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Incorporating Global Warming Risks in Power Sector Planning

A Case Study of the New England Region

Volume I

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November 1992

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INCORPORATING GLOBAL WARMING RISKS IN POWER SECTOR PLANNING

A CASE STUDY OF THE NEW ENGLAND REGION

VOLUME I

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

PREFACE

The pertinence of the topic of inquiry contained in this report became apparent in discussions during 1989 and 1990 among members of the Conservation Committee of the National Association of Utility Regulatory Commissioners (NARUC), scientists of Lawrence Berkeley Lab's (LBL) Energy Analysis Program, and the managers of the Integrated Resource Planning (IRP) program at the U.S. Department of Energy (DOE). Similar policy analysis questions were being raised by the Office of Policy Analysis at the U.S. Environmental Protection Agency (EPA).

These deliberations resulted in a decision to have LBL undertake an illustrative case study of the utility system in New England. The project, which was jointly funded by DOE and EPA, dove-tailed with state externality policy developments in that region. Notably, the Department of Public Utilities of the state of Massachusetts.(MADPU) had adopted in 1990 a rule establishing monetized externality adders as part of a new integrated resource management (IRM) process for the state's utilities. The MADPU adder system, which is undergoing continued review at the time of this writing, includes a substantial externality surcharge for carbon dioxide emissions from new power plants.

Because the six New England states are being served by an electric power pool, their utility regulatory commissions decided to investigate whether they might adopt a uniform policy on the externality issue. In 1990 and 1991, several workshops and meetings were held under the auspices of the New England Governors' Conference (NEGC) and the New England Power Planning Committee, in which regulators and utilities discussed their concerns regarding options to incorporate externalities into utility resource planning. The present study is one input to these region-wide deliberations, which continue at the time of this writing.

EXECUTIVE SUMMARY

A. INTRODUCTION

Growing international concern over the threat of global climate change has led to proposals to buy insurance against this threat by reducing emissions of carbon (short for carbon dioxide) and other greenhouse gases below current levels. The international Toronto conference of 1988 called for a reduction in carbon emissions of 20% by 2005. A number of industrialized countries have made it their policy to freeze carbon emissions by the turn of this century, or to reduce them up to 25% over the next twenty years. Participants at the international conference held in Rio in June 1992 agreed to freeze carbon emissions at current levels, without specifying any timetable. Ultimate global carbon emissions reductions in the neighborhood of 60% relative to current levels have been identified by international scientific bodies as being needed to stop the accumulation of carbon dioxide in the atmosphere and achieve climate stabilization (IPCC 1990).

At the same time, concern over these and other, non-climatic environmental effects of electricity generation has led a number of states to adopt or explore new mechanisms for incorporating environmental externalities in utility resource planning. For example, the New York and Massachusetts utility commissions have adopted monetized surcharges (or adders) to induce emission reductions of federally regulated air pollutants (notably, SO_2, NO_x, and particulates) beyond federally mandated levels. These regulations also include preliminary estimates of the cost of reducing carbon emissions, for which no federal regulations exist at this time. Within New England, regulators and utilities have also held several workshops and meetings under the auspices of the New England Governors' Conference (NEGC) and the New England Power Planning Committee to discuss alternative methods of incorporating externalities as well as the feasibility of regional approaches.

This study examines the potential for reduced carbon emissions in the New England power sector as well as the cost and rate impacts of two policy approaches: environmental externality surcharges and a target-based approach. We analyze the following questions:

- Does New England have sufficient low-carbon resources to achieve significant reductions (10% to 20% below current levels) in fossil carbon emissions in its utility sector?
- What reductions could be achieved at a maximum?
- What is the expected cost of carbon reductions as a function of the reduction goal?
- How would carbon reduction strategies affect electricity rates?
- How effective are environmental externality cost surcharges as an instrument in bringing about carbon reductions?
- To what extent could the minimization of total electricity costs alone result in carbon reductions relative to conventional resource plans?

This document summarizes the findings of the Lawrence Berkeley Laboratory's research on these questions.

B. METHODOLOGY

We first developed a comprehensive menu of low-carbon resource options. Supply-side, demand-side, fuel-switching and cogeneration technologies were considered, and potentials for New England were estimated along with their costs. We then developed various resource mixes and calculated emissions and annual electricity costs using a production cost model.

Table ES-1 summarizes some of the key characteristics of the New England power system. New England's pooled utility system (NEPOOL) was simulated as though it were a single utility. Data provided by Northeast Utilities (a member utility of NEPOOL) were used to benchmark the input assumptions for our modeling runs. In assessing the effectiveness of environmental externality cost adders, we used the adders adopted by the state of Massachusetts.

The time frame for our analysis was 1990 to 2005 (which we extend to 2010 because of lower than expected demand growth in the years since the demand forecast was created). Net generation in New England is projected to grow from 113 TWh in 1990 to 154 TWh in 2005/2010, after including demand-side management (DSM) resources in utility plans committed as of 1990.

To capture the potential effects of real-world complexities in our assumptions, our analysis explores four dimensions of uncertainty. First, we define high and low capital costs for the different low carbon resources. Second, we vary the amount of low carbon resources that are included in our resource portfolios, to capture implementation uncertainties. Third, we use a reference case fuel price forecast with real price escalation of 3 to 5%/year for oil and natural gas (reflecting the expectations of New England's utilities), and then explore the effects of a sensitivity case in which oil and natural gas prices escalate at only 2% per year in real terms (coal prices are approximately the same in these two cases). Finally, we examine the effect of alternative assumptions about existing plant retirements.

C. RESULTS

1. New England's Low-Carbon Resource Potential and Costs

While New England faces a number of challenges in expanding conventional electricity resources, the region also has a large potential of currently undeveloped low-carbon electricity resources. New England's low-carbon electricity resources include efficiency and fuel switching resources on the demand-side, and cogeneration, wind and biomass resources on the supply side. Each resource has been characterized using New England-specific data, relying on utility experience, recent reports, and interviews with experts on regional electricity issues.

Table ES-1: The New England Power Sector in 1990 and 2005/2010			
	1990	*2005/2010*	*(2005/2010)/1990*
Net Generation w/base case DSM (TWh)	112.9	153.6	*1.36*
Peak Demand (GW) [3]	20.4	27.4	*1.34*
Load Factor	63.2%	64.0%	*1.01*
Carbon emissions (Megatonnes C)	17.1	21.2	*1.24*
Carbon burden (g C/kWh.e delivered)	164	149	*0.91*
Resource mix (% of energy)			
Nuclear	36%	26%	*0.74*
Coal Steam	15%	11%	*0.74*
Peakers (Distillate)	0%	0%	*0.32*
Oil Steam	28%	16%	*0.59*
Thermal Purchase	2%	3%	*1.72*
Hydro Purchases (4)	3%	11%	*3.52*
Pumped Storage	1%	1%	*1.58*
Storage Hydro	1%	1%	*0.85*
Baseload Hydro	4%	3%	*0.74*
Independent Power Producers	8%	8%	*0.96*
Combined Cycle	2%	1%	*0.55*
Integrated Gasification Advanced Combined Cycle	0%	4%	*N/A*
Advanced Combined Cycle	0%	12%	*N/A*
Advanced Combustion Turbine	0%	0.1%	*N/A*
Biomass	0%	1%	*N/A*
Refuse	0%	0.4%	*N/A*
Utility Sector Fuel Prices (1990 $/MMBtu) (5)			
Firm natural gas (reference case)	2.42	5.17	*2.14*
Interruptible natural gas (reference case)	2.51	4.76	*1.90*
Firm natural gas (low gas price case)	2.42	3.26	*1.35*
Interruptible natural gas (low gas price case)	2.51	3.38	*1.35*
Distillate oil (reference case)	3.71	6.21	*1.67*
Residual oil 1% sulfur (reference case)	2.59	4.58	*1.77*
Coal 1% sulfur (reference case)	1.87	2.09	*1.12*

(1) real discount rate = 6.3%; inflation = 5.2%; WACC = 11.85%; see GTF 1989 for details.
(2) T&D losses = 8%
(3) peak demand in 1990 is winter peak. New England shifts to summer peaking in 1993 and remains there through the end of the analysis period.
(4) We adopt NEPOOL assumptions about the extent of hydro purchases in the 2005/2010 timeframe. Any estimate of such purchases is subject to uncertainties in Canada's resource planning choices, over which New England has little control.
(5) fuel prices from NEPOOL (GTF 1989)

Figure ES-1 shows our estimates in the form of a supply curve for 75% of the technical potential. If mobilized at the 75% level over the next 20 years, these resources could contribute about 80 TWh of electricity – about three quarters as much as all of New England's 1990 electricity needs combined, and more than half of the projected demand of 154 TWh/yr for the period of 2005/2010.

Under NEPOOL's assumptions for fuel prices and conventional technology options, gas-fired advanced combined cycles (ACC) have the lowest busbar costs, and thus would be the preferred supply-side addition for meeting growth in electricity demand. Insofar as this preferred option dominates current resource plans in New England, the cost impacts of carbon reduction strategies are broadly proportional to the cost difference between low-carbon resource options and gas ACCs.

Based on this comparison, the most economically attractive resources in New England are demand-side efficiency improvements, fuel switching at the point of end-use and gas-fired cogeneration. These resources are cheaper than gas ACCs using low resource cost assumptions and remain so (for DSM) or turn only marginally negative (fuel switching and cogeneration) under high resource cost assumptions. Greater uncertainty exists regarding the future cost of wind and biomass-fired generating technologies. In the more optimistic low resource cost projections, these resources would be cost-competitive with gas ACCs (again, assuming reference case fuel prices). However, under our high resource cost assumptions, they are substantially more expensive.

The mobilization of these resources will require specific policies and utility efforts to overcome market failures[1] affecting the efficiency of energy use, as well as programs to promote the development and use of renewable resources. Such initiatives would include efficiency standards, DSM programs and modifications of PURPA efficiency requirements for cogenerators. The effectiveness of these efforts is another dimension of uncertainty in our analysis. We make the mobilization level for low-carbon (Low-C) resources an explicit variable in formulating resource mixes: Low-C resources are utilized at 0%, 50%, and 75% of their respective technical potentials.

2. Target-Based Analysis

What reductions in carbon emissions could be achieved with these resources relative to 1990 levels while meeting projected 2005/2010 demand for electricity services? To calculate potential emission reductions, we developed low-carbon portfolios and simulated their emissions and costs using a production cost model.

Scenario Definition: Low Cost vs. Low Carbon

The cost of carbon reductions in New England can be illustrated on the basis of two types of bounding scenarios. In the first type of scenario, Low-C resources are combined with the goal of minimizing total costs. In the second type of scenario, the resource mix is formulated with the goal of maximizing emission reductions. We refer to the former as Low-Cost portfolios, and to the latter as Low-Carbon portfolios.

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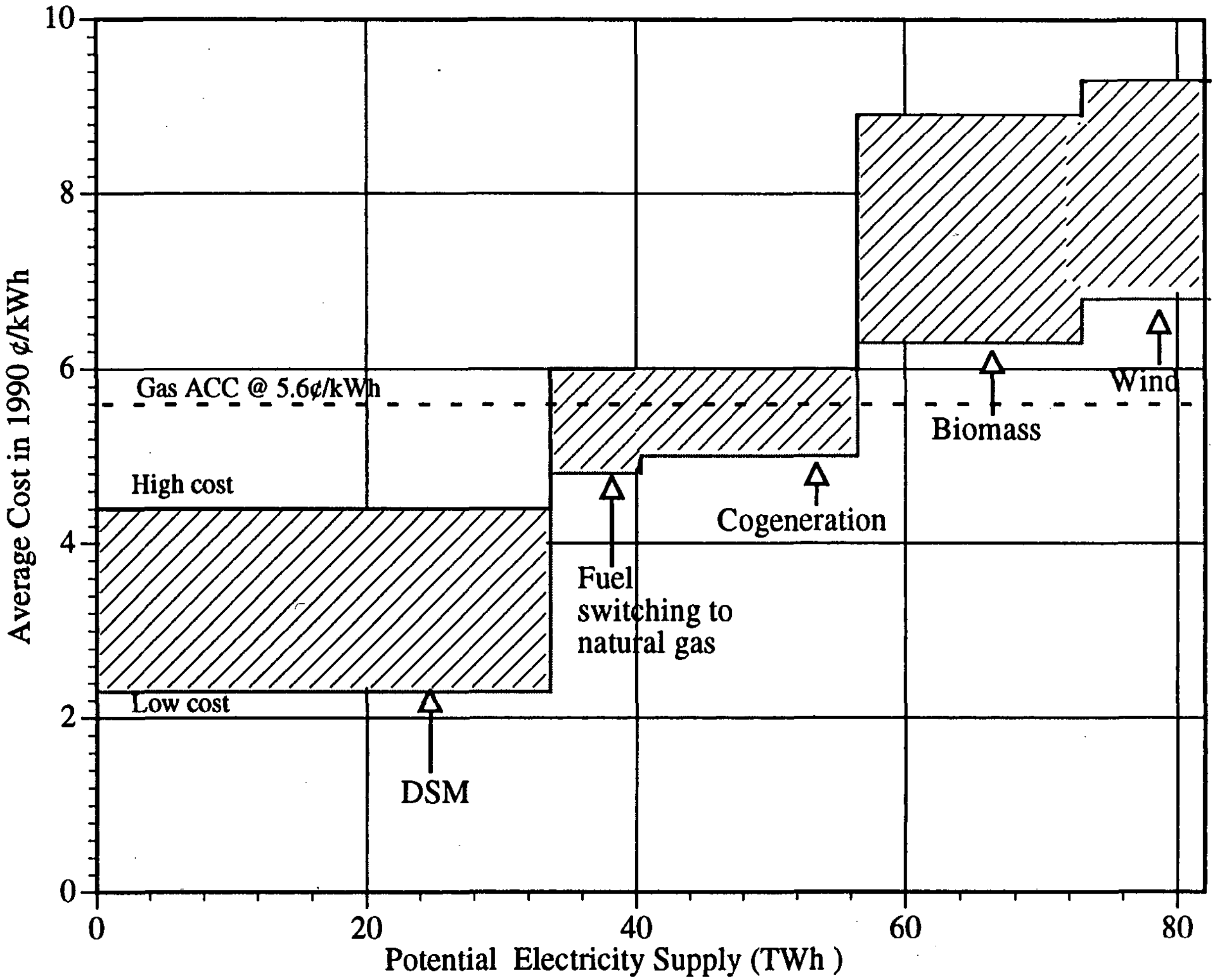
[1]For economic analysis of the sources of such failures, see Koomey 1990b, Fisher and Rothkopf 1990, Sanstad et al. 1992, and Krause and Eto 1988.

Figure ES-1: Supply Curve of Low-Carbon Resource Potentials in New England (Potentials and Costs @ Utilization of 75% Under Reference Case Fuel Prices)



(1) Levelized costs calculated using a real discount rate of 6.3%.

(2) ACC = Advanced combined cycle plant (natural-gas fired)

In the Low-Cost portfolios, we rely on only the least expensive Low-C resources, namely, demand-side efficiency, fuel switching and gas-fired cogeneration. In the Low-Carbon portfolios, renewables are utilized as well. In both cases, a range of retirements and resource constraints apply.

Definition of Business-as-Usual Resource Plan

In our analysis, we calculate the costs of carbon reductions relative to a business-as-usual electricity future for New England that might be expected in the absence of concerns over global warming. Building on NEPOOL's 1990 forecast for 2005, the New England Governor's Conference (NEGC) developed a resource plan that broadly meets this criterion. We refer to this scenario as the NEGC reference case.

In our analysis, we also extend NEGC's time horizon to 2010, because of lower than expected demand growth in the region after the NEGC forecast was finalized. In addition, by 2010, the licenses for almost half of New England's nuclear capacity (3230 MW) will have expired, and retiring these plants will make carbon reductions more difficult to achieve. Such retirements would therefore occur independently of carbon reduction strategies. We treat the uncertainty in nuclear retirements by including a reference case that includes the retirement of nuclear plants that will have reached the end of their useful lives by 2010.

In formulating the alternative 2010 carbon-reduction portfolios, we ensure comparability by including, at a minimum, the same retirements as in the NEGC case or the NEGC case with nuclear retirements. In the Low-Cost portfolios, we add to the scheduled retirements of nuclear plants in the reference case the retirement of oil-fired capacity, which adds little cost while achieving significant carbon savings. In the Low-Carbon portfolios, additional scheduled retirements cover both coal and oil capacity, to maximize carbon reductions.

The *carbon reductions* calculated assuming nuclear retirements are smaller than would be expected if the nuclear plants' lives were extended beyond their license expiration date. The relative *cost impacts* of carbon reduction strategies would be similar, because both the reference case and the policy cases would include the cost of nuclear plant retirements.

Carbon Reductions

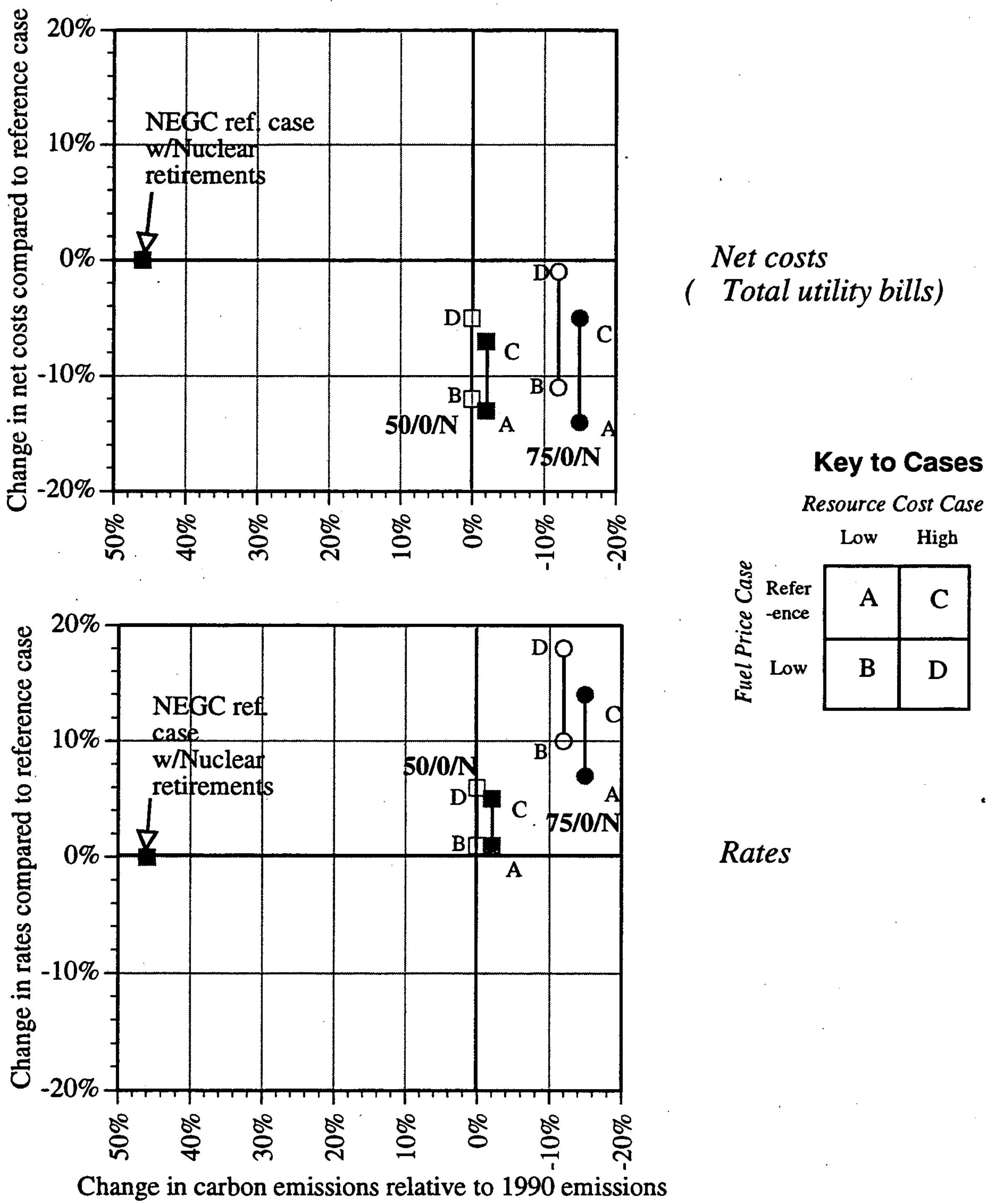
With the imposition of nuclear retirements, and with the additional 75% limit on Low-C resource mobilization, we developed four resource combinations for 2010 under our Low-Cost and Low-Carbon criteria (see Figures ES-2 and ES-3):

— A Low-Cost Case with utilization levels of 50% for DSM, 50% for fuel switching, 50% for cogeneration and 0% for renewables (combined with the retirement of nuclear and oil capacity). This case, designated as Low-Cost (50/0/N), keeps carbon emissions roughly constant at 1990 levels.

— A Low-Cost Case with utilization levels of 75% for DSM, 50% for fuel switching, 50% for cogeneration and 0% for renewables (combined with the retirement of nuclear and oil capacity). This case, designated as Low-Cost (75/0/N), yields carbon emissions reductions of 12% to 15% below 1990 levels.

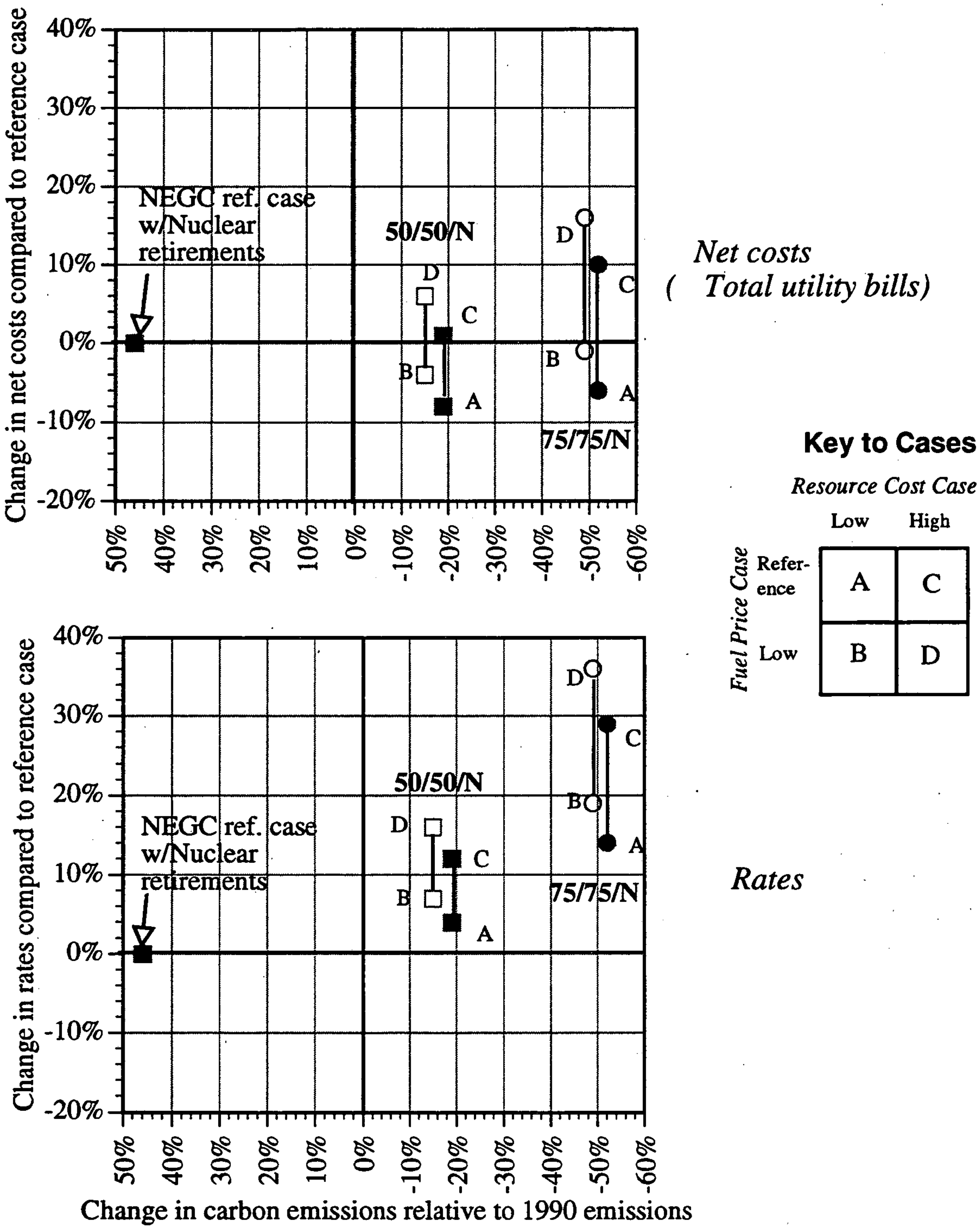
— A Low-Carbon case based on 50% utilization for DSM, cogeneration and renewables (combined with the retirement of nuclear and oil capacity only). This case, designated as Low-Carbon (50/50/N), yields carbon emissions reductions of 15% to 19% below 1990 levels.

Figure ES-2: Low Cost Scenarios for New England in 2005: Changes in Carbon Emissions, Net Costs, and Electricity Rates



Notes:
1) 50/0/N uses 50% of demand-side management (DSM)/fuel switching/cogeneration potentials, and 0% of renewables, with nuclear retirements; 75/0/N uses 75% of the DSM potentials, 50% of the fuel switching/cogeneration potentials, and 0% of the renewables, with nuclear retirements.
2) Carbon emissions in 1990 = 17.1 megatonnes C
3) Total energy service costs in 2005 are $6.2 billion in the reference fuel price case and $5.4 billion in the low fuel price case; Rates in 2005 are 5.8¢/kWh in the reference fuel price case and 5.2¢/kWh in the low fuel price case

Figure ES-3: Low Carbon Scenarios for New England in 2005: Changes in Carbon Emissions, Net Costs, and Electricity Rates



Notes:
1) 50/50/N uses 50% of demand-side management (DSM)/fuel switching/cogeneration potentials, and 50% of renewables potentials, with nuclear retirements; 75/75/N uses 75% of the DSM/ fuel switching/cogeneration potentials, and 75% of the renewables potentials, with nuclear retirements.
2) Carbon emissions in 1990 = 17.1 megatonnes C
3) Total energy service costs in 2005 are \$6.2 billion in the reference fuel price case and \$5.4 billion in the low fuel price case; Rates in 2005 are 5.8¢/kWh in the reference fuel price case and 5.2¢/kWh in the low fuel price case

— A Low-Carbon case based on 75% utilization for DSM, cogeneration and renewables (combined with the retirement of nuclear and fossil capacity). This Low-Carbon 75/75/N portfolio yields carbon emissions reductions of 49% to 52% below 1990 levels.

These figures show that New England could realize carbon reductions relative to 1990 so long as about 50% of the low carbon resource potentials can be mobilized. Under the 50% resource utilization limit, 15% to 19% represents about the maximum feasible carbon reduction, while at the 75% utilization level, reductions can, in principle, be much larger. The comparison of the Low-Cost (75/0/N) portfolio to the Low-Carbon (50/50/N) portfolio shows that there is more than one path to achieving carbon reductions of the same approximate size as those adopted by various countries and recommended by international institutions.

Net Costs (Total Utility Bills)

Figure ES-2 shows the net costs, rate impacts and carbon emissions reductions for our Low-Cost portfolios, and Figure ES-3 shows the same information for the Low-Carbon portfolios. In each figure, changes in carbon emissions relative to 1990 are shown on the x-axis, and changes in costs or rates relative to the NEGC case with nuclear retirements are shown on the y-axis.

Changes in net costs correspond to the change in the total electric bill of utility customers. Rates are the per kWh expression of total costs. As long as total bills go down faster than rates go up, society will be better off.

The results from our analysis indicate that some carbon reductions are likely to be achievable at zero or even negative net cost. Our Low-Cost portfolios show that freezing emissions at 1990 levels (e.g., in the 50/0/N case) or emissions reductions of 12% to 15% relative to 1990 levels (in the 75/0/N case) can be achieved at robustly negative net societal costs across the entire range of input assumptions considered in this study (assuming aggressive mobilization of efficiency resources). Carbon emissions reductions of from 15% to 19% are possible using DSM plus higher cost renewables (in the Low-Carbon 50/50/N case) with negative net cost in all cases except under low fuel prices and high resource costs. The Low-Carbon 75/75/N portfolio, which would reduce carbon emissions by about 50%, would lead to negative net costs (-1% to -6%) in the low resource cost cases, and positive net costs (10% to 16%) in the high resource cost cases.

It is important to note that these portfolios are not optimized. For example, greater use of inexpensive cogeneration and fuel switching resources could raise the percentage carbon reductions feasible at zero or negative net cost beyond the 12-15 percent range. However, logistical difficulties in mobilizing larger amounts of these low carbon resources would also arise from such efforts.

Rate impacts

Our carbon reduction portfolios rely heavily on demand-side resources, and thus result in rate impacts (even though total utility bills will be reduced at the same time). Rate impacts from demand-side resources are caused by spreading the system fixed costs (of existing generation, new generation, customer costs, administration costs, and T&D requirements) over a smaller number of kWh sold. Rate impacts from alternative supply-side resources can result if the cost of such resources is greater than that of the reference case resource (in this case the gas ACC).

In estimating average rate impacts, we assume that DSM resources are mobilized in equal shares through utility programs where utilities pay the full cost for the DSM measures, and through efficiency standards where utilities bear none of the cost. As with the determination of net costs, net rate impacts are dependent on the reference case and fuel price and resource cost assumptions.

These figures show that keeping carbon emissions constant at 1990 levels in the Low-Cost 50/0/N portfolio would cause rate impacts of from 1% to 6% in the year 2010. To achieve carbon reductions relative to 1990 will require further increases in rates relative to the Low-Cost 50/0/N portfolio. The Low-Cost 75/0/N portfolio, with its higher penetration of DSM, yields larger rate impacts of from 7% to 18% for carbon reductions of 12% to 15%.

The Low-Carbon 50/50/N portfolio yields still larger carbon reductions of 15% to 19% with smaller rate impacts of from 4% to 16%. These lower rate impacts are the result of less reliance on DSM and greater reliance on low carbon generation technologies than in the 75/0/N case. The Low-Carbon 75/75/N portfolio, which would produce carbon reductions significantly greater than are now being considered by New England regulators in the 1990 to 2005/2010 time frame, would lead to rate impacts of 14% to 36%.

Rate impacts could be somewhat larger than in our analysis if reliance on thermally optimized gas-fired cogeneration should lead to increased utility system bypass, or if governments were to rely more on utility programs and less on standards than in the 50:50 mix assumed here. If rate impacts from DSM reach significant proportions, this could trigger or reinforce bypass from cogeneration. For these reasons, options for minimizing rate impacts while pursuing carbon reductions are important.

Rate impacts could be somewhat lowered by having customers pay for some of the DSM costs (at the risk of reducing program participation somewhat) or by relying more on standards than on utility programs. Rates also could be somewhat lower than calculated here if our estimates of the avoidable marginal T&D costs should turn out to be too conservative. Given the importance of the rate impacts issue, more analysis on these points is warranted.

A more fundamental method for lowering rate impacts (and net costs as well) is to extend the time period of implementation for achieving carbon reductions. If postponed beyond 2010, rate impacts and net costs of all carbon reduction strategies would be lower than indicated here. The postponement of larger carbon reductions by a decade or two would permit more retirements of existing plants in the business-as-usual reference case, and would allow technological change to reduce the costs of renewables and DSM.

Deferred implementation is an obvious solution for carbon reduction goals in the neighborhood of 50%, for which rate impacts would be high and would span a large uncertainty range. Such large carbon reductions should be considered a longer term goal, since no regulatory body is considering reductions of such magnitude for the 1990 to 2010 period, and the logistical difficulties of implementing such large reductions in such a short period would be substantial.

In view of these rate impact uncertainties, regulators could approach carbon reduction goals based on a given maximum tolerable rate impact, while taking into account the above uncertainties. Our research indicates that a freezing of emissions at 1990 levels would be a "safe" target if limiting rate impacts to about five percent or less were the principal policy concern. Should rate impacts turn out to be larger than calculated here, adjustments could be made in the reduction percentage itself, or in the date by which it is sought.

Implications for Regional Gas Demand

Contrary to expectations, carbon reduction strategies do not necessarily lead to large increases in the region's gas demand beyond those implied in current plans.[2] For the carbon reduction portfolios analyzed here, total New England gas demand (all sectors) would actually decline if it is assumed that nuclear reactors will undergo scheduled retirement in the NEGC reference case. Our finding on gas requirements suggest that gas price feedbacks from carbon reduction strategies in New England would not be significant. However, gas price feedbacks could be significant if carbon reduction strategies in other regions result in larger increases relative to currently projected national gas demand.

Implications for Regional Air Pollution

An important finding of our study is that carbon reduction strategies are simultaneously effective as acid rain reduction strategies. This synergism arises because major reductions in carbon emissions below 1990 levels dictate retirement of existing oil and/or coal capacity. Compared to the NEGC case with scheduled nuclear retirement, our three carbon reduction portfolios produce ancillary reductions in nitrogen oxides of -36% to -69%, and sulfur dioxide emissions that range from -29% to -84%. If valued on the basis of estimated control costs and prices for emission offsets, these reductions represent additional cost credits of substantial, if still somewhat uncertain, magnitude.

3. Environmental Externality Adders-Based Analysis

The effectiveness of the externality surcharges adopted in Massachusetts was assessed for several different planning or operational modes. We did not review the derivation of the adder values in terms of damage or control costs, but simply treated them as a set of normatively determined surcharges. We then examined what emission reductions could be expected from applying these surcharges and which, application, if any, could be used to achieve significant reductions in carbon emissions.[3]

In the context of a carbon reduction strategy, the Massachusetts externality adder system as currently applied could serve a supplementary function to other policy options, by boosting the competitiveness of various low-carbon resource investments at the margin. The Massachusetts adder system effectively eliminates high-carbon coal plants from the competition for marginal investments, but is not sufficient to completely shift investment choices to currently commercial non-fossil supply technologies such as wind or biomass-fired power plants. Other important low-carbon resources, such as demand-side management and gas-fired cogeneration, are already as cheap or cheaper than gas ACC plants before externality adders are even applied.

