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Docket No. D.P.U. 91-131

Investigation by the Department of Public Utilities on its own motion as to the environmental externality values to be used in resource cost-effectiveness tests by electric companies subject to the Department's jurisdiction.	)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

JOINT TESTIMONY OF

PAUL CHERNICK
and
EMILY CAVERHILL

Resource Insight, Inc.

ON BEHALF OF

BOSTON GAS COMPANY

October 4, 1991

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1. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts. Resource Insight, Inc. was formed in August 1990 as the combination of my previous firm, PLC, Inc., with Komanoff Energy Associates.

Q: Summarize your professional education and experience.

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and in my current position at Resource Insight., I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is Attachment 1 to this testimony.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately eighty times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Vermont Public Service Board, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Minnesota Public Utilities Commission, the South Carolina Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously on externalities?

A: Yes. I have testified extensively on externalities valuation in Massachusetts for the past two and a half years on behalf of the Boston Gas Company. My testimony in Vermont Public Service Board Dockets 5270 and 5330 also included externalities. Additionally, I have testified or prepared comment on externalities valuation and incorporation in California, Ontario, Illinois, Maryland, and Indiana, and have worked on the Conservation Law Foundation/New England Electric externalities collaborative.

Q: Have you authored any publications on externalities?

A: Yes. I have authored about a dozen publications, listed on my resume, on externalities valuation. I have presented several of these papers at national conference and was invited to the World Clean Energy Conference in Geneva to speak on externalities.

Q: Ms. Caverhill, please state your name and business address.

A: My name is Emily J. Caverhill, and I am a Research Associate with Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts, 02130.

Q: Please summarize your professional education and experience.

A: I received a Bachelor of Science degree in Chemical Engineering in 1984 from Queens University at Kingston, Ontario. I worked for 2 1/2 years at Petro-Canada Inc. as a Petroleum Engineer in Calgary, Alberta and became a professional member of the Association of Professional Engineers, Geologists, and Geophysicists of Alberta in 1986, of which I am currently a member in good standing. I received a Masters of Business Administration in May, 1989, also from Queens University.

I joined Resource Insight (formerly PLC, Inc.) in July, 1989. Since then, my primary responsibility has been the valuation of environmental externalities of power generation, with some related work in other aspects of least-cost planning. My work has concentrated on valuing externalities which may affect near-term decisions in utility supply planning, and in solving issues related to the practical application of externalities to all aspects of integrated resource planning.

Q: Have you testified previously on externalities?

A: Yes. I have testified on externalities valuation in Delaware's Regulation Docket 29 regarding integrated resource planning on behalf of the Public Service Commission Staff, and in a recent Illinois Statewide proceeding on integrated resource planning on behalf of the City of Chicago. I co-sponsored testimony and attended a workshop on behalf of the Coalition for Energy Efficient and Renewable Technologies (CEERT) before the Public Utility Commission in California. I have prepared reports and testimony for numerous other jurisdictions, including Massachusetts, Vermont, Maryland, Indiana, Pennsylvania, and Ontario.

Q: Have you authored any papers or publications on the valuation of environmental externalities?

A: Yes. I have co-authored several papers on evaluating and monetizing environmental externalities. I have spoken on the evaluation of environmental externalities at several conferences in the United States and Canada, and participated in an international workshop on evaluating externalities in Germany in October, 1990. I am a contributing author to three books on the topic. My papers and publications are listed on my resume.

2. INTRODUCTION

2.1 Purpose and Scope of Testimony

Q: What is the purpose and scope of your testimony?

A: The purpose of this testimony is to respond to Massachusetts Department of Public Utilities (DPU) Docket 91-131, which invited interested parties to update, and add to, the externality values adopted by the Commission in DPU Docket 89-239. We provide analyses that suggest that some of the externality values chosen by the DPU may be low estimates of the value of reducing those externalities, but do not recommend any changes at this time. We provide some additional emissions factors for gas-fired engines; update national and international efforts on developing full-fuel cycle externalities; recommend an externality value for CFCs; and suggest preliminary externality values for heavy metals and thermal pollution. Finally, we briefly review the activities of several states that have adopted explicit valuation of externalities following the Massachusetts Order in 89-239.

Q: How is the rest of your testimony organized?

A: Section 3 contains updates to our previous analyses of externalities including updated information on the externality values for SO_2, CO_2, NO_x, particulates and CO. Section 4 provides suggested additions to the DPU's list of externalities, including CFCs, heavy metals and cooling water. Section 5 updates the regulatory actions in states that have adopted or otherwise supported explicit valuation of externalities.

2.2 Background

Q: Please describe the background of this proceeding.

A: In Massachusetts, the valuation of environmental externalities started with a series of orders (e.g., DPU 86-36-G, DPU 86-67, Phase II) in which the DPU instructed various utilities to incorporate externalities in screening resources, especially DSM. The only utility to respond substantively to this instruction was Boston Gas Company, which filed the results of our first analyses in DPU 88-67, Phase II, early in 1989.

Boston Gas also filed our updated externality analyses in DPU 89-239. The Energy Office filed analyses by the Tellus Institute, which adopted our methodology and some of our values. The Department adopted our approach to the valuation of environmental externalities, and adopted specific values for air emissions based on the combined Resource Insight/Tellus analyses.

DPU 89-239 directed the electric utilities to consider other environmental effects of power plant operation and downstream operations (e.g., disposal of solid and liquid wastes) (p. 84), invited them to propose values for other environmental externalities (p. 89), and encouraged them to address economic and social externalities (particularly oil imports) on a case-by-case basis and in IRM (pp. 81-82). To date, no electric utility has provided estimates of the values of any other externalities, or the data necessary to estimate such values either from the marginal-cost-of-control approach or from the direct costing approach.

Q: What has happened with the valuation of externalities in other jurisdictions since DPU 89-239?

A: The Massachusetts DPU has emerged as a leader in a growing national trend to monetize externalities and include them in utility planning. Prior to DPU 89-239, the only regulatory commission using monetized externalities was New York, which had taken a very tentative and cautious first step in this direction. Following DPU 89-239,

- the California Energy Commission adopted monetized cost-of-control values for various pollutants, for utility planning purposes;
- the California PUC extended and strengthened the Energy Commission approach, and applied the values to acquisition decisions;
- the Nevada PSC adopted externality values very similar to those of Massachusetts;
- the Bonneville Power Administration adopted monetized direct-cost values for several pollutants, for use in resource acquisition;
- the New Jersey Board of Regulatory Commissioners decided to monetize externalities, and adopted interim values per kWh for screening electric and gas conservation programs;

- the South Carolina PSC required utilities to monetize externalities where possible, and to include non-monetized externalities, in their Integrated Resource Management cost analyses; and
- the staff of the Wisconsin PSC concluded that the PSC's current policy of valuing externalities at 17.6% of direct avoided costs was inadequate, and described monetization as "a more sophisticated approach" recently developed in, among other places, Massachusetts.[1]

Thus, the DPU's leadership role in monetization of externalities is helping to move the national state of practice. What the DPU does with externalities will certainly affect emissions in and around New England, as a result of the resource decisions made by Massachusetts utilities. The DPU's leadership also appears to be affecting the actions of other states, and hence emission in those states, some of which are upwind of Massachusetts.

2.3 Summary of Conclusions

Q: Please summarize your conclusions.

A: With respect to the major air pollutants the DPU has previously valued (SO_2, CO_2, NO_x, and particulates), we find that the marginal cost of control is either at least as high

[1] Wisconsin PSC Staff have expressed an interest in seeing the Resource Insight valuation analysis explored in the Advance Plan 6 proceeding. In fact, Wisconsin Gas is sponsoring our testimony in that case.

as the value selected in DPU 89-239, or higher. New data is sparse, except for CO_2, but what is available indicates that some upward movement in the valuation would be justified. Indeed, if the DPU were setting externality values for the first time, the value of each of the major air pollutants might well be increased by anywhere from 30% (for NO_x) up to a few hundred percent (for the other three). In the interests of continuity, and to allow more time to determine how much of an effect the current values will have on utility planning and acquisition, the DPU might impose much smaller increases, if any adjustment is to be made at all.

We have also monetized three new sets of externalities: ozone-depleting chemicals, air toxics, and thermal pollution. The values we develop for these externalities should be promptly incorporated in utility planning and acquisition analyses. Doing so would increase the avoided cost of power from existing oil plants by about 1.4¢/kWh (1¢ for air toxics and 0.4¢ for thermal pollution); increase the environmental costs of new clean coal plants by about 0.4¢/kWh and of combined-cycle plants burning oil for 2 months by about 0.07¢/kWh (both for air toxics); and result in more careful treatment of chlorofluorocarbons in DSM programs.

We continue to support the incorporation of economic externalities, specifically the oil import premium, in the DPU's externality scheme.

3. UPDATES

3.1 Sulfur Dioxide

Q: Have you updated your valuation of SO_2?

A: Yes. Our review of the valuation of utility SO2 emissions covered four aspects, including the effects of the acid rain provisions of the Clean Air Act Amendments of 1990 (CAAA), the cost of SO_2 emissions to be internalized under the CAAA, the interactions between the internalized SO_2 costs and externalities, and new estimates of the external costs of SO_2 emissions.

Q: How will the acid rain provisions of the CAAA affect emissions of SO2 by utilities, and the costs of those emissions?

A: The primary provisions, which determine the emissions reductions required, specific control requirements for many existing sources, compliance dates, and outline the principles behind the SO_2 allowance trading system are contained in Title IV, which deals with reducing emissions of acid gases SO_2 and NO_x.

The primary purpose of this title is to reduce the adverse effects of acid deposition through a reduction in annual SO_2 emissions of 10 million tons and a reduction in annual NO_x emissions of 2 million tons in the lower 48 states and the District of Columbia.[2] The legislation obtains SO_2 emissions reductions through a combination of retrofit control

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[2]U.S. EPA, Clean Air Act Amendments of 1990 Detailed Summary of Titles. November 30, 1990.

requirements on some existing utility plants, and a permanent cap on total national SO_2 emissions through a market based system of emissions allowances, to which all "affected units" (essentially all utility sources larger than 25 MW) of SO_2 will be subject.[3] An allowance is defined as the "authorization, allocated to an affected unit, to emit, during or after a specified calendar year, one ton of SO_2."[4] SO_2 emission allowances will be allocated to exiting units under the Phase I provisions; new units which commence operation after 12/31/95 will be required to obtain allowances from existing units, through allowance trading, or from the EPA Administrator, from whom a limited number of allowances will be available on an annual basis at a fixed price of $1,500/ton (1990$). The penalty for non-compliance is set at $2,000 per ton emissions in excess of the allowances held by the affected source, and the excess emissions will be required to be offset the following year. Beginning in the year 2000, the total number of allowances issued by the EPA is essentially not to exceed 8.9 million tons. If this emissions cap is exceeded, the Administrator can reduce the available allowances on a pro-rata basis for all sources to bring total national emissions below the cap. The intent of Congress was to cap national emissions at 8.9 million tons of SO_2 per annum.

[3]Industrial sources may also opt-in to the allowance program, and may do so depending on their costs of SO_2 reductions and the market price of allowances.

[4]U.S. EPA (1990).

Within several years, the market clearing price of SO_2 allowances, where one allowance equals one ton of SO_2 emissions for one year, will be established through a market trading mechanism, perhaps including trading on the Chicago Board of Trade. SO_2 allowance prices will be determined by the demand for allowances and the supply of allowances, both of which will be determined by, among other factors:

- the marginal costs of various methods of SO_2 control (price differentials between high-sulfur and low-sulfur fuel coal and oil, and between coal or oil and gas; costs of scrubbers and other desulfurization technologies, etc.), which determine the willingness of allowance suppliers to supply more allowances, and the willingness of allowance buyers to avoid their own compliance actions;
- the extent of utility risk aversion and resultant allowance stockpiling;
- demand for electric energy; and
- cost differentials between low-sulfur and high-sulfur options for new generation.

Q: What estimates are available of the cost of SO_2 allowances under Title IV of the CAAA?

A: The cost of each allowance will depend on the demand for allowances, which is a function of new coal- and oil-fired power plant construction, retirements and repowerings, and usage of existing units, and on the supply of allowances, which is a function of the cost of low-sulfur fuels and of emission control technologies. These costs may include, for various utilities, the purchase of allowances, the construction of scrubbers (which also add to variable O&M, increase heat rates, and decrease baseload plant capacity), the use of more expensive low-sulfur fuel, conservation, and the substitution of gas for coal and oil.

ICF (1989) estimated that allowances would trade for \$651-711/ton SO_2 in 2000, \$527-650 in 2005, and \$575-800 in 2010, all in 1988 dollars.[5] National Acid Precipitation Assessment Program (NAPAP) projects a cost of allowances of about \$800-\$1,200/ton SO_2 (1990\$).[6]

The Illinois DENR estimated the cost of several control options to reduce SO_2 emissions in Illinois.[7] For scrubbing high sulfur coal the costs were in the range \$582-\$1,955/ton SO_2, and for fluidized bed technology the cost was \$755-\$1,397/ ton SO_2.[8] The Allegheny Power System projects control costs on its system of about \$576/ton SO_2 to meet its Phase I

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[5]ICF Resources Inc., Economic Analysis of Title V (Acid Rain Provisions) of the Administrations's Proposed Clean Air Act Amendments (H.R.3030/S.1490), Prepared for the U.S. EPA, September, 1989.

[6]NAPAP Key Results, Statement of James R. Mahoney, National Academy of Sciences, September 5, 1990.

[7]Baker D. and Bishop, J., "Analysis of Acid Rain Control Alternatives," Illinois Department of Natural Resources, October, 1987.

[8]Figures are in the study year's dollars.

requirements and $782-$960/ton SO_2 to meets its Phase II requirements.[9] Other utilities report intentions to install similar measures. The Keystone-Conemaugh Owners Committee (KCOC) is considering scrubbing two Conemaugh units to comply with Phase I emissions requirements at an average cost of about $500/ton SO_2.[10] Baltimore Gas and Electric, a member of the KCOC, is considering fuel switching to 0.8% sulfur coal at Crane, at a cost of about $540/ton SO_2 to meet its Phase I requirements.[11] BGE estimates that purchases of allowances from other Conemaugh parties would be an alternative to fuel switching at Crane, at a cost of $497-$1,874/ton SO_2.[12] A preliminary analysis done by Florida Power Corporation showed that switching to lower sulfur coals at its Bartow Plant oil plant and the coal-fired Crystal River Units 1 and 2 should be sufficient to meet its Phase II emissions limits without scrubbing or purchasing allowances. Finally, under the CAAA,

[9]Figures expressed in 1990$. Allegheny Power System, "West Penn Power Company's strategy to comply with the requirements of the Clean Air Act Amendments of 1990," February, 1991. APS expected to meet its Phase I targets through wet FGD on its Harrison plant and its Phase II targets through fuel switching and/or scrubbers on its Hatfield units.

[10]Information is from a letter to Gregory Carmean of the Maryland Public Service Commission regarding Clean Air Act Title IV Compliance, April 12, 1991.

[11]Ibid.

[12]Ibid. Under the Phase I provisions for substitutions, a utility can reallocate its required emissions reductions to another unit "under the control of (the same) owner operator." Therefore, BGE claims purchases from Conemaugh to be a reduction option for Crane.

the Administrator will set up a "Direct Sale Subaccount" within the "Special Allowance Reserve," which will contain 50,000 allowances annually for sale at $1,500 per allowance in 1990 dollars.[13]

Q: How do the SO_2 costs internalized through the CAAA allowance requirements interact with the costs of the external environmental effects of SO_2 emissions?

A: Sulfur dioxide (SO_2) is a special case for externality valuation because of the effects of the impending allowance market. Through this emissions-trading mechanism some of the costs of SO_2 emissions will be internalized.

Some argue that once the allowance trading mechanism is in place, utilities will be paying for the sulfur they emit, and the external cost of SO_2 emissions will drop to zero.[14] This assertion is generally made independent of any estimate of the market value of emissions: in this view, the environmental cost will be whatever the market-clearing price for allowances turns out to be. Proponents of this position may advance two arguments in its support:

- First, it can be argued that the market price of allowances reflects society's willingness-to-pay for emissions reductions. If Congress had wanted higher levels of controls, it would have ordered greater

[13]Clean Air Act Amendments of 1990, Title IV, Section 416(c). This subsection requires the price of allowances to rise with inflation based on the Consumers Price Index.

[14]Goldsmith, M.W., Testimony in ICC Docket No. 91-0050.

reductions in emissions, resulting in a tighter allowance market and a higher allowance price.

- Second, under Title IV of the CAAA, reductions in sulfur emissions by a Massachusetts utility will not result in reduced national emissions. The allowance freed up by the reduced emission will simply be resold to some other utility or QF, increasing emissions elsewhere. Hence, there is no net environmental benefit from SO_2 reductions due to the resource decisions of Massachusetts utilities, only a transfer of pollution from Massachusetts to another region.

Q: Is this a valid position?

A: No. This argument would only hold true if the cost of buying an allowance fully internalized the cost of SO_2 emissions. The allowance system is only designed to reflect a portion of the costs of SO_2 emissions. Once a working market emerges for emissions allowances, the market value of emissions will be an estimate of society's willingness to pay for emissions reductions <u>at the national level, for acid rain control.</u> This is a minimum national level, and ignores both regional differences and all considerations other than acid rain. Sulfur emissions have health and visibility effects that vary in their importance across the country. Emissions in the populous Northeast are likely to be more costly to society than emissions in the Great Plains, so there is apt to be a social saving from transferring a pound of SO_2 from Massachusetts to Nebraska (for example).

Indeed, the Bonneville Power Administration (BPA) has found just such a gradient within its own extensive service territory. In the sparsely populated eastern portion of the service territory, from Montana through eastern Washington and Oregon, BPA estimates a social cost of SO_2 emissions only about 10% of the value it estimates for emissions in the most densely settled portion of the service territory, western Washington.[15]

From the beginning of the externality valuation process, in DPU 89-239, the DPU has recognized that, while the Federal government may set some national requirements, such as the New Source Performance Standards (NSPS), Massachusetts may place a higher value on a pollutant and impose more stringent conditions. Emissions of NOx, VOCs, and PM were valued in DPU 89-239 at the cost of controls required in Massachusetts, but not nationally. At the time, no Massachusetts-specific SO_2 control requirements had been priced out, but there is no reason that the same approach applied to these other pollutants cannot be applied to SO_2.

The allowance requirements under the CAAA will not always be the most demanding or expensive Federal SO_2 requirements. In many cases, Federal Prevention of Serious Deterioration

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[15] Bonneville Power Administration, Environmental Costs and Benefits. February 22, 1991.

(PSD) and NSPS regulations may require emission controls independent of the allowance system. Indeed, EPA has required scrubbers at the Navaho power plant, to improve visibility in the Grand Canyon. The Navaho plant burns very low sulfur coal, and would probably not be scrubbed under the allowance trading system; the owners would find it cheaper to buy allowances.[16]

States are also free to impose environmental requirements in addition to those of the Federal government. Just as individual states adopt other pollution control regulations that are stricter (and more expensive) than the minimum federal standards, the states may initiate independent SO_2 requirements that imply a value of reducing SO_2 emissions that is much higher than the federally defined regulations. For example, the NYSEP expects that state legislation will require a reduction of 100,000 tons beyond the state's Clean Air Act allowance level of 380,000 tons.

Utilities in all states will have to bear at least the cost of the federal SO_2 allowances. In some states, including Massachusetts, the federal SO_2 emissions trading system will not be the limiting factor in utility SO_2 emissions, specific state- and other federal-level regulations will supersede them.

[16]According to The Energy Report, September 30, 1991, p. 693, the scrubbers will cost $89 million per year for 63,000 tons per year of reduction, or $1,400/ton.

Each of these other regulations will direct and channel the trading of emission allowances under Title IV of the CAAA. SO_2 emissions will tend to be reduced more in areas with strict regulations and less in areas with looser regulations.

Q: What new estimates are available of the external costs of SO_2 emissions?

