difference in financial cost between the first and second ranked portfolios (DSM with Low Sulfur Oil, and DSM alone) is $1.6 billion on a net present value basis over 20 years for New England. This represents a 1.3% increase in average costs, a relatively small amount compared to the differences between new capacity options such as coal and natural gas, for example. The cost premium is so small because plants burning the expensive low sulfur fuel (costing from 6% to 19% more than higher sulfur fuels) would be dispatched less often than previously, and in this analysis the small increase in the operating costs of a few plants was spread out over the entire region. Individual utilities would see different rate impacts depending on their generation mixes.

The implied marginal rate of substitution is about $700/ton of avoided SO_2 emissions for the alternative fueling option. This is less than half of the rate imposed by the Massachusetts regulators ($1500/ton). Note that the value for the Massachusetts adder was based on an estimated cost of abatement, a supposedly conservative proxy for the difficult-to-estimate damage-based shadow price (MADPU 1990). In a systemwide context, this adder does not appear to be conservative after all. By looking at a broader array of options the systemwide cost of abatement may be reduced below that estimated at the margin. This suggests that (in the SO_2 case) the externality adder could be halved and still promote environmentally sound decisionmaking; alternatively the utilities in Massachusetts could create a substantial amount of emissions trading permits for sale without exceeding their MADPU mandate. It highlights the difficulty of choosing the magnitude of the adder a priori, and suggests that public review of multi-attribute results might be a rewarding alternative.

Figure 6: Electric Service Cost and SO_2 Emissions Tradeoff for New England



Conclusions

This paper has identified several weaknesses of a regulatory approach that only applies environmental externality adders to new capacity. These include the fact that the main source of pollutant emissions – existing capacity – is not significantly affected by regulating the margin. Also, the dynamic of technological change on the supply side often makes marginal signals inaccurate, because the generating capacity avoided with zero-emissions DSM could be the utility's cleanest unit of supply technology. Further, unless the decision rules governing the operation of a complex, interconnected power system are also changed to reflect environmental priorities, the dirtiest kilowatthours will continue to be produced by plants that may be deep in the loading order, and thus hard to displace. There are also many investment and operational options for reducing pollutant emissions that will be missed if only the marginal investment is targeted. Finally, the limited purview of government agencies regulating utilities makes it difficult to achieve economically efficient emissions reductions.

The solution to the problems mentioned above is to take a systemic perspective on the goal of emissions reduction. Alternative portfolios consisting of existing power plants, new supply technology, demand-side efforts, and operating strategies should be compared, not just individual marginal investments. System operations should be simulated to account for interactions among the options comprising the portfolio. Externality adders could then be applied to net costs and emissions for each portfolio, or simpler multi-attribute analysis under constraints could be used to decide among alternative portfolios. The recent amendments to the Clean Air Act already force utilities to examine this range of options. Regulatory agencies should work together to improve the efficiency of utility emissions reductions activities, by allowing multi-option strategies to be developed. Regulations imposing systemwide emissions caps may be easier to implement than those seeking to impose externality adders on all of the discrete investment and operating decisions made within the system.

An expanded set of principles should drive integrated resource planning efforts. Both and supply- and demand-side options should be integrated. Multiple policy perspectives, including those of non-utility parties, should be integrated. Multiple decision criteria, including environmental factors, should be integrated. Yet a broad array of options, targeting existing and new capacity, investments and operations, should also be integrated. Finally, regulatory activities by public utilities commissions, tax authorities, and environment departments, at the state, regional, and federal levels should be better integrated.

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Appendix

The analysis summarized in this paper was performed using models and data developed for the New England Project, a regional joint factfinding effort to explore feasible electricity alternatives. The project involves a diverse group of decisionmakers, including public utility commissioners, utility executives, environmental advocates, electricity consumers, governmental personnel, and an analysis team from MIT. The group uses a scenario-based multi-attribute tradeoff analysis framework to learn about the strengths and weaknesses of electric power planning options. The group seeks consensus on input assumptions and modeling choices, critically reviews the results, and uses this information to improve the quality of the regional energy policy debate. To the degree possible, this analysis uses assumptions previously approved by the planning committees of the New England Power Pool (NEPOOL).