If the Massachusetts adders are applied only at the margin, they cannot bring about reductions of carbon emissions below 1990 levels in a timely fashion. Dispatching the

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[2]Significant uncertainties exist as to whether there will be enough pipeline capacity to deliver the amount of gas assumed in the reference case to the New England region. See Appendix H in Volume II of this report for more details.

[3]For heuristic purposes, we take the liberty of applying the adder values to decisions about the operation and retirement of existing plants in ways that the Massachusetts DPU did not envision when establishing those values (the adders were intended to affect plant investments at the margin).

New England system on the basis of the Massachusetts adders proved to be ineffective in bringing about carbon reductions as well. What little reductions were realized were significantly more costly than corresponding reductions obtained from implementing low carbon resource plans under a target-based approach.

In order to achieve significant carbon reductions with the adder approach, the Massachusetts externality system would have to be applied to retirement decisions for existing plants in addition to new resources. The adder system would justify scheduled or accelerated retirements of existing coal and oil-fired plants in favor of lower-carbon gas-fired cogeneration plants and utility-scale ACC plants. Used this way, adders could lead to carbon reductions comparable to or even greater than those obtainable with target-based integrated emission reduction plans.

At the same time, the impact of the Massachusetts adder on the economics of existing plants illustrates that the application of externality incorporation policies based on monetized adders alone would be a blunt instrument. Taken literally, the Massachusetts adders would justify the retirement of almost all of NEPOOL's fossil-based generating capacity over a period of a few years.

It is obvious that policies other than externality adders applied to existing plants would be required to ensure that the phase-out of existing high-emission plants remains tolerable in terms of rate impacts, system reliability, and annual investment requirements. Competitive bidding or other integrated resource planning processes could be used to acquire needed resources for replacements and load growth.

D. CONCLUSIONS

Setting aside the issue of costs for the moment, our analysis suggests that New England has enough low-carbon resources to cut its carbon emissions in the utility sector by more than 50% relative to 1990 levels, even after scheduled retirements of nuclear reactors have been taken into account . This reduction potential far exceeds the near-term goals being considered for international agreements. To achieve a 15% to 20% reduction, no more than half of the region's low-carbon resource potentials would have to be mobilized on average. This resource endowment allows New England utilities and regulators significant flexibility in realizing international carbon reduction goals should they decide to do so.

Contrary to a widespread expectation, significant carbon reductions (at least 12% to 15% below 1990 levels) can be achieved at negative net cost, i.e., while lowering the electricity bills of New England's customers. When pursued in a cost-minimizing manner, carbon reductions of this magnitude are accompanied by substantial cost savings. This qualitative finding applies across the broad spectrum of sensitivity analyses performed in our analysis.

This economically attractive outcome is principally due to the existence in New England of significant underutilized demand-side options, and secondarily to the availability of low-cost gas-fired cogeneration potentials and to the existence of expensive existing oil plants that can be retired with little net cost penalty .

Carbon reduction strategies also bring with them major reductions in acid rain emissions. If the societal value of these avoided emissions were monetized and included in our analysis, it would decrease the net cost of all our scenarios.

The fact that carbon reduction strategies would have a strong demand-side component also means that they present the risk of rate impacts. This risk is small for policies that seek to freeze carbon emissions at 1990 levels, but it increases as carbon reduction targets become more stringent. Carbon reductions of 12% to 19% relative to 1990 levels would cause rate impacts of 4% to 19% (depending on assumptions about resource portfolio composition, fuel prices, and resource costs).

Rate impacts of significant size could reinforce current trends toward industrial bypass, which could lead to further rate impacts. However, a countervailing benefit would be the lowering of electricity *bills* for New England's customers from large scale DSM programs and efficiency standards. Regulators will need to trade off this benefit, and the environmental benefits of contributing to greenhouse insurance and improved air quality, against potential rate impacts. To better assess options for keeping rate impacts low, a more detailed analysis is needed of various issues, including the marginal T&D costs avoided by DSM resources.

Regarding suitable policy instruments, our research shows that the incorporation of the risk of global warming into utility planning could be achieved with more flexibility, predictability, and cost-effectiveness than feasible with adders if medium- to long-term emission reduction targets were set and these targets were then gradually implemented through corresponding resource plans. Such an approach is similar to the emission caps established for acid rain precursors in recent federal clean air legislation, and lends itself to emission trading. Also, carbon reduction decrements could become part of competitive bidding for resource decrements. These policies could offer market efficiency advantages similar to those of environmental surcharges while avoiding the ambiguities in deriving adder levels.

Finally, implementation of a carbon reduction strategy requires specific policies to mobilize cost-effective potentials of DSM, fuel switching, renewables, and thermally optimized gas cogeneration resources. These include shared savings incentives for successful utility DSM programs, tightened efficiency requirements for PURPA cogeneration facilities, demonstration projects for biomass gasification plants, and siting procedures for unconventional supply sources such as wind farms. If all these policies are undertaken, efforts to incorporate environmental externalities could then achieve their intended purpose: that of reducing both acid rain and carbon emissions on the basis of a prudent, integrated, and therefore low-cost electric resource strategy.

CHAPTER I

INTRODUCTION

Several recent developments are reshaping the environmental agenda for utility sector resource planning. One is the 1990 Clean Air Act Amendment, which specifies new limits on sulfur dioxide and other power plant emissions. The second development is the growing recognition of the threat of global climate warming, which adds carbon dioxide to the list of air pollutants. The third development is a set of new regulations by a growing number of state utility commissions that apply monetized surcharges for air pollutant emissions (externality adders) in evaluating new power plant alternatives.

The new federal Clean Air Act regulations may impose significant costs on many U.S. regions. Painful as these may be, the legislation removes a major source of planning uncertainty that existed for more than a decade, and establishes a framework for practical clean-up measures by state regulators and utilities.

Just as this resolution has been achieved, the global warming issue has arrived on the environmental policy agenda and brings new uncertainty. In fact, policies aimed at reducing carbon dioxide emissions could have a far greater impact on utility resource planning than all other environmental regulation in the utility sector to date: they could require major resource shifts rather than just additions of control technology or buying low sulfur fuels.

Finally, a number of states are experiencing local and regional air pollution problems that have prompted them to go beyond federal regulations in limiting emissions. The new rules establishing externality adders for use in utility resource planning are one such initiative. Several of these new regulations include externality surcharges for carbon dioxide emissions.

A. QUESTIONS FOR STATE GOVERNMENTS AND UTILITIES

How should state governments and utilities respond to the global warming issue? Since no federal legislation exists as yet on limiting greenhouse gas emissions from power production, they could take a wait-and-see approach. However, such an approach creates a new prudency issue:

— If utilities life-extend and retrofit existing plants with scrubbers and other controls now, without addressing carbon dioxide and other greenhouse gas emissions, will they be forced to scrap much of these investments should carbon reduction regulations come into effect a few years later?

Alternatively, state regulatory commissions might follow the example of New York, Massachusetts, and Nevada and establish an externality adder for carbon dioxide emissions, or states could use some other form of regulation. This approach brings economic risks of its own, as discussed below.

As an introduction to the present study, it is useful to briefly outline what questions state decision-makers might ask to develop their own policy responses, and what analytic support they should seek in answering their questions.

1. Why Should States Act?

The obvious first question is whether there is, indeed, a real case for preventative policy action by state governments and regulators, and for preemptive investments by utilities. Here, the scientific nature and status of the global warming issue is of key significance:

— Why should potentially costly action be taken now, given that greenhouse warming from industrial era activities has not yet been conclusively proven from temperature measurements, and given that significant scientific uncertainties remain?

Since the issue is of a global nature, and since individual states and utilities do not have the resources to undertake fully independent assessments of this question, sound policy development should be guided by conclusions and recommendations reached in the international scientific and environmental policy communities. In particular, one might ask:

— Is there a broad international consensus among the majority of scientists that the *risk* of greenhouse warming is real and requires preventative action?

— If so, what level of emission reductions would be required to stabilize the atmospheric concentration of carbon dioxide and other energy-related greenhouse gases at the lowest possible level? What range of emission reduction targets are being proposed as initial steps that could guide utility resource planning over the next 15 to 20 years?

— What international efforts are afoot to bring about globally coordinated responses? Are governments of other major industrial countries making commitments to reduce emissions?

— Do these steps by other countries make it likely that similar initiatives will eventually be undertaken by the U.S. federal government? In particular, are there indications that the U.S. government might join other nations as a signatory to a global climate treaty and associated greenhouse gas reduction protocols?

2. What Would be the Costs?

Should states and utilities conclude, as some already have, that they are, indeed, at risk of having to take preventative measures soon (i.e., within the next five to ten years or sooner), they would then want to ask a second set of questions. These have to do with the economic impacts of state policy initiatives and utility investments. These can be viewed from a broad societal perspective, and from a more narrow ratepayer perspective. Specifically, state policy-makers might ask:

— How far could states go on their own in reducing carbon dioxide and other energy sector greenhouse gas emissions without incurring negative economic consequences for their regions?

— If states were to adopt internationally proposed emission reduction targets, what would be the impact on the total cost of electricity services, and on electricity rates?

— What would be the impact of pursuing a carbon reduction strategy on electricity rates, and should it differ in scale from the impact on social costs, how can the two be reconciled?

— Are there ancillary benefits of environmental quality, technology innovation, resource diversification, and state economic development that might accompany greenhouse gas reduction strategies?

— Could the already required expenditures for acid rain control under the 1990 Clean Air Act Amendment be leveraged to reduce carbon dioxide emissions? If so, what would be the incremental cost of carbon emissions over and above Clean Air Act compliance?

3. What State Policies Might be Needed?

Finally, state governments that decided to take action would want to understand the specific policy needs of a greenhouse gas reduction strategy. With specific reference to the utility sector, the following questions arise:

— What research and development (R&D) and incentives policies should be pursued to help mobilize and broaden the range of electricity resource options that have low greenhouse gas emissions?

— What policy coordination would be required among utility commissions, state energy offices, and state environmental agencies?

— How could consideration of global warming risks be incorporated into the new integrated resource planning (IRP) processes pursued by many state utility commissions?

To date, state governments have used three alternative methods for incorporating environmental externalities: traditional emission standards for individual sources, emission bubbles, and monetized environmental externality adders.

Prescriptive standards for minimum levels of emission clean-up in each plant build on federal new source performance standards (NSPS) as established in the 1977 Clean Air Act. In many instances, states have used the concept of best available control technology (BACT) to introduce more stringent versions of these "command and control" requirements that go beyond federal legislation.

A more flexible approach is the so-called bubble concept, in which a quantity constraint is set for emissions in a particular airshed. Any increases in emissions from one plant need to be offset by decreases elsewhere. The 1990 Clean Air Act Amendment extends this bubble concept to the national level for sulfur dioxide, in the form of an emissions cap. One attractive feature of the bubble concept is that it lends itself to emission rights trading, and the new federal legislation implements this potentially cost-minimizing feature for the first time.

Finally, a number of state public utility commissions (PUCs) have adopted new resource planning rules that add environmental externality penalties for residual air emissions as a factor in integrated resource planning. Because public utility commissions have statutory authority over rates, PUC environmental policies have taken the form of monetized corrections of the costs of generating resources.

These monetized externality surcharges or adders are used in the preparation of integrated resource plans or in selecting competitive resource bids. They are either expressed in dollars per pound of pollutant, or take the form of broad cost credits for renewables and/or demand-side resources (Cohen et al. 1990, Koomey 1990a).

Given these alternatives, states would want to ask:

— Should global warming risks be incorporated by means of monetized adders for greenhouse gas emissions, as currently done by some states, or should the bubble concept be used and reduction targets be set for utility sector resource plans?

Unlike the case with other air pollutants such as SO_2 or NO_x, externality adders for carbon dioxide would not build on already established federal emission standards that ensure a minimum of environmental protection and control. Instead, monetized adders would be the only means of realizing emission reductions for carbon dioxide and other greenhouse gases. The monetized adder approach would thus be much more heavily relied upon than is the case for other air pollutants.

Another difference between externality adders for carbon dioxide and those for criteria air pollutants is that there is no scientific basis for assessing damage costs for global climate change, while the damage costs for other pollutants can be estimated, at least in principle. Climate change is unique because of its global scope and the long time scale upon which damages may occur. In addition, there are practical limitations on our predictive power. For example, the models that are used to predict global effects of climate change are most limited in assessing regional effects--yet these regional effects are the source of most potential damages. These models assume that the climatic response to a given change in greenhouse gas loading will be relatively linear, but it is possible that the climate system may "snap" in the face of a sufficiently large change in greenhouse gas concentration and a new, somewhat less hospitable equilibrium may be established. The risk of such non-linear response is non-quantifiable in principle, but it is a real risk nonetheless. Because of these issues, we treat externality adders in this study as a set of normatively determined surcharges that are used as a means to achieve certain carbon reductions, and do not address the various mechanisms by which analysts have attempted to set these adders.

4. How Should Monetized Adders be Set?

Given this context, a core issue — apart from considerations of statutory authority — becomes the proper design and application of externality adders:

— Are currently established monetized externality adders suitable for bringing about effective carbon dioxide reductions at appropriate levels? If so, how would they have to be applied?

— In particular, what carbon reductions might currently established adders yield if applied to both existing and new plants, and if used for dispatch of the entire utility system?

— What does the target-based approach tell us about the level at which adders should be set? Is the current derivation of adders on the basis of post-combustion control technology (such as tree planting in the case of CO_2) compatible with a systemic approach in which all available control, system dispatch, and resource planning options are considered, as they would in a well-functioning market for emission reduction options?

To answer these questions it is necessary to study the impact of currently established monetized externality surcharges on both capacity expansion and utility system dispatch. The adder and the target-based approach become equivalent when the adder is sufficient to make all cost-effective low-emission resource options and reduction measures that need to be deployed to meet a specific reduction target. More specifically, the adder must ensure the cost-effectiveness of the most expensive resource or control option that is needed to reach a desired target.

This approach to setting the adder could be called a market-based approach, since it is based on the integration and competition of all available emission reduction options. It has important consequences for regulatory policy: The level of monetized adders for fossil carbon or acid rain precursors can be set in a proper fashion only when the entire supply curve of resource and control options is sufficiently well understood. Furthermore, a proper adder level cannot be defined without also specifying a reduction goal. Different emission reduction goals require a different range of resource and control options to achieve them. Similarly, the most expensive resource required to reach alternative reduction goals will differ as well. Consequently, the monetized adder, which is a marginal cost signal, must also differ.

5. How Should Emission Offsets be Treated?

Once it is recognized that monetized adders cannot really be separated from reduction targets and should be derived from a comprehensive comparison of all reduction options a further issue arises:

— What should be the geographic accounting boundaries for counting emission reductions?

— What offsets from emission reductions outside the utility sector and outside the state's jurisdiction should be allowed?

The latter point relates to the issue of emissions trading. Such trading could be particularly important in the case of carbon dioxide. Since its pollution effects are not localized, a unit of emissions avoided here is as good as one avoided anywhere else in the world. By expanding the accounting boundaries, opportunities for low-cost emission reductions could be greatly expanded, and this expansion, in turn, would lower the externality adder needed to realize a given reduction target.

Unfortunately, such expansions of the supply curve of reduction options bring their own problems. First, the analytic difficulties in determining the magnitude and cost of each option increase. Second administrative and verification problems magnify. Finally, the seeming expansion of the supply of low-cost reduction options could quickly evaporate: to make a climate stabilization strategy effective, all energy producers and users in all sectors of the economy and in all countries would need to avail themselves of such options. Such competition could quickly diminish any low-cost offset opportunities.

We therefore limit the scope of this study to those carbon reduction options that are available within the boundaries of New England, and from investments related to the production and use of electricity.

B. RESOURCE PLANNING ISSUES IN NEW ENGLAND

In New England, utilities and regulators currently face a number of special resource planning issues that have direct bearing on the design of carbon reduction strategies. They can be summarized as follows:

- Operating licenses for a major portion of New England's nuclear capacity will expire toward the end of the planning horizon of our study. This low-carbon capacity may need to be replaced by other resources.
- Parts of the region suffer from serious air quality non-compliance problems related to ozone. Achieving a high level of air quality may require significant additional investments beyond those required to meet new federal and state regulations for sulfur dioxide emissions.
- The region's utility sector generates a high share of its electricity output from residual oil.
- The region is currently short of pipeline capacity for replacing oil with cleaner and lower-carbon natural gas.
- Siting of pipelines or power plants has become increasingly difficult in New England except when existing sites are recycled.
- The amount of low-carbon hydro electricity that could be imported from Canada is uncertain, because of opposition to Hydro Quebec's James Bay project.

These issues pose significant challenges for regional initiatives to reduce power sector carbon dioxide emissions. Will New England be able to cut carbon (and acid rain) emissions when the region might have to replace a significant amount of nuclear capacity, and when it already faces difficulties in expanding gas and hydro supplies? What role could the carbon adder of the Massachusetts externality surcharge system play? The present study seeks to answer these questions

C. OVERVIEW OF REPORT

In the chapters that follow we present our inquiry into these issues In Chapter II we describe the scientific debate surrounding the global climate change issue and present some of the more prominent international and U.S. policy developments related to the subject. In Chapter III we describe our analytical approach in modeling the New England power system and identify some of the key uncertainties. In Chapter IV, we develop a menu of low-carbon electricity resources available to New England, quantifying their size and costs. Next, in Chapter V, we assess the effectiveness of environmental externality surcharges in bringing about significant carbon reductions and compare the implied emission reduction costs of adder-based dispatch with the control costs of specific post-combustion control technologies. In Chapter VI, we present scenarios of low-carbon resource portfolios and estimate the cost of realizing a range of carbon dioxide reductions in the region's power sector. Detailed background data and resource potential analyses for our research are documented in twelve appendices, which are published as Volume II of this report.

CHAPTER II

THE THREAT OF GLOBAL CLIMATE CHANGE: SCIENTIFIC BASIS AND POLICY ISSUES

A. OVERVIEW

In this chapter, we briefly discuss the key scientific and policy issues that would form the basis for a course of global warming prevention in general, and specifically, for state policy action on global warming. We then explore the notion of emission reductions at negative or zero cost, which is central to understanding the connection between integrated resource planning and emission reduction planning. This is followed by a brief outline of the general methodology of our analysis. We then summarize existing utility resource planning issues in the New England region that need to be made an integral part of carbon dioxide reduction strategies.

B. SUMMARY OF CURRENT SCIENTIFIC ASSESSMENTS

In 1988, the World Meteorological Organization (WMO) and the United Nations Environment Program (UNEP) convened an Intergovernmental Panel on Climate Change (IPCC). The panel, which consisted of leading scientists and experts from twenty nations, including the U.S., the Soviet Union, and China, was charged with assessing the scientific information related to the climate change issue. The panel's Scientific Assessment Report (IPCC 1990), released at the Second World Conference in Geneva, is an authoritative summary of the threat of global warming as currently seen by the international scientific community. The report states in its executive summary:

> "We are certain of the following: Emissions resulting from human activities [...] will result [...] on the average in a warming of the Earth's surface."

Based on the findings of the IPCC report, and the large body of research literature from which it draws, the scientific basis of the global warming threat can be summarized as follows:[1]

1. The Greenhouse Effect

The greenhouse effect (the trapping of heat radiation by certain gases in a manner that is analogous to the effect of the window panes of a greenhouse) is one of the oldest and most well-established experimental findings of modern science, its discovery dating back some 150 years.

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[1] See also EPA (1989) and Krause et al. (1989).

There is an already existing greenhouse effect based on the natural occurrence of greenhouse gases in the Earth's atmosphere, such as water vapor, carbon dioxide, and methane. This natural greenhouse effect keeps the earth warmer than it would be otherwise and supports the living environment as we know it.

Various natural phenomena can lead to changes in this natural greenhouse effect. For example, particulates from volcanic eruptions can make the upper atmosphere less transparent to solar radiation and induce a cooling. Such cooling effects will, however, typically last only for a few years.

2. Impacts of Human Activity

Human activity has led to growing emissions of several major greenhouse gases, namely carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and certain chlorofluorocarbons (notably CFC-11 and CFC-12). The atmospheric concentrations of these gases have been rising steadily and continue to grow, as shown by measurements from a global network of monitoring stations.

These concentration increases will enhance the natural greenhouse effect, and will, on average, lead to warmer global temperatures. This warming effect is considered certain on the basis of geophysical climate modeling analyses, and is further supported by empirical data from trapped air samples in ancient ice cores. These air samples have revealed that for the last 150,000 years, interglacial warm periods were very closely correlated with rising atmospheric carbon dioxide concentrations (see Figure II.1).

Carbon dioxide emissions from the combustion of fossil fuels contribute more than half of the potential warming from greenhouse gas emissions. They thus represent the single most important driving force behind the threat of greenhouse warming.

There remains a significant uncertainty in the exact quantitative relationship between increases in atmospheric greenhouse gas concentrations and the degree of global warming.

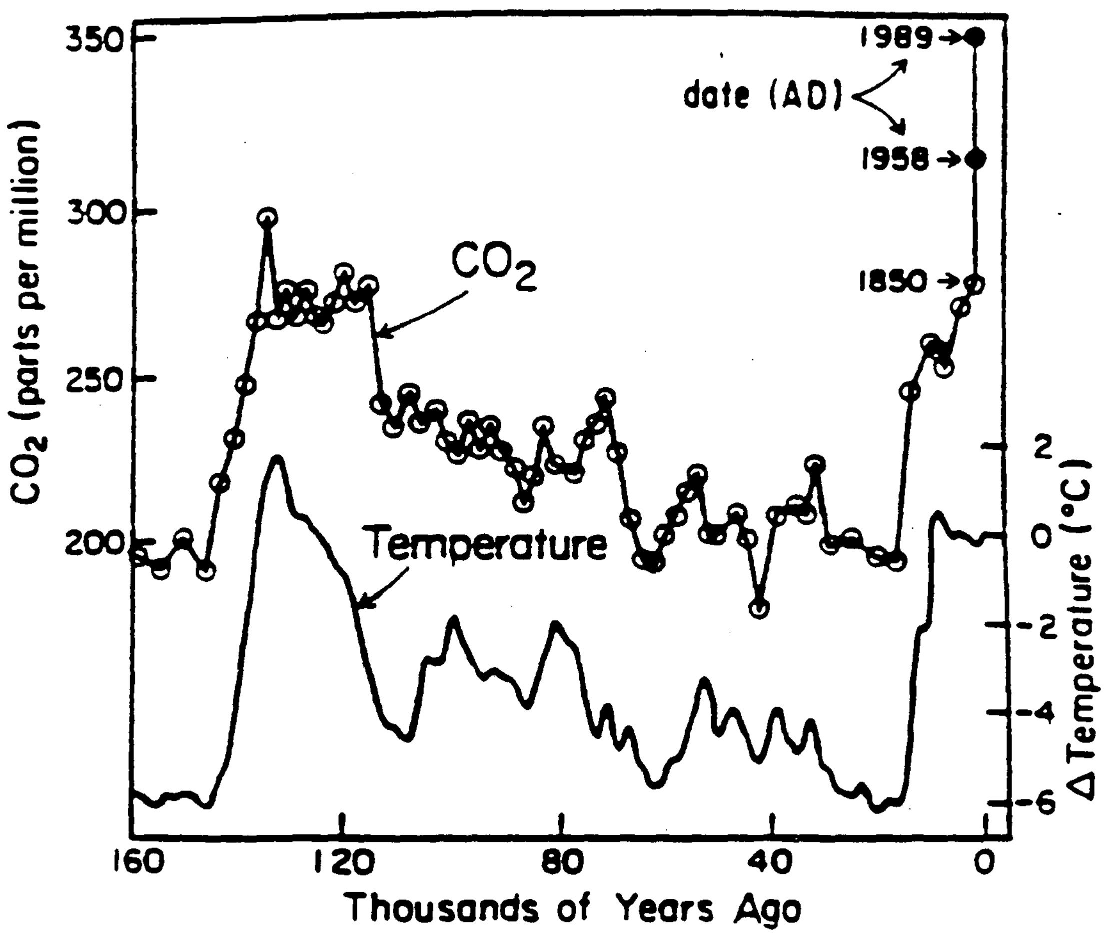
Under its business as usual forecast, and on the basis of central estimates of the climate system's sensitivity to greenhouse gas emissions, the IPCC predicts a temperature rise of 1°C by 2025, and of 3°C by the end of the next century.

3. Expected Delays in Temperature Rises

Known geophysical factors, notably the large heat storage capacity of the oceans, lead to delays in the warming effect of greenhouse gases. The fact that major greenhouse gas emissions have already occurred but measured global warming trends over the last century have not yet exceeded natural climatic variability does not disprove the threat of global warming.

Once global warming has been set in motion, even a complete cut-off of all greenhouse gas emissions will not stop or reverse it. The atmospheric residence times of carbon dioxide and several other long-lived greenhouse gases are of the order of a hundred years.

Figure II.1: Historic Correlation of Atmospheric Carbon Dioxide Concentrations and Global Average Surface Temperatures



Source: Lorius et al. 1990.

4. Potential Environmental Impacts

Based on the historic climate record of the Earth, global warming of 1-3 degrees C would be accompanied by significant changes in sea levels, forest cover, precipitation, and regional climates.

The regional and local distribution of these impacts remains highly uncertain: climate models cannot reliably predict whether impacts would be negative everywhere or only in some regions, or whether some regions might benefit from climate change, and if so, which ones.

For the same reason, observed climate changes in specific regions may not be the same as observed or predicted warming trends overall. For example, a string of cold years or a cooling trend in some local region is not incompatible with an overall global warming trend.

There is a clear *risk* that changes brought on by greenhouse warming in the global environment could prove catastrophic. If changes should occur suddenly or discontinuously, major breakdowns in forests and other ecosystems could occur. The ability of human civilization to plan and complete timely adjustments would be greatly impaired.

More scientific research will be able to narrow, over the next decade or two, the range of uncertainty in global warming predictions. But short of subjecting the entire planet to a full-scale greenhouse experiment, substantial uncertainties will always remain.

C. GLOBAL WARMING AS A POLICY ISSUE

It is this last feature, combined with the delay in the appearance of warming, that distinguishes the threat of greenhouse warming from "classical" air pollution problems such as acid rain or photochemical smog. Because classical air pollution impacts are local or regional in nature and have been manifest for quite some time, it has been possible to measure and observe their effects on human health, agriculture, and natural biota by studying the "sacrifice areas" where major damages were inadvertently incurred.

In the case of the greenhouse effect, the entire globe would have to be converted into a laboratory to obtain a similar empirical basis for policy decisions. Such an experiment would incur the very consequences that research aims to prevent. In fact, the continued emission of greenhouse gases constitutes an undeclared experiment of this kind.

In view of the unique and global nature of the greenhouse warming threat, the international science and policy making community has moved toward a consensus that precautionary measures should be pursued as a risk-minimizing public policy (IPCC 1990), even before human-induced global temperature rises become evident.

1. Buying Greenhouse Insurance

The key question then is: how much prevention should be pursued? Because of the limitations of climate models and the difficulties of calculating potential damages in dollar terms, it is not possible to derive policy guidelines for preventative measures on the basis of economic cost/benefit analysis. It is, however, possible to correlate each trajectory of greenhouse gas emissions with a maximum global warming increment that this trajectory would produce. This maximum warming is obtained by applying the uncertainty ranges in climate modeling in such a way that impacts are calculated with prudent consideration of the risks of negative consequences at each step.

Similarly, it is possible to calculate the net direct economic costs of achieving various emission reduction targets, as compared to continuing business as usual energy strategies or, in the case of utilities, business as usual utility resource plans.

Based on these observations, Krause et al. (1989) propose that prevention policies be considered as a form of buying insurance. In this analogy, the amount of coverage obtained is the reduction in the maximum warming that would result on account of prevention measures. The insurance premium is the net cost of pursuing these prevention measures over the cost of continuing business-as-usual.

For this insurance buying approach to be useful in practical policy-making, it is necessary to define the maximum warming that is considered tolerable. This warming risk limit, or simply warming limit, can then be translated into required cuts in greenhouse gas emissions.

Warming limits and reduction targets

The safest course of action would be to limit future warming risks to the already unavoidable (but still latent) warming impact of past emissions. Relative to average global surface temperatures in 1980, this already existing (but still latent) warming is in the neighborhood of 1-1.5°C when models embodying consensus estimates of climate sensitivity are used. To limit warming to this range would require an immediate reduction in emissions sufficient to stabilize atmospheric concentrations at present levels.

Because there are some natural sinks that remove greenhouse gases from the atmosphere, emissions would not have to be cut to zero. Emission rates of carbon dioxide and other long-lived greenhouse gases would have to be cut by 60 percent or more according to the IPCC study, and by 50 to 80 percent according to EPA (1989), while methane emissions would have to be cut by 15-20 percent.

Such large reductions in carbon dioxide emissions could not be practically achieved overnight. A risk-averse public policy, however, would still seek large reductions as early as practically feasible. The required cuts in emissions are a function of the amount of additional[2] warming risk that is considered tolerable. Various warming limits have been proposed or recommended based on the adaptive capacity of forests, or based on the

[2] This warming is additional in the sense that it would add to the unrealized warming from emissions to date, which is currently hidden by the thermal inertia of the oceans.

Earth's maximum temperatures during human evolution. These fall in the range of a 1-2°C limit relative to 1980.

The most comprehensive and detailed analysis to date of greenhouse gas reduction targets is found in the study by Krause et al. (1989), which is based on a warming risk limit of 2°C relative to current global temperatures. To develop a planning guideline for energy policy decisions, the authors calculate the total remaining fossil fuel combustion over the next century that would still be allowable under this warming limit. The discussion below is based on this work.

An upper limit for the remaining fossil carbon (short for budget of fossil carbon dioxide emissions) is derived by making stringent assumptions about the curtailment of greenhouse gas emissions from other sources. The calculations assume an end to carbon dioxide emissions from forest losses and the reversal of forest biomass losses that will inevitably occur before stabilization is reached, as well as a complete phase-out of CFCs by the turn of the century.[3] With less stringent control assumptions for these other greenhouse gas sources, the remaining permissible fossil fuel consumption would be more restricted. Based on these assumptions, about 300 billion metric tons of fossil carbon (short for carbon dioxide counted as carbon) emissions would be permissible under a 2°C warming limit. This is equivalent to about 50 years at current global rates of fossil fuel consumption.

Next, Krause et al. derive emission reduction targets for various points in time, assuming that emissions at 20 to 25 percent of present levels would not increase atmospheric concentrations. To allow for economic constraints, the average speed of reductions is tied to capital stock turnover rates. The authors find that reduction rates tied to capital stock turnover would be sufficient to realize the required overall emission cuts and observe the cumulative emission budget at the same time. According to their calculations, global fossil carbon emissions would have to be reduced by 50 percent by about 2030, and these would have to be cut in half again by about 2050.

Reduction targets for industrialized countries

The final step in the development of reduction targets is the differentiation among developing and industrialized countries. If historic discrepancies in the consumption of fossil fuels were accounted for on a strict equity basis, industrialized countries would receive no further emission allowances – an obviously unworkable approach. A 50:50 split could present a pragmatic and workable compromise allocation of the global fossil carbon budget.

Under this allocation, developing countries could increase their fossil fuel consumption in the near to medium term, while expected or desired growth would outstrip opportunities for efficiency improvements, and reduce them later as growth slows down and a broader set of low-cost renewable technologies would be available to them. Meanwhile, industrialized countries would have to achieve a 20 percent reduction below present levels by about 2005, and a 50 percent reduction by about 2015-2020 to remain within their carbon budget.

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[3] In accordance with the goal of risk minimization, climate and carbon cycle modeling is based on the higher end of the uncertainty range for climate model sensitivities, and on the lower end of the uncertainty range for absorption of carbon dioxide by the oceans. A 4.5°C climate model sensitivity is used, and a box diffusion carbon cycle model is employed.

Significant differences in historic cumulative fossil carbon emissions also exist among industrialized countries. Between 1950 and 1986, the years when the bulk of total fossil fuel consumption to date occurred, population-normalized cumulative emissions in the U.S. were twice as high as those of Western Europe, 2.5 times as high as those of Eastern Europe, and three times as high as those of Japan. These figures suggest that further differentiations in the allocation of emission allowances and reduction targets would be justified.

2. Adoption of Reduction Targets in the Political Realm

International developments

In the international realm, a call for an initial 20 percent reduction in fossil carbon dioxide emissions by the year 2005 was made by the 1988 Toronto World Conference. The conference also initiated the scientific assessment of the IPCC process, and the negotiation of a framework convention for an international treaty on protecting the global climate. Such a treaty is scheduled as a key agenda item at UNEP's 1992 World Conference on Environment and Development in Brazil.

The United States is participating in these negotiations, but has made no commitments to cut its carbon dioxide emissions . Meanwhile, other leading industrialized countries have committed themselves to various emission reduction targets. The government of the Federal Republic of Germany announced that it will reduce FRG emissions of carbon dioxide by 25 percent relative to 1986 by the year 2005. An agreement to freeze carbon dioxide emissions by 2000 was reached among the environment ministers of the twelve member nations of the European Economic Community (EC), and was announced at the Second World Climate Conference in Geneva in 1990. Other European countries have committed themselves to various reduction goals, ranging from freezing to cuts of up to 20 percent by dates ranging from 1995 to 2005.

The Japanese government has committed itself to freeze carbon dioxide emissions on a per capita basis. Canada and Australia have agreed to cuts in principle, but have made implementation dependent on an international agreement, while New Zealand has established an unconditional reduction goal of 20 percent from 1990 levels.

The EC is currently negotiating a joint internal arrangement for implementing actual cuts in carbon dioxide emissions on a region-wide basis. A new Europe-wide energy tax to be introduced in 1992 will be partly based on the carbon content of the fuels used. R&D policies in Europe and Japan reflect these policy commitments in an increased emphasis on all forms of low-carbon technologies, especially those based on energy efficiency and renewables.