A: We have three new estimates to add to the analysis. First, we can check the valuation of SO_2 by comparing it to the DPU's valuation of particulate matter (PM). Table 3.1.1 shows the ambient air quality standard (AAQS) that can be stated consistently for particulate matter (PM) and for SO_2. The PM standard is the maximum 24-hour arithmetic average concentration of particulates that is acceptable under the Massachusetts AAQS.[17] The SO_2 value is the national AAQS, which is accepted by Massachusetts. The PM standard is stricter. In order to cause the same concern as 150 g of PM, there must be 365 g of SO_2 in the air. Thus, each pound of SO_2 contributes only 41% as much to exceeding the AAQS as does a pound of PM. Hence, if PM is worth $2/lb in 1989$ (as the DPU found in DPU 89-239), SO_2 would appear to be worth $0.82/lb. This is about 10% higher than the 75¢/lb estimated in DPU 89-239.

Second, the Draft New York State Energy Plan (1991) roughly estimates mortality damages to New York citizens <u>after</u> the CAAA Title IV requirements are met at $2,244 per ton of

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[17]The national AAQS is the same number, but for PM10.

SO2 emitted based on dose-response estimates and New York State average population density.[18] Before the CAAA reductions, the NYSEO would apparently estimate that the effects would be greater. The estimate does not include acid rain effects, morbidity, visibility, or any other effect. However, for comparison purposes, Massachusetts' average population density of about 715/mi^2 is about twice New York's (365/mi^2). Simply scaling the New York analysis to Massachusetts' population density would place damages at around $4,500/ton SO_2 in Massachusetts after the CAAA cap is in place.

Third, we now have a Massachusetts-specific estimate of the costs of requirements to control SO_2 emissions. Massachusetts DEP now effectively requires new gas-fired power plants using #2 oil as a winter-period or backup fuel to use oil containing no more than 0.2% S.[19] Boston Edison attempted to license Edgar using 0.3% S oil, but was essentially required by DEP to use 0.2%. Boston Edison estimated that the cleaner fuel would cost $1,185/ton SO_2 reduction, and accepted it as cost-effective. Table 3.1.2 shows the annual cost of

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[18]The Commission expressed a preference for damage cost estimates in its Order in DPU 89-239 (at 83). This initial estimate is admittedly very rough, and New York is embarking on a four year, $1.3 million project to estimate better damage figures.

[19]The plants required to use 0.2% include L'Energia, Masspower, Everett Energy, West Lynn, and Bellingham. Ventron has conditional approval to use 0.3%S #2 for up to 2000 hours, and very clean (0.04%S) kerosene for 1000 hours.

Edison's estimated 0.55% cost differential for the lower-sulfur oil. The cost of SO_2 reduction rises from slightly over $1000/ton in 1994 (Edgar's first possible year of operation) to nearly $1900/ton in 2014 (the end of the proposed contract between Edgar Energy and Boston Edison), all in 1990$. DEP staff has indicated that the agency is considering requiring still lower SO_2 levels, at higher costs.

Table 3.1.3 summarizes our new estimates. All three of these approaches indicate that the $1500/ton value selected in DPU 89-239 is more likely to be understated than overstated. The health-based valuations from the first two approaches should logically be added to the acid-rain-based valuation of the allowances.

Q: What actions do you recommend the DPU take with regard to the valuation of utility SO_2 emissions?

A: The DPU should require that all utilities incorporate in their estimates of direct avoided costs (for evaluating all incremental resources) both the costs of complying with Title IV of the CAAA (e.g., higher fuel costs, lower coal plant capacity) and the incremental costs of allowances sold or not purchased due to the resource. Allowance requirements should be computed for emission levels following the other compliance actions included in the analysis. The incremental costs of allowances might be about $800/Ton (1990$ or 1991$) starting in the year 2000.

The DPU might reasonably increase its estimate of the total environmental value of SO_2. A cost of $2,000/ton would be more consistent with the available data. On the other hand, the DPU's current estimate is not unreasonably low.

Whatever total valuation the DPU selects, it should be used in the period 1991-1999. Beginning in 2000, once Title IV is fully implemented, the internalized allowance cost should be subtracted from the externality value to reflect the internalized portion of the cost of SO_2 emissions; the difference between the total value and the allowance cost remains as the external portion of the cost.[20]

3.2 Carbon Dioxide

Q: What major issues surround the CO_2 valuation debate?

A: The major issues are uncertainties in (1) the analysis of anthropogenic greenhouse effects, including:

- whether global warming has started,
- the rate of future warming,
- and the economic and environmental consequences of global warming;

and (2) the effectiveness of reducing carbon dioxide emissions to slow the rate of warming and diminish potentially deleterious environmental effects, economic damage, and the costs of controlling additional damage.

[20] If the allowance cost exceeded the externality value, then the allowance cost (which will be an internalized cost) would replace the externality value.

Q: Where does the current debate stand?

A: It is widely recognized that large reductions in net anthropogenic CO_2 emissions, especially by the developed countries, will be necessary to slow global warming to tolerable rates, even with the phase-out of CFC's and controls on other greenhouse gases. Krause, Bach, and Koomey (1989) estimate that reductions of 20% from present levels by 2005 or 2010 (or roughly 50% from base case), and reductions of 80% from current levels by 2030 are required from industrialized countries to limit global warming to a tolerable rate. Figure I.6.2 from Krause, Bach, and Koomey is attached as Figure 3.2. The Intergovernmental Panel on Climate Change (1990) estimates that more than a 60% reduction from current emissions levels would be needed to stabilize CO_2 emissions at current levels.[21]

Acting on this principle, many countries have adopted CO_2 emissions reductions targets (summarized in Table 3.2.1) and some have planned implementation strategies. For example, to reduce its CO_2 emissions 25-30% by 2005, Germany will introduce a carbon tax this year.[22] Norway's government has proposed stabilization at 1990 emissions levels by the year 2000. Japan's goal is stabilization at 1990 levels of CO_2 by 2000. New Zealand plans to reduce carbon dioxide emissions 20% by 2000, while Australia's target is stabilization at 1988

[21]IPCC results quoted from <u>Global Environmental Change Report,</u> Vol II, No. 11, 8 June 1990.

[22]"Ruling German Parties Agree to Introduce Carbon Tax," <u>Global Environmental Change Report,</u> vol. III, no. 2. January 18, 1991.

levels by 2000 and 20% reduction by 2005. Other targets are also listed in Table 3.2.1.

Q: How was the original \$22/ton CO_2 value adopted by the DPU derived?

A: In Chernick and Caverhill (1989) we developed a range of tree-planting costs for the U.S. based on reasonable assumptions about carbon uptake per acre and planting and maintenance costs per acre, of 2-10 cents/lb carbon.[23] From that range of costs, we chose 4.0 cents/lb carbon (\$80/ton carbon), or \$22/ton CO_2 as our estimate for an externality value for CO_2. Subsequent estimates of tree planting costs, when corrected for comparability, confirm the reasonableness of this range.[24]

Q: How have you updated this estimate?

A: We have gathered estimates from several studies that compute (or allow us to compute) a marginal cost for reducing carbon dioxide emissions. Some of the studies directly estimate the marginal cost of achieving various reductions in CO_2 emissions. For other studies, we have estimated the marginal cost for the cost of the most expensive measure(s) identified as necessary to achieve the desired reduction in CO_2

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[23]Chernick, P. and Caverhill, E., "The Valuation of Externalities from Energy Production, Delivery, and Use." Report to the Boston Gas Company, December 22, 1989.

[24]Chernick, P. and Schoenberg, J., "Determining the Marginal Value of Greenhouse Gas Emissions," <u>Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets.</u> International Association for Energy Economics; Honolulu: July 1991.

emissions. Among the estimates we consider are those of microeconomic studies, based on estimates from a specific technology or technologies, and those of macroeconomic studies, based on taxation. Unless stated otherwise, all costs are in 1990 dollars, assuming 4% annual inflation.

Q: Have you updated your CO_2 cost analysis using this additional information?

A: Yes, we have updated our analysis to include additional international CO_2 targets and costs. We conclude from this analysis that the DPU externality value of \$22/ton CO_2 is probably far below the marginal cost of control measures other countries are implementing to achieve targeted CO_2 reduction targets.

a. Microeconomic Analyses

Q: What is a microeconomic analysis as applied to CO_2 costs?

A: Microeconomic analyses derive a value per amount of carbon dioxide reduction from the costs and effectiveness of technological strategies, such as conservation, cogeneration, fuel substitution, renewable energy, and tree-planting. The microeconomic analyses we have reviewed were performed by the World Wildlife Fund (1990), the Danish Ministry of Energy (1990), Manne and Richels (1989), Naill, Belanger, and Petersen (1990), Nordhaus (1991), New York State Energy Office (1989, 1991), and Oregon Department of Energy (1990).

Q: What did the World Wildlife Fund study find?

A: World Wildlife Fund (1990) compiled studies of the costs of reducing several countries' carbon dioxide emissions by 2005 to 80% of 1988 levels. With funding from the U.S. E.P.A., climate change analysts from industrialized countries undertook studies to calculate reduction costs in their native countries. In most cases, the authors focused on the possibility and costs of attaining a 20% reduction in emissions by 2005. The results appear in Table 3.2.2 [note 13], and the calculations in Table 3.2.3.[25] The measures reported are those discussed by the various authors. The carbon dioxide reduction costs for the Eastern European countries are much lower than for the U.S. and the U.K.: the result from uncertainties in the exchange rates and/or the low current efficiencies of Eastern European economies. As shown in Table 3.2.2, many measures are necessary to achieve the desired reduction goal.

Q: How were the Danish Ministry of Energy estimates of the cost of CO_2 control developed?

A: The Danish Ministry of Energy sets up three potential scenarios for future energy and economic development. The first, the supply scenario, concentrates on changing sources and uses of fuels to achieve carbon emissions reductions. The second, the environment scenario, assumes the most

[25]World Wildlife Fund (1990) also includes chapters on France, Hungary, Canada, and Japan. Japan's estimated cost is mentioned later in this testimony, while the other countries do not appear in the table because of inconsistencies or omissions within the chapters.

important consideration in energy supply decisions will be their environmental impacts. The third, the economy scenario, gives priority to the socioeconomic effects of these decisions.

Q: How do these three scenarios differ from base case projections of energy capacity and savings in 2000?

A: The difference is the exclusion of new coal plants from all three scenarios mentioned previously. The base case scenario assumes 1400 MW of power will be supplied from new coal plants. To compensate, cogeneration replaces coal-fired power, represents a two- to three-fold increase over the amount of cogeneration present in the base case scenario. The supply, energy, and economic scenarios also postulate wind energy's supplying between 1 1/2 to 2 1/2 times the power as in the base case. All three cases offer substantial increases in residential, commercial, and industrial conservation.

Q: How did you obtain a marginal cost from the Danish Ministry of Energy report?

A: The Danish Ministry of Energy (1990) offers estimates of the average costs of CO_2 emissions reductions as well as average costs of specific measures. To obtain a marginal cost estimate, we examined the differences between the second most expensive scenario - the economy scenario - and the most expensive one - the environmental scenario. As seen in Table 3.2.2, and calculated in Table 3.2.4, the incremental costs of reduction - between \$50-\$250/ton CO_2 - are similar to those of the other Western countries summarized in Table 3.2.2.

Q: What do Manne and Richels estimate?

A: Manne and Richels (1989) estimate the average cost of reducing CO_2 emissions 20% from 1990 values by 2020. The marginal cost would be higher. Their base case is a highly constrained energy scenario, with no new low-cost supply technologies available. The demand side of the scenario assumes no further energy efficiency improvements other than those induced by price changes. In this base case, the average reduction cost peaks at \$86/ton CO_2 in 2020.

Q: What do Naill, Belanger, and Petersen estimate?

A: Naill, Belanger, and Petersen (1990) estimate potential carbon dioxide emissions reductions from energy efficiency through 2030. From conservation supply curves, the authors create categories of "very high" efficiency for the upper end of the curves and "high" efficiency for middle portions of the curves. The incremental costs of reductions are negative for "high" efficiency, and \$69/ton CO_2 for "very high" efficiency. Even the "very high" level would reduce emissions only 28% from the projected levels and would not be sufficient to reduce emissions to 80% of their 1990 levels, even by 2030.

Q: What does Nordhaus analyze?

A: Nordhaus (1991) derives a marginal cost curve for CO_2 reductions by fitting an equation to a range of estimates. Some of the points along the curve are estimates from studies discussed in this testimony (e.g., Manne and Richels, Jorgenson and Wilcoxen). The curve shows that achieving a 50% reduction in CO_2 emissions from a base case scenario by 2005 (bringing 2005 emissions to 80% of 1990 emissions) would require a tax of approximately \$34/ton CO_2. Along with this curve, Nordhaus uses a marginal cost curve for CO_2 reductions from tree planting and a marginal cost curve for CFC reductions, to create a marginal cost curve for total greenhouse gas reductions.[26] Because Nordhaus includes large CFC reductions at low cost, the total greenhouse gas curve is lower than the CO_2 curve derived from the estimates from studies.

Q: What does the New York State Energy Office estimate?

A: The Draft 1991 New York State Energy Plan estimates costs on the order of \$66-\$124/ton CO_2 to achieve goals from stabilization of CO_2 emissions at 1988 levels in 2008 to a 20% reduction in these emissions in the same year. These costs are discussed in Attachment 3.

Q: And the Oregon Department of Energy?

A: An Oregon law passed in 1989 directs several state agencies to develop a strategy to reduce greenhouse gas emissions. A 1990 study by the Oregon Department of Energy (ODOE) presents thirteen technological strategies and the amounts of their contributions toward reducing state carbon dioxide emissions

[26]Both the CFC curve and the total greenhouse gas curve are expressed in dollars per ton of carbon equivalent.

20% below 1988 levels by 2005. Some options examined were increased conservation in all sectors, increased fuel efficiency in cars and light trucks, reduction of single occupancy vehicle trips, vehicular fuel-switching, fuel-switching from electric to gas water heaters, tree planting, and raising participation in recycling programs. ODOE noted uncertainties in mitigation costs, feasibility of reduction measures, and damages caused by climate change, but affirmed its belief that "the threat of global warming is significant."[27]

Table 3.2.2 [note 15] shows the average reduction costs for the strategies for which the ODOE report provided sufficient data to determine costs. It is not clear whether the most expensive of these strategies (at up to $296/ton CO_2) is needed to meet the state's reduction goals; however, the reduced coal strategy (at about $50/ton CO_2) is clearly necessary.

b. Macroeconomic Analyses

Q: What is a macroeconomic analysis as applied to CO_2 costs?

A: Macroeconomic analyses estimate the cost of reducing carbon dioxide emissions through taxation or similar measures, using computer models of national economies. Carbon taxes have been widely discussed in Europe, the U.S., and Japan. Many of the

[27]Oregon Department of Energy, Oregon Fourth Biennial Energy Plan: Global Warming Strategy and Two-Year Action Plan, p. 8. October 1990.

studies we examine estimate both a tax value, which is the amount required to achieve a certain reduction goal, and a tax cost, which represents the cost to society in terms of lost growth. The value and cost for a single tax are not necessarily equal, and often may be very different from each other. The macroeconomic studies we reviewed are from the World Wildlife Fund (1990), Manne and Richels (1989), Naill, Belanger, and Peterson (1990), and Jorgenson and Wilcoxen (1990).

Q: What did the World Wildlife Fund study find?

A: World Wildlife Fund (1990) asserts that Japan's existing high efficiency and low energy intensity make further CO_2 reductions through technological means difficult. The study estimates that a carbon tax sufficient to maintain 1988 emissions levels would reduce gross domestic product growth by .4% per year, or 39 trillion yen (1980 yen) in base case 2005 GDP. The marginal cost of reduction is $6,096/ton CO_2 (Table 3.2.2 [note 13]).[28]

Q: What do Manne and Richels estimate?

A: Manne and Richels (1989), working within the parameters of the highly constrained energy scenario described earlier, estimate the rates of a carbon tax necessary to achieve a 20% reduction from 1990 carbon emissions levels by 2020. The tax rises very sharply, peaks at $149/ton CO_2 in 2020, and falls

[28]The April 22, 1991 exchange rate is 137.65 yen/$.

to $65/ton CO_2 in 2040. The tax would remain fairly stable for the rest of the century.

Q: What do Naill, Belanger, and Petersen estimate?

A: Naill, Belanger, and Peterson (1990) consider several taxation levels, as well as a coal-plant efficiency incentive. Under the incentive approach, coal plants not meeting efficiency standards of the best commercially available technology receive a penalty based on the difference in efficiencies. The incremental reduction costs of these approaches appear in Table 3.2.2 [note 2] (calculated in Table 3.2.5). The study explicitly shows that the $568/ton C tax would achieve the goal of a 20% reduction from 1989 CO_2 emissions by 2020 at a social cost of $273/ton CO_2. The taxes in the range of $227-$364/ton C would reach a 20% reduction around 2030, at costs of $176-$219/ton CO_2. The other taxes and the coal incentive are much less effective in achieving emissions reductions.

Q: How do Jorgenson and Wilcoxen obtain a cost estimate for a carbon tax?

A: Jorgenson and Wilcoxen (1990) estimate the U.S. carbon taxes necessary for achieving three reduction targets, described below. The tax is determined by their model, which accounts for 35 industries, household consumption, investment and capital accumulation, government tax rates and nontax receipts, budget deficit, and foreign trade elasticities. Immediately stabilizing carbon emissions at their 1990 level of 1,576 million tons requires a tax that peaks at $5/ton CO_2

in 2020. The second goal, decreasing carbon emissions to 80% of the 1990 level by 2005, requires a maximum tax of $15/ton CO_2 in 2020. Finally, taxing emissions beginning in 2000 to maintain that year's base level would cost at most $3/ton CO_2 in 2020.

Jorgenson and Wilcoxen estimate the effects of these taxes in terms of percentage change from base case CO_2 and GNP levels. Figure 3.1 combines these percentage reductions with assumptions of 2% annual base case increases in both GNP and carbon emissions to calculate the marginal cost of shifting from the immediate stabilization goal to the goal of the 20% reduction from 1990 emissions levels.[29] The marginal cost of control peaks at approximately $56/ton CO_2.

Q: What are the implications of the costs estimates in these studies?

A: The implication is that the cost of the measures required to meet reasonable emissions reductions targets are very high, generally higher than the CO_2 externality values adopted by any state utility commission including the $22/ton adopted by Massachusetts. While we have not attempted to draw an estimate out of these diverse cost estimates, the Massachusetts' externality value is almost certainly too low to reflect marginal CO_2 emissions reduction measures.

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[29]Jorgenson and Wilcoxen do not compute absolute dollar costs or emission tonnage.

3.3 Nitrogen Oxides (NO_x)

Q: Have you updated the DPU's valuation of NOx?

A: Yes. We have updated the regulatory situation and reviewed estimates of the costs of NO_x controls likely to be required under the CAAA.

Q: What is the status of air quality regulation of NO_x, and of the role of utilities in NO_x production?

A: Utilities are responsible for approximately 25% of total national NO_x emissions.[30] NO_x pollution is linked to acid rain, reduced visibility, excess ambient ozone levels and increased incidence of respiratory ailments. Increased levels of respiratory illness have been positively correlated to increases in ambient ozone concentration (Krupnick, et al., 1990). For one or more of these reasons, NO_x emissions control measures are continually increasing in stringency, both at state and federal levels.

Q: Which provisions of the CAAA address NO_x control measures applicable to Massachusetts?

A: Several provisions in the CAAA address reductions in NO_x emissions, due to its contribution to the serious effects listed above and its variety of stationary and mobile sources. Seven of the eleven Titles of the CAAA address NO_x emissions directly (through specific control requirements) or indirectly (through research and enforcement provisions).

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[30]U.S. Department of Commerce, 1990 Statistical Abstract of the United States.

Q: What regulations does Title I of the CAAA address?