The alternative resource portfolios evaluated in this paper are defined as follows (see Andrews, Connors, and Parker, 1991 for more detail):

1. Base Case: Mixed Resource Emphasis
   (11% Purchases, 46% Gas/Oil CC, 32% Gas/Oil CT, 14% IGCC Coal)

2. Natural Gas Emphasis Case
   (68% Gas/Oil CC, 32% Gas/Oil CT)

3. Coal Emphasis Case
   (32% Gas/Oil CT, 29% AFB Coal, 39% IGCC Coal)

4. Demand-Side Management Emphasis Case
   (32% Gas/Oil CC, 32% Gas/Oil CT, 36% DSM)

5. - 8. Low Sulfur Oil Cases keep the same new technology mixes described above, but change the fuel burned in some existing power plants. Plants currently burning 2.2% or 1% sulfur-content residual oil (#6) are switched to 0.5% sulfur-content residual oil.

New England Cases - Peak Load, Energy, and Capacity Positions

Year	CELT Net Energy (GWH)	CELT Peak Ld (MW)	CELT Capacity (MW)	Capacity Required (MW)	Capacity Position (MW)	Capacity In-Licnsng &RE (MW)	Net Capac Position (MW)	Round Net Position (MW)
1989	111982	20000	24294	*24400*	-106	0	-106	-100
1990	112184	19989	25799	*24387*	1412	0	1412	1400
1991	113342	20087	27403	*24506*	2897	28.5	2925	2950
1992	115869	20674	27499	*25222*	2277	28.5	2305	2300
1993	118650	21335	27190	*26029*	1161	28.5	1190	1200
1994	121869	22039	26837	*26888*	-51	382	331	350
1995	124493	22540	26735	*27499*	-764	877.5	114	100
1996	126994	22970	26750	27940	-1190	916	-274	-200
1997	128969	23328	26750	28394	-1644	933	-711	-700
1998	131384	23732	26692	28926	-2234	933	-1301	-1300
1999	134447	24287	26685	29463	-2778	960	-1818	-1800
2000	137838	24912	26672	30150	-3478	960	-2518	-2500
2001	140424	25351	25386	30624	-5238	2460	-2778	-2800
2002	142736	25754	25354	31005	-5651	*2460*	-3191	-3200
2003	145506	26248	25285	31539	-6254	*2460*	-3794	-3800
2004	148691	26806	25281	32225	-6944	*2460*	-4484	-4500
2005	151866	27417	25219	32863	-7644	*2460*	-5184	-5200
2006	*155046*	*28002*	*25219*	*34162*	-8943	*2460*	-6483	-6500
2007	*158224*	*28599*	*25219*	*34891*	-9672	*2460*	-7212	-7200
2008	*161402*	*29190*	*25219*	*35612*	-10393	*2460*	-7933	-7950
2009	*164580*	*29785*	*25219*	*36337*	-11118	*2460*	-8658	-8650

New England Cases – Expansion Plans

Year	Base Case New Resources (Annual New MW)								Natural Gas Case New Resources (Annual New MW)							
	Fossil Purch	Non-F Purch	GTCC	Peak'g CT	AFB Coal	IGCC Coal	DSM	Cum. MW	Fossil Purch	Non-F Purch	GTCC	Peak'g CT	AFB Coal	IGCC Coal	DSM	Cum. MW
1989	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1993	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1996	300	0	0	0	0	0	0	300	0	0	200	0	0	0	0	200
1997	0	0	200	272	0	0	0	772	0	0	400	136	0	0	0	736
1998	0	0	600	0	0	0	0	1372	0	0	600	0	0	0	0	1336
1999	0	0	200	272	0	0	0	1844	0	0	400	136	0	0	0	1872
2000	0	0	0	408	0	400	0	2652	0	0	200	408	0	0	0	2480
2001	0	0	400	0	0	0	0	3052	0	0	400	0	0	0	0	2880
2002	50	0	0	136	0	0	0	3238	0	0	200	136	0	0	0	3216
2003	50	0	200	136	0	200	0	3824	0	0	400	272	0	0	0	3888
2004	50	0	400	136	0	200	0	4610	0	0	400	272	0	0	0	4560
2005	100	0	400	272	0	0	0	5382	0	0	400	272	0	0	0	5232
2006	150	0	600	408	0	0	0	6540	0	0	1000	272	0	0	0	6504
2007	50	0	400	136	0	200	0	7326	0	0	600	136	0	0	0	7240
2008	100	0	400	136	0	0	0	7962	0	0	600	136	0	0	0	7976
2009	50	0	400	272	0	0	0	8684	0	0	400	272	0	0	0	8648
	11%	0%	46%	32%	0%	14%	0%		0%	0%	68%	32%	0%	0%	0%	
	Target Mix								Target Mix							