Developments in the U.S.

Rather than setting its own reduction goals, the U.S. government has taken the position that more research should be done on the global warming threat. In the meantime, its stance on preventative measures is what what is referred to as a "no-regrets" policy: it will pursue carbon dioxide reductions only insofar as they are obtained through measures that are justified on economic grounds or can be obtained as a side-effect of other environmental policies that are not motivated by the risk of climate change.

One concern for regulators relates to the potential interaction between national and state initiatives. State regulators must face the possibility that the U.S. government may in the future change its stance in the climate negotiations. Utility resource planning actions taken in the interim may then not be in consonance with such a national policy.

A second factor is seen in the concern that diverging policies on carbon reductions between the U.S. and other major industrial countries could lead to competitive disadvantages for the U.S. Europe and Japan have made the accelerated development of low-carbon technologies part of their industrial policy. In the absence of similar commitments in the U.S., American industries are at risk of losing in technological competitiveness (Porter 1991).

On account of these factors, states might face federal carbon dioxide reduction targets in the not too distant future. Taking the initiative, a number of states already have commissioned studies to assess the feasibility of a 20 percent cut in carbon dioxide emissions. The state of Oregon has passed legislation directing its regulatory and planning agencies to develop a strategy for cutting greenhouse gas emissions by 20 percent. California's legislature is in the process of exploring the adoption of a state-wide greenhouse gas reduction target.[4]

In New England, the state of Connecticut passed An Act Concerning Global Warming in 1990. The legislation establishes various new requirements for energy efficiency. Similarly, the governor of Vermont committed the state to a program of energy conservation and use of renewables in 1989, citing the threat of global warming and other environmental problems.

Among utilities, two California firms (Southern California Edison Co. and the Los Angeles Department of Water and Power) announced plans in May 1991 to voluntarily reduce carbon dioxide emissions by 20 percent over 20 years. The Edison Electric Institute, a national utility trade group, takes the same position as the federal government: that carbon reductions should be limited to measures that are justified for other reasons, such as cost savings or reductions in acid rain emissions.

D. THE NET COST OF CARBON REDUCTIONS: A PRIORI CONSIDERATIONS

1. "No-regrets" Versus Reduction Targets

What amount of emission reductions would a "no-regrets" policy produce? The definition of no regrets is based on zero-net-costs for prevention measures. If the potential for emission reductions from such zero-cost options should be small, such a policy would not achieve the goal of minimizing the risk of catastrophic warming. While avoiding costs in the near-term, it could lead to large economic damages in the U.S. and globally in the longer-term.

Short of detailed analyses that specify the range of emission reductions such a policy could achieve, the term "no regrets" is thus deceptive. As a policy *principle*, it is a modified version of the wait-and-see approach: risks that cannot be addressed by zero-cost measures

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4 See Silbiger and Gonring (1991) for a summary of state initiatives related to global warming prevention.

are simply ignored until events prove them real. The risks and even fallacy of that approach in view of the special characteristics of the greenhouse effect is evident from our discussion.

As a global warming prevention policy, the target-based approach is certainly more prudent, forthright, and reliable than an approach that banks, in essence, on the side effects of other policies. Below, we therefore use the more neutrally descriptive term "zero-net-cost" policy rather than the potentially misleading term "no regrets" policy.

2. The Significance of Zero-Net-Cost Policies for State Initiatives on Global Warming

The potential shortcomings of the zero-net-cost approach as an insurance policy not withstanding, the cost of reductions in carbon dioxide and other greenhouse gas emissions is an important and legitimate practical concern. If no limits were put on the cost of emission reductions, the "cure" could be so economically disruptive as to create more damage than the "ailment." In fact, it is this economic constraint that leads to the use of a warming limit that is higher than the warming that would be expected if greenhouse gas emissions were cut to harmless levels instantly.

From an economic point of view, then, we can say that the target-setting approach and the zero-net-cost approach represent polar opposites: While target-setting policies focus on obtaining a certain amount of insurance coverage, without any explicit constraints on the cost of the insurance, the "no regrets" policy aims to buy insurance at a zero cost premium, without any minimum requirement for risk reductions.

But are the two approaches really at odds, and if so, how divergent are they? Absent detailed assessments of the economic cost of alternative carbon reduction strategies, it might well be that a serious effort to implement a zero-net-cost policy would allow significant reductions in carbon emissions as well.

So long as no explicit federal reduction policy is in effect, a zero-net-cost policy should be of particular interest to state governments and utilities. Certainly, such a policy would be politically much easier to implement than a reduction target that leads to significantly higher electricity bills. Though it would arguably be worthwhile to pay a considerable insurance premium to reduce global warming risks, individual states could not venture far without negative competitive impacts on their economies. Federal leadership would be required before states could pursue strategies of substantial net costs to ratepayers.

3. Negative-Cost Carbon Reduction Options

The central notion in a zero-net-cost approach is that some things can be done to reduce fossil carbon emissions that have a zero-net-cost, or indeed, negative net costs. This notion easily blends with the precepts of integrated utility resource planning (IRP), a regulatory reform that has spread to many states over the last few years.

The motivation for introducing IRP processes in state utility regulation has been the recognition that past utility investment plans did not achieve a societal least-cost optimum, principally due to the fact that conventional planning did not integrate utility supply options with non-utility options by independent power producers, and with low-cost resource options on the demand-side.

The existence of such cost disequilibrium in the utility sector has an important consequence for state initiatives to address global warming: as planning is shifted from business as usual to integrated approaches, the total cost of electricity services will be reduced. Because demand-side resources play a major role in this shift on account of their generally lower cost, IRP resource plans will result in carbon emission reductions as well, even before these have been made an explicit consideration. This means that some amount of reduction in carbon (and other) emissions can be achieved at zero or negative net economic cost, compared to a business-as-usual approach.

A second potential source of zero-net-cost carbon reductions are certain cogeneration and small power resources. Cogeneration is generally cost-competitive with utility power production, and most forms of cogeneration emit significantly less carbon than utility power generation combined with the separate production of steam because they displace fossil fuels otherwise used in boilers.

A third synergism that might afford no-cost carbon reductions has arisen on account of the 1990 Clean Air Act Amendment, and through initiatives by states or metropolitan areas that go beyond federal requirements in order to achieve greater control of local air pollution. In the case of sulfur dioxide, these new federal or state requirements can be met, for example, by life-extending existing oil and coal plants while switching them to low-sulfur fuels and/or retrofitting them with scrubbers.

Alternatively, existing plants can be repowered with natural gas, which emits less carbon and much less sulfur per unit of energy. Repowering would thus yield a greenhouse prevention benefit in addition to a sulfur dioxide benefit. So long as the repowering option is cost-competitive with the life extension/fuel switching option, a zero cost opportunity for carbon reductions exists.

Finally, a zero-net-cost policy can rely, to some extent, on positive-cost measures. Up to a certain point, investments in low-carbon resources that are more expensive than conventional resources can be offset with savings from those resources that are not only zero cost but negative net cost. For example, some amount of more expensive renewables resources could possibly be bought with the savings from negative-cost efficiency improvements on the demand-side. Such trade-offs extend the amount of emission reductions beyond the potential of the negative-cost resources.

4. Supply Curves of Carbon Reductions

The question for state regulators and utilities then becomes: what resource mixes could provide carbon emissions at zero or negative total cost (relative to the reference plan), and what amount of carbon reductions could be obtained, given the opportunities to employ zero or negative net cost, low-carbon resource options in each state? And if the amount of reductions that are available at zero or negative net cost should be smaller than what international agreements or future federal legislation might end up requiring, how much would the premium be?

More broadly, then, utilities and regulators will need to know the cost impacts of carbon reductions as a function of the amount of carbon reductions that are being sought, over the full range of needed or feasible reductions. Based on our discussion above, reductions from zero percent to 50 percent (relative to 1990 levels) would be of particular interest.

Such data can be conveniently summarized in the form of a supply curve that shows the net cost of each resource strategy as a function of the carbon reductions, relative to a business-as-usual case. Such a supply curve of carbon reductions allows decision-makers to see the cost of buying insurance against the threat of global warming for each carbon reduction goal.

The net present value (NPV) of the additional resource cost associated with each reduction strategy would be zero or negative for a certain range of carbon reductions. At some point, as the desired risk-reducing coverage grows and more costly options have to be included in the resource mix, it would become positive. This dynamic is illustrated in Figure II.2. The figure shows two kinds of cost curve. The first kind is a marginal-cost supply curve (Figures II.2 a and II.2.b). Here, reduction options are shown in order of increasing costs, and the marginal cost of each measure is plotted against increasing reductions. The second curve is an average-cost supply curve (Figures II.2.c and II.2.d). Here, the sum of all costs from options implemented up to a certain point is plotted against the percentage reduction obtained.

The meaning of a zero-net-cost policy can be gleaned from this graph. While negative cost options alone (area B in the marginal supply curve) would allow reductions only to point x, a zero-net-cost package could use an additional set of measures (area A in the marginal supply curve) and realize the larger reductions of point y at zero-net-cost. Beyond point y, the net cost of the carbon reduction strategy becomes positive, i.e., greater than a suitably defined reference plan that would have been pursued in absence of the goal of greenhouse emission reductions.

As total strategy costs become positive, the slope of the carbon reduction supply curve could be steep or shallow (Figure II.2.a and c versus b and d). If shallow, this would mean that a certain amount of coverage beyond point y could be purchased at a small insurance premium. This characteristic could facilitate the reconciliation of a zero-net-cost policy with a target-based approach should the former fall short of internationally recommended or desirable minimum reduction targets.

Based on such supply curves, states and utilities could set minimum carbon reduction goals for themselves that would not lead to significantly higher electricity bills than conventional plans or could save ratepayers money in more favorable cases.

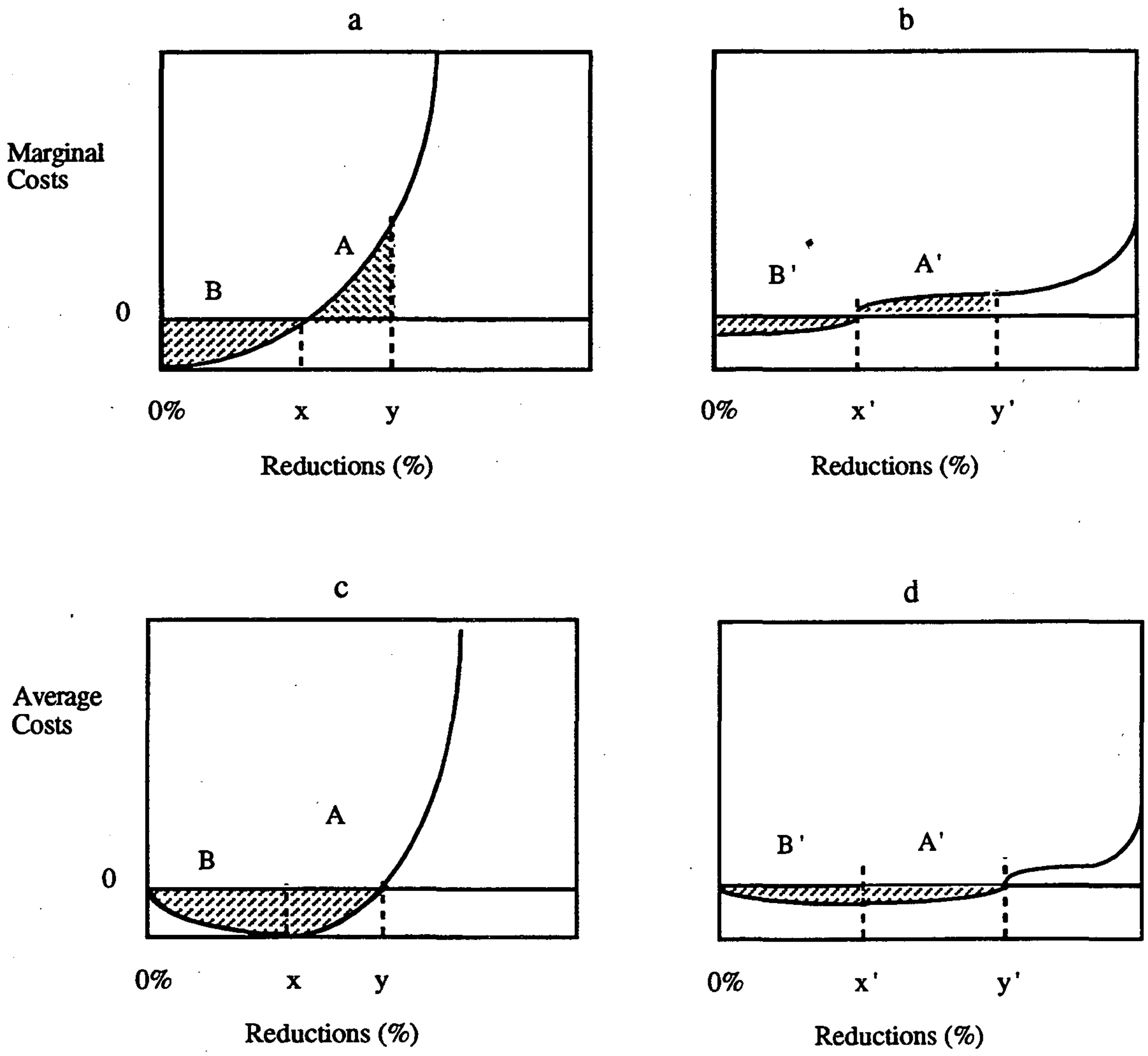

Figure II.2: Possible Shapes of the Supply Curve of Fossil Carbon Reductions

CHAPTER III

MODELING THE NEW ENGLAND POWER SYSTEM

A. OVERVIEW

In this chapter, we describe the approach used to assess the costs and emissions from different resource mixes and system operating strategies. At the end of the chapter we identify a number of exogenous factors with inherent uncertainty that we take explicit account of throughout the analysis.

B. MODELING BOUNDARY ISSUES

In the present analysis, we treat the New England power pool as though it was one large utility. The complexities of pool arrangements and inter-utility agreements are neglected here. We examine the NEPOOL system in two time frames only: present (1990) and 15 years in the future (2005). Because we are looking at two discrete years only, we have explicitly ignored consideration of the time dynamics of capacity expansion to 2005.

C. SIMULATION MODEL

Operation of the NEPOOL system was simulated using the UPLAN model (LCG, 1990). UPLAN belongs to the class of models that operate on a representation of hourly loads sorted into a load-duration curve. The model performs a probabilistic simulation using a form of the mixture of normals approximation algorithm. Unit-by-unit generation, cost, and emissions are calculated by UPLAN on a monthly basis. UPLAN has the capability of handling plant minimum operating levels, heat rates that vary with output, unit commitment targets, maintenance and forced outage rates, block loading, and must-run constraints. Emission rates per unit fuel input from three pollutants can be specified. Fuel costs, operations and maintenance costs (O&M), and cost of consumables are all calculated on the basis of output. Hydro capacity and energy that varies by month can also be simulated.

D. MODELING INPUTS

Due to limitations in the model and the large number of plants in the NEPOOL system, individual plants were aggregated into categories organized by technology, fuel, size, and vintage (see Table III.1). Assumptions used in characterizing plant performance were principally drawn from a public NEPOOL source (NEPLAN,1989) and augmented through communication with a member utility (Stillinger, 1991), and a regional electricity research group (MIT/AGREA, 1990). Plant emissions are based on boiler technology and on the

Table III.1: 1990 baseline system and 2005 reference case						
	1990 Capacity mix MW	*2005 capacity retirements 1990 CELT MW*	*2005 capacity additions 1990 CELT MW*	*2005 likely additions NEGC MW*	*2005 Base case additions NEGC MW*	*2005 Composite ref. case NEGC MW*
Coal steam plants	2850					2850
small	450					450
medium	600					600
large	1800					1800
Nuclear plants	6360					6360
small	2400					2400
medium	1660					1660
large	2300					2300
Oil steam plants	8800					8500
1950s	2000	-300				1700
1960s	1800					1800
1970s	5000					5000
Combined cycle plants	400		400			800
Peakers	1650	-225				1425
Utility hydro	3100					3200
Storage Hydro	620		30	70		720
Baseload Hydro	800					800
Pumped Storage	1680					1680
Purchases	1100					2650
Thermal Purchases	250	-250			550	550
Hydro Purchases	500	-500				
HQ Purchases	350		250	1500		2100
IPPs	1640					2140
Thermal IPPs	1400		600			2000
Hydro IPPs	240	-100				140
New resources						
Advanced CCs				600	2400	3000
Advanced CTs				30	1650	1680
IGCACC					800	800
Refuse				72		72
Biomass				200		200
Total	**25900**	**-1375**	**1280**	**2472**	**5400**	**33677**
Index	*1.00*	*-0.05*	*0.05*	*0.10*	*0.21*	*1.30*

sulfur and carbon content of input fuels. All direct emissions, regardless of plant ownership or geography, are counted.[1] Fuel and O&M costs were escalated in accordance with NEPLAN (1989) and are expressed throughout in real terms (1990 dollars). Independent power producer (IPP) generation was fixed throughout the simulations in accordance with the contractual arrangements typical of these agents. While some new resources in the 2005 mix (other than those in the IPP category) may be acquired through competitive bidding processes, they were modeled as if utility-owned.[2] Emissions of the IPP plant category reflect the mix of technologies and fuels of NEPOOL IPPs. A complete description of input assumptions and modeling conventions can be found in the Appendices (Volume II).

E. SUPPLY AND DEMAND BALANCE

1. NEPOOL Demand Forecast

Electricity is forecast to grow from 112,184 GWh in 1990 to 151,866 GWh in 2005, representing an annual compound growth rate of 2.03% (NEPOOL, 1990). Peak loads are projected to shift from a winter high of 20,392 MW in 1990 to a summer high of 27,417 MW in 2005. The summer peak overtakes the winter peak in 1993 reflecting growth rates of 2.13% and 1.90%, respectively. These load forecasts are given net of the savings anticipated from utility demand side management programs as of 1990.[3]

2. NEPOOL Existing System and 2005 Reference Case

The first column of Table III.1 shows the existing supply side resources of the NEPOOL system in 1990. Existing resources include 2850 MW of coal, 6360 MW of nuclear, 8800 MW of oil, 400 MW of combined cycle (CC), 1650 MW of peaking (including combustion turbines, jet engines, and diesel internal combustion plants), 3100 MW of hydro, 1100 MW of purchases, and 1640 MW of independent power producer capacity, for a total of 25900 MW.

The 2005 reference mix is derived from NEPOOL's 1990 Capacity, Energy, Loads, and Transmission (CELT) report (NEPLAN, 1990) and the subsequent January 1991 Resource Adequacy Report of the New England Governors' Conference (NEGC,1990). We refer to this modified NEPOOL plan as the NEGC reference case.

In the NEGC 2005 reference case, 400 MW of conventional combined cycle plants, 3000 MW of advanced combined cycles (ACC), 1680 MW of advanced combustion turbines (ACT), 800 MW of coal gasification ACC, and 100 MW of storage hydro would comprise

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[1]No attempt was made to account for indirect emissions from the extraction, processing, or transport of fuels.

[2]From a modeling point of view, ownership is not particularly germane; dispatchability and cost are the key issues. Many utility competitive bidding programs are assigning high value to dispatchability in their evaluation of supply projects. Our underlying modeling assumption is that only bids offering a high degree of dispatchability would be accepted in New England. Likewise, we assume that bid price offers would have variable costs that were comparable to those of utility-owned projects.

[3]Utility DSM program efforts are rapidly accelerating - more recent plans reflect higher levels of savings than represented here.

Table III.2 Economic Dispatch Results of NEPOOL System in 1990 and 2005.

	Capacity (MW)	Energy (GWh)	O&M Cost (M$)	Fuel Cost (M$)	Total Production Cost (M$)	Kilotons of Emissions SO_2	NOx	C
1990								
Nuclear	6360	40392	315	258	573	0	0	0
Coal Steam	2850	17351	14	315	329	195	62	4915
Peakers (Distillate)	1650	58	16	3	19	0	0	18
Oil Steam	8800	31066	44	851	895	204	89	9620
Thermal Purchase	250	1997	57	56	113	1	9	589
Hydro Purchase	850	3671	115	87	202	0	0	0
Pumped Storage	1680	603	7	0	7	0	0	0
Storage Hydro	620	1564	5	0	5	0	0	0
Baseload Hydro	800	4387	6	0	6	0	0	0
IPPs	1640	9108	0	501	501	17	22	858
CC	400	2733	1	69	70	5	7	1078
Total	25900	112932	580	2142	2720	422	189	17078
2005 (NEGC)								
Nuclear	6360	40392	360	170	530	0	0	0
Coal Steam	2850	17376	24	352	376	195	62	4917
Peakers (Distillate)	1425	25	15	3	18	0	0	10
Oil Steam	8500	24795	72	1215	1287	162	70	7624
Thermal Purchase	550	4664	144	147	291	3	20	1377
Hydro Purchase	2100	17568	0	444	444	0	0	0
Pumped Storage	1680	1295	7	0	7	0	0	0
Storage Hydro	720	1816	6	0	6	0	0	0
Baseload Hydro	800	4408	7	0	7	0	0	0
IPPs	2140	11923	0	655	655	14	20	1226
CC	800	2046	3	91	94	4	6	808
Total Existing	27925	126309	638	3077	3715	378	178	15962
IGACC	800	6181	62	115	177	7	1	2160
ACC	3000	18869	76	716	792	0	3	2967
ACT	1680	147	2	9	11	0	0	54
Biomass	200	1524	19	39	58	0	2	0
Refuse	72	553	31	0	31	3	3	77
Total New	5752	27274	190	879	1069	10	9	5258
Grand Total	33677	153583	828	3956	4784	388	187	21220

the utility additions to the resource mix. New refuse plants of 72 MW and 200 MW of biomass-fired plants would be added to the 600 MW of committed new independent power producer capacity. Finally, thermal purchases of 550 MW and purchases from Hydro Quebec totaling 2100 MW would fill out the 2005 supply mix. Total capacity would grow by 30 percent, from 25,900 MW to 33,677 MW.

The columns in Table III.1 distinguish between capacity additions labeled "CELT," "NEGC likely" and "NEGC base case." In all scenarios developed in subsequent chapters, we consider the 1,280 MW of "CELT" additions and the 2,472 MW of "NEGC likely" additions as already committed. The remaining 5,400 MW of "NEGC base case" additions are treated as discretionary.

Table III.2 shows UPLAN modeling results of the NEPOOL system in 1990 and 2005 broken down by plant categories. Generation, total production cost with its fuel and O&M components, and emissions of SO_2, NO_x and carbon (C) are all shown in the table. For the 1990 system, nuclear plants supply one third of the total energy, with oil steam plants providing the next largest share (about one quarter), followed by coal steam plants which provide half again as much energy as the oil plants, with the remaining resources making up the balance. Production cost in 1990 totals $2720 million. In the same period, the system is predicted to emit 422 kilotons of SO_2, 189 kilotons of NO_x, and 17078 kilotons of C. These 1990 results were benchmarked to recent modeling of NEPOOL (Stillinger, 1991) to within 5% on generation by fuel type and 10% on emissions (see Appendix B).

For the 2005 NEGC reference case, existing coal and nuclear plants generate the same amount of electricity as in 1990, but oil plant output falls by 20% due to a lower ranking in the dispatch order brought on from a relatively high price escalation of oil. Hydro purchases imported from Canada provide energy on a par with new gas ACCs, which in turn are comparable to that of NEPOOL's coal plants. Total production cost for this generation is $4784 million (expressed in 1990 dollars). Emissions of the acid rain precursor gases falls somewhat over 1990 due to the displacement of oil plant generation by the newer, cleaner units in the system. However, carbon emissions rise by 25% with these same "clean" units contributing most of the increment. Note that total generation in both years exceeds the forecast demand for electricity, the reason being the losses associated with the use of pumped storage plants.

F. PRINCIPAL UNCERTAINTIES

A number of assumptions are built into the NEGC reference case and into the costs of alternative resources which are explored in the next chapter. These assumptions are subject to some measure of uncertainty, and will have a bearing on the results that follow, particularly with regard to the overall cost of carbon reductions. In this section, we identify the more critical uncertainties that will be treated in sensitivity analyses in later chapters.

1. Life Extension vs. Retirement

As shown in Table III.1, the NEGC reference plan assumes no more than about 1,375 MW of existing plant retirements by 2005. This is about 5 percent of existing capacity. By contrast, about 9,600 MW of existing capacity will have reached or exceeded its book life in 2005, and 14,900 MW in 2010 (see Chapter IV, Table IV.7, and subsequent discussion).

Nuclear plant retirements

These NEGC retirement assumptions are quite optimistic, notably with respect to nuclear life extension. Nuclear life extension implies specific policy action by the federal Nuclear Regulatory Commission (NRC) to permit license renewal, and to make such life extension feasible at small cost.[4] Uncertainty about the safety of life extension for existing nuclear

[4] This treatment in the NEGC case stems from the fact that the replacement of nuclear capacity reaching its licensed life around the 2005/10 period is not explicitly addressed in the 1990 CELT forecast on which

plants may lead to regulatory action that will make this option unavailable or uneconomical. As of 1991, an application for life extension for New England's oldest reactor, the Yankee Rowe plant in Massachusetts, has been denied due to concerns over reactor vessel embrittlement. The reactor was ordered closed after 31 years in service, and it remains uncertain whether it will ever reopen again. On account of this precedent, it is prudent to allow for the possibility that nuclear licenses will not be renewed.

Air pollution issues and fossil plant retirements

New England is currently faced with new requirements for SO_2 and NO_x reductions under the 1990 Clean Air Act Amendment (CAAA) and parts of the region have significant ozone-related and other air quality problems that may prompt state regulatory action beyond current federal requirements.

Increased public demands for air quality improvements could have bearing on utility life extension. Utilities in the region account for about three quarters of sulfur dioxide emissions, and for roughly 30 percent of NO_x emissions (HBI 1991). Depending on what new regional air quality goals are formulated, it may turn out to be most economical to retire the dirtiest oil- and coal-fired plants, rather than life-extending them and retrofitting them with control technology.

Whether life extension becomes uneconomic or not based on regional air pollution concerns depends on the cost of control retrofits, which, in turn, depends on the amount of emission reductions sought. The supply curve of SO_2 and NO_x reductions for the region is not known. In the most favorable case, New England utilities would be able to rely on the cheaper (but less effective) control technologies (such as fuel switching for sulfur dioxide, and combustion modifications for nitrogen oxides), or would be able to buy sufficient allowances from industries within the region and utilities and industries outside the region.

In this scenario, life extension would remain economical for most coal plants. Existing oil plants, on the other hand, could already lose their cost advantage over repowering even at modest retrofit cost.

Alternatively, state air quality goals might become much more stringent and might restrict the use of out-of state offsets. In that case, the quantity of emission reductions required from within the region might become larger than available low-cost reductions. To achieve desired levels of emission clean-up, utilities might then be forced to retrofit existing boilers with expensive control technologies (such as scrubbers based on wet flue gas desulfurization for sulfur dioxide and selective catalytic reduction for nitrogen oxides). This could make many existing plants more expensive to run than repowering them with gas ACCs.

A "revealed preference" for much more stringent emission controls can be seen in the 1990 order of the Massachusetts Department of Public Utilities (MADPU 1990), which establishes pollutant-specific monetized externality surcharges or adders for air emissions from new power plants.[5] As shown in a recent analysis (HBI 1991), these adders are based on the most effective (and therefore most expensive) control technologies. These

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the NEGC analysis was based. The NEGC environmental subcommittee recognized this issue and suggested that the replacement of nuclear capacity be modeled in LBL's analysis.

[5] New England's air pollution control associations are considering new definitions of reasonably achievable control technologies (RACT) for power plant retrofits.

would be required if very large emission reductions were to be realized in the region. If applied to typical existing plants, such retrofits could raise the cost of power enough to make new gas ACC plants a more economical option (see Appendix D and G).[6]

Finally, life extensions cannot be used indefinitely, and NEPOOL's reliance on life extension in its 1990-2005 reference plan does not permanently solve the cost issue associated with existing-plant replacement. It merely shifts these costs to a period that is beyond our analytical time horizon.

2. Fuel Prices

Fuel prices used in the modeling were adopted from NEPOOL. From this source, oil and gas prices were forecast to escalate by more than five percent per year in real terms, for each of the next 15 years. This rate and duration of real price escalation is unprecedented in the history of fuel price developments since the 1973 oil crisis. Moreover, a recent comparison of forecasts showed substantial variation in gas prices in particular, several at escalation rates much lower than NEPOOL's (EIA, 1991). The lowest gas price forecast in this compilation was based on the expectation that improved drilling technology would enable the recovery of more gas at less cost. In light of the importance of fuel prices on dispatch logic and choice of new generating technology, we examine a low gas and oil price trajectory that escalates at two percent in real terms as a sensitivity case.

These gas supply requirements raise two issues. One is the siting problem for new pipelines, and the other is the impact of gas demand on fuel prices. Here, two questions arise: are NEPOOL's GTF fuel price projections applicable to the levels of gas demand that would arise in our reference cases? And what gas price impacts relative to the GTF projections would be expected from carbon reduction strategies?

There is another more subtle dimension to the issue of fuel prices and that is the question of price feedbacks. Carbon reduction strategies will likely increase gas demand over presently envisioned NEPOOL plans. Predicting the impact from such an outcome is complicated by the fact that gas prices in New England are not mainly determined by New England gas demand, but by overall gas demand in North America. However, a policy of reducing carbon or acid rain emissions in New England's utility sector, even if initially undertaken unilaterally, would more than likely be followed by similar efforts elsewhere as part of a national-scale undertaking. This depiction could indeed involve a large perturbation in national gas demand, that in turn could have impacts on other fuel markets.

This level of analysis of fuel prices is clearly beyond the scope of this report. Given the ample uncertainties surrounding these issues, and the high gas price escalation rates already projected by NEPOOL, our choice of a single sensitivity of low price escalation would seem to suffice for the purpose of our analysis.

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[6] New, low-pollution policies are currently being negotiated between a utility and an intervener group in Massachusetts. As of mid-1991, the Conservation Law Foundation (CLF) of Boston, Massachusetts, and New England Electric System (NEES) had entered a collaborative process to arrive at a new resource plan that would address, among other things, reductions of emissions in existing power plants to help bring the region into compliance with ozone standards.

3. Costs of New, Unconventional Resources

In the next chapter we will identify resources available to New England with low carbon emissions. Though we rely solely on resources that are either commercially available today or would become so within the time frame of our analysis, their costs are uncertain because many of these resources have not been deployed in significant numbers.

Carbon reduction strategies must rely, to a significant degree, on unconventional resources while restraining conventional ones. They thus involve major shifts in the market shares of various conventional fuels and technology options. These shifts could affect technology costs and fuel prices in ways that go beyond the reach of conventional forecasting methods.

Different resource cost perspectives are routinely and legitimately employed in estimating the economic potential of low-carbon resources. For instance, several of these resources are currently being developed by non-utility investors. These investors often have a more short-term perspective on pay back periods, are less able to share technological and financial risks with ratepayers, and may have less access than utilities to low-cost capital. Thus, the transaction costs of mobilizing various low-carbon resource potentials can be quite high under status quo conditions, particularly if deployed on the scale that our scenarios will suggest.

Alternatively, policies that reduce transaction-costs or developer risks could, in turn, lower the cost of unconventional low-carbon technologies, merely on account of scale economies and accelerated learning. Specific R&D and commercialization incentives such as utility-sponsored "golden carrots" to manufacturers of more efficient end-use devices or set-asides for renewable generating technologies in competitive bidding are examples of proposed and emerging policies that could favorably influence technology costs.

This list of factors suggests that it behooves us to develop a reasonable uncertainty range of the costs of low-carbon resources. For this reason, we present two tiers of resource costs in the next chapter.

CHAPTER IV

LOW CARBON RESOURCES IN NEW ENGLAND

A. OVERVIEW

In this chapter we begin by presenting the range of resources explicitly considered in this analysis, and those that we intentionally neglect. This is followed by discussion of the carbon and acid rain precursor emissions characteristics of these resources. Next we describe the resource potentials we estimate for the New England region. Finally, we conclude the chapter by presenting our high and low cost estimates for the resources, scaled to several increments of utilization.

B. RESOURCES CONSIDERED IN THIS STUDY

The determination of overall carbon reduction costs should include all relevant resource options. Within the scope of the present study, the following resources were examined:

- End-use efficiency improvements (DSM);
- Fuel switching from electricity to gas in residential end uses (DSM);
- Conventional and advanced gas-fired utility-scale combined cycle plants (CCC and ACC);
- Gas-fired industrial gas turbine and combined cycle cogeneration plants in thermally optimized and PURPA-oriented configurations (GT, CC, PURPA-CC);
- Gas-fired packaged cogeneration plants based on internal combustion engines (IC), and combined cycle district heating (DH-CC) plants in the commercial and institutional sector;
- Conventional steam turbine (ST) plants, and advanced biomass-fired power plants based on biogasification gas turbine systems using (intercooled) steam injection cycles (BIG/STIG or BIG/ISTIG);
- Conventional (extraction-condensing ST) cogeneration plants and biogasification (BIG/ISTIG) biomass-fired cogeneration plants; and
- Conventional (constant speed) and advanced (variable speed) wind turbine plants.

For purposes of comparison, we also calculate costs for peaking turbines (CT), for nuclear light water reactors (LWR), conventional coal-fired plants (ST), and advanced atmospheric fluidized bed (AFB) and integrated coal gasification combined cycle (IGACC) plants. No potentials were assigned to these resources.

1. Commercial Status of Resource Options

With the exception of biogasification and variable-speed wind turbines, all low-carbon technologies considered in our study are currently commercially available. Advanced biomass and wind turbine technologies were taken into consideration for two reasons:

— Significant commercialization efforts for these technologies are currently under way in Europe, Japan, and the U.S.

— Policies to reduce carbon emissions in New England and elsewhere would likely accelerate the market introduction of these technologies.