A: Title I addresses the issue of attaining minimum ambient air quality for several pollutants including ozone, particulate mater (PM), CO, NO_x, SO_2 and lead (Pb). Included in this title are specific reduction targets for these pollutants, including targets for reductions of the ozone precursors, NO_x and VOCs. Under these provisions, most of Massachusetts is classified as in serious non-attainment for ozone.[31] As such, Massachusetts, and many areas in the Northeast, are subject to several provisions. Among these are:

1. Enhanced monitoring of ambient ozone, NO_x and VOCs levels.
2. Attainment of reasonable progress toward national ambient air quality standard (NAAQS) for ozone, which requires VOC emissions reductions "at least 3% of baseline emissions each year," (averaged over three consecutive years beginning six years after the date of enactment of the CAAA) or equivalent NO_x and VOC reductions which would have at least the equivalent effect on ozone level reduction.[32]

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[31]Curiously, central Massachusetts is currently considered moderate, rather than serious. The implication of this is that this area must come into compliance sooner (within 6 years of enactment) than the serious-designated areas (nine years). Massachusetts has requested a special waiver making the entire state one serious non-attainment region for compliance purposes.

[32]Less than 3% per year can be allowed if the state demonstrates to the Administrator that all feasible measures are being taken.

3. Enhanced vehicle inspection and maintenance for each urbanized area (1980 census population of 200,000 or more).

4. Clean-fuel vehicle program (as defined in part C of Title II).

5. Transportation control, which includes the evaluation of vehicle mileage, aggregate emissions, congestion levels, and other relevant parameters to determine consistency with attainment of State Implementation Plan (SIP) targets.

6. Control of interstate air pollution in the Northeast transport region, which includes the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and the CMSA of the District of Columbia. States within such a region must submit a new or revised SIP including implementation of enhanced vehicle inspection and maintenance and RACT (reasonably available control technology). Within three years, the Administrator must identify control measures which are as effective as vehicle refueling measures, and the state SIPs must be revised to incorporate such measures within one year of the completion of that study.[33] In addition,

[33]Chernick and Caverhill (April, 1990) estimated the cost of stage II vapor recovery devices for vehicle refueling at $1.02/lb VOC, and noted that other estimates for the same program ranged up to double this estimate (API, 1988). OTA (1989) estimated that the most expensive measures required to meet the CAAA ozone provisions

sources within this region that emit greater than 50 tons per year of VOCs will be considered major sources, and at a minimum will be subject to the requirements for major sources under the moderate non-attainment regions, which includes VOC offsets of 1.15 to one.[34]

Q: What issues does Title II address?

A: Title II reduces mobile source emissions of NMOGs (VOCs), NO_x, particulates and CO. Under the Act, states can choose to adopt either the federal emissions standards, or the more stringent California emissions standards for mobile sources (adopted in California in July 1990).

Q: What are the federal and California standards?

A: The new federal standards for NMOG, CO and NO_x are defined in Title II of the CAAA, and are shown in Table 3.3.1. The most stringent of the clean fuel requirements for NO_x are for Phase II, light duty trucks and vehicles, which have emissions limits of 0.2 grams per mile for vehicles starting in the model year 2001.

The new California standards, referred to as the California Low Emissions Vehicle (LEV) program, set five different emissions limits. A particular vehicle must meet one set of standards, while compliance with a fleet average

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would be $6,600/ton (1994$) or about $5,500 (1990$).

[34] A typical 150 MW gas combined-cycle, a 300 MW coal plant, or a 50 MW oil-fired combined cycle could surpass this threshold.

limit will likely mean manufacturers must market vehicles in categories other than only the most lenient.

Under the LEV program, vehicles categorized as Standard Vehicles (SV) must meet emissions limits equal to the federal regulations. Emission limits for NMOG, CO, NO_x and formaldehyde for the four other categories of vehicles are also shown in Table 3.3.1.[35] Transitional low emission vehicles (TLEV) must limit emissions further than standard vehicles, and emissions limits for low emission vehicles (LEV) are more strict still. Ultra-low emission vehicles (ULEV) must comply with the most strict limits of the program. The California LEV program defines zero emission vehicles (ZEV) as battery-operated electric vehicles. There are no emissions limits since, as the name describes, the zero emission vehicles have zero emissions.[36]

Q: In the LEV program, how are motor vehicles classified into one of the five categories?

A: The vehicle's manufacturer chooses under which category it wants a particular model and year vehicle to be certified. The manufacturer must notify the California Air Resources

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[35]NMOG is non-methane organic gases. Information from Massachusetts Department of Environmental Protection, <u>Background Document for Proposed Amendments to 310 CMR 7.00 et seq.</u> September 1991.

[36]That is, the vehicles have no direct emissions other than the incremental emissions from the electric system.

Board (CARB) which fuel the vehicle will use. CARB has published a list of the types of fuels and control technologies it expects will be necessary for vehicles to use to belong to anything other than the most lenient category, Standard Vehicle.

Q: Have any states in the Northeast adopted or considered adopting the new California standards?

A: Yes. Last year, prior to the passage of the CAAA, Massachusetts adopted California emissions limits.[37] In March 1991, New York also adopted them. Maine and New Jersey are preparing background documents in anticipation of hearings in early 1992. Connecticut has a legislative mandate to study the effects of adopting such a program, while Rhode Island and Vermont have agreed to adopt the program if a majority of the states in the Northeast States for Coordinated Air Use Management district do so.[38]

Q: How does Title IV affect NO_x emissions?

A: Title IV deals with reducing total emissions of acid gases SO_2 and NO_x, and permanently capping emissions of SO_2. Under this title, low-NO_x burners or the equivalent are required to be retrofit onto existing tangentially-fired and dry bottom wall-fired boilers, and equipment that is at least as cost

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[37] Massachusetts modified the California program slightly by requiring that 2% of a manufacturer's new vehicles sold in the Commonwealth from 1998 onward be zero emission vehicles.

[38] Information from telephone conversation with A. Marrin, NESCAUM. October 2, 1991.

effective, and perhaps more costly, will be required on other types of boilers.[39]

Q: What Massachusetts state regulations govern selection of NO_x control measures?

A: Massachusetts uses a top-down approach to determine best available control technology (BACT) for NO_x and other pollutants.[40] The top-down approach requires the developer of an energy project to use the most effective available technology unless it can establish that measure is not cost-effective, and then it is required to use the next most cost-effective measure. Cost-effectiveness determinations appear to take into account benefits of reductions as well as costs.

Q: How do the Massachusetts' top-down BACT regulations interact with the federal CAAA provisions?

A: The requirements under the CAAA will tend to raise the ceiling on determining cost-effectiveness for emissions control measures, particularly under Title I. Title I does not specify the control measures that the states are to use to meet air quality targets; it requires the states to submit state implementation plans (SIPs) that outline how the federal air quality targets and milestones will be achieved. Within

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[39]CAAA Title IV, Section 407(b)(1). Low-NO_x burners are not suitable for cyclone boilers, which would require something like gas reburn, at a cost roughly six times higher than that of low-NO_x burners. (Illinois DENR, Analysis of Acid Rain Control Alternatives. October 1989).

[40]For instance, see United Engineers & Constructors, Edgar Energy Park Project Draft Environmental Impact Report, p. 4.6-1. February 16, 1990.

this framework, each state develops and implements its SIP, presumably at lowest cost for that state given technical and administrative constraints. Other titles of the CAAA (listed above) set minimum NO_x and VOC control requirements, such as specific NO_x emissions limits on mobile sources in Title II, specific minimum NO_x control measures on stationary sources to reduce acid rain effects in Title V, and minimum NO_x and VOC emissions controls requirements as a member of the Northeast transport region. These provisions, along with current air quality regulations, set the base case for the SIP, onto which more expensive controls, on new and existing sources, are added until ozone air level targets defined by the SIP can be achieved and permanently maintained. Massachusetts has not yet revised its implementation plan to respond to the CAAA, and is not required to do so until up to four years after the enactment of the CAAA. However, New York estimates that retrofitting of SCR on coal plants will be necessary to meet CAAA Title I in that state, at a marginal cost of about $8,800/ton.[41] The DPU's valuation of NO_x at $6,250 is quite reasonable in the light of New York's estimate, and may be somewhat understated.

3.4 Particulates

[41]New York State 1991 Draft Energy Plan Issue Report, Issue 9.

Q: Have you updated your estimate of the value of reducing particulate emissions?

A: Yes. Fabric filters may be determined to be BACT control for particulates in Massachusetts.[42] Applied Energy Systems (AES) determined that the incremental cost of particulate removal from 0.015 lbs/MMBtu to 0.012 lbs/MMBtu emissions rate, using a fabric filter on its proposed Harriman coal plant (Bucksport, Maine), was $37,260/ton particulates (1995$) or about $31,200/ton particulates (1991$). AES determined, based on this analysis, that 0.02 lb/MMBtu was BACT for particulate control using a fabric filter. However, this level of emissions from a coal plant is below what is generally required for new coal sources in New England. In fact, new sources are generally not required to achieve 0.015 lb/MMBtus. The expected emission level from the Eastern Energy New Bedford Coal AFBC appear more typical for new plants, 0.02 lb/MMBtu. Therefore, the incremental cost calculated by AES is probably higher than the costs of marginal control measures required in New England at present.

However, AES estimate does provide some useful information. If this incremental cost for very high reductions is comparable to ESP costs, then the cost of achieving reductions down to 0.018 lb/MMBtu would be on the order of 82% that of the cost of going from 0.015 to 0.012,

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[42]Personal communication with A. Aiken of NEES, 1990.

or $25,584/ton[43]. Even to achieve 0.03 lb/MMBtu emissions level, the cost would be about 62%, or $19,344/ton. These costs may overstate the value of particulate reductions somewhat due to differences between baghouses and ESP and the company's use of nominally levelized costs. Nonetheless, it seems likely that the marginal cost of controls required in New England could be on the order of $10,000/ton. The DPU should consider increasing the particulate externality value.

An excerpt from that analysis is attached as Figure 3.4. It is not clear if such a stringent emissions level would be required in Massachusetts or elsewhere in New England. Therefore, we continue to support the use of the DPU value for particulates, which was based on our earlier analysis of the marginal cost of improving ESP efficiency from 95% to 99%, as a minimum value. However, in light of periodic reports in the scientific community regarding previously unsuspected serious health consequences of small particulate matter, we think that this externality is probably undervalued.[44]

[43]Cost = K x Ln(E), where E = 1 - (ESP efficiency). (See workpapers for calculations)

[44]The value of particulate emissions is complicated by the fact that some of the health effects attributed to particulates may be more properly attributed to sulfates and nitrates, which are emitted from the stack as SO_2 and NO_x respectively, and toxics, such as metals, some of which are emitted as gases (mercury) and others which adhere to particulate matter. This problem is unique to direct valuation and does not affect particulate valuation based on the cost of control measures.

3.5 Carbon Monoxide (CO)

Q: Do you have additional information on costs for carbon monoxide (CO) reduction?

A: Yes, we have one additional cost estimate. The Massachusetts Institute of Technology (MIT) proposed cogenerator project proposed the use of a CO catalyst to reduce its CO emissions by 90% from 148.4 tons/year at a cost of $1,100/ton CO removed.[45] MIT asserts that the catalyst was BACT for CO control and justified for the urban location of MIT, which was in non-attainment for CO in 1987 and 1988.[46] This value might be justified for regions within Massachusetts that are out of federal attainment for CO, but may be too high for other areas. We do not recommend a change to the DPU externality value for CO of $820/ton ($1989) at this time.

3.6 Update on Fuel Cycle Externalities Studies

Q: What is currently being done about developing upstream fuel-cycle externalities?

A: Three federally sponsored studies look promising for providing fuel-cycle externalities for energy resources within the next few years:

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[45]MIT does not state whether this is a real or nominally levelized cost. However, it appears to be real levelized based on total initial capital cost of $300,000, $275,000 of which is for catalyst which must be replaced every two years, and $10,000 other annual operating costs. Estimate appears to be in $1989.

[46]U.S. Department of Commerce, 1990 Statistical Abstract of the United States.

Oak Ridge National Lab, in conjunction with the European Community and Resources for the Future, is developing life-cycle emissions and effluents figures, including valuation of effects, for conventional and renewable power generation resources for electricity and transportation fuels where they overlap. The ORNL and the EC are together currently developing coal life-cycle externalities. Other fossil, biomass and nuclear externalities will be developed by the ORNL, while the EC has taken responsibility for developing renewable life-cycle externalities. Preliminary coal results are expected in a Primer this fall, after a guidance document was released this summer for comment. Oil and biomass externalities are expected next year. The guidance document outlined an "incrementalist" perspective for the study, which appears to look at incremental additions to existing facilities. This approach is similar to but not the same as a complete marginal perspective in that it has left out several important effects, such as land use and some materials required for construction. Therefore, the study's results will at best provide a baseline for fuel-cycle emissions, but will not completely characterize upstream externalities.[47]

ORNL is also collaborating with Pacific Northwest Labs, SERI, and the Oko Institut to develop fuel cycle externalities (quantities only, no valuation) for biomass fuels and

[47]Personal communication with J. Beldock of the Office of Environment and Energy Efficiency of the DOE.

renewables. This study is being coordinated by Ken Humphreys of PNL. The Oko Institut (of Germany) has developed a model called TEMIS (total emissions model for integrated systems) for determining fuel cycle environmental effects for utility resources. The model was originally developed in German using data from the European community. It was translated into English through funding by the Department of Energy in 1990, and the original data base has been expanded to include data for the United Kingdom. The model has incorporated preliminary U.S. data, primarily from Argonne National Labs (ANL, 1978), and will be further updated by data supplied by Pacific National Labs and the Solar Energy Research Institute, and possibly ORNL. Attachment 4 is a fact sheet on the Temis model provided by the Oko Institut.[48]

The DOE Office of Environmental Analysis is sponsoring an input/output modelling effort for fuel-cycle externalities using the INFORM model developed at the University of Maryland. This study is focussing on four fuel cycles: Solar, grain ethanol, a coal boiler and integrated coal gasification coal plant. This study is expected to include all sector effects, including, for example, cement and electronic inputs to the fuel cycle.[49]

Q: Have you updated your analysis of any upstream externalities?

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[48]Personal communication with U. Fritsche of the Oko Institut.

[49]Personal communication with J. Beldock of DOE.

A: Yes. Regarding our estimate of the externalities of oil spills, the National Research Council has published a book on the methods and costs of reducing tanker spills, including the cost-effectiveness of the available measures. According to the NRC, in a typical year, 7,500 tons of oil is spilled from groundings and collisions, the U.S. imports about 420 million tons of crude oil, and 600 million tons of oil is moved through U.S. waters.[50] Therefore, about 0.0013% of oil moved through U.S. waters is spilled. In a typical year for oil spills, double-hulled tankers with hydrostatic controls would cost in the range $366,000-$539,000 per ton of oil saved (i.e., per avoided ton spilled). Therefore, the cost of a double-hulled tanker with hydrostatic controls would be about $4.76-$7.00/ton of oil moved through U.S. waters, or $0.12-$0.17 per MMBtu of oil moved through U.S. waters.[51] This estimate compares closely to our original estimate of $0.20/MMBtu calculated in Chernick and Caverhill (1989).

Double-hulled tankers with hydrostatic controls are the most expensive and most effective measure studied by the NRC. Double-hulled tankers without hydrostatic controls would cost about 60% of this cost. These are assumed to be the costs of new vessels. The federal oil spill bill requires new vessels to be built with double hulls and many existing vessels to be

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[50]National Research Council Committee on Tank Vessel Design, Tanker Spills Prevention by Design, National Academy Press, 1991, pages 173-174.

[51]Assuming 7.3 lbs/gal and 150,000 Btu/gal of crude oil.

retrofit with double hulls or taken out of service within 20 years.[52] It was not clear from the lay press whether the bill requires hydrostatic controls or not. The cost of the retrofit is likely to be higher than the cost for a new vessel, although we do not have an estimate of the cost.

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[52]Cushman, J.H., "Oil Spill Compromise Calls for Double Hulls," <u>New York Times.</u> July 13, 1990.

4. ADDITIONS

4.1 Chlorofluorocarbons (CFCs)

Q: What regulations have been proposed or adopted concerning the production and use of CFCs?

A: The most widely known treaty is the Montreal Protocol. Last revised in June 1990, the pact calls for a 20% reduction in CFC consumption by 1993 and a 50% reduction by 1995. Under terms of the agreement, CFCs, halons, and carbon tetrachloride (CCl_4) will be phased out entirely by 2000 and methyl chloroform will be phased out by 2005. Approximately seventy countries have agreed to follow the Montreal Protocol's terms.

On the national level, several countries have adopted CFC policies that are even more strict than the Montreal Protocol. The CAAA legislates the elimination of CFC, CCl_4, and methyl chloroform on a more accelerated basis than called for under the Montreal Protocol. In addition, HCFC's are to be phased out between 2015 and 2029, depending on their application, if they have been recycled, and other factors. In Switzerland, HCFC's are being banned between 1992 and 1994 and CFC's by 1995.[53] Germany also passed a law prohibiting CFC production and use by 1995 and HCFC-22 production and use by 2000.[54]

Q: Is there any precedent for CFC regulations at the state level?

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[53]Global Environmental Change Report, Vol. III, No. 17. September 6, 1991.

[54]Global Environmental Change Report, Vol. III, No. 17. April 5, 1991.

A: Yes. Beginning in 1995, Vermont will not allow any motor vehicle using CFC's in its air conditioning to be sold in state. The South Coast Air Quality Management District has also adopted a CFC elimination policy which among other things, commits to phase out all uses of CFCs and halons as soon as possible and before 1997, and pledges to phase out all HCFC uses as soon as possible.[55]

Q: What quantity of CFC's is emitted by typical equipment?

A: CFC's may be emitted from equipment by servicing, leakage, recycling, or simply disposal. A large commercial air conditioner can emit up to 400 lbs/year of CFC's.[56] A typical residential refrigerator contains approximately one pound of CFC-12,[57] which would eventually be released to the atmosphere if the unit is disposed of in a landfill and which would be released immediately if the unit is crushed or shredded.

Q: How can the relative influences of different chlorinated compounds be measured?

A: As they contribute to global warming and ozone depletion, CFC's, HCFC's, CCl_4, and methyl chloroform are commonly evaluated as to their global warming potential (GWP) and ozone depletion potential (ODP) relative to CFC-11. Table 4.1.1,

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[55] SCAQMD Policy on Global Warming and Stratospheric Ozone Depletion, Public Workshop, February 8, 1990. This document contained a draft policy. The final version was similar according to personal communication with SCAQMD.

[56] Global Environmental Change Report, Vol. II, No. 13, July 6, 1990.

[57] ASHRAE Handbook E.37.6.

columns 2 and 3, show ozone depletion potentials (ODPs) and global warming potentials (GWPs) for several chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), and hydrofluorocarbons (HFC).

a. Costs of CFC phaseout

Q: Are CFCs being phased out because of their contributions to both stratospheric ozone depletion and the greenhouse effect?

A: No. At least under the Montreal protocol, CFCs are being phased out due to their contribution to stratospheric ozone depletion alone. However, since these chemicals also contribute to the greenhouse effect, their phaseout is often credited with reductions in total greenhouse gas emissions. We assume that the costs of the phaseout were justified by the effects on the stratospheric ozone layer alone, and that the Montreal protocol participants did not materially consider the global warming benefits of CFC reductions when deciding to phase out all chemicals with stratospheric ozone depletion potential.[58]

Q: What are the costs of the phaseout?

A: The National Academy of Sciences (1991) reports abatement costs for the elimination of CFC uses in the U.S. According to the NAS, the most expensive measures required under the phaseout are replacement of refrigerants and insulation in

[58]Essentially, this makes the global warming benefits of CFC reduction free goods, and the costs of CFC control imply nothing about the value of reducing CFCs for global warming purposes.

appliances with refrigerants and insulations that contain hydrofluorocarbons (HFCs).[59] The NAS (Table J.1) reports that the cost of fluorocarbon substitutes for appliance insulation is $72,429/tonne of CFC replaced (at a carrying charge of 10%).[60] Since the HFC replacement has an ODP of zero, the ozone depletion potential of the appliance insulation is reduced to zero. Therefore, if CFC-11 is the replaced insulator, then the cost of eliminating the ozone depletion potential of appliance insulation is $72,429/tonne CFC-11, or $65,700/ton CFC-11.