Year	DSM Case New Resources (Annual New MW)								Coal Case New Resources (Annual New MW)							
	Fossil Purch	Non-F Purch	GTCC	Peak'g CT	AFB Coal	IGCC Coal	DSM	Cum. MW	Fossil Purch	Non-F Purch	GTCC	Peak'g CT	AFB Coal	IGCC Coal	DSM	Cum. MW
1989	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1993	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	800	800	0	0	0	272	0	0	0	272
1997	0	0	0	0	0	0	50	850	0	0	0	0	600	0	0	872
1998	0	0	400	0	0	0	50	1300	0	0	0	136	0	400	0	1408
1999	0	0	0	408	0	0	100	1808	0	0	0	408	0	0	0	1816
2000	0	0	200	408	0	0	100	2516	0	0	0	0	400	400	0	2616
2001	0	0	400	0	0	0	0	2916	0	0	0	0	0	200	0	2816
2002	0	0	200	136	0	0	50	3302	0	0	0	272	0	200	0	3288
2003	0	0	200	136	0	0	200	3838	0	0	0	136	200	200	0	3824
2004	0	0	200	136	0	0	350	4524	0	0	0	136	200	400	0	4560
2005	0	0	200	272	0	0	250	5246	0	0	0	136	200	400	0	5296
2006	0	0	400	408	0	0	500	6554	0	0	0	408	400	400	0	6504
2007	0	0	200	272	0	0	250	7276	0	0	0	136	200	400	0	7240
2008	0	0	200	272	0	0	300	8048	0	0	0	272	200	200	0	7912
2009	0	0	200	272	0	0	250	8770	0	0	0	272	200	400	0	8784
	0%	0%	32%	32%	0%	0%	36%		0%	0%	0%	32%	29%	39%	0%	
	Target Mix			DSM is modeled as negative load.					Target Mix							

Input Assumptions

Fuel Prices and New Unit Costs:

NEPOOL Generation Task Force Assumptions Book (GTF)(12/89).

Financial Calculations:

Construction Schedules, Equipment Lifetimes, GNP deflators, Discount Rates and Tax Rates taken from NEPOOL GTF (above).

Depreciation Schedules and Overhead/G&A costs based NEPOOL 1989 Electricity Price Forecast Report and background data.
We calculated annual financial attributes and depreciation streams rather than using levelized fixed charge rates.

DSM Costs:
Costs and impacts based on MIT AGREA Background Packet (12/90), which aggregated filed utility estimates of current program costs throughout New England.
Additional DSM, such as the DSM Emphasis Case, was assumed to have a unit cost 50% higher than the current utility programs to account for diminishing returns.

Load Growth, Energy and Generation Capability:
NEPOOL 1990 CELT Report.
Capacity in-licensing that was included in the previous study was modeled here in the form of generic thermal units, except for the Hydro Quebec purchases contract, which was treated as an extension of the existing contract past the year 2000.
We linearly extrapolated all trends to the year 2009 to allow a 20 year study period.

Environmental Characteristics of New and Existing Power Plants:
Operating characteristics of existing plants (capacities, heat rates, maintenance schedules, availabilities, fuel choices) based on NEPOOL data.
Operating characteristics of new plants based on NEPOOL GTF (above).
Raw emissions rates based on ultimate analysis of fuels.
Plant-specific emissions reduction factors (by which to multiply raw emission rate of fuel) based on plant type, location and vintage. All plants are assumed to at least meet extant state and federal regulations.

System Operations and Plant Dispatch:
Operations assume economic dispatch according to variable costs, constrained by plant energy limits and availabilities.
Operations were modeled using the EPRI EGEAS probabilistic production costing computer model on an annual load duration curve developed using the NEPOOL load forecasting model.