Because current markets for biomass and wind power technologies are narrow, a carbon reduction strategy in the New England region alone could accelerate their development.

Biogasification technology is practically the same as that used in coal gasification plants, and its technological maturity can be seen as moving broadly parallel to that of IGACCs. Remaining technical issues and cost and performance data are referenced in Appendix J. Similarly, intercooled steam-injection gas turbine technology (ISTIG), which promises biomass-compatible scale at high efficiency and low capital cost, is considered near-commercial.

The commercialization of biogasification power technologies has been identified as a priority by the U.S. Department of Energy. Meanwhile, the utility commission of Vermont has an initiative to have a demonstration plant built in that state, and General Electric Company is planning to test biomass chip fuels for that effort in its turbine test facility in New York state.

In the case of variable-speed wind turbines, a major commercialization program is currently under way in the United States. This industry-financed project is jointly sponsored by Pacific Gas and Electric Co. (PG&E), Electric Power Research Institute (EPRI), and U.S. Windpower. It is scheduled to bring these turbines on the market by 1994. U.S. Windpower, the only integrated wind power developer and turbine manufacturer in the United States, is negotiating a site for a first 250 MW wind farm in Maine. This project would be based on variable-speed technology.

2. Other Low-C Resource, Control, and Offset Options

The above list does not include four options that could, in principle, contribute to overall reductions. These are photovoltaics, advanced nuclear reactors, carbon dioxide scrubbing from power plants, and sequestration of atmospheric carbon dioxide through tree planting.

Photovoltaics is neglected because this option is still further away from reaching cost-competitiveness than other renewables-based options. It may approach cost-competitiveness in certain niche market applications, but New England's insolation conditions are probably not sufficiently favorable to pioneer the adoption of this technology.

Advanced nuclear reactors are likewise under development, but present special difficulties. Reactor cost, safety performance, and waste disposal questions remain unresolved, and nuclear technology faces major regulatory and acceptance hurdles in New England. As a result, the technology is not likely to be able to make a significant supply contribution within the time horizon of this study.

In the context of the present study, neglecting these two resource options can be seen as a conservatism. The feasibility of reaching carbon reduction goals would be enhanced should PV or advanced nuclear technologies reach commercial viability in the future.

Carbon emission stack control and emission offset options present special problems of their own. Carbon scrubbing presents unsolved disposal problems for the captured gas. Tree planting could provide significant offsets under certain regulatory policies, but presents important accounting issues from a global point of view (Krause et al. 1989). Again, including these options could enhance the viability of CO_2 emission reductions.

C. CARBON BURDENS OF ALTERNATIVE RESOURCE OPTIONS

For the foreseeable future, a major portion of electricity supplies will continue to be fossil-based. Fortunately, the various fossil-fired electricity supply technologies show wide variations in their emissions of carbon per kWh of electricity generated (henceforth referred to as their carbon burden). Indeed, the range of variations spans a factor of four to six. This is a result of two factors:

1) Among fossil fuels, the carbon content of coal, oil, and gas varies by about a factor of two.
2) There are significant heat rate differences (of the order of 25 percent) between new and existing utility plants. When cogeneration technologies are included, heat rates vary by a factor of two to three across all fossil-fired generating options.

Because of this wide variation, fossil-based generation can itself contribute greatly to the achievement of carbon reduction goals. Moreover, a number of these low-carbon fossil-based generating options are also economically attractive. But before comparing carbon burdens of the major fossil-fired technologies, it is first necessary to clarify the accounting boundaries for quantifying emissions.

1. Emissions Accounting Conventions

Carbon emissions of power plant fuels can be defined in several ways:

— Direct carbon emissions at the power plant;

— Total power plant fuel cycle carbon emissions (direct emissions plus indirect emissions from the entire fuel cycle and from fossil fuel inputs used in manufacturing power plants and other utility system plant);

— Total emissions of carbon plus total emissions of other greenhouse gases, notably methane, on a carbon-equivalent basis.

— Total carbon or carbon-equivalent emissions plus corrections for emissions that are avoided outside the power plant fuel cycle.

The choice of the accounting system for carbon emissions (and for other environmental impacts) is an important policy issue. In this study, we use the following accounting conventions:

— Electricity carbon burdens are based on the direct fossil-carbon burdens of the input fuels only.[1]

— In the case of biomass-fired power generation, fossil carbon emissions are assumed to be reabsorbed during the growth of replacement biomass. The effective carbon burden of electricity from biomass plants is thus zero.[2]

— The carbon burden for cogeneration units takes into account the carbon burden of the displaced boiler fuel (see Appendix I). Depending on whether the carbon burden of the boiler fuel is higher or lower than the input fuel of the cogenerator, a credit or penalty is accrued.

The differences between this approach and other accounting conventions are quantified in Appendix D.

2. Direct Fossil Carbon Burdens Per Unit of Electricity Output

Table IV.1 and Fig. IV.1.show the carbon burdens per unit of electricity output of various generating options. The figures show that major carbon reductions can be obtained not only from renewables or nuclear power, but also from a variety of other sources. The relative effectiveness of carbon substituting thermal generating options can be summarized as follows:

Advanced gas-fired combined cycles (ACCs)

Relative to conventional coal and oil-fired plants (220-300 gC/kWh_e), electricity carbon burdens could be cut by more than 50 percent with advanced gas-fired central stations that achieve low carbon burdens of about 110-120 gC/kWh_e.[3]

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[1] As shown in Appendix C, a full emission accounting would increase C and C-equivalent burdens by only a few percent, or significantly decrease them in the case of landfill gas and refuse fuels.

[2] Biomass fuels are assumed to be obtained from replenishing sources such as wastes from forestry maintenance and harvesting, or from sustainably grown fuel plantations on land not currently used for slow rotation forestry. See Appendix K for discussion of refuse plant carbon burdens.

[3] This range refers to plants with firm (365 day) gas supplies or quasi-firm gas supplies (using distillate oil for 30 days per year).

Figure IV.1: Direct Carbon Emissions Burdens per Unit of Electricity Output

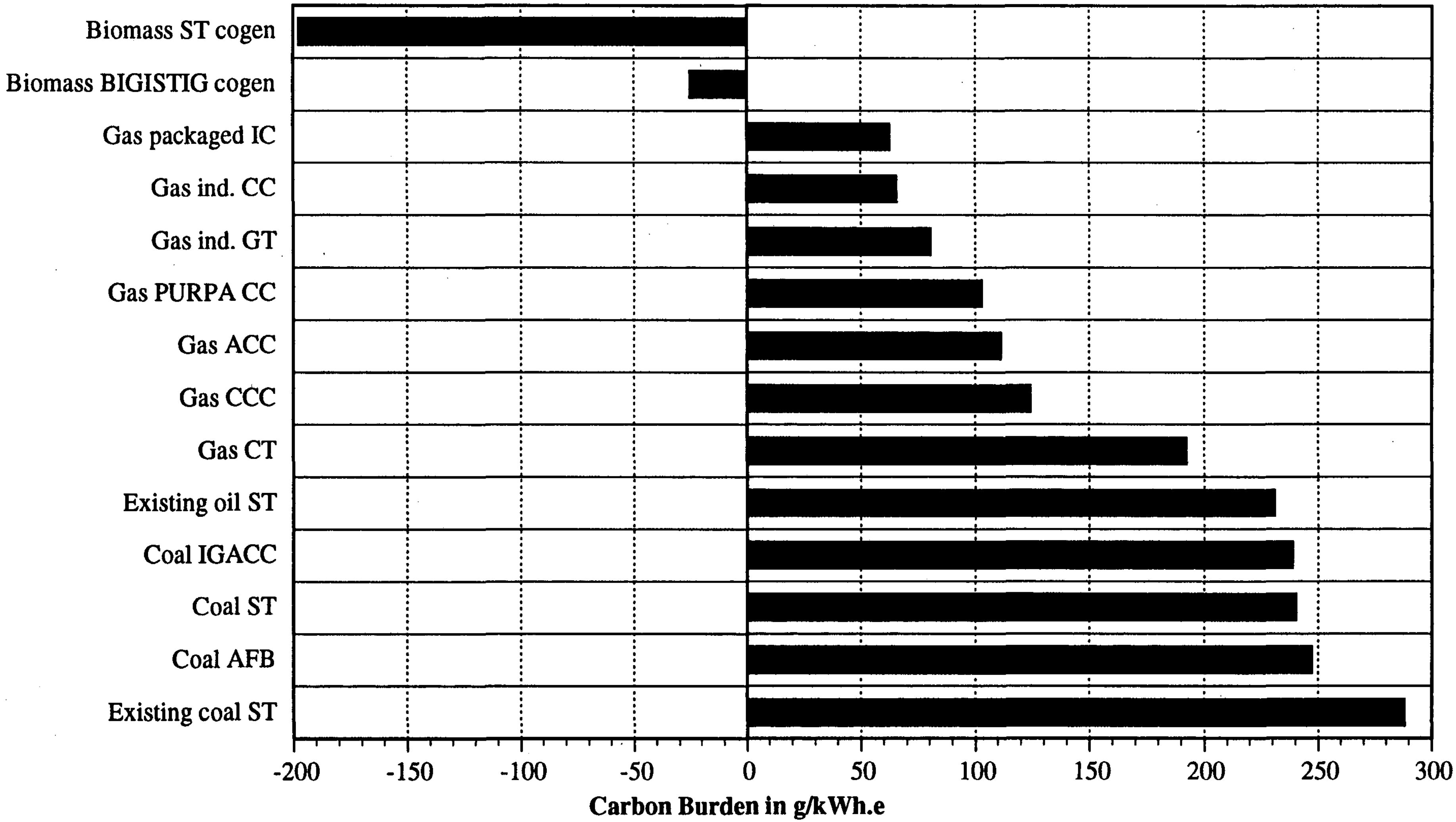

Table IV.1: Direct Emission Burdens per unit of Electricity Output.				
	Heat Rate *kWh.f/kWh.e*	*Carbon* *g/kWh.e*	NO_x *g/kWh.e*	SO_x *g/kWh.e*
Gas CT	3.84	192	0.625	0.004
Gas CCC	2.48	124	0.404	0.002
Gas ACC	2.22	111	0.362	0.002
Coal ST	2.69	240	0.501	0.734
Coal AFB	2.77	247	0.515	0.755
Coal IGACC	2.67	239	0.369	0.730
Nuclear LWR	3.10	0	0.000	0.000
Wind	1.00	0	0.000	0.000
Biomass ST	4.29	0	1.064	0.007
BIG ISTIG	2.38	0	0.591	0.004
BIG ISTIG Cogen	2.64	-25	0.105	-0.197
Ind. GT	1.71	64	-0.076	-0.764
Packaged IC	1.67	64	-0.060	-0.708
Ind. CC	1.93	76	-0.044	-0.716
PURPA CC	2.31	112	0.156	-0.139
Biomass ST cogen	1.67	-198	-0.810	-1.548
Ex. oil (1% S)	3.34	240	1.555	4.145
Ex. coal (0.7% S)	3.08	275	3.341	5.393

"Clean coal" technologies

Best new coal plants, including advanced integrated coal gasification IGACC and atmospheric fluidized bed (AFB) combustion technologies, offer gains of about 15 percent over typical existing coal plants.

Coal-fired cogeneration

In typical New England applications (i.e.,when the displaced boiler fuel carbon burden is, on average, close to that of oil),[4] coal-fired cogeneration plants are also not as effective in reducing electricity carbon burdens as gas-fired ACCs. Coal-fired cogeneration plants typically have net carbon burdens of about 160-220 g/kWh$_e$ for industrial systems with good heat loads.[5]

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4 See Appendix I, footnote for the fuel consumption mix.

5 Data not shown in the table and figure. See Appendix I and Krause et al. (1992).

Though coal-fired cogeneration can provide greater carbon savings than advanced coal-fired central station technology, this improvement remains significantly smaller than that of gas-fired cogeneration.

Gas-fired cogeneration

The carbon burden advantage of gas-fired cogeneration relative to gas-fired central stations depends strongly on the amount of thermal load associated with power production. Units that only satisfy or do not far exceed minimum PURPA efficiency requirements do not offer any carbon advantages over advanced gas-fired central stations.

On the other hand, the carbon burden of electricity from gas-fired industrial cogeneration and on-site, neighborhood, and district heating cogeneration plants designed for thermally optimized cogeneration (60-90 gC/kWh_e) can be lower than advanced gas central stations by 20 to 40 percent or more.

Relative to existing oil and coal plants, such gas-fired cogeneration can cut carbon emissions per unit of electricity by as much as 75 percent. This means that gas-fired cogeneration can provide most of the carbon burden reductions available from non-fossil electricity sources.

Biomass-fired cogeneration

Within the accounting framework used here, the most potent carbon substituting resource option is biomass-fired cogeneration when it displaces fossil fuels in thermal end uses. It results not just in reduced fossil-carbon burdens, but in negative net fossil-carbon emissions.

End-use fuel switching

The carbon burden of fuel switching from electricity to gas is that of the direct gas use including conversion losses, or about 55-75 gC/kWh_e. This is comparable to or lower than that of thermally optimized cogeneration.

3. SO_2 and NO_x Emissions Burdens

Table IV.1 also shows emission factors for the two major acid rain and smog precursors, i.e., sulfur dioxide and nitrogen oxides. The data show that NO_x emissions from new gas-fired central stations are lower by about a factor of five compared to existing oil plants, and by about a factor of ten compared to existing coal plants. (SO_2 emissions from gas plants are practically zero).

An even greater improvement is obtained from gas-fired cogeneration. Because these plants displace sulfur dioxide and nitrogen oxide emissions from boilers, they result in negative emission factors, as was the case for carbon emissions from biomass-fired cogeneration plants (see also Appendix I).

D. COSTS OF LOW CARBON RESOURCE OPTIONS IN NEW ENGLAND

1. Economic Assumptions

To make the cost relationships among conventional and low-carbon resources more transparent, we present in this Section levelized resource costs for a variety of technologies on a simple busbar cost basis. These figures are used for screening purposes only. Neither system integration costs nor supply curve effects are addressed at this stage. In Section E below, we then combine these busbar cost data with our resource potential estimates, which incorporate the effect of rising costs with increased resource utilization (a.k.a "supply-curve effect"). System integration aspects are accounted for in our production cost modeling (see Chapter III).

We distinguish between conventional resources and unconventional resources. We define conventional resources as all those technologies that are part of NEPOOL's own plan for utility investments. These are basically the various fossil and nuclear central station options, as listed in NEPOOL's Long-Range Generation Task Force data book (GTF 1989, henceforth simply referred to as GTF). For these conventional resources, we use a single cost estimate throughout our analysis. Thus, there are no low and high cost assumptions for conventional resources.

These latter cost estimates are based on GTF's fuel price projections for fossil and nuclear fuels. Other assumptions taken from that source are performance, capital, and operating costs for nuclear, coal-fired, and utility scale gas combined cycle plants, as well as other parameters, such as plant life and financial and tax parameters.[6]

Unconventional resources include demand-side management (DSM), fuel switching at the point of end use, cogeneration plants, and biomass-fired plants and wind power. Because they are based on physically limited energy flows or applications, we refer to them also as constrained resources. For these constrained resources, we develop, respectively, a high and low cost estimate. Our cost ranges are based, in part, on cost differences among individual technologies within one broad resource category (e.g., conventional versus advanced wind turbines for wind resources). Details can be found in Vol. II, Appendices E-F and I-L.

Costs are calculated from a societal perspective. In the case of demand-side resources, this means that the total resource cost test is applied, rather than the utility cost or non-participant test.[7] In all cost calculations, the real interest rate is 6.3%. Average taxes of 2.5 percent are assumed in calculating the fixed charge rate for utility investments. In the case of non-utility cogeneration and renewable generating sources, we apply the same real fixed charge rate as for utility investments, i.e., we treat them as though they were utility-owned. Because we use a discount rate without inflation, the busbar cost numbers we calculate are not directly comparable to similar numbers calculated by electric utilities, because utilities typically use a nominal discount rate.

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[6] See the Appendices for further details.

[7] See Krause and Eto (1989) for a definition of alternative least-cost tests.

2. Screening Comparison: Alternative New Electricity Resources

In Table IV.2, we show levelized busbar cost estimates for typical, stylized power plants and for average demand-side management applications. The index shown in the table relates the cost of each plant to that of a gas ACC plant. The generating costs in Table IV.2 are based on stylized typical plants in the spirit of the GTF planning assumptions and do not include soft costs or externality corrections. Dispatchable technologies are compared at their maximum capacity factor (equal to their equivalent availability), and at a 65 percent capacity factor.

Table IV.2: Summary of Busbar Costs for New Power Plants

Resource	*Busbar cost at maximum capacity factor 1990 ¢/kWh*	*Index*	*Busbar cost at 65 percent capacity factor 1990 ¢/kWh*	*Index*
Gas CT	15.4	2.74	15.4	2.53
Gas CCC	6.1	1.08	6.6	1.08
Gas ACC	5.6	1.00	6.1	1.00
Coal ST	6.7	1.19	7.5	1.24
Coal AFB	6.8	1.20	7.7	1.26
Coal IGACC	6.7	1.19	8.0	1.31
Nuclear LWR	10.2	1.82	11.3	1.85
Wind current (power class 6)	8.5	1.51	8.5	1.40
Wind advanced (power class 6)	5.6	1.00	5.6	0.92
Biomass ST	8.2	1.45	9.7	1.59
Biomass BIGISTIG	5.4	0.96	6.6	1.08
Biomass cogen BIGISTIG	3.9	0.68	4.8	0.79
Biomass cogen ST extr.cond.	5.3	0.93	6.7	1.10
Gas cogen ind. GT	5.1	0.91	5.6	0.93
Gas cogen packaged IC	7.6	1.35	8.3	1.37
Gas cogen ind. CC	4.6	0.81	5.1	0.84
Gas cogen PURPA CC	5.4	0.96	5.9	0.96
Average DSM efficiency	3	0.53		
Average DSM fuel switching	5	0.89		

Note:

(1) Wind capacity factor is 25 percent for conventional and 30 percent for advanced technology.
(2) DSM efficiency cost is mean of high and low cost for full potential, see App. E.

The table shows only one cost-figure for each technology option and capacity factor. We briefly discuss how these point values relate to the high and low cost estimates developed in Section E below.

In the case of wind and biomass, the high and low estimates are simply our cost estimates for advanced versus currently commercial technologies, respectively. For DSM and fuel switching resources, our cost range is mainly based on uncertainties in program administration costs. In Table IV.2, we show one estimate for each, which is the mean between the high and low assumptions for the DSM cost when averaged across the entire supply curve (see Appendix E).

Cogeneration is in many ways an established, conventional resource. Here, high versus low cost variations are based on whether capital cost credits are applied for displaced boilers. Table IV.2 shows our low cost estimates (net of boiler credit) for a number of cogeneration technologies.

Comparisons below are for screening purposes only, and are stated from a societal perspective. The following observations can then be made:

- Most demand-side resources and a significant portion of fuel switching resources at the point of end use are cost-effective against all conventional utility generating options.
- Among conventional central station technologies, gas-fired advanced combined cycles currently are the cheapest commercial resource option. Based on GTF assumptions, they are about 15 percent cheaper than either conventional or advanced coal plants,[8] and 45 percent cheaper than nuclear plants.
- Gas-fired industrial cogeneration plants (at 65 percent capacity factor for thermally optimized systems and at maximum capacity factor for the PURPA-CC) can match or slightly exceed this 15 and 45 percent cost advantage over coal and nuclear plants.
- Gas-fired district heating/cooling ACC plants could be similarly attractive. Packaged cogeneration systems for on-site use in buildings are still significantly more expensive, although expanded markets could reduce their costs.
- Conventional wind turbines and biomass-fired plants relying solely on commercial wood chips are not nearly cost-competitive with gas-fired ACCs. They are cheaper only than nuclear reactors.
- Advanced plants based on variable-speed wind turbines and biogasification ISTIGs would be cost-competitive with gas ACCs and could even offer a cost advantage.[9]

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[8] Cost and performance estimates for ICGACC coal plants are in flux. Larson (1991) estimates capital costs for ICGISTIG designs that are 33 percent lower than GTF assumptions. This would make that coal-fired technology about 10 percent cheaper than gas ACC plants. However, gas-fired ISTIG and chemical recuperation cycles are estimated to be still cheaper, so that the overall ranking as stated here would be retained.

[9] The capital cost assumed here for BIGISTIG technology is more than 40 percent higher than the cost calculated by Larson (1991) for commercially mature BIGSTIG technology. Larson also calculates costs for IGACC technology which are higher than the BIG/ISTIG estimates but significantly lower than the GTF assumptions for IGACCs. To make the two data sets internally consistent, the ratio of IGACC to

- A very low-cost option relevant to New England's paper industry are BIG/ISTIG cogeneration plants. When run in paper mills and partially fired with free process biomass wastes, they could be by far the lowest-cost generating option within the portfolio examined here.

Gas-fired ACC plants have been identified as the most economically attractive utility resource option in New England, subject to gas availability. In our analysis, they are therefore used as the reference marginal baseload resource for business-as-usual scenarios.

Screening Comparison: Existing Plants Versus New Gas ACCs

Having established the broad cost relationships among new resources, we now turn to a comparison of new gas ACC plants with existing plants. This comparison is of interest since such capacity retirement or repowering is also a carbon reduction option. In Table IV.3 and Figure IV.2, we show the relative cost of operating existing nuclear, coal, and oil-fired plants, and that of building and operating a new gas ACC plant.[10]

Table IV.3: Relative Cost of Building New Gas ACCs and Operating Existing Plants

	Capacity Factor	*Production Cost ¢/kWh*	*Levelized Capital Cost ¢/kWh*	*Total Annual Cost in 2005 ¢/kWh*
Nuclear	0.725	1.3	0.0	1.3
Coal	0.696	2.2	0.0	2.2
Oil	0.333	5.2	0.0	5.2
ACC	0.718	4.2	1.6	5.8

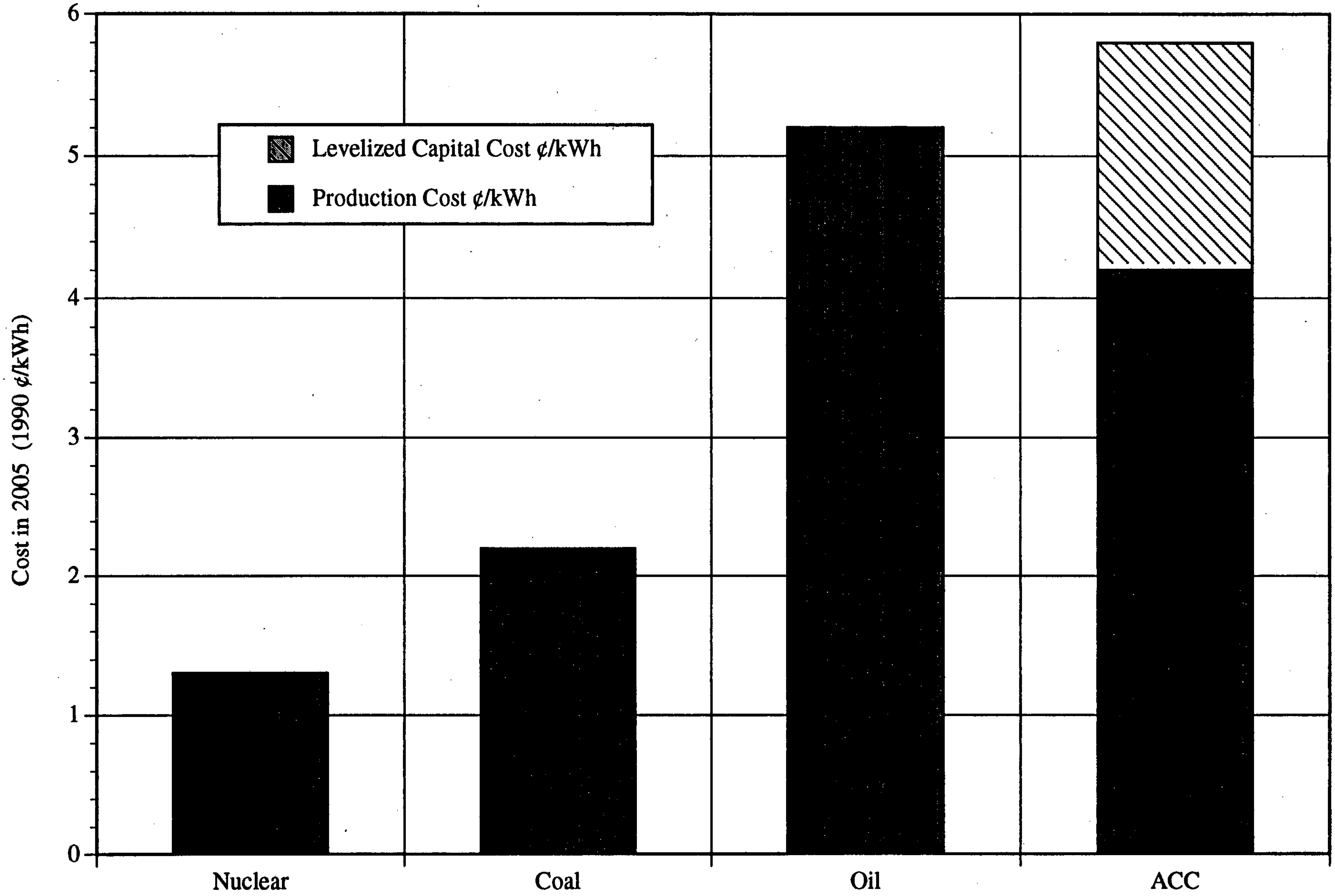
Notes:

(1) Capacity factor and production costs from 2005 reference case of NEGC with fossil and nuclear retirements.
(2) Fuel prices from NEPOOL GTF forecast, see Appendix C.
(3) Gas ACC capital cost from NEPOOL GTF, see Appendix G.
(4) Existing plants are assumed to be fully depreciated, life extension costs are neglected.

BIGISTIG technology costs from Larson was multiplied by the IGACC cost from GTF. This adjustment yielded a 44 percent increase over Larson's BIG/ISTIG estimates.

[10] For the purpose of this comparison, we use production costs and capacity factors that are based on reference case simulations for the year 2005 (see Chapter III for details). All costs are in 1990 dollars. Gas ACC capital costs are levelized. Existing plants are assumed to be fully depreciated. As a conservatism, the cost of life extension is neglected.

Figure IV.2: Cost of Operating Existing Plants Compared to Building New Gas ACC's



Our calculations show an important relationship: existing oil plants cost more to operate than new gas ACCs. Production costs per kWh for a gas ACC are a full cent lower than those of the average oil plant.[11] This fuel cost saving compensates for much of the additional capital cost of the ACC. The remaining cost differential could vanish if acid rain emission controls on existing plants were tightened or if externality surcharges were added. Given these consideration, existing oil plants could be replaced or repowered with more efficient and much cleaner gas-fired combined cycle plants for only a small direct cost, and possibly at a net economic benefit.

By contrast, replacing existing coal or nuclear plants with new gas ACCs would cost several cents per kWh. In the case of coal plants, more stringent pollution control requirements or monetized surcharges for acid rain and other emissions would narrow the cost differential relative to the gas ACC. But much larger externality penalties would be required to approach parity than in the case of existing oil plants (see Chapter V for a more detailed discussion).

Screening Comparison: Unit Cost of Carbon Reductions

As a screening tool for identifying low-cost carbon reduction strategies, we use the above busbar costs and carbon burdens to calculate a cost of avoided carbon (CAC). This index is obtained by dividing the carbon savings relative to a gas ACC by the busbar cost difference relative to a gas ACC.

Figure IV.3 and Table IV.4 show this index for a number of new low-carbon resources, and also for the case where new gas ACCs displace existing oil or coal plants. It is apparent that the various resource options fall into several distinct groupings when evaluated in terms of the CAC index:

- Gas-fired cogeneration, DSM efficiency improvements and fuel switching are clearly in a league of their own. Their cost of avoided carbon emissions is strongly negative, i.e., for every ton removed in this manner, money is saved in addition to reducing emissions. The cost of carbon reduction strategies will be minimized or could be negative if emphasis is placed on these resources.
- Advanced biomass-fired and wind technologies could reduce carbon emissions at moderately negative net cost.
- Retiring existing oil plants and replacing them with gas ACCs yields carbon savings at moderate cost.
- By contrast, displacing existing coal plants in favor of gas ACCs, or displacing gas ACCs with conventional biomass and wind turbine plants yield carbon reductions at significant extra cost. New nuclear reactors do even worse.

Note that this C/$ ranking cannot be used directly for resource planning purposes, for two reasons. First, it substitutes one criterion (i.e., carbon reductions) for the multiple

[11] Fuel prices are taken from Appendix C. The one-year fuel prices for 2005 can be used for comparisons because oil and gas prices are projected to escalate broadly in parallel.

Figure IV.3: Costs of Avoided Carbon Emissions by Resource

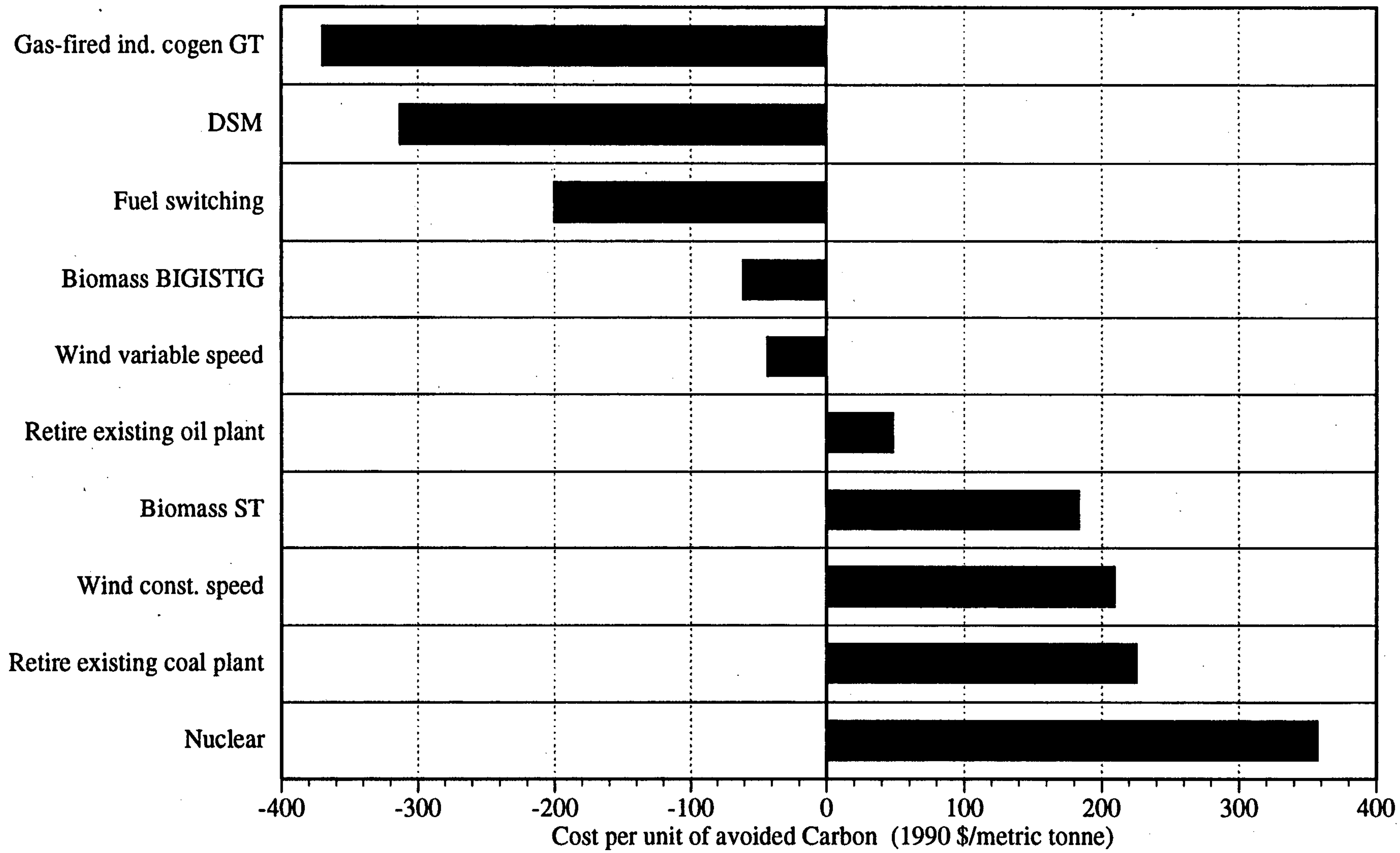


Table IV.4: Costs of Avoided Carbon Emissions Relative to Gas ACCs			
	Difference in C-burden rel. to gas ACC g/kWh.e	*Difference in levelized cost rel. to gas ACC $/kWh*	*Cost per unit of avoided C $/ton*
DSM	115	-0.036	-313
Fuel switching	55	-0.011	-200
Gas-fired ind. cogen GT	27	-0.01	-370
Biomass BIGISTIG	115	-0.007	-61
Wind variable speed	115	-0.005	-43
Retire exist. oil plant	125	0.006	48
Retire exist. coal plant	160	0.036	225
Biomass ST	115	0.021	183
Wind const. speed	115	0.024	209
Nuclear	115	0.041	357

Notes:

(1) Reference system is gas-fired ACC at 65% capacity factor
(2) Costs and carbon burdens from Tables IV.1-IV.3

objectives that must be observed in real world resource planning. Second, it is a comparison at a fixed capacity factor and therefore does not capture the interaction of resources when dispatched in a real system. For these reasons, we employ production cost modeling in more detailed analyses in Chapters V and VI.