Similarly, if CFC-11 is replaced with HFC in appliance refrigerants, the NAS reports a cost of $74,500/tonne CFC-11 (at a carrying charge of 10%) or $67,600/ton CFC-11.[61]

Q: What do these costs imply about the value of reducing CFC emissions?

A: To estimate the value for the reduction of CFC emissions for utility planning, especially the value of capturing CFCs in

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[59] National Academy of Sciences, "Policy Implications of Greenhouse Warming Report of the Mitigation Panel," Tables J.1 and J.2, Cost Impacts of CFC phaseout - United States and Worldwide are attached as Figures 4.1.1 and 4.1.2. For the calculation presented here the U.S. costs are used; Worldwide costs are higher for the same measures.

[60] A tonne is one metric ton. In the NAS report they use "ton" to mean metric ton.

[61] CFC-12 is also a common refrigerant in this application. If the NAS assumed CFC-12 was replaced in its cost calculation, the value for CFC-11 equivalent would be slightly higher due to the slightly lower ODP of CFC-12. For both applications, if the replacement chemical had not had an ODP of zero, the net reduction in ODP would have been lower for the same cost, and the cost of the measure would have been higher per ton of CFC.

DSM program design, the cost of replacing appliance refrigerants provides the best estimate. Although the Montreal protocol and the CAAA require essentially a ban on all new CFC uses, they do not require more expensive CFC emissions reducing measures, such as capture and destruction of CFCs in many existing uses. Clearly, the measures included in the CFC regulation have been individually considered for feasibility and cost-effectiveness.[62] Therefore, we estimate that the value of reducing CFC emissions is implied by the cost of replacing CFCs with HFCs in appliance refrigerants, and is $67,600/ton CFC-11 ($1990).

Q: What are the values of reducing the other ozone-depleting chemicals?

A: To calculate the value of reducing emissions of other CFCs and HCFCs, we can use the relative ODPs of the chemicals. Table 4.1.1, column 4, shows externality values of the ozone depleting chemicals.

Q: How should these values be used in resource selection?

A: Resources that reduce CFC emissions should receive a credit of $67,600/ton CFC-11 equivalent reduced. DSM programs that collect and recycle or destroy CFCs should get a credit for the CFC emission reduction. For example, a DSM program that offers refrigerator retirements including proper CFC destruction should receive this credit. A refrigerator

[62] Indeed, when the Montreal Protocol was adopted, the cost estimates for many measures were much higher.

retirement program that retires refrigerator coolant CFCs without release to the atmosphere is worth $34 per refrigerator for the CFC recovery alone.[63]

4.2 Air Toxics

Q: What are air toxics, and why do they matter?

A: Combustion of oil and coal release a variety of toxic substances into the air, which include organics, such as formaldehyde, and heavy metals such as arsenic and beryllium. The amount emitted from power plants varies considerably depending on many factors, including the type of fuel, the extent of preprocessing, which is usually intended to remove other materials, such as sulfur, the type of equipment used for SO_2 and particulate control (e.g., precipitators, baghouses, scrubbers), and operating conditions. Metals occur naturally in coal and crude-oil deposits. Following combustion, some portion of each metal is released with the flue gases, while the remainder ends up in fly ash, bottom ash, or air-pollution control equipment. Toxic trace metals tend to be found in highest concentrations in the smallest particles emitted from the stack. Such small particles are especially harmful because they easily penetrate deep into the lungs, where they can enter the bloodstream, and they are deposited in bodies of water where they bioaccumulate in fish.

[63] Calculation is $67,600/ton x 1/2000 x 1 lb/refrigerator = $34/refrigerator.

Q: How have you approached the problem of estimating the value of reduced emissions of air toxics?

A: We recognized that it would not be possible to develop marginal costs of control for each individual pollutant. Table 4.2.1, reproduced from an EPRI paper,[64] lists 36 toxic air pollutants that have been found in power plant flue gas. As shown in Tables 4.2.6 and 4.2.7, we have found data on power plant emissions of over a dozen of these air toxics, mostly heavy metals.

All of the listed materials, other than copper, are listed as hazardous air pollutants in Title III of the CAAA. The EPA is to set maximum achievable control technology (MACT) for each of these 14 categories, and 175 others, over the course of the decade. Each source that emits over 10 tons/year of any one toxic, or over 25 tons/year of all toxics combined, will be covered.[65] A power plant would be a single source under the definition of "source." In addition, a special study of utility power plant toxics emissions must be completed by 1993 and used as the basis for regulation of

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[64]Chow, W. et al., Managing Air Toxics. 1990.

[65]Given the large amount of chlorine emitted by coal plants, and the large amount of nickel emitted by residual oil plants, virtually all utility power plants using these fuels would be covered by the size limits. For example, even at just a 30% capacity factor, a residual plant of more than 600 MW would exceed the 10-ton limit for nickel. The limits would be exceeded by smaller plants burning coal, or operating at higher capacity factors. Since a source is defined as including a "group of stationary sources located within a contiguous area and under common control," the limit would apply for power plants, not for units.

power plant emissions.[66] Thus, control requirements for these emissions will be changing rapidly over the next several years, and regulation of utility emissions may lag behind that of emissions from other sources.

Hence, we have concentrated on relating the toxicity of the various toxics to one another, and on estimating the costs of required controls for benchmark toxics.

Q: How have you determined the relative toxicity of the various air toxics?

A: There is no fundamental unit of toxicity (such as mortality per gram) that is applicable to all toxics. Different toxics have different effects, including carcinogenicity, neurological effects, retardation of mental and physical development, and damage to a number of body systems (e.g., kidneys, lungs, blood). Each individual toxic may be known or suspected to have several effects, and each of those effects may be subject to considerable uncertainties. Hence, to relate the toxicity of the various materials, we used the Threshold Effects Exposure Levels (TELs),[67] the maximum air

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[66]The Clean Air Act Amendments appear to defer application of the air toxics provisions to electric utilities, even though arsenic emitted by a power plant is as dangerous as arsenic emitted by a smelter. The apparent rationale for the exemption is that the utilities will be responsible for most of the acid rain reduction, and in some cases for much of the local air quality improvements, mandated in other sections of the same bill, and that equity requires that utilities be temporarily exempted from the burdens of complying with the air toxics provisions.

[67]The TELs are the Massachusetts version of 24-hour limits of ambient concentrations, more generally known as allowed air levels (AALs).

concentrations set for the general environment by the Massachusetts Department of Environmental Protection. These are shown in column 2 of Table 4.2.2. The lower the TEL, the higher the DEP's assessment of the material's danger to the public, per gram in the air, considering the health effects and the uncertainties in those effects. Column 5 of Table 4.2.2 shows the ratio of the TEL for lead (Pb) to that of the particular toxic. This ratio is a measure of the toxicity of the material, with respect to lead.

For example, the lowest TEL is that of beryllium, which is 140 times lower than the TEL for lead. Hence, a microgram of beryllium pollutes 140 times as much air to its TEL as does a microgram of lead. At the other extreme, 14.5 times as much HCl as lead is required to reach the TEL, so hydrogen chloride is one fourteenth as toxic as lead.

For the pollutants for which the DEP has not set TELs or AALs (arsenic, manganese, and polycyclic organic matter, or POM), we determined column 5 from the ratio of AALs set by other states. For arsenic and manganese, we used the AALs of Connecticut, the only other New England state for which the necessary AAL have been reported.[68] For POM, we used Virginia, the only state that has set an AAL.

Q: How did you estimate the marginal costs of control of air toxics?

A: We looked at a number of figures, based on required or anticipated controls.

Arsenic from primary copper smelters: Table 4.2.3 shows the costs of the ESP required at that ASARCO-El Paso copper smelter to reduce arsenic emissions, along with the costs of controls at other facilities, which are not currently required for these existing facilities. The cost of the control is \$18/lb, in roughly 1982\$. Given the high relative value of arsenic compared to lead, this is less than \$1/lb Pb, and is thus not marginal.

EEA (1990) indicates that the CAAA will require arsenic controls on all remaining primary copper smelters. From EPA (1986) and Table 4.2.3, we see that these controls cost as much as \$855/lb in the dollars of the study in 1982\$.[69] Thus,

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[68]As we will see later, the relative environmental cost of As and Pb is important, since As is a major contributor to total power plant toxic emissions. The AAL's for As set by Nevada and Virginia (the other two states that set AALs for both Pb and As) are roughly two orders of magnitude higher than those set by Connecticut, even though all three states use similar AALs for Pb. If Massachusetts adopted the relative valuations for As used by Nevada and Virginia, the total lead-equivalent emissions from oil and coal plants would be considerably lower. On the other hand, the observed costs of control for As would become significant in terms of \$/lb Pb.

[69]The dated cost data in the study are stated in 1982\$. Due to the uncertainties in relative toxicity, a few percent of inflation is not a significant uncertainty.

these controls would cost about $1200/lb As in 1991$. Since EEA (1990) projects much larger As reductions than does EPA (1986) (about 300 tons/yr, as compared to 35 tons/yr), EEA (1990) may also assume other, more expensive, controls. The incremental level of control for each application (e.g., the decision to capture 85% of emissions rather than 80%) will often be still more expensive.

Arsenic from glass manufacturing plants: EPA (1986) estimates the costs and effectiveness of adding electrostatic precipitators (ESPs) to glass furnaces, to control As emissions. Of the furnaces for which controls were required at that time, the most expensive control was for a furnace that emitted 3.75 tons/yr. The control was expected to cost $532,400/yr (roughly 1980$) and the reduction was required to be at least 85% of the emissions, or 3.19 tons/yr. The cost of control was thus $84/lb As in 1980$, or about $125/lb As in 1991$.[70]

The requirement to achieve 85% reduction, as opposed to some other lower level of reduction, has a higher incremental cost. From Radian (1984, p. 52), the size (S) of the ESP required to remove a fraction (F) of particulates follows the formula:

$$S = - k * \ln (1 - F)$$

where k is a constant. For F = .85, S = 1.9 k; for F = .80, S = 1.6 k. Thus, roughly 16% (.3/1.9) of the system cost is

[70]New furnaces will be subject to stricter limits.

due to the last 6% (5%/85%) of collection efficiency. Thus, the incremental cost is about 2.7 (16%/6%) times as high as the average cost. This brings the incremental cost of the required reduction to about $300/lb As. So long as arsenic is valued at 60 times the environmental cost of Pb, this is still only about $5/lb Pb.

Lead from secondary lead smelters: EEA (1990), in a study for EPA, estimated the cost of controls expected to be required of secondary lead smelters under the Clean Air Act Amendment. These controls include the installation on process stack sources of venturi scrubbers downstream of the baghouse, enclosure of the smelter building with ventilation to a new baghouse, use of a water sprinkler system to suppress fugitive dust from area emission sources, and replacement of the blast furnace with a new electrolytic process. The analysis estimates the average cost of these controls to be $330,415/ton Pb, or $165/lb Pb(1989$). Given the variation in costs between plants, the most expensive controls are likely to be several times as expensive, or roughly $500/lb Pb.

Chromium in cooling towers: EPA (1988, Table 7-1) found that replacement of chromium water-treatment products with phosphate water treatment would be cost-effective, even though it could cost up to $1,170,000/ton Cr nationwide, and as much as $4,270,000/ton Cr for the 2,780 smallest cooling towers considered. The middle of the cost range for the small cooling towers is $2,210,000/ton Cr. All of these costs appear to be in 1986$. The middle of the small-tower cost range is thus about $1330/ton Cr, in 1991$.

The particular type of chromium used in cooling tower corrosion control is hexavalent chromium (Cr^{+6}), which is particularly carcinogenic. The only state to report an AAL for hexavalent chromium, Connecticut, sets that AAL an order of magnitude lower than the AAL for chromium in general. Massachusetts rates chromium (TEL of 1.36) as almost an order of magnitude less toxic than lead (TEL of .14). Thus, the cost of the hexavalent chromium controls are roughly equivalent to about $1300/lb Pb.

Lead in paint: One of the most clearly documented and expensive efforts to control heavy metals is the effort to remove lead from paint.[71] Regulations often require removal or encapsulation of paint containing more than 1 gram Pb per cm^2 in buildings that are or might be occupied by children.[72] The costs of this control can vary widely, depending on the care taken to minimize lead dust, the cost of labor, and other considerations. Since lead control may overlap with repair of degraded surfaces, repainting, repapering, and other

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[71]For example, see U.S. Department of Housing and Urban Development, <u>Comprehensive and Workable Plan for the Abatement of Lead-Based Paint in Privately Owned Housing.</u>

[72]Pollack, S., "Solving the Lead Dilemma," <u>Technology Review</u>. October 1989.

structural and aesthetic improvements, identifying specific lead-control costs can be complicated.

Fortunately, we do not need to characterize the entire range of lead paint removal techniques, but only the marginal costs. One of the more expensive control measures involves deleading of windows. The small, uneven surfaces of mullions (the dividing bars between the lights of windows) and other window trim are difficult to scrape, so the least-cost option for deleading windows is generally to replace the entire window. Replacing just the sash (the movable portions of the window) costs about $15/ft^2, while it costs about $25/ft^2 to replace the entire window (including the frame).[73] Both the surface area of the frame and the costs of alternative treatments (such as scraping) will vary. To simplify the analysis, we concentrated on the cost of lead abatement through replacement of window sash.

The cost of sash replacement per gram of lead will vary with the number of lights (which increase the area of the mullions and hence the amount of lead), the size and shape of the window, and the concentration of lead. We examined a number of windows, and found that 3600 cm^2 of painted area was fairly typical. One could get about that much painted area from such representative cases as:

[73] Personal communication from Blair Hamilton, Vermont Energy Investment Corporation, based on experience of conservation programs in New England.

- a 4-over-4-light window of 2x4', with about 2" of exposed cross-section on each mullion and rail (for 24'*2" = 4 sq. ft. of area), or
- a 6-over-1 window of 30" by 62", described in greater detail in the workpapers.

Thus, at 1 mg/cm^2, it would not be unusual to replace 8 to 13 sq. ft. of window to eliminate 3.6 g of lead. At $15/$ft^2$, this would cost $120 - $200, or $33 - $54/g Pb. Since there are 454 gram in a pound, the cost of window replacement for lead abatement is $15,000 - $25,000/lb Pb. Public agencies require, and in some cases pay for, lead abatement at this level of cost-effectiveness.

Air-borne lead is obviously different than lead in paint. Air-borne lead is more important than lead in paint, since all air-borne lead is already in the environment, while most of the lead in paint will stay bound indefinitely. On the other hand, lead in paint, particularly interior paint, can create "hotspots" of lead contamination that can have devastating effects on the physical and mental development of individual children, while the airborne lead will be more evenly distributed across the population of humans and other species. There does not seem to be any straightforward way to convert the value of lead reduction in paint to the value of reducing air-borne lead emissions. Nonetheless, the high implied value of removing lead in paint, combined with the small amounts known to affect human development, suggests a very high value per pound for air-borne emissions as well.

Relative exposure limits for air toxics, PM, and SO_2: Table 4.2.4 extends the approach of Table 4.2.2 to relate air toxics to other regulated air pollutants, which (such as air toxics) are regulated due to their direct health effects.[74] Much higher exposure levels are permitted for PM and SO_2 than for the air toxics, implying that the equivalent health effects (reflecting the differences in the types of health effects, and the uncertainties) of the toxics are correspondingly higher than those of PM and SO_2. Given the relative health valuation, and the DPU's current valuation of SO2 and PM, each pound of lead is worth about $2000.

Q: Please summarize your estimates of the value of lead emissions.

A: Table 4.2.5 lists the valuations from the analyses described above. Recall that the control costs represent minimum, rather than maximum, values.

Q: How have you used this range of estimates?

A: We can be quite confident that airborne lead has a social cost well in excess of $150/lb, from the cost of smelter controls. The cost of chromium controls in chiller cooling towers suggests that the value of reducing lead emissions is at least on the order of $1,500/lb. A somewhat higher value is

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[74]NO_x and VOCs are regulated primarily due to their contribution to forming ozone, and are thus omitted from this analysis.

supported by the relative stringency on exposure limits to lead, PM, and SO_2, given the DPU's current valuation of those pollutants. The cost of replacing lead-painted windows suggests a social cost of lead in excess of $15,000/lb.

In Table 4.2.6, we show the effect of applying these three costs to the toxic emissions of coal- and oil-fired power plants.[75] Table 4.2.7 extrapolates the effectiveness of ESPs, as estimated by Radian (1989), from coal plants to residual-oil plants. Even at the geometric mean of the range ($1,500/ton Pb), the toxic emissions of

- unscrubbed coal plants with electrostatic precipitators (ESP) would be worth about 12¢/kWh,
- scrubbed coal plants (none of which now exist in New England) would be worth about 2¢/kWh,
- uncontrolled residual oil plants would be worth about 5¢/kWh,
- distillate-fired plants (mostly combustion turbines) would be about 2¢/kWh, and
- a residual plant with an ESP would be worth about 1¢/kWh.

These values could easily be ten times as large.

These results are sensitive to a number of factors. First, there are uncertainties in the relative valuation of the various toxics. This is particularly troublesome in the

[75]This table includes the air toxics for which we had emissions data and relative valuations. A number of other air toxics are emitted by coal and/or oil, including fluorine, many metals, and some other organics. As additional data becomes available, we will supplement this table.

case of arsenic, which is valued from Connecticut, rather than Massachusetts, regulations, and which is the most important contributor to the valuations for coal and residual.[76] If As were only 6 times as toxic as Pb, rather than the 60 we derived from Connecticut's regulations, the total valuation would fall about 25% for ESP coal, about 60% for scrubbed coal, and about 30% for residual.

Second, emissions will vary between plants in each category. For example, some ESPs and baghouses may be more efficient than the ESPs EPA studied.

Third, the high values of reductions in air toxics and the requirements for toxics controls under the CAAA may result in retrofit of scrubbers on coal plants and ESPs on residual plants.

Q: How do you recommend that the DPU incorporate air toxics in the valuation of externalities?

A: At this point, the most important determination is for the uncontrolled residual-fired plants that make up most of the NEPOOL marginal supply, since near-term resource decisions seem to be likely to be backing out existing sources for some time. We suggest a very modest initial valuation of 1¢/kWh for the air toxics from these units. We would suggest an air toxics value for about 2.5¢/kWh for ESP coal plants (for purchases from New York or Ontario, for example), about 4

[76]Chlorine is almost as important as As for ESP coal plants.

mills/kWh for scrubbed coal and distillate, and 2 mills for ESP-equipped residual plants.

4.3 Thermal Pollution

Q: What do you mean by thermal pollution?

A: We refer here to the transfer (rejection) of heat from a power plant to a body of water. All steam plants and combined cycle plants must reject heat from their condensers, to maintain a temperature and pressure differential across the steam turbine. The cooler the cooling water, the more efficient the steam turbine can be. Traditionally, New England power plants have rejected heat to natural bodies of water, such as rivers and harbors.

Q: How have you estimated the cost of this heat rejection to bodies of water?

A: It is our understanding that the use of natural bodies of water as the heat sink for a power plant (called once-through cooling) is no longer permitted for most applications in New England.[77] Other than proposals for repowering or reusing existing utility power plant sites (at Edgar and Manchester Street), we are not aware of any serious recent proposal to use once-through cooling in New England. In other words, environmental regulators have essentially determined that the environmental costs of once-through cooling (e.g., pulling

[77] Once-through cooling became rare in some other parts of the country in the 1970s.

small organisms through the cooling systems, injuring fish and other large organisms through impingement against the intake structure) exceed the costs of requiring other cooling methods.

Most new power plants use wet cooling towers for heat rejection. Wet cooling towers use evaporation of water to remove the heat. In the process, they consume fresh water, usually release concentrated pollutants (and water-treatment chemicals) in the "blowdown" of unevaporated water,[78] produce plumes of water vapor (which can result in local fogging, visibility problems, and icing of roads in the winter), and release to the air whatever toxics are present in the water. A few plants use more expensive and less efficient dry cooling systems, which are similar to very large automobile radiators. Dry cooling systems are environmentally beneficial, since they release nothing but heat to the air, but they are more expensive to build and operate, and increase the plant's heat rate even more than do wet cooling towers. Dry cooling towers are not generally required.

We can estimate the environmental costs of once-through cooling from the extra costs regulators are willing to require to avoid it. For this purpose, we will use the cost differential between once-through and evaporative cooling. Since the environmental cost differential must be larger than

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[78]Blowdown is required to limit the buildup of impurities in the cooling water.

the direct cost differential (or else evaporative cooling would not be required), and since evaporative cooling has substantial environmental costs, the total costs of once-through cooling must be larger than the difference in cost between once-through cooling and wet towers.

Q: For what plants do you have estimates of the incremental costs of wet cooling?

A: As we mention above, most power plant proposals do not even discuss the possibility of once-through cooling. The exceptions are Manchester Street, which has been conditionally licensed with once-through cooling, due to space constraints and the lack of adequate fresh water supply for evaporative cooling; and Edgar, which is seeking a similar license. Both New England Electric System and Boston Edison have presented estimates of the additional cost of using evaporative cooling. For Edgar, we have estimates of the costs of evaporative cooling both at the Edgar site and at the alternative Ironstone site. Table 4.3.1 presents those estimates and computes the cost of control per avoided MMBTU rejected to water.[79] Depending on the estimate, the real-levelized cost of control is about 30-80¢/MMBTU rejected. Costs at other sites may be higher. Hence, it is reasonable to assume that

[79]The estimates are not well documented, and Table 4.3.1 represents our best attempt to apply the available data. Perhaps Massachusetts Electric and Boston Edison can improve on our interpretation of the data.

the general prohibition on once-through cooling is based on an implicit value of heat rejected of more than 80¢/MMBTU.

Q: How does this value translate to ¢/kWh?

A: For a gas-fired combined-cycle plant with once-through cooling (Edgar or Manchester St.), rejected heat is about 2.2 MMBTU/MWH. At 80¢/MMBTU, this would add 0.2¢/kWh to the environmental costs of the plant.

For a typical steam plant, using 10,000 BTU/kWH or 10 MMBTU of fuel per MWH, of which 3413 BTU/kWh (or 3.4 MMBTU/MWH) goes out as electricity (by definition) and about 20% goes up the stack, rejection to water is about 4600 BTU/kWh or 4.6 MMBTU/MWH. At 80¢/kWh, this would add about 0.4¢/kWh.

4.4 Oil Import Premium

Q: What is an oil import premium?

A: An oil import premium is a value applied to domestic oil consumption to reflect the external costs of oil imported into the United States caused by the national vulnerability to problems of energy security and high oil prices. The oil import premium reflects the costs of imported oil not reflected in the price of oil, or the external costs. In the terminology used by the DPU in its decision in DPU 89-239, the oil import premium would be considered an economic externality rather than an environmental externality.[80]

Q: How does it relate to the subject of this docket?

A: In its Vote to Open Investigation (DPU 91-131, June 14, 1991), the DPU addresses the periodic update of externality values. The language of the Vote to Open Investigation repeatedly uses the phrase environmental externalities; however, the scope was not expressly limited to any particular externalities, except as outlined in the guidelines referred to in DPU 91-131 (at 4) and contained in DPU 91-141 (pages 23-24).

Department consideration of an oil import premium is consistent with these guidelines. The first guideline directs proposals to avoid externalities that are accounted for elsewhere in the resource selection criteria or the siting process. The oil import premium is not considered elsewhere in the resource selection criteria or the siting process.[81] The second guideline directs proposals to focus on

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[80] In DPU 89-239 (at 81, footnote 37) the Department raised the question of whether the oil import premium should be included in resource selection as a monetized externality or as an issue related to fuel diversity. The DPU deferred decision on this matter, but encouraged the electric companies to address this issue explicitly.

[81] The oil import premium is not a utility fuel diversity issue. An oil import premium reflects the notion that all reductions in domestic use of oil reduce the external costs borne nationally by our increase in imported oil dependence. Fuel diversity issues typically reflect the specific attributes of a particular utility's resource mix. For some utilities it may be advantageous from a fuel diversity perspective to <u>increase</u> their fraction of oil resources in their resource mixes, even though this would increase national dependance on imported oil.

externalities that have global or regional impacts. The oil import premium reflects an externality affecting the nation as a whole. The third guideline outlines the acceptable estimation techniques. The oil import premium estimated in Chernick and Caverhill (1989) was based on the DPU's preferred method of estimation, direct valuation of effects. Therefore, the Department should reconsider the adoption of an oil import premium.

Q: What was the value of the oil import premium estimated in Chernick and Caverhill (1989) and discussed in DPU 89-239 (at 81)?

A: Chernick and Caverhill (1989) estimated an oil import premium of $2.26/MMBtu of fuel input, in 1988$. The discussion of the derivation of this value from Chernick and Caverhill (1989) is attached as Figure 4.4.

Q: Are you resubmitting this estimate for Department consideration?

A: Yes. This estimate is still relevant for the value of reducing the external costs of domestic oil use related to national security and price risk linked to oil imports. The Department should consider including this externality in the utilities resource-selection process.

5. OTHER STATE REGULATORY ACTIONS

Q: Are other states active in valuing externalities?

A: Several states have initiated proceedings or have come out with Orders adopting explicit valuation of externalities since the DPU's IRM Order in DPU 89-239, which included explicit valuation of externalities. Prior to the DPU Order in 89-239, New York was the only state that had adopted a monetized externality policy. Since August of 1990, when the DPU adopted Order DPU 89-239, the California Energy Commission, the California Public Utility Commission and the Nevada Public Service Commission have adopted specific externality values; the Bonneville Power Association has proposed externality values; and New Jersey has adopted externality adders for electric and gas conservation program screening. These recent orders are summarized in Table 5.1. Generally, these states are also engaged in integrated resource planning proceedings, and are considering externalities as a part of the IRP (or a similar) process.

5.1 California

Q: Have there been any further developments in the valuation of externalities before the California Energy Commission and California Public Utilities Commission, since your testimony in DPU 89-239?

A: The California Energy Commission (CEC) adopted externality values for six air pollutants in 1990.[82] In general, the CEC relied on two sources of valuation estimates for air emissions: the CEC staff and JBS Energy (whose work was on behalf on the Independent Energy Producers (IEP)). The CEC adopted values developed by JBS Energy for the out-of-state NO_x and SO_x values, and the staff for the other in- and out-of-state values. The staff approximated the marginal cost of control in the South Coast Air Quality Management District (SCAQMD), which surrounds Los Angeles and is the most polluted area of California, for each pollutant by estimating the average cost of a subset of the very stringent control measures required in this area. The derivation of these figures is in Therkelsen (1989). The result was a value lower than the marginal cost of control in SCAQMD, but perhaps typical of the state as a whole. The out-of-state values the CEC adopted for PM-10 and VOCs were proposed by the staff, and are simply 1/10th the value proposed for in-state. The lower value was justified by the general federal ozone level attainment status of the out-of-state regions that supply power to California. The SO_2 out-of-state value developed by JBS Energy and adopted by the CEC was based on mid-range scrubber costs on large power plants, while the NO_x value was based on JBS's estimate of selective catalytic reduction (SCR)

[82]California Energy Commission, 1990 Electricity Report. October 1990.

costs for NO_x control on gas-fired cogenerators of unspecified size. These estimates are briefly discussed in Schilberg et al. (1989).[83] The CO_2 value used within and out-of-state was developed by the staff based largely on the costs and energy savings from planting trees for shading benefits estimated in Akbari (1988).[84] All of the utilities are required to use the same externality values.

The Public Utilities Commission (PUC) recently adopted the externality values adopted by the CEC for emissions within California,[85] but with some changes. The PUC initially requires the utilities to use the CEC in-state externality values, for both in-state and out-of-state emissions. The PUC also ordered the utilities other than Southern California Edison (which serves primarily the SCAQMD) to develop marginal control cost estimates from their respective dominant air basins, and to use those values for all emissions.[86]

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[83] Schilberg, G.M. et al., Valuing Reductions in Air Emissions and Incorporation into Electric Resource Planning. August 1989.

[84] Akbari, H., et al., "The Impact of Summer Heat Islands on Cooling Energy Consumption and CO_2 Emissions," 1988 ACEEE Summer Study on Energy Efficiency in Buildings. ACEEE; Berkeley, Calif.: 1988.

[85] California Public Utilities Commission, Phase 1B Opinion: Changes to Final Standard Offer Four for use in Conjunction with the 1990 Electricity Report, pages 29-33. June 5, 1991.

[86] The PUC estimates that the values will be similar, and possibly higher, than those developed for the SCAQMD and adopted by the CEC.

5.2 Nevada

Q: How has the Nevada Commission addressed the issue of externalities?

A: In February the Nevada Public Service Commission adopted externality values based on a study by Tellus, which uses the cost-of-control approach. The unit values are equivalent to those of Massachusetts, inflated to 1990$, with the following exceptions. The value for VOCs is lower to reflect costs of controls for reducing fugitive VOC emissions from gasoline in Nevada, which is generally in attainment for ozone. The values for the greenhouse gases CO_2 and CH_4 do not appear to be inflated to 1990$.[87] Nevada is also attempting to value H_2S (which is a major emission of some geothermal plants) and requires the utilities to determine values for the site-specific externalities water impacts and land use.

5.3 New Jersey

Q: How has the New Jersey Commission addressed the issue of externalities?

A: On September 25, 1991 the New Jersey Board of Regulatory Commissioners (formerly the Board of Public Utilities) adopted adders to reflect the environmental benefits of conservation.[88] These values are apparently based on the estimates in

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[87] This appears to be a rounding error, since the value for the greenhouse gas N_2O was inflated to 1990$.

[88] State of New Jersey Board of Regulatory Commissioners, Conservation Incentive Rule, N.J.A.C 14:12. September 25, 1991.

Ottinger, et al. (1990).[89] For electric utility DSM programs, the average environmental externality value is 2.0 cents/kWh.[90] For gas utility DSM programs, the environmental externality value is $0.95/MMBtu. These externalities are expressed in 1991 dollars and are to be adjusted annually with the GNP deflator index. The utilities are to use externalities in setting avoided costs and valuing power purchases, both in bidding and negotiation.

5.4 New York

Q: How has the New York Public Service Commission addressed the issue of externalities?

A: The New York Public Service Commission (PSC) relied partially on work done by the New York State Energy Office (SEO) in its 1989 state energy plan to develop externality values for use in utility planning. In its 1989 energy plan, the SEO estimated the costs of various pollution control measures available in that state. As discussed in Putta (1990), the control costs used by the PSC to develop externality values reflected a mix of high and low cost measures, except for CO_2, which was arbitrarily set at a small fraction (20%) of the

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[89]Ottinger R., et al., Environmental Costs of Electricity, Pace University Center for Environmental Legal Studies, Oceana Press, 1990. Study is referred to as "Pace University values" in Table 5.1.

[90]This is an average value. The Commission asserts that the externalities should be time differentiated by rating period but does not indicate how this should be done.

SEO's original estimate of low-cost tree-planting. Land and water use externalities were loosely based on reports prepared in the Northwest for the Bonneville Power Administration.

The NYSEO has recently released a new draft state energy plan (1991 biennial update), which includes updated control costs for SO_2 and NO_x, and the costs of various CO_2 reduction measures and costs of achieving emissions reductions targets.[91] This report shows higher control cost requirements for SO_2, NO_x and CO_2 for New York emissions reduction targets then previously reported:[92]

SO_x: The NYSEO estimates the external benefit of SO_2 reductions at $2200/ton at the level of emissions covered by the state's allowances for the year 2000.[93] This emission level is 26% below 1988 emissions. NYSEO assumes that the value of SO_2 emissions would fall linearly to zero for emissions below 36% of the Clean Air Act Amendments of 1990 (CAAA) allowance level. Plotting the increasing cost of the supply of reductions against the assumed declining benefit, NYSEO estimates the

[91] A summary of their estimates is provided in the 1991 Draft State Energy Plan biennial update, Issue 9, Table 11.

[92] The costs in the State Energy Plan were apparently calculated from nominal ratemaking costs provided by the utilities, real-levelized using a social discount rate of 3% real. This and other peculiarities of the NYSEP are discussed in Attachment 3.

[93] NYSEO describes this value as being in nominal dollars, but the derivation implies that it is in real 1990$.

optimal emission level to be 30% below the allowance level, with a marginal value of further reductions of \$858/ton (\$1990). These valuations include only human mortality, without any value for morbidity (illness), visibility, acid rain, or other effects of SO_2. Hence, these values are probably understated, and are certainly additive with the acid-rain related allowance cost.

NO_x: NYSEO estimates a marginal cost of control of \$4,204/ton (\$1990), up from \$2,461/ton NO_x in the 1989 Final Draft Report. This value is based on the average cost of low-NO_x burners (LNB) and SCR for NO_x control on coal-fired power plants. NYSEO believes that SCR on coal plants will be necessary to meet the air quality standard of Title I of the CAAA. NYSEO estimates that the incremental cost of SCR, on top of LNB, would be about \$8,800/ton.[94]

CO_2: NYSEO finds that stabilizing CO_2 emissions by 2008 will require measures costing \$300/ton C (\$82/ton CO_2), while reductions of more than 5% will require measures costing \$500/ton C (\$136/ton CO_2). This cost is partially offset by the SO_2 and NO_x benefits of the CO_2 control measures. NYSEO estimates this offset at about \$16/ton on an average-cost basis; on a marginal basis, the offset might be worth as much as \$80/ton, bringing the net marginal

[94]See discussion in Attachment 3.

costs at stabilization and at reduction to $220/ton C ($60/ton CO_2) and $420/ton C ($115/ton) CO_2.

The New York PSC has also ordered the utilities to fund an environmental costing study of the direct costs of full fuel cycle externalities of power generation in New York. This study, cofunded by NYSERDA, ESEERCO, and EPRI will take approximately four years and over one million dollars, and will focus on developing direct costs of specific external effects.

5.5 South Carolina

Q: How has the South Carolina Public Service Commission addressed the issue of externalities?

A: The South Carolina Public Service Commission recently ordered utilities to monetize environmental externalities of supply- and demand-side options "where sufficient data is available," and evaluate externalities qualitatively where not enough information exists on their costs.[95] The staff emphasized:

> environmental costs should be monetized and included within the planning process whenever possible . . . each utility should identify and monetize, to the extent possible, the cost of compliance for existing and projected supply-side options.[96]

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[95]South Carolina Public Service Commission Staff Docket 87-223-E, Integrated Resource Planning Process. August 28, 1991.

[96]South Carolina Public Service Commission Staff Docket 87-223-E, Integrated Resource Planning Process. August 28, 1991.

The PSC has not yet established a specific methodology for utilities to use in monetization or evaluation. The PSC also ordered the utilities to include the internalized costs of complying with both current and anticipated environmental regulations as part of the integrated resource planning process.

5.6 Wisconsin

Q: Has Wisconsin updated its treatment of externalities?

A: Since 1989, the Wisconsin Public Service Commission has discounted non-combustion energy options by 15 percent. In its 1991 assessment of the state's electric utility plans, however, the Commission staff noted that the 15% credit may be too low. Among the advantages of monetization cited by the staff was its ability to distinguish differences among resources and make comparisons among options easier.[97]

5.7 Bonneville Power Administration

Q: How does the Bonneville Power Administration address the issue of externalities?

A: The Environmental Cost Work Group was formed in 1990 to determine externality values for resource options in the Northwest. Resources evaluated by the workgroup include pulverized coal; atmospheric fluidized bed combustion (AFBC);

[97] Wisconsin Public Service Commission, Staff Assessment of Electric Utility Plans: Advance Plan 6. July 1991.

integrated gasification combined cycle (IGCC); gas turbines; cogeneration fired by natural gas, biomass, and municipal solid waste; stand-alone municipal solid waste; new hydro and additions to existing hydro; geothermal; solar; wind; and conservation. Preliminary externality values were determined for several externalities, among them air emissions SO_2, NO_x, CO_2, and total suspended particulates, and proxies for water and land use. Those values are listed in Figure 5.7. However, the Work Group recently dropped the CO_2 value from its analysis, citing uncertainty in costs. The group has also limited its fish impacts analysis in light of two other parallel efforts on the same topic. Where possible, the Work Group relied on direct environmental cost estimates developed by ECO Northwest.[98] The externality values derived from these studies are substantially understated, due to understatements of the value of human life, and to the limitations of the range of effects considered. The Work Group continues to meet to discuss the issues.

[98]The ECO Northwest studies (1985, 1986, 1988) have been previously reviewed in Chernick and Caverhill, 1989 and Ottinger, et al. (1990).

6. CONCLUSIONS

Q: What are your conclusion and recommendations with respect to the externalities that the Department has already valued?

A: The DPU should at least maintain its current estimates of the values of externalities. Upward adjustments of externality costs would be justified, up to about:

- $4,500/T for SO_2, based on direct costing for health effects;
- $300/T for CO_2, based on estimated costs of control;
- $8,800/T for NO_x, based on New York's estimate of measures required for compliance with the Clean Air Act Amendments ozone limits; and
- $10,000/T for particulates.

Smaller increases may be justified by considerations of continuity. Also, once the more modest externality values already adopted by the DPU have been implemented by all electric and gas utilities, and once other regulators adopt similar approaches, the cost of reaching environmental targets will decrease, and the marginal costs of compliance and the marginal damage costs may also fall. No electric utility has yet incorporated the DPU's externality values in an integrated plan; until the DPU determines the effect of the established values, it may not want to radically increase those values.

Modest increases, at least covering inflation, should be applied to all the existing values, and those values should be at least rounded up, to reflect the likely understatement of costs.

Q: What are your conclusion and recommendations with respect to the valuation of additional externalities?

A: We recommend that the Department adopt valuations for ozone depletion, air toxics, thermal pollution, and oil imports.

For ozone depletion, we recommend a value of $67,600/ton (or $34/lb) of CFC-11 equivalent eliminated. This is a value per pound installed in equipment, only a small part of which leaks out each year. The value of reducing leakage would be higher.

For air toxics, we recommend initial values in Section 4.2. The most important value is that for residual plants, for which we suggest 1¢/kWh. The actual costs of air toxics may be much higher.

For thermal pollution, we recommend a value of 80¢/MMBTU rejected to water, or about 0.4¢/kWh for typical existing plants.

For oil imports, we recommend that the Department adopt a value of $2.50/MMBTU in 1991$, based on the analysis we presented in DPU 89-239.

Q: Does this conclude your testimony?

A: Yes.