E. POTENTIALS OF LOW CARBON RESOURCES IN NEW ENGLAND

In this Section, we summarize the key assumptions in our resource potential estimates in the discussion below. Detailed derivations of our resource potential estimates are provided in Appendices H-L. The various potentials are listed in Table IV.5 along with their busbar costs. Where multiple technologies were analyzed, we show weighted averages. Costs are given as a function of the level of resource mobilization to indicate supply curve effects. A simplified supply curve plot, which is based on reference case fuel prices, is shown in Figure IV.4

1. End-Use Efficiency (DSM)

Our estimate of DSM resources covers the commercial, residential, and industrial sector and relies almost entirely on currently available technologies. The resource estimate is derived from an end-use based analysis of the technical potential of these technologies in New York (Miller, 1989). In adapting the technical savings potential for New York to New England, the end-use savings of the former were applied to end-use shares of the

Table IV.5: Summary of Constrained Low-Carbon Resource Potentials in New England (reference fuel prices)					
	Potential	*C-burden*		*Ave. cost in 1990 ¢/kWh.e @ utilization of*	
	TWh.e	*gC/kWh.e*	*25%*	*50%*	*75%*
DSM (utility programs & standards)	*44.8*	*0*			
low			1.0	1.9	2.3
high			2.8	3.9	4.4
Fuel switching, end-use	*9.0*	*60*			
low			4.6	4.6	4.8
high			5.7	5.7	6.0
Cogeneration	*21.5*	*88*			
low			5.0	5.0	5.0
high			6.0	6.0	6.0
Biomass-fired generation	*22.0*	*0*			
low			8.2	6.8	6.3
high			8.9	8.9	8.9
Wind power	*12.7*	0			
low			8.5	7.1	6.8
high			9.9	9.0	9.3
Total/ave	**110**	**22**			
low			**4.4**	**4.3**	**4.4**
high			**5.7**	**6.1**	**6.3**
Ratio low-C resources/GTF gas ACC		*0.19*			
low			*0.78*	*0.77*	*0.78*
high			*1.02*	*1.09*	*1.13*

Notes:
(1) Cost figures are cumulative average costs in 1990 $.
(2) Gas ACC cost based on NEPOOL GTF projection of firm gas price.
(3) DSM potential is in addition to 2005 DSM contribution of 8 TWh as projected by NEPOOL.
(4) DSM costs include program administrative costs, verification and O&M costs, and T&D credits
(5) Costs of Biomass and wind decline in the higher utilization cases because of the use of more cost-effective advanced technologies to achieve higher penetrations.

latter. With this approach, the electricity savings potential for New England is found to be 33 percent. The technical potential in 2005 represents about 53 TWh relative to NEPOOL's 1990 CELT gross load forecast for 2005.[12] In the 1990 CELT report, about 8 TWh are forecast to be implemented by the utilities. We estimate that the net potential additional contribution from DSM options is thus about 45 TWh.

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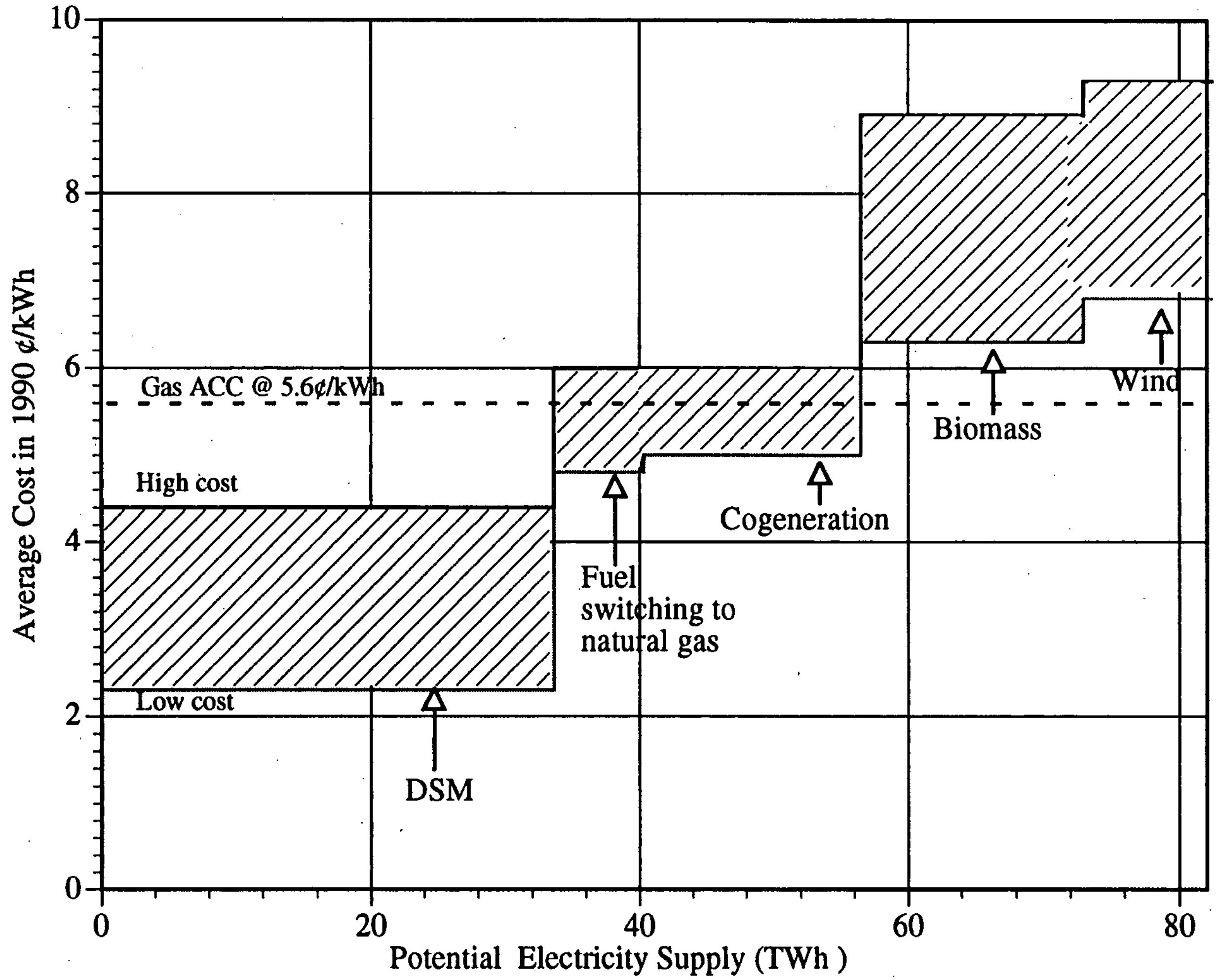
[12] The 1990 CELT report is used as a reference in this study. The gross load forecast (without DSM) was 160.45 TWh. The 1991 CELT report predicts lower growth in electricity demand, partly as a result of a 2 TWh increase, relative to the previous forecast, in the DSM contribution in 2005.

Figure IV-4: Supply Curve of Low-Carbon Resource Potentials in New England (Potentials and Costs @ Utilization of 75% Under Reference Case Fuel Prices)



(1) Levelized costs calculated using a real discount rate of 6.3%.

(2) ACC = Advanced combined cycle plant (natural-gas fired)

This analysis assumes that half of the savings would be implemented through utility DSM programs. The other half would be realized through efficiency standards, and to a small extent, market forces. The breakdown of DSM resource acquisition by means of implementation draws upon a follow-on study in New York, which estimated that the achievable portion of technical conservation potential was 80% and that it could be obtained in equal shares through utility program and standards approaches (Nadel, 1990). The perspective taken in this study is that utility DSM programs establish initial markets and standards complete the penetration of efficient technologies.[13] The advantage of phasing in standards to supplant utility programs in a given market niche is that the implementation costs of standards are often lower than the administration and savings verification costs associated with utility programs where customers participate voluntarily in response to incentives.

DSM load factor

Current DSM plans of most New England utilities are strongly geared toward reducing peak loads.[14] As more emphasis is placed on energy savings and as larger fractions of the DSM efficiency resource are mobilized, the average Conservation Load Factor (CLF)[15] of DSM programs increases. Even then, DSM resources could have peak-shifting impacts, depending on the mix of end-uses and end-use loadshapes. Current loadshape data for individual end-uses, and projections of future time-use patterns of customers are too uncertain to reliably predict these impacts fifteen or twenty years hence. As a default, we assume that by 2005, the average CLF of the DSM resource contribution is equal to the system average load factor as forecast by NEPOOL. DSM resources therefore do not change the load characteristics of the NEPOOL system in the forecast year.

Supply curve effects

The rising DSM costs shown in Table IV.5 reflect the fact that projected costs increase as more of the technical potential is mobilized (otherwise known as a "supply curve" effect). In practice, DSM resources are not necessarily mobilized in this cost-ordered manner. For example, packages of measures and packages of programs may be used to take account of opportunity costs. Such packaging may become more common as utilities seek to capture a larger fraction of DSM resources in a shorter period of time by increasing per-customer savings.

The impact that rising resource contributions from DSM efficiency improvements have on cost is difficult to predict for other reasons. Initially, program administration costs are

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13 This characterization of standards places them in a "technology forcing" role, as opposed to a role of eliminating the most inefficient cases.

14 As shown by Connors and Andrews (1991), peak-load oriented DSM can delay the entry of cleaner generating plants into the system when retirements of existing, high-emission plants are small. In that case, DSM can lead to less than expected emission reductions relative to the reference case without DSM. In the present analysis, this effect is not important for two reasons. First, the reported effect of DSM on emissions does not apply to carbon, since the carbon burden of displaced kWh from different plants is quite homogeneous. Second, we deviate in our analysis from NEPOOL's very limited retirement plans and analyze various retirement scenarios for existing resources. Such retirements bring low emission resources into the supply mix at the same time that demand growth is reduced through DSM.

15 The Conservation Load Factor is defined as the average annual load savings from a conservation measure, divided by the peak load savings. See Koomey et al. 1990a and 1990b for details.

often high. Learning effects reduce program administration costs over time while rising penetration levels may increase the cost of reaching remaining customers.

The high and low estimates in Table IV.5 for Net DSM costs differ by about 1.8-2.1 ¢/kWh. This range mainly reflects uncertainties in program administration costs, costs associated with the verification of savings, and transmission and distribution (T&D) cost credits as outlined in Table IV.6 (reproduced from Appendix E). In the high-cost case, program designs remain as expensive as in the first generation of utility programs. Similarly, the cost of guaranteeing savings remains as high as currently reported by energy service companies. T&D credits, meanwhile, are limited to avoided energy losses. In the low case, learning effects reduce program administration costs while the cost of

Table IV.6 Components of DSM Costs (1990 ¢/kWh)

	Low	*High*
DSM Technology Cost		
@ 25% utilization	*1.2*	*1.4*
@ 50% utilization	*2.1*	*2.5*
@ 75% utilization	*2.5*	*3.0*
Program Administration Cost (weighted)	*0.2*	*0.6*
Utility Programs	0.3	0.8
State Standards/Codes	0.1	0.4
Verification and O&M Cost (weighted)	*0.4*	*1.0*
ESCO Bids	1.0	2.0
Utility Programs	0.5	1.0
State Standards/Codes	0.15	0.5
TOTAL GROSS DSM Resource Costs		
@ 25% utilization	*1.85*	*3.0*
@ 50% utilization	*2.75*	*4.1*
@ 75% utilization	*3.15*	*4.6*
Transmission & Distribution Credit	*-0.8*	*-0.2*
TOTAL NET DSM Resource Costs		
@ 25% utilization	1.05	2.8
@ 50% utilization	1.95	3.9
@ 75% utilization	2.35	4.4
Shareholder financial incentives (for rate impact calculation only)	*0.24*	*0.35*

(1) For administrative costs, standards-based costs and program-based costs are weighted 1:1.

(2) For verification and O&M costs, energy service company (Esco) bid costs are given a weight of 25%, utility program costs are given a weight of 25% and efficiency standards costs are given a weight of 50%.

(3) All costs calculated using a 6.3% real discount rate. Such costs are not directly comparable to DSM costs calculated using nominal discount rates (which include inflation), and care should therefore be used in making such comparisons.

guaranteeing savings is lowered through more efficient verification techniques and greater utilization of the utilities' special capabilities to monitor customer demand at low cost.

T&D credits are based on marginal cost filings by various utilities in the Northeast, as well as a recent, state-of-the-art, bottom-up analysis by Central Maine Power (CMP). The value of the T&D credit found in these analyses is about 50% higher than the credit we use in our optimistic case. We chose this conservative value because of the considerable uncertainty surrounding the avoided T&D calculation. As more experience is gained in measuring actual avoided T&D costs, we expect that the uncertainty in the size of avoided T&D costs will be reduced. Because of the importance of this and other parameters to the amount of rate impacts from the carbon reduction portfolios, it is imperative that more detailed research be conducted on this topic.

At the bottom of Table IV.6 we show the size of shareholder incentives needed to make the utility an enthusiastic participant in mobilizing the DSM resource. We consider these incentives to be a transfer payment and hence ignore them in the net cost calculation, but include them in the calculation of rate impacts.

Levelized DSM costs as shown in Table IV.6 are based on the 6.3 % real discount rate assumptions used in our analysis. Most utilities report the costs of DSM programs based on the use of a nominal discount rate (including inflation). If inflation is 5%, then the nominal discount rate would be 11.6%. Assuming a 15 year lifetime for DSM investments, the gross cost of conserved energy (CCE) for DSM using the nominal discount rate would be 37% greater than that calculated using the real discount rate.[16] For example, the gross DSM cost for 50% utilization in the low technology cost case would change from 2.7¢/kWh to 3.7¢/kWh using the nominal discount rate to calculate the CCE. Care must therefore be used in comparing our estimates of DSM costs to the nominal costs often used by utilities.

2. Fuel Switching

We estimate that the maximum fuel switching potential from electricity to gas or propane at the point of end use is about 9 TWh_e. This estimate covers only residential water heating and clothes dryers. Fuel switching opportunities in space heating could increase this figure by about 50 percent. They are neglected in our analysis because of data uncertainties. Opportunities in the commercial sector could increase this figure further. However, the carbon saving benefits of fuel switching in air conditioning, which represents the largest potential in that sector, is presently uncertain (see Appendix F and I).

Water heater conversions are the more economical portion of the fuel switching resource. An estimated 80 percent of New England's 1.57 million electric water heating customers currently have access to natural gas. With growing availability of gas supplies in the region, this figure could rise further. Propane could be used by other customers.

[16] The cost of conserved energy is calculated using the capital recovery factor formula (CRF), which is defined as (r (1+r)^n)/((1+r)^n -1) where n is the lifetime and r is the discount rate. The CRF is multiplied by the capital cost to calculate the annualized capital cost, and this annualized cost is divided by the annual energy savings to calculate the CCE.

These estimates are no more than crude assessments of the technical-economic potential. They do include an estimate of adminstrative/program costs, but do not address the customer acceptance issues surrounding the use of propane gas, or the limited (significantly less than 100 percent) fuel switching penetration that utility programs might achieve. Also, the size distribution of per customer electricity consumption is likely to make a portion of the total resource potential more expensive than indicated by our average figures.

Supply curve effects

The high and low cost figures shown in Table IV.5 reflect both uncertainties in the average savings and costs per participating customer, and uncertainties in program administration costs.

3. Cogeneration

Our cogeneration potential refers to thermally optimized systems rather than systems designed to meet minimum PURPA efficiency requirements only. It is derived from projections for New England as developed by the Gas Research Institute (GRI). The institute's market potential estimates are based on the same steep real escalation of gas prices as assumed by NEPOOL's long-range generation planning task force, and GRI assumes flat or declining real avoided costs and industrial electricity rates.

Several scoping calculations were performed to determine how the GRI potential, which includes market shares for oil- and coal-fired projects, could be adapted to a carbon reduction regime in which coal and oil would no longer be viable cogeneration fuels (see Appendix I). Our preliminary calculations indicate that no significant busbar cost or resource potential penalty would be incurred if gas cogeneration were substituted for coal- and oil-fired cogeneration, provided that gas is available. However, the incentives for third party project developers to pursue cogeneration projects could be reduced, because thermally optimized systems would be smaller than those designed for minimum PURPA standards.

Our high and low cost estimates for cogeneration resources differ by about 1¢/kWh. The low case is a reference cost. In the high case, capital cost credits for avoided boiler investments are small, or site- or process-related problems increase costs.

5. Biomass-Fired Generation

Biomass fuel potential

Our estimate of the biomass resource potential is based solely on biomass process wastes in the lumber and paper industry, and on biomass chips from forest residues (tree crowns, branches, culling trees, thinnings, dead tree removal) that become available during routine commercial forestry operations and are largely unused today. Biomass fuel plantations based on hybrid poplar or similar species are not considered in our estimate. This exclusion reduces the overall fuel resource potential but also greatly limits ecological risks.

The long-term sustainable fuel residue potential is estimated on the basis of an in-depth "Forest of the Future" modeling study for the state of Maine (see Appendix J). Maine's resource potential was extrapolated to the New England region as a whole under conservative assumptions that reflect the lower share of commercially managed holdings in the forestry industry of the other states. Further research should be done on the region-wide sustainable forest residue potential.

Future prices for biomass chip fuels are estimated based on inputs from Maine forestry and paper industry experts about potentially competing uses, revenue impacts for land owners, the impact of increased paper recycling on biomass chip prices in the pulp and paper markets, and the structure of the biomass chip industry (see Appendix J). Taken together, these factors suggest stable real residue chip prices over a wide range of resource utilization.

Biomass power potential

The electricity production potential associated with the fuel resource is different for conventional and biogasification technology. Advanced biogasification/ISTIG technology doubles the total electricity resource obtainable from available fuels, from 13 TWh_e to 26 TWh_e. In addition, biogasification promises substantially lower costs.

For the purpose of our scenario development, we assume that a certain portion of the fuel resource would be exploited by conventional steam turbine plants (including already existing ones) and by biogasification plants using conventional gas turbines rather than ISTIG technology. Because the efficiency of these plants is lower, the weighted average power potential is estimated as 22 TWh. This figure includes biomass-fired cogeneration.

Supply curve effects

The cost structure of this resource potential as shown in Table IV.5 reflects the shift from conventional to biogasification technology. The cost for the first 25 percent resource increment is shaped by the high cost of the steam turbine technology and by similarly high initial costs for biogasification technology. Differences in costs between the high and low case are correspondingly modest.

In the low case, further market penetration leads to the same cost reductions for biogasification technology that are widely predicted for coal gasification. In the high case, biogasification technology continues to be as expensive as steam turbine technology as a result of unforeseen technical problems.

Refuse-burning power plants

New England has been in the forefront of developing trash-to-energy power plants and produces about 3 TWh of electricity from that resource. In assessing the additional resource potential of this option, we took into account greatly expanded state government goals for recycling (typically 50 percent of total volume) as well as trends in the amount, composition, and heating value of total discards. On that basis, it appears that refuse plants could make only a moderate (about 1 TWh/yr) additional contribution by 2005.

6. Wind Power

Our wind power potential shown in Table IV.5 is a preliminary technical potential estimate based on U.S. wind atlas data compiled by Pacific Northwest Laboratories (PNL). The estimate is limited to high wind speed areas and is discounted to reflect major siting constraints: All environmentally sensitive lands, such as parks, monuments, wildlife refuges, and recreation areas are excluded, and so is all urban land, 50 percent of all forestry land, 30 percent of all agricultural land, and 10 percent of all range land. These exclusions eliminate two thirds of the technical potential wind resource in New England.

On that basis, about 13 TWh could be produced in the best wind density areas in New England. Advanced wind turbines (including variable-speed designs) could increase the power potential by about 15 percent on account of higher capacity factors. The technology would also lower the minimum required wind speed to achieve economical operation and could thus increase siting options.

Power development can be expected to concentrate initially on the most attractive sites (i.e., power class 6, see Appendix L), which constitute about one third of the estimated resource potential.

Siting issues

Significant power potentials can result from just a few highly productive wind resource sites. California's approximately 3 TWh of wind power production is located in just three sites. The Altamont Pass site is about 20 square miles in size and produces close to one third of the state total.

However, different environmental siting constraints can be expected to apply in New England. Wide open spaces such as those found in the West are rare in the region. Most of New England is forested, and some of the higher wind potential areas are in remote mountain areas. The advanced 300 kW wind turbines now being commercialized will be above the forest canopy and can be installed in forests with minimal disturbance to the timber cover, but transmission and road access issues must also be considered.[17]

Assessments of commercially attractive and feasible New England sites by a major commercial wind developer are now under way. Until such assessments have been completed and experience has been gained with the acceptance of the technology by New England's communities, the practical wind resource potential in New England remains uncertain.

Supply curve effects

It is plausible that New England wind farms will mainly be based on second-generation, variable-speed turbines. We assume that during the first 25 percent resource increment, that technology will still be undergoing technological maturation and will therefore show high costs.

In the low case, the technology is assumed to have declining costs as more capacity is installed similar to those observed for current generation technology. These will offset cost pressures from more remote and less favorable sites. In the high case, transmission access and remoteness costs are significantly higher than expected, and siting problems make some of the more attractive sites unavailable.

[17]We include an additional cost of $250/kW to wind plants to account for increased costs likely to be associated with such access issues.

F. POTENTIAL OF EXISTING CAPACITY RETIREMENTS

Under conventional resource plans, the bulk of air pollutant emissions in the year 2005 would arise from plants that exist today. This suggests that emission reduction scenarios should take into account options that are not currently considered for retirement of existing plants.

Any existing plant with unfavorable emission characteristics could be repowered[18] or retired at any time of its useful life. If the plant has not been fully depreciated, the impact on ratepayers would be higher For this reason, it is helpful to know the fraction of existing capacity that is fully depreciated, i.e., has already exceeded its book life. As defined by NEPOOL's generation task force (GTF), this book life is 39 years for nuclear plants, 35 years for coal, oil, and gas plants, and 25 years for peaking turbines. The book life for nuclear plants is almost the same as their licensed operating period, which is 40 years.

Table IV.7 shows existing capacity by type of plant, retirements as projected in the 1990 CELT report, and retirements that would result if the NEPOOL book life were made the basis for decommissioning existing thermal plants. Figures for both 2005 and 2010 are given.

The figures show that according to the CELT forecast, only 775 MW of thermal plants and purchases would be retired by 2005, out of an existing capacity of 25,900 MW. By contrast, thermal plant retirements based on the NEPOOL book life would be 9000 MW in 2005, and 14,280 MW in 2010.[19]

Of particular importance for this study is the fuel composition of the fully depreciated capacity. In 2005, more than 90 percent of the fully depreciated thermal capacity will be fossil-fired, and thus carbon intensive. Of the 6360 MW of nuclear capacity, only 600 MW or six percent would exceed its licensed operating period by that date. By contrast, 3230 MW (more than 50 percent of New England's nuclear capacity) would reach or exceed its licensed operating period if the planning horizon is extended to 2010. By that date, a quarter of all fully depreciated capacity will be low-carbon nuclear capacity.

The nuclear retirement issue is even more complex because of regulatory factors unique to nuclear reactors. While life extension and repowering are established practices for thermal plants, no such precedent exists for nuclear plants. Issues of reactor aging, possibly increased accident risks, unsolved waste disposal questions, and uncertainties about costs need to be taken into account.

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18 Repowering means rebuilding the entire power plant at an existing site while recycling only buildings, land, etc.

19 These figures are upper limit indicators only. They do not take into account the life extension and fuel conversion investments already made in some plants.

Table IV.7: Fully Depreciated Generating Capacity in New England, 2005-2010				
	1990 Capacity mix *MW*	*2005 capacity exceeding GTF book life* *MW*	*2010 capacity exceeding GTF book life* *MW*	*2005 capacity retirements 1990 CELT* *MW*
Coal steam plants	2850			
small	450	-450	-450	
medium	600	-600	-600	
large	1800	-1800	-1800	
Nuclear plants	6360			
small	2400	-600	-2400	
medium	1660		-830	
large	2300			
Oil steam plants	8800			
1950s	2000	-2000	-2000	-300
1960s	1800	-1800	-1800	
1970s	5000		-2500	
Combined cycle plants	400			
Peakers	1650	-1500	-1650	-225
Utility hydro	3100			
Storage Hydro	620			
Baseload Hydro	800			
Pumped Storage	1680			
Purchases	1100			
Thermal Purchases	250	-250	-250	-250
Hydro Purchases	500	-500	-500	-500
HQ Purchases	350			
QFs	1640			
Thermal QFs	1400			
Hydro QFs	240	-100	-100	-100
Total	**25900**	**-9600**	**-14880**	**-1375**
Index	*1.00*	*-0.37*	*-0.57*	*-0.05*

Notes:

(1) Book life as defined in NEPOOL GTF Handbook. (NEPLAN 1989)
(2) Book life is 35 years for fossil plants, 39 years for nuclear reactors, 25 years for peakers.

CHAPTER V

IMPLEMENTING CARBON REDUCTIONS THROUGH ENVIRONMENTAL EXTERNALITY SURCHARGES

A. OVERVIEW

In this chapter, we explore what happens when the environmental externality surcharges adopted in Massachusetts are applied to the New England power system in several different planning modes. For each case we show how the Massachusetts adders would change the relative costs of alternative resources. Specifically, we discuss the use of adders when limited to application to new plants, as is the case under the current order in Massachusetts. Next, we calculate the impacts when the same adders are applied to retirement decisions of older, existing plants. Finally, we present the use of adders as a modifier to the conventional economic logic used in dispatching power plants, and juxtapose these results to dispatch on the basis of least-emissions.

B. THE ADDER SYSTEM ADOPTED IN MASSACHUSETTS

A number of state public utility commissions in the U.S. have begun to implement or consider monetized externality surcharges (adders) for air emissions and other environmental impacts from power plants (Cohen et al., 1990). These environmental externality adders are charged for emissions not already avoided by current emissions standards. They are intended to give utilities an incentive to reduce emissions beyond current requirements, including, in some cases, currently unregulated emissions such as carbon dioxide. The Massachusetts Department of Public Utilities (MADPU) recently adopted a specific set of surcharges that the state's utilities are required to use in analyses and decisions regarding development or procurement of supply and demand resources (MADPU, 1990 and Shimsak et al., 1990). In the case of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), these surcharges reflect cost estimates for applying wet gas desulfurization and selective catalytic reduction. These technologies are the most effective currently available post-combustion control technologies for acid rain precursors, and afford reductions in excess of 95 percent for SO_2 and 80 percent for NO_x. For carbon dioxide (henceforth referred to and accounted for as carbon), the MADPU adder is based on the costs of sequestration through tree planting (Chernick and Caverhill, 1989 and Shimshak et al., 1990).

Table V.1 shows the values assigned to residual air emissions in Massachusetts.[1] Plant emission rates in lbs/MBtu fuel input are multiplied by an average plant heat rate in Btu/kWh and the MADPU system unit externality costs shown in Table V.1 to yield externality surcharges per unit output. Over a range of generation technologies approximately 95% of the total externality surcharges is due to three pollutants: sulfur dioxide, nitrogen oxides, and carbon. Therefore, externality adders used here are composed from emissions of these three air pollutants only.

Table V.1. MDPU Valuation of Air Pollutants

Pollutant	*($/lb)*
SO_2	$0.781
NO_x	$3.383
CO_2	$0.012
CH_4	$0.116
CO	$0.452
N_2O	$2.082
TSP	$4.103
VOCs	$2.787

Table V.2. MADPU Adders Applied to NEPOOL Resources

	Emission Rates (lbs/MBtu)			*Components of Total Externality Surcharges (¢/kWh)*			
Existing Resources	*SO_2*	*NO_x*	*C*	*SO_2*	*NO_x*	*C*	*Total*
Small Coal	2.4	0.8	57	2.1	3.0	2.7	7.8
Medium Coal	2.3	0.7	57	1.7	2.3	2.3	6.4
Large Coal	2.2	0.7	57	1.6	2.2	2.2	6.1
1950s Oil	1.1	0.6	44	1.0	2.3	2.1	5.3
1960s Oil	1.2	0.6	44	0.9	2.0	1.8	4.7
1970s Oil	0.8	0.3	44	0.7	1.1	2.0	3.8
CC	0.2	0.3	44	0.1	0.9	1.7	2.8
Peakers	0.1	0.5	44	0.1	2.4	2.6	5.2
Thermal Purchases	0.12	0.87	59	0.1	2.9	2.5	5.5
Thermal IPPs(1990)	0.44	0.56	22	0.3	1.9	0.9	3.2
New Resources							
Thermal IPPs(2005)	0.25	0.36	22	0.2	1.2	0.9	2.3
Adv.CCs	0	0.04	31	0	0.1	1.0	1.1
Adv. CTs	0	0.04	31	0	0.2	1.7	1.9
IGCC	0.18	0.04	57	0.1	0.1	2.2	2.4
Biomass	0	0.16	0	0	0.8	0	0.8
Refuse	0.8	0.6	18	1.0	3.1	1.2	5.3

Table V.2 contains the components of total environmental externality surcharges associated with those existing and new resources in the NEGC resource mix that emit air pollutants. Not surprisingly, existing coal plants receive the highest externality adders, with the older, smaller plants suffering a 7.8 ¢/kWh penalty, while the newer, cleaner, and more efficient

[1]These values are currently under review by the MA DPU.

large plants attract a lesser surcharge of 6.1 ¢/kWh. Thermal purchases, based on coal-fired technology with sulfur controls, brings an externality adder of 5.5 ¢/kWh. Residual oil steam plants and peaking units running on distillate oil have the next highest adders, ranging from 5.3 to 3.8 ¢/kWh. Thermal IPPs have adder costs of 3.2 ¢/kWh The adder for IPPs decreases from 1990 to 2005 primarily because the technology mix changes to include more cogeneration, which benefits from credits for displacement of existing boiler emissions. followed by existing combined-cycle plants at 2.8 ¢/kWh. In the new resource category, the highest adder by far comes from refuse with 5.3 ¢/kWh and the lowest from biomass (steam) with 0.8 ¢/kWh, with the rest coming in lower than all existing resources.

By inspecting the composition of the adders, one can see the influence of current environmental regulations – the SO_2 and NO_x components of emissions in new resources are reduced considerably from those of the older technology. For example, with existing coal plants, the adders are made up of roughly equal shares of costs from the three pollutants, whereas with the new IGACC plants equipped with selective catalytic recovery, 90% of the adder comes from the C emissions. In the case of other new resources, the low emissions (and hence, externality cost) are largely a function of fuel choice rather than technological improvement, though improved heat rates also play a role.

C. ADDERS APPLIED TO NEW RESOURCE SELECTION

Even if the MADPU adder were to make all resources with carbon emissions uneconomical, its application to new plant investments alone could not reduce carbon emissions below 1990 levels over the next 20 years, given current retirement plans for New England's existing plants. Nevertheless, emission reductions in new plants are an important component of climate stabilization policies, and marginal investments will have to be based on low-carbon primary energy sources if the goal of these policies is to be achieved.

Taking a gas ACC as the reference resource, the question then becomes whether low-carbon resources that are more expensive than this option on a direct-cost basis would be able to compete economically. A simplified approach to answering this question is to compare levelized busbar costs. Table V.3 shows the changes in busbar costs for various new conventional and low-carbon generating technologies. Overall, the table shows that for new resources, the MADPU adder is essentially a carbon adder: NO_x and SO_2 emissions account for at most about 25 percent of the total NO_x, SO_2, and C surcharge. Also, adder-induced cost increases overall are limited to about 25 percent of direct costs. An exception are new coal plants, where costs increase by about 40 percent due to the Massachusetts surcharge.

As is evident from Table V.3, the adder is not too critical for cogeneration resources. Against utility-scale ACCs, thermally optimized gas-fired cogeneration resources in industrial applications are already cost-competitive to cost-effective when our low resource cost assumptions are used. Here, the adder only maintains or reinforces this cost-effectiveness. With our higher resource cost assumptions, cogeneration would be somewhat more expensive than gas ACCs. Here, the adder has the effect of making cogeneration cost-competitive. This resilience of cogeneration economics to air emission surcharges is due to the emission credits earned from displaced boiler fuels.[2]

Table V.3 suggests that the key marginal resources to be examined in terms of carbon adder impacts are wind and biomass resources. With our lower resource cost assumptions for the more advanced technologies, these renewables are cost-competitive with gas ACCs even before the adder is applied. We therefore examine the impact of the adder for our high cost assumptions.

Table V.3: Summary of MADPU Externality Costs for New Power Plants

Resource	*Busbar cost at maximum capacity factor 1990 ¢/kWh*	*MA DPU externalities 1990 ¢/kWh*	*MA DPU externalities (w/o CO2) 1990 ¢/kWh*	*MA DPU externalities % of busbar cost*	*MA DPU externalities (w/o CO_2) % of busbar cost*
Gas CT	15.4	2.2	0.5	15%	3%
Gas CCC	6.1	1.5	0.3	24%	5%
Gas ACC	5.6	1.3	0.3	23%	5%
Coal ST	6.7	2.7	0.5	41%	7%
Coal AFB	6.8	2.8	0.5	41%	8%
Coal IGACC	6.7	2.6	0.4	39%	6%
Nuclear LWR	10.2	0.0	0.0	0%	0%
Wind current	8.3	0.0	0.0	0%	0%
Wind advanced	5.2	0.0	0.0	0%	0%
Biomass ST	5.7	0.8	0.8	15%	14%
BIGISTIG	5.0	0.5	0.4	9%	9%
BIGISTIG COGEN	3.6	-0.3	-0.3	-9%	-9%
BioST cogen	5.3	0.7	0.0	14%	-1%
Ind. GT	5.1	0.6	-0.2	11%	-3%
Packaged IC	6.1	0.4	-0.2	7%	-3%
Ind. CC	4.6	0.4	-0.2	10%	-4%
PURPA CC	5.4	1.0	0.1	19%	2%

Notes:

(1) Externality costs include only those for SO_2 (1720 \$/tonne), NO_x (7460 \$/tonne), and CO_2 (93 \$/tonne).

[2] For the same reason, cogeneration systems with low steam loads do less well under the adder. For example, the PURPA combined cycle would become (somewhat) more expensive than gas ACCs.

Screening curve analysis of carbon adder impacts

Figure V.1 shows a screening curve diagram in which the levelized cost of the gas ACC is plotted as a function of the carbon charge. The sulfur dioxide and nitrogen oxide components of the MADPU adder are included in the cost plotted on the y-axis.