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Table 3.1.1
Extrapolation of Particulate Matter Valuation to SO2

	Ambient Air Quality Standard (ug/m^3)	Relative Hazard Per Pound	Value Per Lb If PM Is Worth $2/Lb
	[1]	[2]	[3]
PM	150	1.00	$2.00
SO2	365	0.41	$0.82

Notes:
[1]: National Ambient Air Quality Standards or Massachusetts Ambient Air Quality Standards, in micrograms per cubic meter, 24–hour simple average.
[2]: ([1] for PM/[1])
[3]: [2]*($2/lb)

Table 3.1.2: Boston Edison Edgar – Costs of Switching from .3% S oil to .2% S oil

Boston Edison Forecast Levelized Fuel Costs	(1990$/MMBtu)	#2 oil:		
		BTU/lb	19,200	(Fink & Beatty, p. 5–5)
0.3%S No. 2 Fuel Oil	$10.97	lb/MMBTU	52	
0.2%S No. 2 Fuel Oil	$11.03	sulfur differential		
Percentage increase	0.55%	lb/MMBTU	0.052	

Year	Fuel price 0.3% S oil (Current $/MMBtu)	GNP deflator	Fuel price 0.3% S oil (1990$/MMBtu)	Fuel price 0.2% S oil (1990$/MMBtu)	Price Differential (1990$/MMBtu)	Cost of Sulfur Reduction (1990$/lb S)	Cost of Sulfur Reduction (1990$/ton S)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
1990	$4.46	131.60	$4.46	$4.48	$0.0245	$0.471	$942
1991	$4.82	137.40	$4.62	$4.64	$0.0254	$0.488	$975
1992	$5.14	144.40	$4.68	$4.71	$0.0258	$0.495	$989
1993	$5.46	151.70	$4.74	$4.76	$0.0261	$0.500	$1,000
1994	$5.81	159.20	$4.80	$4.83	$0.0264	$0.507	$1,014
1995	$6.25	167.30	$4.92	$4.94	$0.0270	$0.519	$1,038
1996	$6.78	176.10	$5.07	$5.09	$0.0279	$0.535	$1,070
1997	$7.50	185.60	$5.32	$5.35	$0.0292	$0.562	$1,123
1998	$8.30	195.80	$5.58	$5.61	$0.0307	$0.589	$1,178
1999	$9.32	206.80	$5.93	$5.96	$0.0326	$0.626	$1,253
2000	$10.42	218.50	$6.28	$6.31	$0.0345	$0.663	$1,325
2001	$11.69	230.50	$6.67	$6.71	$0.0367	$0.705	$1,410
2002	$13.05	243.10	$7.06	$7.10	$0.0389	$0.746	$1,492
2003	$14.49	256.10	$7.45	$7.49	$0.0410	$0.786	$1,573
2004	$15.79	269.70	$7.70	$7.75	$0.0424	$0.814	$1,627
2005	$17.09	283.90	$7.92	$7.97	$0.0436	$0.837	$1,673
2006	$18.43	298.80	$8.12	$8.16	$0.0446	$0.857	$1,714
2007	$19.85	314.40	$8.31	$8.35	$0.0457	$0.877	$1,755
2008	$21.18	330.80	$8.43	$8.47	$0.0463	$0.890	$1,780
2009	$22.50	347.80	$8.51	$8.56	$0.0468	$0.899	$1,798
2010	$23.82	365.90	$8.57	$8.61	$0.0471	$0.905	$1,809
2011	$25.25	385.00	$8.63	$8.68	$0.0475	$0.911	$1,823
2012	$26.68	405.20	$8.67	$8.71	$0.0477	$0.915	$1,830
2013	$28.26	426.50	$8.72	$8.77	$0.0480	$0.921	$1,842
2014	$29.93	448.70	$8.78	$8.83	$0.0483	$0.927	$1,854

Sources:
Boston Edison, "Request for Proposals (RFP#3)." September 20, 1991.
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Notes:
[2] Boston Edison, "Request for Proposals (RFP#3)," Table 5. September 20, 1991.
[3] Boston Edison, "Request for Proposals (RFP#3)," Table 4. September 20, 1991.
[5] [4]*1.0055
[6] [5] – [4]
[7] [6]/.052
[8] [7] * 2000

Table 3.1.3
Summary of New SO2 Externality Value Estimates

Estimate Source	Value per Ton of Avoided Emissions in MA	Notes
Mass. DPU PM value and DEP Ambient Air Quality Standards	$1,640	In 1989$.
Draft NY State Energy Plan 1991	$4,500	After meeting CAAA Title IV, adjusted for MA population density.
Switching Edgar from .2% to .3% sulfer oil	$1,000–$1,900	Actual cost depends on year. All in 1990$

Derivations can be found in text.

Figure 3.2.1

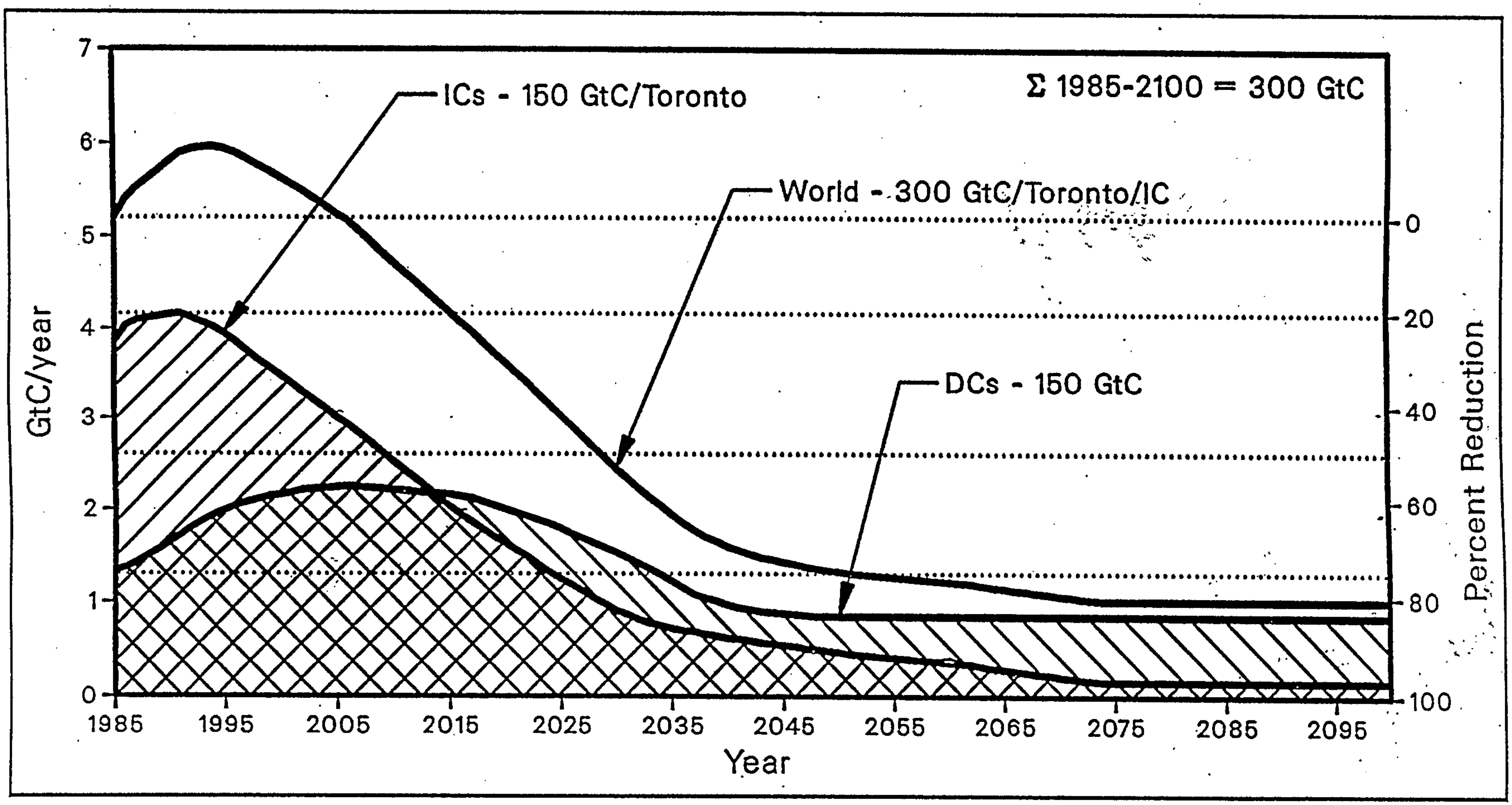
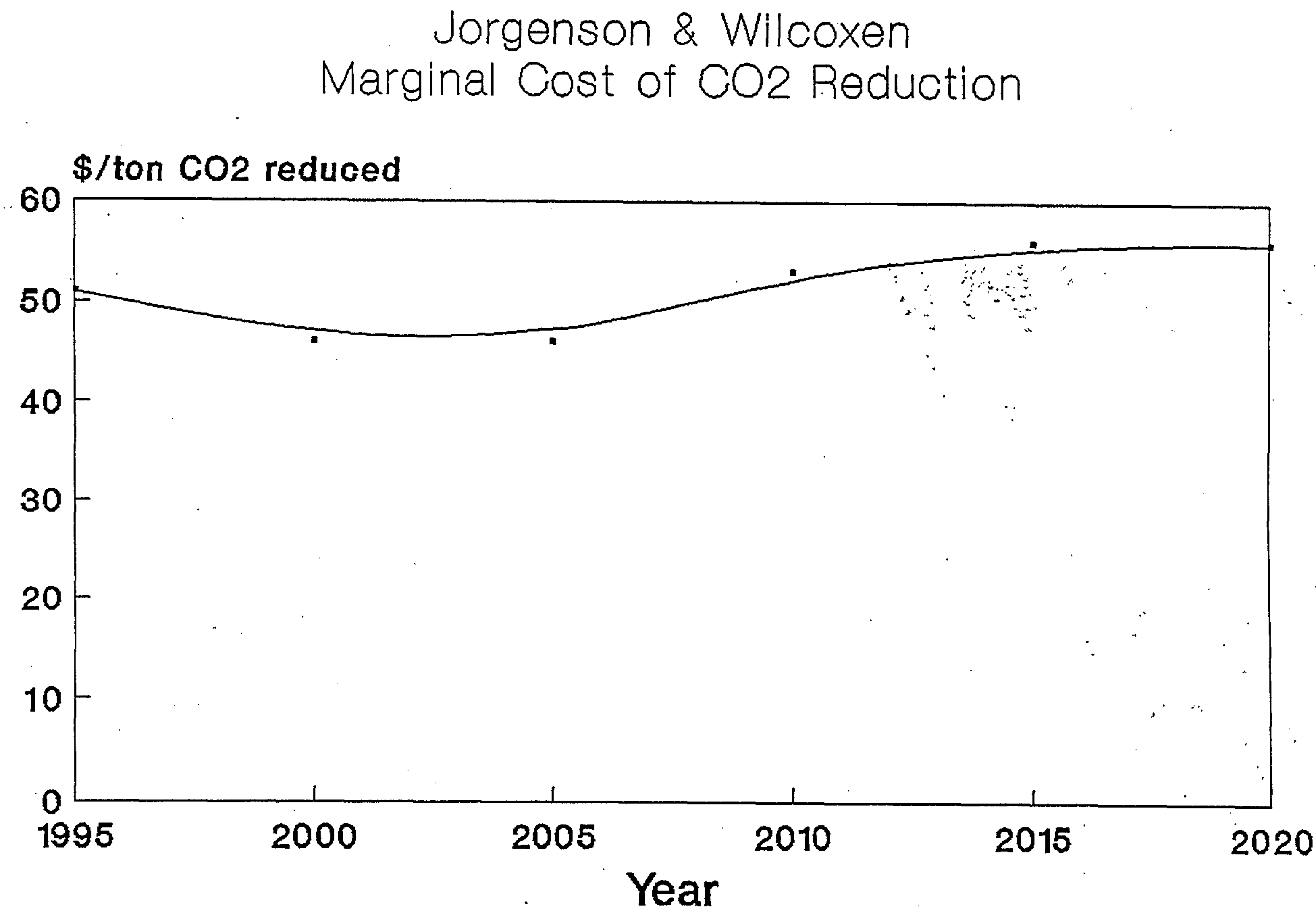


Figure I.6.2 Application of Toronto Target to Industrialized Countries

SOURCE: Krause, Bach, and Koomey. "Energy Policy in the Greenhouse," 1989.

Figure 3.2.2



Source: Jorgenson, D.W. and Wilcoxen, P.J., "Reducing US Carbon Dioxide Emissions: The Cost of Different Goals"

Costs are in 1990$

Table 3.2.1

Selected CO2 Reduction Targets

Sept 26, 1991

	Source	Target for CO2 Emission Reductions	Implied % reduction from base, assuming base annnual growth of CO2 emissions of: 2%	1%
[1]	IPCC	Over 60% immediate reduction needed to stabilize concentrations at today's levels.	NA	NA
[2]	Krause, et al.	25% reduction required by industrialized countries from 1990 levels by 2005.	44%	35%
		50% reduction required by industrialized countries from 1990 levels by 2015.	70%	61%
[3]	Canada	Stabilization at 1990 levels by 2000.	18%	9%
[4]	United Kingdom	Stabilization at 1990 levels by 2005.	26%	14%
[5]	Norway	Stabilization at 1990 levels by 2000.	18%	9%
[6]	Japan	Stabilization at 1990 levels by 2000.	18%	9%
[7]	Sweden	Stabilization at 1990 levels by 2000.	18%	9%
[8]	Denmark	20% reduction from 1990 levels by 2000.	34%	27%
[9]	Netherlands	3-5% reduction from 1989-90 levels by 2000.	20-22%	12-14%
[10]	Austria	20% reduction from 1990 levels by 2005.	41%	31%
[11]	New Zealand	20% reduction from 1990 levels by 2000.	34%	27%
[12]	Oregon	20% reduction from 1990 levels by 2005.	41%	31%
[13]	Germany	25% reduction from 1990 levels by 2005.	44%	35%
[14]	Toronto	20% reduction from 1988 levels by 2005.	43%	32%
[15]	Australia	Stabilization of 1988 levels by 2000.	21%	12%
		20% reduction from 1988 levels by 2005.	43%	32%
[16]	France	Stabilization at 1990 levels by 2005.	26%	14%
		20% reduction from 1990 levels by 2025.	60%	44%
[17]	Urban CO2 Project	1-2% reduction per year.	NA	NA

Sources:

[1]: Global Environmental Change Report, Vol II, No. 11 (6/8/90). p. 4.

[2]: Krause, Bach and Koomey, "Energy Policy in the Greenhouse," Vol 1 (1989), figure 1.6.2.

[3]-[9]: Global Environmental Change Report, Vol II No. 16 (8/17/90), p.4.

[10]: Global Environmental Change Report, Vol II, No. 17 (9/14/90). p. 3.

[12]: Clearing Up, No 368 (6/2/89), p. 2.

[11],[13]: Science News, Mar 1991.

[14]: Global Environmental Change Report, Vol. III, No. 7, April 5, 1991.

[15]: Global Environmental Change Report, Vol. III, No. 16, August 16, 1991.

[16]: Global Environmental Change Report, Vol. II, No. 19, October 12, 1990.

[17]: The regions affiliated with the Urban CO2 Project are Toronto, Denver, Minneapolis/St. Paul, Portland (Ore.), Dade County (Fla.), San Jose (Calif.), Hannover (Germany), Saarbrucken (Germany), Copenhagen, Helsinki, and Ankara. From Global Environmental Change Report, Vol. III, No. 12, June 21, 1991.

Table 3.2.2

Estimates of the Cost of CO2 Emission Reductions.

	Source and Measure [a]	Cost of reduction (1990$/T CO2) [b]	Percent reduction from base [c]
[1]	U.S. EPA		
	CO2 scrubbing	$39 - $51	90% of plant stack emissions controlled
[2]	Naill, Belanger and Petersen		
	Conservation		
	high	negative	18% reduction from base
	very high	$69	28% reduction from base
	Reforestation offsets	$22	55% reduction from base
	Coal efficiency tax	$65	12% reduction from base
	Carbon tax		
	$91/Ton C	$140	31% reduction from base
	$227/Ton C	$176	51% reduction from base
	$364/Ton C	$219	53% reduction from base
	$568/Ton C	$273	57% reduction from base
[3]	New York State Energy Office		
	CO2 scrubbing (coal plant)	$43	reduction of 20% of 1988 levels by 2000.
[4]	New York State Energy Plan (1989)		
	CO2 scrubbing (coal plant)	$25	reduction of 20% of 1988 levels by 2000.
	CO2 scrubbing (oil plant)	$37	
[5]	NYSEO (FRG externalities workshop)		
	utility sector mix (tree	$48	31% reduction from base by 2008
	planting, conservation, fuel	$91	36% reduction from base by 2008
	switching, renewables, etc...)	$136	39% reduction from base by 2008
		$167	43% reduction from base by 2008

cont...

Table 3.2.2 continued

	Source and Measure [a]	Cost of reduction (1990$/T CO2) [b]	Percent reduction from base [c]
[6]	Manne and Richels		
	$250/Ton carbon tax	--	20% reduction of 1990 emissions by 2020 and stabilization thereafter.
[7]	Steinberg and Cheng		
	CO2 scrubbing (coal plant)	$58	90% of plant stack emissions controlled
[8]	Nordhaus		
	mix (sequestration, emission	$23	17% from base emissions
	reduction)	$28	21% from base emissions
		$48	25% from base emissions
		$78	34% from base emissions
		$119	42% from base emissions
[9]	Spectrum Economics		
	utility sector mix (tree	$49	25% reduction from base by 2008
	planting, conservation, fuel	$88	29% reduction from base by 2008
	switching, renewables, etc...)	$172	33% reduction from base by 2008
		$261	37% reduction from base by 2008
[10]	Chernick and Caverhill		
	Carbon sequestration (trees)	$23	N/A
[11]	DOE, Office of Energy Research		
	fuel switching coal 1995	$98	N/A
	to gas 2010	$222	
[12]	Worldwatch Institute		
	improving energy efficiency	< 4.58	N/A
	wind power	$27	
	geothermal power	$32	
	wood power	$36	
	steam inj. GT	$51	N/A
	solar-thermal (gas)	$52	
	nuclear power	$153	
	photovoltaics	$235	
	CC coal	$273	

Table 3.2.2, cont.

	Source and Measure	Cost of reduction (1990$/T CO2)	Percent reduction from base
	[a]	[b]	[c]
[13]	World Wildlife Fund		
	U.S.A.		
	Natural gas replacing coal	$145	8%
	Gas combined cycles	$21	11%
	Nuclear	$12	14%
	Biomass as boiler fuel	$54	14%
	Biomass liquid fuels	$75	14%
	United Kingdom		
	Nuclear/non-fossil	$244	NA
	Poland		
	All energy conservation options	$1	51%
	Marginal conservation options	$7	NA
	USSR		
	Additional renewables	$12	NA
	CO2 scrubbers	$18	1%
	Japan		
	$95/ton CO2 tax	$6,096	18%
[14]	Danish Ministry of Energy		
	Change from an economic growth scenario to an environmental growth scenario		
	in 2000	$68	12%
	in 2015	$131	10%
	in 2030	$182	12%
	Heat conservation in existing buildings	$107	11%
	Heat conservation in new buildings	$41	2%
	More efficient electricity production	$19	29%
	Renewable energy	$6	26%

Table 3.2.2, cont.

Estimates of the Cost of CO2 Emission Reductions.

	Source and Measure	Cost of reduction (1990$/T CO2)	Percent reduction from base
	[a]	[b]	[c]
[15]	Oregon Department of Energy		
	Convert public and private fleets to natural gas	$296	0.02%
	Convert intra-city buses to natural gas	$108	1%
	No new coal plants; Back down some coal plants after 1997; Build 900 MW renewable energy	$43.5-$56	5%
[16]	Jorgenson & Wilcoxen		
	Switching from one CO2 emissions reduction target to a more strict target	$56	15%

[b]: 4% annual inflation assumed.

[1]: U.S. Environmental Protection Agency, "Policy Options for Stabilizing Global Climate," draft report to Congress (2/89) Vol II, p. V11-135. Assumes CO2 emissions of 2 lb/kWh.

[2]: Naill, Belanger, Petersen, " A Least-Cost Strategy for CO2 Reduction," from NARUC National Conference on Environmental Externalities (10/90), Table 4.

[3]: New York State Energy Office Division of Policy Analysis and Planning, "Environmental Externality Issue Report" (2/89), Preliminary Draft, p. 11.

[4]: New York State Energy Office, NYS Dep't of Public Service, NYS Dep't of Environmental Conservation, "Draft New York State Energy Plan; Issue 2b: Air Impacts, Electricity," (5/89) p. 36. New York could meet its 20% goal through tree planting and coal plant scrubbing; the 20% goal would not necessitate the more expensive oil plant scrubbing.

[5]: NYSEO paper prepared by A. Sanghi for Oct. 1990 conference.

[6]: Manne and Richels, "CO2 Energy Limits: an Economic Cost Analysis for the USA," Energy Journal preprint, (9/89), p. 26. The figure provided represents the long-run equilibrium tax. The economic cost of the CO2 reductions is higher than the tax value, due to multiplier effects.

[7]: Steinberg and Cheng, " Systems Study fo the Removal of Recovery, and Disposal of CO2 from Fossil Fuel Power Plants in the U.S.," Brookhaven National Laboratory (2/85).

[8]: Chernick and Caverhill, 1989.

[9]: Nordhaus, W.D. "A Survey of Estimates of the Cost of Reduction of Greenhouse Gas Emissions. 1990.

[10]: Spectrum Economics, "Economic Impacts of the Greenhouse Gas Reduction Plan." 1990.

[11]: U.S. DOE, Office of Energy Research, "A Preliminary Analysis of U.S. CO2 Emissions Reduction Potential from Energy Conservation and the Substitution of Natural Gas for Coal in the Period to 2010. Feb. 1989.