This graph shows that the MADPU carbon charge is much too low to bring present wind and biomass power technology to the break-even point, even with the additional help from the SO_2 and NO_x adders. A carbon charge about three times as high would be required. This finding reflects the fact that gas ACCs have low emissions in both SO_2 and NO_x. The MADPU carbon adder reduces the gap between current technology costs and gas ACC costs by about 1 ¢/kWh, leaving about a 1.3 to 2.5 ¢/kWh advantage for the gas ACC.

While the MADPU adder is insufficient for making present wind and biomass technology cost-competitive with gas ACCs, it nevertheless could have an important market-pull effect on wind and biomass power technologies. As these technologies improve and costs are lowered, the present MADPU carbon adder could advance their market entry to an earlier date, as described by Hohmeyer (1988) for wind generation.

The carbon adder also makes other, lower-cost resources such as cogeneration and DSM more definitely cost-competitive or cost-effective against ACCs, by making uncertainties in cost estimates less important.

D. ADDERS APPLIED TO RETIREMENT DECISIONS

At present, externality cost adders in Massachusetts and elsewhere are being applied only to new resources. Application to existing plants can take the form of dispatching the existing system on the basis of the adder, or of replacing existing capacity outright. We analyze adder-based dispatch in Section E below.

The decision point regarding plant retirement is typically first reached when existing plants have reached their book life and are fully depreciated. Continuing their use can at that point be considered a marginal decision. Seen this way, the application of the externality adder in retirement versus life extension decisions could be congruent with the marginal plant philosophy of current externality regulations.

Table V.2 shows the impact of the MADPU adder if applied in this spirit to typical existing coal- and oil-fired plants.[3] Depending on the vintage or size of the plants, there can be significant plant-by-plant variation. While the carbon component of the total MADPU surcharge had completely dominated in the case of new resources, the adders for the "classical" emissions of SO_2 and NO_x contribute half or more to the total surcharge in the case of existing plants. At the same time, the percentage increases in costs are much larger:

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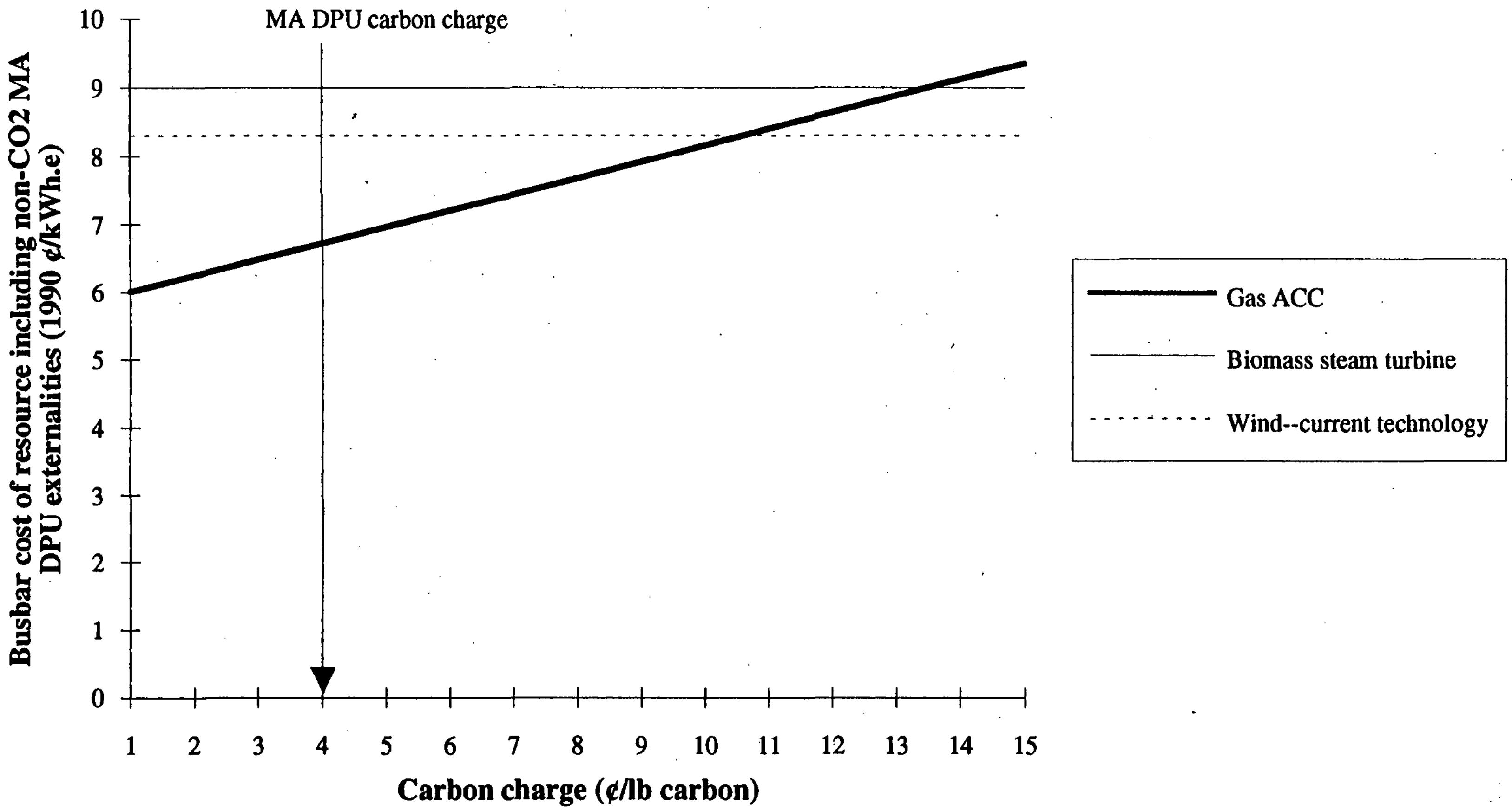
[3] We assume here that existing plants are fully depreciated, and no capital cost component is included in our calculations.

Figure V.1: Effect of carbon charges on busbar cost comparison between gas ACC and conventional biomass and wind power plants



against 2005 real fuel prices,[4] the adders almost double the cost of running existing oil plants and almost quadruple that of coal plants.

These results are further illustrated in Figure V.2, which again shows a screening curve based on variations in the carbon adder. This figure leads to several important observations:

- Under the MADPU adder system, running typical existing oil and coal plants would become more expensive than building new gas ACC plants. This result is not sensitive to the level of the carbon charge. The adders for classical pollutants alone would be sufficient to yield this cost relationship.
- When the carbon surcharge is applied in addition to the SO_2 and NO_x adders, existing oil and coal plants become so expensive to run that investments in new conventional (high cost) wind and biomass resources could be cost-competitive.

These results suggest that application of the MADPU adder to existing plants could even justify the retirement of existing capacity that has only partially depreciated.

These observations point to a salient characteristic of the Massachusetts adder system and similar adder systems: while externality surcharges based on control technology costs appear to be only marginally effective in shifting investment choices to new low carbon resources, they would be overwhelmingly effective in justifying scheduled or accelerated retirements of existing plants with high carbon burdens.

Improved estimates for the proper level of carbon, sulfur dioxide, and nitrogen oxide adders could lead to lower values for the two acid rain and smog precursors. Even with such revisions, life extension of existing coal plants would become at least as expensive as repowering them.

The results would be even more clear-cut for oil plants. In the case of the 1950s and 1960s oil capacity, even much lower adders for SO_2 and NO_x would suffice by themselves to make repowering cost-competitive. When the carbon adder is also included, the life extension of these oil plants becomes overwhelmingly uneconomical.

An observation of practical importance for price-based incorporation policies is that the impact of the carbon adder changes dramatically over a narrow range of values, from justifying no retirements to complete retirement of all plants. It would thus be difficult to fine-tune the carbon adder in such a way that only portions of existing plants would be affected. A fine-tuned application of the adder could be easier when it is used in dispatch, where it affects the capacity factor of existing plants rather than their continued operation as such.

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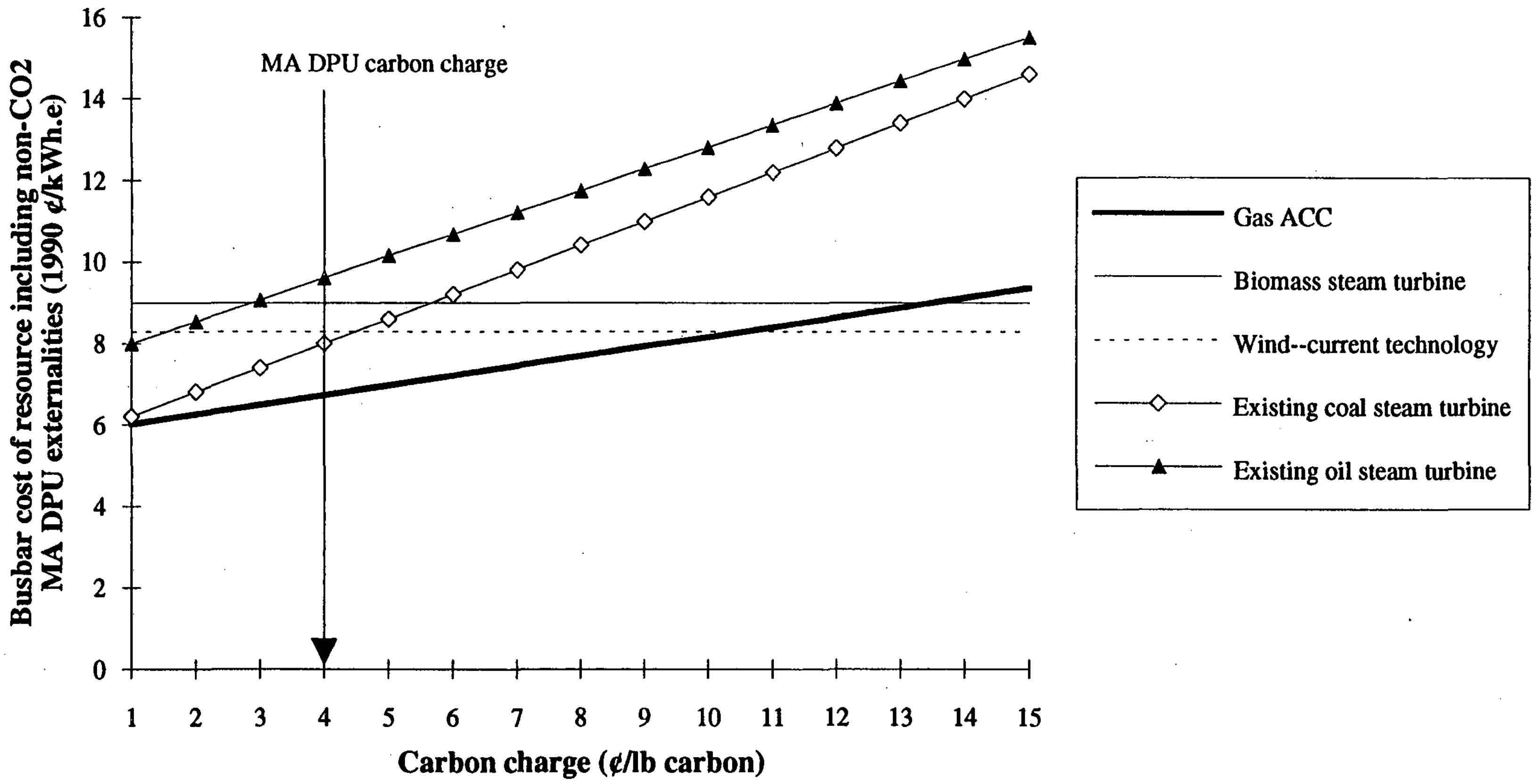
[4] 2005 fuel prices are used in this comparison as a limiting case, due to the projection of real fuel price escalation. In years before 2005, the impact of the adder on existing plants would be even larger.

Figure V.2: Effect of carbon charges on busbar cost comparison between gas ACC, conventional biomass, wind, existing oil steam, and existing coal steam power plants



E. ENVIRONMENTAL DISPATCH

In this section we explore what happens when environmental externality costs are incorporated into the logic of dispatch. This proposed approach has been variously referred to as environmental dispatch or full-cost dispatch. We first discuss results from applying a fixed externality surcharge (the MADPU adder) to dispatch of various system configurations. We begin with the base year NEPOOL system in 1990 and the NEGC reference case resource mix for 2005/10. The emissions and direct production costs of these environmental dispatch cases can be compared to the corresponding conventional dispatch results described in Chapter III.

To explore the sensitivity of environmental dispatch to the size of the adder, we next perform system dispatch on the basis of least-emissions for the 1990 base year system. Though no adder is actually applied in this limiting case experiment, it can be thought of as equivalent to applying an infinite adder. This calculation defines the maximum emission reductions obtainable through dispatch of a fixed system.

1. Adder-Based Dispatch of the 1990 NEPOOL System

Massachusetts environmental externality costs were applied to plants in the existing NEPOOL system simulated with the UPLAN model. In Table V.4, the production cost and emissions results are shown disaggregated by plant categories. SO_2 and NO_x emissions fall by 14% over the case using no adders, while C decreases only 1%. Direct production costs increase by $100 million or about 4%. If the externality surcharges were actually collected or paid, total production costs would rise by $2435 million, or 93% over conventional dispatch. The main impact the adders have in the way the existing system is operated is essentially to switch coal and oil plants in the dispatch order. The adders have a sufficiently large deleterious impact on coal plants that their dispatch price goes from being a third cheaper than oil to a third more costly. This results in coal plants going from an average capacity factor of 70% to 34% while oil plants go from 40% to 50% and the change in SO_2 emissions is entirely due to this effect. A minor contribution to NOx emission reductions is due to the capacity factor of thermal purchases dropping from over 90% to 6%.

Larger potential emissions reductions from adder-based dispatch of the existing NEPOOL system were predicted in Bernow et al 1990. Using a simplified spreadsheet dispatch model and stylized inputs of the existing NEPOOL system, they found emissions reductions in SO_2, NO_x, and CO_2 of 67%, 27%, and 19%, respectively, through application of the MADPU system of externality cost adders. The authors of that study cautioned that their results could be misleading on account of their model not capturing any of the operating constraints of a power system, such as minimum operating levels or unit commitment logic, that serve to reduce flexibility to shift generation among resources. The UPLAN model also lacks the capability to model all relevant constraints in system dispatch. For instance, UPLAN neglects minimum ramp rates or minimum unit down times. Nonetheless, the use of UPLAN in this study, while not without limitations, does represent a significant improvement in modeling sophistication over previous studies of this topic.

Table V.4. Adder-Based Dispatch Results in 1990.

	Capacity Factor (%)	Dispatch Cost (¢/kWh)	Direct Prod. Cost (M$)	Emissions (ktons)			Percent Change due to MDPU Adders				
				SO_2	NO_x	C	Capacity Factor	Dispatch Cost	SO_2	NO_x	C
Nuclear	72.5	0.6	573	0	0	0	0%	0%	0%	0%	0%
Coal Steam	33.7	8.0	164	91	29	2325	-52%	339%	-53%	-53%	-53%
Peakers	0.4	10.4	19	0	0	20	0%	100%	0%	0%	11%
Oil Steam	50.1	6.9	1121	250	104	12455	24%	151%	23%	17%	29%
Thermal Puchase	6.1	8.2	61	0	1	39	-93%	194%	0%	-89%	-93%
Hydro Purchase	90.6	2.6	289	0	0	0	84%	9%	0%	0%	0%
Pumped Storage	3.3	0.0	7	0	0	0	-20%	0%	0%	0%	0%
Storage Hydro	28.8	0.0	5	0	0	0	0%	0%	0%	0%	0%
Baseload Hydro	62.9	0.0	6	0	0	0	0%	0%	0%	0%	0%
IPPs	63.4	8.2	501	17	22	858	0%	50%	0%	0%	0%
CC	82	5.3	74	5	8	1133	5%	111%	0%	14%	5%
TOTAL			2819	363	163	16831			-14%	-14%	-1%

2. Adder-Based Dispatch of 2005 NEGC Reference Case

Table V.5 presents the production cost and emissions results by plant category for the reference case 2005 resource mix when dispatched on the basis of operating costs that incorporate adders. While these results do not represent use of the MADPU adders in choosing new resources or making life extension/retirement decisions, they could be likened to what might happen if the Massachusetts adder scheme (or one like it) were adopted throughout New England after several years delay once the currently planned resources have already been built or committed. In this instance, SO_2 and NO_x emissions are reduced by 14% and 9%, respectively, while C emissions rise by 1% as compared to the conventionally dispatched system. At the same time the adders raise direct production costs $140 million, or by 3%. If collected, the externality surcharges would add $2875 million to total production costs, or 63%. The diminished impact of externality surcharges on total production costs relative to the 1990 system is due in part to their remaining fixed (in real price terms) while fuel and O&M costs steadily escalate over the period.

Coal plant generation again falls due to the adders, but not to the same extent as with the existing system: here the capacity factor goes to 55% from 70%. In this case, the breach left by diminished output from coal plants is not made up by oil plants (which themselves experience slightly reduced output), but rather from increased production from new gas and distillate fired technologies whose dispatch cost goes up proportionally less. Coal plants revert back to their position ahead of oil plants in the dispatch order in what is another effect of static externality costs. Over 95% of the SO_2 and NO_x is emitted from existing resources, as is nearly 75% of the C.

To summarize, carbon emissions are virtually unaffected by the inclusion of the MADPU adders in dispatch of the NEPOOL system, whereas SO_2 and NO_x emissions undergo sizable reductions. For these latter two pollutants, a comparable level of emissions reductions can be achieved (in proportional terms) in either year by converting to adder-based dispatch.

Alternative NEPOOL 2005/2010 configurations

The impact of adders on other configurations of the NEPOOL system (described in the next chapter) is broadly the same as for the reference NEGC system: direct production costs increase by one to three percent, SO_2 and NO_x emissions drop moderately, and carbon emissions remain virtually unchanged or even increase slightly. The range of emissions reductions for the two acid rain precursors is primarily a function of whether or not coal plants are still in the resource mix. In those configurations where coal plants or both oil and coal plants are retired, adders have less of an impact on acid rain precursor emissions than in cases where they remain in service.

Table V.5. Adder-Based Dispatch Results in 2005.

	Capacity Factor (%)	Dispatch Cost (¢/kWh)	Direct Prod. Cost (M$)	Emissions (ktons) SO_2	Emissions (ktons) NO_x	Emissions (ktons) C	Percent Change due to MDPU Adders: Capacity Factor	Dispatch Cost	SO_2	NO_x	C
Nuclear	72.5	0.4	530	0	0	0	0%	0%	0%	0%	0%
Coal Steam	55.4	8.1	297	148	47	3800	-20%	302%	-24%	-24%	-23%
Peakers	0.2	20.0	18	0	0	10	0%	67%	0%	0%	0%
Oil Steam	32	9.0	1271	151	62	7603	-4%	85%	-7%	-11%	0%
Thermal Puchase	96.2	8.7	290	3	20	1367	-1%	174%	0%	0%	-1%
Hydro Purchase	95.4	2.5	444	0	0	0	0%	0%	0%	0%	0%
Pumped Storage	10.3	0.0	7	0	0	0	17%	0%	0%	0%	0%
Storage Hydro	28.8	0.0	6	0	0	0	0%	0%	0%	0%	0%
Baseload Hydro	62.9	0.0	7	0	0	0	0%	0%	0%	0%	0%
IPPs	63.6	7.6	655	14	20	1226	0%	39%	0%	0%	0%
CC	59.3	7.4	193	7	11	1637	103%	66%	75%	83%	103%
Total Existing			3718	323	160	15643			-15%	-10%	-2%
IGCC	88.4	4.6	177	7	1	2164	0%	108%	0%	0%	0%
Adv. CC	78.2	5.1	863	0	4	3228	9%	28%	0%	33%	9%
Adv. CT	6.9	8.0	63	0	0	360	590%	17%	0%	0%	567%
Biomass Steam	87.5	3.9	59	0	2	0	1%	27%	0%	0%	0%
Refuse	87.6	7.6	31	3	3	77	0%	223%	0%	0%	0%
Total New			1193	10	10	5829			0%	11%	11%
GRAND TOTAL			4911	333	170	21472			-14%	-9%	1%

3. Least-Emissions Dispatch

We thought it instructive to portray a limiting case in which the NEPOOL system were dispatched to minimize emissions. These runs approximate the result of applying infinite externality surcharges to individual pollutants in successive runs. They also reveal the limitations inherent in a fixed resource mix to bringing about large emissions reductions. UPLAN has no formal procedure for performing least-emissions dispatch; however by substituting pollutant emission rates (in lbs/MBtu) for fuel prices in the input file, the model is "tricked" into dispatching plants on a minimum emissions basis.[5]

Table V.6 shows, for each of 1990 and 2005, results of individually minimizing emissions of SO_2, NO_x, and C in successive UPLAN runs. Minimizing one pollutant has a synergistic effect on emissions of the other pollutants. However, the effect is not uniform. Generally, when either SO_2 or NO_x are minimized, then the other of the two is also lowered (albeit to a lesser extent), but also the tendency is to raise carbon emissions. Whereas, when carbon is minimized, reductions in both SO_2 and NO_x emissions accrue.

Table V.6. Least-Emissions Dispatch Results

Case	*Year*	*Production Cost*	*Emissions* SO_2	*Emissions* NO_x	*Emissions* C
Least SO_2	1990	32%	-52%	-9%	1%
Least NO_x	1990	22%	-14%	-31%	-1%
Least C	1990	23%	-16%	-10%	-25%
Least SO_2	2005	64%	-61%	-23%	7%
Least NO_x	2005	52%	-31%	-42%	3%
Least C	2005	58%	-29%	-12%	-27%

How are these large emissions reductions achieved under emissions-minimizing runs? They come mainly through curtailment of coal generation. Least-dispatch is the most extreme case of this, with the coal capacity factor plummeting down to 6% (from a base case 70%). In 1990, two-thirds of the lost coal generation under least- dispatch is made up from increased peaking unit output, and from minor increases in pumped storage, oil steam, and combined-cycle output. In 2005 for the same case, existing peaking units make up one-quarter of the coal generation shortfall (and in this instance, oil as well) with new IGCC, advanced CC, and CT plants filling in the remainder.

When carbon emissions are minimized, increased oil steam generation and hydro purchases make up for a coal capacity factor of 14% in 1990. In 2005, with existing coal steam and new coal IGCC capacity factors down in the 10% range and thermal purchases virtually shut-off, the balance comes from existing combined cycle, and new gas advanced CC and CT plants. Coal plant curtailment is the least severe under least- dispatch, with coal capacity factors around 33% and replacement generation coming from a variety of sources.

These least-emissions runs quantify potentials for reducing emissions in a fixed system, We can now evaluate how effective the MADPU adders are in reaching these potentials. In 1990, one-third of the potential SO_2 reductions and one-half of the potential NO_x reductions are captured through adder-based dispatch. Furthermore, adders accomplish these reductions at a fraction of the cost of achieving the full, fixed-system potentials. In

[5]Generation fuel expenses were, in turn, calculated in the simulations by entering fuel prices in the place of emission rates in the UPLAN input protocol.

2005, the fractions of potential reductions of SO_2 and NO_x are smaller, and are again achieved at relatively modest cost. The adders capture little or none of the potential for carbon reductions available in a fixed-system.

4. Discussion

At first glance it is puzzling that C reductions are negligible while SO_2 and NO_x reductions are much greater, particularly in light of the MADPU adder system in which the C component of emissions costs can be quite large, especially for newer resources (see Table V.3). The explanation for this result uncovers a fact that is crucial to understanding how adders actually work. When adders are calculated using the MADPU system and applied to any given resource, they affect dispatch as a lumped sum. That is, any distinction in emission rates between pollutants is lost and all that remains is the aggregated externality cost. These cost adders act primarily to shuffle the dispatch order. For instance, existing coal plants have both high acid rain precursor emissions and high carbon emissions. As a result, they lose out to existing oil plants when adders are charged in dispatching the 1990 system (see Table V.4). But while oil plants exhibit significant advantages over coal plants in terms of acid rain precursor emissions, they are only moderately better in terms of carbon emissions. The increase in oil plant utilization under adder-based dispatch ends up being such that SO_2 and NO_x emissions come down markedly while carbon emissions do not.

Which pollutants are reduced, and by how much, is a function of the emissions characteristics of the plants that are preferentially run when adders are included. If these plants have low emissions of a given pollutant relative to the generation they displace, then reductions of that pollutant will follow, but otherwise they will not. Since the adders act in aggregate, it is almost inconsequential that they are made up primarily of any given pollutant's costs. Thus, having CO_2 form a certain (in some cases large) portion of the total externality cost adder does not guarantee that reductions of CO_2 will follow in equal proportion.

Further insight is provided by the observation that a smaller proportion of potential emissions reductions (as determined through least-emissions dispatch) are achieved by the adders in 2005 than in 1990. As we mentioned before, this is due in part to the fact that the adders were not escalated in our runs along with other variable costs, but is primarily because the new resources in the 2005 system tend to be both lower cost than existing ones – so they are already being run at relatively high output levels – and have lower emissions. Therefore, the adders don't act to significantly boost the output from cleaner resources because they are already being utilized through inherently low variable costs. For environmental externality adders to produce large emissions reductions in plant dispatch, the system needs to have high-variable-cost/low-emissions resources that the adder can place higher in the dispatch order.

Finally, we can compare the increased direct costs from adder-based dispatch with the associated emissions reductions. In so doing, we derive an alternate cost of control based on the system as a whole. In simulating dispatch based on the total adder, however, the ability to disaggregate the effect of any given pollutant's costs from the others is lost. As a conservatism, we calculate the cost per unit emissions reduction based on one pollutant at a time. In assigning the whole cost to a single pollutant's reductions, we arrive at what could be considered a maximum implied cost, since in actuality the cost should be shared among all diminished pollutants. Table V.7 displays these unit costs of reducing emissions through adder-based dispatch juxtaposed with the corresponding figures from least-emissions dispatch and from conventional control technology as represented by the MADPU adder system. These unit cost figures from environmental dispatch do not, however, permit a proper ranking of emissions control approaches. First, the adder-based dispatch unit costs of reduction reflect *maximum* costs as already pointed out, rather than actual costs when the ancillary pollutant emissions reductions are somehow valued. Secondly, for both adder-based dispatch and least-emissions dispatch, the *percentage reductions* obtained of either SO_2 or NO_x are much lower than those possible through application of conventional control technologies such as wet gas desulfurization and selective catalytic reduction. In the case of carbon, meaningful emissions reductions from adder-based dispatch are limited at best, and as we found with the 2005 NEGC resource mix, carbon emissions can actually increase as compared to conventional economic dispatch.

Table V.7. Unit Costs of Reducing Emissions ($/lb)

Approach	SO_2	NO_x	C
Control Technology (MADPU)	$0.78	$3.38	$0.04
Adder-Based Dispatch (1990)	$0.84	$1.90	$0.20
Least-Emissions Dispatch (1990)	$2.02	$5.06	$0.07

F. EXTERNALITY SURCHARGES IN PERSPECTIVE

We can summarize the effectiveness of the Massachusetts adder as follows: When used to influence new resource selection, all resources costing less than about 7 ¢/kWh would become cost-competitive. Under our high cost assumptions for new resources (see Chapter IV), this would not be sufficient to mobilize wind and biomass resources, while all other resources including retirement options would be easily cost-effective. Thus, in the extreme case, the Massachusetts adder would be too low if renewables costs should remain high and if carbon reduction goals should be such that wind and biomass resources would be needed to achieve them. The need for increasing the carbon adder would be enhanced if the current MADPU surcharges for SO_2 and NO_x were to be revised downward, as proposed by some intervenors. On the other hand, for moderate reduction targets and/or low resource cost assumptions, the current Massachusetts carbon adder would appear too high, in particular if such moderate reduction targets could be met without retiring existing coal plants.

These results point to an inherent difficulty in using monetized adders as a environmental policy tool: The effect of adders is not very predictable. While the costs of each carbon reduction option varies over a considerable range, the adder is by definition a point value. The best regulators can hope for is to bring the adder within the right "ball park." As technology costs change, periodic adjustments would still be necessary.

More fundamentally, our analysis brings us back to two key points we made in the Introduction. First, since emission reduction options come in the form of a supply curve, any adder is implicitly a reduction target. Second, externality adders cannot be sensibly derived from post-combustion control technologies alone, but should be based on all available reduction options, including fuel switching, dispatch modifications, and portfolio analyses of low-emission resource mixes. Based on such information, the proper size of the adders can be determined as a function of the desired emission level. We now turn, in the next chapter, to a target-based approach to achieving carbon reductions for New England.

CHAPTER VI

PORTFOLIO ANALYSIS OF LOW CARBON RESOURCE MIXES

A. OVERVIEW

In this chapter, we use the menu of resources in Chapter IV to make detailed assessments of the size and cost of feasible carbon reductions in New England. Our basic approach is to develop alternative portfolios for the composition of New England's future electricity resource mix and to calculate emissions and costs of electricity services for each. In our calculations, we use production cost modeling to capture expected emissions and variable costs accurately from each type of power plant under economic dispatch.

Because of some uncertainty surrounding the evolution of the New England power system even in the absence of specific measures to combat global climate change, we present a range of possible reference futures, pivoting around different assumptions about existing plant retirements. We then present several sets of portfolios that illustrate important themes. These themes include maximum feasible carbon reductions, minimum cost carbon reductions, alternate low carbon resource costs and fuel price forecasts, and the net costs of carbon reduction under each strategy. Finally, we examine the impacts of each strategy on electricity rates, gas demand, and acid rain precursor emissions in the New England region.

B. PORTFOLIO DEVELOPMENT

Modeling and interpreting a large number of portfolio variations was not feasible within the scope of this project. Instead we focus our analysis on the important themes identified in earlier chapters. Our portfolios aim to cover the spectrum of possible policy approaches, to take into account the major dimensions of uncertainty, and to meet binding modeling constraints. In presenting these portfolios, we do not imply that they are optimized; rather our intent is to illustrate the range and character of electricity futures that are plausible under alternative perspectives.

The New England Governor's Conference (NEGC) asked us to assess the feasibility, net costs, and rate impacts of achieving certain carbon emissions targets in 2005. These targets ranged from freezing emissions at current levels to reducing emissions 20% relative to 1990.[1]

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[1] In addition, the international Toronto conference of 1988 called for carbon emissions reductions of 20% by 2005, and other industrialized countries have pledged to freeze carbon emissions by the turn of the century or reduce them by 25% over the next twenty years. Thus, the request of NEGC falls well within the targets being discussed in the international arena.

Therefore, the main focus of this chapter is on carbon emissions reductions of from 0% to 20% compared to 1990 levels, even though our analysis includes portfolios that provide much larger carbon reductions.

Our analysis consists of the following steps:

— Portfolios are created as variations on the NEGC resource mix. In the NEGC case, certain resources are defined as committed or likely additions, while others are defined as "base case additions" (see Table III.1). We treat this latter capacity block of 5400 MW as "discretionary", and we substitute alternative resources for conventional resources within this discretionary block. Sensitivity cases examining various existing capacity retirement cases expand the opportunities for substituting alternative for conventional resources.

— Contributions from the major low-carbon resources (i.e., DSM, cogeneration, biomass, wind) are varied in increments of 50 and 75 percent of their total identified potentials.

— New capacity requirements that cannot be met by these constrained-potential fractions are met by gas ACC plants, making these the unconstrained "swing" resource in our portfolios.

— Capacity needs in each portfolio are defined on the basis of loss of load probability (LOLP) equivalence.

1. Low Cost vs. Low Carbon Strategies

The cost of carbon reductions in New England can be illustrated on the basis of two types of bounding scenarios. In the first type of scenario, low-C resources are combined with the goal of minimizing total costs. In the second type of scenario, the resource mix is formulated with the goal of maximizing emission reductions. We refer to the former as Low Cost portfolios, and to the latter as Low Carbon portfolios.

In the Low Cost portfolios, we rely on only the least expensive low-C resources, namely, demand-side efficiency, fuel switching, and gas-fired cogeneration. In the Low Carbon portfolios, renewables are utilized as well. In both cases, a range of retirements and resource constraints apply.

2. Definition of Reference Cases

In our analysis, we calculate the costs of carbon reductions relative to a business-as-usual electricity future for New England that might be expected in the absence of concerns over global warming. Building on NEPOOL's 1990 forecast for the year 2005, the NEGC developed a resource plan that broadly meets this criterion. We refer to this scenario as the NEGC reference case, and create alternative reference cases by varying the retirements of existing plants.

In our analysis, we also extend NEGC's time horizon to 2010, because of lower than expected demand growth in the region after the NEGC forecast was finalized. In addition, by 2010 the licenses for almost half of New England's nuclear capacity (3230 MW) will have expired, and retiring these plants will make carbon reductions more difficult to achieve. Such retirements would therefore occur independently of carbon reduction strategies. We treat the uncertainty in nuclear retirements by including a reference case that includes the retirement of nuclear plants that will have reached the end of their useful lives by 2010.

In formulating the alternative 2010 portfolios, we ensure comparability by including, at a minimum, the same retirements as in the NEGC case or the NEGC case with nuclear retirements. In the Low Cost portfolios, we add to the scheduled retirements of nuclear plants in the reference case only the retirement of oil-fired capacity, which adds little cost while achieving significant carbon savings. In the Low Carbon portfolios, additional scheduled retirements cover both coal and oil capacity, to maximize carbon reductions.

The *carbon reductions* calculated assuming nuclear retirements are smaller than would be expected if the nuclear plants' lives were extended beyond their license expiration date. The relative *cost impacts* of carbon reduction strategies would be similar, because both the reference case and the policy cases would be charged the cost of nuclear plant retirements.

3. Treatment of Uncertainty in Resource Constraints

The limitation of resource use to at most about 75 percent of their estimated potential reflects the uncertainties in these potentials, and the significant policy needs associated with their mobilization. For example, to mobilize available DSM resources fully, efficiency standards will need to be promulgated in addition to pursuing aggressive utility DSM programs. Similarly, wind and biomass-fired plants will bring their own siting issues with them, and expanded investments in thermally optimized cogeneration will also require special policies (see also Appendix I).

4. Treatment of Uncertainty in Resource Costs and Fuel Prices

We capture uncertainty in our resource cost assumptions using the low and high values presented in Chapter IV.

We use NEGC reference case fuel prices for our reference case (this forecast predicts real growth in natural gas prices of 4% to 5% per year over the analysis period). In addition, we use an alternate forecast for natural gas, residual oil, and distillate oil that is both within the range of current forecasts from reputable sources, and more reflective of historic price escalation. We chose 2 percent real price escalation for these three fuels, a rate of escalation that approximately corresponds to that predicted for utility natural gas by the American Gas Association (in EIA 1991). For more details on the low fuel price case, see Chapter III.

C. REFERENCE CASES AND ALTERNATIVE RESOURCE PORTFOLIOS

1. Reference Electricity Futures Under Alternative Retirements

Table VI.1 summarizes the costs and emissions for our reference cases under reference and low fuel price assumptions. The first four rows in Table VI.1 show the NEGC reference case, and three different scenarios depicting retirements of NEPOOL units existing in 1990. Only plants whose book life is exceeded by 2005 are considered, or in the case of nuclear plants, those whose operating license from the NRC will have expired by 2010.[2] For this reason, these can be thought of as scheduled retirement cases. In these runs the retired capacity is replaced with gas ACC plants.

Table VI.1. Comparison of alternative retirement cases

	Fuel price case	*Total Cost (M$)*	*SO2 Emis. (ktons)*	*NOx Emis. (ktons)*	*C Emis. (ktons)*	*% Chg from 1990 C Emis.*
NEGC	reference	8102	387	188	21322	25%
NEGC w/ Nuclear Retirement	reference	8837	408	199	24987	46%
NEGC w/ Oil Retirement	reference	8208	276	139	18873	11%
NEGC w/ Fossil & Nuclear Retirement	reference	9458	92	88	20232	18%
NEGC	low	7515	380	186	21463	26%
NEGC w/ Nuclear Retirement	low	7972	400	198	25245	48%
NEGC w/ Oil Retirement	low	7578	270	137	19569	15%
NEGC w/ Fossil & Nuclear Retirement	low	8300	86	87	20929	23%

(1) High and low resource cost cases are the same for the alternative retirement scenarios.
(2) total costs include all fuel costs, O&M costs, capital costs for new resources, capital costs for T&D, and other embedded capital and overheads for power system.
(3) 1990 Carbon emissions = 17.1 Mt - C
(4) All costs are in 1990 $.

The second reference case involves retirement of 3230 MW of nuclear capacity. As expected, costs are higher than the NEGC case (by $730 million) because the generation from inexpensive nuclear plants must be replaced by new ACCs. Carbon emissions also rise by 17% over NEGC because nuclear plants emit no carbon at the plant, whereas ACC plants do. Emissions of acid rain precursors also rise for the same reason.

The third reference case involves retirement of 3500 MW of oil-fired capacity. The increased cost of this transformation is about $100 million. In this case, however, carbon emissions are lower than NEGC by 11% due to the higher efficiency of ACCs and the lower carbon content of natural gas over fuel oil. Acid rain precursor emissions are likewise lowered.

The fourth reference case in Table VI.1 depicts the case where nuclear, oil, and coal capacity has undergone scheduled retirement, a total of 9580 MW. While the likelihood of this case is not high, it is a possible future that New England could face under extreme environmental

[2] We extend the time horizon in considering nuclear plant retirement because by 2005 none of the nuclear plant licenses will have expired, but by 2010, several licenses will have expired, amounting to substantial capacity. In so doing, we are accounting for uncertainty surrounding the timing of the load forecast as well as some end effects in our modeling.

pressures. Costs are higher than NEGC by $1350 million under reference case fuel prices. Even with the loss of zero carbon and acid rain precursor emitting nuclear capacity, emissions of carbon fall by 5% from those of the NEGC case in 2005, while those of SO_2 and NO_x fall by 76% and 53%, respectively. ACC plants possess substantial advantages in air pollutant emissions over old steam coal plants, and this is the major explanation for the emissions outcome of this scenario. These advantages come at a price, however, because the loss of relatively cheap coal generation pushes costs markedly higher.

2. Alternative Resource Portfolios

We now turn to portfolios incorporating both scheduled retirements and utilization of low carbon resources. Table VI.2 describes the resource portfolios[3] in qualitative terms, and Table VI.3 quantifies the resource contributions in each portfolio. Low Carbon (50/50/N) signifies that DSM, cogeneration, and fuel switching are utilized at the 50% level (indicated by the first 50%), renewables are used at the 50% level (indicated by the second 50%), and nuclear plants are retired (indicated by the N). In the Low Cost Portfolios (50/0 and 50/0/N), DSM is utilized at the 50% level, cogeneration and fuel switching are utilized at the 50% level, and renewables are not utilized at all. In the Low Cost 75/0 and 75/0/N portfolios the format is changed somewhat. For these cases, DSM is utilized at the 75% level, cogeneration and fuel switching are utilized at the 50% level, and renewables are not utilized at all.

Table VI.2. Description of carbon reduction portfolios

	Utilization of Constrained Resource Potential	*Portfolio Resource Composition*	*Retirements*
Low Cost Portfolios			
Low Cost (50/0)	50%	DSM + Fuel Switch + Cogen	Oil
Low Cost (50/0/N)	50%	DSM + Fuel Switch + Cogen	Oil, Nuclear
Low Cost (75/0/N)	75%/50%*	DSM@75% + (Fuel Switch + Cogen)@50%	Oil, Nuclear
Low Carbon Portfolios			
Low Carbon (50/50)	50%	DSM + Renew + Cogen	Oil
Low Carbon (75/75)	75%	DSM + Renew + Cogen	Fossil
Low Carbon (50/50/N)	50%	DSM + Renew + Cogen	Oil, Nuclear
Low Carbon (75/75/N)	75%	DSM + Renew + Cogen	Fossil, Nuclear

* note that the Low Cost (75/0/N) case uses 75% of the DSM potential and 50% of cogeneration and fuel switching potentials, with no renewables.

[3] The word "portfolio" is used here to describe a set of production-cost modelling runs with the same resource availability assumptions. Within a portfolio is a set of "cases" with different assumptions for resource capital costs and fuel prices. Thus, there is a low fuel price, high resource cost *case* within the Low Carbon 50/50/N *portfolio*.

Table VI.3 Composition of Carbon Reduction Portfolios

	New Discretionary Capacity Additions								
	DSM (TWh)	Fuel Switching (TWh)	ACC (MW)	Adv. CT (MW)	Biomass Steam (MW)	Biomass ISTIG (MW)	Conv. Wind (MW)	Adv. Wind (MW)	Cogen (MW)
Low Cost Portfolios									
Low Cost (50/0)	20	4.5	1400	1400	0	0	0	0	1400
Low Cost (50/0/N)	20	4.5	3400	1820	0	0	0	0	1400
Low Cost (75/0/N)	32	4.5	2000	980	0	0	0	0	1400
Low Carbon Portfolios									
Low Carbon (50/50)	20	0	600	980	450	840	1500	1250	1400
Low Carbon (75/75)	32	0	0	0	450	1680	1500	2750	2100
Low Carbon (50/50/N)	20	0	2800	1120	450	840	1500	1250	1400
Low Carbon (75/75/N)	32	0	800	1260	450	1680	1500	2750	2100

Table VI.4 shows the production cost simulation results for our Low Cost and Low Carbon resource portfolios. Carbon emissions reductions compared to 1990 levels range from 21% to 74% for portfolios without nuclear retirements and from 0% to 52% with nuclear retirements.[4] Low Cost cases show carbon emissions reductions of from 0% to 25%. Low Carbon cases show larger reductions of from 15% to 74%. The switch from reference case fuel prices to low fuel prices reduces carbon savings by 2-4 percentage points.

D. NET COST ANALYSIS

1. Methodological Considerations

To calculate changes in net costs in percentage terms, we include transmission and distribution (T&D) fixed costs, in addition to the costs given in previous tables (e.g., production costs and annualized fixed costs of new, discretionary resources). We also assume that the remaining undepreciated cost of New England's power plants existing in 1990 is equal to zero, because of their advanced age. We estimated that the cost of maintaining the T&D system is 1.5 cents/kWh, which is computed on the basis of a 161 TWh level of electricity service, regardless of the DSM resource utilized by the portfolios. Credit for avoided costs of T&D are included in the DSM resource cost estimates described in Chapter IV and Appendix E. An addi-

[4]For the rest of this Chapter, we always refer to carbon emissions relative to the 1990 baseline power sector emissions of 17.1 million tons of carbon.

Tables VI.4. Alternative resource portfolios

Low Cost Portfolios	*Fuel price case*	*Total Cost (Low) (M$)*	*Total Cost (High) (M$)*	*SO2 Emis. (ktons)*	*NOx Emis. (ktons)*	*C Emis. (ktons)*	*% Chg from 1990 C Emis.*
Low Cost (50/0)	reference	6991	7502	265	115	12840	-25%
Low Cost (50/0/N)	reference	7726	8237	290	128	16730	-2%
Low Cost (75/0/N)	reference	7600	8428	283	122	14524	-15%
Low Cost (50/0)	low	6581	7092	263	116	13488	-21%
Low Cost (50/0/N)	low	7042	7553	284	127	17133	0%
Low Cost (75/0/N)	low	7081	7909	276	122	14965	-12%
Low Carbon Portfolios	***Fuel price case***	***Total Cost (Low) (M$)***	***Total Cost (High) (M$)***	***SO2 Emis. (ktons)***	***NOx Emis. (ktons)***	***C Emis. (ktons)***	***% Chg from 1990 C Emis.***
Low Carbon (50/50)	reference	7489	8299	243	111	10695	-37%
Low Carbon (75/75)	reference	7717	9096	32	43	4361	-74%
Low Carbon (50/50/N)	reference	8147	8947	256	121	13836	-19%
Low Carbon (75/75/N)	reference	8343	9716	64	62	8127	-52%
Low Carbon (50/50)	low	7200	8010	241	110	11308	-34%
Low Carbon (75/75)	low	7475	8854	27	40	4998	-71%
Low Carbon (50/50/N)	low	7629	8429	255	119	14545	-15%
Low Carbon (75/75/N)	low	7898	9271	65	61	8643	-49%

tional cost item included in this calculation is the fixed cost of committed, new resources from the NEGC plan. These resources appear in Table III.1 under the headings "Capacity Additions CELT 1990," and "Likely Additions NEGC," and the costs used can be found in the relevant appendices of Volume II.

2. Low Cost Portfolios

Table VI.5 summarizes the net costs (in absolute and percentage terms) for the Low Cost portfolios under our different resource cost and fuel price assumptions. Net costs of the carbon reduction portfolios are calculated successively in comparison to NEGC, NEGC with nuclear retirement, and NEGC with oil retirement.

Net costs are negative in all cases, for carbon reductions relative to 1990 of from 0% to 25%. The assumption of nuclear retirements reduces the possible carbon savings by roughly twenty percentage points, but as expected, the relative changes in costs are similar to those found when comparing our resource portfolios to the NEGC case without nuclear retirements.

3. Low Carbon Portfolios

Table VI.6 shows the net cost results for the Low Carbon portfolios. Regardless of reference case, all Low Carbon portfolios (50/50, 75/75, 50/50/N and 75/75/N) show negative net costs in the low resource cost cases, and positive net costs in the high resource cost cases. The net cost of the 75/75/N portfolio when compared to the NEGC case with fossil and nuclear retirements is 4 to 7 percentage points lower than the 75/75/N portfolio compared to the NEGC case with nuclear retirements, which illustrates the importance of the choice of reference case to the net cost results.[5]

4. Unit Costs of Carbon Savings

We present one final calculation on the net costs of low carbon portfolios: the unit cost in relation to the extent of the carbon reduction. Table VI.7 shows the resulting unit costs of carbon savings in ($/lb. C) for the three carbon reduction portfolios relative to the appropriate reference cases. The range of unit costs is from -$0.11/lb. C to $0.03/lb. C.

These costs can be compared with those of other carbon reduction strategies, such as we have done in the previous chapter (see Table V.7). Recall that the marginal control cost of carbon used in the MADPU adder system estimates the unit cost of mitigating carbon emissions (through tree planting) at $0.04/lb. C. Adder-based dispatch of the existing system in 1990 produced carbon savings at $0.20/lb. C,[6] while least-emissions dispatch produced carbon savings at $0.07/lb. C.

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[5]We only include the 75/75/N portfolio here because the other low carbon portfolios include only scheduled oil plant retirement and in this context, it makes no sense to compare these portfolios to a reference case with larger retirements. This would be equivalent to proposing that NEPOOL put retired coal plants back into service as part of a carbon reduction strategy.

[6] Recall that the adder-based dispatch unit cost of carbon savings is a *maximum* value, and not an expected value as with the other unit costs expressed here.

Table VI.5. Net Costs of Carbon Savings: Low Cost Portfolios

Change in Costs (M $)	Base Fuel Prices *Change in C emissions rel. to 1990 % of 1990*	*Net Cost (Low) (M$)*	*Net Cost (High) (M$)*	Low Fuel Prices *Change in C emissions rel. to 1990 % of 1990*	*Net Cost (Low) (M$)*	*Net Cost (High) (M$)*
Compared to NEGC:						
Low Cost (50/0)	-25%	-1112	-601	-21%	-935	-424
Compared to NEGC w/ Nuclear Retirement:						
Low Cost (50/0/N)	-2%	-1110	-599	0%	-929	-418
Low Cost (75/0/N)	-15%	-1236	-409	-12%	-890	-63
Compared to NEGC w/ Oil Retirement:						
Low Cost (50/0)	-25%	-1217	-706	-21%	-997	-486

Change in Costs (%)	*Change in C emissions rel. to 1990 % of 1990*	*Change in Net Cost (Low)*	*Change in Net Cost (High)*	*Change in C emissions rel. to 1990 % of 1990*	*Change in Net Cost (Low)*	*Change in Net Cost (High)*
Compared to NEGC:						
Low Cost (50/0)	-25%	-14%	-7%	-21%	-12%	-6%
Compared to NEGC w/ Nuclear Retirement:						
Low Cost (50/0/N)	-2%	-13%	-7%	0%	-12%	-5%
Low Cost (75/0/N)	-15%	-14%	-5%	-12%	-11%	-1%
Compared to NEGC w/ Oil Retirement:						
Low Cost (50/0)	-25%	-15%	-9%	-21%	-13%	-6%

Table VI.6. Net Costs of Carbon Savings: Low Carbon Portfolios

Change in Costs (M $)	Base Fuel Prices *Change in C emissions rel. to 1990 % of 1990*	*Net Cost (Low) (M$)*	*Net Cost (High) (M$)*	Low Fuel Prices *Change in C emissions rel. to 1990 % of 1990*	*Net Cost (Low) (M$)*	*Net Cost (High) (M$)*
Compared to NEGC:						
Low Carbon (50/50)	-37%	-614	197	-34%	-316	495
Low Carbon (75/75)	-74%	-385	994	-71%	-40	1339
Compared to NEGC w/ Nuclear Retirement:						
Low Carbon (50/50/N)	-19%	-690	111	-15%	-343	458
Low Carbon (75/75/N)	-52%	-494	880	-49%	-74	1300
Compared to NEGC w/ Oil Retirement:						
Low Carbon (50/50)	-37%	-719	91	-34%	-378	432
Low Carbon (75/75)	-74%	-490	889	-71%	-102	1277
Compared to NEGC w/ Fossil & Nuclear Retirement:						
Low Carbon (75/75/N)	-52%	-1116	258	-49%	-403	971

Change in Costs (%)	*Change in C emissions rel. to 1990 % of 1990*	*Change in Net Cost (Low)*	*Change in Net Cost (High)*	*Change in C emissions rel. to 1990 % of 1990*	*Change in Net Cost (Low)*	*Change in Net Cost (High)*
Compared to NEGC:						
Low Carbon (50/50)	-37%	-8%	2%	-34%	-4%	7%
Low Carbon (75/75)	-74%	-5%	12%	-71%	-1%	18%
Compared to NEGC w/ Nuclear Retirement:						
Low Carbon (50/50/N)	-19%	-8%	1%	-15%	-4%	6%
Low Carbon (75/75/N)	-52%	-6%	10%	-49%	-1%	16%
Compared to NEGC w/ Oil Retirement:						
Low Carbon (50/50)	-37%	-9%	1%	-34%	-5%	6%
Low Carbon (75/75)	-74%	-6%	11%	-71%	-1%	17%
Compared to NEGC w/ Fossil & Nuclear Retirement:						
Low Carbon (75/75/N)	-52%	-12%	3%	-49%	-5%	12%

Table VI.7. Unit Costs of Carbon Savings

	Base Fuel Prices			Low Fuel Prices		
Low Cost Portfolios	*Change in C emissions rel. to 1990 % of 1990*	*Unit Cost (Low) ($/lb. C)*	*Unit Cost (High) ($/lb. C)*	*Change in C emissions rel. to 1990 % of 1990*	*Unit Cost (Low) ($/lb. C)*	*Unit Cost (High) ($/lb. C)*
Compared to NEGC:						
Low Cost (50/0)	-25%	-$0.07	-$0.04	-21%	-$0.06	-$0.03
Compared to NEGC w/ Nuclear Retirement:						
Low Cost (50/0/N)	-2%	-$0.07	-$0.04	0%	-$0.06	-$0.03
Low Cost (75/0/N)	-15%	-$0.06	-$0.02	-12%	-$0.04	$0.00
Compared to NEGC w/ Oil Retirement:						
Low Cost (50/0)	-25%	-$0.10	-$0.06	-21%	-$0.08	-$0.04

	Base Fuel Prices			Low Fuel Prices		
Low Carbon Portfolios	*Change in C emissions rel. to 1990 % of 1990*	*Unit Cost (Low) ($/lb. C)*	*Unit Cost (High) ($/lb. C)*	*Change in C emissions rel. to 1990 % of 1990*	*Unit Cost (Low) ($/lb. C)*	*Unit Cost (High) ($/lb. C)*
Compared to NEGC:						
Low Carbon (50/50)	-37%	-$0.03	$0.01	-34%	-$0.02	$0.02
Low Carbon (75/75)	-74%	-$0.01	$0.03	-71%	$0.00	$0.04
Compared to NEGC w/ Nuclear Retirement:						
Low Carbon (50/50/N)	-19%	-$0.03	$0.00	-15%	-$0.02	$0.02
Low Carbon (75/75/N)	-52%	-$0.01	$0.03	-49%	$0.00	$0.04
Compared to NEGC w/ Oil Retirement:						
Low Carbon (50/50)	-37%	-$0.04	$0.01	-34%	-$0.02	$0.03
Low Carbon (75/75)	-74%	-$0.02	$0.03	-71%	$0.00	$0.04
Compared to NEGC w/ Fossil & Nuclear Retirement:						
Low Carbon (75/75/N)	-52%	-$0.05	$0.01	-49%	-$0.02	$0.04

5. Discussion

Zero cost carbon reductions are at the core of the "no regrets" policy currently favored by the U.S. government (as presented in Chapter II). The results from our Low Cost portfolios show that freezing emissions at 1990 levels (e.g. in the 50/0/N case) and emissions reductions of 12% to 15% (in the 75/0/N case) can be achieved at robustly negative net costs (assuming aggressive mobilization of efficiency resources). Carbon emissions reductions of from 15% to 19% are possible using DSM plus higher cost renewables (in the 50/50/N case) with negative net cost in all cases except under low fuel prices and high resource costs.

It is important to note that these portfolios could still be improved slightly from the perspective of reducing costs and increasing carbon reductions. For example, greater use of inexpensive cogeneration and fuel switching resources could raise the percentage carbon reductions feasible at zero or negative net cost beyond the 12-15 percent range.

Interestingly, higher net costs are found among the low fuel price cases. The explanation lies in the fact that our carbon saving portfolios are largely composed of capital-intensive technologies – DSM, biomass, wind, cogeneration – that essentially substitute capital for operating costs, which are mostly from fuel. This trade-off of fixed for variable costs is advantageous under high fuel price trajectories, but less so when fuel price escalation is low. Thus, the downside exposure of carbon reduction portfolios is from low fuel price escalation.

All other things being equal, the greater the amount of retired existing capacity in the reference case, the lower the net social costs will be from implementing low carbon strategies. In the Low Cost cases, larger scheduled retirements in the reference case lead to a greater swing in net costs between the base and low fuel price scenarios. The effect is particularly pronounced for comparisons involving nuclear retirement in the reference case because of the low and stable price projections for uranium. For example, when the Low Cost cases are compared to NEGC with nuclear retirement, they exhibit a $300 - $400 million increase in net cost when going from base to low fuel prices, whereas with NEGC proper, the shift is less than $100 million. In the Low Carbon cases, capital intensive renewables displace gas ACC plants, thus reducing the importance of this effect.

E. RATE IMPACTS

1. Methodological Considerations

We next calculate the impact of our carbon reduction portfolios on electricity rates. We only calculate average rate impacts based on the overall relationship between electricity sales and the cost of delivering energy services (i.e., supply costs plus demand-side efficiency and fuel switching costs), leaving aside the question of how rate changes would be allocated among customer classes.

We assume that DSM and fuel switching resources are mobilized through a combination of utility incentive programs, and through appliance/building efficiency standards that impose no direct cost on the utility (as indicated in Chapter IV, Sections E.1 and E.2). A recent study in New York determined that only half of the achievable potential for electricity conservation was obtainable through utility programs, and that the rest would have to come through new appliance standards and revisions to building codes (Nadel, 1990). Accordingly, we assume that the implementation of DSM resources in New England would be equally shared between utility programs on the one hand, and various government initiatives on the other. Furthermore, we assume that the utility programs are designed in such a way that they pay 100 percent of the DSM resource costs.[7] As we describe below, different assumptions about the proportion of the electricity savings achieved through efficiency standards or about the proportion of resource costs borne by the utility have a relatively small impact on final results.

Another important assumption concerns the size of the credit to DSM for avoided transmission and distribution (T&D) system costs. Our assumptions are detailed in Chapter IV and Appendix E. In the optimistic low resource cost case for DSM, about half of the cost (0.8¢/kWh) of maintaining the T&D system (1.5¢/kWh, see above) is considered avoidable by DSM programs, while in the pessimistic case, less than 15 percent of these costs are avoidable. The art of estimating T&D credits is still in its infancy (see Appendix E), so we have adopted relatively conservative numbers. Rate impacts could be lower than in our calculations if further analysis and experience demonstrate that the value of the T&D credits is greater than assumed here.

With these assumptions, we present our stylized calculation of rates and rate impacts for the alternative retirement cases, Low Cost portfolios, and Low Carbon portfolios in Tables VI.8 and VI.9. The first of these Tables gives the average prices for the reference cases and portfolios. Also shown are the electricity sales that go into the denominator of the rate calculation. For NEGC and its retirement variations, the average electricity rate ranges from 4.9 ¢/kWh for NEGC under low fuel costs to 6.2 ¢/kWh for NEGC with nuclear and fossil retirement under reference fuel costs.[8] Of the resource portfolios we consider, the lowest rate of 5.0 ¢/kWh comes with the Low Cost 50/0 portfolio under low fuel and resource costs, while the highest rate of 7.5 ¢/kWh comes with the Low Carbon 75/75/N portfolio under reference fuel and high resource costs.

2. Low Cost Portfolios

Table VI.9 shows the percentage change in rates for the Low Cost portfolios. Compared to the NEGC case with nuclear retirements the Low Cost 50/0/N case, which keeps carbon emissions constant at 1990 levels, would increase rates by 1% to 6%. Rate impacts for the Low Cost 75/0/N case, which achieves carbon reductions of 12 to 15%, would total 7% to 18%. As was found in the net cost analysis, low fuel prices tend to adversely impact the net change in rates because savings in fuel costs are less valuable than before, while the capital cost in these portfolios remains the same.

In the Low Cost portfolios, the average electricity rate climbs because of DSM and fuel switching. While ratepayers as a whole are bearing only half of the costs of the DSM resources, and even though these resources are inexpensive relative to most new supply alternatives, total energy service costs are spread over fewer kilowatt-hours, resulting in net rate impacts.

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[7] The large penetration of DSM resources implicit in our low carbon portfolios is consistent with utilities bearing the full costs of utility programs (Nadel, 1990).

[8] Our analysis uses a real discount rate, which contains no inflation and hence is lower than the nominal discount rate used in utility ratemaking. The absolute values for the rates in Tables VI.8 and VI.9 may therefore seem low compared to actual electricity rates. However, the relative ranking of rate impacts will not be affected by our use of the real discount rate.

Table VI.8. Average Electricity Rates

	Sales (TWh)	Base Fuel Prices: Change in C emissions rel. to 1990 % of 1990	Base Fuel Prices: Average Price (Low) (¢/kWh)	Base Fuel Prices: Average Price (High) (¢/kWh)	Low Fuel Prices: Change in C emissions rel. to 1990 % of 1990	Low Fuel Prices: Average Price (Low) (¢/kWh)	Low Fuel Prices: Average Price (High) (¢/kWh)
NEGC	152	25%	5.33	5.33	26%	4.94	4.94
NEGC w/ Nuclear Retirement	152	46%	5.81	5.81	48%	5.24	5.24
NEGC w/ Oil Retirement	152	11%	5.40	5.40	15%	4.99	4.99
NEGC w/ Fossil & Nuclear Retirement	152	18%	6.22	6.22	23%	5.46	5.46
Low Cost Portfolios							
Low Cost (50/0)	128	-25%	5.31	5.55	-21%	4.99	5.23
Low Cost (50/0/N)	128	-2%	5.85	6.09	0%	5.32	5.55
Low Cost (75/0/N)	116	-15%	6.22	6.65	-12%	5.78	6.21
Low Carbon Portfolios							
Low Carbon (50/50)	132	-37%	5.52	5.99	-34%	5.30	5.77
Low Carbon (75/75)	120	-74%	6.11	6.99	-71%	5.91	6.79
Low Carbon (50/50/N)	132	-19%	6.03	6.49	-15%	5.63	6.10
Low Carbon (75/75/N)	120	-52%	6.64	7.51	-49%	6.27	7.14

Table VI.9. Percentage Rate Impacts

Low Cost Portfolios	Base Fuel Prices: Change in C emissions rel. to 1990 % of 1990	Base Fuel Prices: Change in Rates (Low)	Base Fuel Prices: Change in Rates (High)	Low Fuel Prices: Change in C emissions rel. to 1990 % of 1990	Low Fuel Prices: Change in Rates (Low)	Low Fuel Prices: Change in Rates (High)
Compared to NEGC:						
Low Cost (50/0)	-25%	0%	4%	-21%	1%	6%
Compared to NEGC w/ Nuclear Retirement:						
Low Cost (50/0/N)	-2%	1%	5%	0%	1%	6%
Low Cost (75/0/N)	-15%	7%	14%	-12%	10%	18%
Compared to NEGC w/ Oil Retirement:						
Low Cost (50/0)	-25%	-2%	3%	-21%	0%	5%

Low Carbon Portfolios	Base Fuel Prices: Change in C emissions rel. to 1990 % of 1990	Base Fuel Prices: Change in Rates (Low)	Base Fuel Prices: Change in Rates (High)	Low Fuel Prices: Change in C emissions rel. to 1990 % of 1990	Low Fuel Prices: Change in Rates (Low)	Low Fuel Prices: Change in Rates (High)
Compared to NEGC:						
Low Carbon (50/50)	-37%	4%	12%	-34%	7%	17%
Low Carbon (75/75)	-74%	15%	31%	-71%	20%	37%
Compared to NEGC w/ Nuclear Retirement:						
Low Carbon (50/50/N)	-19%	4%	12%	-15%	7%	16%
Low Carbon (75/75/N)	-52%	14%	29%	-49%	19%	36%
Compared to NEGC w/ Oil Retirement:						
Low Carbon (50/50)	-37%	2%	11%	-34%	6%	16%
Low Carbon (75/75)	-74%	13%	29%	-71%	19%	36%
Compared to NEGC w/ Fossil & Nuclear Retirement:						
Low Carbon (75/75/N)	-52%	7%	21%	-49%	15%	31%

While complete utility subsidization of customer investments in DSM would certainly be required in the early years to reach the high participation rates of these low carbon portfolios, it is conceivable that this practice would not have to continue unabated over 15-20 years. Thus, as a further sensitivity, we calculate the rate impact from the utility bearing half the cost of the DSM resource captured through utility programs, which again are the means by which only half the DSM resource at a given utilization level is captured. This lowers the rate impact by 2-3 percentage points for most of the Low Cost portfolios, and by 6 percentage points at a maximum. The Low Cost 75/0/N case, because of its heavy reliance on DSM, is most sensitive to changes in the assumption of who bears the costs.

3. Low Carbon Portfolios

Table VI.9 also shows the percentage change in rates for the Low Carbon portfolios. Compared to the NEGC case with nuclear retirements, the Low Carbon 50/50/N case (which reduces carbon emissions by 15 to 19%) would increase rates by 4% to 16%. The Low Carbon 75/75/N case, which represents the most aggressive mobilization of low carbon resources that we consider, would increase rates by 14% to 36% relative to NEGC with nuclear retirements.

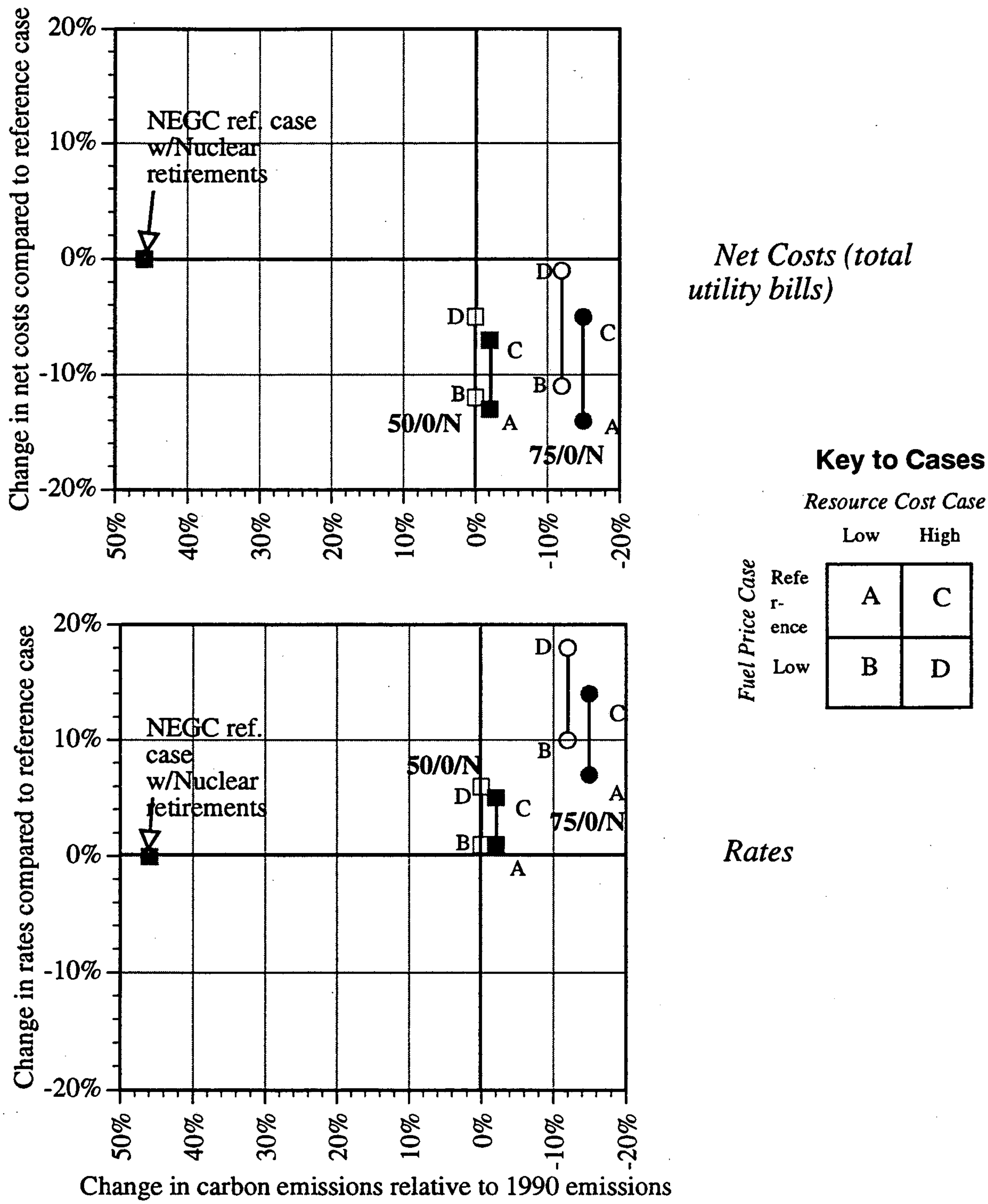
In the Low Carbon portfolios, rate impacts are caused by the combination of DSM and high cost renewables. Renewables cause rate impacts when their costs exceed that of our swing resource (the ACC). If, as before, we calculate the rate impact from the utility bearing only half the cost of the DSM resource captured through utility programs, we find that the rate impact is reduced by 2-3 percentage points for most of the Low Carbon portfolios, and by 6 percentage points for the Low Carbon 75/75/N case under high resource cost assumptions.

F. SUMMARY OF RATE AND COST IMPACTS

To clarify the tradeoff between net costs and rates, we combine the information from Sections D and E in Figures VI.1, VI.2, and VI.3. In Figures VI.1 and VI.2, changes in carbon emissions relative to 1990 are shown on the x-axis, and changes in costs or rates relative to the NEGC case with nuclear retirements are shown on the y-axis. In Figure VI.3, changes in costs are shown on the y-axis and changes in rates are shown on the x-axis.