[12]: Worldwatch Institute, Lester R. Brown, et al. "State of the World 1990."

[13]: Chandler, W., "Carbon Emissions Control Strategies." World Wildlife Fund, 1990. In the U.S.A., we have assumed nuclear power costs 1.3 cents/kWh more than coal. Poland's energy conservation options include space heating managment, reduction of transmission and distribution losses, buildings insulation, automation and measurement, existing industrial equipment, railway electrification, coal quality improvement, shift to diesel engines in light trucks, and new industrial technology. The marginal measure is new industrial technology. We have used the following exchange rates: .5822 pounds/$, 2933 zlotys/$, 16.92 rubles/$ (commercial exchange rate), and 137.65 yen/$.

[14]: Danish Ministry of Energy, "Energy 2000." April 1990. The environmental scenario emphasizes reducing energy consumption. The economic scenario assumes all cost-effective reduction options have been carried out by 2000. Costs for the individual measures are average measure costs. Exchange rate = 6.585 krone/$.

[15]: Oregon Department of Energy, "Oregon Fourth Biennial Energy Plan." 1990.

[16]: Jorgenson, D. and Wilcoxen, P., "Reducing US Carbon Dioxide Emissions: The Cost of Different Goals." 1990. The less strict reduction target is immediate stabilization of carbon emissions at their 1990 levels. The more strict goal is 20% reduction of 1990 emissions levels by 2005.

FIGURE 3.4

TABLE 3.2-2 DIFFERENTIAL CAPITAL AND LEVELIZED ANNUAL COSTS FOR 0.012 LB/MBTU PARTICULATE REMOVAL SYSTEM*

	0.012 lb/MBtu Particulate Emission ($1,000)
Capital Costs	
Fabric filter	1,410
Ductwork and ID fans	0
Waste handling	0
1990 capital cost	1,410
Contingency	140
1990 Direct capital cost	1,550
Escalation	180
1994 Direct capital cost	1,730
Indirects	270
Interest during construction	460
1995 Total differential capital cost	2,460
Levelized Annual Costs	
Operating Personnel	0
Maintenance	550
Energy	30
1994 levelized annual operating cost	580
Fixed charges on capital	400
1995 total levelized annual cost	980
Incremental Particulate Removal, tpy	26.3
Incremental Removal Cost, $/ton	$37,260

*Costs are for fabric filter particulate removal system installed downstream of two circulating fluidized bed boilers.

SOURCE: AES Harriman Cove Cogeneration Project Air Emission Liscense Application to the Maine Department of Environmental Protection, May 1, 1991. Page 3-13.

TABLE 3.2.3: WORLD WILDLIFE FUND SURVEY OF CARBON DIOXIDE EMISSIONS REDUCTION COSTS

Country	Proposed measures [a]	Tons/year C reduced (in 2005 unless otherwise indicated) [b]	Cost (1990$) [c]	$/ton C (1990$) [d]	$/ton CO2 (1990$) [e]	Necessary to achieve 20% reduction by 2005? [f]
1. United States	Natural gas replacing coal	130,000,000	$76,000,000,000	$585	$145	?
	Gas combined cycles	180,000,000	$15,600,000,000	$87	$21	Yes
	Nuclear	240,000,000	$11,900,000,000	$50	$12	Yes
	Biomass as boiler fuel	240,000,000	$52,000,000,000	$217	$54	Yes, without
	Biomass liquid fuels	240,000,000	$72,800,000,000	$303	$75	new nuclear
2. United Kingdom	Nuclear/Non-fossil	NA	NA	NA	$244	?
3. Poland	All energy conservation potentials	35,000,000	$156,000,000	$4	$1	Yes
	Marginal measure	33,000,000	$960,960,000	$29	$7	Yes
4. USSR	Additional renewables	NA	NA	$49	$12	Yes
	CO2 scrubbers	50,000,000	$1,001,000,000	NA	$18	?

Notes

1a. Nuclear power is assumed to cost 1.3 cents/kWh more than coal.

1b, 1c. Tons of carbon and costs are projected for the year 2010.

3a. Poland's energy conservation options include space heating management, reduction of transmission and distribution losses, buildings insulation, automation and measurement, existing industrial equipment, railway electrification, coal quality improvement, shift to diesel engines in light trucks, and new industrial technology. The marginal measure is new industrial technology.

4b. Figure for CO2 scrubbers is in tons/year CO2.

Source

Chandler, W., "Carbon Emissions Control Strategies." World Wildlife Fund, 1990.

Exchange Rates:

.5822 pounds/$

2933 zlotys/$

16.92 rubles/$ (commercial exchange rate)

TABLE 3.2.4: CARBON EMISSIONS REDUCTION COSTS IN DENMARK

		Economic Scenario		Environmental Scenario		Cost of Incremental Reduction	
Year	Change in Scenario [1]	CO2 Reduction from 1988 (Tons) [2]	Average Cost (DKK0.01/ kg) [3]	CO2 Reduction from 1988 (Tons) [4]	Average Cost (DKK0.01/ kg) [5]	DKK0.01/ kg [6]	1990$/ ton CO2 [7]
2000	C to B	11,000,000	-20	16,800,000	4	50	$68
2015	C to B	24,500,000	-9	29,300,000	8	95	$131
2030	C to B	25,000,000	-9	31,200,000	19	132	$182

Measure [8]

2030	Heat conservation in existing buildings	85	$107
2030	Heat conservation in new buildings	33	$41
2030	More efficient electricity production	15	$19
2030	Renewable energy	5	$6

Source:

Danish Ministry of Energy, "Energy 2000." April 1990.

Notes:

[1] Scenario B is the environmental scenario, which emphasizes reducing energy consumption. Scenario C is the economic scenario, which assumes that all cost-effective reduction options have been carried out by 2000.

[2], [4] Table 5.13.

[3], [5] Table 5.14, assuming "central" prices and 7% real discount rate.

[6] ([4][5] - [2]*[3])/([4] - [2])*

[7] Assumes 6.585 krone per dollar.

[8] Table 4.18. Costs are average measure costs.

TABLE 3.2.5: NAILL ET AL. COSTS OF CO2 REDUCTION FROM TAXES

Tax Type	Amount (1990$/ton C)	Incremental Cost (1990$/ton CO2)
Coal efficiency	NE	$65
Carbon	$91	$140
Carbon	$227	$176
Carbon	$364	$219
Carbon	$568	$273

Source: Naill, R., Belanger, S., and Petersen, E., "A Least-Cost Strategy for CO2 Reduction," Proceedings of the NARUC Conference on Environmental Externalities. October 1990.

Table 3.3.1: Exhaust Emissions Standards for Cars and Light-Duty Trucks

		in grams/mile through 50,000 miles				
Program/ Standard	Year/ Category	Non-methane hydrocarbons	Non-methane organic gases	CO	NOx	Formaldehyde
Clean Air Act	1994-95	0.25		3.4	0.4	
Clean Air Act	1996-2000		0.125	3.4	0.4	0.015
Clean Air Act	2001		0.075	3.4	0.2	0.015
LEV	Standard	0.25		3.4	0.4	
LEV	TLEV		0.125	3.4	0.4	0.015
LEV	LEV		0.075	3.4	0.2	0.015
LEV	ULEV		0.040	1.7	0.2	0.008
LEV	ZEV		NA	NA	NA	NA

Sources:

Clean Air Act Amendments of 1990

Massachusetts Department of Environmental Protection, "Background Documents for Proposed Amendments to 310 CMR 7.00, et seq." September 1991.

Notes:

LEV = low emission vehicle. It is both the name of the program and of a category of vehicle under the program.

TLEV = transitional low emission vehicle.

ULEV = ultra-low emission vehicle.

ZEV = zero emission vehicle.

Table 4.1.1 Relative Global Warming and Ozone Depletion Potentials of Selected Gases

Gas	Global Warming Potential (CO2 = 1)	Ozone Depletion Potential (CFC-11 = 1)	Value of Reducing Emissions (1990$/ton)
[1]	[2]	[3]	[4]
CO2	1	NA	NA
CO	2.2	NA	NA
CH4	10	NA	NA
N2O	180	NA	NA
CFC-11	1,300	1.0	67,600
CFC-12	3,700	0.93	62,578
CFC-113	1,900	0.83	56,108
CFC-114	1,690	0.8	54,080
CFC-115	13,800	0.38	25,688
HCFC-22	410	0.05	3,380
HCFC-134a	338	0	0
HCFC-123	26	0.02	1,352
HCFC-124	NA	0.019	1,294
HCFC-141b	NA	0.088	5,949
HCFC-142b	NA	0.054	3,650
HFC-125	NA	0	0
HFC-134a	400	0	0
HFC-143a	NA	0	0
HFC-152a	46	0	0
NH3	NA	0	0

Notes:

[2]: CO2, CO, CH4, N2O, HCFC-22, CFC-11, and CFC-12 from Lashof and Ahuja. CFC-114, HCFC-134a, and HCFC-123 from York International, normalized to the CO2 unit on the basis of CFC-11. CFC-113, CFC-115, HFC-134a, and HFC-152a from Epstein & Manwell. (Note: Epstein, et al. cited a GWP of 6,400 for CFC-114.)

[3]: CFC-11, CFC-114, HCFC-22, HCFC-134a, HCFC-123, and NH3 from York International. Fisher, et al. describe similar results obtained by four atmospheric modelling groups: Atmospheric and Environmental Research, Inc., Du Pont Central Research, Lawrence Livermore National Laboratory, and the University of Oslo. CFC-12, CFC-113, CFC-115, HCFC-124, HCFC-141b, HCFC-142b, HFC-125, HFC-134a, HFC-143a, and HFC-152a are from Fisher, et al., and are based on the means of both the 1-D and 2-D models presented. Due to uncertainties of the models, only one digit is significant, though two were presented.

[4]: [3]*($67,600/ton). See text for derivation. Note that both the ODPs and this unit cost are normalized to CFC-11.

Sources:

* Epstein, Gary, and S. Manwell. "An assessment of the environmental trade-offs between CFC use and lower efficiency cooling with alternative refrigerants," in DSM and the Global Environment. Synergic Resources Corp. April 1991.
* Fisher, DA, CH Hales, DL Filkin, MKW Ko, ND Sze, PS Connell, DJ Wuebbles, ISA Isaksen, & F Stordal. "Model calculations of the relative effects of CFCs and their replacements on stratospheric ozone." Nature 344, 508-512.
* Lashof, Daniel A. and Dilip R. Ahuja. "Relative global warming potentials of greenhouse gas emissions." Submitted to Nature February 1990. Authors of Natural Resources Defense Council and Tara Energy Research Institute, respectively.
* York International. CFC Update, presented at International District Heating and Cooling Association. 1990 5th Annual Cooling Conference.

Figure 4.1.1

TABLE J.1 Cost Impact of CFC Phaseout--United States

CFC Policy Option	CFC Reduction (Mt/yr)	CO_2-Equivalent Reduction (Mt/yr)	Capital Cost (M$/life)	Equipment Lifetime (years)	Annual Capital Cost (M$/yr)			Operating Cost (M$/yr)	Total Cost (M$/yr)			Abatement Cost ($/t CFC)			Abatement Cost ($/t CO_2 Equivalent)		
					3%	6%	10%		3%	6%	10%	3%	6%	10%	3%	6%	10%
Cleaning and blowing agents, aerosols, refrigerants, not-in-kind substitutes	0.086	302	172	10	20	23	28	-17	3	6	11	35	70	128	0.01	0.02	0.04
Conservation and recycle	0.098	509	74	5	16	18	20	0	16	18	20	163	184	204	0.03	0.04	0.04
Cleaning and blowing agents, aerosols, fluorocarbon substitutes	0.074	248	0	10	0	0	0	167	167	167	167	2250	2250	2250	0.67	0.67	0.67
Refrigerants, fluorocarbon substitutes																	
Chillers	0.023	88	2,500	30	128	182	265	78	206	260	343	8956	11304	14913	2.35	2.97	3.92
Mobile air conditioning	0.030	170	5,000	10	586	679	814	135	721	814	949	24033	27133	31633	4.25	4.80	5.60
Appliance	0.002	11	1,067	15	89	110	140	9	98	119	149	49000	59500	74500	8.67	10.53	13.11
Other	0.010	67	1,500	10	176	204	244	45	221	249	289	22100	24900	28900	3.32	3.74	4.34
Appliance insulation, fluorocarbon substitutes	0.007	14	3,733	15	313	384	491	16	329	400	507	47000	57143	72429	23.59	28.69	36.36
TOTAL	0.33	1409	14,046						1761	2033	2435						

NOTE: Mt = megaton = 1 million tons. Tons are metric.

Source: NAS, "Policy Implications of Greenhouse Warming, 1991.

Figure 4.1.2

TABLE J.2 Cost Impact of CFC Phaseout--Worldwide

CFC Policy Option	CFC Reduction (Mt/yr)	CO_2-Equivalent Reduction (Mt/yr)	Capital Cost (M$/life)	Equipment Lifetime (years)	Annual Capital Cost (M$/yr) 3%	6%	10%	Operating Cost (M$/yr)	Total Cost (M$/yr) 3%	6%	10%	Abatement Cost ($/t CFC) 3%	6%	10%	Abatement Cost ($/t CO_2 Equivalent) 3%	6%	10%
Aerosols, refrigerants, not-in-kind substitutes	0.12	492	25	10	3	3	4	-161	-158	-157	-157	-1316	-1312	-1307	-0.32	-0.32	-0.32
Conservation and recycle	0.27	1402	203	5	44	48	53	0	44	48	53	164	178	198	0.03	0.03	0.04
Cleaning and blowing agents, refrigerants, not-in-kind substitutes	0.20	701	400	10	47	54	65	-40	7	14	25	35	72	126	0.01	0.02	0.04
Cleaning and blowing agents, aerosols, fluorocarbon substitutes	0.21	705	0	10	0	0	0	473	473	473	473	2250	2250	2250	0.67	0.67	0.67
Refrigerants, fluorocarbon substitutes																	
Chillers	0.04	152	3,750	30	191	272	398	135	326	407	533	8158	10185	13320	2.14	2.68	3.49
Mobile air conditioning	0.08	452	10,000	10	1172	1359	1628	360	1532	1719	1988	19154	21484	24844	3.39	3.80	4.40
Appliance	0.013	73	7,800	15	653	803	1026	59	712	862	1084	54762	66277	83385	9.69	11.73	14.76
Other	0.03	200	3,500	10	410	476	570	135	545	611	705	18177	20350	23487	2.73	3.05	3.52
Appliance insulation, fluorocarbon substitutes	0.037	74	22,200	15	1860	2286	2919	83	1943	2369	3002	52514	64027	81132	26.36	32.14	40.65
TOTAL	1.0	4251	47,878						5424	6346	7706						

NOTE: Mt = megaton = 1 million tons. Tons are metric.

Source: NAS, "Policy Implications of Greenhouse Warming, 1991.

Table 4.2.1

Toxic Chemicals in Combustion Flue Gas

Acetaldehyde	Formaldehyde
Antimony Compounds	Hexachorobenzene
Arsenic Compounds	Hydrochloric Acid
Benzene	Hydrofluoric Acid (Hydrogen fluoride)
Beryllium Compounds	Lead Compounds
Biphenyl	Manganese Compounds
Bis (2-ethylhxyl) phthalate (DEHP)	Naphthalene
Cadmium Coumpounds	Nickel Compounds
Carbon Disulfide	Pentachlorophenol
Carbon Tetrachloride	Phenol
Carbonyl Sulfide	Phosphorous
Clorine	Selenium Compounds
Chlorobenzene	2,3,7,8-Tetrachlorodibenzo-p-dioxin
Cloroform	Tetrachloroethylene (Perchloroethane)
Chromium Compounds	Toluene
Cobalt Compounds	Trichloroethylene
Dibenzofuranz	2,4,5-Trichlorphenol
1,4-Dichlorobenzene (p)	

Source: Chow, Winston, et al. (1990). "Managing Air Toxics". Presented at the 83rd Annual Air & Waste Management Association Meeting.

Table 4.2.2
Relative Toxicity of Toxic Air Emissions

Toxic Emission	Mass. Standard (ug/m3)	Connecticut Standard (ug/m3)	Virginia Standard (ug/m3)	Relative Toxicity (Based on Lead)
[1]	[2]	[3]	[4]	[5]
Arsenic		0.05		60
Beryllium	0.001			140
Cadmium	0.003			47
Chromium	1.36			0.10
Copper	0.54			0.26
HCl	2.03			0.07
Lead	0.14	3.00	2.50	1.0
Manganese		20.00		0.15
Mercury	0.14			1.00
Nickel	0.27			0.52
POM			7.00	0.36
Selenium	0.54			0.26
Vanadium	0.27			0.52
Formaldehyde	0.33			0.42

Notes:

[2]: Massachusetts Department of Environmental Protection, Office of Research and Standards, "Threshold Effects Exposure Limits (TEL)," March 1989. Concentrations are for a 24-hour average.

[3]: NATICH Data Base Report on State, Local, and EPA Air Toxics Activities, 1989. PB90-131459. Concentrations are averaged over an eight hour period. Connecticut was chosen for its geographical and political proximity to Massachusetts.

[4]: NATICH Data Base Report on State, Local, and EPA Air Toxics Activities, 1989. PB90-131459. Concentrations are averaged over a twenty-four hour period. Virginia was the only state listed as having a polycyclic organic matter standard.

[5]: The ratio of the acceptable ambient concentration of the indicated element to that of lead. For any given emission, both figures are based on the standards of only one state.

Table 4.2.3
Arsenic Control Costs

Plant [1]	Revised EPA Annualized Cost (1000$/yr) [2]	Revised EPA Baseline Emissions (Mg/yr) [3]	Control Equipment Efficiency [4]	Average Unit Control Cost ($/lb controlled) [5]
ASARCO-Hay	798	5.4	96%	70
ASARCO-El Paso	379	9.9	96%	18
Kennecott-Utah	2,028	1.5	96%	640
Kennecott-Hayden	2,140	6.5	96%	156
Kennecott-McGill	2,200	10.1	96%	103
Phelps Dodge-Morenci	3,430	1.9	96%	855
Total	10,975	35.3	96%	147

Notes:
[1],[2]: EPA. Inorganic Arsenic Emissions from Primary Copper Smelters and Arsenic Plants – Background Information for Promulgating Standards. EPA-450/3-83-010b. May 1986. Table 8-3.
[3]: EPA-450/3-83-010b, Table 4-1. 1 Mg = 1 tonne = 1.10 short tons.
[4]: EPA-450/3-83-010b, Section 1-6.0.
[5]: [2]*1000/([3]*1.10*2000*[4]).

Table 4.2.4
Valuation of Lead Implied By Valuation of SO2 and PM

Emission	Maximum 24-hour Air-Borne Concentration (ug/m3)	Implied Ratio of Health Risks: Ratio of Lead to Substance	Implied Ratio of Health Risks: Ratio of Substance to Lead	DPU Valuation (1989$/lb)	Implied Value of Lead (1989$/lb)
	[1]	[2]	[3]	[4]	[5]
Lead	0.14	1	1	---	
SO2	150	0.000933	1071	$2.00	$2,143
PM	365	0.000384	2607	$0.75	$1,955

Notes:

[1]: Massachusetts Ambient Air Quality Standards.

[2]: ([1] for lead)/[1]

[3]: [1]/([1] for lead)

[4]: These values were originally established by the Massachusetts DPU in Docket 89-239.

[5]: [3]*[4]

Table 4.2.5
Summary of Lead Emissions Valuations

Control Context		Implied Marginal Cost of Control Per Pound of As or Cr	Implied Marginal Cost of Control Per Pound of Lead
A.	Arsenic from primary copper smelters	$855	$14
B.	Arsenic from glass manufacturers	$300	$5
C.	Lead from secondary lead smelters		$500
D.	Chromium in cooling towers	$1,330	$1,300
E.	Lead in paint		$15,000 –$25,000
F.	Mass DPU SO2 and PM externality values		$2,000

Derivations and caveats can be found in the text.