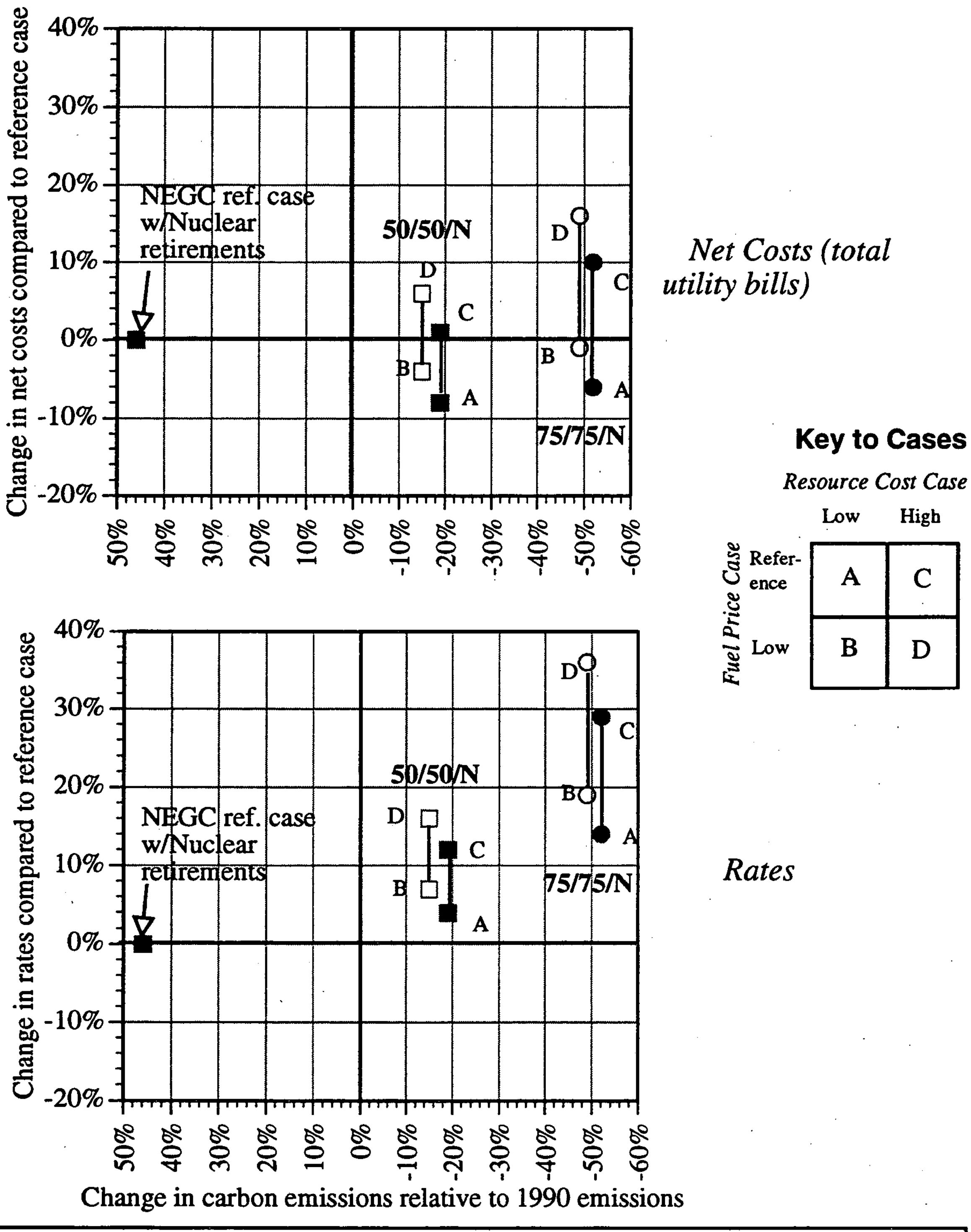
These figures show that keeping carbon emissions constant at 1990 levels in the Low Cost 50/0/N portfolio would cause rate impacts of from 1% to 6%. To achieve carbon reductions relative to 1990 will require further increases in rates relative to the Low Cost 50/0/N portfolio. The Low Cost 75/0/N portfolio, with its higher penetration of DSM, yields larger rate impacts of from 7% to 18% for carbon reductions of 12% to 15%. Both of these portfolios have negative net costs under all assumptions for fuel prices and resource costs.

Figure VI.1: Low Cost Scenarios for New England in 2005: Changes in Carbon Emissions, Net Costs, and Electricity Rates



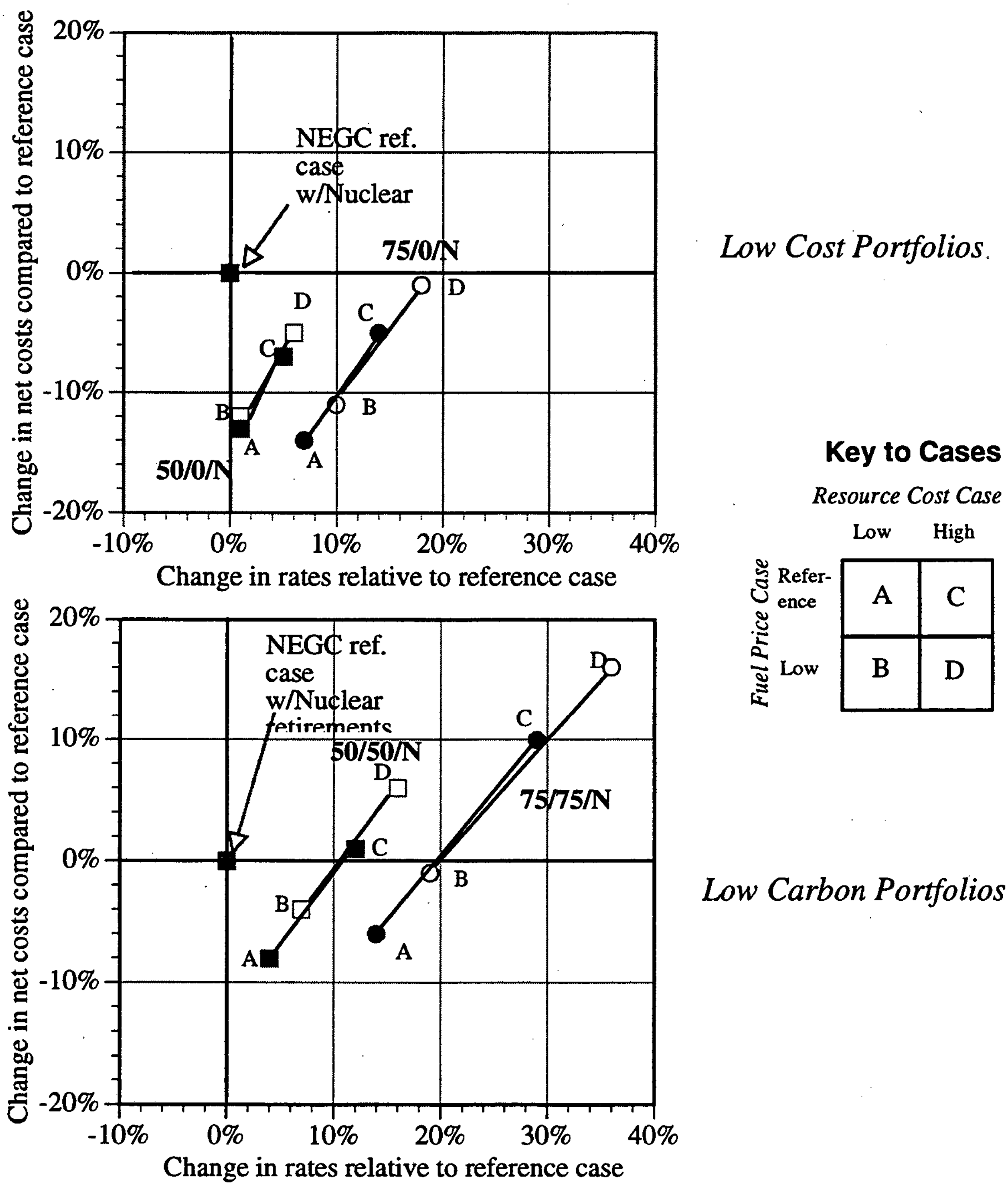
Notes:
1) 50/0/N uses 50% of demand-side management (DSM)/fuel switching/cogeneration potentials, and 0% of renewables, with nuclear retirements; 75/0/N uses 75% of the DSM potentials, 50% of the fuel switching/cogeneration potentials, and 0% of the renewables, with nuclear retirements.
2) Carbon emissions in 1990 = 17.1 megatonnes C
3) Total energy service costs in 2005 are $6.2 billion in the reference fuel price case and $5.4 billion in the low fuel price case; Rates in 2005 are 5.8¢/kWh in the reference fuel price case and 5.2¢/kWh in the low fuel price case

Figure VI.2: Low Carbon Scenarios for New England in 2005: Changes in Carbon Emissions, Net Costs, and Electricity Rates



Notes:
1) 50/50/N uses 50% of demand-side management (DSM)/fuel switching/cogeneration potentials, and 50% of renewables potentials, with nuclear retirements; 75/75/N uses 75% of the DSM/ fuel switching/cogeneration potentials, and 75% of the renewables potentials, with nuclear retirements.
2) Carbon emissions in 1990 = 17.1 megatonnes C
3) Total energy service costs in 2005 are $6.2 billion in the reference fuel price case and $5.4 billion in the low fuel price case; Rates in 2005 are 5.8¢/kWh in the reference fuel price case and 5.2¢/kWh in the low fuel price case

Figure VI.3: Low Carbon and Low Cost Scenarios for New England in 2005: Changes in Net Costs and Electricity Rates



Notes:
1) 50/0/N uses 50% of demand-side management (DSM)/fuel switching/cogeneration potentials, and 0% of renewables, with nuclear retirements; 75/0/N uses 75% of the DSM potentials, 50% of the fuel switching/cogeneration potentials, and 0% of the renewables, with nuclear retirements.
2) 50/50/N uses 50% of demand-side management (DSM)/fuel switching/cogeneration potentials, and 50% of renewables potentials, with nuclear retirements; 75/75/N uses 75% of the DSM/ fuel switching/cogeneration potentials, and 75% of the renewables potentials, with nuclear retirements.
3) Total energy service costs in 2005 are \$6.2 billion in the reference fuel price case and \$5.4 billion in the low fuel price case; Rates in 2005 are 5.8¢/kWh in the reference fuel price case and 5.2¢/kWh in the low fuel price case
4) For changes in carbon emissions see Figures VI.1 and VI.2.

The Low Carbon 50/50/N portfolio yields still larger carbon reductions of 15 to 19% with smaller rate impacts of from 4% to 16%. The net costs in this case range from -4% to -8% for the low resource cost assumptions and from 1% to 6% for the high resource cost assumptions. The Low Carbon 75/75/N portfolio, which would produce carbon reductions vastly greater than any now being considered by New England regulators in the 1990 to 2005/2010 time frame, would lead to negative net costs (-1% to -6%) in the low resource cost cases, and positive net costs (10% to 16%) in the high resource cost cases. Rate impacts would range from 14% to 36%.

Figure VI.3 directly shows the relationship of costs and rates (the labels and symbols are the same as for the previous two figures), and clearly shows the effect of DSM on rate impacts. When one takes into account differences in the scenarios examined, the cost/rate relationships shown in Figure VI.3 are similar to those found by Connors and Andrews (1991) and Hirst (1991). Both studies examined a more limited range of changes to the reference resource mix than in our analysis, and neither included significant amounts of renewables. Hirst's schematic calculations examined only additions of DSM resources. The key assumptions in these studies come closest to our 50/0 case. Like Figure VI.3 for our 50/0 low cost case, their findings imply that for DSM contributions of these magnitudes, the percentage rate impacts are quite small, and total electricity bills are actually reduced. It is only when larger DSM contributions are considered, or when the more expensive renewables are heavily relied on, that significant rate impacts arise.

G. GAS DEMAND IMPACTS

At present, New England's gas supply capacity is used at close to maximum capacity. Of the pipeline projects recently approved for New England by the Federal Energy Regulatory Commission (FERC) in its "Open Season" proceedings, four projects of 155 Bcf/yr total capacity are expected to be completed: Norex, Iroquois, Niagara spur, and Texas Eastern. These projects will not be sufficient to meet the region's anticipated additional demand for gas in 2005/2010 (see Appendix H).

Table VI.10 shows gas requirements for the various resource mixes dispatched under the reference and low fuel price forecasts. In the table, increases in gas requirements are expressed in four ways: in absolute terms relative to 1990, relative to the four Open Season additions, relative to 2005/2010 power sector demand in the NEGC reference case, and relative to projected 2005/2010 all-sector gas demand. The gas from these pipelines has already been committed to supply non-generation customers and modest increases in planned new generation. In the NEGC 2005 reference case, the increase in total power sector gas demand by 2005 would equal 88% of the capacity of these four pipeline projects, an increase that would overwhelm the supply of gas. New England will clearly have to address serious gas supply problems even before global warming issues are considered.

Table VI.10 Impact of Low Carbon Portfolios on Gas Supply Requirements in New England.

Portfolio	*Fuel price scenario*	*Total incremental gas requirement over 1990 use (Bcf/yr)*	*Incremental supply over 1990 as % of FERC Open Season projects*	*Change in demand from power sector over NEGC w/ ref. case fuel prices*	*Change in demand from all sectors over NEGC w/ ref. case fuel prices*
REFERENCE FUEL PRICE CASES					
NEGC	Reference	136	88%	0%	0%
NEGC w/ Nuclear Retirement	Reference	261	168%	90%	22%
NEGC w/ Oil Retirement	Reference	253	164%	84%	21%
NEGC w/ Nuclear and Fossil Retirement	Reference	508	328%	270%	66%
Low Cost Portfolios					
Low Cost (50/0)	Reference	186	120%	35%	9%
Low Cost (50/0/N)	Reference	300	193%	118%	29%
Low Cost (75/0/N)	Reference	222	143%	62%	15%
Low Carbon Portfolios					
Low Carbon (50/50)	Reference	127	82%	-8%	-2%
Low Carbon (75/75)	Reference	123	79%	-11%	-3%
Low Carbon (50/50/N)	Reference	250	161%	82%	20%
Low Carbon (75/75/N)	Reference	221	143%	61%	15%
LOW FUEL PRICE CASES					
NEGC	Low	152	98%	11%	3%
NEGC w/ Nuclear Retirement	Low	272	176%	98%	24%
NEGC w/ Oil Retirement	Low	294	189%	114%	28%
NEGC w/ Nuclear and Fossil Retirement	Low	548	354%	299%	73%
Low Cost Portfolios					
Low Cost (50/0)	Low	210	136%	53%	13%
Low Cost (50/0/N)	Low	320	206%	133%	32%
Low Cost (75/0/N)	Low	244	157%	77%	19%
Low Carbon Portfolios					
Low Carbon (50/50)	Low	168	109%	22%	5%
Low Carbon (75/75)	Low	187	121%	36%	9%
Low Carbon (50/50/N)	Low	283	182%	106%	26%
Low Carbon (75/75/N)	Low	245	158%	78%	19%

(1) The FERC Open Season pipeline projects for New England are estimated to add gas supplies of 155 bcf/yr.
(2) All gas-fired power generation is assumed to be on firm (365 days per year) supply.
(3) 2005/2010 gas demand for non-generation uses from Appendix H.

The key issue is the impact of carbon reduction strategies on overall gas demand in the region. We explore gas demand projections for other sectors in Appendix H, Volume II. In the estimate for the increase in total gas use, we also take into account (albeit crudely) the potential for natural gas efficiency improvements and for end-use fuel switching from electricity to gas. Our gas demand figures are associated with considerable uncertainty, but provide an order of magnitude orientation.

Table VI.10 shows that portfolios without nuclear retirements would involve slight decreases or only modest increases in total gas demand when compared to the NEGC reference case (from -3% to +13 percent on an all-sector basis). The conclusion is the same when portfolios with nuclear retirements are compared to the NEGC reference case plus nuclear retirements.[9] The Low Cost 50/0/N case, which keeps carbon emissions roughly constant at 1990 levels, would involve a 6% increase in gas demand over the NEGC case with nuclear retirements. The Low Cost 75/0/N case, which reduces carbon emissions 12 to 15%, leads to a decrease in gas use of about 6%. The Low Carbon 50/50/N case, which reduces carbon emissions by 15 to 19% relative to 1990 levels, would keep gas use within 2% of that in the NEGC case with nuclear retirements.

Gas supply requirements under the low fuel price trajectory are somewhat larger than with reference fuel prices, primarily from increased generation of gas ACC plants and gas-fired cogeneration facilities.

In calculating the impacts of carbon reduction strategies on gas demand, we have assumed that both cogenerators and utility-scale plants would operate on a firm gas supply basis of 365 days per year. This assumption somewhat overstates the gas demand impacts of carbon reduction strategies. In practice, power producers and gas companies might prefer a quasi-firm gas supply arrangement in which distillate oil would be burned during the peak winter heating period. Such contracts would reduce gas requirements. However, air pollution rules in some parts of New England restrict such distillate substitution. For example, Massachusetts regulations for new plants currently limit distillate use to 30 days per year. A quasi-firm supply arrangement based on 30-60 days of distillate combustion would reduce incremental 2005/2010 power sector gas demand by 8-16 percent relative to all-gas operation. At the same time, carbon emissions of gas-fired central stations would increase by 4-7 percent.

In summary, gas demand in the NEGC reference case in 2005 cannot be met by gas pipeline additions that are existing, currently approved, or under construction. Additional pipeline capacity will be needed regardless of whether carbon reduction strategies are implemented. Our results indicate that freezing carbon emissions or reducing them by 12% to 19% will change total gas use by no more than about 6% relative to the NEGC reference case with nuclear retirements. This result assumes that thermally optimized cogeneration, renewables, and efficiency measures for both gas and electricity are implemented as described above for the Low Cost 50/0/N, Low Cost 75/0/N, and Low Carbon 50/50/N cases.

[9]Recall that any nuclear retirements would be undertaken independent of the carbon reduction strategy, and so the appropriate comparison is between the NEGC case with nuclear retirements and portfolios with nuclear retirements.

H. REGIONAL AIR POLLUTION IMPACTS

An important byproduct of the carbon reduction portfolios is the simultaneous reduction in acid rain precursor gases. This synergism arises because major reductions in carbon emissions below 1990 levels dictate retirement of depreciated, existing oil and/or coal plants, the main producers of SO_2 and NO_x. Acid rain precursor emissions from the three low carbon portfolios are compared to those of the reference cases in Table VI.11.

There is little difference between emissions in reference fuel price and low fuel price cases. There is also little difference in the percentage decreases of SO_2 and NO_x brought about by the carbon reduction portfolios in relation to NEGC or NEGC with nuclear retirement. All portfolios show significant acid rain gas reductions in comparison to these reference cases. In comparison to NEGC with oil retirement, however, the reductions are more modest because the potential benefits of the portfolio in lowering SO_2 and NO_x are largely captured in the reference case.

Relative to NEGC or NEGC with nuclear retirements, SO_2 reductions total roughly 30% for the Low Cost portfolios, and range from 36% to 93% in the Low Carbon portfolios. NO_x reductions range from 36% to 39% for the Low Cost Portfolios and from 39% to 78% for the Low Carbon portfolios.

The reference case incorporating depreciated fossil and nuclear plant retirement has the lowest emissions of SO_2 and NO_x of any of the reference cases by far. Even though the new capacity in this case exhibits higher SO_2 and NO_x emissions than the nuclear capacity it replaces, the differential in emissions characteristics between the new capacity and the retired fossil capacity is sufficiently great to dominate the result. Consequently, the Low Carbon 75/75/N portfolio shows its smallest acid rain gas reductions in comparison to this latter reference case, but nonetheless shows reductions of 24 % to 30% for NO_x and 30% for SO_2.

Table VI.11. Changes in Acid Rain Precursor Emissions Relative to Various Reference Cases

	Base Fuel Prices		Low Fuel Prices	
Low Cost Portfolios	*SO2*	*NOx*	*SO2*	*NOx*
Compared to NEGC:				
Low Cost (50/0)	-32%	-39%	-31%	-38%
Compared to NEGC w/ Nuclear Retirement:				
Low Cost (50/0/N)	-29%	-36%	-29%	-36%
Low Cost (75/0/N)	-31%	-39%	-31%	-38%
Compared to NEGC w/ Oil Retirement:				
Low Cost (50/0)	-4%	-17%	-3%	-15%

	Base Fuel Prices		Low Fuel Prices	
Low Carbon Portfolios	*SO2*	*NOx*	*SO2*	*NOx*
Compared to NEGC:				
Low Carbon (50/50)	-37%	-41%	-37%	-41%
Low Carbon (75/75)	-92%	-77%	-93%	-78%
Compared to NEGC w/ Nuclear Retirement:				
Low Carbon (50/50/N)	-37%	-39%	-36%	-40%
Low Carbon (75/75/N)	-84%	-69%	-84%	-69%
Compared to NEGC w/ Oil Retirement:				
Low Carbon (50/50)	-12%	-20%	-11%	-20%
Low Carbon (75/75)	-88%	-69%	-90%	-71%
Compared to NEGC w/ Fossil & Nuclear Retirement:				
Low Carbon (75/75/N)	-30%	-30%	-24%	-30%

CHAPTER VII

CONCLUSIONS

A. SUMMARY

Over the next 20 years, New England currently faces several challenges in utility resource planning, including the possible need to replace nuclear capacity, to clean up or replace existing fossil-fired capacity, and to reduce oil dependence. All this would ideally be achieved while minimizing the need for new gas supplies, while keeping new environmental impacts to a minimum, and while holding down electricity bills and rates.

Our analysis investigated whether and how these objectives and constraints could be met while simultaneously addressing a new challenge: buying insurance against the risks of global warming by reducing carbon dioxide emissions. To determine how New England's utility sector might meet this challenge, we explored two disparate approaches: the use of environmental externality surcharges and a target-based approach.

Use of the externality surcharges adopted in Massachusetts was assessed for its effectiveness in several different planning or operational modes. The Massachusetts adder system effectively eliminates high-carbon coal plants from the competition for marginal investments, but is not sufficient to fully shift investment choices to currently commercial non-fossil supply technologies such as wind or biomass-fired power plants. Other important low-carbon resources, such as demand-side management and gas-fired cogeneration, are already as cheap or cheaper than gas ACC plants even before externality adders are applied. The adder system would be overwhelmingly effective in justifying scheduled or accelerated retirements of existing coal and oil-fired plants in favor of lower-carbon gas-fired cogeneration plants and utility-scale ACC plants. Finally, dispatching the New England system on the basis of the Massachusetts adders proved to be ineffective in bringing about carbon reductions, and even when some reductions were realized, they were significantly more costly than corresponding reductions obtained under a target-based approach.

A target-based approach was formulated first by establishing the costs and potentials of low-carbon resources for the region, and then calculating the emissions and system costs associated with several alternative electricity resource mixes fifteen to twenty years hence. Simulation of these low carbon portfolios established that moderate to even ambitious carbon reduction targets can indeed be met in New England. We showed that the net costs depend primarily on four factors: the definition of the resource future that would be anticipated in absence of concerns over global warming (the reference case); the estimated uncertainty range for the costs and potentials of low-carbon resources; the progression of fuel prices; and the levels of emission reduction being sought. New England faces challenges in meeting gas demand even in the NEGC reference case. Low carbon portfolios would not increase gas demand significantly from the various reference cases because gas ACCs (the "swing resource") are displaced by low carbon resources that either do not use gas or use it more efficiently than do ACCs.

B. REGULATORS' OPPORTUNITY: CARBON REDUCTIONS AND SOCIAL COSTS

Zero cost carbon reductions are at the core of the "no regrets" policy currently favored by the U.S. government (as presented in Chapter II). The results from our analysis indicate that some carbon reductions are likely to be achievable at zero or even negative net cost. Our Low Cost scenarios show that freezing emissions at 1990 levels (eg in the 50/0/N case) and emissions reductions of 12% to 15% (in the 75/0/N case) can be achieved at robustly negative net costs (assuming aggressive mobilization of efficiency resources). Carbon emissions reductions of from 15% to 19% are possible using DSM plus higher cost renewables (in the 50/50/N case) with negative or approximately zero net cost in all cases except under low fuel prices and high resource costs.

It is important to note that these portfolios are not optimized. For example, greater use of inexpensive cogeneration and fuel switching resources could raise the percentage carbon reductions feasible at zero or negative net cost beyond the 12-15% range. However, logistical difficulties in mobilizing larger amounts of these low carbon resources would also arise from such efforts.

C. REGULATORS' DILEMMA: SOCIAL COSTS VS. RATES

Our results show that keeping carbon emissions constant at 1990 levels in the Low Cost 50/0/N case would cause rate impacts of from 1% to 6%. To achieve carbon reductions relative to 1990 will require further increases in rates relative to the 50/0/N case. The Low Cost 75/0/N case, with its higher penetration of DSM, yields larger rate impacts of from 7% to 18% for carbon reductions of 12% to 15%. Both of these portfolios have negative net costs under all assumptions for fuel prices and resource costs. The Low Carbon 50/50/N case yields still larger carbon reductions of 15 to 19% with smaller rate impacts of from 4% to 16%. The net costs in this case range from -4% to -8% for the low resource cost assumptions and from 1% to 6% for the high resource cost assumptions.

Freezing carbon emissions at 1990 levels appears feasible at negative net cost and with rate impacts of less than 6%. Modest reductions in carbon emissions below 1990 levels can be achieved at negative net costs but with larger rate impacts. The pursuit of such carbon reductions highlights a classic tradeoff with which the region's regulators must grapple.

The underlying dynamic is conceptually akin to the disparity that often appears between the total resource and non-participants' cost-benefit tests when applied to utility conservation programs (Krause and Eto, 1988). The non-participants' test is essentially a test of rate impact. Typically, in these cases the non-participant's perspective is not binding; if the social benefits are large enough and the rate impacts are not too large, then utilities will be instructed to pursue the conservation program in any event. In these situations, regulators have (implicitly or explicitly) decided that the greater social good of conservation outweighs any disadvantages incurred by non-participating ratepayers who will see higher electricity bills.

Similarly, in considering whether utilities should implement low carbon strategies, regulators will have to assess the size of the net cost savings or, in the case of positive net costs, the value of these as greenhouse insurance, versus the higher rates that would inevitably ensue. The rate impacts of the low carbon portfolios are a consequence of heavy reliance on DSM. One predictable outcome of higher rates is that it would increase the pressure for large customers to bypass the system and generate their own electricity, which in turn would lead to even higher rates as fixed costs get spread over fewer customers. However, a countervailing benefit would come from the probable lowering of electricity *bills* for many, if not most, customers from the large scale DSM programs and efficiency standards.

By implementing efficiency standards to supplant utility programs where possible, the rate impacts can be reduced but not eliminated. Another option for mitigating both rate impacts and reducing net costs when seeking higher carbon reductions is to lengthen the schedule for achieving those reductions. Stretching the schedule in this way will reduce cost and rate impacts for two reasons: 1) more existing plants will reach their natural retirement age over a longer implementation period and 2) technological progress in efficiency and renewables technologies will probably reduce capital costs over time.

These and other issues inherent to the regulatory process will have to be weighed in assessing the best course of action for New England's utilities. Should the choice be to pursue a carbon mitigation strategy further, we can recommend some key policy initiatives to promote and accelerate its realization (see Section E, below).

D. ENVIRONMENTAL EXTERNALITY ADDERS-BASED ANALYSIS

The effectiveness of the externality surcharges adopted in Massachusetts was assessed for several different planning or operational modes. We did not review the derivation of the adder values in terms of damage or control costs, but simply treated them as a set of normatively determined surcharges. We then examined what emission reductions could be expected from applying these surcharges and which application, if any, could be used to achieve significant reductions in carbon emissions.

In the context of a carbon reduction strategy, the Massachusetts externality adder system as currently applied could serve a supplementary function to other policy options, by boosting the competitiveness of various low-carbon resource investments at the margin. The Massachusetts adder system effectively eliminates high-carbon coal plants from the competition for marginal investments, but is not sufficient to completely shift investment choices to currently commercial non-fossil supply technologies such as wind or biomass-fired power plants. Other important low-carbon resources, such as demand-side management and gas-fired cogeneration, are already as cheap or cheaper than gas ACC plants before externality adders are even applied.

If the Massachusetts adders are applied only at the margin, they cannot bring about reductions of carbon emissions below 1990 levels in a timely fashion. Dispatching the New England system on the basis of the Massachusetts adders proved to be ineffective in bringing about carbon reductions as well. What little reductions were realized were significantly more costly than corresponding reductions obtained from implementing low carbon resource plans under a target-based approach.

In order to achieve significant carbon reductions with the adder approach, the Massachusetts externality system would have to be applied to retirement decisions for existing plants in addition to new resources. The adder system would justify scheduled or accelerated retirements of existing coal and oil-fired plants in favor of lower-carbon gas-fired cogeneration plants and utility-scale ACC plants. Used this way, adders could lead to carbon reductions comparable to or even greater than those obtainable with target-based integrated emission reduction plans.

At the same time, the impact of the Massachusetts adder on the economics of existing plants illustrates that the application of externality incorporation policies based on monetized adders alone would be a blunt instrument. Taken literally, the Massachusetts adders would justify the retirement of almost all of NEPOOL's fossil-based generating capacity over a period of a few years.

It is obvious that policies other than externality adders applied to existing plants would be required to ensure that the phase-out of existing high-emission plants remains tolerable in terms of rate impacts, system reliability, and annual investment requirements. Competitive bidding or other integrated resource planning processes could be used to acquire needed resources for replacements and load growth.

E. POLICY REQUIREMENTS FOR CARBON REDUCTIONS

What policies would be needed or could be used to realize New England's opportunities for zero-net-cost or low-cost carbon reductions? The single most important policy that New England states probably *must* pursue to implement a successful carbon reduction strategy is the implementation of regulatory reforms that decouple utility earnings from electricity sales, and that provide utilities with profit incentives for successful DSM programs. These profit incentives can be based on the shared savings approach. Such policies are currently being tested in several New England states.

Regulatory commissions could also encourage systematic experiments to determine low-cost means of guaranteeing the savings on which shared-savings payments to utilities would be based. Such monitoring and verification experiments, along with full-scale experiments with aggressive DSM programs, could reduce current uncertainties surrounding the cost and practically achievable potential of DSM resources. They also could increase customer contributions and lower the rate impacts from DSM program incentives.

To complete the penetration of efficient technologies after utility incentive programs have established initial markets, state governments would have to pursue efficiency standards for end-uses not currently covered by federal regulations, and implement them as necessary. Such standards could also lower the cost of DSM resources to utilities by making implementation cheaper, and would reduce electricity rate impacts.

To give an incentive for further efficiency improvements, utilities and regulatory commissions could engage in so-called "golden carrots" initiatives that provide manufacturers with predictable initial markets and premiums for new efficient products.

On the supply-side, similar policies could be pursued to mobilize low-carbon resources. One such approach would be separate requests for proposals (RFPs) that set aside a certain amount of capacity in competitive resource bidding for wind, biomass, and other unconventional low-carbon generating technologies. Such a set-aside was recently proposed by New England Electric System (NEES) in the course of a collaborative in the state of Massachusetts. Such low-carbon RFPs would support the commercialization of advanced biomass and wind generating technologies by creating initial markets.

To bring forth low-carbon (i.e., thermally optimized and gas-fired) cogeneration projects and to discourage projects designed to meet only minimum PURPA requirements, states could require a higher efficiency standard for such projects. A somewhat increased efficiency requirement for PURPA cogeneration projects has already been implemented in Connecticut. As a more aggressive approach, thermally optimized gas-fired cogeneration could be specified as best available control technology (BACT) for industrial boilers under state air quality regulations, as currently done by the state of Hessia in Germany.

A shift to gas-fired cogeneration could be implemented by outright fuel use or carbon emission regulations for such units, or implicitly on the basis of efficiency requirements. At the point of end-use, fuel switching to gas dryers and gas water and space heating could be pursued with utility DSM programs; these types of pilot programs are being considered or implemented in some states.

More broadly, the bidding or integrated planning process for resource acquisitions could be modified to incorporate carbon reduction goals explicitly. For example, RFPs for capacity could be expanded to acquire both certain carbon reduction decrements and needed capacity decrements. Alternatively, or as a complement, externality adders could support the development of low-carbon resources. Such adders could be used to give low-carbon gas-fired cogeneration projects cost advantages over coal-fired cogeneration projects (see Vol. II).

Adder policies would be most effective when coupled with retirement of existing resources to create a sufficient market for cleaner replacements. To this end, utility commissions could establish rules to encourage the retirement of fully depreciated existing fossil-fired capacity.

Finally, state governments in New England might undertake specific R&D, demonstration, and commercialization technologies for new biomass gasification based or other advanced technologies. These initiatives would best be pursued in conjunction with industry and federal programs. An example of such an endeavor is Vermont's initiative to test and demonstrate woodchip gasification technology in cooperation with General Electric's research center in New York.

1. Coordination Needs

These policy initiatives will require unprecedented coordination among energy and environmental agencies: utility regulatory commissions, air resources boards, and other state environmental agencies. Here, integration with policies outside the electric utility sector could become important, even when only carbon emissions in the utility sector itself are being aimed at. For example, carbon reduction potentials in the utility sector could be larger than in direct fuel applications for transportation or heating, and these intersectoral relationships could influence reduction goals for the utility sector. In the case of biomass, increased demand for direct applications of this renewable fuel have to be accounted for when estimating what biomass fuel resources could be available for power generation (see Appendix J). States should also explore the curtailment of greenhouse gases other than fossil carbon dioxide. To address these issues, comprehensive state- or region-wide plans for curtailing greenhouse gas emissions would be needed. At least one state (California) has already commissioned complete emissions inventories and comprehensive reduction plans (CEC 1990, CEC 1991).

Fully integrated, low cost emission reduction strategies would also require that state governments cooperate among each other and with the federal government and that they coordinate many regulatory, policy, and planning functions that now exist side by side. Because such an integration is politically difficult and time consuming, it is important for states to examine pragmatic initiatives that rely, for the time being, on the more limited policy instruments of public utility commissions and other state agencies.

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