Table 4.2.6
Valuation of Air Toxics Emissions of Selected Electric Utility Plants

Toxic Emission	Relative Toxicity (lb Pb eq/lb)	ESP Coal lb/10^12 btu	ESP Coal lb Pb eq	Scrubbed Coal lb/10^12 btu	Scrubbed Coal lb Pb eq	Residual Oil lb/10^12 btu	Residual Oil lb Pb eq	Distillate Oil lb/10^12 btu	Distillate Oil lb Pb eq
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Arsenic	60	40.1	2406.0	17.2	1032.0	19.0	1140.0	4.2	252.0
Beryllium	140	3.0	420.0	0.1	15.4	4.2	588.0	2.5	350.0
Cadmium	47	9.2	429.3	1.0	45.5	15.7	732.7	10.5	490.0
Chromium	0.10	401.5	41.3	115.5	11.9	21.0	2.2	48.0	4.9
Copper	0.26	194.0	50.3	24.0	6.2	280.0	72.6	280.0	72.6
HCl	0.07	63,040.0	4347.6	3,940.0	271.7				
Lead	1	49.0	49.0	16.8	16.8	28.0	28.0	8.9	8.9
Manganese	0.15	642.0	96.3	36.0	5.4	26.0	3.9	14.0	2.1
Mercury	1	12.0	12.0	4.2	4.2	3.2	3.2	3.0	3.0
Nickel	0.52	316.0	163.9	41.5	21.5	1260.0	653.3	170.0	88.1
POM	0.36	3.9	1.4	8.6	3.1	8.4	3.0	22.5	8.0
Selenium	0.3	1.6	0.4						
Vanadium	0.52					0.02	0.01		
Formaldehyde	0.42	9.3	4.0	8.6	3.6	405.0	171.8	405.0	171.8
Totals (lbs OR lb Pb eqiv.):		64721.6	8021.5	4213.4	1437.3	2070.5	3398.7	968.6	1451.5
Value @ $150/lb Pb equiv. ($/mmbtu):			$1.20		$0.22		$0.51		$0.22
Value @ $1,500/lb Pb equiv. ($/mmbtu):			$12.03		$2.16		$5.10		$2.18
Value @ $15,000/lb Pb equiv. ($/mmbtu):			$120.32		$21.56		$50.98		$21.77

NOTES:

[2]: Relative toxicity is the ratio of the acceptable ambient concentrations for each enission to that of lead. Whenever possible, relative toxicity was determined using Massachusetts standards. Arsenic and manganese were based on the ratios of the standards in Connecticut. POM was based on Virginia standards. Sources: Massachusetts Department of Environmental Protection, March 1989 standards. NATICH Data Base Report on State, Local, and EPA Air Toxics Activities, 1989. PB90-131459.

[3],[5],[7],[9]: EPA-450/2-89-001: all emissions figures except for: selenium and vanadium, which come from DOE Technology Characterizations Handbook, 1981; and HCl, from T.E. Emmel, et al. (1989), Acidic Emissions Control Technology and Costs. Noyes Data Corp. ESP control for HCl from Winston Chow, et al. (1990) "Managing Air Toxics," presented at the 83rd Annual Air & Waste Management Meeting. EPRI 90.108.1.

[4],[6],[8],[10]: [2]*(lb*10^12 for each source and each emission).

Table 4.2.7
Valuation of Toxic Air Emissions of Residual Oil-Fired Boilers with Electrostatic Precipitators

Toxic Emission	Relative Toxicity (lb Pb eq/lb)	Uncontrolled Coal lb/10^12 btu	Coal With ESP lb/10^12 btu	Coal ESP Efficiency	Unscrubbed Residual Oil lb/10^12 btu	Residual Oil With ESP lb/10^12 btu	Residual Oil With ESP lb Pb eqiv
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Arsenic	60	684	40.1	94%	19	1.1	66.8
Beryllium	140	81	3	96%	4.2	0.2	21.8
Cadmium	47	44.4	9.2	79%	15.7	3.3	151.8
Chromium	0.10	1410	401.5	72%	21	6.0	0.6
Copper	0.26	848	194	77%	280	64.1	16.6
HCl	0.07	78800		20%			
Lead	1	316	49	84%	28	4.3	4.3
Manganese	0.15	2980	642	78%	26	5.6	0.8
Mercury	1	16	12	25%	3.2	2.4	2.4
Nickel	0.52	1160	316	73%	1260	343.2	178.0
POM	0.36		3.9		8.4	8.4	3.0
Selenium	0.26	5	1.6	68%			
Vanadium	0.52				0.015		
Formaldehyde	0.42		9.315		405	405.0	171.8
Totals (lbs OR lb Pb eqiv.):						843.6	618.0
Value @ $150/lb Pb equiv. ($/mmbtu):							$0.09
Value @ $1,500/lb Pb equiv. ($/mmbtu):							$0.93
Value @ $15,000/lb Pb equiv. ($/mmbtu):							$9.27

NOTES:

[2]: Relative toxicity is the ratio of the acceptable ambient concentrations for each enission to that of lead. Whenever possible, relative toxicity was determined using Massachusetts standards. Arsenic, manganese and mercury were based on the ratios of the standards in Connecticut. POM was based on Virginia standards. Source: NATICH Data Base Report on State, Local, and EPA Air Toxics Activities, 1989. PB90-131459.

[3],[4],[6]: EPA-450/2-89-001: all emissions figures except for: selenium and vanadium, which come from DOE Technology Characterizations Handbook, 1981; and HCl, from T.E. Emmel, et al. (1989), Acidic Emissions Control Technology and Costs. Noyes Data Corp. ESP control for HCl from Winston Chow, et al. (1990) "Managing Air Toxics," presented at the 83rd Annual Air & Waste Management Meeting. EPRI 90.108.1.

[5]: 1-[4]/[5]

[7]: [6]*(1-[5])

[8]: [2]*[7]

Table 4.3.1
Incremental Costs of Cooling Towers

	Capital or Present Value ($M)		Annual Cost ($M)			Capacity	Heat Rejection	Control Cost
	Capital	O&M	Capital	O&M	Total	(MW)	(MMBtu/hr)	($/MMBtu)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Edgar								
A. Fan Wet Tower	2.18	18.17	0.26	1.45	1.72	306	676	0.34
B. Natural Dry Tower	7.48	28.68	0.90	2.29	3.19	306	676	0.63
C. Ironstone Wet Tower	2.89	15.62	0.35	1.25	1.60	306	676	0.32
Manchester Street								
D. Wet Tower	13.93		1.67	4.30	5.97	457.5	1010.7	0.79

Notes:
[1],[2] A,B: from Edgar Supplemental Draft EIR, page WQ-2-5.
C: from Edgar ~~Long-Range Forecast~~. Energy Park Project 5/1/90 EFSC
D: from Environmental Assessment.
[3]: [1]*12% real carrying charge
[4]: A,B,C: [2]*8% real levelization
D: from Environmental Assessment.
$4.3M/yr = 9 MW (penalty) * 85% (capacity factor) * 8760 hrs * 6.4 cents/kWh (escalated to 1990$)
[5]: [3]+[4]
[6]: A,B,C: from Edgar Long-Range Forecast, page 2-3.
D: from Environmental Assessment, page 3-93.
[7]: A,B,C: from Edgar Supplemental Draft EIR, page WQ-2-1.
D: [6] for D, times the ratio of [7] to [6] for A.
[8]: [5]/([7]*8760*.85)*10^6, assuming an 85% capacity factor.

Sources:
Edgar Supplemental Draft EIR:
United Engineers and Constructors, March 1990. Edgar Energy Park Supplemental Draft Environmental Impact Report.
Edgar Long-Range Forecast:
Boston Edison Company, May 1, 1990, before the Massachusetts Energy Facilities Siting Council.
Long-Range Forecast of Electric Power Needs and Requirements Edgar Energy Park Project.
Environmental Assessment:
Narragansett Electric Co. and New England Power Co., September 1989. Manchester Street Station Repowering Project Environmental Assessment.

4. DIRECT ASSESSMENT OF AN OIL IMPORT PREMIUM

About one-third of the oil consumed in the U.S. annually, or approximately 6 million bbls/day of crude and petroleum products, is imported.

The literature on the national costs of imported oil dates from the late 1980s. So far as we are aware, the most recent estimate of the national economic cost of oil imports (including vulnerability to interruptions and price swings, increases in inflation, deterioration of the balance of payments, and encouragement of further increases in oil prices) is in Broadman and Hogan (1988). This study estimates an expected oil import premium (taking into account the uncertainty in a range of parameters) of $11.09/bbl in 1985$. Assuming 5.7 MMBTU/bbl of crude oil, and 5% loss of energy content in the refining process, this is equivalent to $2.05/MMBTU of oil products (including both #6 and #2 oil) in 1985$, or $2.26/MMBTU in 1988$.

For comparison, Broadman (1986) reports a range of import premium estimates of $2-$124/bbl. CRA (1984) surveyed 17 estimates done between 1978 and 1981 and reported a similar range of results. Some estimates from the early 1980s were much higher than Broadman and Hogan (1988). Other estimates include only a subset of identified costs, and are therefore clearly understated. Recent estimates tend to cluster around the results of Broadman and Hogan (1988).

These estimates of oil import premiums include only effects on the United States. If the benefits to oil exporters of increased oil use in the U.S. were included in the analysis, the premium would be smaller. We would expect that policy makers and the public would generally be concerned about effects on the local population, which in the case of oil imports is the entire country. In addition, they may be concerned about those similarly situated (for oil imports, most of Western Europe, and Japan) or less advantageously situated (e.g., most of the Third World). However, some value might be assigned to the benefits of high oil prices to exporters who are otherwise similarly situated to the U.S. -- such as Canada, the U.K., or Norway -- or those which are disadvantaged in other respects, such as Mexico, Venezuela, or Nigeria.

Other international economic and political objectives may also affect the value of the oil import premium.

SOURCE: Chernick & Caverhill - 1989

Table 5.1: Externality Values

Externality	Mass DPU values ($/lb)	Calif. PUC values ($/lb)	Nevada PSC values ($/lb)	Pace University values ($/lb)	BPA East values ($/lb)	BPA West values ($/lb)	BPA values adjusted for Northeast ($/lb)
SO2	0.78	6.48	0.78	2.03	0.20	1.80	3.6–18
NOx	3.38	6.53	3.40	0.82	0.03	0.44	.88–4.4
CO	0.45	NE	0.46	NE	NE	NE	NE
PM10 (TSP for BPA values)	2.08	4.39	2.09	1.19	0.08	0.77	1.54–7.70
VOC's	2.76	1.83	0.59	NE	NE	NE	NE
CO2	0.011	0.004	0.011	0.0068	0.003	0.003	0.003

Sources:

California Public Utility Commission Decision 91-06-022. June 1991.

Massachusetts DPU Decision in Docket 89-239. August 31, 1990.

Nevada PSC Docket No. 89-752. January 22, 1991.

Ottinger, R. et al., "Environmental Costs of Electricity." Oceana; Dobbs Ferry, NY: 1990.

Bonneville Power Administration, "Environmental Costs and Benefits: Documentation and Supplementary Information." February 22, 1991.

Notes:

All values expressed in 1990$.

The "BPA values adjusted for Northeast" are the BPA West values multiplied by 2-10 times to reflect the greater population density in the Northeast.

FIGURE 5.7

Bonneville Power Administration

DRAFT ENVIRONMENTAL COST ADJUSTMENTS

COMPETITIVE ACQUISITION OF FIRM ENERGY

February 22, 1991

(1990 mills/kWh)

Resource Type	East	West
Pulverized Coal	9.6	15.5
AFBC Coal (Fluidized Bed)	8.5	10.4
IGCC Coal (Coal Gasification)	8.0	9.1
Simple Cycle Combustion Turbine	5.3	6.1
Combined Cycle Combustion Turbine	3.8	4.4
New Hydro Facility	2.0	2.0
Natural Gas-Fired Cogeneration	1.9	2.2
Additions to Existing Hydro Facility	1.0	1.0
Geothermal	0.1	0.1
Wind	0.1	0.1
Solar	0.1	0.1
Conservation	0	0
Nuclear	Under development	
Wood-Fired Cogeneration	Under development	
Municipal Solid Waste-Fired Cogeneration	Under development	

- These adjustments are subject to change based on an on-going review and are in real levelized 1990 mills/kWh. The adjustments will be finalized on April 15, 1991.
- Explanatory documentation of these adjustments can be obtained by calling BPA's document request line. Call 1-800-841-5867 (Oregon), 1-800-624-9495 (other western states), and 503-230-7334 (elsewhere).

(31421)

SOURCE: Bonneville Power Administration, February 22, 1991. "Environmental Costs and Benefits: Documentation and Supplementary Information."

FIGURE 5.7

Bonneville Power Administration

DRAFT ENVIRONMENTAL COST ADJUSTMENTS

COMPETITIVE ACQUISITION OF FIRM ENERGY

February 22, 1991

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Simple Cycle Combustion Turbine	5.3	6.1
Combined Cycle Combustion Turbine	3.8	4.4
New Hydro Facility	2.0	2.0
Natural Gas-Fired Cogeneration	1.9	2.2
Additions to Existing Hydro Facility	1.0	1.0
Geothermal	0.1	0.1
Wind	0.1	0.1
Solar	0.1	0.1
Conservation	0	0
Nuclear	Under development	
Wood-Fired Cogeneration	Under development	
Municipal Solid Waste-Fired Cogeneration	Under development	

- These adjustments are subject to change based on an on-going review and are in real levelized 1990 mills/kWh. The adjustments will be finalized on April 15, 1991.
- Explanatory documentation of these adjustments can be obtained by calling BPA's document request line. Call 1-800-841-5867 (Oregon), 1-800-624-9495 (other western states), and 503-230-7334 (elsewhere).

(31421)

SOURCE: Bonneville Power Administration, February 22, 1991. "Environmental Costs and Benefits: Documentation and Supplementary Information."

ATTACHMENT 3

REVIEW OF THE NEW YORK STATE ENERGY OFFICE

1991 EXTERNALITY ESTIMATES

In connection with the 1991 State Energy Plan, the New York State Energy Office (NYSEO) has updated its 1989 estimates of externality values. This information can be found in Issue Report 9 of the SEP, and in the **Analysis of Carbon Reduction in New York State**, June 1991. This review will discuss the derivation of these values, and their potential shortcomings, in terms of generic issues, SO_2 issues, NO_x issues, and CO_2 issues.

1. Generic Issues

a. Nominal and real costs

The 1991 Report characterizes the 1989 externality values, which the PSC has used as real-levelized values, as if they were nominally levelized values. However, the SEO's own 1989 reports state these costs in 1989$.

For 1991, NYSEO presents undocumented cost estimates for SO_2 and NO_x, asserts that those values are nominally levelized, and then adjusts those values down to real-levelize them. NYSEO appears to be taking capital costs and present values, and levelizing them with a low discount rate or cost of capital. Personal communications with NYSEO indicate that the 1991 estimates use a 7% rate. This is too low even for a real-levelized analysis of capital costs; for a 30-year life, utility real-levelized carrying charges are typically in the 10.5% to 12% range. For the shorter lives SEO assumes for some retrofits, carrying charges should be even higher. The 7% value is roughly correct as a real utility discount rate. Hence, the NYSEO costs appear to be closer to real-levelized cost than to nominally-levelized costs.

b. Taxes

NYSEO appears to assume that externality costs can be internalized through "Trust Fund" (TF) taxes on emissions, where the tax is set at

$$C/T,$$

where

C is the cost of reducing the emissions by the desired amount (D), and

E is the total current emissions.

This value is lower than either the average cost of control (C/D), or the marginal cost of control (dC/dD). While this approach could theoretically offset emissions, it does not give polluters adequate incentives to reduce usage, since they will pay less for emitting than for controlling. Hence, it may be difficult to define the set of efficient controls, especially if the polluters are concerned that they may be required to undertake some of the controls without compensation from the trust fund.

2. SO_2 Issues

NYSEO estimates the marginal damage cost of SO_2, at an emission level equal to NY allowances under the 1990 Clean Air Act Amendments (CAAA), 280,000 Tons/yr, as $2200/T in 1990$. This damage cost is understated, since it includes only mortality, without morbidity, visibility, or other effects.

NYSEO then assumes that the marginal damage cost falls linearly to 0 as emissions fall to 100,000 tons/year. This is a very strong assumption, and is not supported by any data. NYSEO claims that "economic theory suggests" this shape for the marginal damage cost curve, but of course economic theory is irrelevant to estimating a dose-response curve.

If NYSEO were correct that marginal damage costs are linear, then damage cost at current emissions (380,000 tons) would be $3400/T, falling gradually to $2200 as the CAAA SO_2 provisions take effect by 2000.

NYSEO estimates a marginal cost of abatement, which starts with the cost of switching oil plants to lower-sulfur fuel. NYSEO assumes that 70,000 of the 100,000 T/yr of emission reductions required to live within the state's CAAA allowance limits are achieved by some other means, but does not specify them. These measures may include LILCo's reduction in oil sulfur content, use of summer gas, and installation of scrubbers on units targeted by the CAAA for 1995 reductions.

The marginal cost of control curve for remaining measures appears to be consistent with other estimates of the costs of fuel-switching and of scrubbing smaller, older, less utilized units. However, each increment of the curve lumps together a group of options. For example, NYSEO's option C is fuel-switching oil plants to 0.3% S oil. This actually includes relatively inexpensive reductions (e.g., 1.0% to 0.75%), and some very expensive reductions (e.g., 0.37% to 0.3%). Similarly, the scrubbing option will have a range of costs at different units.

NYSEO then plots its marginal damage curve against its marginal abatement-cost curve, and determines that a reduction of

75,000 T/yr beyond the CAAA requirements would be optimal. The intersection it finds, about $1300/T, would probably be higher with a realistic cost curve.

NYSEO describes the resulting value as nominally-levelized, but the damage curve is definitely real-levelized and the cost curve also appear to be real-levelized.

The NYSEO results should be interpreted to indicate that the mortality value of SO2 reductions are near $3400/T now, falling to $2200/T in 2000, and then falling further to something above $1300/T whenever the additional reductions are complete. With acid rain, morbidity, visibility, and other effect, the value may be considerably higher.

3. NO_x Issues

NYSEO estimates that the marginal cost of required NOx control (to meet Title I of the CAAA) is the installation of SCR (or the equivalent) on existing coal-fired plants, at a cost of $6,100/T. However, of the 85% reduction achieved at this average cost, 50% is due to low-NO_x burners (LNB), which cost almost nothing in $/T NO_x. The 1989 plan estimated a cost of $395/T for LNB, and $7,281 for SCR. Assuming $870/T for LNB, which may be implied in Figure IV.7 of the Carbon Analysis, the marginal cost of adding SCR to LNB is $13,600/T. Even assuming NYSEO is correct in describing this cost as nominally-levelized, the real-levelized cost would be about $9400/T.

4. CO_2 Issues

NYSEO constructs a supply curve for CO_2 reductions, including a broad range of control options. One large set of options is lumped together as a "Low Emission Scenario;" it is not clear how much the individual options in this group cost. NYSEO finds that stabilization of emissions at 1988 levels would require measures costing up to $300/T carbon, and that reductions of more than about 5% would require measures costing $500/T carbon.

NYSEO credits these costs with about $51/T in SO2 and NOx reductions, using the values from the Pace study. The value used for NOx is only $1640/T, which is clearly too low. The value of $4060/T for SO_2 exceeds NYSEO's own estimate. Insufficient data are provided to allow for correction of these figures. In any case, this adjustment leaves NYSEO with a net carbon cost of $240 to $450/T, depending on the required reduction. (NYSEO's computations are not easy to follow at this point.)

NYSEO then converts these marginal costs to average costs, including measures with negative net carbon costs, which should be pursued in any case. NYSEO's reported carbon "externality" value of \$8-\$50/T carbon is not an externality value at all, but a cost estimate for a hypothetical mitigation program. This value is useless in screening resources; indeed, using the NYSEO carbon "externality" values, most of the measures NYSEO has identified as necessary would be screened out.

The appropriate value for carbon externalities from the NYSEO 1991 studies would be \$240-\$450/T C, or \$66-125/T CO_2 (1990\$). This range is far higher than the values adopted by regulators to date.